Ontario Energy Board

Ontario

EBRO 496

IN THE MATTER OF THE
ONTARIO ENERGY BOARD ACT
AND
IN THE MATTER OF AN APPLICATION BY

NATURAL RESOURCE GAS LIMITED

FOR RATES

DECISION WITH REASONS

1998 August 20

EBRO 496

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF an Application by Natural Resource Gas Limited to the Ontario Energy Board for an order or orders approving or fixing just and reasonable rates for the sale, distribution and transmission of gas commencing October 1, 1997.

BEFORE: F.A. Drozd
Presiding Member

F.G. Laughren
Chair and Member

S.F. Zerker
Member

DECISION WITH REASONS

August 20, 1998

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1. INTRODUCTION

1.1 THE PROCEEDING

1.1.1 Natural Resource Gas Limited ("NRG", the "Applicant", or the "Company") filed an Application with the Ontario Energy Board ("OEB"or the "Board") dated November 26, 1997 ("Application") pursuant to section 19 of the Ontario Energy Board Act, R.S.O. 1990, c.O.13 ("Act"), requesting an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for two fiscal years. These are the fiscal 1998 year commencing on October 1, 1997 and ending on September 30, 1998, and the fiscal 1999 year commencing on October 1, 1998 and ending on September 30, 1999.

1.1.2 The Board issued an interim order (EBRO 496-01) on September 26, 1997 directing that the rates and other service charges approved for the fiscal 1997 rate year be declared interim, effective October 1, 1997, for a period of no longer than one year, and subject to change retroactive to that date. The Board issued a Notice of Application dated December 23, 1997 along with directions for service of the Notice.

1.1.3 On January 28, 1998, the Board issued Procedural Order No. 1, which specified dates for a technical conference, the issues day hearing, the filing of interrogatories, the filing of intervenor evidence and the alternative dispute resolution ("ADR") settlement conference.

1.1.4 The technical conference was held on Friday, February 13, 1998, to review NRG's prefiled evidence and to discuss the issues relevant to the hearing of the Application. On February 19, 1998 the Board issued Procedural Order No. 2, which set out the issues for the proceeding.

1.1.5 Procedural Order No. 3, dated April 17, 1998, established the commencement of the hearing on Monday, May 4, 1998.

1.1.6 The hearing of the oral evidence began on Monday May 4, 1998 and continued for three days, ending on Wednesday May 6, 1998. The Company's Argument-in-Chief was filed on May 20, 1998; Board Staff filed its Argument on May 28, 1998; and NRG filed its Reply Argument on June 3, 1998. Copies of all the evidence, exhibits and submissions in this proceeding, together with a verbatim transcript of the hearing are available for public review at the Board's office.

1.2 APPEARANCES AND WITNESSES

1.2.1 The participants and their representatives were:

NRG	Peter Budd Judy Goldring
Board Staff	Jennifer Lea
Heating, Ventilation and Air Conditioning Contractors Coalition Inc. ("HVAC Coalition")	Ian Mondrow

1.2.2 Although not an active participant, The Consumers' Gas Company Limited ("Consumers Gas") intervened and was represented by Barbara Bodnar.

1.2.3 Union Gas Limited ("Union") was also registered as an intervenor but did not participate.

1.2.4 Because of the absence of other active intervenors, Board Staff was an active party in the proceedings.

1.2.5 As a witness, counsel to NRG called W. Blake, President and General Manager.

1.2.6 In addition, NRG called the following expert consultants to testify on behalf of the Company:

R. Aiken	Principal, Aiken and Associates
G. Bowman	Partner, Crosbie Houlihan Lokey Inc.
C. McLelland	Associate, Crosbie Houlihan Lokey Inc.
K.C. McShane	Foster Associates, Inc.
W.E. Suchard	Chartered Accountant

Mr. Suchard gave his evidence via a telephone conference call.

1.3 SUMMARY OF THE COMPANY'S PROPOSAL

1.3.1 The Applicant's prefiled evidence was:

	Fiscal 1998	Fiscal 1999
Utility Income	$1,121,637	$1,045,705
Utility Rate Base	$8,258,977	$8,937, 281
Overall Rate of Return	11.10%	10.85%
Rate of Return on Equity	10.30%	10.10%
Revenue Sufficiency	$369,850	$137,174

1.4 THE ALTERNATIVE DISPUTE RESOLUTION AGREEMENT

1.4.1 The ADR settlement conference was held at the Board's offices from April 7 to 9, 1998. It was attended by the Applicant, Board Staff and counsel for the HVAC Coalition. An ADR Agreement ("Agreement") was drafted by NRG's counsel in consultation with the parties and filed with the Board Secretary on April 16, 1998. The Presiding Member informed the parties at the beginning of the hearing that the Agreement provided sufficient evidence for the Board to render a decision on all issues settled in the Agreement.

1.4.2 The ADR Agreement in its entirety is included as Appendix A to this decision.

1.4.3 Approximately 26 of the total of 41 major issues were settled between the parties, subject to the Board's approval, leaving 15 that remained unresolved in part or total. The settled issues and agreed positions corresponding to the issues identified on the Issues List were:

A. GENERAL

- With regard to Economic Feasibility Model Revisions, NRG would consider the EBO 188 Report and, if appropriate, make adjustments to its discounted cash flow model and provide the Board with a detailed description of the model by October 1, 1998.

- NRG has adequately addressed the Board's directives from EBRO 491.

B. RATE BASE

- The methodology used by NRG in the working cash study and the resulting revenue and expense lags were appropriate.

- NRG's analysis of its performance in the area of capital expenditures for fiscal 1996 and fiscal 1997 was accurate.

- NRG's proposed fiscal 1998 capital budget should be reduced by:

    - 8 meters for new customer additions;
    - 25 regulators; and
    - 11 residential water heaters.

- NRG's proposed fiscal 1999 capital budget should be reduced by:

    - 4 service additions;
    - $99 to reflect the forecast number of customer attachments;
    - 15 regulators; and
    - 11 residential water heaters.

- NRG's methodology and determination of working capital were appropriate.

- NRG should continue to expand service wherever the Company can maintain a project profitability index ("PI") of 1.0 according to its current and future economic feasibility studies.

C. OPERATING REVENUE

- The five-year weighted average forecast as supported by the statistical data entered into evidence was appropriately used in the degree day forecast methodology.

- NRG's proposed customer attachments should be increased by 10 residential attachments in each of 1998 and 1999.

- In 1998, NRG should increase the estimated volume throughput by 14,955 m^3 and the estimated capital budget by $3,470 because of the increased number of customer attachments.

- In 1999, NRG should increase the estimated volume throughput by 59,662 m^3 and the estimated capital budget by $3,540 because of the increased number of customer attachments.

- NRG's amended estimated volume throughput and gas sales revenue for residential, commercial, industrial, seasonal and contract customers for

1998 were acceptable, but were acceptable for 1999 only as they relate to residential, commercial, seasonal and contract customers.

- NRG's forecasts of net operating revenue from the water heater rental program, the contract work program, customer service charges and delayed payment charges for 1998 and 1999 were acceptable.

- With regard to allocation of costs to ancillary programs and the impact on rates of return, NRG would investigate a change to fully allocated costing for ancillary programs, and file its proposals in this respect in its next rates case. The Company would provide the necessary data, including cost allocations to the ancillary programs based on a fully allocated methodology as mandated by the Board for Consumers Gas in EBRO 495, to enable immediate application of a fully allocated costing methodology for its ancillary programs, if approved by the Board.

D. COST OF SERVICE

- NRG's updated, corrected forecasts of Union's gas transportation costs for 1998 and 1999 were acceptable.

- NRG's 1998 and 1999 forecasts of unaccounted for gas of 1.4 percent and 1.9 percent respectively were acceptable.

- With respect to wages and benefits, NRG committed to moving in the direction of adopting employee performance policies before its next rates case.

- NRG's proposed staff levels for 1998 and 1999 were acceptable.

- NRG would limit its costs for intervening in Union's main rates case to $25,000 for 1998 and would record costs for participating in other Union proceedings and in generic proceedings in a newly opened Regulatory Expenses Deferral Account.

- Reductions in various forecast cost of service expenses would be:
    - travel and expenses - $15,000 for each of 1998 and 1999;
    - consulting fees - $1,800 for 1999;
    - automotive expenses - $2,500 for 1998 and $5,000 for 1999; and
    - bank charges - $250 for 1998.

- Estimated cost of service expenses that were acceptable would be NRG's forecasts of:
    - management fees for 1998 and 1999, as updated;
    - office rent for 1998 and 1999;
    - consulting fees for 1998;
    - insurance costs for 1998 and 1999, as updated; and
    - bank charges for 1999, as updated.

- The total service life and salvage rate of plastic mains would remain unchanged as would the depreciation rate of 2.25 percent. The methodology and results of the depreciation study for the remaining categories of assets were also acceptable.

- The proposed disposition of the Purchased Gas Variance Account ("PGVA") was appropriate.

- NRG would proactively manage its gas volumes under Union's bundled T-Service during 1998 and 1999 by (i) ongoing monitoring of its balance position; (ii) where appropriate, making cost effective purchases of gas to address its balance situation; and (iii) considering alternative gas supply/transportation options to help manage balancing and demand charges on the Union system.

- NRG would split the PGVA into commodity and transportation components with respective reference prices, but the two-step threshold point would remain based on the aggregate amount.

- The Company would discontinue its Demand Side Management ("DSM") Initiatives Deferral Account and transfer the balance of $4,627.88 to 1998 cost of service.

- NRG's proposed disposition of the Long-term Financing Strategy Deferral Account was appropriate.

- NRG would conduct a DSM survey, which would include an adequate group of commercial customers, with the results to be presented in the Company's next rates case.

E. COST OF CAPITAL

- The cost of short-term debt for fiscal 1998 and fiscal 1999 would be 7.53 percent and 7.75 percent respectively.

- Although the cost of long-term debt might change depending on the Board's finding on the issue of the Junsen standby fee, subject to that finding, the cost for fiscal 1998 and fiscal 1999 would be 11.85 percent and 11.72 percent respectively.

F. COST ALLOCATION

- The revised results of the zero intercept study, based on the inclusion of the mains additions undertaken in 1996 and 1997 had been accurately reflected by the Company. NRG would update the zero intercept study and refile the study results in the Company's next rates case.

- The revised results of the weighted customer allocators for customer billing, meters and services were appropriate.

- NRG's proposal to unbundle the gas commodity costs for gas received from the transmission and storage costs incurred on the Union system was appropriate.

- DSM costs had been appropriately assigned to Rate 1 customers (residential, commercial and industrial) and allocated to these categories on the basis of the number of customers.

Board Findings

1.4.4 Based on the evidence and the submissions of the parties, the Board accepts the positions agreed to by the parties in the ADR settlement conference and NRG's commitments.

1.4.5 After giving effect to the ADR Agreement, the calculations of amounts considered significant for this hearing were:

	Fiscal 1998	**Fiscal 1999**
Utility Income	$1,184,820	$1,090,133
Utility Rate Base	$8,264,722	$8,967,741
Overall Rate of Return	11.10%	10.84%
Rate of Return on Equity	10.30%	10.10%
Revenue Sufficiency	$483,527	$213,749

2. UTILITY RATE BASE

2.0.1 The issues discussed in this Chapter are:

- capital budget variances;
- the appropriate amount to include in rate base for the Township of Yarmouth franchise;
- the prudence of the costs related to the construction of the NPS 6 line to Imperial Tobacco; and
- the inclusion in rate base of Mr. Graat's vehicle.

2.1 CAPITAL BUDGET VARIANCES

2.1.1 The substance of this issue related to the results of the capital budgeting process used by NRG to arrive at the Company's capital budget forecasts. The specific methodology in and of itself was not in question. The problem was that previous Board-approved capital budgets (EBRO 491) and actual results had been at significant variance.

2.1.2 NRG's capital budget process began with a review of all the accounts. Pipelines had traditionally comprised the largest component of this budget. The Applicant utilized a zero-based methodology for other expenditures in preparing its capital budget.

2.1.3 The following table illustrates the issue of variances:

Fiscal Year	Board-approved	Actual	Variance
1995	$1,325,119	$842,870	($482,249)
1996	$1,390,658	$1,168,889	($221,769)
1997	$1,216,260	$883,421	($332,839)

Positions of the Parties

2.1.4 Board Staff submitted that the net revenue sufficiencies in fiscal 1996 and 1997 were achieved in part by overstating the proposed capital budget expenditures in the EBRO 491 rates proceeding. Hence, Board Staff recommended that NRG should be directed to inform the Board Secretary if the variance in the capital budget expenditures for either the 1998 or 1999 test year exceeded 10 percent of the Board-approved budget. Board Staff also argued that NRG should be required to provide an explanation for the variance.

2.1.5 NRG argued that these variances arose because several large capital projects were delayed or canceled due to the delay in obtaining franchise approval for service to even a portion of the Township of Yarmouth. NRG submitted that these developments should be viewed as one-time occurrences, and should not be taken as indicative of the Company's current budgeting proposals, since NRG was not forecasting any capital expenditures in either of the test years for areas for which it did not hold a valid franchise agreement.

2.1.6 NRG stated that Board Staff had agreed that a good forecast should have an equal chance of being too high or too low. Over the past 8 years, NRG's actual expenditures had been higher than the Board-approved levels in four years, and lower in four years, thus meeting Board Staff's own criterion. Taking the recent 8 years as the measure, the actual historical record of expenditures averaged 107.1 percent of the Board-approved capital budget.

2.1.7 NRG also informed the Board that the Company was in the process of improving the methodology for capital budget forecasting and preparation. This involved longer term forecasting with a 5-year planning horizon, a more formal approach to the operation, and a more methodical scheduling of building projects.

2.1.8 In sum, NRG submitted that there was no credible reason or evidence for requiring variance explanations, should NRG's actual capital expenditures exceed the 10 percent variance.

Board Findings

2.1.9 The Board is concerned that inaccurate capital budget forecasts may lead to inappropriate rates in the latter years of a multi-year rate approval. The Board believes that reporting of variances from the capital budget forecasts that form the basis of the rate proposal would allow the Board to determine whether rate adjustments were necessary. The Board therefore directs NRG to inform the Board Secretary if the variance in annual capital budget expenditures exceeds 10 percent of a Board-approved budget. The Board also directs NRG to provide reasons for the variance to the Board Secretary at the time that the Company informs the Board of the variance.

2.2 TOWNSHIP OF YARMOUTH FRANCHISE

2.2.1 In 1993, NRG began to attempt to secure a franchise to provide natural gas to the Township of Yarmouth ("Township" or "Yarmouth"). In EBRO 480, issued on January 25, 1994, the Board noted the absence of a franchise and certificate for Yarmouth, although NRG was serving two customers in this area. The Board directed the Company to "proceed expeditiously to file appropriate franchise and certificate applications."

2.2.2 Pursuant to Board directions contained in EBRO 491, NRG indicated that the actual Yarmouth franchise costs transferred to the construction work in progress ("CWIP") account as of October 1, 1995 were $44,578. Since that date, a further $16,789 in costs were incurred, of which $15,316 were legal costs. In addition, the CWIP account attracted $5,888 of interest in fiscal 1996 and a further $7,352 of interest in fiscal 1997, resulting in a balance as at October 1, 1997 of $74,607.

2.2.3 On August 12, 1996, Yarmouth gave final reading to a by-law that provided NRG with a franchise for part of the Township, with Union receiving a franchise for the other portion. The franchise obtained by NRG included the area containing the two customers for whom the Company had previously provided service.

2.2.4 NRG stated that, as a result of receiving the franchise from Yarmouth, the Company had connected, to March 19, 1998, 19 new industrial, commercial or seasonal customers, which according to the Company's analysis was equivalent to about 80 residential customers. In addition, NRG was forecasting an incremental load over the next five years equivalent to that of about 160 residential customers.

2.2.5 The Company also said that the net present value benefit of this project was approximately $211,000. Compared with $74,000 in franchise costs, the residual overall net present value was $137,000.

Positions of the Parties

2.2.6 Board Staff agreed that the customers of NRG would benefit from its partial expansion into the Township, but argued that the $15,316 of legal costs incurred in fiscal 1996 appeared to be excessively high. Board Staff argued for a reduction of $10,000, to compensate for what they believed were "excessive legal fees incurred in the preparation for the EBA 730/EBC 242 proceeding." The result, Board Staff submitted, would be that $64,607 should be allowed in the rate base as of October 1, 1997.

2.2.7 NRG noted that Board Staff presented no evidence to support its submission that legal fees were excessive and argued that the Company "would have been at a serious disadvantage without legal counsel when the other parties involved [Yarmouth] had legal counsel assisting them."

Board Findings

2.2.8 The Board notes that the total historic cost of acquiring the 14 other existing franchises for NRG was about $76,272, or approximately the cost of obtaining the Yarmouth franchise. It also notes, however, that the resolution of this issue took from fall 1993 to fall 1996, a period of three years.

2.2.9 The Board considers the costs of obtaining the Yarmouth franchise to have risen to such unprecedented heights due to unique circumstances. The inclusion in the Company's rate base of costs of this magnitude to obtain a single franchise should not be considered as an example to be cited in support of future actions by the Company.

2.2.10 The Board finds that, in the specific circumstances under which the franchise was obtained for the Township, it is appropriate to include $74,607 in NRG's rate base as of October 1, 1997.

2.3 NPS 6 LINE TO IMPERIAL TOBACCO

2.3.1 The Company included $671,083 in its fiscal 1998 capital expenditures budget for the construction of 14,350 metres of 6 inch pipeline ("NPS 6") from the 7th concession line to the Imperial Tobacco plant in Aylmer. This amount was after receipt of $50,000 from Imperial Tobacco as an aid to construction. The project had a PI of 1.0.

2.3.2 The pipeline was constructed in November and December, 1997, by Ayerswood Development Corporation ("Ayerswood"), an affiliate of NRG. The contract with Ayerswood was for $493,200. Another $51,245 of the total project cost was paid to Ayerswood for change orders, transportation and early completion of the project. Of the remainder, $162,330 was budgeted for consulting, legal, surveying, easements, etc. and $14,308 was for contingencies related to these activities.

2.3.3 According to NRG's witnesses, the project was sole-sourced to Ayerswood because of "the urgency of ... getting this pipeline built". NRG stated that the Company does not have a policy of soliciting competitive bids for pipelines as the Company usually constructs these itself.

2.3.4 The Company stated that Imperial Tobacco committed to additional volumes of gas on October 20, 1997 and wanted to receive these volumes during the 1998 winter season. Consequently, the Ayerswood contract included a performance bonus of $1,800 per day for each day that the project was completed prior to December 24, 1997.

2.3.5 The cost of the line was calculated by NRG to be $34.56 per metre. Some $20 of this was identified by the Company as being the cost of materials.

Positions of the Parties

2.3.6 Board Staff noted that both Consumers Gas and Union are required to comply with undertakings established by the Lieutenant-Governor-in-Council as a condition of approval for changes in ownership. One of the undertakings requires that these utilities obtain prior Board approval for any affiliate transaction aggregating $100,000 or more annually. While this condition did not apply to NRG, Board Staff submitted that the spirit of this undertaking should be observed by NRG. Specifically, Board Staff submitted that contracts for capital projects should not be signed with any affiliate without competitive bids being sought so that NRG could determine whether the affiliate provided the lowest price.

2.3.7 Board Staff also submitted that:

- "the costs for constructing the NPS 6 line to Imperial Tobacco were excessive and unnecessarily inflated by the desire to have the project completed by December 24, 1997";

- there was "no corroboration that the project was undertaken at a price [which was] fair to NRG's existing ratepayers, since no competitive bids were sought";

- the Ayerswood contract price of $493,200 should be replaced with a figure of $446,000 (a difference of $47,200), calculated by multiplying 14,350 metres of pipeline by $31.08 per metre, which was NRG's historical cost of constructing NPS 6 pipelines;

- the amount paid to consultants on the project appeared "to offer excellent value";

- the legal and survey costs appeared to be reasonable;

- the average unit price paid to acquire easements could be considered high, but not excessive; and

- the allowance for contingency should be reduced by $39,508, which included $25,200 paid for the early completion of the project.

2.3.8 As a result of the proposed reductions of $47,200 and $39,508, Board Staff argued that $86,708 should not be included in NRG's rate base, effective January 1, 1998.

2.3.9 NRG argued that, despite the lack of competitive bidding, the Company obtained the services of Ayerswood at a competitive price to the benefit of its ratepayers. NRG did not agree that all construction of capital projects should be put out for competitive tender because this could constrain the Company from moving as expeditiously as required to deal with customers needs.

2.3.10 NRG replied that the required project completion date was driven by their client's requirements and the potential for the Company to lose future revenue if it did not meet this need on a timely basis, i.e., the fact that:

> *.....Imperial Tobacco required the increased capacity to operate their plant during the 1997/98 winter. If natural gas had not been available, Imperial Tobacco would have used another fuel. If Imperial Tobacco incurred the expense related to providing the infrastructure necessary to use another fuel, such as propane or oil storage tanks, NRG would run the risk of losing this additional load for not just the current year, but for several years in the future.*

2.3.11 The Company estimated that, if the project had not been undertaken until the spring of 1998, the lost revenue in fiscal 1998 would have been $140,000 and that "the inclusion of the $671,000 in rate base for 9 months in fiscal 1998 has a cost of service that is considerably less than the benefit of $140,000." NRG submitted that the resulting lost revenue and the potential loss of future revenue would not have been offset by lower construction costs.

2.3.12 NRG argued that, while the historical cost of constructing NPS 6 lines was $31.08 per metre, the $34.57 cost per metre associated with the Ayerswood contract reflected the fact that the project "required a substantial amount of boring under environmentally sensitive areas, creek crossings, municipal drains, railroad crossings, and major roads."

2.3.13 The Company argued that no reduction was required in the amount included in the budget for contingencies as this amount applied "not only to the Ayerswood portion of the costs, but also to the soft costs (consulting, legal, easements, etc.) as well as the costs associated with NRG labour and equipment, and the regulator station."

Board Findings

2.3.14 The Board notes that the potential for cross-subsidization and inappropriate asset transfer pricing always exists. Utility costs associated with affiliate transactions must be transparently reasonable and not detrimental to the utility ratepayers.

2.3.15 The Board understands the Company's rationale for seeking to commence construction of the NPS 6 pipeline to Imperial Tobacco as quickly as possible in order to capture the revenue expected to flow from the additional capacity. The Board wonders, however, since the project was contemplated for some time and was completed earlier than the required deadline, if it might have been possible to seek competitive bids for planned pipeline construction during the period of contemplation. This action on the part of NRG would have:

- provided evidence that the construction costs incurred, even if paid in a non-arm's length transaction, were the least-cost option for NRG's ratepayers; and
- avoided the bonus payment made for early completion of the project.

2.3.16 To provide a degree of assurance that capital project costs are prudently incurred, the Board directs NRG to develop and implement a policy requiring the Company to seek competitive bids on all capital expenditure projects over $50,000 that would otherwise be sole-sourced to an affiliate.

2.3.17 Based on the evidence that the NPS 6 pipeline project has a PI of 1.0 over the five-year life of the existing contract with Imperial Tobacco and that the per metre cost appears reasonable in the circumstances, the Board finds that $671,083 is properly included in NRG's rate base.

2.4 MR. GRAAT'S VEHICLE

2.4.1 The Company proposed to include the vehicle of the Chairman and sole owner of NRG, Mr. Graat, in rate base. This cost had been removed in the Board's EBRO 491 Decision.

2.4.2 The Company's witnesses indicated that there had been no changes in circumstances since EBRO 491. The rationale given for inclusion of the vehicle in the rate base was that Mr. Graat required transportation to do his job at NRG and that provision of a vehicle, as part of his compensation package, was not unreasonable.

2.4.3 Mr. Suchard, the Company's witness on Mr. Graat's compensation, stated that 71 percent of the full-time executives included in the Morneau Sobeco Coopers & Lybrand survey were provided with a company vehicle, but that he had no "particular knowledge of part-time executives and what perks they might be provided."

Positions of the Parties

2.4.4 Board Staff submitted that nothing had changed since EBRO 491 and that the Board should confirm its previous decision to exclude the costs of Mr. Graat's vehicle from rate base.

2.4.5 NRG argued that Mr. Graat required transportation to do his job at the Company and should not be expected to manage the Company from his office.

Board Findings

2.4.6 The Board notes that NRG indicated that basically nothing has changed relative to the use of Mr. Graat's vehicle. Additionally, Mr. Suchard was unable to provide any information about "perks" for part-time executives.

2.4.7 The Board therefore finds that the cost of Mr. Graat's vehicle should not be included in rate base. The Board, however, agrees with NRG that Mr. Graat should not be required to manage the Company from his office. The Board deals with this matter, along with the depreciation expense implications of excluding Mr. Graat's vehicle from rate base, in Chapter 3 of this Decision.

2.4.8 Excluding Mr. Graat's vehicle from rate base will decrease NRG's gross plant in fiscal 1998 by $37,891 and in fiscal 1999 by $39,946. This finding will also result in a reduction of the capital cost allowance used by the Company in its calculations of income tax by $5,035 in fiscal 1998 and $3,787 in fiscal 1999.

2.5 IMPACT OF THE BOARD'S FINDINGS ON UTILITY RATE BASE

2.5.1 As a result of the ADR Agreement and the Board's findings in this Chapter, NRG's rate base for fiscal 1998 and 1999 will be $8,234,572 and $8,938,508 respectively. The impact statements showing the results of the Board's findings are set out in Appendix B.

3. UTILITY INCOME

3.1 OPERATING REVENUE

3.1.1 This segment of this Chapter deals with:

- the number of Rate 1 industrial customers forecast for fiscal 1999; and
- forecast volumes for these customers for fiscal 1999.

Number of Rate 1 Industrial Customers - 1999

3.1.2 The forecast provided by NRG indicated that there would be 24 Rate 1 industrial customers in 1999.

3.1.3 NRG indicated that there had been a steady increase in the number of Rate 1 industrial customers since 1996 and this trend was expected to continue into fiscal 1999. The recent history of Rate 1 industrial customer numbers is set out in the following table.

Fiscal Year	Forecast	Board-approved	Actual
1995	(Note 1)	17	17
1996	(Note 1)	16	17
1997	(Note 1)	17	22
1998 (Note 2)	23	23	
1999	24		

Note 1: Prior to 1998, the Rate 1 industrial customer forecasts were not segmented from the Rate 3 industrial customer forecasts.
Note 2: The proposed 1998 number was agreed to during the ADR process.

Positions of the Parties

3.1.4 Board Staff submitted that, for the past two years, actual number of Rate 1 industrial customers had been above the Board-approved level. Board Staff argued that an appropriate level of industrial customers could be determined by taking the average level of under forecasting from fiscal 1995 to 1997, or 2 customers, and adding this amount to NRG's 1999 forecast to arrive at total of 26 Rate 1 industrial customers.

3.1.5 NRG argued that, if the Board believed that NRG had under forecast Rate 1 industrial customers, at most 2 additional customers should be added to the 23 accepted by Board Staff in fiscal 1998 as part of the ADR agreement, for a total of 25 Rate 1 industrial customers for fiscal 1999.

Board Findings

3.1.6 The Board notes that the actual number of customers in 1997 was significantly higher than forecast. Under forecasting of customer numbers may disadvantage NRG's customers in that rates are higher than they would otherwise have been. Approving a number of customers that is greater than that which actually materializes does not have a negative effect on NRG's actual customers. Weighing these factors, the Board finds that the appropriate number of Rate 1 industrial customers for 1999 should be 26. The Board has not made any specific changes to rate base as a result of these additions, deeming the amount to be immaterial.

Volumes for Rate 1 Industrial Customers - 1999

3.1.7 NRG's forecast of volumes from Rate 1 industrial customers in 1999 was 562,719 m^3. Average use per customer in 1999 was forecast to be 23,824 m^3, on a normalized basis.

3.1.8 The forecast was based on the use of the degree day methodology. The Company used degree day data provided by Environment Canada in its regression analysis. The results of the regression analysis were adjusted based on the judgment of the Company's management.

3.1.9 The Company's evidence on normalized volumes related to Rate 1 industrial customers was:

Fiscal Year	Forecast	Board-approved	Actual
1995	(Note 1)	691,700	653,271
1996	(Note 1)	299,062	369,758
1997	(Note 1)	288,670	721,629
1998 (Note 2)	867,647	867,647	
1999	562,719		

Note 1: Prior to 1998, the Rate 1 industrial customer forecasts were not segmented from the Rate 3 industrial customer forecasts.
Note 2: The proposed 1998 volumes were agreed to during the ADR process.

3.1.10 NRG stated that normalized use by Rate 1 industrial customers in fiscal 1997 was about 150 percent higher than forecast, partly due to the number of customers being 29.4 percent higher than forecast. According to the Company's evidence, normalized Rate 1 industrial volumes were also above the Board-approved levels in 1996.

3.1.11 According to NRG, the updated forecast for 1998 was higher than originally calculated because of a larger than normal crop with a higher than normal moisture content. NRG also said that 1998 was an abnormal period due to higher than expected use by the grain dryers in the months of November and December, 1997. According to the Company, two factors were responsible for this occurrence, an extremely wet spring in 1997, which delayed planting and in turn made harvesting unusually late with a colder and wetter period for this activity, and a higher than normal moisture content in the crop that season.

3.1.12 The Rate 1 industrial throughput forecast for fiscal 1999 indicated a decline of 35.2 percent from fiscal 1998. NRG explained the reduction in the 1999 forecast as a return to normal use by the small grain dryers that dominate the Rate 1 industrial category.

Position of the Parties

3.1.13 Board Staff argued that the reduction in forecast volumes from 1998 to 1999 was very significant and there was no concrete data to support this drop. Basically, a judgment call had been made that the fiscal 1999 growing season would be "normal" while the past two years had been "abnormal". Board Staff said that one indication of a good forecast was that the actual level of volumes should be expected to be above forecast level half of the time and under the forecast level half of the time. It was Board Staff's contention that, in NRG's case, there was a trend to under forecasting volumes.

3.1.14 Board Staff also submitted that the econometric model used had remained unchanged despite the evidence that there was a genuine need for a new forecasting model, which incorporated better weather information as it related to grain drying. Board Staff argued that, since NRG's forecasting methodology was inadequate, it would be more accurate to determine the average normalized use per customer based on an average of the past four years of data.

3.1.15 Board Staff concluded that the appropriate level of Rate 1 industrial volumes for fiscal 1999 was 722,077 m^3, based on multiplying the average use per customer from 1995 to 1998 of 28,184 m^3 by 26, the number of Rate 1 industrial customers considered appropriate by Board Staff.

3.1.16 NRG argued that, during 1995, volumes consumed in this category were below the Board-approved level, and only two years actually were under forecast, 1996 and 1997. NRG submitted that experience over two years does not constitute a trend.

3.1.17 As for the appropriate figure for average use per customer to be used for forecasting volumes for 1999, NRG was opposed to including the forecast fiscal 1998 figure of 37,723 m^3 in the averaging process because of the uniqueness of the period.

3.1.18 NRG submitted that its rates should be set on the basis of normalized throughput, which in turn was based on normal conditions, whether those were heating degree days, growing degree days or moisture content. In sum, NRG's position was that its forecast for Rate 1 industrial volumes in fiscal 1999 was appropriate and reflected a return to normal conditions.

Board Findings

3.1.19 The Board is concerned that, recently, the results of NRG's forecasting methodology, after adjustment for management's judgment, have been highly inaccurate. The Board therefore directs NRG to undertake a review of its forecasting methodology, with the objective of identifying any improvements that can be introduced. The Board expects the Company to file the results of the review at the Company's next rates hearing.

3.1.20 The Board also directs NRG to document what is considered to be a "normal" year for Rate 1 industrial customers, in particular with respect to temperature, precipitation, crop size and crop moisture content. Further, NRG is directed to indicate how such a "normal" year assumption would be applied in its forecasting. The explanation should be filed at NRG's next rates hearing so that the description may be tested during the proceeding.

3.1.21 Given the Board's finding earlier in this Chapter, that the Company's forecast of Rate 1 industrial customers should be 26, the Board finds that an additional 47,648 m^3 [23,824 m^3 x 2] should be included in the Company's forecast of volumes related to Rate 1 industrial customers for 1999.

3.1.22 The Board will not substitute a forecast based on averages for that produced by the Company. The Board finds that the appropriate volume to be included in the 1999 fiscal year for Rate 1 industrial customers is 610,367 m^3.

3.1.23 The Board directs NRG to file annually with the Board Secretary the actual volumes consumed by Rate 1 industrial customers on a regular and normalized basis.

3.2 COST OF SERVICE

3.2.1 This segment of this Chapter deals with:

- 1998 gas commodity cost forecasts;
- 1999 gas commodity cost forecasts;
- the wages and benefits related to the executive payroll;
- transfers between wages category and management fees;
- costs, both operational and depreciation, related to Mr. Graat's vehicle;
- the depreciation expense related to the Yarmouth franchise;
- the methodology used by NRG in calculating capital taxes; and
- the methodology used by NRG in calculating income taxes.

Gas Supply Portfolio 1998

3.2.2 NRG's gas commodity purchases for 1998 were forecast as:

Suppliers	Volumes * m^3	Commodity Costs $
Norfolk	1,852,441	218,008
Hemlock	1,199,329	104,292
NRG Corp.	17,623,236	1,981,936
* Agreed to during the ADR process		

3.2.3 Two of NRG's gas supply arrangements were with affiliates: NRG Corp., and Norfolk. Norfolk is owned by NRG Corp. For the 1998 test year, NRG has forecast that the Company would purchase approximately 85% of its gas supply from NRG Corp., and that the Company would buy approximately 9% of its gas supply needs from Norfolk.

3.2.4 With regard to the gas supplied by Norfolk, NRG stated that the pricing mechanism in this contract, which would expire in June, 1999, tied the price paid by NRG for the volumes purchased from Norfolk to Union's gas supply commodity charge for utility sales. For the period June 1998 to September 1998, NRG forecast that the Company would purchase 619,828 m^3 of gas from Norfolk.

3.2.5 With respect to its arrangements with NRG Corp., NRG stated that the Company had signed an agency agreement and a separate gas supply contract with NRG Corp. Both agreements will expire on September 30, 1998.

3.2.6 For the gas supply underpinned by NRG's TransCanada PipeLines capacity, the Company indicated that NRG Corp. was paid a fixed price of \$0.108577 per m^3. This price was determined at the end of September 1997, through negotiations between NRG and NRG Corp. The balance of the volumes forecast to be delivered by NRG Corp. were Ontario-delivered supplies and the price forecast for this supply was \$0.124470 per m^3. NRG's price forecast for Ontario-delivered volumes was based on recent market information obtained by NRG. NRG said, however, that the Company was not bound to buy gas from NRG Corp. for any needed Ontario-delivered volumes, but could instead buy these volumes from another supplier.

3.2.7 NRG forecast an average gas commodity cost of \$0.111450 per m^3 in fiscal 1998, prior to any adjustment arising from the Board's findings on Union's EBRO 494-09 application. To the extent that there are any differences in gas prices for fiscal 1998, these would be captured in NRG's PGVA account and disposed of by the Board at a future date.

Position of the Parties

3.2.8 Board Staff submitted that the prices forecast to be paid to NRG's gas suppliers for fiscal 1998 were reasonable. However, Board Staff indicated a residual level of discomfort with the transactions with NRG Corp. for fiscal 1998 because NRG did not solicit bids from other potential suppliers prior to entering into arrangements with its affiliate.

3.2.9 NRG submitted that the Board had approved the EBRO 494-09 Union application on May 26, 1998, resulting in an increase of Union's gas commodity price to \$0.131160 per m^3 effective June 1, 1998, with a resulting increase of \$0.013794 per m^3. NRG determined that this increase in the price resulted in an additional cost of gas for Norfolk purchases of \$8,550 over the June to September period. NRG argued that the Board should take this approved price change into consideration when setting the gas commodity price, and approve a commodity cost of gas of \$0.111864 per m^3 for fiscal 1998.

Board Findings

3.2.10 The Board notes that the situation with regard to NRG's purchase of gas will change in 1999, and comments on it in the next section.

3.2.11 The Board finds that NRG's revised forecast of gas supply commodity costs based upon the Board-approved EBRO 494-09 rates for Union is reasonable. NRG's forecast of gas costs of \$0.111864 per m^3, the weighted average cost of gas ("WACOG"), for fiscal 1998 is found to be appropriate by the Board.

Gas Supply Portfolio 1999

3.2.12 NRG's gas commodity purchases for 1999 were forecast as:

Suppliers	Volumes * m^3	Commodity Cost \$
Norfolk	1,673,536	196,416
Hemlock	1,042,438	90,650
NRG Corp.	18,218,379	2,289,404
* Agreed to during the ADR process		

3.2.13 NRG stated that, in fiscal 1999, the Company was planning to issue a tender for the volumes previously delivered by NRG Corp. NRG suggested that the tendering might be done directly by NRG or by NRG Corp. in exchange for a fee. NRG was also prepared to accommodate whatever suggestions or orders the Board might make on how the gas supply arrangements might be priced.

3.2.14 The Company's witnesses indicated that there was a relatively high degree of uncertainty associated with the forecast of volumes required because of the Company's proposal to introduce the option of direct purchase to all its customers.

Position of the Parties

3.2.15 Board Staff submitted that NRG's forecast cost of gas for fiscal 1999 was reasonable given the state of developments and the high degree of uncertainty in NRG's 1999 gas supply portfolio.

3.2.16 Board Staff submitted that any variance in the 1999 cost of gas could be dealt with in one of two ways:

- by the Board's directing that NRG file a revised 1999 forecast along with a forecast year-end PGVA balance sometime before the start of the 1999 test year, with a decision to be made at that time on whether the 1999 gas costs should be changed given the new information; or

- the Board could rely on the existing PGVA trigger threshold mechanism approved in the EBRO 491 Decision, recognizing the change in the gas commodity charge under EBRO 494-09.

3.2.17 Board Staff also noted that NRG planned, for fiscal 1999, on tendering for the volumes previously supplied by NRG Corp. and was encouraged by this determination. In Board Staff's opinion, this would ensure that NRG would realize the lowest available market price for its gas supply. Board Staff noted that NRG Corp. did not need to be excluded from making a bid provided the tendering process was arranged in such a way that no advantage accrued to the affiliate company.

3.2.18 NRG submitted that the Board-approved increase in Union's gas commodity cost would result in an increased cost of gas for Norfolk purchases of $23,085, which would raise the total commodity cost of gas by $0.001103 per m^3 from $0.123074 per m^3 to $0.124177 per m^3. NRG argued that the Board-approved commodity cost of gas for fiscal 1999 be set at $0.124177 per m^3.

3.2.19 NRG also argued that the existing PGVA trigger threshold was the appropriate mechanism to deal with the uncertainty surrounding gas costs in fiscal 1999. In the Company's opinion, this mechanism provided a proven process through which gas cost variances could be dealt with.

Board Findings

3.2.20 As indicated previously in this Chapter, the Board approved an increase in Union's gas commodity rate to $0.131160 per m^3 effective June 1, 1998.

3.2.21 The Board finds that NRG's revised forecast of gas supply costs based upon the Board-approved EBRO 494-09 rates for Union is reasonable. NRG's submission of a WACOG of $0.124177 per m^3 for fiscal 1999 is accepted by the Board.

3.2.22 Earlier in this Chapter, the Board has found that the Company's forecast of gas volumes to be sold should increase by 47,648 m^3. Consequently, the Board finds that the gas purchased volume should also increase by this amount. Applying the Board-approved WACOG, this results in an increase in the 1999 forecast cost of gas of $5,917. The Board has used WACOG in this calculation because of the immaterial difference between WACOG and the incremental cost of gas for NRG.

3.2.23 The Board finds that the existing PGVA trigger threshold mechanism should continue as the appropriate method for dealing with uncertainty surrounding gas costs in fiscal 1999.

3.2.24 The Board directs NRG to proceed with its plan to tender for non-local gas volumes that would otherwise be supplied by an affiliate. This will meet the Board's concerns that NRG and, hence, its customers should realize the lowest available market price for the Company's gas supply.

3.2.25 The Board expects that NRG will manage the tendering process itself, and that NRG Corp. will not be excluded from tendering, provided that the affiliate does not benefit from its affiliate status.

Executive Payroll

3.2.26 NRG proposed a salary range for Mr. Graat for fiscal 1998 and 1999 of $65,000 to $75,000. The evidence indicated that on average Mr. Graat spent about 15-20 hours per week on various responsibilities and duties relating to NRG.

3.2.27 In the EBRO 491 Decision, paragraph 2.7.19 indicated that "the Board expects NRG to develop a comparative standard to measure the appropriateness of Mr. Graat's executive compensation package". A study completed by Mr. Weston Suchard responded to the Board's directive.

3.2.28 Mr. Suchard said that he relied mainly on a national compensation survey for 1997 prepared by Morneau Sobeco Coopers & Lybrand and on conversations with the Company's management on Mr. Graat's role and responsibilities. He also stated that he had little knowledge of part-time compensation, utility companies or how executives of utility companies are generally compensated. In addition, Mr. Suchard indicated that utility companies were not included in the survey he relied on to conduct his analysis.

3.2.29 Mr. Suchard concluded that "it would be reasonable for the Company to pay Mr. Graat a salary in the range of $65,000 to $75,000". In addition, NRG indicated that Mr. Graat does not receive any other form of compensation from the utility, outside of a company vehicle.

Position of the Parties

3.2.30 Board Staff argued that, while Mr. Suchard's evidence did provide some insight into executive compensation, there was a lack of evidence related to part-time executive and utility executive compensation. Board Staff therefore submitted that the study was inconclusive about the appropriateness of Mr. Graat's compensation level as a part-time executive in a utility operation.

3.2.31 Board Staff submitted that a disallowance of 25% of Mr. Graat's salary was necessary. Given that a salary range of $65,000 to $75,000 had been identified for Mr. Graat, Board Staff argued that a reduction of $17,500 to the utility cost of service was appropriate.

3.2.32 NRG argued that it had more than adequately fulfilled the Board's EBRO 491 directive with respect to Mr. Graat's executive compensation package, and that no reduction should be made to the cost of service with respect to Mr. Graat's salary.

Board Findings

3.2.33 The Board is disappointed that Mr. Suchard's study did not include evidence on the salaries paid to part-time executives or executives within the regulated utility industry.

3.2.34 Nevertheless, the Board finds that the salary of $65,000 for Mr. Graat's services to NRG is acceptable for each of 1998 and 1999, taking into account the evidence that this represents approximately one third of the range for full-time executive compensation. However, the Board stresses that it needs to be satisfied on an ongoing basis that the ratepayers are getting value for Mr. Graat's services.

<u>Transfers Between Wages and Management Fees</u>

3.2.35 In 1998, according to NRG, accounting services that were provided by NRG in 1997 would be provided by a new Financial Manager position within Cornerstone Properties Inc. ("Cornerstone"), an affiliate of NRG, and charged back to NRG through a management fee.

3.2.36 The Company also said that the Financial Manager provided services to two or three other affiliate companies. However, the position was physically located in NRG's building in Aylmer.

Position of the Parties

3.2.37 Board Staff submitted that NRG should be directed to locate the Financial Manager position, charged out to other companies on an as needed basis, within the regulated utility because:

- the majority of the Financial Manager's responsibilities (i.e. 75% of his time commitment) relate to NRG and include supervisory duties at NRG; and
- it is physically located at NRG's Aylmer office.

3.2.38 Board Staff also submitted that NRG's current time studies did not provide an accurate indication of future time commitments of the Financial Manager position, which made it difficult to determine the related costs on a prospective basis.

3.2.39 NRG submitted that the location of the Financial Manager position within Cornerstone provided the Company with greater flexibility through the cost sharing of the function. NRG also expected the time commitment of the Financial Manager to change, with the possibility that the Company might require less time from the Financial Manager in the future. NRG also revealed that, to date, it had not experienced conflicting priorities resulting from the structure of the position.

3.2.40 NRG argued that its use of an employee of Cornerstone as Financial Manager was not a new practice, but rather a reversion to previous arrangements.

Board Findings

3.2.41 The Board notes that whether the Financial Manager position is within NRG or within Cornerstone should have no overall cost impact in fiscal 1998 and fiscal 1999.

3.2.42 For fiscal 1998 and fiscal 1999, the Board finds that the current position of the Financial Manager as an employee of Cornerstone, which charges back an appropriate management fee to NRG, is acceptable.

Costs Related to Mr. Graat's Vehicle

3.2.43 The Company stated that Mr. Graat utilized a company vehicle for transportation while providing services for NRG. Automotive expenditure for this vehicle was also included in the forecast cost of operation and maintenance for both fiscal years.

3.2.44 NRG provided the following forecasts for each test year regarding Mr. Graat's vehicular expenses:

Category	1998	1999
Automotive Expense	$500	$500
Depreciation Expense	$7,741	$10,713

Positions of the Parties

3.2.45 Board Staff submitted no argument on the subject of automotive expense allowances for Mr. Graat's vehicle.

3.2.46 NRG argued that Mr. Graat required transportation to travel to Aylmer and to attend meetings in Toronto, and in general to carry on the work of the Company. NRG noted that Mr. Graat cannot manage the company solely from his office at NRG's headquarters.

Board Findings

3.2.47 In the light of the Board's finding regarding the unacceptability of including Mr. Graat's vehicle in the rate base, the Board finds that NRG should include $500 for each test year in its cost of service for Mr. Graat's automotive expenses.

3.2.48 The Board also finds that depreciation expenses of $7,741 in fiscal 1998 and $10,713 in fiscal 1999 should be excluded from NRG's cost of service calculation.

Depreciation Expense Related to the Yarmouth Franchise

3.2.49 According to NRG, the Company's proposed depreciation rate for franchises was calculated by dividing the net book value of all franchises by the remaining life of the franchise agreements.

3.2.50 For 1998 and 1999, assuming as the Company did, that the net book value should include the proposed cost of the Yarmouth franchise, the proposed depreciation rate was 4.33 percent. Applied on a straight line basis to the cost of the Yarmouth franchise, this results in $2,423 being included in cost of service as depreciation of the Yarmouth franchise in fiscal 1998 and $3,230 in fiscal 1999.

Positions of the Parties

3.2.51 Neither party made specific submissions on the subject of either the depreciation rate that would be applicable to the Yarmouth franchise or the amount of the depreciation relating to the Yarmouth franchise.

Board Findings

3.2.52 In Chapter 2 of this Decision, the Board found that the costs of obtaining the franchise for the Township of Yarmouth, as estimated by the Company, should be included in rate base. Consequently, the Board finds that:

- these costs are properly included in the calculation of the depreciation rate to be applied to capitalized franchise costs;
- the rate of 4.33 percent is appropriate; and
- the depreciation expense to be included in NRG's cost of service for fiscal 1998 and fiscal 1999 is $2,423 and $3,230 respectively.

Capital Tax

3.2.53 Companies with assets of over $10 million are required to pay the large corporations tax (also known as the federal capital tax). NRG, as a stand alone entity, had taxable capital employed in Canada of about $6 to $7 million, which was substantially less than the $10 million threshold that identifies a large corporation.

3.2.54 NRG explained that, for federal capital tax calculation purposes, the Company was considered together with other affiliated companies that were also owned by Mr. Graat. Consequently, the Company was not exempt from the large corporations tax, as the assets of the affiliated companies, when grouped together, amounted to more than $10 million.

3.2.55 The level of federal capital tax that NRG forecast for fiscal 1999 was $10,317. The federal capital tax figure for fiscal 1998 was $6,626.

Position of the Parties

3.2.56 Board Staff submitted that it was standard regulatory practice to treat a utility as a stand alone entity for regulatory tax purposes. In Board Staff's opinion, NRG should be held to the same regulatory standard as other utilities.

3.2.57 Board Staff argued that ratepayers should not have to pay higher taxes because of NRG's affiliate relationships. Ratepayers should not have to subsidize or pay any taxes related to unregulated activities. As a result, Board Staff submitted that NRG should be directed to remove from the utility's cost of service the $10,317 identified as the federal capital tax for fiscal 1999 and $6,626 identified as the federal capital tax for fiscal 1998.

3.2.58 NRG maintained that the Company obtained benefits from its association with the Graat group of affiliated companies. NRG indicated that the chief benefits were access to financing and management support. According to the Company, therefore, it was appropriate to treat NRG as part of the group for tax purposes.

Board Findings

3.2.59 The Board notes that the avoidance of cross-subsidization between regulated and non-regulated activities of a company or group of companies is a key principle in regulation. While there may be benefits to NRG from being part of the Graat group of affiliated companies, there are benefits to other entities within the group from the presence of NRG within the family. NRG's management fee compensates the Graat group of affiliated companies for any access to financing or management support provided.

3.2.60 Consequently, the Board finds that NRG should be treated as a stand alone entity for purposes of calculating the federal capital tax to be included in NRG's cost of service. Therefore, NRG is directed to remove $10,317, identified as the federal capital tax for 1999, and $6,626, identified as the federal capital tax for 1998, from the utility's cost of service for those fiscal years.

Income Tax

3.2.61 NRG's witnesses testified that, for income tax purposes, all the Graat companies were pooled and taxes payable calculated on the consolidated finances of these companies. The Company stated that it paid two levels of taxes: provincial and federal.

3.2.62 NRG received a Small Business Deduction at both the provincial and federal levels. Surtaxes were also applied to the Company at both the provincial and federal levels.

3.2.63 NRG indicated that the surtax and the Small Business Deduction offset one another at the provincial level, so that the net impact was zero. In its presentation of income taxes, NRG included an amount for the federal corporate surtax but did not reduce the amount shown for the federal Small Business Deduction.

Positions of the Parties

3.2.64 Board Staff submitted that, for regulatory purposes, NRG should have included in the Company's cost of service only the level of taxes appropriate for a stand alone entity, regardless of its association with other companies. Furthermore, Board Staff argued that a proper filing of tax calculations, including all the appropriate deductions, should be expected from NRG as part of it regulatory filing.

3.2.65 Board Staff submitted that NRG was entitled to the federal Small Business Deduction. This deduction should have been included in the calculation of income tax for regulatory purposes. Therefore it was Board Staff's position that the income tax calculation has been over stated by an amount corresponding to the Small Business Deduction, i.e., 16% of the first $200,000 of income or $32,000. Consequently, income taxes included in the Company's cost of service should be reduced by this amount for each of the test years 1998 and 1999.

3.2.66 NRG argued that the Company should be allowed to recover in its cost of service the total income tax that the Company expected to pay.

Board Findings

3.2.67 As previously stated, the Board is a strong proponent of the principle of avoidance of cross-subsidization. Consequently, the Board finds that NRG should be treated as a stand alone entity for purposes of calculating the income tax to be included in NRG's cost of service.

3.2.68 The Board finds that, since NRG should be entitled to the federal Small Business Deduction, this deduction must be included in the calculation of income tax for regulatory purposes. Therefore, the Board directs the Company to reduce the amount allowed in the cost of service for income taxes by $32,000 for each of the 1998 and 1999 test years.

3.2.69 The Board also directs NRG to include in its filings for future rate hearings, a detailed calculation of the income taxes included in the Company's cost of service, showing any surtaxes that the Company must pay and any deductions to which the Company, considered on a stand alone basis, is entitled.

3.2.70 The Board holds that interest expense deductions allowed in determining NRG's taxable income must include the interest calculated on all components of the capital structure approved by the Board for rate making purposes. The Board therefore has incorporated the interest associated with the unfunded debt component of the capital structure in the net interest expense deducted in determining NRG's taxable income.

3.3 IMPACT OF THE BOARD'S FINDINGS ON UTILITY INCOME

3.3.1 As a result of the ADR Agreement and the Board's findings in this Chapter, NRG's utility income for fiscal 1998 and 1999 will be $1,210,766 and $1,122,689 respectively. The impact statements showing the results of the Board's findings are set out in Appendix B.

4. COST OF CAPITAL

4.0.1 This Chapter of the Decision deals with:

- capital structure;
- cost of equity; and
- cost of debt.

4.0.2 In the EBRO 491 Decision, the Board requested that NRG prepare a long-term financing strategy report. The goal, in the Board's view, was to provide "independent, objective information, supported by the appropriate theoretical underpinnings, for a company as unique as NRG". That report (the "Crosbie Report") was completed and filed in this proceeding. The Crosbie Report provided expert advice on: NRG's business risk, appropriate debt to equity ratios, likely long-term debt costs, the availability of third party financing and prepayment penalty clauses.

4.1 CAPITAL STRUCTURE

4.1.1 NRG requested a deemed equity ratio of 50 percent, although the Company's actual equity ratio was forecast to be 51.02 percent in fiscal 1998 and 52.14 percent in fiscal 1999, before any adjustments arising from the ADR Agreement. According to NRG, the Company's request for a deemed equity ratio of 50 percent was based on two independent studies: the Crosbie Report, and the Opinion on Required Equity Risk Premium of Foster Associates, Inc.

4.1.2 The Crosbie Report concluded that NRG's capital structure should have a long-term equity target of between 50 percent and 60 percent. According to Mr. Bowman and Mr. McLelland, NRG's witnesses from Crosbie Houlihan Lokey Inc., (the "Crosbie witnesses") the rationale for this was the perspective given in the Crosbie Report on the impact of NRG's size on business risk and the expectations of the marketplace.

4.1.3 Ms. McShane, of Foster Associates, another witness on behalf of NRG, recommended that NRG should have a deemed common equity ratio of 50 percent. Ms. McShane stated that, in her approach, it is the deeming of a capital structure (i.e., establishing the weighting of the capital components) that is the mechanism to adjust for relative business risk rather than adjusting the percentage cost of, or return on, equity.

4.1.4 There was also a discussion in the evidence of the appropriateness of NRG's actual equity ratio as opposed to a deemed component. Ms. McShane held that the Board should not focus on the actual ratio unless "the actual ratio is the optimal equity ratio".

Positions of the Parties

4.1.5 Board Staff acknowledged that the optimal balance of equity within the capital structure cannot be divorced from the return on, or cost of, that equity. Board Staff noted that Ms. McShane's oral and written evidence was compelling. Secondly, in Board Staff's opinion, any Board-approved capital structure would form the cornerstone of NRG's capital structure and should not vary with changes in the actual equity ratio or without significant cause.

4.1.6 Board Staff submitted that deeming a 50 percent equity ratio would have very little impact on NRG's proposed revenue requirement, since the Company's proposed equity ratios for fiscal 1998 and fiscal 1999 were approximately 50 percent.

4.1.7 NRG submitted that the Board should approve the Company's proposal, i.e., an equity ratio of 50 percent. The Company argued that this deemed equity component was consistent with its business risk.

Board Findings

4.1.8 The Board notes that the recommendations of Board Staff, Ms. McShane and the Crosbie witnesses are congruent. The Board finds that a deemed 50 percent debt to equity ratio for NRG is appropriate for fiscal 1998 and fiscal 1999.

4.1.9 The Board wishes to emphasize that this is a "deemed" debt/equity ratio, and is not a finding that the actual debt to equity ratio is appropriate. The deeming of the 50 percent ratio would be the Board's decision even if the actual debt to equity ratio was different.

4.2 COST OF EQUITY

Required Risk Premium

4.2.1 Ms. McShane presented analysis on the issue of business risk and concluded that NRG's business risk relative to that of Consumers Gas had not changed materially since EBRO 491. The analysis focused on customer base and size-related factors. Ms. McShane found that, as a small company, NRG had fewer opportunities to spread the risk, could be more susceptible to negative events, had fewer financing options and attracted less financial institutional interest.

4.2.2 Ms. McShane recommended that the Board allow an equity risk premium equal to that of Consumers Gas, provided that the Company was allowed a deemed common equity ratio of 50 percent. Ms. McShane stated that "the common equity ratio of NRG offsets the differential level of business risk relative to Consumers, ... there's no need for any adjustment to Consumers Gas' equity risk premium" and "that an approximate fifteen ... percentage point spread between the two common equity ratios; that is, 35% for Consumers Gas and 50% for NRG, would equate the companies' total risk."

4.2.3 Ms. McShane also noted that "the appropriate risk premium based on a 50% common equity ratio is not directly related to the fact that ... they [NRG] happen to have around 50 [percent] this year."

4.2.4 Ms. McShane noted that the Board had applied a significantly higher common equity risk premium to the 40 percent equity element allowed by the Board in EBRO 491. Additionally, Ms. McShane asserted that a 40 percent ratio would only partially compensate equity investors for the differences in business risk between Consumers Gas and NRG and would, therefore, command a higher risk premium than a 50 percent equity ratio.

4.2.5 With respect to business risk, the Crosbie Report concluded that NRG faced significantly higher business risks than Consumers Gas and Union because of NRG's restricted franchise area, economic and weather-related risks, dependency on a single industry or small group of consumers, forecast risks and the market impact of deregulation.

Positions of the Parties

4.2.6 Board Staff agreed with both Ms. McShane and the Crosbie Report that NRG had an inherently higher business risk profile than Consumers Gas. NRG's recent good performance and the growth opportunities available to the Company did not negate the underlying risk characteristics. Board Staff submitted that the tone of the Crosbie Report was unduly negative in light of NRG's progress in customer additions and system improvements. Board Staff suggested that the Crosbie Report's conclusions were weakened by lack of experience with regulated utilities, the use of generic material and selection of publicly-traded comparables.

Board Findings

4.2.7 Given the consensus of opinions among the witnesses, the Board finds that NRG does indeed have a higher business risk than Consumers Gas. The Board finds that the difference in business risk is fully accounted for by the larger deemed equity component approved for NRG.

4.2.8 The Board notes that, while the Crosbie Report was helpful, it reflects a lack of experience with, and reference to, regulated utilities in its conclusions.

Rate of Return on Equity

4.2.9 Subsequent to the EBRO 491 decision, the Board moved to adopt a formula-based return on common equity for regulated utilities.

4.2.10 Ms. McShane presented evidence indicating that, if the Board imposed a deemed 50 percent equity ratio, the deemed equity component would allow for the greater business risk of NRG versus Consumers Gas. For 1998, Ms. McShane's opinion was that this deemed equity should be allowed a rate of return of 10.30 percent, the same cost of equity awarded to Consumers Gas.

Positions of the Parties

4.2.11 Board Staff submitted that, for 1998, if the Board approved a deemed 50 percent equity ratio, it would be appropriate for NRG to be allowed the same cost of equity as approved by the Board for Consumers Gas in EBRO 495. Similarly, Board Staff argued that there should be no equity premium applied over that of Consumers Gas for the 1999 test year. Board Staff suggested applying the Board's formula using the most current Consensus Forecasts available at the time of the Decision to determine the 1999 rate.

4.2.12 NRG also submitted that a cost of equity equivalent to that allowed to Consumers Gas in its most recent proceeding should be applied to a deemed 50 percent equity. NRG agreed with Board Staff's suggestion on the calculation of the 1999 cost of equity.

Board Findings

4.2.13 Given the Board's finding on the appropriate debt to equity ratio for NRG, the Board finds that a 10.30 percent rate of return on equity should be allowed for 1998.

4.2.14 The formula used to adjust the 1998 return on equity reflects interest rate changes between the August 1997 and July 1998 Consensus Forecasts. This results in a 9.50 percent rate of return on equity for 1999. The Board finds that this percentage should be used in the determination of the NRG's revenue requirement for 1999.

4.3 COST OF DEBT

Standby Fee

4.3.1 NRG stated that, pursuant to an amendment of its loan agreement with Junsen, an affiliated company, in February 1998, Junsen provided NRG with a line of credit of not more than $1.3 million with a standby fee, to be paid to Junsen, of 1 percent per annum on the unused balance. The estimated outstanding loan balance was forecast as $278,339 in 1998 and $484,104 in 1999.

4.3.2 The Crosbie witnesses expressed the view that the standby fee and the prepayment penalty negotiated with Junsen were reasonable and normal in the industry. These witnesses indicated that the rate for a standby fee "may be as high as 1.0%" and "it is our view that 1% of the unused facility for this type of loan would not be unreasonable under the circumstances".

Positions of the Parties

4.3.3 Board Staff noted that while such a fee is not unusual, at 1 percent it is at the high end of the range, as acknowledged by the Crosbie Report. Board Staff argued that the allowed amount of carrying cost of the debt should be reduced in two ways:

- the standby fee should be reduced from 1.0% to 0.75%; and
- the level of the line of credit should be reduced, since the unused portion was forecast to be approximately $1 million in 1998 and approximately $800,000 in 1999.

4.3.4 NRG submitted that the total cost of the line of credit was reasonable. NRG argued that the full credit facility of $1.3 million was required to cover all contingencies in the test years, including the impact of Board findings; warmer weather in 1998 and, potentially, in 1999; smaller tobacco crops; and other factors. NRG contended that these factors could put the Company at financial risk and if the credit facility was exhausted, NRG would be forced to seek additional financing at higher rates than those negotiated under the amendment of the Junsen loan agreement.

Board Findings

4.3.5 The Board finds that the 1 percent standby fee recoverable in cost of service should be reduced to 0.75 percent. The Board also finds that the level of the line of credit on which the standby fee is calculated for cost of service purposes should be reduced to $500,000.

4.3.6 The Board notes that the standby fee is described as being at the high end of the range and believes that a transaction with an affiliate should be, if not at the low end, at least towards the middle of the range. The Board also notes that, during the 1998 test year, NRG does not intend to avail itself of the line of credit and, for test year 1999, the amount needed will be only $220,000. This means that if NRG earns higher net income or reduces its capital expenditures for the fiscal year 1999, the full amount will not be needed.

4.3.7 These changes would reduce the standby fee costs for 1998 (8 months) to $2,500 from the $6,717 indicated in the evidence. For 1999, the fee would be reduced to $2,100 from $7,875.

4.3.8 The Board's finding will also reduce the cost of long-term debt recoverable in cost of service from 11.85 percent in fiscal 1998 to 11.74 percent and from 11.72 percent in fiscal 1999 to 11.59 percent.

Long-term Debt — Terms and Conditions

4.3.9 NRG stated that the Company had an outstanding loan with Imperial Life Assurance Company ("Imperial Life") with various covenants attached to it. The Company noted that NRG had been in breach of the covenant related to capital expenditures for the year ended September 30, 1997.

4.3.10 Mr. Blake admitted that the covenant would continue to be breached as capital expenditures were forecast to exceed the limits specified in the covenant. The limits on capital expenditures as specified in the loan agreement were $525,000 for fiscal 1998 and $550,000 for fiscal 1999. NRG's capital expenditures for 1998 and 1999 were forecast to be $1,818,444 and $1,140,087 respectively.

4.3.11 While NRG did not expect the loan agreement to be terminated because of the breach of the covenant, Imperial Life had refused to waive this covenant. The evidence indicated that this was a potential problem since the penalties could be as high as $1,126,000, although the terms regarding the penalties were ambiguous.

4.3.12 The Company said that, although negotiations continued between NRG and Imperial Life on the loan covenants, nothing had been resolved.

Positions of the Parties

4.3.13 Board Staff submitted that the Board needed to be kept informed of any developments with Imperial Life, NRG's senior lender. Board Staff was concerned that if there was a hardening of Imperial Life's position with respect to covenant contraventions, the likelihood of penalties could increase.

Board Findings

4.3.14 The Board believes that the covenant contraventions could have a serious impact on the financial viability of NRG, particularly in light of the evidence submitted concerning the difficulty of a company such as NRG being able to obtain financing.

4.3.15 Consequently, the Board directs NRG to file with the Board Secretary correspondence relating to loan covenants, requests for waivers and any item relating to the violation of covenants, as such documentation originates. If the Company feels that this information is confidential, it may be filed with the Energy Returns Officer.

4.4 IMPACT OF THE BOARD'S FINDINGS ON COST OF CAPITAL

4.4.1 The cost of capital resulting from the ADR Agreement and the Board's findings in this Chapter is:

Capital Component	Fiscal 1998		Fiscal 1999	
	Per ADR Impact Statement	Per Board	Per ADR Impact Statement	Per Board
Long-term Debt	11.85%	11.74%	11.72%	11.59%
Short-term Debt	7.53%	7.53%	7.75%	7.75%
Common Equity	10.30%	10.30%	10.10%	9.50%

4.4.2 The resulting cost of capital, as adjusted for the Board's findings, will be 11.06 percent for fiscal 1998 and 10.49 percent for fiscal 1999. The impact statements showing the results of the Board's findings are included in Appendix B.

5. RATE DESIGN

5.0.1 This Chapter deals with:

- revenue to cost ratios;
- rate unbundling;
- the disposition of the fiscal 1998 revenue sufficiency;
- rate restructuring; and
- long-term changes to rates.

Revenue to Cost Ratios

5.0.2 The prefiled evidence of NRG shows that its historical and proposed revenue to cost ratios are:

Customer Classes	1998 at 1997 rates	1998 Proposed	1999 Proposed
Rate 1 - residential customers	.8745	.8921	.9174
Rate 1 - commercial customers	1.2583	1.1817	1.1711
Rate 1 - industrial customers	1.3083	1.2998	1.1064
Rate 2 - seasonal customers	1.1729	1.0322	1.0323
Rate 3 - firm customers	1.591	1.1662	1.1071
Rate 3 - interruptible customers	1.0079	1.0076	.9723

5.0.3 Mr. Aiken, NRG's witness, explained that the intent of the proposed rate design was to reduce the rates paid by NRG's non-residential customers, in rate classes 1, 2 and 3, while proposing a small increase in rates to residential customers in rate class 1. He indicated that the proposed rate design was part of a long-term process of improving residential revenue to cost ratios.

Positions of the Parties

5.0.4 Board Staff made no specific submission on revenue to cost ratios.

5.0.5 NRG indicated that customers in rate classes with ratios of more than 1.0 were over contributing in relation to the costs that were allocated to that customer class. Conversely, customers in rate classes with ratios of less than 1.0 were under contributing.

Board Findings

5.0.6 The Board has espoused, in previous NRG proceedings the concept of cost-based rates. However, to minimize the possibility of rate shock on the captive Rate 1 residential customers, the Board directs NRG to maintain, for fiscal 1999, the revenue to cost ratio of Rate 1 residential customers at .8745, subject to adjustment for the ADR Agreement and the Board's findings on rate design and customer impacts appearing later in this Chapter. The Board also directs the Company to allocate the impact of the Board's findings in this rate case in such a way that the movement toward cost-based rates continues for all other classes of NRG's customers.

Rate Unbundling

5.0.7 NRG proposed to unbundle all three rate structures to allow customers to supply their own natural gas. The Company designed a "Bundled Direct Purchase Contract Rate" ("BT1") to enable NRG to pass the costs of transporting gas to Ontario to direct purchase customers or their agent(s).

5.0.8 The Company stated that the delivery charge would be based on the cost of service within NRG's franchise plus the cost of storage, load balancing and transportation across the Union franchise that NRG pays under Union's M9 rate. The Company proposed to bill the delivery charge to the direct purchase customers, or their agent(s), on a monthly basis.

5.0.9 However, NRG's witnesses did not provide detailed information concerning the proposed service. The Company indicated that none of the customer documentation had yet been prepared.

Positions of the Parties

5.0.10 NRG stated that the Company's proposal to unbundle the gas supply charge from the delivery charge across Rates 1, 2 and 3 would facilitate the use of the direct purchase option by all of NRG's customers. NRG's witnesses said that the change would also bring NRG more in line with the other utilities in Ontario and eliminate the need for gas supply credits for Rate 3 customers who elected to supply their own natural gas.

5.0.11 Board Staff stated its support for the proposed separation of gas commodity costs from the utility transportation and distribution costs in the rates proposed for all customer classes, and for the proposed concept that unbundled T-service (transportation service) should be available to all customers.

5.0.12 Board Staff submitted that NRG should, however, submit the documentation related to its proposed ABC (Agent Billing and Collection) T-service to the Board for its review and approval before the ABC T-service was introduced. Consequently, Board Staff argued that the new ABC T-service, if approved by the Board, should not be available for customers until October 1, 1998. In Board Staff's opinion, NRG should be directed to file with the Board a complete package of all necessary customer documentation by August 1, 1998.

5.0.13 Board Staff also argued that approval of the proposed ABC T-service for NRG should be contingent upon NRG adopting the code of conduct previously developed by the Direct Purchase Industry Committee (now the Ontario Energy

Marketers Association), and ensuring that the code is observed by any marketers active in its franchised territory.

5.0.14 In its reply, NRG indicated that the Company agreed with Board Staff's submission that Rate 1 and 2 customers should have the option to become direct purchase customers, along with Rate 3 customers, after proper notice had been issued to all NRG's customers.

5.0.15 NRG also stated that the Company agreed with the conditions suggested by Board Staff, but was concerned that it might not be able to meet an August 1, 1998 filing deadline if the Company waited for the Board's Decision. As a result, NRG indicated its intention to move forward on this documentation and provide the material to the Board as soon as it was available.

Board Findings

5.0.16 The Board agrees with the concept of unbundled rates and notes that NRG has indicated its willingness to adopt the code of conduct developed by the Direct Purchase Industry Committee, and ensure that the code is observed by any marketers active in its franchise territory. However, the Board is concerned that the lack of supporting information regarding an unbundled service and the extent of review that will be required before the service is approved, could unduly delay the implementation of NRG's rate order. In the interest of timely implementation of NRG's fiscal 1999 rates, the BT1 rate is not approved at this time.

5.0.17 The Board will consider an application for a special rate to enable NRG to provide an unbundled service. The application should contain the necessary details on the operation of this service, a forecast of customer migration to this service and the impact on WACOG. It should also provide information about how NRG has addressed the fairness issue regarding the attribution of the cost of the load balancing component of gas supply commodity costs.

Disposition of the Fiscal 1998 Revenue Sufficiency

5.0.18 NRG proposed to rebate the 1998 revenue sufficiency by introducing the proposed rate changes retroactively to be effective as of October 1, 1997.

Positions of the Parties

5.0.19 Board Staff argued that Rate 2 customers would unfairly benefit from the retroactive rate restructuring proposed by NRG, since this customer class would receive a disproportionate share of the projected 1998 revenue sufficiency at the expense of the Rate 1 residential customers.

5.0.20 Board Staff also argued that it was inappropriate to undertake rate restructuring retroactively. Board Staff submitted that the fiscal 1998 revenue sufficiency of $483,527 resulting from the ADR Agreement should be rebated uniformly to all customers in the form of a rate decrease of approximately $.0195 per m^3.

5.0.21 In reply, NRG stated that:

> *Given that a new rate order is not likely to be implemented prior to September 1, 1998, NRG agrees with Board Staff's submission that the fiscal 1998 revenue sufficiency should be rebated uniformly to all customers in the form of a rate decrease on a per m(3) basis for all consumption during fiscal 1998.*

Board Findings

5.0.22 The Board finds, after adjustment for the impact of the findings made throughout this Decision, that the 1998 revenue sufficiency is $541,239. The Board directs that this amount should be rebated uniformly to all customers on the basis of their consumption during 1998.

Rate Restructuring

5.0.23 The changes proposed by NRG in its prefiled evidence were:

	Rate 1		Rate 2		Rate 3	
	1998	1999	1998	1999	1998	1999
Fixed Monthly Customer Charge	+$.50	+$.50	+$.50	+$.50	N/C	N/C
Differential between first and second block rates (April - October)	+$.0426	N/C	+$.007	N/C	N/A	N/A
Differential between second and third block rates	N/A	N/A	+$.0285	N/C	N/A	N/A
Firm Demand Charge	N/A	N/A	N/A	N/A	N/C	N/C
Firm Delivery Commodity Rate	N/A	N/A	N/A	N/A	-	-$.0286 per m^3
N/C means no change N/A means not applicable						

5.0.24 The effect of the changes proposed in NRG's prefiled evidence on the Rate 1 and Rate 2 customer classes were:

Customer Classes	1998	1999
Rate 1 - residential customers	0.9%	4.3%
Rate 1 - commercial customers	-2.1%	4.3%
Rate 1 - industrial customers	-9.2%	4.7%
Rate 2 - seasonal customers	-11.8%	5.2%

5.0.25 Information on the proposed rate on Rate 3 customers was not available.

5.0.26 NRG stated that the proposed increase in the fixed monthly customer charge to Rate 1 customers would enable the Company to recover 26.5 percent of the fixed customer costs allocated to the Rate 1 class by 1999, up from 22 percent in 1997. The Company also said that the widening of the differential in the delivery charge between the first and second blocks allowed for a reduction in rates collected from larger Rate 1 customers, which were primarily commercial and industrial entities.

5.0.27 As with the proposed changes in the fixed monthly customer charge for Rate 1 customers, NRG said that the increase in the amount paid by Rate 2 customers would enable the Company to recover a higher percentage of the fixed customer costs allocated to the Rate 2 class.

5.0.28 The Company also stated that the proposed widening of the differential between the first and second blocks and between the second and third blocks of Rate 2, together with the overall reduction in delivery charges across all blocks would reduce rates to Rate 2 customers and bring these rates more in line with the costs of serving this customer class.

Positions of the Parties

5.0.29 Board Staff indicated their concern that Rate 2 customers have paid only 8 to 10 percent of the fixed charges through the fixed monthly customer charges, compared to the 25 to 30 percent paid by Rate 1 customers. Board Staff argued that NRG should be directed to review the fixed monthly customer charge for Rate 2 customers and to propose a charge that would recover approximately 25 to 30 percent of the fixed costs allocated to the Rate 2 customer class.

5.0.30 Board Staff noted that NRG did not propose to increase the $50 fixed monthly customer charge to Rate 3 customers, introduced in 1995 and unchanged since then. Board Staff argued that NRG should be directed to bring forward evidence on the appropriateness of this customer charge at the Company's next rates application.

5.0.31 Board Staff also argued that the Rate 3 delivery charge was too low, since it resulted in customers taking interruptible delivery paying a higher rate, at the top end of the interruptible rate range and assuming a 100 percent load factor, than did customers taking firm delivery. Board Staff submitted that, to avoid this perverse result, NRG would have to offer service to interruptible customers at the lower end of the price range, regardless of the criteria provided in the Rate 3 interruptible class rate schedule.

5.0.32 Board Staff submitted that the proposed changes to the rate structures should become effective October 1, 1998, after due notice had been issued to all NRG's customers.

5.0.33 In reply, NRG was pleased that Board Staff saw merit in moving towards cost-based rates in the fiscal 1999 rate proposals and also recommended that the Rate 1 and 2 changes as proposed by NRG should become effective October 1, 1998.

5.0.34 With regard to the Rate 2 fixed monthly customer charge, NRG submitted that increasing the charge so that it recovered approximately the same percentage as was recovered in the fixed monthly customer charge to Rate 1 customers could result in a tripling of the charge from the $9.20 proposed in fiscal 1999 to nearly $30 per month. The Company stated that, given that Rate 2 customers only used gas for 2 months of the year, it would be concerned that a $25 to $30 per month charge for ten months, when gas was not used, could result in a large number of Rate 2 customers requesting a temporary discontinuance of service in order to avoid paying the monthly charge.

5.0.35 NRG also argued that it was not necessary for the Board to direct the Company to bring forward evidence on the appropriateness of the $50 fixed monthly customer charge for Rate 3 customers in the next rates application. The Company indicated that one of its goals is to increase the fixed monthly customer charges to increase recovery of the fixed costs across all rate classes.

Board Findings

5.0.36 The Board notes that the impacts in 1999 of an order to change rates from those in effect in 1997 could be:

- increases in the monthly fixed charge by $1.00 for both Rate 1 and Rate 2 customers (Rate 1- from $7.95 in 1997 and 1998 to $8.95 in 1999; Rate 2 - from $8.20 in 1997 and 1998 to $9.20 in 1999);

- increases in the differentials between the first and the second block rates from $0.0174 in 1997 and 1998 to $0.06 in 1999 for Rate 1 customers and from

$0.038 in April-October, 1997 and 1998 to $0.045 in April-October, 1999 for Rate 2 customers;

- an increase in the differential between the second and third block rates applicable in the April-October period for Rate 2 customers, from $0.0135 in 1997 and 1998 to $0.035 in 1999; and

- reductions in the firm commodity rate charged to Rate 3 customers from 19.858 cents per m^3 to 17.9416 cents per m^3 in 1999 (both figures include gas commodity and transportation charges).

5.0.37 The Board is concerned about the impact of increasing rates to Rate 1 residential customers by a greater percentage than could be justified by projected inflation rates, at a time when substantial reductions in rates are being proposed for other classes of customers.

5.0.38 The Board notes that the anticipated rates of inflation for 1998 and 1999 calendar years are approximately 1.5 percent and 1.7 percent respectively. The Board also notes that the proposed fixed monthly customer charge to Rate 1 residential customers will recover a higher percentage of the fixed customer costs allocated to this customer class than is apparently recovered from any other type of customer.

5.0.39 In light of the evidence and these facts, the Board finds that:

- the fixed monthly customer charge to Rate 1 customers should not be increased;

- the proposed rates for Rate 1 residential customers should increase by no more than the anticipated rate of inflation for 1999, i.e., 1.7 percent;

- the widening of the differentials between the first and second blocks for Rate 1 and Rate 2 customer classes and between the second and the third blocks for the Rate 2 customer class are reasonable and appropriate;

- the rate restructuring proposed for the Rate 3 customer class is reasonable and appropriate; and

- the proposed rates for the Rate 2 customer class should be used to provide the balance of the revenue requirement of the Company, after taking into account the calculated revenue sufficiency for 1999 and the impact of the Board's findings elsewhere in this document.

5.0.40 The Board finds, after adjustment for the impact of the findings made throughout this Decision, that the 1999 revenue sufficiency is $334,104.

5.0.41 The Board also finds that the new rates, once approved, should be effective from October 1, 1998.

5.0.42 The Board directs NRG to develop rates for 1999 based on the findings stated in this Decision and to provide these and the resulting revenue to cost ratios to the Board for its review.

5.0.43 The Board notes NRG's goal of increasing fixed monthly customer charges to increase recovery of fixed costs across all rate classes. The Board directs NRG to provide information in its next rate hearing on the percentage of fixed costs recovered from each rate class or group and the rationale for this percentage recovery.

Long-term Changes

5.0.44 NRG proposed no new long-term rate proposals in the current proceeding, but relied on the proposals that the Company had filed in the EBRO 491 application.

5.0.45 As part of the actions to be taken to achieve these long-term objectives, NRG stated that the Company proposed to file a seasonal load study in its next main rates case. The rationale given for this action was that the load study would examine the customer load profile for the purpose of determining the block levels for Rate 2. The Company also proposed to investigate the possibility of a separate rate class for those contract (Rate 3) customers who have a distinctive fall peaking load. The results of this study would also be filed at NRG's next rates case.

Positions of the Parties

5.0.46 Board Staff submitted that the long-term rate objectives were appropriate as long as the rate-making criteria established by Bonbright were observed. Board Staff argued that, for the captive residential customers, a revenue to cost ratio of 95 percent must be attained slowly and should, where possible, be achieved through efficiencies that reduce NRG's costs.

Board Findings

5.0.47 The Board agrees that NRG's long-term rate-making goals remain appropriate. However, the Board expects that NRG will not take advantage of its captive customers, i.e., the Rate 1 residential customers, by subjecting them to the full impact of reducing rates to those customers who have other fuel-use options. The Board expects the Company to operate effectively and efficiently, thereby being able to reduce rates for all customer classes, not just a select few.

5.0.48 The Board will expect to see the proposed seasonal load study and study of the characteristics of Rate 3 customers at NRG's next rates hearing.

6. DEFERRAL ACCOUNTS, COMPLETION OF PROCEEDINGS AND COSTS

6.1 DEFERRAL ACCOUNTS

6.1.1 This section deals with the issues of:

- treatment of the Purchased Gas Deferral Account ("PGVA"); and
- establishing a Property Tax Deferral Account ("PTDA").

Purchased Gas Deferral Account

6.1.2 During the ADR settlement conference, the parties agreed that the PGVA would be split into two components: the Purchased Gas Commodity Variance Account ("PGCVA"), and the Purchased Gas Transportation Variance Account ("PGTVA"). Each component would have its own reference price.

6.1.3 Evidence and discussion on the commodity cost of gas is set out in Chapter 3 of this Decision.

6.1.4 NRG's evidence was that the transportation cost of gas would be \$0.017636 per m^3 for fiscal 1998 and \$0.018993 per m^3 for fiscal 1999.

Positions of the Parties

6.1.5 Neither party commented on the reference prices for the PGCVA or the PGTVA.

Board Findings

6.1.6 In Chapter 3 of this Decision, the Board found that the 1998 WACOG would be \$0.111864 per m^3 and that the 1999 WACOG would be \$0.124177 per m^3. The Board therefore finds that these shall be the reference prices for commodity gas for purposes of calculating amounts to be recorded in the PGCVA for fiscal 1998 and 1999 respectively.

6.1.7 Based on the fact that there was no dispute among the parties about the estimated transportation cost of gas, the Board finds that \$0.017636 per m^3 and \$0.018993 per m^3 shall be the reference prices for gas transportation for calculating amounts to be recorded in the PGTVA for fiscal 1998 and fiscal 1999 respectively.

Property Tax Deferral Account

6.1.8 Because of uncertainty arising from the property tax assessment reform initiated by the Ontario Government, NRG proposed the establishment of a PTDA to record any property taxes in excess of the levels forecast for the test years 1998 and 1999.

6.1.9 The Company stated that the deferral account would accumulate both negative and positive variances arising from the direct charges for municipal taxes, for a period that began in the last few months of fiscal 1998 and lasted until such time as the Ontario Government completed its property tax reform.

Positions of the Parties

6.1.10 Board Staff agreed with the Company's proposition to establish a PTDA, which would capture both positive and negative variances. Board Staff also said that the disposition of such an account should be at the Board's discretion at the appropriate time.

Board Findings

6.1.11 The Board does not believe that the establishment of a PTDA is necessary at this time. As indicated previously, the Board does not support the principle of creating deferral accounts "just in case".

6.1.12 However, NRG may apply to the Board for an Accounting Order to set up a PTDA should material negative variances result from actual tax expenditures in fiscal 1998 and 1999.

6.2 COMPLETION OF PROCEEDINGS

6.2.1 By Order dated September 26, 1997, NRG's rates and other charges were declared interim pending final disposition of the Application. The Board finds that the effective date for a change in the Company's rates shall be October 1, 1998 for the 1999 fiscal year and that, as indicated earlier in this Decision, the Company's revenue sufficiency of $541,239 for fiscal 1998 shall be refunded to its customers on a cents per m^3 consumed basis.

6.2.2 The one-time adjustment that shall appear on the customer's first bill issued on or after the implementation date of this Decision, will incorporate:

- the refund of the sufficiency for fiscal 1998; and
- the impact of clearing the balances in the deferral accounts, as agreed to in the ADR settlement conference.

6.2.3 If necessary, the adjustment shall also include the difference between NRG's interim rates and the rates approved for fiscal 1999, for the period from October 1, 1998 to the date of implementation ("the interim period"), without interest.

6.2.4 The Board directs NRG to file a draft Rate Order within 15 days from the receipt of this Decision. The draft rate order shall include appropriate rate schedules with supporting documentation and proposed notices to customers reflecting the Board's findings in this Decision.

6.2.5 The draft Rate Order shall also include:

- details supporting the disposition of the 1997 and 1998 deferral accounts;
- deferral account descriptions for fiscal 1999 Board-approved accounts;
- listing of the Board's directives contained in this Decision;
- the rate schedules; and
- rate base continuation schedules impacted by the findings in this Decision.

6.3 COSTS

6.3.1 Consumers Gas, Union and the HVAC Coalition were intervenors in these proceedings. Consumers Gas, and Union, however, did not take an active role, submit argument nor request costs.

6.3.2 The HVAC Coalition asked a small number of interrogatories and took an active role in the ADR settlement conference, specifically on the issue of allocation of costs to NRG's ancillary businesses. Since settlement of the issue in which the HVAC Coalition had an interest was included in the ADR Agreement and since the Board accepted the agreement, the HVAC Coalition did not actively participate in the hearing nor submit argument, other than its cost claim.

6.3.3 The HVAC Coalition requested that the Board order NRG to pay its reasonably incurred costs, but reduced its claim for fees by 30 percent "in deference to the scope and scale of NRG's operations, and the relative impact on NRG's cost of service of intervenor cost awards."

Board Findings

6.3.4 The Board concludes that the settlement reached on the issue of allocation of costs to ancillary programs, and the agreement of NRG to investigate other cost allocation models and ensure that water heater installation grants remain available to qualified customers, will benefit the customers of the NRG. The Board therefore finds that the HVAC Coalition is entitled to recover its reasonable costs of participating in this proceeding, after the proposed 30 percent reduction. The Board directs NRG to pay this amount upon receipt of the Board's Cost Awards Officer's report.

6.3.5 The Board also finds that the Applicant shall bear the Board's costs of these proceedings. Accordingly, NRG shall pay the Board's costs of, and incidental to, this proceeding immediately on receipt of the Board's invoice.

DATED at Toronto August 20, 1998.

F.A. Drozd
Presiding Member

F.G. Laughren
Chair and Member

S.F. Zerker
Member

APPENDIX A

ALTERNATIVE DISPUTE RESOLUTION AGREEMENT
WITH IMPACT STATEMENTS

APPENDIX A

ONTARIO ENERGY BOARD

E.B.R.O. 496

IN THE MATTER OF the *Ontario Energy Board Act*, R.S.O. 1990, Chapter 0.13

AND IN THE MATTER OF an Application by Natural Resource Gas Limited to the Ontario Energy Board for an Order or for Orders approving or fixing just and reasonable rates and other charges for the sale, distribution and transmission of gas.

AGREEMENT AMONG INTERESTED PARTIES

BENNETT JONES VERCHERE
Barristers & Solicitors
3400, One First Canadian Place
P.O. Box 130
Toronto, Ontario
M5X 1A4

April 16, 1998

AGREEMENT AMONG INTERESTED PARTIES

This ADR Agreement ("Agreement") is for the consideration of the Board in its determination of rates for Natural Resource Gas Limited ("NRG") under Board file E.B.R.O. 496. This Agreement deals with all issues identified in the Board's Issues List and notes where agreement has been reached between Board Staff and NRG for the purpose of establishing rates for fiscal 1998 and 1999. This Agreement also identifies where agreement has been reached between NRG and the HVAC Coalition with respect to the issue of allocation of costs to ancillary programs and the impact on rates of return (Issue C5.5), which is the issue HVAC Coalition raised. With acceptance of the agreement on this issue by the Board, HVAC Coalition will forego further participation in this proceeding. HVAC Coalition takes no position with respect to the balance of the Agreement. The Agreement is supported by the existing pre-filed evidence. The financial impacts of the Agreement are attached as Appendix "A".

A. GENERAL

A.1 Budget Process

There was no agreement on this issue.

A.2 Economic Feasibility Model Revisions

Board Staff and NRG agree that the E.B.O. 188 Report is not binding on NRG. However, Board Staff and NRG will meet as soon as possible to discuss how the principles of E.B.O. 188 may be adopted by NRG. To the extent that the principles of E.B.O. 188 are considered appropriate to NRG, NRG will make adjustments to its DCF model and provide a detailed description of the model by October 1, 1998.

A.3 Affiliate Transactions

There was no agreement on this issue.

A.4 Status of Board directives

Board Staff and NRG agree that NRG has adequately addressed the Board directives from E.B.R.O. 491. Both parties also observe that the results of the survey of seasonal customers directed by the Board at paragraph 2.2.5 of E.B.R.O. 491 were not conclusive (A/T8/S1).

A.5 Audited Fiscal 1997 Financial Statements

Board Staff and NRG agree that NRG will file audited financial statements with the Board by April 28, 1998.

B. RATE BASE

B.1 Lead/lag study

Board Staff and NRG agreed with the methodology presented by NRG in the working cash study, and the resulting revenue and expense lags. (B2/T1/S1)

B.2 CWIP – Township of Yarmouth Franchise

There was no agreement on this issue.

B.3 Fiscal 1996 and Fiscal 1997 Capital Budgets compared to Board approved

	Actual	Board Approved	Variance
Fiscal 1997	$861,954	$1,216,260	($332,839)
Fiscal 1996	$1,168,889	$1,390,658	($221,769)
Fiscal 1995	$842,870	$1,325,119	($482,249)

Board staff accept that much of the variance in the capital expenditures for fiscal 1995 and fiscal 1996 was caused by the delay in obtaining a franchise to serve part of the Township of Yarmouth and the limitation of that franchise which only permitted NRG to economically serve from the Township of Malahide boundary west to Catfish Creek.

The variances of ($332,839) in the fiscal 1997 capital budget (I/T1/S28) and of ($221,769) in the fiscal year 1996 capital budget (I/T1/S29) led to a lower actual rate base which has been partly responsible for NRG's sufficiency during the bridge years 1996 and 1997.

B.4 Reconciliation of Fiscal 1997 rate base with Board approved.

Board Staff and NRG agree with NRG's analysis of its performance for fiscal 1996 and 1997 as set out in I/T1/S1 updated. As appears from that analysis, the change in the actual rate base from that approved by the Board contributed $5,793 to the 1996 net sufficiency of $234,709 and $44,099 to the 1997 net sufficiency of $402,181 (I/T1/S1/U).

B.5.1 Proposed Fiscal 1998 Capital Budget

Mains Additions: there was no agreement on the prudence of the costs incurred for the construction of the NPS 6 line to Imperial Tobacco in the fiscal 1998 Capital Budget.

Board Staff and NRG have agreed to settling the balance of the 1998 Capital Budget on the following terms while noting that there is no agreement on the inclusion in rate base of Mr. Graat's vehicle for the fiscal year 1998:

Service Additions: Board staff accepted NRG's up-dated evidence of $58,095 for service additions to reflect forecasted customer attachments and the service line costs. (I/T1/S26/U and B4/T2/S1/U).

Service Replacements: Board Staff and NRG agreed with the service replacements of $15,015 based on the updated evidence filed by NRG respecting the number and the unit cost of replacements (I/T1/S26/U).

Meters: Board Staff and NRG agreed to a reduction of 8 meters for new customer additions at a unit cost of $97(totaling $776) to reflect the forecast of customer attachments (C4/T2/S2/U; and I/T1/S26/U).

Regulators: NRG agreed to a reduction of 25 regulators in the forecast for fiscal 1998 to reflect the number of customer attachments forecasted by NRG for fiscal 1998 (C3/T2/S2/U). NRG agreed to a reduction of 10 regulators from the forecasted number of 150 "627" high pressure regulators to 140 (I/T1/S26/p4/U) and from the forecasted number of 157 regulators for new customer additions to 142 (I/T1/S26/p.4/U) for a total reduction of $3,235.

Buildings: Board Staff accepted NRG's updated explanation for expenditures of $49,000 for buildings for fiscal 1998 (B4/T2/S1/U).

Computer Software: Board Staff and NRG agreed on the updated evidence filed on forecasted expenditures of $26,300 for computer software (I/T1/S27/U).

Automotive: Board Staff accepted NRG's updated evidence on automotive expenditures of $110,400 for fiscal 1998 (I/T1/S27/U).

Rental Water Heaters: Board Staff and NRG agreed to a reduction of 11 residential water heaters. This results in a reduction of capital expenditures of $6,292 (I/T1/S26/U).

B.5.2 Proposed Fiscal 1999 Capital Budget

Mains Additions: Board Staff accepted NRG's proposed expenditure of $317,595 for mains additions (B3/T2/S1/U).

Service Additions: NRG accepted Board Staff's adjustment to reflect the forecast for customer attachments resulting in a reduction of 4 service additions at a per unit cost of $205, or a total reduction of $820 (I/T1/S26/U).

Service Replacements: Board Staff and NRG agreed with the service replacements of $12,555 based on the updated evidence filed by NRG on the number and the unit cost of replacements (I/T1/S26/U).

Meters: Board Staff and NRG agreed to the updated evidence filed in respect of meters. NRG agreed to a reduction in the forecast of $99 to reflect the forecast number of customer attachments for fiscal 1999 (C3/T2/S2/U) and the updated residential meter costs (I/T1/S26/U).

Regulators: NRG agreed to a reduction of 15 regulators in the forecast for fiscal 1999 to reflect the number of customer attachments forecasted by NRG for fiscal 1999 (C3/T2/S2/U). NRG agreed to a reduction of 5 regulators from the forecasted number of 130 "627" high pressure regulators to 125 (I/T1/S26/p4/U) and from the forecasted number of 155 regulators for new customer additions to 145 (I/T1/S26/p.4/U) for a total reduction of $1,770.

Buildings: Board Staff and NRG agreed to the expenditures of $29,000 forecasted for fiscal 1999 as set out in the updated evidence (B3/T2/S1/U; and I/T1/S27/U).

Computer Software: Board Staff agreed to the updated expenditure of $10,000 forecasted by NRG for fiscal 1999 (B3/T2/S1/U; and I/T1/S27/U).

Automotive: There was no agreement on Mr. Graat's vehicle in the capital budget for fiscal 1999.

Rental Water Heaters: Board Staff and NRG agreed to a reduction of 11 residential water heaters. This results in a reduction of capital expenditures of $6,424 (I/T1/S26/U).

B.6 Fiscal 1998 and Fiscal 1999 Rate base: Allowance for Working Capital

Board Staff and NRG agree with NRG's methodology and determination of working capital of $104,585 for fiscal 1998 and $91,095 for fiscal 1999 (B4/T1/S1/U; and B3/T1/S1/U).

B.7 Per Customer Capital Expenditures

Board Staff and NRG agree that NRG should continue expanding service wherever it can maintain a project PI of 1.0 according to its current and future economic feasibility studies.

C. OPERATING REVENUE

C.1 Degree Day Forecast Methodology

Board Staff and NRG agree with the use of the five year weighted average forecast as supported by the statistical data at C2/T1/S2.

C.2 Customer Attachments -- actual and forecast

Board Staff and NRG have agreed to an adjustment of residential attachments from 275 to 285 for fiscal 1998 and from 265 to 275 for fiscal 1999. The impact of this adjustment is an increase in capital budget in fiscal 1998 by $3,470 to account for additional service lines, regulators and meters. Volume throughput in fiscal 1998 is increased by 14,955 m(3) (average annual consumption for new attachments calculated as 1495.5 m(3) per customer). Similarly, the capital budget in fiscal 1999 will be increased by $3,540 and volume throughput will be increased by 37,253 m(3) (average annual consumption for new attachments calculated as 1484.4 m(3) per customer, plus 22,409 m(3) for 10 additional customers at the beginning of 1999) (C3/T2/S2/U; C4/T2/S2/U; and I/T1/26/U).

C.3 Volume Forecast -- actual and forecast

Board Staff and NRG agree on the updated forecast (taking account for the adjustment of ten new residential attachments for each of 1998 and 1999) for residential, commercial, seasonal and contract customers for 1998 and 1999, and for industrial customers for 1998. No agreement was reached for rate 1 industrial throughput for fiscal 1999 (C4/T2/S1/U; and C3/T2/S1/U).

C.4 Gas Sales Revenue

Board Staff and NRG agree on the updated forecast (taking account for the adjustment of ten new residential attachments for each of 1998 and 1999) for residential, commercial, seasonal and contract customers for 1998 and 1999, and for industrial customers for 1998. No agreement was reached for rate 1 industrial revenue for fiscal 1999 (C4/T2/S1/U; and C3/T2/S1/U).

C.5 Other Operating Revenue -- water heater rental program

Board Staff and NRG agree with the forecast of net operating revenue from the water heater rental program for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue -- contract work program

Board Staff and NRG agree with the forecast of net operating revenue from the contract work program for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue -- customer service charges

Board Staff and NRG agree with the forecast of net operating revenue from customer service charges for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue -- delayed payment charges

Board Staff and NRG agree with the forecast of net operating revenue from delayed payment charges for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue --Allocation of costs to ancillary programs and the impact on rates of return

The currently accepted costing methodology for NRG's ancillary programs is a combination of fully allocated costing (in the case of most capital costs) and marginally allocated costing (in the case of most general overheads) as set out in I/T2/S5. NRG agrees to investigate a change to fully allocated costing for the ancillary programs it operates or proposes to operate at the time of its next rates case and to file its proposal in this respect in its next rates case. To facilitate resolution of the issue at that time, NRG agrees to provide sufficient costing information in its next rates case to enable immediate application of a fully allocated costing methodology for its ancillary programs, should the Board accept the methodology as appropriate for NRG to adopt. This information will include cost allocations to the ancillary programs based on a fully allocated methodology as mandated by the Board for Consumers Gas in E.B.R.O 495.

HVAC Coalition and NRG also agree that, to the extent that the water heater installation grants currently available to NRG franchise area customers continue to be offered in the test years, such grants will remain available to all NRG franchise area customers regardless of where those customers chose to obtain their natural gas water heaters. These grants are addressed in C3/T3/S1; C4/T3/S1; and I/T2/S2.

Board Staff also agrees with the foregoing resolution of this issue.

D. COST OF SERVICE

D.1.1 Gas Costs: Gas supply portfolio 1998 and 1999

Board Staff and NRG agree with the updated forecast of the 1998 and 1999 Union Gas Transportation costs of $434,468 for fiscal 1998 (D4/T2/S1/U) and $501,925 for fiscal 1999 (D3/T2/S1/U). The 1999 figure represents a correction from the updated evidence. There is no agreement on the 1998 and 1999 gas commodity costs forecasts.

D.1.2 Gas Costs: Forecast of unaccounted for gas

Board staff agreed with NRG's updated forecast of unaccounted for gas of 1.4% for fiscal 1998 and 1.9% for fiscal 1999 (D4/T2/S2/U and D3/T2/S2/U).

D.2 Operation and Maintenance Expense: Explanation of significant variances and major cost drivers, including:

(A) Wages and Benefits: explanation of wage and merit increases

Board Staff and NRG agree to an adjustment of wages to $755,035 for fiscal 1998 and $790,358 for fiscal 1999 and to an adjustment of benefits for fiscal 1998 to $93,122 based on a headcount in fiscal 1998 of 19.8 and in 1999 of 20.3 as well as a CPI of 1.7% in 1998 and 2.1% in 1999 (I/T1/57).

Following up on the Board's direction in E.B.R.O. 491 (s.2.7.13), and NRG's evidence filed in response to that direction, Board Staff and NRG agree that NRG will commit to move in the direction of adopting employee performance policies in its next rates case.

Wages and Benefits: headcount levels

As indicated above, Board Staff and NRG agree with the proposed staff level for fiscal 1998 and 1999 (I/T1/57).

Wages and Benefits: executive payroll

There was no agreement on this issue.

Wages and Benefits: Transfers between wages category and management fees

There was no agreement on this issue.

(B) Regulatory Costs: Review of Forecast Assumptions for key components

Board Staff and NRG agreed that NRG will limit its costs for intervening in Union's main rates case to $25,000 in 1998. NRG's costs for participating in proceedings arising out of Union's main rates case, such as various interim proceedings, in addition to the costs for participating in generic hearings, will be recorded in the Regulatory Expenses Deferral Account.

(C) Travel and Entertainment: Justification for forecast increase

Board Staff and NRG agreed to reduce NRG's forecast of fiscal 1998 and 1999 travel and entertainment expenses from $36,000 (D4/T3/S2/U) to $21,000 and from $37,000 for 1999 (D3/T3/S2/U) to $22,000. The adjustment reflects a reduction of $15,000 due to Mr. Graat's entertainment expenditures as identified by NRG (I/T1/S63).

(D) Management Fees and Office Rent: Explanation of key components and staff transfer

Board Staff and NRG agreed to the management fees updated forecast for fiscal 1998 of $71,900 (D4/T3/S2/U) and $75,000 for fiscal 1999 (D3/T3/S2/U).

Board Staff and NRG agreed to the office rent forecast for fiscal 1998 and 1999 of $9,600 (D3/T3/S2/U and D4/T3/S2/U).

(E) Consulting Fees: Explanation of Significant Components

Board Staff and NRG agreed to NRG's forecast for consulting fees of $35,000 in fiscal 1998 (D4/T3/S2/U) and to a reduction of $1,800 in consulting fees for fiscal 1999 from $40,000 to $38,200 (D3/T3/S2/U).

(F) Insurance Costs

Board Staff and NRG agreed with the updated forecast for insurance costs of $141,415 for fiscal 1998 (D4/T3/S2/U) and $143,000 for fiscal 1999 (D3/T3/S2/U).

(G) Automotive: Variance explanations and costs for Mr. Graat's vehicle

Board staff and NRG agreed to a reduction of $2,500 in automotive expenses forecasted for fiscal 1998 from $76,900 to $74,400 (D4/T3/S2/U). Board staff and NRG also agreed to a reduction of $5,000 in automotive expenses forecasted for fiscal 1999 from $82,700 to $77,700 (D3/T3/S2/U). There was no agreement on the treatment of Mr. Graat's vehicle.

(H) Bank Charges: Explanation of Junsen prepayment charge

Board Staff and NRG agreed to a reduction of $250 in the updated banking charges forecasted by NRG from $7,500 to $7,250 for fiscal 1998 and to the updated forecasted banking charged by NRG for fiscal 1999 of $8,000 (D4/T3/S2/U; and D3/T3/S2/U).

Board Staff and NRG agreed with the updated evidence filed by NRG which reflected the removal of prepayment charges in the provision of the Junsen loan (D1/T3/S5/U).

D.3 Depreciation Expense: Depreciation Study and proposed changes to depreciation rates

As indicated in issue B.2, Board Staff and NRG did not reach agreement as to the proper treatment of the expenses incurred in obtaining the Yarmouth franchise. As a result, there was no agreement on the depreciation rate respecting franchises.

Board Staff and NRG agree that total service life and salvage rate of plastic mains will remain as approved by the Board in E.B.R.O. 488 and the depreciation rate will therefore not be changed as proposed in D2/T1/S1/p7; that rate will remain at 2.25%.

Board Staff and NRG agree with the methodology and results of the depreciation study filed at D2/T1/S1 for the remaining category of assets.

D.4. Property and Capital Tax: mill rate forecast and assessed value forecast

As discussed below, in light of the uncertainty of the property tax assessment initiated by the Government, NRG proposes the establishment of a property tax deferral account to record any property taxes in excess of the levels forecast for the test years 1998 and 1999 (D1/T7/S1/U/pp9-10). Board Staff takes no position on this issue.

D.5 Income Taxes: derivation of effective rate for Fiscal 1998 and 1999 and explanation of 34.9% drop in 1998

There is no agreement on these issues.

D.6 Deferral Accounts:

PGVA: Board Staff and NRG agree to the proposed disposition of the PGVA balance (D5/T2/S3/U; and D1/T7/S1/U). Board Staff and NRG also agreed that NRG will proactively manage its balance position under Union's bundled-T Service during 1998 and 1999 by (i) ongoing monitoring of its balance position; (ii) where appropriate, making cost effective purchases of gas to address its balance situation; and (iii) considering alternative gas supply/transportation options to help manage balancing and demand charges on the Union system.

PGCVA and PGCTA: Board Staff and NRG agree that NRG will split the PGVA into commodity and transportation components with respective reference prices and that the two-step threshold point remains based on the aggregate amount. (D1/T7/S1; I/T1/S70)

DSM: Board Staff and NRG agree with NRG's proposal to discontinue this account and transfer the balance of $4,627.88 to 1998 cost of service (D1/T3/S4/U/p1; D1/T7/S1/U/pp5-6; and D5/T3/S5/U).

LTFS: Board Staff and NRG agreed with the proposed disposition of the LTFS deferral account (D1/T7/S1/pp 6-8; and E5/T1/S6/U).

REDA: As indicated at D.2 (B), Board Staff and NRG agree to NRG's opening a new account to capture the costs of NRG's intervention in generic hearings as well as proceedings arising out of Union's main rates cases, such as interim proceedings (D1/T7/S1/U/pp 8-9).

PTDA: Given the uncertainty of the property tax assessment reform initiated by the Government, NRG proposes the establishment of a property tax deferral account to record any property taxes in excess of the levels forecast for the test years 1998 and 1999 (D1/T7/S1/U/pp9-10). Board Staff takes no position on this issue.

D.7 DSM Initiatives: DSM Plan, advertising and promotion and impact on revenues and capital budgets

Board staff and NRG agreed that a DSM survey will be conducted and presented in the next rates case, and that in conducting the survey, NRG will include an adequate group of commercial customers (D2/T2/S2).

E. COST OF CAPITAL

E.1 Capital Structure: Long Term Financing Strategy Study (Crosbie Report)

There was no agreement on this issue.

Capital Structure: Ratio of Debt to Equity Financing

There was no agreement on this issue.

Capital Structure: Forecast Debt Levels

There was no agreement on this issue.

Capital Structure: Deemed Equity Component

There was no agreement on this issue.

Capital Structure: Business Risk

There was no agreement on this issue.

E.2 Cost of Debt: Cost of Short-Term Debt

Board Staff and NRG agree with the updated forecast of prime at 6.03% for fiscal 1998 and 6.25% for fiscal 1999 and the short term cost of debt of 7.53% and 7.75%, respectively (E1/T1/S2/U).

Cost of Debt: Cost of Long-Term Debt

Board Staff and NRG agree with the cost of long-term debt as forecast (E1/T1/S2/U). However, Board Staff opposes the inclusion of the stand-by fee on the Junsen loan in the carrying cost of long term debt capital.

Cost of Debt: Long term debt, term and conditions

There was no agreement on this issue.

E.3 Cost of Equity

There was no agreement on this issue.

F. COST ALLOCATION

F.1 Proposed Changes to the cost allocation methodology including:

Update of the zero intercept study

Board Staff and NRG agree with the revised results of the zero intercept study based upon the inclusion of the mains additions undertaken in 1996 and 1997 (G2/T1/S1/pp3-5). They also agree that the study should be updated and refiled in NRG's next rates case.

Weighted customer allocators

Board Staff and NRG agree with the revised results of the weighted customer allocators for customer billing, meters and services (G2/T1/S1/pp6-9).

Separation of gas commodity costs from transmission and storage costs

Board Staff and NRG agree with NRG's proposal to unbundle the gas commodity costs for gas received from the transmission and storage costs incurred on the Union Gas system and allocated as part of NRG's unbundling proposal (G2/T1/S1/p2).

Demand side management costs

Board Staff and NRG agree with the allocation of DSM costs as filed (G2/T1/S1/p2). DSM costs have been assigned to Rate 1 customers and allocated on the basis of the number of Rate 1 customers.

Revenue to cost ratios

Although Board Staff accepts and supports NRG's determination of the revenue to cost ratios, Board Staff intends to address this issue at the hearing because, according to Board Staff, revenue to cost ratios bridge the cost allocation and rate design issues.

G. RATE DESIGN

G.1 Proposed Rate 1 Changes

There was no agreement on the updated changes.

G.2 Proposed Rate 2 Changes

There was no agreement on the updated changes.

G.3 Rate Unbundling

There was no agreement on this issue.

G.4 Proposed long term changes

There was no agreement on this issue.

Parties to the Agreement

Natural Resource Gas Limited

Ontario Energy Board Staff

HVAC Coalition

NATURAL RESOURCE GAS LIMITED

UTILITY INCOME

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments		Per Agreement
Revenue				
Gas Sales	6,289,074	4,843	(1)	6,293,917
Cost of Gas & Transportation	2,757,126	1,861	(2)	2,758,987
Gas Sales Margin	3,531,948	2,982		3,534,930
Other Revenue (Net)	424,993	0		424,993
Total Revenue	3,956,941	2,982		3,959,923
Expenses				
Operation & Maintenance	1,559,115	(63,093)	(3)	1,496,022
Depreciation & Amortization	513,527	(23,512)	(4)	490,015
Property & Capital Taxes	242,728	0		242,728
Total Expenses	2,315,370	(86,605)		2,228,765
Utility Income Before Income Taxes	1,641,571	89,587		1,731,158
Income Taxes	519,934	26,404	(5)	546,338
Utility Income	1,121,637	63,183		1,184,820

(1) Increase due to addition of 10 residential customers with associated volume of 14,955 m3.

(2) Increase due to increased gas sales. Increased volumes costed at rate for gas in excess of TCPL based supplies of $0.124470/m3 (I/T1/S53/U).

(3)
(17,165)	Reduction in wage expenses
(3,178)	Reduction in benefits expenses
(25,000)	Reduction in regulatory expenses
(15,000)	Reduction in travel and entertainment expenses
(2,500)	Reduction in automotive expenses
(250)	Reduction in bank charges
(63,093)	

(4) Reduction in depreciation rate for plastic mains from 2.71% to 2.25%.

(5) Per Appendix A, Page 2 of 10

NATURAL RESOURCE GAS LIMITED

CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments		Per Agreement
Utility Income Before Income Taxes	1,641,571	89,587		1,731,158
Plus: Depreciation Expense	513,527	(23,512)		490,015
Federal Capital Tax (non-deductible)	6,626	0		6,626
Meals & Entertainment (non-deductible portion)	12,000	(7,500)	(1)	4,500
Less: Capital Cost Allowance	502,977	(600)	(2)	502,377
Interest Expense	505,499	0		505,499
Taxable Income	1,165,248	59,175		1,224,423
Income Taxes (at 44.62%)	519,934	26,404		546,338

(1) Change in non-deductible portion of travel & entertainment expenses due to reduction in travel & entertainment expenses.

(2) 29 Increase in capital expenditures in class 1
(629) Decrease in capital expenditures in class 8
(600)

NATURAL RESOURCE GAS LIMITED

UTILITY RATE BASE

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments		Per Agreement
Gas Utility Plant				
Gross Plant at Cost	11,337,789	(2,012)	(1)	11,335,777
Less: Accumulated Depreciation	3,183,397	(9,940)	(2)	3,173,457
Net Utility Plant	8,154,392	7,928		8,162,320
Allowance for Working Capital				
Inventory	140,895	0		140,895
Working Cash Allowance	33,562	(2,183)	(3)	31,379
Security Deposits	(69,872)	0		(69,872)
Total Working Capital	104,585	(2,183)		102,402
Utility Rate Base	8,258,977	5,745		8,264,722

(1)
834 Increase in expenditures for service replacements
(323) Decrease in expenditures for meters
(1,348) Decrease in expenditures for regulators
(2,621) Decrease in expenditures for water heaters
1,446 Increase in expenditures for 10 additional residential customers
(2,012)

(2)
34 Increase in expenditures for service replacements
(10) Decrease in expenditures for meters
(57) Decrease in expenditures for regulators
(165) Decrease in expenditures for water heaters
54 Increase in expenditures for 10 additional residential customers
(9,796) Decrease due to reduction in plastic mains depreciation rate
(9,940)

(3)
(691) Decrease in labour costs
(447) Decrease in labour-related costs
(352) Decrease in other costs
(623) Decrease in GST - O & M expenses
(70) Decrease in GST - Capital expenditures
(2,183)

NATURAL RESOURCE GAS LIMITED

CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1998
($)

Per Company	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.67%	11.85%	6.00%	495,706
Short-Term Debt					
Operating Loan	130,000	1.57%	7.53%	0.12%	9,793
Unfunded Debt	(185,305)	-2.24%	7.53%	-0.17%	(13,953)
Common Equity	4,129,489	50.00%	10.30%	5.15%	425,337
Total	8,258,977	100.00%		11.10%	916,883

Per Agreement	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.63%	11.85%	6.00%	495,706
Short-Term Debt					
Operating Loan	130,000	1.57%	7.53%	0.12%	9,793
Unfunded Debt	(182,432)	-2.20%	7.53%	-0.17%	(13,737)
Common Equity	4,132,361	50.00%	10.30%	5.15%	425,633
Total	8,264,722	100.00%		11.10%	917,395

NATURAL RESOURCE GAS LIMITED

DETERMINATION OF REVENUE DEFICIENCY

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments	Per Agreement
Net Utility Income	1,121,637	63,183	1,184,820
Utility Rate Base	8,258,977	5,745	8,264,722
Indicated Rate of Return	13.58%	0.76%	14.34%
Required Rate of Return	11.10%	0.00%	11.10%
Sufficiency in Rate of Return	2.48%	0.76%	3.24%
Revenue Sufficiency (after tax)	204,823	62,954	267,777
Provision for Income Tax	165,027	50,723	215,750
Gross Revenue Sufficiency	369,850	113,677	483,527

NATURAL RESOURCE GAS LIMITED

UTILITY INCOME

For the Year Ending September 30, 1999
($)

	Per Company (1)	Agreement Adjustments		Per Agreement
Revenue				
Gas Sales	6,411,424	12,228	(2)	6,423,652
Cost of Gas & Transportation	3,078,395	4,774	(3)	3,083,169
Gas Sales Margin	3,333,029	7,454		3,340,483
Other Revenue (Net)	468,127	0		468,127
Total Revenue	3,801,156	7,454		3,808,610
Expenses				
Operation & Maintenance	1,572,086	(22,142)	(4)	1,549,944
Depreciation & Amortization	514,143	(25,435)	(5)	488,708
Property & Capital Taxes	255,504	0		255,504
Total Expenses	2,341,733	(47,577)		2,294,156
Utility Income Before Income Taxes	1,459,423	55,031		1,514,454
Income Taxes	413,718	10,603	(6)	424,321
Utility Income	1,045,705	44,428		1,090,133

(1) Company evidence corrected to reflect increase in gas transportation costs.

(2) Increase due to addition of 10 residential customers in fiscal 1998 and a further 10 residential customers in 1999, with a total associated volume of 37,253 m3.

(3) Increase due to increased gas sales. Increased volumes costed at rate for gas in excess of TCPL based supplies of $0.128149/m3 (I/T1/S53/U).

(4) (342) Reduction in wage expenses
(15,000) Reduction in travel and entertainment expenses
(5,000) Reduction in automotive expenses
(1,800) Reduction in consulting expenses
(22,142)

(5) Reduction in depreciation rate for plastic mains from 2.71% to 2.25%.

(6) Per Appendix A, Page 7 of 10

NATURAL RESOURCE GAS LIMITED

CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1999
($)

	Per Company (1)	Agreement Adjustments		Per Agreement
Utility Income Before Income Taxes	1,459,423	55,031		1,514,454
Plus: Depreciation Expense	514,143	(25,435)		488,708
Federal Capital Tax (non-deductible)	10,317	0		10,317
Meals & Entertainment (non-deductible portion)	12,500	(7,500)	(2)	5,000
Less: Capital Cost Allowance	551,392	(1,668)	(3)	549,724
Interest Expense	517,788	0		517,788
Taxable Income	927,203	23,764		950,967
Income Taxes (at 44.62%)	413,718	10,603		424,321

(1) Company evidence corrected to reflect increase in gas transportation costs.

(2) Change in non-deductible portion of travel & entertainment expenses due to reduction in travel & entertainment expenses.

(3) 107 Increase in capital expenditures in class 1
(1,775) Decrease in capital expenditures in class 8
(1,668)

NATURAL RESOURCE GAS LIMITED

UTILITY RATE BASE

For the Year Ending September 30, 1999
($)

	Per Company	Agreement Adjustments		Per Agreement
Gas Utility Plant				
Gross Plant at Cost	12,435,241	(6,950)	(1)	12,428,291
Less: Accumulated Depreciation	3,589,055	(37,984)	(2)	3,551,071
Net Utility Plant	8,846,186	31,034		8,877,220
Allowance for Working Capital				
Inventory	140,833	0		140,833
Working Cash Allowance	20,164	(574)	(3)	19,590
Security Deposits	(69,902)	0		(69,902)
Total Working Capital	91,095	(574)		90,521
Utility Rate Base	8,937,281	30,460		8,967,741

(1)
(4,831) Decrease due to reduced capital expenditures in fiscal 1998
(444) Decrease in expenditures for service additions
901 Increase in expenditures for service replacements
(54) Decrease in expenditures for meters
(959) Decrease in expenditures for regulators
(3,480) Decrease in expenditures for water heaters
1,917 Increase in expenditures for 10 additional residential customers
(6,950)

(2)
(528) Decrease due to reduced capital expenditures in fiscal 1998
(18) Decrease in expenditures for service additions
37 Increase in expenditures for service replacements
(2) Decrease in expenditures for meters
(41) Decrease in expenditures for regulators
(218) Decrease in expenditures for water heaters
75 Increase in expenditures for 10 additional residential customers
(37,289) Decrease due to reduction in plastic mains depreciation rate
(37,984)

(3)
(14) Decrease in labour costs
(6) Decrease in labour-related costs
(179) Decrease in other costs
(318) Decrease in GST - O & M expenses
(57) Decrease in GST - Capital expenditures
(574)

NATURAL RESOURCE GAS LIMITED

CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1999
($)

Per Company	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,331,513	48.47%	11.72%	5.68%	507,713
Short-Term Debt					
Operating Loan	130,000	1.45%	7.75%	0.11%	10,075
Unfunded Debt	7,127	0.08%	7.75%	0.01%	552
Common Equity	4,468,641	50.00%	10.10%	5.05%	451,333
Total	8,937,281	100.00%		10.85%	969,673

Per Agreement	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,331,513	48.30%	11.72%	5.66%	507,713
Short-Term Debt					
Operating Loan	130,000	1.45%	7.75%	0.11%	10,075
Unfunded Debt	22,357	0.25%	7.75%	0.02%	1,733
Common Equity	4,483,871	50.00%	10.10%	5.05%	452,871
Total	8,967,741	100.00%		10.84%	972,392

NATURAL RESOURCE GAS LIMITED

DETERMINATION OF REVENUE DEFICIENCY

For the Year Ending September 30, 1999
($)

	Per Company (1)	Agreement Adjustments	Per Agreement
Net Utility Income	1,045,705	44,428	1,090,133
Utility Rate Base	8,937,281	30,460	8,967,741
Indicated Rate of Return	11.70%	0.46%	12.16%
Required Rate of Return	10.85%	-0.01%	10.84%
Sufficiency in Rate of Return	0.85%	0.47%	1.32%
Revenue Sufficiency (after tax)	75,967	42,407	118,374
Provision for Income Tax	61,207	34,168	95,375
Gross Revenue Sufficiency	137,174	76,575	213,749

(1) Company evidence corrected to reflect increase in gas transportation costs.

APPENDIX B

IMPACT OF THE BOARD'S FINDINGS IN THIS DECISION

NATURAL RESOURCE GAS LIMITED
UTILITY INCOME

For the Year Ending September 30, 1998
($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Revenue				
Gas Sales	6,293,917			6,293,917
Cost of Gas	2,758,987	8,550	[2]	2,767,537
Gas Sales Margin	3,534,930	(8,550)		3,526,380
Other Revenue (Net)	424,993	0		424,993
Total Revenue	3,959,923	(8,550)		3,951,373
Expenses				
Operations and Maintenance	1,496,022			1,496,022
Depreciation	490,015	(2,819)	[3]	487,196
Property and Capital Taxes	242,728	(6,626)	[4]	236,102
Total Expenses	2,228,765	(9,445)		2,219,320
Utility Income Before Income Taxes	1,731,158	895		1,732,053
Income Taxes	546,338	(25,051)	[5]	521,287
Utility Income	1,184,820	25,946		1,210,766

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement	
[2] Increase in Gas Commodity Cost of Norfolk Contract Commencing June 1998	8,550
[3] Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base	(2,819)
[4] Elimination of Federal Capital Tax Provision	(6,626)
[5] See Appendix B, Page 2 of 10	

NATURAL RESOURCE GAS LIMITED
CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1998

($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Utility Income Before Taxes [2]	1,731,158	895		1,732,053
Plus:				
Depreciation Expense	490,015	(2,819)	*[3]*	487,196
Federal Capital Tax	6,626	(6,626)	*[4]*	0
Meals and Entertainment	4,500			4,500
Less:				
Capital Cost Allowance	502,377	(5,035)	*[5]*	497,342
Interest Expense	505,499	(19,089)	*[6]*	486,410
Taxable Income	1,224,423	15,574		1,239,997
Income Taxes (44.62%)	546,338	6,949		553,287
Small Business Deduction	0	(32,000)		(32,000)
Income Taxes (44.62%)	546,338	(25,051)		521,287

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Refer to Appendix B, Page 1 of 10

[3] Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base	(2,819)
[4] Elimination of Federal Capital Tax Provision	(6,626)
[5] Capital Cost Allowance Impact of Removing Mr. Graat's Vehicle From Rate Base	(5,035)
[6] Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate)	(4,217)
Inclusion of Unfunded Debt in Interest Provision	(14,872)
	(19,089)

NATURAL RESOURCE GAS LIMITED
UTILITY RATE BASE

For the Year Ending September 30, 1998
($)

	Company After ADR Impact [1]	Board Adjustments	Per Board
Utility Plant			
Gross Plant at Cost	11,335,777	(37,891) [2]	11,297,886
Accumulated Depreciation	3,173,457	(7,741) [3]	3,165,716
Net Utility Plant	8,162,320	(30,150)	8,132,170
Allowance for Working Capital			
Inventory	140,895		140,895
Working Cash Allowance	31,379		31,379
Customer Security Deposits	(69,872)		(69,872)
Total Working Capital	102,402		102,402
Utility Rate Base	8,264,722	(30,150)	8,234,572

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Removal of Mr. Graat's Vehicle on Gross Plant	(37,891)
[3] Impact of Removal of Mr. Graat's Vehicle on Accumulated Depreciation	(7,741)

NATURAL RESOURCE GAS LIMITED
CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1998
($)

Per Company and ADR Agreement [1]	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.63%	11.85%	6.00%	495,706
Short-Term Debt					
Operating Loan	130,000	1.57%	7.53%	0.12%	9,793
Unfunded Debt	(182,432)	-2.20%	7.53%	-0.17%	(13,737)
Common Equity	4,132,361	50.00%	10.30%	5.15%	425,633
Total	8,264,722	100.00%		11.10%	917,395

Per Board	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.82%	11.74% *[2]*	5.97%	491,489
Short-Term Debt					
Operating Loan	130,000	1.58%	7.53%	0.12%	9,793
Unfunded Debt	(197,507)	-2.40%	7.53%	-0.18%	(14,872)
Common Equity	4,117,286	50.00%	10.30%	5.15%	424,080
Total	8,234,572	100.00%		11.06%	910,490

NOTES:

[1] No Direct ADR Agreement Impact. Indirect Impact of ADR Rate Base Agreements.

[2] Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate) 4,217

NATURAL RESOURCE GAS LIMITED
DETERMINATION OF REVENUE EXCESS/(DEFICIENCY)

For the Year Ending September 30, 1998
($)

	Company After ADR Impact [1]	Board Adjustments	Per Board
Net Utility Income	1,184,820	25,946	1,210,766
Utility Rate Base	8,264,722	(30,150)	8,234,572
Indicated Rate of Return	14.34%	0.36%	14.70%
Required Rate of Return	11.10%	-0.04%	11.06%
Rate of Return Excess/(Deficiency)	3.24%	0.40%	3.64%
Excess/(Deficiency) After Taxes	267,777	31,961	299,738
Provision for Income Tax (44.62%)	215,750	25,751	241,501
Gross Revenue Excess/(Deficiency)	483,527	57,712	541,239

NOTES:
[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

NATURAL RESOURCE GAS LIMITED
UTILITY INCOME

For the Year Ending September 30, 1999
($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Revenue				
Gas Sales	6,423,652	12,956	[2]	6,436,608
Cost of Gas	3,083,169	29,002	[3]	3,112,171
Gas Sales Margin	3,340,483	(16,046)		3,324,437
Other Revenue (Net)	468,127	0		468,127
Total Revenue	3,808,610	(16,046)		3,792,564
Expenses				
Operations and Maintenance	1,549,944			1,549,944
Depreciation	488,708	(3,125)	[4]	485,583
Property and Capital Taxes	255,504	(10,317)	[5]	245,187
Total Expenses	2,294,156	(13,442)		2,280,714
Utility Income Before Income Taxes	1,514,454	(2,604)		1,511,850
Income Taxes	424,321	(35,160)	[6]	389,161
Utility Income	1,090,133	32,556		1,122,689

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Impact of Rate 1 Industrial Customers Using Weighted Sales Rate ($0.271903 Per m3).	12,956
[3] Impact of Rate 1 Industrial Customers Using Weighted Gas Costs ($.124177 Per m3).	5,917
Increase in Gas Commodity Cost of Norfolk Contract Commencing June 1998	23,085
	29,002
[4] Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base	(3,125)
[5] Elimination of Federal Capital Tax Provision	(10,317)

[6] See Appendix B, Page 7 of 10

NATURAL RESOURCE GAS LIMITED
CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1999
($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Utility Income Before Taxes [2]	1,514,454	(2,604)		1,511,850
Plus:				
Depreciation Expense	488,708	(3,125)	*[3]*	485,583
Federal Capital Tax	10,317	(10,317)	*[4]*	0
Meals and Entertainment	5,000			5,000
Less:				
Capital Cost Allowance	549,724	(3,787)	*[5]*	545,937
Interest Expense	517,788	(5,175)	*[6]*	512,613
Taxable Income	950,967	(7,084)		943,883
Income Taxes (44.62%)	424,321	(3,160)		421,161
Small Business Deduction	0	(32,000)		(32,000)
Income Taxes (44.62%)	424,321	(35,160)		389,161

NOTES:

[1]	*Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement*	
[2]	*Refer to Appendix B, Page 6 of 10*	
[3]	*Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base*	(3,125)
[4]	*Elimination of Federal Capital Tax Provision*	(10,317)
[5]	*Capital Cost Allowance Impact of Removing Mr. Graat's Vehicle From Rate Base*	(3,787)
[6]	*Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate)*	(5,775)
	Inclusion of Unfunded Debt in Interest Provision	600
		(5,175)

NATURAL RESOURCE GAS LIMITED
UTILITY RATE BASE

For the Year Ending September 30, 1999

($)

	Company After ADR Impact *[1]*	Board Adjustments		Per Board
Gas Utility Plant				
Gross Plant at Cost	12,428,291	(39,946)	*[2]*	12,388,345
Accumulated Depreciation	3,551,071	(10,713)	*[3]*	3,540,358
Net Utility Plant	8,877,220	(29,233)		8,847,987
Allowance for Working Capital				
Inventory	140,833			140,833
Working Cash Allowance	19,590			19,590
Customer Security Deposits	(69,902)			(69,902)
Total Working Capital	90,521			90,521
Utility Rate Base	8,967,741	(29,233)		8,938,508

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Removal of Mr. Graat's Vehicle on Gross Plant	(39,946)
[3] Impact of Removal of Mr. Graat's Vehicle on Accumulated Depreciation	(10,713)

NATURAL RESOURCE GAS LIMITED
CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1999
($)

Per Company and ADR Agreement [1]	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,331,513	48.30%	11.72%	5.66%	507,713
Short-Term Debt					
Operating Loan	130,000	1.45%	7.75%	0.11%	10,075
Unfunded Debt	22,357	0.25%	7.75%	0.02%	1,733
Common Equity	4,483,871	50.00%	10.10%	5.05%	452,871
Total	8,967,741	100.00%		10.84%	972,392

Per Board	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,331,513	48.46%	11.59% *[2]*	5.62%	501,938
Short-Term Debt					
Operating Loan	130,000	1.45%	7.75%	0.11%	10,075
Unfunded Debt	7,741	0.09%	7.75%	0.01%	600
Common Equity	4,469,254	50.00%	9.50% *[3]*	4.75%	424,579
Total	8,938,508	100.00%		10.49%	937,192

NOTES:

[1] No Direct ADR Agreement Impact. Indirect Impact of ADR Rate Base Agreements.

[2] Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate) (5,775)

[3] Reflects Rate of Return Formula Using July 1998 Consensus Forecast

NATURAL RESOURCE GAS LIMITED
DETERMINATION OF REVENUE EXCESS/(DEFICIENCY)

For the Year Ending September 30, 1999
($)

	Company After ADR Impact [1]	Board Adjustments	Per Board
Net Utility Income	1,090,133	32,556	1,122,689
Utility Rate Base	8,967,741	(29,233)	8,938,508
Indicated Rate of Return	12.16%	0.40%	12.56%
Required Rate of Return	10.84%	-0.35%	10.49%
Rate of Return Excess/(Deficiency)	1.32%	0.75%	2.07%
Excess/(Deficiency) After Taxes	118,374	66,653	185,027
Provision for Income Tax (44.62%)	95,375	53,702	149,077
Gross Revenue Excess/(Deficiency)	213,749	120,355	334,104

NOTES:
[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

ISBN: 0-7778-7858-5

E.B.R.O. 496

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c.O.13;

AND IN THE MATTER OF an Application by Natural Resource Gas Limited to the Ontario Energy Board for an order or orders approving or fixing just and reasonable rates for the sale, distribution and transmission of gas commencing October 1, 1997.

BEFORE: F.A. Drozd
Presiding Member

F.G. Laughren
Chair and Member

S.F. Zerker
Member

DECISION WITH REASONS - ADDENDUM

September 21, 1998

In preparing NRG's rate order for fiscal 1998 and 1999 certain matters have come to the Board's attention. The following findings are necessary for the rate order to be finalized.

6. DEFERRAL ACCOUNTS, COMPLETION OF PROCEEDINGS AND COSTS

6.1 DEFERRAL ACCOUNTS

Interest Calculation

6.1.13 The Board finds that interest shall be calculated on the monthly opening balance for each deferral account at the Board-approved short-term cost of debt for fiscal 1998 and 1999 respectively.

Purchased Gas Transportation Variance Account

6.1.14 Subsequent to the Reasons With Decision being issued, NRG informed the Board by letter dated August 26, 1998, that NRG had neglected to file Ex. D3/T2/S1/U, dated April 10, 1998, which takes into account the updated forecast of Union's transportation costs. This update had been recognized in the ADR settlement, but not formally entered as an exhibit in the proceedings. The revised exhibit shows the total gas transportation cost revised to $0.020116 per m(3).

With this information the Board revises its finding at paragraph 6.1.7 and approves a PGTVA reference price for transportation of gas in 1999 of \$0.020116 per m^3 in place of \$0.018993 per m^3.

Long-Term Financing Study Deferral Account

6.1.15 Subsequent to the hearing of evidence, NRG advised the Board by letter dated June 24, 1998 that the actual cost of the Long-Term Financing Strategy Report was greater than the amount forecast by the Company. NRG requested in its letter that the Board use the actual figure when setting rates for 1998 and 1999. The Board finds that the forecast study costs are the appropriate amounts for the purpose of setting rates for fiscal 1998 and 1999. The Board directs NRG to establish a Long-Term Financing Study Deferral Account to capture the difference between the actual and forecast study costs. The Board will consider the disposition of this account in NRG's next main rates case.

DATED at Toronto September 21, 1998.

F.A. Drozd
Presiding Member

F.G. Laughren
Chair and Member

S.F. Zerker
Member

APPENDIX A

ALTERNATIVE DISPUTE RESOLUTION AGREEMENT WITH IMPACT STATEMENTS

APPENDIX A

ONTARIO ENERGY BOARD

E.B.R.O. 496

IN THE MATTER OF the *Ontario Energy Board Act*, R.S.O. 1990, Chapter 0.13

AND IN THE MATTER OF an Application by Natural Resource Gas Limited to the Ontario Energy Board for an Order or for Orders approving or fixing just and reasonable rates and other charges for the sale, distribution and transmission of gas.

AGREEMENT AMONG INTERESTED PARTIES

BENNETT JONES VERCHERE
Barristers & Solicitors
3400, One First Canadian Place
P.O. Box 130
Toronto, Ontario
M5X 1A4

April 16, 1998

AGREEMENT AMONG INTERESTED PARTIES

This ADR Agreement ("Agreement") is for the consideration of the Board in its determination of rates for Natural Resource Gas Limited ("NRG") under Board file E.B.R.O. 496. This Agreement deals with all issues identified in the Board's Issues List and notes where agreement has been reached between Board Staff and NRG for the purpose of establishing rates for fiscal 1998 and 1999. This Agreement also identifies where agreement has been reached between NRG and the HVAC Coalition with respect to the issue of allocation of costs to ancillary programs and the impact on rates of return (Issue C5.5), which is the issue HVAC Coalition raised. With acceptance of the agreement on this issue by the Board, HVAC Coalition will forego further participation in this proceeding. HVAC Coalition takes no position with respect to the balance of the Agreement. The Agreement is supported by the existing pre-filed evidence. The financial impacts of the Agreement are attached as Appendix "A".

A. GENERAL

A.1 Budget Process

There was no agreement on this issue.

A.2 Economic Feasibility Model Revisions

Board Staff and NRG agree that the E.B.O. 188 Report is not binding on NRG. However, Board Staff and NRG will meet as soon as possible to discuss how the principles of E.B.O. 188 may be adopted by NRG. To the extent that the principles of E.B.O. 188 are considered appropriate to NRG, NRG will make adjustments to its DCF model and provide a detailed description of the model by October 1, 1998.

A.3 Affiliate Transactions

There was no agreement on this issue.

A.4 Status of Board directives

Board Staff and NRG agree that NRG has adequately addressed the Board directives from E.B.R.O. 491. Both parties also observe that the results of the survey of seasonal customers directed by the Board at paragraph 2.2.5 of E.B.R.O. 491 were not conclusive (A/T8/S1).

A.5 Audited Fiscal 1997 Financial Statements

Board Staff and NRG agree that NRG will file audited financial statements with the Board by April 28, 1998.

B. RATE BASE

B.1 Lead/lag study

Board Staff and NRG agreed with the methodology presented by NRG in the working cash study, and the resulting revenue and expense lags. (B2/T1/S1)

B.2 CWIP – Township of Yarmouth Franchise

There was no agreement on this issue.

B.3 Fiscal 1996 and Fiscal 1997 Capital Budgets compared to Board approved

	Actual	Board Approved	Variance
Fiscal 1997	$861,954	$1,216,260	($332,839)
Fiscal 1996	$1,168,889	$1,390,658	($221,769)
Fiscal 1995	$842,870	$1,325,119	($482,249)

Board staff accept that much of the variance in the capital expenditures for fiscal 1995 and fiscal 1996 was caused by the delay in obtaining a franchise to serve part of the Township of Yarmouth and the limitation of that franchise which only permitted NRG to economically serve from the Township of Malahide boundary west to Catfish Creek.

The variances of ($332,839) in the fiscal 1997 capital budget (I/T1/S28) and of ($221,769) in the fiscal year 1996 capital budget (I/T1/S29) led to a lower actual rate base which has been partly responsible for NRG's sufficiency during the bridge years 1996 and 1997.

B.4 Reconciliation of Fiscal 1997 rate base with Board approved.

Board Staff and NRG agree with NRG's analysis of its performance for fiscal 1996 and 1997 as set out in I/T1/S1 updated. As appears from that analysis, the change in the actual rate base from that approved by the Board contributed $5,793 to the 1996 net sufficiency of $234,709 and $44,099 to the 1997 net sufficiency of $402,181 (I/T1/S1/U).

B.5.1 Proposed Fiscal 1998 Capital Budget

Mains Additions: there was no agreement on the prudence of the costs incurred for the construction of the NPS 6 line to Imperial Tobacco in the fiscal 1998 Capital Budget.

Board Staff and NRG have agreed to settling the balance of the 1998 Capital Budget on the following terms while noting that there is no agreement on the inclusion in rate base of Mr. Graat's vehicle for the fiscal year 1998:

Service Additions: Board staff accepted NRG's up-dated evidence of $58,095 for service additions to reflect forecasted customer attachments and the service line costs. (I/T1/S26/U and B4/T2/S1/U).

Service Replacements: Board Staff and NRG agreed with the service replacements of $15,015 based on the updated evidence filed by NRG respecting the number and the unit cost of replacements (I/T1/S26/U).

Meters: Board Staff and NRG agreed to a reduction of 8 meters for new customer additions at a unit cost of $97(totaling $776) to reflect the forecast of customer attachments (C4/T2/S2/U; and I/T1/S26/U).

Regulators: NRG agreed to a reduction of 25 regulators in the forecast for fiscal 1998 to reflect the number of customer attachments forecasted by NRG for fiscal 1998 (C3/T2/S2/U). NRG agreed to a reduction of 10 regulators from the forecasted number of 150 "627" high pressure regulators to 140 (I/T1/S26/p4/U) and from the forecasted number of 157 regulators for new customer additions to 142 (I/T1/S26/p.4/U) for a total reduction of $3,235.

Buildings: Board Staff accepted NRG's updated explanation for expenditures of $49,000 for buildings for fiscal 1998 (B4/T2/S1/U).

Computer Software: Board Staff and NRG agreed on the updated evidence filed on forecasted expenditures of $26,300 for computer software (I/T1/S27/U).

Automotive: Board Staff accepted NRG's updated evidence on automotive expenditures of $110,400 for fiscal 1998 (I/T1/S27/U).

Rental Water Heaters: Board Staff and NRG agreed to a reduction of 11 residential water heaters. This results in a reduction of capital expenditures of $6,292 (I/T1/S26/U).

B.5.2 Proposed Fiscal 1999 Capital Budget

Mains Additions: Board Staff accepted NRG's proposed expenditure of $317,595 for mains additions (B3/T2/S1/U).

Service Additions: NRG accepted Board Staff's adjustment to reflect the forecast for customer attachments resulting in a reduction of 4 service additions at a per unit cost of $205, or a total reduction of $820 (I/T1/S26/U).

Service Replacements: Board Staff and NRG agreed with the service replacements of $12,555 based on the updated evidence filed by NRG on the number and the unit cost of replacements (I/T1/S26/U).

Meters: Board Staff and NRG agreed to the updated evidence filed in respect of meters. NRG agreed to a reduction in the forecast of $99 to reflect the forecast number of customer attachments for fiscal 1999 (C3/T2/S2/U) and the updated residential meter costs (I/T1/S26/U).

Regulators: NRG agreed to a reduction of 15 regulators in the forecast for fiscal 1999 to reflect the number of customer attachments forecasted by NRG for fiscal 1999 (C3/T2/S2/U). NRG agreed to a reduction of 5 regulators from the forecasted number of 130 "627" high pressure regulators to 125 (I/T1/S26/p4/U) and from the forecasted number of 155 regulators for new customer additions to 145 (I/T1/S26/p.4/U) for a total reduction of $1,770.

Buildings: Board Staff and NRG agreed to the expenditures of $29,000 forecasted for fiscal 1999 as set out in the updated evidence (B3/T2/S1/U; and I/T1/S27/U).

Computer Software: Board Staff agreed to the updated expenditure of $10,000 forecasted by NRG for fiscal 1999 (B3/T2/S1/U; and I/T1/S27/U).

Automotive: There was no agreement on Mr. Graat's vehicle in the capital budget for fiscal 1999.

Rental Water Heaters: Board Staff and NRG agreed to a reduction of 11 residential water heaters. This results in a reduction of capital expenditures of $6,424 (I/T1/S26/U).

B.6 Fiscal 1998 and Fiscal 1999 Rate base: Allowance for Working Capital

Board Staff and NRG agree with NRG's methodology and determination of working capital of $104,585 for fiscal 1998 and $91,095 for fiscal 1999 (B4/T1/S1/U; and B3/T1/S1/U).

B.7 Per Customer Capital Expenditures

Board Staff and NRG agree that NRG should continue expanding service wherever it can maintain a project PI of 1.0 according to its current and future economic feasibility studies.

C. OPERATING REVENUE

C.1 Degree Day Forecast Methodology

Board Staff and NRG agree with the use of the five year weighted average forecast as supported by the statistical data at C2/T1/S2.

C.2 Customer Attachments -- actual and forecast

Board Staff and NRG have agreed to an adjustment of residential attachments from 275 to 285 for fiscal 1998 and from 265 to 275 for fiscal 1999. The impact of this adjustment is an increase in capital budget in fiscal 1998 by $3,470 to account for additional service lines, regulators and meters. Volume throughput in fiscal 1998 is increased by 14,955 m(3) (average annual consumption for new attachments calculated as 1495.5 m(3) per customer). Similarly, the capital budget in fiscal 1999 will be increased by $3,540 and volume throughput will be increased by 37,253 m(3) (average annual consumption for new attachments calculated as 1484.4 m(3) per customer, plus 22,409 m(3) for 10 additional customers at the beginning of 1999) (C3/T2/S2/U; C4/T2/S2/U; and I/T1/26/U).

C.3 Volume Forecast -- actual and forecast

Board Staff and NRG agree on the updated forecast (taking account for the adjustment of ten new residential attachments for each of 1998 and 1999) for residential, commercial, seasonal and contract customers for 1998 and 1999, and for industrial customers for 1998. No agreement was reached for rate 1 industrial throughput for fiscal 1999 (C4/T2/S1/U; and C3/T2/S1/U).

C.4 Gas Sales Revenue

Board Staff and NRG agree on the updated forecast (taking account for the adjustment of ten new residential attachments for each of 1998 and 1999) for residential, commercial, seasonal and contract customers for 1998 and 1999, and for industrial customers for 1998. No agreement was reached for rate 1 industrial revenue for fiscal 1999 (C4/T2/S1/U; and C3/T2/S1/U).

C.5 Other Operating Revenue -- water heater rental program

Board Staff and NRG agree with the forecast of net operating revenue from the water heater rental program for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue -- contract work program

Board Staff and NRG agree with the forecast of net operating revenue from the contract work program for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue -- customer service charges

Board Staff and NRG agree with the forecast of net operating revenue from customer service charges for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue -- delayed payment charges

Board Staff and NRG agree with the forecast of net operating revenue from delayed payment charges for fiscal 1998 and 1999 (C4/T1/S1/U; and C3/T1/S1/U).

Other Operating Revenue –Allocation of costs to ancillary programs and the impact on rates of return

The currently accepted costing methodology for NRG's ancillary programs is a combination of fully allocated costing (in the case of most capital costs) and marginally allocated costing (in the case of most general overheads) as set out in I/T2/S5. NRG agrees to investigate a change to fully allocated costing for the ancillary programs it operates or proposes to operate at the time of its next rates case and to file its proposal in this respect in its next rates case. To facilitate resolution of the issue at that time, NRG agrees to provide sufficient costing information in its next rates case to enable immediate application of a fully allocated costing methodology for its ancillary programs, should the Board accept the methodology as appropriate for NRG to adopt. This information will include cost allocations to the ancillary programs based on a fully allocated methodology as mandated by the Board for Consumers Gas in E.B.R.O 495.

HVAC Coalition and NRG also agree that, to the extent that the water heater installation grants currently available to NRG franchise area customers continue to be offered in the test years, such grants will remain available to all NRG franchise area customers regardless of where those customers chose to obtain their natural gas water heaters. These grants are addressed in C3/T3/S1; C4/T3/S1; and I/T2/S2.

Board Staff also agrees with the foregoing resolution of this issue.

D. COST OF SERVICE

D.1.1 Gas Costs: Gas supply portfolio 1998 and 1999

Board Staff and NRG agree with the updated forecast of the 1998 and 1999 Union Gas Transportation costs of $434,468 for fiscal 1998 (D4/T2/S1/U) and $501,925 for fiscal 1999 (D3/T2/S1/U). The 1999 figure represents a correction from the updated evidence. There is no agreement on the 1998 and 1999 gas commodity costs forecasts.

D.1.2 Gas Costs: Forecast of unaccounted for gas

Board staff agreed with NRG's updated forecast of unaccounted for gas of 1.4% for fiscal 1998 and 1.9% for fiscal 1999 (D4/T2/S2/U and D3/T2/S2/U).

D.2 Operation and Maintenance Expense: Explanation of significant variances and major cost drivers, including:

(A) Wages and Benefits: explanation of wage and merit increases

Board Staff and NRG agree to an adjustment of wages to $755,035 for fiscal 1998 and $790,358 for fiscal 1999 and to an adjustment of benefits for fiscal 1998 to $93,122 based on a headcount in fiscal 1998 of 19.8 and in 1999 of 20.3 as well as a CPI of 1.7% in 1998 and 2.1% in 1999 (I/T1/57).

Following up on the Board's direction in E.B.R.O. 491 (s.2.7.13), and NRG's evidence filed in response to that direction, Board Staff and NRG agree that NRG will commit to move in the direction of adopting employee performance policies in its next rates case.

Wages and Benefits: headcount levels

As indicated above, Board Staff and NRG agree with the proposed staff level for fiscal 1998 and 1999 (I/T1/57).

Wages and Benefits: executive payroll

There was no agreement on this issue.

Wages and Benefits: Transfers between wages category and management fees

There was no agreement on this issue.

(B) Regulatory Costs: Review of Forecast Assumptions for key components

Board Staff and NRG agreed that NRG will limit its costs for intervening in Union's main rates case to $25,000 in 1998. NRG's costs for participating in proceedings arising out of Union's main rates case, such as various interim proceedings, in addition to the costs for participating in generic hearings, will be recorded in the Regulatory Expenses Deferral Account.

(C) Travel and Entertainment: Justification for forecast increase

Board Staff and NRG agreed to reduce NRG's forecast of fiscal 1998 and 1999 travel and entertainment expenses from $36,000 (D4/T3/S2/U) to $21,000 and from $37,000 for 1999 (D3/T3/S2/U) to $22,000. The adjustment reflects a reduction of $15,000 due to Mr. Graat's entertainment expenditures as identified by NRG (I/T1/S63).

(D) Management Fees and Office Rent: Explanation of key components and staff transfer

Board Staff and NRG agreed to the management fees updated forecast for fiscal 1998 of $71,900 (D4/T3/S2/U) and $75,000 for fiscal 1999 (D3/T3/S2/U).

Board Staff and NRG agreed to the office rent forecast for fiscal 1998 and 1999 of $9,600 (D3/T3/S2/U and D4/T3/S2/U).

(E) Consulting Fees: Explanation of Significant Components

Board Staff and NRG agreed to NRG's forecast for consulting fees of $35,000 in fiscal 1998 (D4/T3/S2/U) and to a reduction of $1,800 in consulting fees for fiscal 1999 from $40,000 to $38,200 (D3/T3/S2/U).

(F) Insurance Costs

Board Staff and NRG agreed with the updated forecast for insurance costs of $141,415 for fiscal 1998 (D4/T3/S2/U) and $143,000 for fiscal 1999 (D3/T3/S2/U).

(G) Automotive: Variance explanations and costs for Mr. Graat's vehicle

Board staff and NRG agreed to a reduction of $2,500 in automotive expenses forecasted for fiscal 1998 from $76,900 to $74,400 (D4/T3/S2/U). Board staff and NRG also agreed to a reduction of $5,000 in automotive expenses forecasted for fiscal 1999 from $82,700 to $77,700 (D3/T3/S2/U). There was no agreement on the treatment of Mr. Graat's vehicle.

(H) Bank Charges: Explanation of Junsen prepayment charge

Board Staff and NRG agreed to a reduction of $250 in the updated banking charges forecasted by NRG from $7,500 to $7,250 for fiscal 1998 and to the updated forecasted banking charged by NRG for fiscal 1999 of $8,000 (D4/T3/S2/U; and D3/T3/S2/U).

Board Staff and NRG agreed with the updated evidence filed by NRG which reflected the removal of prepayment charges in the provision of the Junsen loan (D1/T3/S5/U).

D.3 Depreciation Expense: Depreciation Study and proposed changes to depreciation rates

As indicated in issue B.2, Board Staff and NRG did not reach agreement as to the proper treatment of the expenses incurred in obtaining the Yarmouth franchise. As a result, there was no agreement on the depreciation rate respecting franchises.

Board Staff and NRG agree that total service life and salvage rate of plastic mains will remain as approved by the Board in E.B.R.O. 488 and the depreciation rate will therefore not be changed as proposed in D2/T1/S1/p7; that rate will remain at 2.25%.

Board Staff and NRG agree with the methodology and results of the depreciation study filed at D2/T1/S1 for the remaining category of assets.

D.4. Property and Capital Tax: mill rate forecast and assessed value forecast

As discussed below, in light of the uncertainty of the property tax assessment initiated by the Government, NRG proposes the establishment of a property tax deferral account to record any property taxes in excess of the levels forecast for the test years 1998 and 1999 (D1/T7/S1/U/pp9-10). Board Staff takes no position on this issue.

D.5 Income Taxes: derivation of effective rate for Fiscal 1998 and 1999 and explanation of 34.9% drop in 1998

There is no agreement on these issues.

D.6 Deferral Accounts:

PGVA: Board Staff and NRG agree to the proposed disposition of the PGVA balance (D5/T2/S3/U; and D1/T7/S1/U). Board Staff and NRG also agreed that NRG will proactively manage its balance position under Union's bundled-T Service during 1998 and 1999 by (i) ongoing monitoring of its balance position; (ii) where appropriate, making cost effective purchases of gas to address its balance situation; and (iii) considering alternative gas supply/transportation options to help manage balancing and demand charges on the Union system.

PGCVA and PGCTA: Board Staff and NRG agree that NRG will split the PGVA into commodity and transportation components with respective reference prices and that the two-step threshold point remains based on the aggregate amount. (D1/T7/S1; I/T1/S70)

DSM: Board Staff and NRG agree with NRG's proposal to discontinue this account and transfer the balance of $4,627.88 to 1998 cost of service (D1/T3/S4/U/p1; D1/T7/S1/U/pp5-6; and D5/T3/S5/U).

LTFS: Board Staff and NRG agreed with the proposed disposition of the LTFS deferral account (D1/T7/S1/pp 6-8; and E5/T1/S6/U).

REDA: As indicated at D.2 (B), Board Staff and NRG agree to NRG's opening a new account to capture the costs of NRG's intervention in generic hearings as well as proceedings arising out of Union's main rates cases, such as interim proceedings (D1/T7/S1/U/pp 8-9).

PTDA: Given the uncertainty of the property tax assessment reform initiated by the Government, NRG proposes the establishment of a property tax deferral account to record any property taxes in excess of the levels forecast for the test years 1998 and 1999 (D1/T7/S1/U/pp9-10). Board Staff takes no position on this issue.

D.7 DSM Initiatives: DSM Plan, advertising and promotion and impact on revenues and capital budgets

Board staff and NRG agreed that a DSM survey will be conducted and presented in the next rates case, and that in conducting the survey, NRG will include an adequate group of commercial customers (D2/T2/S2).

E. COST OF CAPITAL

E.1 Capital Structure: Long Term Financing Strategy Study (Crosbie Report)

There was no agreement on this issue.

Capital Structure: Ratio of Debt to Equity Financing

There was no agreement on this issue.

Capital Structure: Forecast Debt Levels

There was no agreement on this issue.

Capital Structure: Deemed Equity Component

There was no agreement on this issue.

Capital Structure: Business Risk

There was no agreement on this issue.

E.2 Cost of Debt: Cost of Short-Term Debt

Board Staff and NRG agree with the updated forecast of prime at 6.03% for fiscal 1998 and 6.25% for fiscal 1999 and the short term cost of debt of 7.53% and 7.75%, respectively (E1/T1/S2/U).

Cost of Debt: Cost of Long-Term Debt

Board Staff and NRG agree with the cost of long-term debt as forecast (E1/T1/S2/U). However, Board Staff opposes the inclusion of the stand-by fee on the Junsen loan in the carrying cost of long term debt capital.

Cost of Debt: Long term debt, term and conditions

There was no agreement on this issue.

E.3 Cost of Equity

There was no agreement on this issue.

F. COST ALLOCATION

F.1 Proposed Changes to the cost allocation methodology including:

Update of the zero intercept study

Board Staff and NRG agree with the revised results of the zero intercept study based upon the inclusion of the mains additions undertaken in 1996 and 1997 (G2/T1/S1/pp3-5). They also agree that the study should be updated and refiled in NRG's next rates case.

Weighted customer allocators

Board Staff and NRG agree with the revised results of the weighted customer allocators for customer billing, meters and services (G2/T1/S1/pp6-9).

Separation of gas commodity costs from transmission and storage costs

Board Staff and NRG agree with NRG's proposal to unbundle the gas commodity costs for gas received from the transmission and storage costs incurred on the Union Gas system and allocated as part of NRG's unbundling proposal (G2/T1/S1/p2).

Demand side management costs

Board Staff and NRG agree with the allocation of DSM costs as filed (G2/T1/S1/p2). DSM costs have been assigned to Rate 1 customers and allocated on the basis of the number of Rate 1 customers.

Revenue to cost ratios

Although Board Staff accepts and supports NRG's determination of the revenue to cost ratios, Board Staff intends to address this issue at the hearing because, according to Board Staff, revenue to cost ratios bridge the cost allocation and rate design issues.

G. RATE DESIGN

G.1 Proposed Rate 1 Changes

There was no agreement on the updated changes.

G.2 Proposed Rate 2 Changes

There was no agreement on the updated changes.

G.3 Rate Unbundling

There was no agreement on this issue.

G.4 Proposed long term changes

There was no agreement on this issue.

Parties to the Agreement

Natural Resource Gas Limited

Ontario Energy Board Staff

HVAC Coalition

NATURAL RESOURCE GAS LIMITED

UTILITY INCOME

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments		Per Agreement
Revenue				
Gas Sales	6,289,074	4,843	(1)	6,293,917
Cost of Gas & Transportation	2,757,126	1,861	(2)	2,758,987
Gas Sales Margin	3,531,948	2,982		3,534,930
Other Revenue (Net)	424,993	0		424,993
Total Revenue	3,956,941	2,982		3,959,923
Expenses				
Operation & Maintenance	1,559,115	(63,093)	(3)	1,496,022
Depreciation & Amortization	513,527	(23,512)	(4)	490,015
Property & Capital Taxes	242,728	0		242,728
Total Expenses	2,315,370	(86,605)		2,228,765
Utility Income Before Income Taxes	1,641,571	89,587		1,731,158
Income Taxes	519,934	26,404	(5)	546,338
Utility Income	1,121,637	63,183		1,184,820

(1) Increase due to addition of 10 residential customers with associated volume of 14,955 m3.

(2) Increase due to increased gas sales. Increased volumes costed at rate for gas in excess of TCPL based supplies of $0.124470/m3 (I/T1/S53/U).

(3)
(17,165) Reduction in wage expenses
(3,178) Reduction in benefits expenses
(25,000) Reduction in regulatory expenses
(15,000) Reduction in travel and entertainment expenses
(2,500) Reduction in automotive expenses
(250) Reduction in bank charges
(63,093)

(4) Reduction in depreciation rate for plastic mains from 2.71% to 2.25%.

(5) Per Appendix A, Page 2 of 10

NATURAL RESOURCE GAS LIMITED

CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments		Per Agreement
Utility Income Before Income Taxes	1,641,571	89,587		1,731,158
Plus: Depreciation Expense	513,527	(23,512)		490,015
Federal Capital Tax (non-deductible)	6,626	0		6,626
Meals & Entertainment (non-deductible portion)	12,000	(7,500)	(1)	4,500
Less: Capital Cost Allowance	502,977	(600)	(2)	502,377
Interest Expense	505,499	0		505,499
Taxable Income	1,165,248	59,175		1,224,423
Income Taxes (at 44.62%)	519,934	26,404		546,338

(1) Change in non-deductible portion of travel & entertainment expenses due to reduction in travel & entertainment expenses.

(2)
29 Increase in capital expenditures in class 1
(629) Decrease in capital expenditures in class 8
(600)

NATURAL RESOURCE GAS LIMITED

UTILITY RATE BASE

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments		Per Agreement
Gas Utility Plant				
Gross Plant at Cost	11,337,789	(2,012)	(1)	11,335,777
Less: Accumulated Depreciation	3,183,397	(9,940)	(2)	3,173,457
Net Utility Plant	8,154,392	7,928		8,162,320
Allowance for Working Capital				
Inventory	140,895	0		140,895
Working Cash Allowance	33,562	(2,183)	(3)	31,379
Security Deposits	(69,872)	0		(69,872)
Total Working Capital	104,585	(2,183)		102,402
Utility Rate Base	8,258,977	5,745		8,264,722

(1)
834 Increase in expenditures for service replacements
(323) Decrease in expenditures for meters
(1,348) Decrease in expenditures for regulators
(2,621) Decrease in expenditures for water heaters
1,446 Increase in expenditures for 10 additional residential customers
(2,012)

(2)
34 Increase in expenditures for service replacements
(10) Decrease in expenditures for meters
(57) Decrease in expenditures for regulators
(165) Decrease in expenditures for water heaters
54 Increase in expenditures for 10 additional residential customers
(9,796) Decrease due to reduction in plastic mains depreciation rate
(9,940)

(3)
(691) Decrease in labour costs
(447) Decrease in labour-related costs
(352) Decrease in other costs
(623) Decrease in GST - O & M expenses
(70) Decrease in GST - Capital expenditures
(2,183)

NATURAL RESOURCE GAS LIMITED

CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1998
($)

Per Company	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.67%	11.85%	6.00%	495,706
Short-Term Debt					
Operating Loan	130,000	1.57%	7.53%	0.12%	9,793
Unfunded Debt	(185,305)	-2.24%	7.53%	-0.17%	(13,953)
Common Equity	4,129,489	50.00%	10.30%	5.15%	425,337
Total	8,258,977	100.00%		11.10%	916,883

Per Agreement	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.63%	11.85%	6.00%	495,706
Short-Term Debt					
Operating Loan	130,000	1.57%	7.53%	0.12%	9,793
Unfunded Debt	(182,432)	-2.20%	7.53%	-0.17%	(13,737)
Common Equity	4,132,361	50.00%	10.30%	5.15%	425,633
Total	8,264,722	100.00%		11.10%	917,395

NATURAL RESOURCE GAS LIMITED

DETERMINATION OF REVENUE DEFICIENCY

For the Year Ending September 30, 1998
($)

	Per Company	Agreement Adjustments	Per Agreement
Net Utility Income	1,121,637	63,183	1,184,820
Utility Rate Base	8,258,977	5,745	8,264,722
Indicated Rate of Return	13.58%	0.76%	14.34%
Required Rate of Return	11.10%	0.00%	11.10%
Sufficiency in Rate of Return	2.48%	0.76%	3.24%
Revenue Sufficiency (after tax)	204,823	62,954	267,777
Provision for Income Tax	165,027	50,723	215,750
Gross Revenue Sufficiency	369,850	113,677	483,527

NATURAL RESOURCE GAS LIMITED

UTILITY INCOME

For the Year Ending September 30, 1999
($)

	Per Company (1)	Agreement Adjustments		Per Agreement
Revenue				
Gas Sales	6,411,424	12,228	(2)	6,423,652
Cost of Gas & Transportation	3,078,395	4,774	(3)	3,083,169
Gas Sales Margin	3,333,029	7,454		3,340,483
Other Revenue (Net)	468,127	0		468,127
Total Revenue	3,801,156	7,454		3,808,610
Expenses				
Operation & Maintenance	1,572,086	(22,142)	(4)	1,549,944
Depreciation & Amortization	514,143	(25,435)	(5)	488,708
Property & Capital Taxes	255,504	0		255,504
Total Expenses	2,341,733	(47,577)		2,294,156
Utility Income Before Income Taxes	1,459,423	55,031		1,514,454
Income Taxes	413,718	10,603	(6)	424,321
Utility Income	1,045,705	44,428		1,090,133

(1) Company evidence corrected to reflect increase in gas transportation costs.

(2) Increase due to addition of 10 residential customers in fiscal 1998 and a further 10 residential customers in 1999, with a total associated volume of 37,253 m3.

(3) Increase due to increased gas sales. Increased volumes costed at rate for gas in excess of TCPL based supplies of $0.128149/m3 (I/T1/S53/U).

(4)
(342)	Reduction in wage expenses
(15,000)	Reduction in travel and entertainment expenses
(5,000)	Reduction in automotive expenses
(1,800)	Reduction in consulting expenses
(22,142)	

(5) Reduction in depreciation rate for plastic mains from 2.71% to 2.25%.

(6) Per Appendix A, Page 7 of 10

NATURAL RESOURCE GAS LIMITED

CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1999
($)

	Per Company (1)	Agreement Adjustments		Per Agreement
Utility Income Before Income Taxes	1,459,423	55,031		1,514,454
Plus: Depreciation Expense	514,143	(25,435)		488,708
Federal Capital Tax (non-deductible)	10,317	0		10,317
Meals & Entertainment (non-deductible portion)	12,500	(7,500)	(2)	5,000
Less: Capital Cost Allowance	551,392	(1,668)	(3)	549,724
Interest Expense	517,788	0		517,788
Taxable Income	927,203	23,764		950,967
Income Taxes (at 44.62%)	413,718	10,603		424,321

(1) Company evidence corrected to reflect increase in gas transportation costs.

(2) Change in non-deductible portion of travel & entertainment expenses due to reduction in travel & entertainment expenses.

(3) 107 Increase in capital expenditures in class 1
(1,775) Decrease in capital expenditures in class 8
(1,668)

NATURAL RESOURCE GAS LIMITED

UTILITY RATE BASE

For the Year Ending September 30, 1999
($)

	Per Company	Agreement Adjustments		Per Agreement
Gas Utility Plant				
Gross Plant at Cost	12,435,241	(6,950)	(1)	12,428,291
Less: Accumulated Depreciation	3,589,055	(37,984)	(2)	3,551,071
Net Utility Plant	8,846,186	31,034		8,877,220
Allowance for Working Capital				
Inventory	140,833	0		140,833
Working Cash Allowance	20,164	(574)	(3)	19,590
Security Deposits	(69,902)	0		(69,902)
Total Working Capital	91,095	(574)		90,521
Utility Rate Base	8,937,281	30,460		8,967,741

(1) (4,831) Decrease due to reduced capital expenditures in fiscal 1998
(444) Decrease in expenditures for service additions
901 Increase in expenditures for service replacements
(54) Decrease in expenditures for meters
(959) Decrease in expenditures for regulators
(3,480) Decrease in expenditures for water heaters
1,917 Increase in expenditures for 10 additional residential customers
(6,950)

(2) (528) Decrease due to reduced capital expenditures in fiscal 1998
(18) Decrease in expenditures for service additions
37 Increase in expenditures for service replacements
(2) Decrease in expenditures for meters
(41) Decrease in expenditures for regulators
(218) Decrease in expenditures for water heaters
75 Increase in expenditures for 10 additional residential customers
(37,289) Decrease due to reduction in plastic mains depreciation rate
(37,984)

(3) (14) Decrease in labour costs
(6) Decrease in labour-related costs
(179) Decrease in other costs
(318) Decrease in GST - O & M expenses
(57) Decrease in GST - Capital expenditures
(574)

NATURAL RESOURCE GAS LIMITED

CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1999
($)

Per Company	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,331,513	48.47%	11.72%	5.68%	507,713
Short-Term Debt					
Operating Loan	130,000	1.45%	7.75%	0.11%	10,075
Unfunded Debt	7,127	0.08%	7.75%	0.01%	552
Common Equity	4,468,641	50.00%	10.10%	5.05%	451,333
Total	8,937,281	100.00%		10.85%	969,673

Per Agreement	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,331,513	48.30%	11.72%	5.66%	507,713
Short-Term Debt					
Operating Loan	130,000	1.45%	7.75%	0.11%	10,075
Unfunded Debt	22,357	0.25%	7.75%	0.02%	1,733
Common Equity	4,483,871	50.00%	10.10%	5.05%	452,871
Total	8,967,741	100.00%		10.84%	972,392

NATURAL RESOURCE GAS LIMITED

DETERMINATION OF REVENUE DEFICIENCY

For the Year Ending September 30, 1999
($)

	Per Company (1)	Agreement Adjustments	Per Agreement
Net Utility Income	1,045,705	44,428	1,090,133
Utility Rate Base	8,937,281	30,460	8,967,741
Indicated Rate of Return	11.70%	0.46%	12.16%
Required Rate of Return	10.85%	-0.01%	10.84%
Sufficiency in Rate of Return	0.85%	0.47%	1.32%
Revenue Sufficiency (after tax)	75,967	42,407	118,374
Provision for Income Tax	61,207	34,168	95,375
Gross Revenue Sufficiency	137,174	76,575	213,749

(1) Company evidence corrected to reflect increase in gas transportation costs.

APPENDIX B

IMPACT OF THE BOARD'S FINDINGS IN THIS DECISION

NATURAL RESOURCE GAS LIMITED
UTILITY INCOME

For the Year Ending September 30, 1998

($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Revenue				
Gas Sales	6,293,917			6,293,917
Cost of Gas	2,758,987	8,550	[2]	2,767,537
Gas Sales Margin	3,534,930	(8,550)		3,526,380
Other Revenue (Net)	424,993	0		424,993
Total Revenue	3,959,923	(8,550)		3,951,373
Expenses				
Operations and Maintenance	1,496,022			1,496,022
Depreciation	490,015	(2,819)	[3]	487,196
Property and Capital Taxes	242,728	(6,626)	[4]	236,102
Total Expenses	2,228,765	(9,445)		2,219,320
Utility Income Before Income Taxes	1,731,158	895		1,732,053
Income Taxes	546,338	(25,051)	[5]	521,287
Utility Income	1,184,820	25,946		1,210,766

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Increase in Gas Commodity Cost of Norfolk Contract Commencing June 1998	8,550
[3] Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base	(2,819)
[4] Elimination of Federal Capital Tax Provision	(6,626)

[5] See Appendix B, Page 2 of 10

NATURAL RESOURCE GAS LIMITED
CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1998

($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Utility Income Before Taxes [2]	1,731,158	895		1,732,053
Plus:				
Depreciation Expense	490,015	(2,819)	[3]	487,196
Federal Capital Tax	6,626	(6,626)	[4]	0
Meals and Entertainment	4,500			4,500
Less:				
Capital Cost Allowance	502,377	(5,035)	[5]	497,342
Interest Expense	505,499	(19,089)	[6]	486,410
Taxable Income	1,224,423	15,574		1,239,997
Income Taxes (44.62%)	546,338	6,949		553,287
Small Business Deduction	0	(32,000)		(32,000)
Income Taxes (44.62%)	546,338	(25,051)		521,287

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Refer to Appendix B, Page 1 of 10

[3] Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base	(2,819)
[4] Elimination of Federal Capital Tax Provision	(6,626)
[5] Capital Cost Allowance Impact of Removing Mr. Graat's Vehicle From Rate Base	(5,035)
[6] Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate)	(4,217)
Inclusion of Unfunded Debt in Interest Provision	(14,872)
	(19,089)

NATURAL RESOURCE GAS LIMITED
UTILITY RATE BASE

For the Year Ending September 30, 1998
($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Utility Plant				
Gross Plant at Cost	11,335,777	(37,891)	[2]	11,297,886
Accumulated Depreciation	3,173,457	(7,741)	[3]	3,165,716
Net Utility Plant	8,162,320	(30,150)		8,132,170
Allowance for Working Capital				
Inventory	140,895			140,895
Working Cash Allowance	31,379			31,379
Customer Security Deposits	(69,872)			(69,872)
Total Working Capital	102,402			102,402
Utility Rate Base	8,264,722	(30,150)		8,234,572

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Removal of Mr. Graat's Vehicle on Gross Plant	(37,891)
[3] Impact of Removal of Mr. Graat's Vehicle on Accumulated Depreciation	(7,741)

NATURAL RESOURCE GAS LIMITED
CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1998
($)

Per Company and ADR Agreement [1]	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.63%	11.85%	6.00%	495,706
Short-Term Debt					
Operating Loan	130,000	1.57%	7.53%	0.12%	9,793
Unfunded Debt	(182,432)	-2.20%	7.53%	-0.17%	(13,737)
Common Equity	4,132,361	50.00%	10.30%	5.15%	425,633
Total	8,264,722	100.00%		11.10%	917,395

Per Board	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	4,184,793	50.82%	11.74% *[2]*	5.97%	491,489
Short-Term Debt					
Operating Loan	130,000	1.58%	7.53%	0.12%	9,793
Unfunded Debt	(197,507)	-2.40%	7.53%	-0.18%	(14,872)
Common Equity	4,117,286	50.00%	10.30%	5.15%	424,080
Total	8,234,572	100.00%		11.06%	910,490

NOTES:

[1] No Direct ADR Agreement Impact. Indirect Impact of ADR Rate Base Agreements.

[2] Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate) 4,217

NATURAL RESOURCE GAS LIMITED
DETERMINATION OF REVENUE EXCESS/(DEFICIENCY)

For the Year Ending September 30, 1998

($)

	Company After ADR Impact [1]	Board Adjustments	Per Board
Net Utility Income	1,184,820	25,946	1,210,766
Utility Rate Base	8,264,722	(30,150)	8,234,572
Indicated Rate of Return	14.34%	0.36%	14.70%
Required Rate of Return	11.10%	-0.04%	11.06%
Rate of Return Excess/(Deficiency)	3.24%	0.40%	3.64%
Excess/(Deficiency) After Taxes	267,777	31,961	299,738
Provision for Income Tax (44.62%)	215,750	25,751	241,501
Gross Revenue Excess/(Deficiency)	483,527	57,712	541,239

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

NATURAL RESOURCE GAS LIMITED
UTILITY INCOME

For the Year Ending September 30, 1999
($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Revenue				
Gas Sales	6,423,652	12,956	[2]	6,436,608
Cost of Gas	3,083,169	29,002	[3]	3,112,171
Gas Sales Margin	3,340,483	(16,046)		3,324,437
Other Revenue (Net)	468,127	0		468,127
Total Revenue	3,808,610	(16,046)		3,792,564
Expenses				
Operations and Maintenance	1,549,944			1,549,944
Depreciation	488,708	(3,125)	[4]	485,583
Property and Capital Taxes	255,504	(10,317)	[5]	245,187
Total Expenses	2,294,156	(13,442)		2,280,714
Utility Income Before Income Taxes	1,514,454	(2,604)		1,511,850
Income Taxes	424,321	(35,160)	[6]	389,161
Utility Income	1,090,133	32,556		1,122,689

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement	
[2] Impact of Rate 1 Industrial Customers Using Weighted Sales Rate ($0.271903 Per m3).	12,956
[3] Impact of Rate 1 Industrial Customers Using Weighted Gas Costs ($.124177 Per m3).	5,917
Increase in Gas Commodity Cost of Norfolk Contract Commencing June 1998	23,085
	29,002
[4] Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base	(3,125)
[5] Elimination of Federal Capital Tax Provision	(10,317)
[6] See Appendix B, Page 7 of 10	

NATURAL RESOURCE GAS LIMITED
CALCULATION OF INCOME TAXES

For the Year Ending September 30, 1999

($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Utility Income Before Taxes [2]	1,514,454	(2,604)		1,511,850
Plus:				
Depreciation Expense	488,708	(3,125)	*[3]*	485,583
Federal Capital Tax	10,317	(10,317)	*[4]*	0
Meals and Entertainment	5,000			5,000
Less:				
Capital Cost Allowance	549,724	(3,787)	*[5]*	545,937
Interest Expense	517,788	(5,175)	*[6]*	512,613
Taxable Income	950,967	(7,084)		943,883
Income Taxes (44.62%)	424,321	(3,160)		421,161
Small Business Deduction	0	(32,000)		(32,000)
Income Taxes (44.62%)	424,321	(35,160)		389,161

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement	
[2] Refer to Appendix B, Page 6 of 10	
[3] Depreciation Impact of Removing Mr. Graat's Vehicle From Rate Base	(3,125)
[4] Elimination of Federal Capital Tax Provision	(10,317)
[5] Capital Cost Allowance Impact of Removing Mr. Graat's Vehicle From Rate Base	(3,787)
[6] Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate)	(5,775)
Inclusion of Unfunded Debt in Interest Provision	600
	(5,175)

NATURAL RESOURCE GAS LIMITED
UTILITY RATE BASE

For the Year Ending September 30, 1999
($)

	Company After ADR Impact [1]	Board Adjustments		Per Board
Gas Utility Plant				
Gross Plant at Cost	12,428,291	(39,946)	[2]	12,388,345
Accumulated Depreciation	3,551,071	(10,713)	[3]	3,540,358
Net Utility Plant	8,877,220	(29,233)		8,847,987
Allowance for Working Capital				
Inventory	140,833			140,833
Working Cash Allowance	19,590			19,590
Customer Security Deposits	(69,902)			(69,902)
Total Working Capital	90,521			90,521
Utility Rate Base	8,967,741	(29,233)		8,938,508

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement

[2] Removal of Mr. Graat's Vehicle on Gross Plant	(39,946)
[3] Impact of Removal of Mr. Graat's Vehicle on Accumulated Depreciation	(10,713)

NATURAL RESOURCE GAS LIMITED
CAPITALIZATION AND COST OF CAPITAL

For the Year Ending September 30, 1999
($)

Per Company and ADR Agreement [1]	Capital Structure	Ratios	Cost Rate		Return Component	Return
Long-Term Debt	4,331,513	48.30%	11.72%		5.66%	507,713
Short-Term Debt						
Operating Loan	130,000	1.45%	7.75%		0.11%	10,075
Unfunded Debt	22,357	0.25%	7.75%		0.02%	1,733
Common Equity	4,483,871	50.00%	10.10%		5.05%	452,871
Total	8,967,741	100.00%			10.84%	972,392

Per Board	Capital Structure	Ratios	Cost Rate		Return Component	Return
Long-Term Debt	4,331,513	48.46%	11.59%	*[2]*	5.62%	501,938
Short-Term Debt						
Operating Loan	130,000	1.45%	7.75%		0.11%	10,075
Unfunded Debt	7,741	0.09%	7.75%		0.01%	600
Common Equity	4,469,254	50.00%	9.50%	*[3]*	4.75%	424,579
Total	8,938,508	100.00%			10.49%	937,192

NOTES:

[1] No Direct ADR Agreement Impact. Indirect Impact of ADR Rate Base Agreements.

[2] Reduction in Junsen Loan Standby fee ($500,000 in Provision and 0.25 Percent in Rate) (5,775)

[3] Reflects Rate of Return Formula Using July 1998 Consensus Forecast

NATURAL RESOURCE GAS LIMITED
DETERMINATION OF REVENUE EXCESS/(DEFICIENCY)

For the Year Ending September 30, 1999

($)

	Company After ADR Impact [1]	Board Adjustments	Per Board
Net Utility Income	1,090,133	32,556	1,122,689
Utility Rate Base	8,967,741	(29,233)	8,938,508
Indicated Rate of Return	12.16%	0.40%	12.56%
Required Rate of Return	10.84%	-0.35%	10.49%
Rate of Return Excess/(Deficiency)	1.32%	0.75%	2.07%
Excess/(Deficiency) After Taxes	118,374	66,653	185,027
Provision for Income Tax (44.62%)	95,375	53,702	149,077
Gross Revenue Excess/(Deficiency)	213,749	120,355	334,104

NOTES:

[1] Refer to Appendix A for Details of Adjustments Contained in the ADR Agreement