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Administration

Overview

Finance

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Board Approved – 2007

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Board Approved – 2007

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Bridge Year – 2010

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<u>Historical Year – 2008</u>

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	7	1	Other Deferral and Variance Accounts – 2008 Actual

<u>Historical Year – 2009</u>

D6	1	1	Cost of Service – 2009 Actual
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<u>Bridge Year – 2010</u>

D7	1	1	Cost of Service – 2010 Bridge
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	7	1	Other Deferral and Variance Accounts – 2010 Bridge

Test Year – 2011

D8	1	1	Cost of Service – 2011 Test
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		4	Summary of Capital Cost Allowance – 2011 Test
	5	1	Property and Capital Taxes – 2011 Test
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	7	1	Other Deferral and Variance Accounts – 2011 Test

<u>Historical Year – 2008</u>

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<u>Historical Year – 2009</u>

E6	1	1	Capital Structure – Cost of Capital – 2009 Actual
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<u>Bridge Year – 2010</u>

E7	1	1	Capital Structure – Cost of Capital – 2010 Bridge
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<u>Test Year – 2011</u>

E8	1	1	Capital Structure – Cost of Capital – 2011 Test
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<u>Test Year – 2011</u>

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ONTARIO ENERGY BOARD

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

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

APPLICATION

1. The Applicant is Natural Resource Gas Limited ("NRG"), an Ontario corporation with its head office in the City of London, Ontario. NRG carries on the business, among other things, of selling and distributing natural gas within Ontario.

2. NRG hereby applies to the Ontario Energy Board (the "Board" or "OEB"), pursuant to section 36 of the *Ontario Energy Board Act, 1998* (the "Act"), for an Order or Orders approving a five-year incentive rate ("IR") mechanism to determine rates for the sale and distribution of gas effective October 1, 2010 (the "IR Period"). A list of specific approvals requested is set out in Exhibit A1, Tab 2, Schedule 1.

3. For the purpose of subsection 36(3) of the Act, NRG requests the Board's approval of an IR mechanism which:

    (a) establishes base rates for the Fiscal 2011 Test Year (October 1, 2010 to September 30, 2011) using a cost-of-service methodology;

    (b) maintains those rates over the remaining four years of the IR Period, limiting the net annual rate increase to 1.5% with no X-Factor adjustment;

    (c) provides for a Y-Factor and Z-Factor; and,

    (d) provides for an off-ramp for NRG in the event of a 300 basis point variance in normalized earnings from the Board approved ROE.

4. In order for the Board to establish base rates for the IR Period (i.e., for the Fiscal 2011 Test Year), the Board would determine the Applicant's rate base for the Fiscal 2011 Test Year and the reasonable return on such rate base, including a fair rate of return on capital that the Applicant should be allowed to earn. To this end, NRG will file with the Board, among other things, its actual results for Fiscal 2006 through Fiscal 2009, its estimated results for the Fiscal 2010 bridge year, and its forecast results for the 2010 test year, together with supporting information.

5. NRG's proposed rates are based on depreciation rates approved by the Board in previous NRG rate proceedings, with the exception of the IGPC pipeline which will be depreciated over 20 years. NRG has also filed a rate schedule (for illustrative purposes only) based on a depreciation rate that corresponds to NRG's Aylmer franchise renewal period (EB-2008-0413)

6. NRG further applies to the Board for such final and interim Orders, accounting orders and deferral and variance accounts as may be necessary in relation to the approving or fixing of just and reasonable rates for the sale and distribution of gas effective October 1, 2010.

7. NRG further applies to the Board pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure* for such final and interim Orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

8. NRG further applies to the OEB for all necessary orders and directions to provide for pre-hearing and hearing procedures for the determination of this application.

9. This application will be supported by written and oral evidence. The written evidence will be pre-filed and may be amended from time to time as circumstances may require.

10. The persons affected by this Application are the present and future customers of NRG. It is impractical to set out in this Application the names and addresses of such parties because they are too numerous.

11. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's Counsel, as follows:

The Applicant:

Mr. Jack Howley
Natural Resource Gas Limited
39 Beech Street East
Aylmer, ON N5H 1A1

Telephone: (519) 773-5321
Fax: (519) 773-5335
Email: howley@nrgas.on.ca

- and -

The Applicant's Counsel:

Mr. Richard J. King
Ogilvy Renault LLP
Royal Bank Plaza, South Tower
200 Bay Street, Suite 3800
Toronto, ON M5J 2Z4

Telephone: (416) 216-2311
Fax: (416) 216-3930
Email: rking@ogilvyrenault.com

12. NRG also requests that this proceeding be held in Toronto, Ontario.

DATED at Toronto, Ontario this 26th day of February, 2010.

NATURAL RESOURCE GAS LIMITED

By its counsel, Ogilvy Renault LLP
Per: Richard J. King

NATURAL RESOURCE GAS LIMITED

SPECIFIC APPROVALS REQUESTED

- Approval to charge rates effective October 1, 2010 to recover a $462,417 delivery-related revenue deficiency (see Exhibit F8, Tab 1, Schedule 1)
- Approval of NRG's proposed incentive rate plan ("IRP") covering the five-year period from October 1, 2010 to September 30, 2015 (see Exhibit H1, Tab 1, Schedule 2)
- Approval of a cost of capital for NRG based upon:
  - a deemed capital structure of 58% debt and 42% equity, with a return on equity ("ROE") for NRG of 50 basis points above the Board-approved ROE (adjusted annually); or
  - in the alternative, a deemed capital structure of 49% debt and 51% equity, with an ROE for NRG established at the Board-approved ROE.
- Approval to continue the following deferral/variance accounts in fiscal 2011 (see Exhibit D1, Tab 7, Schedule 1):
  - Purchased Gas Commodity Variance Account (PGCVA)
  - Purchased Gas Transportation Variance Account (PGTVA)
  - Gas Purchase Rebalancing Account (GPRA)
  - Regulatory Expenses Deferral Account (REDA)

- Approval to establish a new deferral account to record any potential costs to move to an IFRS accounting system (see Exhibit D1, Tab 7, Schedule 1)

- Approval to establish a new Rate 6 based on directly assigned costs and appropriately allocated common costs (see Exhibit G1, Tab 1, Schedule 1 and Exhibit H2, Tab 1, Schedule 1)

- Approval of revised Rules and Regulations for NRG (see <u>Exhibit A1, Tab 5, Schedule 1</u>)

- Approval to increase the Direct Purchase Administration Fee (Monthly Fee per Bundled-T Contract) (see Exhibit H1, Tab 1, Schedule 2)

- Approval for a new Schedule of Service Charges (see Exhibit A1, Tab 5, Schedule 2)

- Approvals related to three Board Directives from previous Board decisions, as follows:

    - approval of NRG's fleet policy;
    - approval of NRG's proposal for dealing with declining volumes in Rate 2; and,
    - approval of the derivation of an Incremental System Gas Fee (see Exhibit A1, Tab 4, Schedule 1).

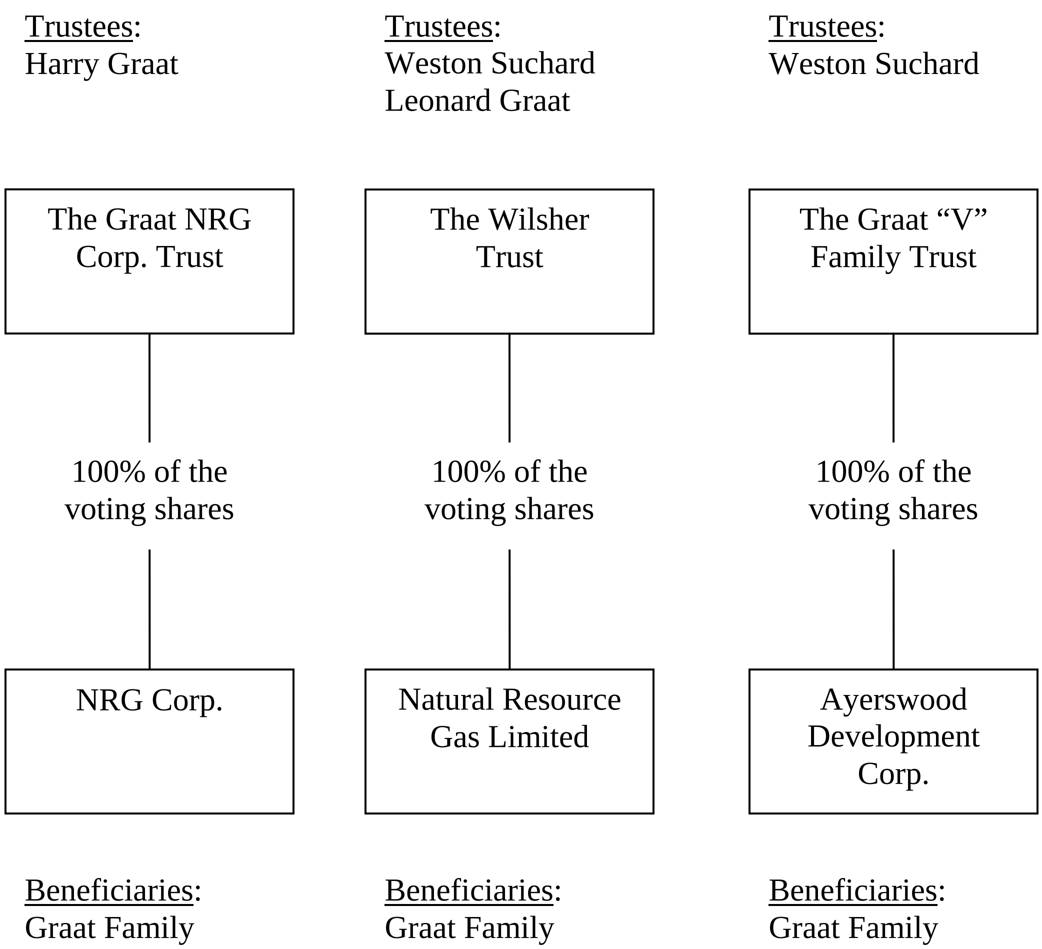
- Approval to increase the monthly fixed charge for Rates 1, 2, and 4 (see Exhibit H2, Tab 1, Schedule 1)

- Approval of proposed rates in the test year calculated using depreciation rates approved by the Board in its previous NRG rate proceedings (with the exception of the IGPC pipeline which is proposed to be depreciated over 20 years). As mentioned in the Application, NRG has filed a separate rate schedule (for illustrative purposes only) showing what rates would be using a deprecation rate that corresponds to NRG's Aylmer franchise renewal period granted by the Board in EB-2008-0413.

NATURAL RESOURCE GAS LIMITED

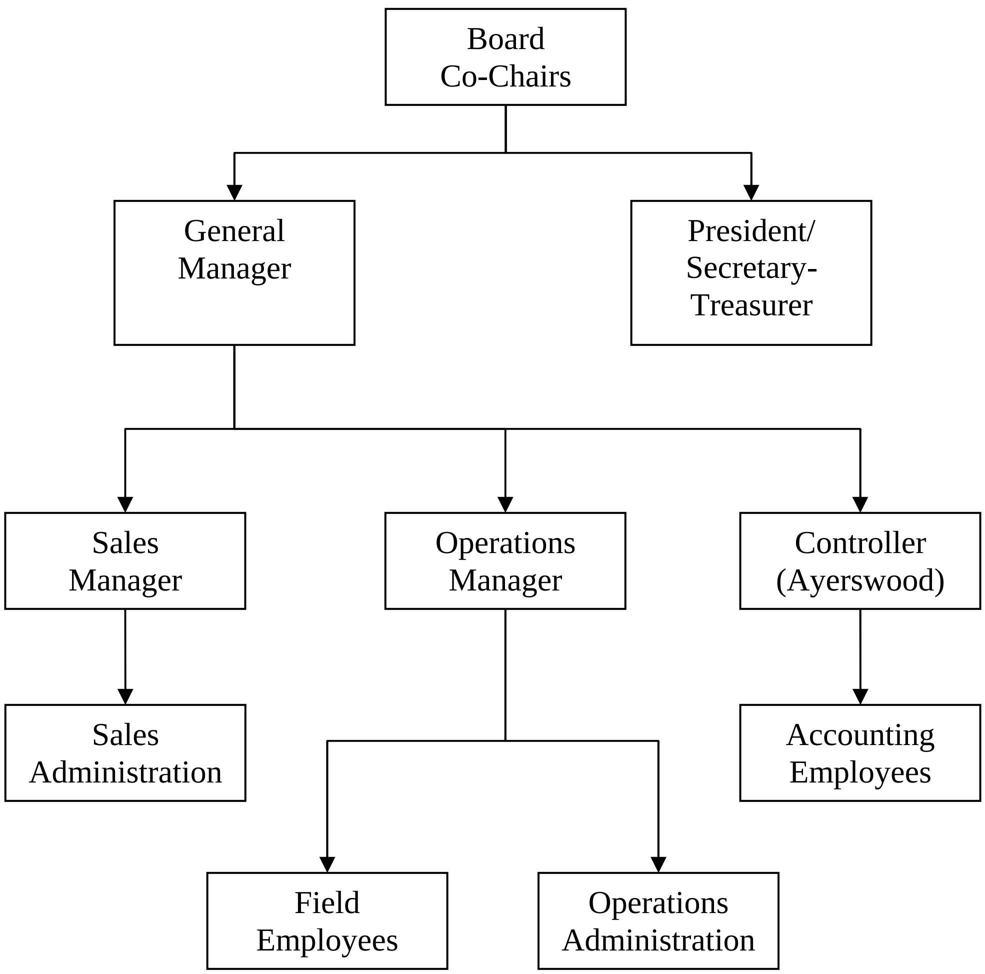
CORPORATE ORGANIZATION CHART FOR RELATED PARTY TRANSACTIONS

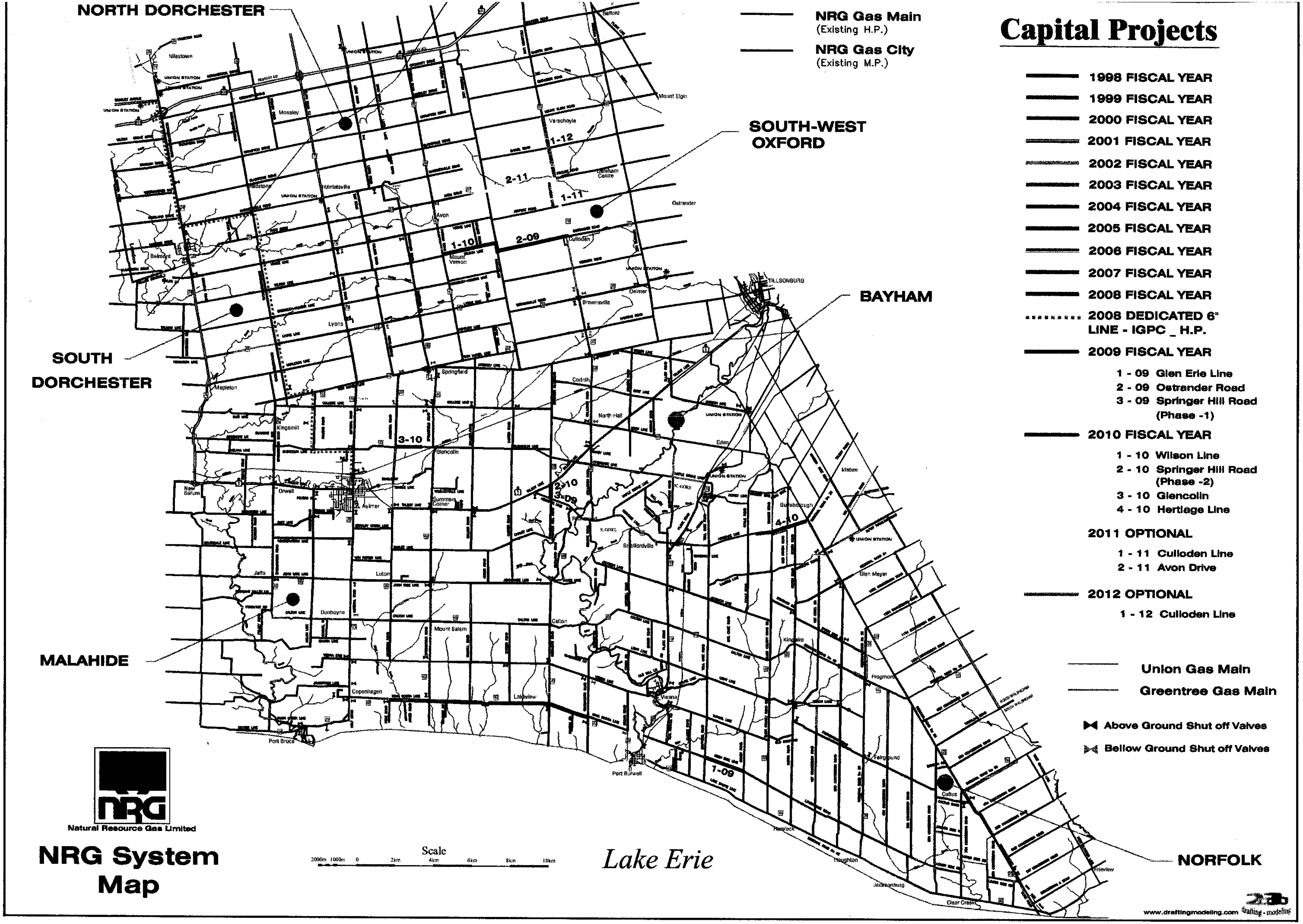
NRG Corp., Natural Resource Gas Limited and Ayerswood are not affiliated entities within the meaning of the *Business Corporations Act* (Ontario).



NATURAL RESOURCE GAS LIMITED

UTILITY ORGANIZATION CHART





Capital Projects
NRG Gas Main (Existing H.P.)
NRG Gas City (Existing M.P.)
1998 FISCAL YEAR
1999 FISCAL YEAR
2000 FISCAL YEAR
2001 FISCAL YEAR
2002 FISCAL YEAR
2003 FISCAL YEAR
2004 FISCAL YEAR
2005 FISCAL YEAR
2006 FISCAL YEAR
2007 FISCAL YEAR
2008 FISCAL YEAR
2008 DEDICATED 6" LINE - IGPC _ H.P.
2009 FISCAL YEAR
1 - 09 Glen Erie Line
2 - 09 Ostrander Road
3 - 09 Springer Hill Road (Phase -1)
2010 FISCAL YEAR
1 - 10 Wilson Line
2 - 10 Springer Hill Road (Phase -2)
3 - 10 Glencolin
4 - 10 Hertiage Line
2011 OPTIONAL
1 - 11 Culloden Line
2 - 11 Avon Drive
2012 OPTIONAL
1 - 12 Culloden Line
Union Gas Main
Greentree Gas Main
Above Ground Shut off Valves
Bellow Ground Shut off Valves
NORTH DORCHESTER
SOUTH-WEST OXFORD
BAYHAM
SOUTH DORCHESTER
MALAHIDE
NORFOLK
Lake Erie
Natural Resource Gas Limited
NRG System Map
Scale
www.draftingmodeling.com

NATURAL RESOURCE GAS LIMITED
<u>STATUS REPORT ON ONTARIO ENERGY BOARD DIRECTIVES</u>

This Schedule addresses three directives from the OEB to NRG, as follows: (a) the preparation of a written fleet policy by NRG; (b) the proposed treatment of Rate 2 customers (i.e., declining tobacco load); and (c) moving NRG to an incremental cost-based system gas fee.

Each is dealt with in turn, below.

DIRECTIVE #1 – Preparation of a Proposed Fleet Policy

NRG was asked to prepare a vehicle fleet policy. To that end, NRG has reviewed the fleet policies of other gas and electric utilities, and Appendix A to this Schedule contains NRG's fleet policy.

DIRECTIVE #2 – Treatment of Rate 2 Customers

In its Decision with Reasons, EB-2005-0544, the Board directed NRG to: "consider developing a contingency plan to address possible reduction in volumes as well as a potential loss of the entire rate class."

The purpose of this evidence is to summarize NRG's contingency plan.

Applicable Rate Making Principles

Under sound rate making a customer class should consist of homogeneous customers that are heterogeneous versus all other customer classes. There should also be a reasonable cost/benefit of offering a customer class; for example, a customer class should be maintained if it results in an efficient price signal to the members of the class and should not be maintained if it gives rise to inefficient costs that must be recovered from customers.

NRG's Rate 2 Customer Class

NRG's Rate 2 Customer Class customers were, historically, tobacco drying operations. With the decline and ultimate elimination of the tobacco growing quota in NRG's franchise area, NRG has experienced a loss of customers from this class. The remaining customers have continued to dry tobacco, often on a smaller scale than in past years or have transitioned to other crops – some which require gas service for drying purposes (eg., grains) and some which do not. This is reflected in the declining average consumption per customer.

NRG's Rate 2 customers exhibit a seasonal consumption pattern (please refer to Exhibits C3 through C8, Tab 2, Schedule 1). Exhibit C shows that NRG has steadily lost Rate 2 customers and their average consumption has declined steadily over the period 2006-2009 and is projected to continue to decline during the 2010BY and the 2011TY.

Analysis of Rate 2 Customer Class Heterogeneity

NRG reviewed the average monthly consumption levels and pattern of Rate 2 customers and compared it to the average monthly consumption levels and pattern of Rate 4 customers and Rate 5 customers. NRG concluded that Rate 2 and Rate 4 customers' consumption seasonality is comparable and that the consumption levels are different. NRG's only other seasonal customer class is Rate 5; its eligibility criteria are distinguishable versus that applicable to Rate 2. NRG concluded that Rate 2 customers are comparable to rate 4 customers.

Analysis of Comparability of Currently Authorized Rates

NRG notes that Rate 2 eligibility criteria and Rate 4 eligibility criteria are comparable and that the level of the currently authorized rates are also comparable. Rate 5, NRG's other seasonal customer class has distinguishable eligibility criteria that depend on the size of the load served and the currently authorized rates are rather different from those authorized for Rate 2.

Developing the Contingency Plan

NRG considered the following issues when developing the proposed contingency plan:

- Under what circumstances would it be inappropriate to continue to maintain Rate 2 as a separate customer class?
- What process should be used to reclassify existing Rate 2 if NRG ceases to maintain the class?

NRG considers it appropriate to maintain a customer class if:

- The members of the class are homogeneous;
- The members of the class are heterogeneous versus all other customer classes;
- The rates estimated using NRG's fully allocated cost study are materially different.

NRG considers it inappropriate to maintain a customer class if the revenues recovered from that customer class are relatively low – eg., <1% of total distribution revenue – or if maintaining the customer class will result in inappropriately high rates or if the rates are not reasonably predictable. Application of these criteria suggest that it is appropriate to anticipate the elimination of its Rate 2 customer class.

Absent any other considerations, these criteria support merging customer classes 2 and 4 and do not support merging customer class 2 with customer class 5.

Issues: How should existing Rate 2 customers be reclassified if NRG ceases to maintain the class?

NRG believes that the reclassification of customers should proceed according to the process summarized below:

Step 1: Close Rate 2 to new entrants.

Step 2: NRG advises Rate 2 customers that they can request reassignment to Class 4 and concurrently adjusts Rate 2 rates to maintain or achieve comparability with Rate 4 rates.

Step 3: NRG contacts remaining Rate 2 customers and requests that they consider transferring to Rate 4.

Step 4: NRG reclassifies remaining customers from Rate 2 to Rate 4 and eliminates Rate 2.

Under the above approach NRG would first take steps to close its Rate 2 customer class to new entrants. Any customers who satisfy the eligibility criteria of either Rate 2 or Rate 4 would be classified as Rate 4 customers. While the Class 2 is closed to new entrants NRG would facilitate processing requests from existing Rate 2 customers to transfer from Rate 2 to Rate 4. While the customer transfer election period continues NRG would strive to maintain comparability between its Rate 2 rates and Rate 4 rates. This may result in the under-recovery of allocated costs from Rate 2 customers, potentially by incremental adjustments to Rate 4 or Rate 1 rates. When the rates are immaterially different NRG may approach customers seeking additional customer initiated requests to transfer from Rate 2 to Rate 4. The customer election period should have a sunset date of 12-24 months in the future. After the Rate 2 customers had all been transferred to Rate 4 the Rate 2 class would expire.

DIRECIVE #3 – Derivation of Incremental System Gas Charge

In its Amended Decision and Order, EB-2008-0106, the Board directed NRG to file a proposal to move to an incremental cost based system gas fee (EB-2008-0106, p. 33).

The purpose of this evidence is to present NRG's response to the Board's directive.

Adjustments to NRG's Fully Allocated Cost Model

NRG identified the components of its revenue requirement that were recovered through the System Gas Fee. Each component was identified as common or specifically incurred in connection with the provision of System Gas. Any common costs were removed from the System Gas revenue requirement by eliminating the functionalization, classification or allocation of costs.

Proposed Recoveries through the Estimated Incremental System Gas Fee

Under the proposed $0.000348/$m^3$ rate, NRG will recover:

- The return on the portion of the 2011TY Working Cash Allowance related to Gas Commodity: the allocated $86.0k credit of Working Cash Allowance changes the revenue requirement by ($7.9k);
- The 2011TY income tax expense associated with the ($86.0k) of Working Cash Allowance, being ($1.0k);
- 2011TY Regulatory and Consulting Fee expenses totalling $15.0k, representing the costs of QRAM submissions;
- $1.1k of assigned Administrative and General expenses.

The revenue requirement totals $7.2k.

This revenue requirement is applied to projected 2011 Test Year System Gas sales volumes of 20,646,638 m^3 to estimate the average incremental System Gas Fee of $0.000348/$m^3$.

Natural Resource Gas Limited

FLEET POLICY – MAINTENANCE AND REPLACEMENT POLICY

1.0 PURPOSE:
To ensure the fleet is maintained in accordance with regulatory and industry requirements. Aim is to deliver the highest lifecycle efficiency at the lowest possible costs in order to optimize vehicle assets.

2.0 RESPONSIBILITY:
It is the responsibility of the General Manager to ensure this procedure is followed.

3.0 PROCEDURE/POLICY:

3.1 Fleet Types and Quantity

3.1.1 The number of vehicles in the fleet are outlined in Schedule A. This number and type are considered optimal in order to service our customers. Due to a change in customer demand, the number may change. All changes are approved by the Board and General Manager. Schedule A will be updated for any permanent changes.

3.1.2 Fleet standards are developed through communication with staff and service quality indicators.

3.2 Replacement (Replacement Cycle outlined in Schedule A)

3.2.1 Vehicles are reviewed for replacement by the Board, General and Service Manager when:

- Reach a certain point of usage based on mileage;
- Reach a certain age, based on years in service; and
- Repair expense exceeds an acceptable level (any expense over $2,500 is scrutinized); expenses per vehicle are tracked.

Note: NRG will continue to use vehicles that exceed the years or km if it is economic to do so and if driver and/or public safety will not jeopardized.

3.2.2 Based on the assessment of mileage, service and repair costs, if it is determined that it is no longer economical to keep a vehicle in service the vehicle purchase will conform to the following:

- Highway Traffic Act
- Canadian Motor Vehicle Safety Standards (CMVSS)

In addition, we ensure it is fitted to utilize both petrol and natural gas. A minimum of 2 quotes will be obtained in order for the General Manager to review for approval of purchase.

SCHEDULE A

FLEET

Description	Quantity	Replacement Cycle Years	KM
Flat Bed - 5 Ton	1	n/a	200,000
Flat Bed - 1 Ton	1	n/a	200,000
Pick Up - 1/2 Ton	2	5-7	150,000
Pick Up - 3/4 Ton	1	5-7	150,000
Van - Service	4	5	150,000
Van - Line Crew	1	5	150,000
Car	1	5	150,000

NATURAL RESOURCE GAS LIMITED

NATURAL GAS SERVICE

RULES & REGULATIONS

Effective August 1, 1995

Revised October 1, 2009

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1. INITIATION OF SERVICE

1.1 APPLICATIONS

The Company may, at its discretion, accept applications for gas service on existing service laterals or new service laterals. Each applicant must complete an Application for Gas Service in the form attached as Schedule 1A. Any business or company making application must also complete a Credit Application in the form attached as Schedule 1B. The applicant must complete both sides of the blue copy and will receive the yellow copy for their records after approval.

The only exception to the above shall be in the case of contract rate customers. Contract rate customers are required to execute a contract for a specified term of not less than one year.

The Company will charge a $30.00 transfer/connection charge, plus applicable taxes, on all approved applications, which will be charged on the first gas billing.

1.2 SECURITY DEPOSITS (as per EB 2008-0413)

General:
After an application for Gas Service is completed, the Credit Department will run a credit check and determine if a security deposit is required (outlined further below).The Security Deposit must be paid before connection can occur.

Determination of Security Deposit (All Residential & Commercial Customers)
The security deposit is determined based on the average monthly consumption of gas during the last 12 consecutive months, within the past two years, at the specific address in which the gas service is installed or will be installed. Note this is for new customers or for customers who no longer have a good payment history (defined below).

The maximum amount of a security deposit NRG may require a consumer to pay shall be calculated as follows:

> Billing cycle factor 2.5 X average annual consumption over past 12 consecutive months or consumers estimated consumption, or a reasonable estimate made by NRG.

Security deposits will not be required:

- If a consumer is residential or general service, and a satisfactory credit check has been conducted, at the time of application. A beacon score of 680 + and a credit utilization of less than 50% will be required.

- If a consumer can provide a letter from another gas/ electricity distributor in Canada confirming good payment history.

- A good payment history (definition below): 1 year residential/ 5 years general service/ 7 years for other

- Definitions: "general service consumer" means a consumer that is not a residential consumer and that annually consumes no more than 100,000m^3 of gas.

- The time period that makes up a good payment history is the most recent period of time, and must have occurred in the past 24 months

  Unconditional "Letters of Credit" from a customer's banker in an appropriate amount or a personal guarantee from the owners may be accepted in lieu of cash security on commercial and industrial accounts.

Definition of Good Payment History:

- If a consumer has received more than one disconnection notice from NRG, or another gas vendor in the past 12 months

- If a consumer has more than one NSF cheque: returned by reason of insufficient funds.

- If a consumer has more than one NSF cheque from a pre- authorized payment plan

- If a consumer has had at least one visit, from NRG, to the consumer's premises, for purpose of payment of an overdue amount, or to shut off or limit the gas supply to the consumer's premises for non-payment.

Security Deposit Refunds

- Annual reviews are conducted on all accounts to determine if consumer is entitled to a refund, or an adjustment is required.

- Requests for a refund of security deposits can be made after 1 year of service (residential) / 5 years (General accounts) 7 years (Other accounts) must be made in writing to our Credit department.

- Security deposit will not be refunded if the customer does not have a good payment history (as defined above).

- Security deposit will either be given by a cheque or a credit to the customer.

Interest on Security Deposits

Interest accrued on security deposits will be credited to the customers' account on an annual basis. The interest rate shall be the Prime Business Rate published on the Bank of Canada Website less 2 % updated quarterly.

For any quarter that the PBR is 2 percent or less the interest rate will be 0.

Security Deposits and Cancellation of Service

When a customer discontinues service, a Cancellation Service form is filled out. After the final billing period has been processed, and the account is settled in full, the Security Deposit will be refunded to the customer.

If the customer's account is not settled in full prior to requesting the refund, the Security deposit will be applied to unpaid balance and any remaining Security Deposit will be refunded to the customer.

Transfer of Security Deposits

If a customer should move to another location that is serviced by Natural Resource Gas Limited the Security Deposit is reviewed, and adjusted according to the for Security Deposits requirements
A Security Deposit may increase or decrease depending on the consumption of the new location, and past history of the consumer's account.

Third Party Security Deposits

As per The Ontario Energy Board amendments to the gas distribution access rule (GDAR IN EB) 2008-0413 APPENDIX B MAY5/2009

Where all or part of a security deposit has been paid by a third party on behalf of a consumer, NRG shall return the amount of the security deposit paid by the third party, including interest where applicable, to the third party. This obligation shall apply where and to the extent that:

(a) The third party paid all or part (as applicable) of the security deposit **directly**, to NRG;

(b) The third party has requested, at the time the security deposit was paid or within a reasonable time thereafter, that NRG return all or part (as applicable) of the security deposit to them rather than to the consumer; and

(c) There, is not then any amount overdue for payment by the consumer, that, NRG is permitted by this Rule to off set using the security deposit.

1.3 MAIN EXTENSIONS

The Company will make extensions of its mains to some applicants when, in the sole discretion of the Company, the main extension is economically feasible.

When the extension is not economically feasible, the applicant will be required to pay an "Aid to Construction" in an amount determined by the Company to make the project economically feasible.

1.4 SERVICE LATERAL INSTALLATIONS

Service laterals will only be installed provided that:

(i) an application (contract) has been properly completed and approved,
(ii) any deposit required has been collected,
(iii) any main extension can be justified in accordance with the Company's line extension practice, and
(iv) any charges for service lateral installation in accordance with the following have been paid

All Customers - A gas service lateral extending from the property line to the meter location selected by the Company will be installed for a fee of $ 100.00 for the first 20 meters plus an additional charge of $ 10.00 per meter thereafter.

Meter Set Locations are determined as follows:

a) For residential customers, meters may be located on the front or on either side of the dwelling in which it serves. If the meter is located along one of the sides of the dwelling, the distance from the front corner to the meter location cannot exceed 10 feet.

b) All meter set locations must comply with the Technical Standards and Safety Act and Codes and Standards Adopted by Regulation.

c) When the distance from the property line to a dwelling or building requiring the gas service exceeds 100 meters, it may be required that the meter be located near the property line. In these cases, a cost estimate must be done to determine the outlet cost of underground piping from the meter set to the building.

1.5 CUSTOMER PIPING

Applicants for service shall, at their own expense, equip their premises with all piping and attachments from the meter to the appliances or equipment served. It is the customer's responsibility to maintain the piping and equipment beyond the outlet side of the meter. Such piping and attachments shall be installed and maintained in accordance with the rules of the Company and the Technical Standards and Safety Act and Codes and Standards Adopted by Regulation.

Meters will not be connected with customer's piping when that piping and/or appliances or heating equipment attached thereto are known by the Company to be defective or not in accordance with applicable rules and regulations, ordinances or codes. The Company reserves the right to discontinue service at any time it finds the piping, venting, appliances or other gas-fired equipment on customer's premises defective or in an unsafe condition.

The customer is expected to immediately notify the Company of any leakage or escape of gas on his premises.

1.6 INSPECTION OF NEW AND EXISTING INSTALLATIONS

All inspections shall conform to the “Ontario Energy Act” and the "Technical Standards and Safety Act and Codes and Standards Adopted by Regulation" and amendments in force at the time of inspection.

All new installations of supply piping and gas appliances on premises served with gas for the first time require inspection to ensure that they are in accordance with legislative requirements.

A general inspection will be made of gas appliances and installations:

(a) whenever a meter is initially installed,
(b) whenever a meter is changed,
(c) whenever a meter is physically reset on an inactive service or account, or
(d) in accordance with the requirements of the Ontario Energy Act

A modified inspection will be made of vented gas appliances:

(a) whenever a previously inactive account is reactivated,
(b) when a meter is turned on after credit lock offs, seasonal turn offs or routine repairs to mains or services, or
(c) when vented equipment is lit up after component replacement

2. MAINTENANCE OF SERVICE

2.1 MAINTENANCE

The Company and its authorized representatives shall have the right to enter upon the premises of the customer at all reasonable times, upon reasonable notice, to read, inspect, test, repair, replace or remove meter and regulator equipment.

2.2 TESTING METERS

Meters will be tested at the Company's option or at the request of the customer or when required by legislative requirements. When a meter is tested at the customer's request, the Company will collect from the customer any cost involved in the removal, testing, Government inspection and meter replacement where it is determined that the meter was within acceptable tolerances.

2.3 SERVICE DEPARTMENT CHARGES

The Company provides regular service during the normal working hours, and emergency service 24 hours per day.

(i) ***Charge for Service to Customer Owned Appliances***

Repairs will be performed on a time and material basis in accordance with the Company's prevailing parts and labour prices, except when covered by Company or manufacturer's warranties.

(ii) ***Charge for Service to Company Owned Appliances***

The Company agrees to supply such maintenance as in the judgement of the Company is required for the proper use of the appliance at no charge to the customer.

(iii) The Company does not charge for leak complaints, insufficient gas supply, and inspection of appliances in accordance with Government Regulations. Repairs required to remedy gas leaks and insufficient supply of gas from causes downstream of the meter will be charged on a time and material basis.

2.4 CUSTOMER SERVICE WORK

The following are the rates currently in effect by the company. These rates are subject to amendment from time to time.

Regular Hours

Minimum charge (up to 60 minutes)	$67.00
each additional half hour (or part thereof)	$30.00

After Hours

Minimum charge (up to 60 minutes)	$110.90
each additional half hour (or part thereof)	$58.10

Disconnection- Non Payment or Discontinuance of Service (i.e. seasonal)

Flat Fee	$78.00

Customer Transfer/Connection Charge

Flat Fee	$30.00

Applicable taxes will also be added to the above charges.

3. RENTAL EQUIPMENT

3.1 MONTHLY RENTALS

The Company rents water heaters. Water softeners are also rented on a rent to own basis. The rates for water heaters are as indicated below:

Conventional Models	
40 US Gallon	$ 10.75 monthly
50 US Gallon	$ 12.50 monthly
60 US Gallon	$ 15.00 monthly

Power Vented or Direct	
40 US Gallon	$19.00 monthly
50 US Gallon	$21.00 monthly
60 US Gallon	$22.00 monthly
50/65 US Gallon	$23.00 monthly
50 DV US Gallon	$21.00 monthly
Tankless Water Heater	$34.50 monthly

The rental for water heaters other than those listed above will be calculated by the General Manager.

3.2 INSTALLATION COSTS

The customer bears the initial installation cost of all equipment. Such installation done by NRG is generally done on a quoted basis. NRG may, from time to time, offer installation assistance through its marketing and promotion efforts. The cost of installing replacement units still under warranty is borne by the Company.

3.3 RENTAL AGREEMENT

Prior to installation of a rental water heater, or removal from inventory for rental, a Rental Agreement form must be completed by the customer in the form attached as Schedule 2. The blue copy remains in the office, the yellow copy is returned to the customer after insertion of the installation and contract dates, and serial and Company numbers.

A Rental Agreement must also be completed by an applicant who is moving into a property where a rental water heater exists. The form can be fully completed at the time of application, and the yellow copy may be given to the customer at that time for his records.

4. BILLINGS & COLLECTIONS

4.1 BILLINGS & COLLECTIONS

Bills will be issued and payable monthly and must be paid at or mailed to the office of the Company, an established collection agency of the Company, or at any chartered bank authorized by the Company.

Bills for gas service furnished by the Company are due when rendered. For customers paying their bill after sixteen days from the billing date, a late payment charge will apply (see section 4.2).

Bills will be mailed to the customer at the last known address as shown on the Company records, unless the customer has directed the Company to send the bill to another address.

Gas consumed will be based on meter readings, or estimates with an estimated bill issued for interim months, and will be computed on the applicable rate schedule approved by the Ontario Energy Board. Any necessary adjustments due to estimated bills will be made on the next regular billing.

A claim for an error in billing should be made by the customer as soon as discovered. If in the opinion of the Company the claim is valid, the Company will make a proper adjustment to the bill.

Where billing errors have resulted in overbilling, the customer will be credited with the amount erroneously paid for a period not exceeding six years.

Where billing errors have resulted in under-billing, the customer shall be charged with the amount erroneously not billed for a period not exceeding:

(a) two years, in the case of an individual residential customer who was not responsible for the error, and

(b) six years, in other cases.

The timing for billings and notices etc., will be as follows. The days represent the days after the end of a billing cycle (e.g. if a normal billing cycle ended on the 14th of the month, day one would commence on the 15th).

Day 1 to 3	Reading, billing and mailing of invoices
Day 13 to 15	Bills due
Day 30	Final Disconnection Notices are mailed for past due accounts. See comments in section 5.1 Disconnection & Reconnection – non-payment.

Day 45 Credit department determines if customer is to be disconnected.
See section 5 Disconnection & Reconnection of Service.

4.2 DELAYED PAYMENT

Payments made after sixteen days after the billing date will be considered late and those accounts will have their balances increased by 1.5% of the amount unpaid after sixteen days. Payments made at any chartered bank will be considered paid on the date payment is made to the bank. Any amounts unpaid for subsequent months will be increased by a further 1.5% for each billing cycle that the balance remains unpaid. The minimum increase will be $1.00.

4.3 PAYMENT BY MAIL

When payments are made by mail, bills will be considered to have been paid one day prior to the postmark date.

4.4 BUDGET BILLING PLAN

The budget plan for payment of gas bills is designed to equalize the monthly payments for gas service of residential customers using gas for heating purposes and is available to any heating customer who can establish satisfactory credit with the Company.

New residential heating customers and existing heating customers with satisfactory credit and no balance outstanding may be enrolled in the plan at their request. Customers may withdraw from the plan at any time upon notification to the Company.

The Company will estimate the aggregate amount of the customer's bill for gas service for a normal year's operation from June to April. Such estimated amount will then be divided by eleven, rounded up to the next $5.00 or $10.00 amount, and shall be the monthly budget instalment the customer will pay in lieu of the regular monthly billing

Bills for the month of May will be computed for settlement of the account either by the customer paying the excess of actual charges incurred over the sum of budget payments made, or by the Company crediting to the customer any credit balance then existing. This budget to actual difference will be added or subtracted, as the case may be, to the actual gas charges incurred on bills for the month of May.

Any estimate furnished by the Company in connection with such payment plan shall not be construed as a guarantee or assurance that the total actual charges will not exceed the estimates. The Company may at any time submit a revised estimate to the customer and require that the customer pay the revised monthly budget instalment as a condition to the continuation of the budget payment plan for that customer.

Such estimates shall apply only to the premises then occupied by the customer. If the customer vacates such premises, the budget payment plan with respect to those premises, and for that customer, shall immediately terminate and any amount payable by the customer shall be paid or any amount due to the customer by the Company shall be refunded.

Non-payment of budget will result in the customer receiving a disconnection notice and possibly removed from the budget plan. The account will be reconciled on the following billing cycle, and the customer will be responsible to bring the account up to-date.

4.5 GROUP BILLINGS

Combinations of reading from several meters may be done at the Company's sole discretion.

Group billing will be permitted only in special situations at the discretion of the Company.

5. DISCONNECTION & RECONNECTION OF SERVICE

5.1 DISCONNECTION & RECONNECTION - NON PAYMENT

Disconnection notices are mailed on Day 34 after the end of billing cycle. The customer is given until Day 45 to pay balance due before they are disconnected. In addition, Credit Department will call all customers 2 days before disconnection date if payment has not been received. If customer can still not pay by due date or no effort to work out a repayment plan can be made the customer will be disconnected.

DISCONNECTION OF SERVICE FOR NON PAYMENT

- If it has been determined that a customer will not pay and the account must be locked for non payment.
- A lock form is prepared and authorized by the Credit Department and Approved by the General Manager.
- A copy of the Lockout form is given to service to set the call to lock the account.
- Customers receive a hand delivered notice at time of locking the meter explaining the disconnection of service

If a customer should be disconnected for non-payment and then reconnected, the following charges will be added to the account

- Disconnection charge 78.00
- Reconnection charge 78.00

plus Applicable taxes

Payment of the reconnection charge must be made before reconnection can occur and an increase in security deposit or a security deposit may be required before reconnection of service is made. Amount is determined as outlined in section 1.2.

Non-Payment of Accounts

Definition of Accounts = past work orders, accounts locked for non-payment and customers that have moved and have a balance outstanding.

If the customer is unresponsive, or refuses to pay further collection action may take place, which is outlined below:

- If a customer refuses to pay on the account or does not follow a payment schedule legal action will commence.
- Customers will be notified that a claim has been issued for small Claims court.
- Court Documents will be filed, and Court procedures used to collect money owing
- Any court costs, incurred by Natural Resource Gas Limited, for the collection of money will be added to the customer’s debt, as allowed by Small Claims Court.
- Will be forwarded to the Credit Bureau of St. Thomas for collections and the debt will be reported to Equifax on the customers credit file.

5.2 DISCONTINUANCE FOR CAUSE OTHER THAN NON-PAYMENT

Service may be discontinued by the Company at any time to prevent fraudulent use or to protect its property.

The Company further reserves the right upon discovery of any condition of the customer's appliance or piping which is, in the opinion of the Company, immediately hazardous to life and property, to discontinue gas service until such time as the hazardous conditions shall be remedied.

5.3 DISCONTINUANCE ON CUSTOMER'S ORDER

The agreement between the customer and the Company created by the acceptance of the customer's request for gas service, where no contract for a main extension or term of service is involved, shall continue in full force and effect until terminated by the customer (except as provided under Sections 5.1 and 5.2) giving sufficient notice to a Company business office relative to the intent to discontinue service. The customer shall be liable for all gas supplied to the premises and safe custody of the Company's property until service is discontinued in accordance with the customer's instructions. When a customer requests disconnection of service within 90 days of connection, a disconnection charge of $78.00 plus applicable taxes will be applied to the final billing.

5.4 TEMPORARY DISCONTINUANCE OF SERVICE

Customers who temporarily discontinue service during any twelve consecutive months without payment of a monthly fixed charge for the months, in which the gas is temporarily disconnected, shall pay for disconnection and reconnection.

Natural Resource Gas Limited
Application for Gas Service

Natural Resource Gas Limited
PO Box 307, 39 Beech St. E.
Aylmer, Ont. N5H 2S1

Service Department
Aylmer: 519-773-5321
Fax: 519-773-5335

____________________ 20 ______

I/WE ______________________________ (the "Customer")

apply to Natural Resource Gas Limited ("the Company") for gas service at ______________________________

______________________________(the "premises")

according to the following terms and conditions:

1. The Customer agrees to pay accounts when due.
2. Customer agrees that a meter connection will be established immediately after the installation of the service line and will be subject to the monthly fixed charge from that date.
3. Customers intending to vacate premises supplied with gas or to discontinue the use of gas shall give notice to the Company at 39 Beech Street E., Aylmer, Ontario or other such address as customer may be advised, fifteen (15) days before the Customer intends to discontinue service and in default of providing such notice, the Customer will remain liable for all gas which passes through the meter until such notice is given. In the event accounts for natural gas, rentals or other services are not paid in accordance with this agreement and collection procedures are made by the Company and/or its agent, Customers will be liable for collection costs incurred by the Company and/or its agent. ______X
4. If the Customer discontinues service within ninety (90) days of application for gas service, there will be a charge for removal plus GST, or such charge as is currently in effect by the Company which will be added to the final billing and/or deducted from the original deposit.
5. The Company may discontinue service and disconnect and remove the meter for repair, lack of supply and/or non-payment of bills (including late penalty charges) when due. The original deposit will be refunded upon full payment of any outstanding amount.
6. Gas will be supplied to a meter installed by the Company. If that meter should fail to register the quantity of gas consumed or if access to read the meter cannot be made, the account of the Customer will be estimated by the Company.
7. Customer agrees to give immediate notice at the office of the Company of any escape of gas. In case of a leak, the stop-cock at the meter must be immediately closed and no light taken near the escape until after free and full ventilation.
8. Except in the case of an emergency, the Company and/or its authorized agent shall at all reasonable hours, have access to the premises for the purposes of examining, regulating or repairing the gas apparatus installed, ascertaining the quantity of gas consumed or supplied and/or to discontinue or remove the meter. In the case of an emergency, the Company and/or its authorized agents shall have access to the premises at any hour.
9. The Company shall not be liable for any damages or losses resulting from any failure to supply. The Customer agrees with the Company that the Company will not be held liable by the Customer for any loss, damage, injury or delay to any person or to any property resulting from the transportation, storing or any use of the gas supplied to the premises including any damage or loss from explosion or fire. Further the Customer agrees to indemnify and save harmless the Company from and against all claims and demands arising out of the transportation, storing or use of the gas supplied to the Customer's premises including any loss or damage from explosion or fire made by any person and from and against all damages, losses, costs, charges and expenses which the Company may sustain or incur and be liable for as a consequence of any such claim or demand.
10. The Customer acknowledges that there will be a late charge on the past due amount (minimum $1.00) if the bill is not paid within sixteen (16) days of rendering and there will be a monthly fixed charge of $______________ . ______X
Both of the charges are subject to revision and approval by the Ontario Energy Board.
11. The Customer acknowledges that there will be a transfer/connection charge of <u>$30 plus GST</u>, or as may be ordered by the Ontario Energy Board, which will be charged on the first billing. ______X

SIGNATURE OF APPLICANT ______________________________

DEPOSIT RECEIVED: $ ______________ DEPOSIT RECEIVED BY: ______________

PREMISES OWNED BY: ______________________________

SEE REVERSE FOR CREDIT APPLICATION

APPLICATION FOR GAS SERVICE

Date of Application:____________________ Date Service Req'd:________________ 20____

☐ Residential ☐ Commercial ☐ Industrial ☐ Seasonal

Last Name First Name Initial	Date of Birth MM/DD/YY	Martial Status Married ☐ Single ☐	Spouse Name	No. of Dependents
Service Address				Home Phone #
Mailing Address			Drivers Lic. No.	
Name of Landlord & Address (If Applicable)			Social Ins. No.	
Employer Name & Address	Position		How Long	Business Phone #
Spouse's Employer Name & Address	Position		How Long	Business Phone #
Previous Address				How Long
Previous Employer Name & Address			Position	How Long
Spouse's Previous Employer Name & Address			Position	How Long

Bank	Credit Cards	
Name	Name	Name
Branch	Branch	Branch

Nearest Relative (Not Living with Applicant)	Relationship	Address	Phone #
Other Personal Reference	Relationship	Address	Phone #

Some of the information contained in this application constitutes "personal information" and is thereby covered under Federal privacy legislation. NRG obtains this information in order to bill for the products identified in this agreement, repairs and service to the equipment and for collections of arrears of amounts owing under this agreement. NRG does not share this information with third parties with the exception of consultants, professional advisors and regulatory bodies. All of these parties are bound by their own privacy obligations which restricts further dissemination of such information.

The undersigned agree(s) that a personal investigation may be conducted or a credit report obtained in respect of this contract

Signature of Applicant:______________________________

Notes

NATURAL RESOURCE GAS LIMITED - RENTAL AGREEMENT

NRG, please supply the following goods to:		Owner ☐ Tenant ☐ Builder ☐	Telephone Number
Address	City	Postal Code	Contract Date
Installation Address (if other than above)	City	Postal Code	Bill as Rental Only

ADDITIONS	Gas to Gas ☐	Builder ☐	Other Fuel to Gas ☐		Other ☐
REPLACEMENTS GAS TO GAS	Upgrade ☐	Leaker ☐	Limed Up ☐		Other (specify) ☐
DELETIONS	Demolitions ☐	Rental to Sale ☐	Gas to Gas ☐	Gas to Other Fuel ☐	Other ☐

Natural Resource Gas (hereinafter called NRG) leases to the Customer and the Customer rents from NRG the following:

Equipment	Water Heater Size	Description of Equipment	Monthly Rental	TAX
Res. ☐ Comm. ☐ Ind. ☐			$	Yes No GST ☐ ☐ PST ☐ ☐
Other Equipment	Description of Equipment		Monthly Rental $	GST ☐ PST ☐

Model Number (Commercial & Industrial Equipment Only) Original Date of Installation Year 20 Month Day Min. # Bills

ISSUE

Qty	Stock Number	Make	Mfg Code	Serial Number	Account Number

"(hereinafter called the Appliance) from the date hereof, for a monthly rental of $____ (plus applicable sales taxes), which monthly rental amount shall be subject to increase by NRG on at least thirty (30) days prior written notice and subject to the Conditions on the reverse side hereof."

Natural Resource Gas (hereinafter called NRG) leases to the Customer and the Customer rents from NRG the following:

Equipment	Water Heater Size	Description of Equipment other than Water Heater	Monthly Rental	TAX
Res. ☐ Comm. ☐ Ind. ☐			$	Yes No GST ☐ ☐ PST ☐ ☐
Removal Date - Year 20 Month Day	Original Installation Date - Year 20 Month Day		Storeroom	Original Contract #

RETURN

Qty	Stock Number	Make	Mfg Code	Serial Number	Account Number

☐ Scrapped ☐ In Inventory

ALL CONDITIONS OF RENTAL AGREEMENT ON REVERSE SIDE

Executed in duplicate this _____ day of __________________ 20_____

Customer Signature

Sales Department Signature

NRG not responsible for any damages resulting from tank leakage.

I hereby consent to the supply of service and installation of the equipment in the above premises, owned by me and agree to the conditions set forth herein. Any equipment of the Owner's removed by NRG in accordance with this authorization shall be left by NRG in the said premises and NRG shall have no further responsibility with respect to same.

Owner's Signature

Owner's Address

CONDITIONS OF RENTAL AGREEMENT

1. The CUSTOMER agrees to permit and keep the Appliance at the above address or at such other address as NRG may agree to in writing. The CUSTOMER agrees to protect the Appliance from any lien or encumbrance of any nature whatsoever and the CUSTOMER agrees not to sublet or assign his interest hereunder or part with possession of the Appliance without the written consent of NRG. The CUSTOMER shall supply adequately sized and properly charged water conditioning equipment, as specified by NRG. In the event the CUSTOMER fails to supply and maintain adequately sized equipment, the CUSTOMER shall reimburse NRG for all costs incurred as a result of such failure. The CUSTOMER further agrees to keep the Appliance insured for the full insurable value thereof. EXCEPT AS SPECIFICALLY PROVIDED HEREIN THE APPLIANCE SHALL BE OPERATED AT THE RISK OF THE CUSTOMER AND CUSTOMER AGREES TO INDEMNIFY AND SAVE HARMLESS NRG FROM ANY AND ALL CLAIMS AND DAMAGES HOWSOEVER CAUSED ARISING OUT OF THE USE OR THE INSTALLATION OF THE APPLIANCE.

2. Ownership of the Appliance shall at all times remain in NRG.

3. NRG shall maintain and repair the Appliance at its own expense provided that the CUSTOMER will indemnify NRG from any such costs or expenses arising as a result of damage to or destruction of the Appliance from any cause, reasonable wear and tear excepted.

4. If the CUSTOMER discontinues using gas supplied by NRG or fails to perform or observe any of the conditions herein, NRG may forthwith terminate this agreement and without any previous notice or demand or process of law enter the premises wherein the Appliance is situated to repossess the same. If the Appliance is removed by NRG as aforesaid, NRG shall not be liable for any damages resulting from such removal. If the CUSTOMER defaults within twelve months from the installation date, then in addition to any other rights NRG may have, the rental for the remaining months shall, at NRG's option, be due and payable immediately.

5. It is agreed by the CUSTOMER and NRG that the Appliance shall remain personalty.

6. Time is of the essence.

7. The terms of this Agreement constitute the entire Agreement between the parties and, except the monthly rental amount which is subject to increase by NRG, no modification to this Agreement shall be made except in writing signed by both parties.

8. Some of the information contained in this application constitutes "personal information" and is thereby covered under Federal privacy legislation. NRG obtains this information in order to bill for the rental of the products identified in this agreement, repairs and service to the equipment and for collections of arrears of amounts owing under this agreement. NRG does not share this information with third parties with the exception of consultants, professional advisors and regulatory bodies. All of these parties are bound by their own privacy obligations which restricts further dissemination of such information.

Natural Resource Gas Limited

P.O. Box 307, 39 Beech Street East
Aylmer, ON N5H 2S1

Phone: 519-773-5321

SERVICE POLICY

Regular Hours Calls

See section 2.4 for rates to be charged.

All service calls to be done on a time and material basis except for the following:

1. New equipment sold by NRG, no charge for the first year except for parts that are not guaranteed for one year.

2. No charge for service of any kind on any call due to failure of Company equipment.

3. After hours calls (see section 2.4 for rates).

4. All charges to be collected at time of call, unless otherwise authorized.

MISCELLANEOUS CHARGES

1. **Returned Cheques**

Account Closed Cannot Trace Funds Not Cleared More Than One Signature Required No Chequing Privileges Not Sufficient Funds Present Again Refer to Drawer Signature Required Signature Irregular Body & Figures Differ	$ 20.00/each + taxes

2. **Lawyer's Letters**

Reply to request for account information	$ 20.00 + taxes

NATURAL RESOURCE GAS LIMITED

SCHEDULE OF SERVICE CHARGES

	Fiscal 2006	Fiscal 2007	Fiscal 2008	Fiscal 2009	Bridge 2010	Test Year 2011
Rental Water Heaters						
(Monthly Rental Rates)						
30 gallon	$6.85-7.00	$6.85-7.00	$6.85-7.00	$6.85-7.00	$8.85-9.55	$8.85-10.55
40 gallon	$7.25-9.70	$7.25-9.70	$7.25-9.70	$7.25-9.70	$9.25-10.75	$9.25-11.75
40 gallon PV	$12.80-15.50	$12.80-15.50	$12.80-15.50	$12.80-15.50	$14.80-19.00	$14.80-20.00
50 gallon	$8.40-12.00	$8.40-12.00	$8.40-12.00	$8.40-12.00	$11.00-12.50	$11.00-13.50
50 gallon PV	$13.90-17.00	$13.90-17.00	$13.90-17.00	$13.90-17.00	$16.50-21.00	$16.50-22.00
60 gallon	$9.50-12.25	$9.50-12.25	$9.50-12.25	$9.50-12.25	$11.50-15.00	$11.50-16.00
60 gallon PV	$15.30-22.00	$15.30-22.00	$15.30-22.00	$15.30-22.00	$17.50-22.00	$17.50-23.00
Tankless	n/a	n/a	n/a	$34.50	$34.50	$34.50-35.50
Connect/Transfer Charge	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Reply to Lawyer's Letter	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Disconnection Charge	$78.00	$78.00	$78.00	$78.00	$78.00	$78.00
Reconnection Charge	$78.00	$78.00	$78.00	$78.00	$78.00	$78.00
NSF Charge	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Contract Work	On a Quoted Basis					
Merchandise	Parts Marked UP 30 - 50%					
Customer Service Work - Regular Hours						
Minimum Charge - up to 30 minutes	$46.20	$48.50	$48.50	$48.50	n/a	n/a
Minimum Charge - up to 60 minutes	$63.80	$67.00	$67.00	$67.00	$67.00	$90.00
Each additional half hour or part thereof	$28.60	$30.00	$30.00	$30.00	$30.00	n/a
Each additional hour or part thereof	n/a	n/a	n/a	n/a	n/a	$90.00
Customer Service Work - After Hours						
Minimum Charge - up to 30 minutes	$81.95	$86.05	$86.05	$86.05	n/a	n/a
Minimum Charge - up to 60 minutes	$105.60	$110.90	$110.90	$110.90	$110.90	$115.00
Each additional half hour or part thereof	$52.80	$58.10	$58.10	$58.10	$58.10	n/a
Each additional hour or part thereof	n/a	n/a	n/a	n/a	n/a	$95.00

NATURAL RESOURCE GAS LIMITED

<u>SUMMARY OF THE APPLICATION</u>

<u>Need for Application</u>

Natural Resource Gas Limited ("NRG") has not been before the Board with a rate application since EB-2005-0544, which set rates effective October 1, 2006. In EB-2008-0413 (the "Aylmer Franchise Decision"), the Board ordered NRG to file an application for new rates by November 5, 2009. This filing deadline was subsequently extended to January 31, 2010 by way of a Vary Order issued on July 24, 2009.

<u>Forecasted Deficiency</u>

NRG estimates that its present rates will produce a gross deficiency in revenue of <u>$462,417</u> for the 2011 Test Year. Consequently, NRG seeks the Board's approval to revise the rates applicable to the sale and distribution of natural gas by NRG.

<u>Key Issues</u>

Exhibit A1, Tab 2, Schedule 1 (Specific Approvals Requested) contains many of the key issues to be determined during the course of the proceeding. Among these are the following issues (which have not been dealt with in previous NRG rate proceedings):

<u>NRG's Adoption of an IRP</u>: In this application, NRG is applying for Board approval of its proposed five-year incentive regulation <u>plan</u> ("IRP"). This is the first time NRG has made an IRP proposal to the Board. Because of NRG's relatively small size, NRG is bringing forward a simplified IRP proposal, without an inflation factor or X factor adjustment, but with a Y factor and Z factor. Consequently, the form and elements of this IRP will be issues of interest in this proceeding.

<u>Creation of a New Rate Class</u>: Since its last rate proceeding, NRG has added a very large customer, IGPC Ethanol Inc., to its system. In this application and pre-filed evidence, NRG is proposing a new Rate 6 class specifically for IGPC, based on directly assigned costs and appropriately allocated common costs. This is a novel issue to be canvassed in this proceeding.

<u>Depreciation</u>: As mentioned in the Application and Specific Approvals Requested schedule, NRG has submitted two sets of proposed rates – the first are based on depreciation rates approved by the Board in its previous NRG rate proceedings (with the exception of the pipeline dedicated to IGPC which is proposed to be depreciated over 20 years), and the second, <u>which is filed for illustrative purposes,</u> based on a depreciation rate corresponding to NRG's Aylmer franchise renewal period granted by the Board in EB-2008-0413.

<u>Filed Information and Test Year Period</u>

The information used in this Application is NRG's forecasted results for its 2011 fiscal (test) year. With the rates presently in effect, NRG estimates that its revenue for 2011 would not be sufficient to provide a reasonable return. NRG is also presenting the historical actual information for fiscal 2006 through fiscal 2009 (inclusive), and a mix of actual and forecast information for the fiscal 2010 bridge year.

The level of return allowed for the 2011 fiscal year and the risk affecting the ability to achieve that level will have a direct and material effect on the amount of new capital that can be raised in the future. NRG will require funds for plant replacements and reinforcements, inventory holding costs, payment of debt, and demands upon it for service extensions.

The Test Year for this Application will be the NRG fiscal year commencing October 1, 2010 and ending September 30, 2011 (the "2011 Test Year"). The Test Year revenue requirement is that forecast by NRG as needed to enable it to cover its costs and earn a reasonable return for fiscal 2011. For the required revenues to match and appropriately offset the expected costs of service for the Test Year, revised rates reflecting the Board's decision must be effective for volumes consumed on and after October 1, 2010.

NATURAL RESOURCE GAS LIMITED

CAUSES OF DEFICIENCY/SUFFICIENCY
2011 Test Year

		($'s)	Deficiency (Increase)/ Decrease
Change in Rate Base			
2011 Test Year		13,618,731	
2007 Board Approved (RP-2005-0544)		9,676,712	
Increase in Rate Base		3,942,019	
2007 Approved Rate of Return (RP-2005-0544)	@	8.87%	-349,657
Change in Rate of Return			
2011 Test Year Requested Rate of Return		9.14%	
2007 Approved Rate of Return (RP-2005-0544)		8.87%	
Increase in Rate of Return		0.27%	
2011 Test Year Rate Base	@	13,618,731	-37,223
Change in Utility Net Income			
2011 Test Year		895,593	
2007 Board Approved (RP-2005-0544)		780,808	
Increase in Utility Income		114,785	114,785
Sub-total			-272,095
2007 Board Authorized (Deficiency)/Sufficiency			-77,414
Rounding Adjustment			-103
Net Revenue (Deficiency)/Sufficiency			-272,198
Provision for Income Taxes			-112,805
Gross Revenue (Deficiency)/Sufficiency			-462,417

NATURAL RESOURCE GAS LIMITED

CAUSES OF DEFICIENCY/SUFFICIENCY
2011 Test Year

	Reference	($'s)	($'s)
Cost of Capital			
Rate Base	B5.T1.S1	13,618,731	
Required Rate of Return	E5.T1.S1	9.14%	1,245,204
Cost of Service			
Gas Transportation Costs	D5.T1.S1	732,331	
Operation and Maintenance	D5.T1.S1	2,859,299	
Depreciation and Amortization	D5.T1.S1	1,206,523	
Property and Capital Taxes	D5.T1.S1	400,776	5,198,928
Operating Revenue			
Other Operating Revenue (Net)	C5.T1.S1	664,160	-664,160
Income Taxes			
Income Taxes on Earnings	D5.T1.S1	50,252	
Income Taxes on (Deficiency)/Sufficiency	F5.T1.S1	112,805	163,057
Revenue Requirement			
Distribution Revenue	C5.T1.S1	5,480,613	
Rounding Adjustment		-1	-5,480,613
Gross Revenue (Deficiency)/Sufficiency	F5.T1.S1		-462,417

NATURAL RESOURCE GAS LIMITED

BUDGET PROCESS

NRG compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the bridge and test years.

Revenue Forecast

The gas delivery volume forecasting process is described at Exhibit C2, Tab 1, Schedule 1. The forecast of gas sales and throughput volume is prepared considering such factors as weather, new customer additions and load profiles for all classes of customers. The forecast amounts were applied to estimate distribution revenues at currently approved rates for fiscal 2010 and fiscal 2011. The ancillary revenue forecast is also prepared by NRG.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2006 bridge year and the 2007 test year have been forecast using a zero based methodology and is strongly influenced by prior year experience. Each item is reviewed account by account for each of the forecast years.

Capital Budget

The capital budgeting process begins with a review of all the accounts, with pipelines making up the largest component. NRG determines which pipelines require replacement and where additions are warranted. All other capital expenditures are budgeted on a line by line basis based on need and forecasted customer growth.

NATURAL RESOURCE GAS LIMITED

ECONOMIC FEASIBILITY PROCEDURE AND POLICY

Natural Resource Gas Limited continues to use a standard economic feasibility test to evaluate system expansion projects. The test compares the net present value of the cash inflows to the net present value of the costs of the project. A detailed description of the model was filed in RP-1999-0031, in Exhibit B2, Tab 1, Schedule 1.

If the net present value of the project is positive (or the benefit cost ratio is 1.0 or greater), the project is approved. If the net present value of the project is negative (or the benefit cost ratio is less than 1.0), the project is either abandoned, postponed, or an "aid to construction" may be sought from the customer or customers. This aid to construction is calculated as the amount of additional revenue required to equate the net present value of the project to zero.

In some instances a project with a negative net present value may be approved without an aid to construction being collected. These are projects where the primary reason for the project is to improve system integrity and reliability.

NATURAL RESOURCE GAS LIMITED

FINANCIAL STATEMENTS

SEPTEMBER 30, 2009

NPT+ LLP
CHARTERED ACCOUNTANTS
Adding value. Finding balance.

P: 519-432-5534
F: 519-432-6544
300-633 COLBORNE ST.
LONDON, ONTARIO N6B 2V3
www.nptca.com

AUDITORS' REPORT

To the Directors of Natural Resource Gas Limited

We have audited the balance sheet of Natural Resource Gas Limited as at September 30, 2009 and the statements of income (loss), deficit, and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

Except as explained in the following paragraph, we conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

The company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian generally accepted accounting principles require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet. The company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities would increase by $13,461,418 and share capital would decrease by $13,461,418.

In our opinion, except that the Class C shares of the company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the company as at September 30, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

NPT LLP

London, Canada
December 11, 2009

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2009		2008
Assets				
Current assets:				
Cash	$	**66,593**	$	-
Temporary investments		**2,751,130**		-
Accounts receivable (note 6)		**785,770**		1,612,745
Inventory		**143,457**		89,856
Prepaid expenses		**87,660**		54,959
Income taxes recoverable		-		60,377
Due from related company (note 6)		-		492,505
		3,834,610		2,310,442
Property, plant, and equipment (note 2)		**14,043,851**		14,080,608
Other assets:				
Franchises and consents (note 3)		**253,775**		97,261
Deferred finance costs (note 4)		**18,978**		23,896
Deferred charges (note 5)		**63,986**		106,636
		336,739		227,793
	$	**18,215,200**	$	16,618,843

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

	2009	2008
Liabilities and Shareholders' Equity		
Current liabilities:		
Bank indebtedness	$ -	$ 217,422
Line of credit (note 7)	-	806,763
Accounts payable and accrued liabilities (note 6)	**1,772,182**	3,013,533
Income taxes payable	**31,532**	-
Deferred revenue	-	120,193
Customer deposits	**409,851**	757,065
Due to related company (note 6)	-	795,264
Term notes payable (note 8)	**10,870,177**	6,257,192
	13,083,742	11,967,432
Shareholders' equity:		
Share capital (note 11)	**13,461,439**	13,461,439
Deficit	**(8,329,981)**	(8,810,028)
	5,131,458	4,651,411
Contingent liability (note 12)		
	$ 18,215,200	$ 16,618,843

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Deficit

Year ended September 30

		2009		2008
Balance, beginning of year	$	**(8,810,028)**	$	(8,707,085)
Net income (loss) for the year		**480,047**		(102,943)
Balance, end of year	$	**(8,329,981)**	$	(8,810,028)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income (Loss)

Year ended September 30

		2009		2008
Gas commodity revenue	$	**7,226,938**	$	6,548,084
Gas commodity cost		**7,193,028**		6,509,145
Gross margin on commodity		**33,910**		38,939
Distribution revenue		**5,357,493**		3,991,759
Distribution costs		**970,246**		446,710
Gross margin on distribution		**4,387,247**		3,545,049
Other sales		**955,610**		1,113,891
Other costs		**486,167**		716,277
Gross margin on other sales		**469,443**		397,614
Other revenue		**92,577**		133,415
Total gross margin		**4,983,177**		4,115,017
Expenses		**4,275,518**		3,790,127
Income from operations		**707,659**		324,890
Decline in value of natural gas well		**(177,612)**		(439,833)
Income (loss) before provision for income taxes		**530,047**		(114,943)
Provision for (recovery of) income taxes (note 10)		**50,000**		(12,000)
Net income (loss) for the year	$	**480,047**	$	(102,943)

Included in expenses are the following:				
Amortization of deferred financing costs	$	**10,718**	$	9,550
Amortization of deferred charges	$	**42,650**	$	42,650
Amortization of franchises and consents	$	**65,474**	$	7,259
Amortization of property, plant and equipment	$	**913,222**	$	753,187
Interest on term notes payable	$	**603,854**	$	476,110

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flows
Year ended September 30

		2009		2008
Cash flows from operating activities:				
Net income (loss) for the year	$	**480,047**	$	(102,943)
Items not affecting working capital:				
Amortization		**1,032,064**		812,646
Decline in value of natural gas well		**177,612**		439,833
Changes in non-cash working capital:				
Accounts receivable		**826,977**		(506,351)
Inventory		**(53,601)**		39,008
Prepaid expenses		**(32,701)**		9,467
Income taxes recoverable (note 16)		**60,377**		(60,377)
Accounts payable and accrued liabilities		**(1,241,351)**		1,392,120
Income taxes payable (note 16)		**31,532**		(90,712)
Deferred revenue		**(120,193)**		(97,520)
Customer deposits		**(347,214)**		154,205
		813,549		1,989,376
Cash flows from investing activities:				
Additions to property, plant, and equipment		**(1,054,078)**		(5,723,722)
Additions to franchises and consents		**(221,990)**		(39,974)
Additions to deferred charges		**(5,800)**		-
Advances from (advances to) related company (net)		**(302,758)**		971,106
		(1,584,626)		(4,792,590)
Cash flows from financing activities:				
Proceeds on issuance of term note payable		**5,200,000**		-
Advances from (repayments of) line of credit		**(806,763)**		806,763
Repayments of term notes payable		**(587,015)**		(102,346)
		3,806,222		704,417
Increase (decrease) in cash and cash equivalents during the year		**3,035,145**		(2,098,797)
Cash and cash equivalents, beginning of year		**(217,422)**		1,881,375
Cash and cash equivalents, end of year	$	**2,817,723**	$	(217,422)
Represented by:				
Cash	$	**66,593**	$	-
Temporary investments		**2,751,130**		-
Bank indebtedness		**-**		(217,422)
	$	**2,817,723**	$	(217,422)

See accompanying notes to the financial statements.

Summary of significant accounting policies:

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles, the more significant of which are summarized below.

Regulation:

The utility operations of the company is a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company follows Canadian generally accepted accounting principles. Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under GAAP for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

Temporary investments:

Temporary investments consist of a bank issued Guaranteed Investment Certificate, and is valued at cost which equals fair market value.

Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Deferred charges:

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant, and equipment:

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment, excluding major disposals, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization. For major disposals, gains or losses are included in current earnings.

For natural gas wells, the successful efforts method is used to account for oil and gas exploration and development costs. Under this method, acquisition costs of oil and gas properties and costs of drilling and equipping development wells are capitalized. Costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to exploration and development expense. All other exploration costs, including geographical and geophysical costs and annual lease rentals, are charged to exploration and development expense when incurred. Producing properties and significant unproven properties are assessed annually, or more frequently as economic events dictate, for potential impairment. Any impairment loss is recognized when the carrying value of the asset is not recoverable and exceeds its fair value.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2009.

Amortization:

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. All categories are amortized using the straight-line method, except for computer equipment and computer software which are amortized using the declining-balance method, at the following annual rates for the property, plant and equipment categories listed below:

Automotive equipment	17 %
Buildings	2 %
Computer equipment	33 %
Computer software	20 %
Furniture and fixtures	7 %
Machinery and equipment	6 % to 9 %
Meters and regulators	3 % to 4 %
Pipeline installations	3 % to 13 %

Amortization of deferred finance costs (related to the issue of debt) is calculated at the annual rate of 20% using the straight-line method over the life of the related debt issuance.

Amortization of franchises and consents is calculated using the straight-line method over the term of the applicable franchise and consent.

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year and any such changes in estimate are applied on a prospective basis.

Capitalized costs of proven oil and gas properties are depleted using the units of production method.

Income taxes:

The company's regulated billing rates as established by the OEB, allow for the recovery of income taxes as calculated on a basis which differs from the amount as determined under the asset and liability method, but approximates the taxes payable method. Accordingly, the company accounts for income taxes using the taxes payable method. This basis does not provide for future income taxes which may be payable in future years as a result of the difference between current financial reporting and reporting for income tax purposes. This method is followed for accounting purposes as there is a reasonable expectation that all such taxes will ultimately be recovered through rates when they become payable. Future income taxes not provided in these financial statements would amount to a provision of $144,000 for the year ended September 30, 2009 (2008 - recovery of $55,000) and an accumulated future liability of $476,000 at September 30, 2009 (2008 - $332,000).

Revenue recognition:

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet pending disposition by a decision of the OEB.

Gas commodity costs:

Gas commodity costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for future disposition subject to the approval of the OEB, usually within a maximum timeframe of the next fiscal year. In a non-regulated environment periodic variances between gas commodity sales rates and costs would be reported through the income statement annually without the use of deferral accounts.

Use of estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

1. Accounting policy change:

Effective October 1, 2008, the company adopted Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031, "Inventories", which supersedes Section 3030. The new standard introduces significant changes to the measurement and disclosure of inventory and provides guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. In addition, in certain circumstances, write-downs of inventory previously recognized may be reversed.

Effective October 1, 2008, the company was also required to adopt Section 1400, "General standards of financial statement presentation", which is effective for years, beginning on or after January 1, 2008. This Section now includes requirements to assess and disclose an entity's ability to continue as a going concern.

The adoption of this new recommendations had no material impact on the opening retained earnings or on the company's financial statements for the year ended September 30, 2009.

NATURAL RESOURCE GAS LIMITED

Notes to the Financial Statements - continued

September 30, 2009

2. Property, plant, and equipment:

		2009		2008
	Cost	**Accumulated Amortization**	**Net Book Value**	Net Book Value
Land	$ 71,700	$ -	$ 71,700	$ 71,700
Buildings	682,331	137,285	545,046	560,194
Furniture and fixtures	69,176	40,211	28,965	19,586
Machinery and equipment	2,836,947	1,257,617	1,579,330	1,477,426
Computer equipment	230,548	179,684	50,864	38,671
Computer software	106,519	90,629	15,890	15,890
Automotive equipment	521,483	337,393	184,090	214,829
Meters and regulators	3,274,774	1,704,137	1,570,637	1,629,445
Pipeline installations	14,667,268	4,669,939	9,997,329	5,688,461
Pipeline under construction	-	-	-	4,364,406
	$ 22,460,746	$ 8,416,895	$ 14,043,851	$ 14,080,608

During the year, the company completed construction of a 28.5 kilometre natural gas pipeline between London and Aylmer to service a new customer. The company entered into a Pipeline Cost Recovery Agreement with the customer, whereby the company and the customer share in the construction cost of the pipeline under defined terms and conditions.

As of September 30, 2009, a final cost reconciliation has not yet been agreed upon between the two parties. While the net cost to the company of the pipeline constructed cannot be determined with complete accuracy until a cost reconciliation is agreed upon, it is management's opinion that the amount capitalized during the year is a reasonable estimate of the final cost given current information available.

3. Franchises and consents:

		2009		2008
Franchises and consents	$	**413,057**	$	191,068
Less: accumulated amortization		**159,282**		93,807
	$	**253,775**	$	97,261

4. Deferred finance costs:

		2009		2008
Deferred finance costs	$	**53,593**	$	47,793
Less: accumulated amortization		**34,615**		23,897
	$	**18,978**	$	23,896

5. Deferred charges:

		2009		2008
Total deferred charges - other assets	$	**213,253**	$	213,253
Less: accumulated amortization		**149,267**		106,617
	$	**63,986**	$	106,636

The company has been given approval by the OEB to recover the above costs already incurred from rate payers over future periods. The remaining balance will be recovered over future years as noted below:

2010	$	42,651
2011		21,335
	$	63,986

6. Related party transactions:

Due from related company consists of the following:

		2009		2008
Demand promissory note receivable, bearing interest at 4.59% payable monthly	$	-	$	492,505

Due to related company consists of the following:

		2009		2008
Non interest bearing with no set repayment terms	$	-	$	795,264

Included in accounts receivable are amounts receivable from related companies of $544,657 as at September 30, 2009 (2008 - $287,594).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $99,095 as at September 30, 2009 (2008 - $864,725).

During the year, rent of $nil (2008 - $9,600) and management fees of $457,020 (2008 - $457,000) were paid to a related company.

During the year, the company purchased gas in the amount of $1,508,369 (2008 - $2,011,482) from a related company.

6. Related party transactions (continued):

During the year, the company earned interest of $nil (2008 - $27,505) on the demand promissory note receivable to a related company.

During the year, maintenance charges of $12,000 (2008 - $58,200) were charged to a related company.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

7. Operating line of credit:

The company has credit facilities in the amount of $2,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and

b) Revolving line of credit in the amount of $1,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 8.

8. Term notes payable:

		2009		2008
Bank of Nova Scotia term note payable, 7.52% interest, repayable in blended monthly installments of $48,201, due March 2011	$	**6,146,844**	$	6,257,192
Bank of Nova Scotia term note payable, interest at prime plus 0.25%, repayable in monthly payments of $43,333 plus interest, due October 2017		**4,723,333**		-
	$	**10,870,177**	$	6,257,192

Although the above loans are due on demand, the company expects to make installments as per the amortization schedule that forms part of the loan agreement. The aggregate amount of principal payments required in each of the next five years to meet minimum retirement provisions is as follows:

2010	$	638,963
2011		6,547,881
2012		520,000
2013		520,000
2014		520,000
Thereafter		2,123,333
		$ 10,870,177

The company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 7):

a) General assignment of book debts
b) General Security Agreement over all of the present and future personal property and undertaking of the company
c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank
d) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

9. Capital management:

The Company defines capital as debt and shareholders' equity. As at September 30, 2009, the company had debt consisting of: bank indebtedness, line of credit, due to related company, and term notes payable.

The company's objectives in managing capital are to:

a) Ensure financial capacity to meet current obligations is maintained and continue as a going concern;
b) Ensure financial capacity to maintain and expand the distribution pipeline infrastructure of the utility as determined necessary by the company; and
c) Ensure financial capacity to execute strategic plan is maintained.

In order to manage capital, the company regularly identifies and assesses risks that threaten the ability to meet the company's capital management objectives, and determines the appropriate strategy to mitigate these risks.

The Company is subject to externally imposed capital requirements related to the term note payable (note 8). Specifically, the company must meet the following conditions:

a) maintain a ratio of EBITDA (Earnings before interest, taxes, depreciation and amortization) to interest expense plus current portion of long term debt of 1.25:1 or better;
b) maintain a ratio of current assets to current liabilities (excluding term note payable) of 1:1 or better; and
c) maintain a ratio of total debt to tangible net worth of less than 3:1.

At September 30, 2009, the company was not in violation of any of the above conditions.

10. Income tax expense:

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory income tax rates to income before income taxes. The reasons for the difference and the related tax effects are as follows:

		2009		2008
Income (loss) before provision for income taxes	$	**530,047**	$	(114,943)
Statutory tax rate		**33.13 %**		34.16 %
Tax on net income at statutory rates		**175,605**		(39,265)
Amortization on financial statements in excess of Capital Cost Allowance for tax purposes		**56,802**		35,328
Ontario Small Business Deduction utilized		**(6,741)**		(2,884)
Non-deductible expenses		**-**		2,525
Charitable donations carried forward (carry forward utilized) for tax purposes		**(41,553)**		33,555
Charges deferred on financial statements deductible on a cash basis for tax purposes		**(134,113)**		(41,259)
Provision for (recovery of) income taxes	$	**50,000**	$	(12,000)

11. Share capital:

		2009		2008
Authorized:				
Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends				
Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution				
Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share				
Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement				
Unlimited number of common shares				
Issued and outstanding:				
Retractable shares:				
50,000 Class A shares	$	**1**	$	1
10 Class B shares		**10**		10
134,614.18 Class C shares		**13,461,418**		13,461,418
10 Class Z shares		**10**		10
	$	**13,461,439**	$	13,461,439

12. Contingent liability:

The company is aware of a potential regulatory liability in an amount of a maximum of $140,000. The matter is currently under appeal, and in the opinion of management, and its external legal counsel, the company will be successful in its appeal. The OEB and its counsel have made no attempt to defend the appeal and these proceedings, as the company's external counsel believes there to be no precedent in the OEB regulations for the regulator to levy such amounts against the company. As such, no liability has been accrued in these financial statements.

13. Gas imbalances:

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas sold and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $899,509 (2008 - $936,466) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

14. Regulatory matters:

The Company has rates that are approved by the OEB. The fiscal year 2007 was a one year Cost of Service Rate filing. The company received the OEB decision dated September 28, 2006 and the rate order was effective September 28, 2006. The company did not make a submission for the fiscal year 2009 which left rates unchanged from 2007 and 2008.

Rates for the sale of gas commodity are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the deferred balances. The OEB's approval for recovery of these gas purchase costs primarily considers the prudence of costs incurred.

15. Financial instruments and risk:

The carrying values of the company's financial current assets and liabilities, including cash, accounts receivable, bank indebtedness, line of credit, and accounts payable and accrued liabilities approximate their values due to their short-term maturity.

The fair value of the term notes payable is estimated using a discounted cash flow calculation that uses market interest rates currently charged for similar debt instruments at September 30, 2009 to expected maturity dates.

Based upon the above calculation the carrying value of $ 10,870,177 of term notes payable has a fair value of approximately $ 12,415,000.

Natural gas prices:

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

Interest rate risk:

One of the term notes payable bears a fixed interest rate and, as such, the company is exposed to the interest rate risk of having a fixed rate, but has the security of a fixed rate for operational management purposes.

The other term note payable and the line of credit (when utilized) bears interest at a fluctuating bank prime related interest rate and, as such, the company is exposed to interest rate risk.

Credit risk:

Credit risk arises from the potential that a trade customer will fail to pay its account. The company is exposed to credit risk from its customers. However, the company has a large number of diverse customers, which minimizes concentration of credit risk.

16. Additional cash flow statement information:

		2009		2008
Interest paid	$	**603,854**	$	476,110
Income taxes paid (recoveries received)	$	**(5,785)**	$	183,050

17. Future accounting changes:

(a) International Financial Reporting Standards (IFRS)

In May 2009, the Accounting Standards Board (AcSB) re-confirmed that Canadian public companies will have to adopt International Financial Reporting Standards (IFRS) effective for years beginning on or after January 1, 2011. Therefore these standards will be effective for the Company's fiscal year ended September 30, 2012 with appropriate comparative IFRS financial information to be presented for the fiscal year ended September 30, 2011. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that will need to be addressed as part of the conversion analysis. The Company is currently evaluating the impact of this new framework.

(b) Future Income Taxes

Section 3465 - Income Taxes has been amended to include the requirement for rate-regulated enterprises to recognize future income tax assets or liabilities in accordance with the asset and liability method, rather than the taxes payable method as the company is currently using, and is effective for year end beginning on or after January 1, 2009. The impact on the financial statements is currently being assessed by management.

18. Comparative figures:

Certain of the comparative balances have been reclassified to conform to the presentation adopted for the current year.

NPT+ LLP
CHARTERED ACCOUNTANTS
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P: 519-432-5534
F: 519-432-6544
300-633 COLBORNE ST.
LONDON, ONTARIO N6B 2V3
www.nptca.com

ADDITIONAL COMMENTS OF AUDITORS

The accompanying schedule of expenses is presented as supplementary information only. In this respect, it does not form part of the financial statements of Natural Resource Gas Limited for the year ended September 30, 2009 and hence is excluded from the opinion expressed in our auditor's report dated December 11, 2009 to the Directors on such financial statements. The information in this schedule has been subject to audit procedures only to the extent necessary to express an opinion on the financial statements of the company and, in our opinion, are fairly presented in all respects material to those financial statements.

NPT LLP

London, Canada
December 11, 2009

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Unaudited Schedule of Expenses

Year ended September 30

	2009	2008
Advertising	$ 9,873	$ 38,006
Automotive and maintenance	155,229	146,979
Bad debts	51,982	37,239
Bank charges and other interest	626,316	509,089
Capital tax	36,180	21,200
Consulting fees	55,332	117,549
Donations and community sponsorships	13,953	201,720
Dues and fees	19,424	23,088
Employee benefits	148,883	146,885
Insurance	197,396	180,659
Legal and audit	63,049	11,628
Management fees - related company	457,020	457,000
Miscellaneous	15,322	13,560
Office	154,293	183,042
Ontario Energy Board hearings	32,211	4,345
Promotional rebates	14,437	5,978
Property taxes	390,404	334,612
Rent - related company	-	9,600
Salaries and wages	923,983	624,883
Telephone	59,776	61,698
Travel and promotion	3,371	7,062
Utilities	12,658	13,879
Amortization - Automotive equipment	86,566	70,635
Buildings	15,148	15,148
Computer equipment	10,145	13,543
Computer software	11,615	6,867
Deferred finance costs and charges	49,815	52,200
Franchises and consents	69,027	7,260
Furniture and Fixtures	4,669	3,721
Machinery and equipment	52,974	46,113
Meters and regulators	119,159	116,968
Pipeline installations	447,343	323,164
	4,307,553	3,805,320
Equipment expenses capitalized to pipeline installations	(17,956)	(11,436)
Interest expense (income)	(6,661)	2,827
Amortization capitalized to pipeline installations	(7,418)	(6,584)
	$ 4,275,518	$ 3,790,127

NATURAL RESOURCE GAS LIMITED

FINANCIAL STATEMENTS

SEPTEMBER 30, 2008

AUDITORS' REPORT

To the Board of Directors
Natural Resource Gas Limited

We have audited the balance sheet of Natural Resource Gas Limited as at September 30, 2008 and the statements of income, retained earnings, and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

The company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian generally accepted accounting principles require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet. The company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities would increase by $13,461,418 and share capital would decrease by $13,461,418.

In our opinion, except that the Class C shares of the company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the company as at September 30, 2008 and the results of its operations and cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Neal, Pallett & Townsend LLP

London, Canada
December 12, 2008

Neal, Pallett & Townsend LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2008		2007
Assets				
Current assets:				
Cash	**$**	**-**	$	1,881,375
Accounts receivable (note 6)		**1,612,168**		1,105,820
Inventory		**89,856**		128,864
Prepaid expenses		**54,959**		64,426
Income taxes recoverable		**60,377**		-
Due from related company (note 6)		**492,505**		668,347
		2,309,865		3,848,832
Property, plant, and equipment (note 2)		**14,080,608**		9,549,902
Other assets:				
Franchises and consents (note 3)		**97,261**		64,547
Deferred finance costs (note 4)		**23,896**		33,455
Deferred charges (note 5)		**106,636**		149,277
		227,793		247,279
	$	**16,618,266**	$	13,646,013

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2008		2007
Liabilities and Shareholders' Equity				
Current liabilities:				
Bank indebtedness	$	**217,422**	$	-
Line of credit (note 7)		**806,763**		-
Accounts payable and accrued liabilities (note 6)		**3,012,956**		1,620,836
Income taxes payable		**-**		90,712
Deferred revenue		**120,193**		217,713
Customer deposits		**757,065**		602,860
Due to related company (note 6)		**795,264**		-
Term note payable (note 8)		**6,257,192**		6,359,538
		11,966,855		8,891,659
Shareholders' equity:				
Share capital (note 11)		**13,461,439**		13,461,439
Deficit		**(8,810,028)**		(8,707,085)
		4,651,411		4,754,354
Contingent liability (note 12)				
	$	**16,618,266**	$	13,646,013

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Deficit

Year ended September 30

		2008		2007
Balance, beginning of year	$	**(8,707,085)**	$	(9,090,159)
Net income (loss) for the year		**(102,943)**		383,074
Balance, end of year	$	**(8,810,028)**	$	(8,707,085)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income (Loss)

Year ended September 30

		2008		2007
Gas commodity revenue	$	**6,548,084**	$	7,509,837
Gas commodity cost		**6,509,145**		7,306,666
Gross margin on commodity		**38,939**		203,171
Distribution revenue		**3,991,759**		3,751,671
Distribution costs		**446,710**		439,629
Gross margin on distribution		**3,545,049**		3,312,042
Other sales		**1,113,891**		1,057,476
Other costs		**716,277**		637,258
Gross margin on other sales		**397,614**		420,218
Other revenue		**133,415**		170,456
Total gross margin		**4,115,017**		4,105,887
Expenses		**3,790,127**		3,417,915
Income from operations		**324,890**		687,972
Decline in value of natural gas well		**(439,833)**		-
Income (loss) before provision for income taxes		**(114,943)**		687,972
Provision for (recovery of) income taxes (note 10)		**(12,000)**		304,898
Net income (loss) for the year	$	**(102,943)**	$	383,074
Included in expenses are the following:				
Amortization of deferred financing costs	$	**9,550**	$	9,558
Amortization of deferred charges	$	**42,650**	$	42,651
Amortization of franchises and consents	$	**7,259**	$	7,271
Amortization of property, plant and equipment	$	**753,187**	$	720,037
Interest on term note payable	$	**476,110**	$	483,490

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flows

Year ended September 30

	2008	2007
Cash flows from operating activities:		
Net income (loss) for the year	$ **(102,943)**	$ 383,074
Items not affecting working capital:		
Amortization	**812,646**	779,517
Decline in value of natural gas well	**439,833**	-
Changes in non-cash working capital:		
Accounts receivable	**(506,351)**	969,462
Inventory	**39,008**	24,646
Prepaid expenses	**9,467**	(57,505)
Income taxes recoverable (note 16)	**(60,377)**	83,647
Accounts payable and accrued liabilities	**1,392,120**	175,308
Income taxes payable (note 16)	**(90,712)**	90,712
Deferred revenue	**(97,520)**	30,462
Customer deposits	**154,205**	321,886
	1,989,376	2,801,209
Cash flows from investing activities:		
Additions to property, plant, and equipment	**(5,723,722)**	(839,661)
Additions to franchises and consents	**(39,974)**	-
Advances from (advances to) related company (net)	**971,106**	(668,347)
	(4,792,590)	(1,508,008)
Cash flows from financing activities:		
Advances from line of credit	**806,763**	-
Repayments of term note payable	**(102,346)**	(94,946)
	704,417	(94,946)
Increase (decrease) in cash and cash equivalents during the year	**(2,098,797)**	1,198,255
Cash and cash equivalents, beginning of year	**1,881,375**	683,120
Cash and cash equivalents, end of year	$ **(217,422)**	$ 1,881,375
Represented by:		
Cash	$ **-**	$ 1,881,375
Bank indebtedness	**(217,422)**	-
	$ **(217,422)**	$ 1,881,375

See accompanying notes to the financial statements.

Summary of significant accounting policies:

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles, the more significant of which are summarized below.

Regulation:

The utility operations of the company is a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company follows Canadian generally accepted accounting principles. Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under GAAP for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Deferred charges:

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals have been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant, and equipment:

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment, excluding major disposals, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization. For major disposals, gains or losses are included in current earnings.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2008.

Amortization:

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated using the straight-line method on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis, at the following annual rates for the property, plant and equipment categories listed below:

Automotive equipment	17 %
Buildings	2 %
Computer equipment	33 %
Computer software	20 %
Furniture and fixtures	7 %
Machinery and equipment	6 % to 9 %
Meters and regulators	3 % to 4 %
Pipeline installations	3 % to 13 %

Amortization of deferred finance costs (related to the issue of debt) is calculated at the annual rate of 20% using the straight-line method over the life of the related debt issuance. In the prior year, the company refinanced some of its existing debt. The deferred finance costs associated with the retired debt was amortized in full in the year of retirement.

Amortization of franchises and consents is calculated using the straight-line method over the term of the applicable franchise and consent.

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year and any such changes in estimate are applied on a prospective basis.

Income taxes:

The company's regulated billing rates as established by the OEB, allow for the recovery of income taxes as calculated on a basis which differs from the amount as determined under the asset and liability method, but approximates the taxes payable method. Accordingly, the company accounts for income taxes using the taxes payable method. This basis does not provide for future income taxes which may be payable in future years as a result of the difference between current financial reporting and reporting for income tax purposes. This method is followed for accounting purposes as there is a reasonable expectation that all such taxes will ultimately be recovered through rates when they become payable. Future income taxes not provided in these financial statements would amount to a recovery of $55,000 for the year ended September 30, 2008 (2007 - $41,000) and an accumulated future liability of $332,000 at September 30, 2008 (2007 - $387,000).

Revenue recognition:

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet pending disposition by a decision of the OEB.

Gas commodity costs:

Gas commodity costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for future disposition subject to the approval of the OEB, usually within a maximum timeframe of the next fiscal year. In a non-regulated environment periodic variances between gas commodity sales rates and costs would be reported through the income statement annually without the use of deferral accounts.

Use of estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

1. Accounting policy change:

Effective October 1, 2007, the company adopted the new recommendations of the Canadian Institute of Chartered Accountants (CICA) under sections 1530-Comprehensive income, 3250-Equity, 3855-Financial instruments – measurement and disclosure, 3861-Financial instruments – presentation and disclosure and 3865-Hedges. These new Handbook sections, which apply to years beginning on or after October 1, 2007 provide requirements for the recognition, measurement, presentation and disclosure of financial instruments. Section 1530 establishes standards for reporting and presenting comprehensive income, which is defined as the change in equity from transactions and other events from non-owner sources. Other comprehensive income refers to items recognized in comprehensive income but are excluded from net income calculated in accordance with generally accepted accounting principles.

The adoption of these new recommendations has no material impact on the opening retained earnings or on the company's financial statements for the year ended September 30, 2008.

The company has also adopted Section 1535 – Capital Disclosures which requires disclosure of the company's objectives, policies and processes for managing capital. Implementation of this section required further note disclosure about how the company defines capital, what externally imposed capital requirements it faces, the consequences of non-compliance with external capital requirements, if any, and how it monitors and manages capital. This section applies to fiscal year ends beginning on or after October 1, 2007.

This new standard has been adopted prospectively. Adoption of this standard did not have an impact on the October 1, 2007 opening balances.

2. Property, plant, and equipment:

			2008	2007
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 71,700	$ -	$ 71,700	$ 71,700
Buildings	682,331	122,137	560,194	575,342
Furniture and fixtures	55,127	35,541	19,586	23,064
Machinery and equipment	2,652,774	1,175,348	1,477,426	1,357,923
Computer equipment	196,594	157,923	38,671	38,626
Computer software	106,519	90,629	15,890	15,890
Automotive equipment	465,655	250,826	214,829	285,463
Meters and regulators	3,214,423	1,584,978	1,629,445	1,650,855
Pipeline installations	9,911,722	4,223,261	5,688,461	5,531,039
Natural gas well	439,833	439,833	-	-
Pipeline under construction	4,364,406	-	4,364,406	-
	$ 22,161,084	$ 8,080,476	$ 14,080,608	$ 9,549,902

3. Franchises and consents:

	2008	2007
Franchises and consents	$ 191,068	$ 151,094
Less: accumulated amortization	93,807	86,547
	$ 97,261	$ 64,547

4. Deferred finance costs:

		2008		2007
Deferred finance costs	**$**	**47,793**	$	47,793
Less: accumulated amortization		**23,897**		14,338
	$	**23,896**	$	33,455

5. Deferred charges:

		2008		2007
Total deferred charges - other assets	**$**	**213,253**	$	213,253
Less: accumulated amortization		**106,617**		63,976
	$	**106,636**	$	149,277

The company has been given approval by the OEB to recover the above costs already incurred, from rate payers over future periods. The remaining balance will be recovered over future years as noted below:

2009	$	42,651
2010		42,651
2011		21,334
	$	106,636

6. Related party transactions:

Due from related companies consists of the following:

		2008		2007
Non interest bearing with no set repayment terms	$	-	$	203,347
Demand promissory note receivable, bearing interest at 4.59% payable monthly		**492,505**		465,000
	$	**492,505**	$	668,347

Due to related company consists of the following:

		2008		2007
Non interest bearing with no set repayment terms	**$**	**795,264**	$	-

Included in accounts receivable are amounts receivable from related companies of $287,594 as at September 30, 2008 (2007 - $nil).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $864,725 as at September 30, 2008 (2007 - $254,575).

During the year, rent of $9,600 (2007 - $9,600) and management fees of $457,000 (2007 - $107,250) were paid to a related company.

During the year, the company purchased gas in the amount of $2,606,281 (2007 - $2,011,482) from a related company.

6. Related party transactions (continued):

During the year, the company earned interest of $27,505 (2007 - $nil) on the demand promissory note receivable to a related company.

During the year, maintenance charges of $58,200 (2007 - $58,200) were charged to a related company.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

7. Operating line of credit:

The company has credit facilities in the amount of $2,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and
b) Revolving line of credit in the amount of $1,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 8.

8. Term note payable:

		2008		2007
Bank of Nova Scotia term note payable, 7.52% interest, repayable in blended monthly installments of $48,201, due March 2011	**$**	**6,257,192**	$	6,359,538

Although the above loan is due on demand, the company expects to make installments as per the amortization schedule which forms part of the loan agreement. The aggregate amount of principal payments required in each of the next 3 years to meet minimum retirement provisions is as follows:

2009	$	109,661
2010		118,222
2011		6,029,309
	$	6,257,192

The company has pledged the following as security against the term note payable, the operating line of credit, and the revolving line of credit (note 7):

a) General assignment of book debts
b) General Security Agreement over all of the present and future personal property and undertaking of the company
c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank
d) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

9. Capital management:

The Company defines capital as debt and shareholders' equity. As at September 30, 2008, the company had debt consisting of: bank indebtedness, line of credit, due to related company, and term note payable.

The company's objectives in managing capital are to:

a) Ensure financial capacity to meet current obligations is maintained and continue as a going concern;
b) Ensure financial capacity to maintain and expand the distribution pipeline infrastructure of the utility as determined necessary by the company; and
c) Ensure financial capacity to execute strategic plan is maintained.

In order to manage capital, the company regularly identifies and assesses risks that threaten the ability to meet the company's capital management objectives, and determines the appropriate strategy to mitigate these risks.

The Company is subject to externally imposed capital requirements related to the term note payable (note 8). Specifically, the company must meet the following conditions:

a) maintain a ratio of EBITDA (Earnings before interest, taxes, depreciation and amortization) to interest expense plus current portion of long term debt of 1.25:1 or better;
b) maintain a ratio of current assets to current liabilities (excluding term note payable) of 1:1 or better; and
c) maintain a ratio of total debt to tangible net worth of less than 3:1.

At September 30, 2008 the company was not in violation of any of the above conditions.

10. Income tax expense:

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory income tax rates to income before income taxes. The reasons for the difference and the related tax effects are as follows:

		2008		2007
Income (loss) before provision for income taxes	$	**(114,943)**	$	687,972
Statutory tax rate		**34.16 %**		36.12 %
Tax on net income at statutory rates		**(39,265)**		248,495
Amortization on financial statements in excess of Capital Cost Allowance for tax purposes		**35,328**		61,035
Ontario Small Business Deduction utilized		**(2,884)**		(5,508)
Non-deductible expenses		**2,525**		876
Charitable donations carried forward for tax purposes		**33,555**		-
Charges deferred on financial statements deductible on a cash basis for tax purposes		**(41,259)**		-
Provision for income taxes	$	**(12,000)**	$	304,898

11. Share capital:

		2008		2007
Authorized:				
Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends				
Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution				
Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share				
Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement				
Unlimited number of common shares				
Issued and outstanding:				
Retractable shares:				
50,000 Class A shares	$	**1**	$	1
10 Class B shares		**10**		10
134,614.18 Class C shares		**13,461,418**		13,461,418
10 Class Z shares		**10**		10
	$	**13,461,439**	$	13,461,439

12. Contingent liability:

The company is aware of a potential regulatory liability in an amount of a maximum of $140,000. The matter is currently under appeal, and in the opinion of management, and its external legal counsel, the company will be successful in its appeal. The OEB and its counsel have made no attempt to defend the appeal and these proceedings, as the company's external counsel believes there to be no precedent in the OEB regulations for the regulator to levy such amounts against the company. As such, no liability has been accrued in these financial statements.

13. Gas imbalances:

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas sold and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $936,466 (2007 - $723,354) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

14. Regulatory matters:

The Company has rates that are approved by the OEB. The fiscal year 2007 was a one year Cost of Service Rate filing. The company received the OEB decision dated September 28, 2006 and the rate order was effective September 28, 2006. The company did not make a submission for the fiscal year 2008 which left rates unchanged from 2007.

Rates for the sale of gas commodity are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the deferred balances. The OEB's approval for recovery of these gas purchase costs primarily considers the prudence of costs incurred.

15. Financial instruments and risk:

The carrying values of the company's financial current assets and liabilities, including cash, accounts receivable, bank indebtedness, line of credit, and accounts payable and accrued liabilities approximate their values due to their short-term maturity.

The fair value of the amount due to related company is less than its carrying value. As the amount is non interest bearing, and the timing of repayment is uncertain, the fair value is not readily obtainable.

The fair value of the demand promissory note receivable from related company is estimated using a discounted cash flow calculation that uses market interest rates currently charged for similar debt instruments at September 30, 2008 to expected maturity dates. Since the market interest rate at the time the demand promissory note receivable was entered into is not significantly different than the market interest rate around year end, the carrying value approximates its fair value.

The fair value of the term note payable is estimated using a discounted cash flow calculation that uses market interest rates currently charged for similar debt instruments at September 30, 2008 to expected maturity dates. Since the market interest rate at the time the term note payable was entered into is not significantly different than the market interest rate around year end, the carrying value approximates its fair value.

Natural gas prices:

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

Interest rate risk:

The term note payable bears a fixed interest rate and, as such, the company is exposed to the interest rate risk of having a fixed rate, but has the security of a fixed rate for operational management purposes.

The line of credit bears interest at a fluctuating bank prime related interest rate and, as such, the company is exposed to interest rate risk.

Credit risk:

Credit risk arises from the potential that a trade customer will fail to pay its account. The company is exposed to credit risk from its customers. However, the company has a large number of diverse customers, which minimizes concentration of credit risk.

16. Additional cash flow statement information:

		2008		2007
Interest paid	$	**476,070**	$	483,490
Income taxes paid	$	**183,050**	$	149,896

17. Future accounting changes:

The Canadian Institute of Chartered Accountants has issued a number of new accounting pronouncements that have not yet come into effect that will need to be considered for subsequent years.

(a) Inventory

Section 3031 - Inventories is effective for fiscal periods commencing after January 1, 2008 and replaces section 3030 of the same name. The impact on the financial statements is currently being assessed by management.

(b) Future Income Taxes

Section 3465 - Income Taxes has been amended to include the requirement for rate-regulated enterprises to recognize future income tax asset or liabilities in accordance with this asset and liability method, rather than the taxes payable method as the company is currently using, and is effective for year ends beginning on or after January 1, 2009. The impact on the financial statements is currently being assessed by management.

NP&T

NEAL, PALLETT & TOWNSEND LLP
CHARTERED ACCOUNTANTS

ADDITIONAL COMMENTS OF AUDITORS

The accompanying schedule of expenses is presented as supplementary information only. In this respect, it does not form part of the financial statements of Natural Resource Gas Limited for the year ended September 30, 2008 and is hence excluded from the opinion expressed in our report dated December 12, 2008 to the board of directors on such financial statements. The information in this schedule has been subject to audit procedures only to the extent necessary to express an opinion on the financial statements of the company and, in our opinion, is fairly presented in all respects material to those financial statements.

Neal, Pallett & Townsend LLP

London, Canada
December 12, 2008

Neal, Pallett & Townsend LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Unaudited Schedule of Expenses

Year ended September 30

		2008		2007
Advertising	$	**38,006**	$	13,850
Automotive and maintenance		**137,569**		114,623
Bad debts		**37,239**		-
Bank charges and other interest		**509,089**		505,517
Capital tax		**21,200**		37,900
Consulting fees		**329,025**		199,629
Donations and community sponsorships		**201,720**		-
Dues and fees		**32,498**		17,914
Employee benefits		**146,885**		113,602
Insurance		**180,659**		185,199
Legal and audit		**11,628**		67,308
Management fees - related company		**457,000**		107,250
Miscellaneous		**13,558**		52,709
Office		**110,780**		102,882
Ontario Energy Board hearings		**4,345**		48,559
Promotional rebates		**5,978**		2,652
Property taxes		**334,612**		286,180
Rent - related company		**9,600**		9,600
Salaries and wages		**485,669**		886,050
Telephone		**61,698**		54,018
Travel and promotion		**7,062**		6,972
Utilities		**13,879**		14,541
Amortization - Automotive equipment		**70,635**		77,299
Buildings		**15,148**		15,148
Computer equipment		**13,543**		14,375
Computer software		**6,867**		6,441
Deferred finance costs and charges		**52,201**		52,209
Franchises and consents		**7,259**		7,271
Furniture and Fixtures		**3,721**		3,705
Machinery and equipment		**46,113**		41,182
Meters and regulators		**116,968**		113,504
Pipeline installations		**323,166**		311,197
		3,805,320		3,469,286
Equipment expenses capitalized to pipeline installations		**(11,436)**		(15,152)
Interest expense (income)		**2,827**		(27,490)
Amortization capitalized to pipeline installations		**(6,584)**		(8,729)
	$	**3,790,127**	$	3,417,915

NATURAL RESOURCE GAS LIMITED

FINANCIAL STATEMENTS

SEPTEMBER 30, 2007

AUDITORS' REPORT

To the Board of Directors
Natural Resource Gas Limited

We have audited the balance sheet of Natural Resource Gas Limited as at September 30, 2007 and the statements of income, deficit, and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

The company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian generally accepted accounting principles require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet. The company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities would increase by $13,461,418 and share capital would decrease by $13,461,418.

In our opinion, except that the Class C shares of the company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the company as at September 30, 2007 and the results of its operations and changes in its financial position for the year then ended in accordance with the basis of accounting disclosed in the summary of significant accounting policies.

Neal, Pallett & Townsend LLP

London, Canada
May 6, 2008

Neal, Pallett & Townsend LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2007		2006
Assets				
Current assets:				
Cash	$	**1,881,375**	$	683,120
Accounts receivable (note 5)		**1,106,066**		2,075,529
Inventory		**128,864**		153,510
Prepaid expenses		**64,426**		6,921
Income taxes recoverable		**-**		83,647
Due from related company (note 5)		**668,347**		-
		3,849,078		3,002,727
Property, plant, and equipment (note 1)		**9,549,902**		9,430,278
Other assets:				
Franchises and consents (note 2)		**64,547**		71,817
Deferred finance costs (note 3)		**33,455**		43,014
Deferred charges (note 4)		**149,277**		191,928
		247,279		306,759
	$	**13,646,259**	$	12,739,764

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2007		2006
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities (note 5)	**$**	**1,621,083**	$	1,445,775
Income taxes payable		**90,712**		-
Deferred revenue		**217,713**		187,251
Customer deposits		**602,860**		280,974
Term note payable (note 6)		**6,359,538**		6,454,484
		8,891,906		8,368,484
Shareholders' equity:				
Share capital (note 8)		**13,461,439**		13,461,439
Deficit		**(8,707,086)**		(9,090,159)
		4,754,353		4,371,280
Commitments (note 9)				
Contingent liability (note 10)				
	$	**13,646,259**	$	12,739,764

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Deficit

Year ended September 30

		2007		2006
Balance, beginning of year	$	**(9,090,159)**	$	(9,362,117)
Net income for the year		**383,073**		271,958
Balance, end of year	$	**(8,707,086)**	$	(9,090,159)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income

Year ended September 30

		2007		2006
Gas commodity revenue	$	**7,509,837**	$	8,947,781
Gas commodity cost		**7,306,666**		8,757,743
Gross margin on commodity		**203,171**		190,038
Distribution revenue		**3,751,671**		3,529,715
Distribution costs		**439,629**		494,736
Gross margin on distribution		**3,312,042**		3,034,979
Other sales		**1,057,476**		1,162,561
Other costs		**637,258**		683,797
Gross margin on other sales		**420,218**		478,764
Other revenue		**170,456**		123,199
Total gross margin		**4,105,887**		3,826,980
Expenses		**3,417,916**		3,375,022
Income before provision for income taxes		**687,971**		451,958
Provision for income taxes (note 7)		**304,898**		180,000
Net income for the year	$	**383,073**	$	271,958

Included in expenses are the following:				
Amortization of deferred financing costs	$	**9,559**	$	22,013
Amortization of deferred charges	$	**42,651**	$	21,326
Amortization of franchises and consents	$	**7,270**	$	7,270
Amortization of property, plant and equipment	$	**720,037**	$	690,084
Interest on long-term debt	$	-	$	141,393
Interest on short-term debt	$	**483,490**	$	251,352

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flows

Year ended September 30

		2007		2006
Cash flows from operating activities:				
Net income for the year	$	**383,073**	$	271,958
Items not affecting working capital:				
Amortization		**779,517**		740,693
Changes in non-cash working capital:				
Accounts receivable		**969,463**		(620,015)
Inventory		**24,646**		(31,986)
Prepaid expenses		**(57,505)**		286
Income taxes recoverable (note 7)		**83,647**		(83,647)
Accounts payable and accrued liabilities		**175,308**		(419,017)
Income taxes payable (note 14)		**90,712**		(58,560)
Deferred revenue		**30,462**		40,522
Customer deposits		**321,886**		175,929
		2,801,209		16,163
Cash flows from investing activities:				
Additions to property, plant, and equipment		**(839,661)**		(692,016)
Additions to deferred charges		**-**		(213,254)
Additions to deferred financing costs		**-**		(47,793)
		(839,661)		(953,063)
Cash flows from financing activities:				
Repayments of long-term debt		**-**		(2,723,409)
Reduction of stated capital of Class A shares		**-**		(2,038,581)
Proceeds from term note payable		**-**		6,500,000
Repayments of term note payable		**(94,946)**		(45,516)
Advances to related company		**(668,347)**		-
Repayments of demand debenture payable		**-**		(118,000)
		(763,293)		1,574,494
Increase in cash and cash equivalents during the year		**1,198,255**		637,594
Cash and cash equivalents, beginning of year		**683,120**		45,526
Cash and cash equivalents, end of year	**$**	**1,881,375**	$	683,120

See accompanying notes to the financial statements.

Summary of significant accounting policies:

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles, the more significant of which are summarized below.

Regulation:

The utility operations of the company is a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company follows Canadian generally accepted accounting principles. Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under GAAP for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Deferred charges:

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals have been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant, and equipment:

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment, excluding major disposals, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization. For major disposals, gains or losses are included in current earnings.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2007.

Amortization:

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated using the straight-line method on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis, at the following annual rates for the property, plant and equipment categories listed below:

Automotive equipment	17 %
Buildings	2 %
Computer equipment	33 %
Computer software	20 %
Furniture and fixtures	7 %
Machinery and equipment	6 % to 9 %
Meters and regulators	3 % to 4 %
Pipeline installations	3 % to 13 %

Amortization of deferred finance costs (related to the issue of debt) is calculated at the annual rate of 20% using the straight-line method over the life of the related debt issuance. In the current year, the company refinanced some of its existing debt. The deferred finance costs associated with the retired debt was amortized in full in the year of retirement.

Amortization of franchises and consents is calculated using the straight-line method over the term of the applicable franchise and consent.

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year and any such changes in estimate are applied on a prospective basis.

Income taxes:

The company's rate and revenues, established for regulatory purposes, allow for the recovery of income taxes on a formula basis which differs from the amount as determined under the tax allocation basis of accounting. Accordingly, the company accounts for income taxes using the taxes payable basis. This basis does not provide for future income taxes which may be payable in future years as a result of the difference between current financial reporting and reporting for income tax purposes. This method is followed for accounting purposes as there is a reasonable expectation that all such taxes will ultimately be recovered through rates when they become payable. Future income taxes not provided in these financial statements would amount to a recovery of $41,000 for the year ended September 30, 2007 (2006 - $4,000 provision) and an accumulated future liability of $387,000 at September 30, 2007 (2006 - $428,000).

Revenue recognition:

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet pending disposition by a decision of the OEB.

Gas commodity costs:

Gas commodity costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for future disposition subject to the approval of the OEB, usually within a maximum timeframe of the next fiscal year. In a non-regulated environment periodic variances between gas commodity sales rates and costs would be reported through the income statement annually without the use of deferral accounts.

Use of estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

1. Property, plant, and equipment:

			2007	2006
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 71,700	$ -	$ 71,700	$ 71,700
Buildings	682,331	106,989	575,342	590,489
Furniture and fixtures	54,884	31,820	23,064	25,904
Machinery and equipment	2,430,507	1,072,584	1,357,923	1,307,671
Computer equipment	176,139	137,513	38,626	41,173
Computer software	106,519	90,629	15,890	15,890
Automotive equipment	465,655	180,192	285,463	321,346
Meters and regulators	3,118,865	1,468,010	1,650,855	1,669,104
Pipeline installations	9,431,137	3,900,098	5,531,039	5,387,001
	$ 16,537,737	$ 6,987,835	$ 9,549,902	$ 9,430,278

2. Franchises and consents:

	2007	2006
Franchises and consents	$ 151,094	$ 151,094
Less: accumulated amortization	86,547	79,277
	$ 64,547	$ 71,817

3. Deferred finance costs:

		2007		2006
Deferred finance costs	**$**	**47,793**	$	47,793
Less: accumulated amortization		**14,338**		4,779
	$	**33,455**	$	43,014

4. Deferred charges - other assets:

		2007		2006
Total deferred charges - other assets	**$**	**213,253**	$	213,253
Less: accumulated amortization		**63,976**		21,325
	$	**149,277**	$	191,928

The company has been given approval by the OEB to recover the above costs already incurred, from rate payers over future periods. The recovery will occur over the next four years as noted below.

2008	$	42,651
2009		42,651
2010		42,651
2011		21,324
	$	149,277

5. Related party transactions:

Due from related companies consists of the following:

		2007		2006
Non interest bearing with no set repayment terms	$	**203,347**	$	-
Demand promissory note receivable, bearing interest at 4.59% payable monthly		**465,000**		-
	$	**668,347**	$	-

Included in accounts receivable are amounts receivable from related companies of $nil as at September 30, 2007 (2006 - $8,726).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $254,575 as at September 30, 2007 (2006 - $665,948).

During the year, rent of $9,600 (2006 - $9,600) and management fees of $107,250 (2006 - $117,000) were paid to a related company.

During the year, the company purchased gas in the amount of $2,606,281 (2006 - $4,006,684) from a related company.

During the year, maintenance charges of $60,460 (2006 - $58,200) were charged to a related company.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of business, and are measured at the exchange amount which approximates fair value.

6. Term note payable:

		2007		2006
Bank of Nova Scotia term note payable, 7.52% interest, repayable in blended monthly installments of $48,201, due March 2011	$	**6,359,538**	$	6,454,484

Although the above loan is due on demand, the company expects to make installments as per the amortization schedule which forms part of the loan agreement. The aggregate amount of principal payments required in each of the next 5 years to meet minimum retirement provisions is as follows:

2008	$	102,346
2009		110,348
2010		118,963
2011		6,027,881
	$	6,359,538

The company has pledged the following as security against the term note payable, the operating line of credit, and the revolving line of credit:

a) General assignment of book debts

b) General Security Agreement over all of the present and future personal property and undertaking of the company

c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank

d) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

The company also has unused credit facilities in the amount of $2,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and

b) Revolving line of credit in the amount of $1,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The company has not used either of the above credit facilities during the year, and their continuation is subject to annual review by the Bank.

NATURAL RESOURCE GAS LIMITED

Notes to the Financial Statements - continued

September 30, 2007

7. Income tax expense:

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory income tax rates to income before income taxes. The reasons for the difference and the related tax effects are as follows:

		2007		2006
Income before provision for income taxes	$	**687,971**	$	451,958
Statutory tax rate		**36.12 %**		36.12 %
Tax on net income at statutory rates		**248,495**		163,247
Amortization on financial statements in excess of Capital Cost Allowance for tax purposes		**55,527**		49,883
Ontario Small Business Deduction utilized		**-**		(34,000)
Non-deductible expenses		**876**		870
Provision for income taxes	$	**304,898**	$	180,000

8. Share capital:

		2007		2006
Authorized:				
Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends				
Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution				
Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share				
Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement				
Unlimited number of common shares				
Issued and outstanding:				
Retractable shares:				
50,000 Class A shares	**$**	**1**	$	1
10 Class B shares		**10**		10
134,614.18 Class C shares		**13,461,418**		13,461,418
10 Class Z shares		**10**		10
	$	**13,461,439**	$	13,461,439

9. Commitments:

The Company has entered into various contracts, whereby it has agreed to construct a 28.5 kilometre natural gas pipeline between London and Aylmer to service a new customer, at an estimated cost of $9,100,000. As part of an agreement between the Company and the customer, the customer has agreed to pay a $3,790,000 construction subsidy to the Company to share in the construction cost of the pipeline, effectively reducing the pipeline's capital cost to the Company.

10. Contingent liability:

The company is aware of a potential regulatory liability in an amount of a maximum of $140,000. The matter is currently under appeal, and in the opinion of management, and its external legal counsel, the company will be successful in its appeal. The OEB and its counsel have made no attempt to defend the appeal and these proceedings, as the company's external counsel believes there to be no precedent in the OEB regulations for the regulator to levy such amounts against the company. As such, no liability has been accrued in these financial statements.

11. Gas imbalances:

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas sold and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $723,354 (2006 - $43,441) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

12. Regulatory matters:

The Company has rates that are approved by the OEB. The fiscal year 2007 was a one year Cost of Service Rate filing. The company received the OEB decision dated September 28, 2006 and the rate order was effective September 28, 2006. The company did not make a submission for the fiscal year 2008 which left rates unchanged from 2007.

Rates for the sale of gas commodity are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the deferred balances. The OEB's approval for recovery of these gas purchase costs primarily considers the prudence of costs incurred.

13. Financial instruments:

The carrying values of the company's financial current assets and liabilities, including cash, accounts receivable, and accounts payable and accrued liabilities approximate their values due to their short-term maturity.

The fair value of the non interest bearing portion of the amount due from related company is less than its carrying value. As the amount is non interest bearing, and the timing of repayment is uncertain, the fair value is not readily obtainable. The fair value of the demand promissory note receivable from related company approximates the carrying value as the market interest rate at the time the note was issued is not significantly different than the market interest rate around year end.

The fair value of the term note payable is estimated using a discounted cash flow calculation that uses market interest rates currently charged for similar debt instruments at September 30, 2007 to expected maturity dates. Since the market interest rate at the time the term note payable was entered into is not significantly different than the market interest rate around year end, the carrying value approximates its fair value.

Natural gas prices:

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

Credit risk:

Credit risk arises from the potential that a trade customer will fail to pay its account. The company is exposed to credit risk from its customers. However, the company has a large number of diverse customers, which minimizes concentration of credit risk.

14. Additional cash flow statement information:

		2007		2006
Interest paid	**$**	**483,490**	$	385,085
Income taxes paid	**$**	**149,896**	$	289,045

ADDITIONAL COMMENTS OF AUDITORS

The accompanying schedule of expenses is presented as supplementary information only. In this respect, it does not form part of the financial statements of Natural Resource Gas Limited for the year ended September 30, 2007 and is hence excluded from the opinion expressed in our report dated May 6, 2008 to the board of directors on such financial statements. The information in this schedule has been subject to audit procedures only to the extent necessary to express an opinion on the financial statements of the company and, in our opinion, is fairly presented in all respects material to those financial statements.

London, Canada
May 6, 2008

Neal, Pallett & Townsend LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Unaudited Schedule of Expenses

Year ended September 30

		2007		2006
Advertising	$	**13,850**	$	28,472
Automotive and maintenance		**114,623**		187,793
Bad debts		-		13,500
Bank charges and other interest		**505,517**		281,434
Capital tax		**37,900**		10,818
Consulting fees		**199,629**		95,972
Dues and fees		**17,914**		19,596
Employee benefits		**113,602**		126,485
Insurance		**185,199**		235,774
Interest on long-term debt		**-**		141,393
Legal and audit		**67,308**		145,446
Management fees - related company		**107,250**		117,000
Miscellaneous		**52,709**		15,593
Office		**102,882**		93,487
Ontario Energy Board hearings		**48,559**		164,540
Promotional rebates		**2,652**		11,511
Property taxes		**286,180**		261,404
Rent - affiliated company		**9,600**		9,600
Salaries and wages		**886,050**		832,251
Telephone		**54,018**		41,658
Travel and promotion		**6,972**		2,158
Utilities		**14,541**		16,565
Amortization - Automotive equipment		**77,299**		74,039
Buildings		**15,148**		15,148
Computer equipment		**14,375**		12,428
Computer software		**6,441**		8,051
Deferred finance costs and charges		**52,210**		43,339
Franchises and consents		**7,270**		7,270
Furniture and Fixtures		**3,705**		3,646
Machinery and equipment		**41,182**		39,817
Meters and regulators		**113,504**		110,047
Pipeline installations		**311,198**		296,915
		3,469,287		3,463,150
Equipment expenses capitalized to pipeline installations		**(15,152)**		(17,102)
Interest expense (income)		**(27,490)**		(60,747)
Amortization capitalized to pipeline installations		**(8,729)**		(10,279)
	$	**3,417,916**	$	3,375,022

NATURAL RESOURCE GAS LIMITED

FINANCIAL STATEMENTS

SEPTEMBER 30, 2006

NEAL, PALLETT & TOWNSEND LLP

NP&T

CHARTERED ACCOUNTANTS
633 Colborne Street
Suite 300
London, Ontario
N6B 2V3

Telephone: (519) 432-5534
Fax: (519) 432-6544
Website: www.nptca.com

Partners:
Glenn J. Hardman C.A.*
Barrie J. Neal F.C.A.*
David J. Pallett C.A.*
Douglas Plummer C.A.*
John D.R. Prueter C.A., M.B.A.*
Piyush Shah C.A.*
Jonathan R. Townsend C.A.*
L.J. Sandy Wetstein C.A.*

*Professional Corporation

AUDITORS' REPORT

To the Board of Directors
Natural Resource Gas Limited

We have audited the balance sheet of Natural Resource Gas Limited as at September 30, 2006 and the statements of income, deficit, and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

The company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian generally accepted accounting principles require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet. The company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities would increase by $13,461,418 and share capital would decrease by $13,461,418.

In our opinion, except that the Class C shares of the company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the company as at September 30, 2006 and the results of its operations and changes in its financial position for the year then ended in accordance with the basis of accounting disclosed in the summary of significant accounting policies.

Neal, Pallett & Townsend LLP

London, Canada
December 20, 2006

Neal, Pallett & Townsend LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2006		2005
Assets				
Current assets:				
Cash	$	**683,120**	$	45,526
Accounts receivable (note 5)		**2,075,375**		1,455,365
Inventory		**153,510**		121,524
Prepaid expenses		**6,921**		7,207
Income taxes recoverable		**83,647**		-
Deferred charges		**154**		149
		3,002,727		1,629,771
Property, plant, and equipment (note 1)		**9,430,278**		9,428,346
Other assets:				
Franchises and consents (note 2)		**71,817**		79,087
Deferred financing costs (note 3)		**43,014**		17,234
Deferred charges (note 4)		**191,928**		-
		306,759		96,321
	$	**12,739,764**	$	11,154,438

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2006		2005
Liabilities and Shareholders' Equity				
Current liabilities:				
Demand debenture payable	$	-	$	118,000
Accounts payable and accrued liabilities (note 5)		**1,445,775**		1,864,792
Income taxes payable		-		58,560
Deferred revenue		**187,251**		146,729
Customer deposits		**280,974**		105,045
Term note payable (note 6)		**6,454,484**		-
Current portion of long-term debt (note 8)		-		387,780
		8,368,484		2,680,906
Long-term debt (note 8)		-		2,335,629
		8,368,484		5,016,535
Shareholders' equity:				
Share capital (note 9)		**13,461,439**		15,500,020
Deficit		**(9,090,159)**		(9,362,117)
		4,371,280		6,137,903
	$	**12,739,764**	$	11,154,438

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Deficit

Year ended September 30

	2006	2005
Balance, beginning of year	**$ (9,362,117)**	$ (9,761,070)
Net income for the year	**271,958**	398,953
Balance, end of year	**$ (9,090,159)**	$ (9,362,117)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income

Year ended September 30

		2006		2005
Gas commodity revenue	$	**8,947,781**	$	7,342,777
Gas commodity cost		**8,757,743**		7,132,905
Gross margin on commodity		**190,038**		209,872
Distribution revenue		**3,529,715**		3,704,162
Distribution costs		**494,736**		544,676
Gross margin on distribution		**3,034,979**		3,159,486
Other sales		**1,162,561**		1,208,357
Other costs		**683,797**		779,635
Gross margin on other sales		**478,764**		428,722
Other revenue		**123,199**		79,137
Total gross margin		**3,826,980**		3,877,217
Expenses		**3,375,022**		3,204,264
Income before provision for income taxes		**451,958**		672,953
Provision for income taxes (note 7)		**180,000**		274,000
Net income for the year	$	**271,958**	$	398,953

Included in expenses are the following:				
Amortization of deferred financing costs	$	**22,013**	$	6,196
Amortization of deferred charges	$	**21,326**	$	-
Amortization of franchises and consents	$	**7,270**	$	7,270
Amortization of property, plant and equipment	$	**690,084**	$	657,232
Interest on long-term debt	$	**141,393**	$	320,867
Interest on short-term debt	$	**251,352**	$	4,164

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flows

Year ended September 30

	2006	2005
Cash flows from operating activities:		
Net income for the year	$ **271,958**	$ 398,953
Items not affecting working capital:		
Amortization	**740,693**	670,698
Changes in non-cash working capital:		
Accounts receivable	**(620,010)**	(165,929)
Inventory	**(31,986)**	8,738
Prepaid expenses	**286**	16,712
Income taxes recoverable (note 13)	**(83,647)**	-
Accounts payable and accrued liabilities	**(419,017)**	143,989
Income taxes payable (note 13)	**(58,560)**	117,538
Deferred revenue	**40,522**	27,791
Deferred charges	**(5)**	32,646
Customer deposits	**175,929**	2,831
	16,163	1,253,967
Cash flows from investing activities:		
Additions to property, plant, and equipment	**(692,016)**	(814,214)
Additions to deferred charges	**(213,254)**	-
Additions to deferred financing costs	**(47,793)**	-
	(953,063)	(814,214)
Cash flows from financing activities:		
Repayments of long-term debt	**(2,723,409)**	(345,042)
Reduction of stated capital of Class A shares	**(2,038,581)**	-
Proceeds from term note payable	**6,500,000**	-
Repayments of term note payable	**(45,516)**	-
Repayments of demand debenture payable	**(118,000)**	(7)
	1,574,494	(345,049)
Increase in cash and cash equivalents during the year	**637,594**	94,704
Cash and cash equivalents, beginning of year	**45,526**	(49,178)
Cash and cash equivalents, end of year	$ **683,120**	$ 45,526

See accompanying notes to the financial statements.

Summary of significant accounting policies:

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles, the more significant of which are summarized below.

Regulation:

The utility operations of the company is a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company follows Canadian generally accepted accounting principles. Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under GAAP for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Deferred charges:

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals have been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant, and equipment:

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment, excluding major disposals, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization. For major disposals, gains or losses are included in current earnings.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2006.

Amortization:

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated using the straight-line method on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis, at the following annual rates for the property, plant and equipment categories listed below:

Automotive equipment	17 %
Buildings	2 %
Computer equipment	33 %
Computer software	20 %
Furniture and fixtures	7 %
Machinery and equipment	6 % to 9 %
Meters and regulators	3 % to 4 %
Pipeline installations	3 % to 13 %

Amortization of deferred finance costs (related to the issue of debt) is calculated at the annual rate of 20% using the straight-line method over the life of the related debt issuance. In the current year, the company refinanced some of its existing debt. The deferred finance costs associated with the retired debt was amortized in full in the year of retirement.

Amortization of franchises and consents is calculated using the straight-line method over the term of the applicable franchise and consent.

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year and any such changes in estimate are applied on a prospective basis.

Income taxes:

The company's rate and revenues, established for regulatory purposes, allow for the recovery of income taxes on a formula basis which differs from the amount as determined under the tax allocation basis of accounting. Accordingly, the company accounts for income taxes using the taxes payable basis. This basis does not provide for future income taxes which may be payable in future years as a result of the difference between current financial reporting and reporting for income tax purposes. This method is followed for accounting purposes as there is a reasonable expectation that all such taxes will ultimately be recovered through rates when they become payable. Future income taxes not provided in these financial statements would amount to a provision of $4,000 for the year ended September 30, 2006 (2005 - $102,000 recovery) and an accumulated future liability of $428,000 at September 30, 2006 (2005 - $424,000).

Revenue recognition:

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet pending disposition by a decision of the OEB.

Gas commodity costs:

Gas commodity costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for future disposition subject to the approval of the OEB, usually within a maximum timeframe of the next fiscal year. In a non-regulated environment periodic variances between gas commodity sales rates and costs would be reported through the income statement annually without the use of deferral accounts.

Use of estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

1. Property, plant, and equipment:

			2006	2005
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 71,700	$ -	$ 71,700	$ 71,700
Buildings	682,331	91,842	590,489	605,637
Furniture and fixtures	54,020	28,116	25,904	28,720
Machinery and equipment	2,344,902	1,037,231	1,307,671	1,256,667
Computer equipment	157,870	116,697	41,173	9,845
Computer software	106,519	90,629	15,890	15,890
Automotive equipment	446,015	124,669	321,346	376,192
Meters and regulators	3,023,610	1,354,506	1,669,104	1,557,008
Pipeline installations	8,976,619	3,589,618	5,387,001	5,506,687
	$ 15,863,586	$ 6,433,308	$ 9,430,278	$ 9,428,346

2. Franchises and consents:

	2006	2005
Franchises and consents	$ 151,094	$ 151,094
Less: accumulated amortization	79,277	72,007
	$ 71,817	$ 79,087

3. **Deferred finance costs:**

		2006		2005
Deferred finance costs	$	**47,793**	$	92,945
Less: accumulated amortization		**4,779**		75,711
	$	**43,014**	$	17,234

During the year, the company refinanced its debt. The result was that the remaining deferred finance costs of $17,234 associated with the old debt were fully amortized in the year. The costs associated with the new term note payable of $47,793 were deferred and are amortized over the expected term of the debt.

4. **Deferred charges - other assets:**

		2006		2005
Total deferred charges - other assets	$	**213,253**	$	-
Less: accumulated amortization		**21,325**		-
	$	**191,928**	$	-

The company has been given approval by the OEB to recover the above costs already incurred from rate payers over future periods. The recovery will occur over the next five years as noted below.

2007	$	42,651
2008		42,651
2009		42,651
2010		42,651
2011		21,324
	$	191,928

5. Related party transactions:

During the year, rent of $9,600 (2005 - $9,600) and management fees of $117,000 (2005 - $87,000) were paid to a related company.

During the year, the company purchased gas in the amount of $4,006,684 (2005 - $2,028,997) from a related company.

During the year, maintenance charges of $58,200 (2005 - $41,280) were charged to a related company.

During the year, the company provided installation services and product to a related company in the amount of $nil (2005 - $15,015).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $665,948 as at September 30, 2006 (2005 - $462,345).

Included in accounts receivable are amounts receivable from related companies of $8,726 as at September 30, 2006 (2005 - $16,642).

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of business, and are measured at the exchange amount.

6. Term note payable:

	2006	2005
Bank of Nova Scotia term note payable, 7.52%, repayable in blended monthly installments of $48,201, due March 2011	$ 6,454,484	$ -

Although the above loan is due on demand, the company expects to make installments as per the amortization schedule which forms part of the loan agreement. The aggregate amount of principal payments required in each of the next 5 years to meet minimum retirement provisions is as follows:

2007	$ 94,946
2008	102,346
2009	110,348
2010	118,963
2011	6,027,881
	$ 6,454,484

The company has pledged the following as security against the term note payable, the operating line of credit, and the revolving line of credit:

a) General assignment of book debts
b) General Security Agreement over all of the present and future personal property and undertaking of the company
c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank
d) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss, if any, payable to the Bank as mortgagee.

The company also has unused credit facilities in the amount of $2,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and
b) Revolving line of credit in the amount of $1,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The company has not used either of the above credit facilities during the year, and their continuation is subject to annual review by the Bank..

7. **Income tax expense:**

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory income tax rates to income before income taxes. The reasons for the difference and the related tax effects are as follows:

		2006		2005
Income before provision for income taxes	**$**	**451,958**	$	672,953
Statutory tax rate		**36.12 %**		36.12 %
Tax on net income at statutory rates		**163,247**		243,071
Amortization on financial statements in excess of Capital Cost Allowance for tax purposes		**49,883**		46,931
Ontario Small Business Deduction utilized		**(34,000)**		(34,000)
Non-deductible expenses		**870**		6,206
Deferred charges on financial statements deductible on a cash basis for tax purposes		**-**		11,792
Provision for income taxes	**$**	**180,000**	$	274,000

8. Long-term debt:

		2006		2005
Debenture payable, 11.8%, repayable in blended monthly installments of $44,525 principal and interest, repaid in the year	$	-	$	1,615,977
Debenture payable, 11.03%, repayable in blended monthly installments of $3,384, principal and interest, repaid in the year		-		156,432
Debenture payable, 9.57% (interest rate adjusted annually based upon the allowed rate of return as set by the Ontario Energy Board. Minimum rate of 9.25%), repayable in monthly interest only installments, repaid in the year		-		951,000
		-		2,723,409
Less: current portion		-		387,780
	$	-	$	2,335,629

9. Share capital:

		2006		2005
Authorized:				
Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends				
Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution				
Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share				
Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement				
Unlimited number of common shares				
Issued and outstanding:				
Retractable shares:				
50,000 Class A shares	**$**	**1**	$	2,038,582
10 Class B shares		**10**		10
134,614.18 Class C shares		**13,461,418**		13,461,418
10 Class Z shares		**10**		10
	$	**13,461,439**	$	15,500,020

During the year, the company paid to the Class A shareholder $2,038,581 as a reduction in the stated capital of the Class A shares.

10. Gas imbalances:

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas sold and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $43,441 (2005 - $84,351) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

11. Regulatory matters:

The Company has rates that are approved by the OEB. The fiscal year 2005 was a one year Cost of Service Rate filing. The company received the OEB decision dated December 20, 2004 and the rate order was dated December 31, 2004. The company did not make a submission for the fiscal year 2006 which left rates unchanged from 2005. The company's fiscal 2007 rate submission to the OEB was approved, and the company is currently working on the fiscal 2008 submission.

Rates for the sale of gas commodity are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the deferred balances. The OEB's approval for recovery of these gas purchase costs primarily considers the prudence of costs incurred.

12. Financial instruments:

The carrying values of the company's financial current assets and liabilities, including cash, accounts receivable, deferred charges, and accounts payable and accrued liabilities approximate their values due to their short-term maturity.

The fair value of the term note payable is estimated using a discounted cash flow calculation that uses market interest rates currently charged for similar debt instruments at September 30, 2006 to expected maturity dates. Since there have not been significant changes to market interest rates since the term note payable was obtained in the year, the carrying value approximates its fair value.

Natural gas prices:

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

Credit risk:

Credit risk arises from the potential that a trade customer will fail to pay its account. The company is exposed to credit risk from its customers. However, the company has a large number of diverse customers, which minimizes concentration of credit risk.

13. Additional cash flow statement information:

		2006		2005
Interest paid	**$**	**385,085**	$	325,099
Income taxes paid	**$**	**289,045**	$	226,118

ADDITIONAL COMMENTS OF AUDITORS

The accompanying schedule of expenses is presented as supplementary information only. In this respect, it does not form part of the financial statements of Natural Resource Gas Limited for the year ended September 30, 2006 and is hence excluded from the opinion expressed in our report dated December 20, 2006 to the board of directors on such financial statements. The information in this schedule has been subject to audit procedures only to the extent necessary to express an opinion on the financial statements of the company and, in our opinion, is fairly presented in all respects material to those financial statements.

London, Canada
December 20, 2006

Neal, Pallett & Townsend LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Unaudited Schedule of Expenses

Year ended September 30

		2006		2005
Advertising	$	**28,472**	$	29,888
Automotive and maintenance		**187,793**		233,851
Bad debts		**13,500**		8,000
Bank charges and other interest		**281,434**		26,854
Capital tax		**10,818**		24,524
Consulting fees		**95,972**		35,800
Dues and fees		**19,596**		22,543
Employee benefits		**126,485**		129,604
Insurance		**235,774**		263,750
Interest on long-term debt		**141,393**		320,867
Legal and audit		**145,446**		105,327
Management fees - affiliated company		**117,000**		87,000
Miscellaneous		**15,593**		37,538
Office		**93,487**		82,181
Ontario Energy Board hearings		**164,540**		150,256
Promotional rebates		**11,511**		-
Property taxes		**261,404**		285,288
Rent - affiliated company		**9,600**		9,600
Salaries and wages		**832,251**		773,372
Telephone		**41,658**		39,366
Travel and promotion		**2,158**		6,787
Utilities		**16,565**		14,263
Amortization - Automotive equipment		**74,039**		75,649
Buildings		**15,148**		15,148
Computer equipment		**12,428**		7,716
Computer software		**8,051**		2,575
Deferred finance costs		**43,339**		6,196
Franchises and consents		**7,270**		7,270
Furniture and Fixtures		**3,646**		3,590
Machinery and equipment		**39,817**		37,006
Meters and regulators		**110,047**		101,970
Pipeline installations		**296,915**		290,692
		3,463,150		3,234,471
Equipment expenses capitalized to pipeline installations		**(17,102)**		(31,690)
Interest expense (income)		**(60,747)**		12,521
Amortization capitalized to pipeline installations		**(10,279)**		(11,038)
	$	**3,375,022**	$	3,204,264

NATURAL RESOURCE GAS LIMITED

CORPORATE FINANCIAL STATEMENTS AND CORPORATE/UTILITY INCOME - 2010

Balance Sheet
as at September 30, 2010
($'s)

ASSETS

Current Assets	
Short Term Investment	$2,750,000
Accounts Receivable	1,042,336
Inventory	140,869
Prepaid Expenses	87,660
PGCVA	(179,112)
PGTVA	(390,603)
GPRA	2,007
REDA	779,683
	4,232,839
Fixed Assets	
Property, Plant & Equipment	23,662,027
Less Accum. Depreciation	9,633,718
	14,028,309
Other Assets	
Deferred Charges	21,345
Franchises	156,294
Financing Costs (Net)	14,059
	191,698
Total Assets	$18,452,846

NATURAL RESOURCE GAS LIMITED

Balance Sheet
as at September 30, 2010
($'s)

LIABILITIES AND SHAREHOLDERS' EQUITY

Current Liabilities	
Bank Indebtedness	$189,212
Accounts Payable and Accruals	2,108,178
Income Taxes Payable	7,424
Customer Deposits	250,000
	2,554,813
Long Term Debt	
Bank of Nova Scotia	10,231,316
	10,231,316
Shareholder's Equity	
Capital Stock	13,461,439
Retained Earnings	(7,794,721)
	5,666,718
Liabilities and Shareholder's Equity	$18,452,847

NATURAL RESOURCE GAS LIMITED

Statement of Retained Earnings
For the year ended September 30, 2010
($'s)

RETAINED EARNINGS - BEGINNING OF YEAR	($8,329,979)
Regulatory Earnings	535,258
RETAINED EARNINGS - END OF YEAR	($7,794,721)

NATURAL RESOURCE GAS LIMITED

Statement of Income
Fiscal Year Ending September 30, 2010
($'s)

Gas Sales	$5,617,804
Cost of Gas	5,584,003
Gas Sales Margin	33,800
Distribution Revenue	5,414,814
Distribution Costs	1,011,858
Distribution Margin	4,402,956
Other Revenue (net)	629,669
Gross Profit	5,066,425
Expenses	
Operating & Maintenance	2,394,120
Depreciation & Amortization	992,555
Property & Capital Taxes	425,283
	3,811,958
Income Before Interest & Income Taxes	1,254,467
Interest Charges	630,127
Earnings Before Tax	624,341
Income Taxes	89,083
Net Income	$535,258

NATURAL RESOURCE GAS LIMITED

Statement of Changes in Financial Position
Fiscal Year Ending September 30, 2010
($'s)

Operating Activities	
Net Earnings for the Year	$535,258
Items Not Affecting Cash	
Depreciation Fixed Assets	999,973
Depreciation on HWH	179,887
Net Decrease (Increase) in Non-Cash	
Items Related to Operations	(601,220)
	1,113,897
Financing Activities	
Repayments of Long Term Debt	(638,861)
Borrowings of Long Term Debt	0
	(638,861)
Investing Activities	
Purchase of Fixed Assets	(730,841)
Increase (Decrease) in CWIP	0
	(730,841)
Increase (Decrease) in Cash	(255,805)
Cash - Beginning of Year	66,593
Cash - End of Year	($189,212)

NATURAL RESOURCE GAS LIMITED

CORPORATE FINANCIAL STATEMENTS AND CORPORATE/UTILITY INCOME - 2011

Balance Sheet
as at September 30, 2011
($'s)

ASSETS

Current Assets	
Cash	$489,387
Short Term Investment	2,751,130
Accounts Receivable	1,042,336
Inventory	145,095
Prepaid Expenses	87,660
PGCVA	(503,198)
PGTVA	(579,757)
GPRA	2,007
REDA	674,683
	4,109,344
Fixed Assets	
Property, Plant & Equipment	24,375,062
Less Accum. Depreciation	10,652,374
	13,722,688
Other Assets	
Deferred Charges	0
Franchises	58,813
Financing Costs (Net)	4,500
	63,313
	$17,895,344

NATURAL RESOURCE GAS LIMITED

Balance Sheet
as at September 30, 2011
($'s)

LIABILITIES AND SHAREHOLDER'S EQUITY

Current Liabilities	
Accounts Payable and Accruals	$2,108,178
Income Taxes Payable	4,188
Customer Deposits	250,000
	2,362,366
Long Term Debt	
Bank of Nova Scotia	9,583,165
	9,583,165
Shareholder's Equity	
Capital Stock	13,461,439
Retained Earnings	(7,511,626)
	5,949,813
	$17,895,344

NATURAL RESOURCE GAS LIMITED

Statement of Retained Earnings
For the year ended September 30, 2011
($'s)

RETAINED EARNINGS - BEGINNING OF YEAR	$ (7,794,721)
Regulatory Earnings	283,095
RETAINED EARNINGS - END OF YEAR	$ (7,511,626)

NATURAL RESOURCE GAS LIMITED

Statement of Income
Fiscal Year Ending September 30, 2011
($'s)

Gas Sales	$6,237,510
Cost of Gas	6,199,675
Gas Sales Margin	37,835
Distribution Revenue	5,480,613
Distribution Costs	921,485
Distribution Margin	4,559,129
Other Revenue (net)	664,159
Gross Profit	5,261,123
Expenses	
Operating & Maintenance	2,859,299
Depreciation & Amortization	1,018,815
Property & Capital Taxes	400,776
	4,278,890
Income Before Interest & Income Taxes	982,233
Interest Charges	648,886
Earnings Before Tax	333,347
Income Taxes	50,252
Net Income	$283,095

NATURAL RESOURCE GAS LIMITED

Statement of Changes in Financial Position
Fiscal Year Ending September 30, 2011
($'s)

Operating Activities	
Net Earnings for the Year	$283,095
Items Not Affecting Cash	
Depreciation Fixed Assets	1,025,399
Depreciation on Water Heaters	187,708
Net Decrease (Increase) in Non-Cash	
Items Related to Operations	640,551
	2,136,753
Financing Activities	
Repayments of Long Term Debt	(648,151)
Borrowings of Long Term Debt	(648,151)
Investing Activities	
Purchase of Fixed Assets	(810,004)
Increase (Decrease) in CWIP	(810,004)
Increase (Decrease) in Cash	678,599
Cash - Beginning of Year	(189,212)
Cash - End of Year	$489,387

NATURAL RESOURCE GAS LIMITED

RATE BASE

Fiscal 2011 Test Year

As shown in Exhibit B8, Tab 1, Schedule 1, total rate base in the 2011 test year is forecast to be $13,618,731. Property, Plant and Equipment accounts for $13,843,071 of this total. The allowance for working capital totals ($224,340), including ($98,602) for the working cash allowance, ($270,833) for security deposits and $145,095 for inventory.

Comparison to Fiscal 2010 Bridge Year

Total rate base is expected to be $451,734 or 3.2% lower in the 2011 test year than in the 2010 bridge year. This decrease is shown in Exhibit B8, Tab 1, Schedule 1. This decrease is the result of a $522,035 decrease in net property, plant and equipment and an increase of $70,301 in the working cash allowance. This latter increase is related to changes in security deposits. The decrease in property, plant and equipment is directly related to changes in capital expenditures and 2011 depreciation expense.

Fiscal 2010 Bridge Year

The bridge year rate base, shown in Exhibit B7, Tab 1, Schedule 1, is $14,070,465. Net property, plant and equipment totals $14,365,106 while the allowance for working capital totals ($294,641).

Comparison to Fiscal 2009 Actual

As shown in Exhibit B7, Tab 1, Schedule 1, NRG's fiscal 2010 rate base is $363,910 or 2.7% higher than the fiscal 2009 rate base. Net property, plant and equipments is $30,547 higher in fiscal 2010 than in fiscal 2009, the result of the capital expenditures planned for the bridge year and the 2010 depreciation expense. The allowance for working capital is $333,363 higher than in fiscal 2009 and is the result of reduced deposits of $287,600.

Fiscal 2009 Historical Year

As shown in Exhibit B6, Tab 1, Schedule 1, the fiscal 2009 rate base was $4,835,480 higher than the corresponding level in fiscal 2008. This increase is principally due to the proposed inclusion in rate base of NRG's $5,073,000 investment in the IGPC pipeline and other more routine capital spending which amounted to $879,951. A reduction of $37,556 in the allowance for working capital is chiefly due to a $145,716 reduction in Inventory.

The costs of the IGPC pipeline that are proposed to be included in rate base are set out at Exhibit B6, Tab 2, Schedule 1.

Fiscal 2008 Historical Year

As shown in Exhibit B5, Tab 1, Schedule 1, the fiscal 2008 rate base was $150,180 lower than the corresponding level in fiscal 2007. This decrease was the result of an decrease in the allowance for working capital of $190,384 and an increase of $40,204 in net property, plant and equipment.

<u>Fiscal 2007 Historical Year</u>

As shown in Exhibit B4, Tab 1, Schedule 1, the fiscal 2007 rate base was $189,698 lower than the corresponding level in fiscal 2006. This decrease was the result of a reduction of $244,552 in the allowance for working capital and an increase of $54,854 in net property, plant and equipment.

The fiscal 2007 rate base was $655,457 lower than the Board authorized 2007 Test Year rate base. This reflects that Property, Plant and Equipment was $278,749 lower and the Allowance for Working Capital was $376,708 lower. The reduction in Property, Plant and Equipment is due to lower opening balances and lower capital spending while the reduction in the Allowance for Working Capital reflects a $351,502 reduction in Security Deposits.

<u>Fiscal 2006 Historical Year</u>

As shown in Exhibit B3, Tab 1, Schedule 1, the fiscal 2006 rate base was $189,452 lower than the corresponding level in fiscal 2005. This decrease was the result of a reduction of $143,538 in the allowance for working capital which was partially offset by an increase of $45,914 in net property, plant and equipment.

NATURAL RESOURCE GAS LIMITED

CAPITAL EXPENDITURES

Fiscal 2011 Test Year

Capital expenditures in the fiscal 2011 test year are forecast to total $810,004, as shown in Exhibit B8, Tab 2, Schedule 1. Expenditures directly related to distribution infrastructure (main additions, main replacements, service additions, service replacements, meters and regulators) account for $436,532 or 53.9% of total expenditures. Other significant capital expenditures include $202,659 for rental equipment and $44,631 for Machinery and Equipment.

Comparison to Fiscal 2010 Bridge Year

Exhibit B8, Tab 2, Schedule 1, provides a comparison of the forecast for capital expenditures in 2011 to that forecast for the 2010 bridge year. Total expenditures are forecast to be $79,163 higher in 2011. This reflects an increase of $38,431 for Machinery and Equipment and proposed capital spending on buildings of $40,000 to provide an additional storage shed for extra pipe. These increases are offset by a decrease of $30,000 for vehicles.

Fiscal 2010 Bridge Year

NRG's capital expenditure in fiscal 2010 is forecast to total $730,840, as shown in Exhibit B7, Tab 2, Schedule 1. Expenditures directly related to distribution infrastructure (main additions, main replacements, service additions, service replacements, meters and regulators) account for $431,329 or 59.0% of total expenditures. Vehicles expenditures total $65,000 or 8.9% of the total expenditures. Rental equipment accounts for a further $193,009 or 26.4% of total expenditures.

Comparison to Fiscal 2009 Actual

As shown in Exhibit B7, Tab 2, Schedule 1, capital expenditures in 2010 are $5,222,111 lower than or 12.3% of the level recorded in 2009. This decrease is primarily due to NRG's $5,073,000 investment in the steel pipeline to serve IGPC in fiscal 2009 as well as NRG's capitalization of costs related to the renewal of its franchise agreement with the Town of Aylmer of $261,963.

Fiscal 2009 Historical Year

As shown in Exhibit B6, Tab 2, Schedule 1, NRG's capital expenditures in fiscal 2009 were $5,952,951 or 657.5% greater than capital expenditures in fiscal 2008. $5,073,000 of this increase is NRG's investment in the IGPC pipeline. Investment in main additions, services additions and meters was $362,804 lower than in 2008 due to fewer connecting customers.

Fiscal 2008 Historical Year

As shown in Exhibit B5, Tab 2, Schedule 1, NRG's capital expenditures in fiscal 2008 were $905,350 and $37,573 or 4.3% greater than fiscal 2007 levels. This increase was primarily due to $83,052 of increased spending on Services Additions. It also reflects $48,996 of increased spending on communications equipment. Reduced spending on Mains Additions of $56,985 and Automotive of $45,196 offset this increase.

Fiscal 2007 Historical Year

As shown in Exhibit B4, Tab 2, Schedule 1, NRG's capital expenditures in fiscal 2007 were $867,777 or 18.6% greater than fiscal 2006 levels. Capital spending on distribution system plant accounts for 63.4% of the spending and reflects investment in Mains Additions, Meters and Regulators. Other significant 2007 capital expenditures include $237,721 on Rental Equipment and $45,196 on fleet.

The spending on distribution system infrastructure was $152,016 greater than that invested in 2006. Capital spending on Computer Software and Hardware decreased by $33,356 and net spending on rental equipment increased by $24,956.

Fiscal 2006 Historical Year

As shown in Exhibit B3, Tab 2, Schedule 1, NRG's capital expenditures in fiscal 2006 were $122,560 or 14.4% lower than fiscal 2005 levels. The decrease was primarily due to reduced spending on Mains and Services Additions and Replacements of $186,876 net of increased spending on meters and regulators of $101,644. It also reflects increased net spending on rental equipment of $39,886 and decreased spending on Machinery and Equipment of $31,507 and on Automotive Fleet of $70,342.

NATURAL RESOURCE GAS LIMITED

DISTRIBUTION SYSTEM EXPANSION & FEASIBILITY

Fiscal 2011 Test Year

Fiscal 2011 contains two main addition projects costing $76,461 and $101,775 as shown in Exhibit B8, Tab 2, Schedule 2. In addition $23,003 has been budgeted for miscellaneous and short main addition projects.

The benefit cost ratio for these projects, as shown in Exhibit B6, Tab 2, Schedule 3 are 1.04 and 0.83 and the overall benefit cost ratio for the main additions portfolio for the 2011 test year is 0.92. The financial tests for the main addition projects are shown in Exhibit B8, Tab 2, Schedule 3.

Fiscal 2010 Bridge Year

Fiscal 2010 contains four main addition projects costing between $11,645 and $35,051 as shown in Exhibit B7, Tab 2, Schedule 2. In addition $107,514 has been budgeted for miscellaneous and short main addition projects. The benefit cost ratio for these projects, as shown in Exhibit B7, Tab 2, Schedule 3, range from 0 to 2.48. The overall benefit cost ratio for the main additions portfolio for 2010 bridge year is 1.32. The financial tests for the main addition projects are shown in Exhibit B7, Tab 2, Schedule 4.

Fiscal 2009 Historic Year

Fiscal 2009 contains three main addition projects costing between $5,482 and $36,052 as shown in Exhibit B6, Tab 2, Schedule 2. In addition $976 has been incurred for miscellaneous and short main addition projects. The benefit cost ratio for these projects, as shown in Exhibit B6, Tab 2, Schedule 3, range from 2.46 to 3.18. The overall benefit cost ratio for the main additions portfolio for 2009 historic year is 2.84. The financial tests for the main addition projects are shown in Exhibit B6, Tab 2, Schedule 4.

<u>Fiscal 2008 Historic Year</u>

Fiscal 2008 contains 5 main addition projects costing between $21,600 and $206,250 as shown in Exhibit B5, Tab 2, Schedule 2. In addition $16,739 has been incurred for miscellaneous and short main addition projects. The benefit cost ratio for these projects, as shown in Exhibit B5, Tab 2, Schedule 3, range from 1.00 to 1.98.1. The overall benefit cost ratio for the main additions portfolio for 2008 historic year is 1.08. The financial tests for the main addition projects are shown in Exhibit B5, Tab 2, Schedule 4.

<u>Fiscal 2007 Historic Year</u>

Data on main additions constructed in 2007 will be filed at a later date.

<u>Fiscal 2006 Historic Year</u>

Data on main additions constructed in 2006 is found in Exhibit B3, Tab 2.

NATURAL RESOURCE GAS LIMITED

Summary of Utility Rate Base
2006 Actual
($'s)

	Actual 2006	Last Year 2005
Property, Plant & Equipment		
Asset Values at Cost	15,615,529	15,130,013
Accumulated Depreciation	6,249,064	5,717,634
	9,366,465	9,412,379
Allowance for Working Capital		
Inventory	213,693	140,670
Working Cash Allowance	-230,615	-47,127
Security Deposits	-138,590	-105,517
	-155,512	-11,974
Utility Rate Base	9,210,953	9,400,405

	Variance from 2005
Property, Plant & Equipment	
Asset Values at Cost	485,516
Accumulated Depreciation	531,430
	-45,914
Allowance for Working Capital	
Inventory	73,023
Working Cash Allowance	-183,488
Security Deposits	-33,073
	-143,538
Utility Rate Base	-189,452

NATURAL RESOURCE GAS LIMITED

Utility Capital Expenditures
2006 Actual
($'s)

	Actual 2006	Actual 2005
Mains - Additions	125,468	274,097
- Replacements	0	13,659
Services - Additions	50,146	70,800
- Replacements	0	3,934
New Steel Mains	0	0
Meters	149,944	84,813
Regulators	72,199	35,685
Franchises	0	0
Land	0	0
Buildings	0	0
Furniture & Fixtures	831	1,024
Computer Equipment	21,852	23,151
Computer Software	29,954	12,875
Machinery & Equipment	18,205	49,712
Communication Equipment	14,665	5,707
Automotive	35,661	106,003
Water Softeners	-338	1,307
Rental Water Heaters	213,103	171,572
Total Capital Expenditures	731,689	854,339

	Variance from 2005
Mains - Additions	-148,629
- Replacements	-13,659
Services - Additions	-20,654
- Replacements	-3,934
New Steel Mains	0
Meters	65,131
Regulators	36,514
Franchises	0
Land	0
Buildings	0
Furniture & Fixtures	-193
Computer Equipment	-1,299
Computer Software	17,079
Machinery & Equipment	-31,507
Communication Equipment	8,958
Automotive	-70,342
Water Softeners	-1,645
Rental Water Heaters	41,531
Total Capital Expenditures	-122,650

NATURAL RESOURCE GAS LIMITED

Capital Projects
2006
($'s)

Description	Cost
Main Additions	
Vienna Line to Nova Scotia	24,893
Other Main Extensions	100,575
Total Main Additions	125,468
Main Replacements	
No Replacements	0
Total Main Replacements	0
Service Additions	
Service additions	50,146
Total Service Additions	50,146
Service Replacements	
Service replacements	0
Total Service Replacements	0
Summary	
Total Main Additions	125,468
Total Main Replacements	0
Total Mains	125,468
Total Service Additions	50,146
Total Service Replacements	0
Total Services	50,146
Total Capital Projects	175,614

NATURAL RESOURCE GAS LIMITED

Aggregate Cost/Benefit Ratio for Main Additions
2006 Actual
($'s)

Main Additions	NPV of Revenues	NPV of Costs	Project Ratio
Vienna Line to Nova Scotia	-279	23,750	-0.01
Total Main Additions	-279	23,750	-0.01

(1) An aid to construction is collected for any project with a benefit/cost ratio less than 1.00. As a result, the net present value of these projects in aggregate is at least equal to the net present value of the costs, resulting in a project ratio of at least 1.00.

NATURAL RESOURCE GAS LIMITED

Financial Tests
2006 Actual

Attached

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description:	**Vienna line to Nova Scotia**	**project # 7016**
Planned for Fiscal:		
Date of Last Test:	**work done 2006**	**(well production)**
Nature of Project (MA, MR)		

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe	2,105	m	$ 6.79	14,293
2"	P.E. Pipe	-	m	$ 3.16	-
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	2,316	m	$ 0.22	509
				Total	14,802

Labour	Hours	Hourly Rate	Total
	72	20.00	1,440
	-	25.40	-
	-	25.40	-
		Total	1,440

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	32	$ 4.90	157
Generator	9	$ 1.50	14
Trencher	4	$ 39.00	156
Compressor	2	$ 3.60	7
Kubota	4	$ 2.20	9
Plow	-	$ 22.10	-
		Total	342

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	32	$ 1.20	38
Generator	9	$ 0.50	5
Trencher	4	$ -	-
Compressor	2	$ 4.20	8
Kubota	4	$ 4.80	19
Plow	-	$ 26.50	-
		Total	71

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	1	$ 2,000.00	2,000
		1	$ 6,238.00	6,238
			Total	8,238

Total Cost		**$ 24,893**
Contingency	10%	2,489
Total Project Cost		**$ 27,382**
Cost per Meter		$ 11.80
Benefit Cost Ratio		- 0
Aid to Construction		$ 24,029
Aid to Const (each)		$ 24,029
Payback (Years)		30

		Year					
Expected Customer Additions	**Potential**	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	1	-	-	-	-	1
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Vienna line to Nova Scotia project # 7016**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	-	-	-	-	1
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	2,105
2"	-
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	2,316

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ 6.79
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	23,750
NPV of revenue plus tax shield	-279
AID TO CONSTRUCTION	24,029
BENEFIT/COST RATIO	-0.012
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Vienna line to Nova Scotia project # 7016**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	14,293					14,293
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	14,293	-	-	-	-	14,293
Subcontractor & Rental Equipment						
Subcontractor	8,238					8,238
Contingency	2,489					2,489
Sub-total	10,727	-	-	-	-	10,727
Service Cost	190	-	-	-	-	190
Sub-total	190	-	-	-	-	190
Class 2 Pipelines	25,210	-	-	-	-	25,210
Meters & Regulators	168	-	-	-	-	168
Class 8 Equipment	168	-	-	-	-	168
Total Project Cost	25,378	-	-	-	-	25,378
NPV of Project Cost	$23,750					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 5,671	$ 42

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Vienna line to Nova Scotia project # 7016**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**2,000**	**-**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	2,000	2,000	2,000	2,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	2,000	**2,000**	**2,000**	**2,000**	**2,000**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	1	1	1	1	1
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Vienna line to Nova Scotia project # 7016**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

			Year			
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	306	306	306	306	306	
Commercial	-	-	-	-	-	
Industrial Rate 1	-	-	-	-	-	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	306	306	306	306	306	
Plus: Fixed Revenue	-	-	-	-	-	
Sub-Total	-	-	-	-	-	
Less: M9 Delivery Costs	11	11	11	11	11	
Less: O&M Expense	-	-	-	-	-	
Less: Capital Tax	76	76	76	76	76	
Less Property Tax	947	947	947	947	947	
Sub-Total	1,034	1,034	1,034	1,034	1,034	
Pre Tax Revenue	- 728	- 728	- 728	- 728	- 728	
Less: Income Tax	- 252	- 252	- 252	- 252	- 252	
Net Revenue	- 476	- 476	- 476	- 476	- 476	-476

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Vienna line to Nova Scotia project # 7016

		Consumption Profile		
Rate 1 - General Service Rate		**Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate	6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Vienna line to Nova Scotia project # 7016

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Vienna line to Nova Scotia project # 7016

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED

Property, Plant & Equipment
Summary of Averages - 2006 Actual
($'s)

Item	Gross Property Plant & Equip.	Accumulated Depreciation	Net Plant
Land	71,700	0	71,700
Buildings	682,331	84,846	597,485
Furniture & Fixtures	53,362	26,432	26,930
Computer Equipment	114,948	97,318	17,630
Computer Software	113,271	100,551	12,720
Machinery & Equipment	373,960	289,505	84,455
Communication Equipment	42,683	15,888	26,795
Automotive	447,114	103,820	343,294
Rental Equipment - Res	1,781,241	676,635	1,104,606
Rental Equipment - Com	55,458	16,810	38,648
Rental Equipment - Softeners	11,775	4,128	7,647
Meters	1,735,679	714,606	1,021,073
Regulators	1,136,198	589,080	547,118
Plastic Mains	6,386,222	2,027,291	4,358,931
Steel Mains	33,014	25,783	7,231
New Steel Mains	0	0	0
Plastic Services	2,425,479	1,400,452	1,025,027
Franchises & Consents	151,094	75,919	75,175
Total	15,615,529	6,249,064	9,366,465

NATURAL RESOURCE GAS LIMITED

Gross Property, Plant and Equipment
2006 Actual
($'s)

Asset Values at Cost	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331
Furniture & Fixtures	53,189	53,189	53,189	53,313	53,319	53,325	53,330	53,335	53,339	53,344	53,639	53,830	53,362
Computer Equipment	105,902	109,675	111,808	112,103	112,403	113,480	113,819	117,071	120,462	119,239	119,634	123,775	114,948
Computer Software	106,519	106,519	106,907	106,924	107,616	114,719	115,892	116,277	116,645	116,997	117,332	126,902	113,271
Machinery & Equipment	366,687	366,687	366,687	371,037	372,099	376,216	376,610	376,986	377,346	377,689	378,016	381,454	373,960
Communication Equipment	41,353	41,353	41,353	41,488	41,494	41,500	41,505	41,511	42,361	43,999	44,183	50,100	42,683
Automotive	453,824	451,849	449,962	448,162	446,444	444,803	443,237	441,743	440,316	438,954	455,381	450,698	447,114
Rental Equipment - Res	1,748,541	1,752,592	1,757,257	1,762,506	1,768,314	1,774,655	1,781,505	1,788,841	1,796,641	1,804,883	1,813,548	1,825,608	1,781,241
Rental Equipment - Com	54,907	54,777	55,781	55,714	55,650	55,589	55,531	55,670	55,626	55,584	55,544	55,121	55,458
Rental Equipment - Softeners	11,965	11,796	11,788	11,781	11,774	11,767	11,761	11,755	11,749	11,743	11,738	11,682	11,775
Meters	1,690,347	1,690,724	1,691,145	1,707,629	1,721,361	1,728,976	1,743,932	1,746,211	1,751,161	1,773,225	1,776,244	1,807,198	1,735,679
Regulators	1,113,444	1,116,991	1,118,189	1,122,363	1,122,975	1,138,592	1,140,342	1,141,375	1,142,841	1,152,712	1,154,547	1,170,002	1,136,198
Plastic Mains	6,365,064	6,374,422	6,374,706	6,379,296	6,379,451	6,380,132	6,380,783	6,381,404	6,381,997	6,382,562	6,408,051	6,446,802	6,386,222
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	2,409,742	2,412,722	2,418,201	2,423,053	2,424,489	2,425,518	2,426,273	2,426,870	2,427,621	2,432,324	2,433,276	2,445,664	2,425,479
Franchises & Consents	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094
Total Assets	15,459,621	15,481,433	15,495,113	15,533,509	15,555,528	15,597,411	15,622,659	15,637,187	15,656,243	15,701,394	15,759,270	15,886,975	15,615,529

NATURAL RESOURCE GAS LIMITED

Accumulated Depreciation Property, Plant and Equipment
2006 Actual
($'s)

Accumulated Depreciation	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	0	0	0	0	0	0	0	0	0	0	0	0	0
Buildings	77,956	79,219	80,481	81,743	83,006	84,268	85,530	86,792	88,055	89,317	90,579	91,211	84,846
Furniture & Fixtures	24,773	25,077	25,381	25,685	25,989	26,292	26,596	26,900	27,204	27,508	27,812	27,964	26,432
Computer Equipment	91,665	92,701	93,736	94,772	95,808	96,843	97,879	98,915	99,950	100,986	102,022	102,539	97,318
Computer Software	96,889	97,560	98,231	98,902	99,573	100,244	100,915	101,586	102,257	102,927	103,598	103,934	100,551
Machinery & Equipment	273,364	276,321	279,278	282,235	285,193	288,150	291,107	294,064	297,022	299,979	302,936	304,415	289,505
Communication Equipment	13,918	14,279	14,640	15,000	15,361	15,722	16,083	16,444	16,805	17,166	17,526	17,707	15,888
Automotive	83,284	87,046	90,809	94,571	98,333	102,096	105,858	109,620	113,383	117,145	120,907	122,788	103,820
Rental Equipment - Res	661,946	664,637	667,328	670,019	672,710	675,401	678,092	680,783	683,475	686,166	688,857	690,202	676,635
Rental Equipment - Com	16,192	16,305	16,418	16,532	16,645	16,758	16,872	16,985	17,098	17,212	17,325	17,382	16,810
Rental Equipment - Softeners	3,797	3,858	3,918	3,979	4,040	4,100	4,161	4,221	4,282	4,342	4,403	4,433	4,128
Meters	684,339	689,884	695,429	700,974	706,519	712,065	717,610	723,155	728,700	734,245	739,790	742,563	714,606
Regulators	569,290	572,916	576,541	580,167	583,792	587,418	591,044	594,669	598,295	601,920	605,546	607,358	589,080
Plastic Mains	1,931,730	1,949,237	1,966,744	1,984,252	2,001,759	2,019,267	2,036,774	2,054,281	2,071,789	2,089,296	2,106,804	2,115,557	2,027,291
Steel Mains	23,763	24,133	24,503	24,873	25,243	25,613	25,983	26,353	26,723	27,093	27,463	27,648	25,783
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	1,363,505	1,370,274	1,377,043	1,383,812	1,390,581	1,397,350	1,404,119	1,410,888	1,417,657	1,424,426	1,431,195	1,434,579	1,400,452
Franchises & Consents	72,612	73,218	73,824	74,430	75,036	75,642	76,248	76,853	77,459	78,065	78,671	78,974	75,919
Total Accum. Depreciation	5,989,025	6,036,666	6,084,306	6,131,947	6,179,588	6,227,229	6,274,870	6,322,511	6,370,152	6,417,793	6,465,434	6,489,254	6,249,064

NATURAL RESOURCE GAS LIMITED

Net Property, Plant and Equipment
2006 Actual
($'s)

Net Fixed Asset Values	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	604,374	603,112	601,850	600,588	599,325	598,063	596,801	595,538	594,276	593,014	591,751	591,120	597,485
Furniture & Fixtures	28,416	28,112	27,808	27,629	27,331	27,032	26,733	26,434	26,135	25,836	25,828	25,866	26,930
Computer Equipment	14,237	16,974	18,072	17,331	16,595	16,637	15,940	18,157	20,511	18,254	17,612	21,236	17,630
Computer Software	9,629	8,958	8,676	8,022	8,043	14,475	14,977	14,692	14,389	14,069	13,733	22,968	12,720
Machinery & Equipment	93,323	90,366	87,409	88,802	86,907	88,066	85,503	82,922	80,324	77,710	75,080	77,039	84,455
Communication Equipment	27,435	27,074	26,713	26,487	26,132	25,778	25,422	25,067	25,556	26,833	26,657	32,393	26,795
Automotive	370,540	364,802	359,154	353,591	348,110	342,707	337,379	332,122	326,933	321,809	334,474	327,910	343,294
Rental Equipment - Res	1,086,595	1,087,955	1,089,928	1,092,487	1,095,604	1,099,254	1,103,413	1,108,058	1,113,166	1,118,718	1,124,692	1,135,406	1,104,606
Rental Equipment - Com	38,715	38,472	39,362	39,182	39,005	38,831	38,659	38,685	38,527	38,372	38,218	37,739	38,648
Rental Equipment - Softeners	8,167	7,938	7,870	7,802	7,734	7,667	7,600	7,533	7,467	7,401	7,335	7,249	7,647
Meters	1,006,007	1,000,839	995,716	1,006,655	1,014,842	1,016,911	1,026,322	1,023,057	1,022,461	1,038,980	1,036,454	1,064,635	1,021,073
Regulators	544,153	544,075	541,648	542,196	539,182	551,174	549,299	546,706	544,546	550,792	549,001	562,644	547,118
Plastic Mains	4,433,334	4,425,185	4,407,962	4,395,044	4,377,692	4,360,866	4,344,009	4,327,122	4,310,208	4,293,266	4,301,247	4,331,245	4,358,931
Steel Mains	9,251	8,881	8,511	8,141	7,771	7,401	7,031	6,661	6,291	5,921	5,551	5,366	7,231
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	1,046,237	1,042,447	1,041,158	1,039,241	1,033,908	1,028,168	1,022,155	1,015,982	1,009,964	1,007,898	1,002,081	1,011,085	1,025,027
Franchises & Consents	78,481	77,875	77,269	76,664	76,058	75,452	74,846	74,240	73,634	73,028	72,423	72,120	75,175
Net Fixed Assets	9,470,597	9,444,767	9,410,807	9,401,561	9,375,939	9,370,182	9,347,789	9,314,676	9,286,091	9,283,601	9,293,837	9,397,721	9,366,465

NATURAL RESOURCE GAS LIMITED

Allowance for Working Capital
2006 Actual
($'s)

Allowance for Working Capi	Inventory	Cash Working Capital	Security Deposits	Total Allowance
October	138,429	-230,615	-106,465	-198,651
November	183,301	-230,615	-109,893	-157,207
December	221,349	-230,615	-113,425	-122,692
January	223,541	-230,615	-113,893	-120,967
February	217,362	-230,615	-112,841	-126,094
March	215,887	-230,615	-111,646	-126,375
April	208,019	-230,615	-109,116	-131,713
May	208,364	-230,615	-108,987	-131,238
June	232,554	-230,615	-129,110	-127,171
July	247,214	-230,615	-172,072	-155,474
August	256,450	-230,615	-216,599	-190,764
September	211,848	-230,615	-259,029	-277,796
Total	213,693	-230,615	-138,590	-155,512

NATURAL RESOURCE GAS LIMITED

Cash Requirements for Working Capital
2006 Actual
($'s)

	Annual Revenue	Allowance (Days)		
Revenue Lag				
Rate 1	10,830,482	31.1		
Rate 2	1,504,852	31.4		
Rate 3	900,285	32.2		
Rate 4	165,160	32.2		
Rate 5	350,648	35.5		
Rate 6	0	32.2		
Weighted Revenue Lag		31.3		
Expense Lag	Annual Expense	Allowance (Days)	Net Lag (Days)	Cash Need
Gas Costs				
- Local Production A (Affiliate)	4,110,774	45.6	(14.3)	-161,052
- Local Production B (Other)	71,082	32.0	(0.7)	-136
- Dawn Deliveries	1,645,579	32.5	(1.2)	-5,410
- Parkway Deliveries	3,635,125	40.3	(9.0)	-89,633
- Western Deliveries	1,351	36.4	(5.1)	-19
- Ontario Delivered	211	32.8	(1.5)	-1
-TCPL	1,879	40.5	(9.2)	-47
- Union Gas	424,381	34.2	(2.9)	-3,372
Weighted Gas Cost Lag		40.9		-259,670
O & M Costs				
- Prepaid Insurance	24,948	(90.4)	121.7	8,318
- Labour	268,535	10.0	21.3	15,671
- Labour Related Costs	115,086	10.0	21.3	6,716
- Other Costs	938,040	30.0	1.3	3,341
Weighted O & M Cost Lag		22.1		34,046
GST Costs				
- Revenues	-825,086	30.9		-69,850
- O & M Expenses	56,002	15.6		2,394
- Capital Expenditures	57,912	15.6		2,475
- Gas Costs	593,395	36.9		59,990
Weighted GST Lag		15.5		-4,991
Total Working Cash Requirement				-230,615

NATURAL RESOURCE GAS LIMITED

Summary of Utility Rate Base
2007 Actual
($'s)

	Actual 2007	Last Year 2006
Property, Plant & Equipment		
Asset Values at Cost	16,236,261	15,615,529
Accumulated Depreciation	6,814,942	6,249,064
	9,421,319	9,366,465
Allowance for Working Capital		
Inventory	194,201	213,693
Working Cash Allowance	-136,860	-230,615
Security Deposits	-457,405	-138,590
	-400,064	-155,512
Utility Rate Base	9,021,255	9,210,953

	Variance from 2006
Property, Plant & Equipment	
Asset Values at Cost	620,732
Accumulated Depreciation	565,878
	54,854
Allowance for Working Capital	
Inventory	-19,492
Working Cash Allowance	93,755
Security Deposits	-318,815
	-244,552
Utility Rate Base	-189,698

NATURAL RESOURCE GAS LIMITED

Utility Capital Expenditures
2007 Actual
($'s)

	Actual 2007	Actual 2006
Mains - Additions	403,643	125,468
- Replacements	0	0
Services - Additions	50,874	50,146
- Replacements	0	0
New Steel Mains	0	0
Meters	78,939	149,944
Regulators	16,317	72,199
Franchises	0	0
Land	0	0
Buildings	0	0
Furniture & Fixtures	864	831
Computer Equipment	18,270	21,852
Computer Software	0	29,954
Machinery & Equipment	8,816	18,205
Communication Equipment	7,137	14,665
Automotive	45,196	35,661
Water Softeners	0	-338
Rental Water Heaters	237,721	213,103
Total Capital Expenditures	867,777	731,689

	Variance from 2006
Mains - Additions	278,175
- Replacements	0
Services - Additions	728
- Replacements	0
New Steel Mains	0
Meters	-71,005
Regulators	-55,882
Franchises	0
Land	0
Buildings	0
Furniture & Fixtures	33
Computer Equipment	-3,583
Computer Software	-29,954
Machinery & Equipment	-9,389
Communication Equipment	-7,528
Automotive	9,535
Water Softeners	338
Rental Water Heaters	24,618
Total Capital Expenditures	136,087

NATURAL RESOURCE GAS LIMITED

Capital Projects
2007
($'s)

Description	Cost
Main Additions	
Best Line - West of Culloden	19,651
James Line down Richmond Road	41,247
Richmond Road for Walker Barn	24,501
Best Line Loop to Corinth	25,732
Seville to Richmond	173,880
Other main Extensions	118,932
Total Main Additions	403,943
Main Replacements	
No Replacements	0
Total Main Replacements	0
Service Additions	
Service additions	50,874
Total Service Additions	50,874
Service Replacements	
Service replacements	0
Total Service Replacements	0
Summary	
Total Main Additions	403,943
Total Main Replacements	0
Total Mains	403,943
Total Service Additions	50,874
Total Service Replacements	0
Total Services	50,874
Total Capital Projects	454,817

NATURAL RESOURCE GAS LIMITED

Aggregate Cost/Benefit Ratio for Main Additions
2007 Actual
($'s)

NRGL will file at a later date.

NATURAL RESOURCE GAS LIMITED

Financial Tests
2007 Actual

NRGL will file at a later date

NATURAL RESOURCE GAS LIMITED

Property, Plant & Equipment
Summary of Averages - 2007 Actual
($'s)

Item	Gross Property Plant & Equip.	Accumulated Depreciation	Net Plant
Land	71,700	0	71,700
Buildings	682,331	99,994	582,337
Furniture & Fixtures	54,252	30,109	24,143
Computer Equipment	134,221	110,794	23,427
Computer Software	136,472	107,736	28,736
Machinery & Equipment	390,114	325,430	64,684
Communication Equipment	56,761	20,515	36,246
Automotive	462,189	154,551	307,638
Rental Equipment - Res	1,870,691	685,842	1,184,849
Rental Equipment - Com	54,699	19,617	35,082
Rental Equipment - Softeners	11,627	4,855	6,772
Meters	1,865,744	782,685	1,083,059
Regulators	1,191,354	632,908	558,446
Plastic Mains	6,598,021	2,244,221	4,353,800
Steel Mains	33,014	30,223	2,791
New Steel Mains	0	0	0
Plastic Services	2,471,977	1,482,272	989,705
Franchises & Consents	151,094	83,190	67,904
Total	16,236,261	6,814,942	9,421,319

NATURAL RESOURCE GAS LIMITED

Gross Property, Plant and Equipment
2007 Actual
($'s)

Asset Values at Cost	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331
Furniture & Fixtures	54,020	54,020	54,020	54,020	54,020	54,020	54,236	54,462	54,481	54,500	54,517	54,701	54,252
Computer Equipment	127,916	127,916	130,122	130,222	130,318	135,599	135,922	136,762	137,080	137,384	138,883	142,534	134,221
Computer Software	136,472	136,472	136,472	136,472	136,472	136,472	136,472	136,472	136,472	136,472	136,472	136,472	136,472
Machinery & Equipment	389,151	389,344	389,529	389,248	389,395	389,536	390,278	390,434	390,583	390,725	390,861	392,285	390,114
Communication Equipment	56,017	56,017	56,017	56,017	56,017	56,017	56,017	56,017	56,017	56,017	59,586	61,370	56,761
Automotive	444,950	443,837	465,872	465,908	465,942	465,974	466,005	465,535	465,540	465,545	465,550	465,603	462,189
Rental Equipment - Res	1,830,664	1,823,343	1,854,865	1,861,674	1,866,729	1,873,156	1,876,439	1,882,100	1,887,727	1,895,822	1,894,740	1,901,029	1,870,691
Rental Equipment - Com	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699
Rental Equipment - Softeners	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627
Meters	1,838,152	1,843,225	1,845,387	1,845,857	1,860,861	1,865,638	1,866,724	1,871,375	1,881,949	1,883,479	1,885,157	1,901,124	1,865,744
Regulators	1,186,192	1,187,702	1,187,801	1,187,896	1,188,920	1,190,873	1,192,113	1,192,357	1,193,524	1,195,007	1,195,315	1,198,544	1,191,354
Plastic Mains	6,485,554	6,486,554	6,489,921	6,496,200	6,496,662	6,593,991	6,598,816	6,603,422	6,698,742	6,707,262	6,716,353	6,802,775	6,598,021
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	2,458,052	2,462,881	2,464,770	2,466,096	2,466,416	2,470,172	2,472,196	2,475,127	2,476,101	2,477,264	2,480,124	2,494,525	2,471,977
Franchises & Consents	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094
Total Assets	16,011,605	16,015,777	16,079,242	16,094,076	16,116,217	16,235,914	16,249,684	16,268,527	16,382,682	16,403,944	16,422,021	16,555,426	16,236,261

NATURAL RESOURCE GAS LIMITED

Accumulated Depreciation Property, Plant and Equipment
2007 Actual
($'s)

Accumulated Depreciation	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	0	0	0	0	0	0	0	0	0	0	0	0	0
Buildings	93,104	94,366	95,629	96,891	98,153	99,416	100,678	101,940	103,203	104,465	105,727	106,358	99,994
Furniture & Fixtures	28,424	28,733	29,042	29,351	29,659	29,968	30,277	30,585	30,894	31,203	31,512	31,666	30,109
Computer Equipment	104,255	105,453	106,651	107,849	109,047	110,245	111,443	112,640	113,838	115,036	116,234	116,833	110,794
Computer Software	104,806	105,343	105,879	106,416	106,953	107,490	108,026	108,563	109,100	109,636	110,173	110,442	107,736
Machinery & Equipment	308,919	311,944	314,969	317,994	321,018	324,043	327,068	330,093	333,118	336,143	339,168	340,681	325,430
Communication Equipment	18,294	18,701	19,108	19,515	19,921	20,328	20,735	21,142	21,549	21,955	22,362	22,566	20,515
Automotive	129,296	133,923	138,550	143,177	147,804	152,431	157,057	161,684	166,311	170,938	175,565	177,878	154,551
Rental Equipment - Res	690,664	689,781	688,897	688,014	687,130	686,247	685,363	684,480	683,596	682,713	681,829	681,387	685,842
Rental Equipment - Com	17,776	18,113	18,450	18,788	19,125	19,462	19,800	20,137	20,474	20,811	21,149	21,317	19,617
Rental Equipment - Softeners	4,524	4,585	4,645	4,706	4,766	4,827	4,887	4,948	5,008	5,069	5,130	5,160	4,855
Meters	751,118	756,902	762,685	768,468	774,251	780,034	785,818	791,601	797,384	803,167	808,951	811,842	782,685
Regulators	612,847	616,522	620,197	623,873	627,548	631,224	634,899	638,575	642,250	645,925	649,601	651,439	632,908
Plastic Mains	2,142,878	2,161,444	2,180,011	2,198,578	2,217,145	2,235,711	2,254,278	2,272,845	2,291,412	2,309,978	2,328,545	2,337,828	2,244,221
Steel Mains	28,203	28,573	28,943	29,313	29,683	30,054	30,424	30,794	31,164	31,534	31,904	32,089	30,223
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	1,444,411	1,451,347	1,458,284	1,465,220	1,472,157	1,479,093	1,486,030	1,492,966	1,499,903	1,506,839	1,513,776	1,517,244	1,482,272
Franchises & Consents	79,883	80,489	81,095	81,700	82,306	82,912	83,518	84,124	84,730	85,336	85,942	86,244	83,190
Total Accum. Depreciation	6,559,402	6,606,218	6,653,035	6,699,851	6,746,668	6,793,484	6,840,300	6,887,117	6,933,933	6,980,750	7,027,566	7,050,975	6,814,942

January-29-10
EB-2010-0018
Exhibit B4
Tab 3
Schedule 4

NATURAL RESOURCE GAS LIMITED

Net Property, Plant and Equipment
2007 Actual
($'s)

Net Fixed Asset Values	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	589,227	587,964	586,702	585,440	584,178	582,915	581,653	580,391	579,128	577,866	576,604	575,972	582,337
Furniture & Fixtures	25,596	25,287	24,979	24,670	24,361	24,052	23,960	23,877	23,587	23,297	23,006	23,035	24,143
Computer Equipment	23,661	22,463	23,471	22,373	21,271	25,354	24,479	24,121	23,242	22,348	22,649	25,701	23,427
Computer Software	31,666	31,130	30,593	30,056	29,519	28,983	28,446	27,909	27,373	26,836	26,299	26,031	28,736
Machinery & Equipment	80,232	77,401	74,560	71,254	68,377	65,493	63,210	60,341	57,464	54,582	51,692	51,604	64,684
Communication Equipment	37,723	37,317	36,910	36,503	36,096	35,689	35,282	34,876	34,469	34,062	37,224	38,805	36,246
Automotive	315,654	309,914	327,322	322,731	318,138	313,544	308,948	303,850	299,229	294,607	289,986	287,724	307,638
Rental Equipment - Res	1,140,000	1,133,562	1,165,968	1,173,660	1,179,598	1,186,909	1,191,076	1,197,620	1,204,131	1,213,110	1,212,911	1,219,642	1,184,849
Rental Equipment - Com	36,923	36,586	36,248	35,911	35,574	35,236	34,899	34,562	34,224	33,887	33,550	33,381	35,082
Rental Equipment - Softeners	7,103	7,042	6,982	6,921	6,861	6,800	6,739	6,679	6,618	6,558	6,497	6,467	6,772
Meters	1,087,034	1,086,323	1,082,702	1,077,389	1,086,609	1,085,604	1,080,907	1,079,774	1,084,565	1,080,312	1,076,206	1,089,281	1,083,059
Regulators	573,345	571,180	567,604	564,023	561,372	559,650	557,214	553,782	551,274	549,082	545,714	547,106	558,446
Plastic Mains	4,342,676	4,325,109	4,309,909	4,297,622	4,279,518	4,358,280	4,344,538	4,330,577	4,407,330	4,397,284	4,387,808	4,464,946	4,353,800
Steel Mains	4,811	4,441	4,071	3,701	3,331	2,961	2,591	2,221	1,851	1,481	1,110	925	2,791
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	1,013,641	1,011,534	1,006,487	1,000,876	994,259	991,079	986,167	982,161	976,198	970,425	966,348	977,281	989,705
Franchises & Consents	71,211	70,605	69,999	69,393	68,787	68,181	67,576	66,970	66,364	65,758	65,152	64,849	67,904
Net Fixed Assets	9,452,203	9,409,558	9,426,208	9,394,225	9,369,549	9,442,430	9,409,384	9,381,410	9,448,748	9,423,194	9,394,455	9,504,452	9,421,319

NATURAL RESOURCE GAS LIMITED

Allowance for Working Capital
Actual 2007
($'s)

Allowance for Working Capital	Inventory	Cash Working Capital	Security Deposits	Total Allowance
October	173,131	-136,860	-311,007	-274,737
November	213,473	-136,860	-360,973	-284,360
December	210,679	-136,860	-392,620	-318,801
January	189,154	-136,860	-411,593	-359,299
February	194,528	-136,860	-427,607	-369,939
March	208,663	-136,860	-445,428	-373,625
April	225,863	-136,860	-462,720	-373,717
May	210,020	-136,860	-478,991	-405,831
June	175,992	-136,860	-501,755	-462,623
July	164,410	-136,860	-533,574	-506,025
August	191,174	-136,860	-568,247	-513,933
September	173,324	-136,860	-594,340	-557,875
Total	194,201	-136,860	-457,405	-400,064

NATURAL RESOURCE GAS LIMITED

Cash Requirements for Working Capital
2007 Actual
($'s)

	Annual Revenue	Allowance (Days)
Revenue Lag		
Rate 1	9,988,505	31.1
Rate 2	740,489	31.4
Rate 3	965,608	32.2
Rate 4	203,534	32.2
Rate 5	512,762	35.5
Rate 6	0	32.2
Weighted Revenue Lag		31.4

Expense Lag	Annual Expense	Allowance (Days)	Net Lag (Days)	Cash Need
Gas Costs				
- Local Production A (Affiliate)	2,606,825	45.6	(14.2)	-101,416
- Local Production B (Other)	36,818	32.0	(0.6)	-61
- Dawn Deliveries	1,061,812	32.5	(1.1)	-3,200
- Parkway Deliveries	2,136,707	40.3	(8.9)	-52,101
- Western Deliveries	805	36.4	(5.0)	-11
- Ontario Delivered	164	32.8	(1.4)	-1
-TCPL	969	40.5	(9.1)	-24
- Union Gas	404,347	34.2	(2.8)	-3,102
Weighted Gas Cost Lag		40.7		-159,916
O & M Costs				
- Prepaid Insurance	52,020	(90.4)	121.8	17,359
- Labour	300,490	10.0	21.4	17,618
- Labour Related Costs	128,781	10.0	21.4	7,550
- Other Costs	542,605	30.0	1.4	2,081
Weighted O & M Cost Lag		15.5		44,608
GST Costs				
- Revenues	-744,654	30.9		-63,041
- O & M Expenses	31,908	15.6		1,364
- Capital Expenditures	52,059	15.6		2,225
- Gas Costs	374,891	36.9		37,900
Weighted GST Lag		27.5		-21,552
Total Working Cash Requirement				-136,860

NATURAL RESOURCE GAS LIMITED

Summary of Utility Rate Base
2007 OEB Approved
($'s)

	OEB Approved 2007	Historic Year 2007
Property, Plant & Equipment		
Asset Values at Cost	16,466,812	16,236,261
Accumulated Depreciation	6,766,744	6,814,942
	9,700,068	9,421,319
Allowance for Working Capital		
Inventory	121,524	194,201
Working Cash Allowance	-38,977	-136,860
Security Deposits	-105,903	-457,405
	-23,356	-400,064
Utility Rate Base	9,676,712	9,021,255

	Variance from Historic Year 2007
Property, Plant & Equipment	
Asset Values at Cost	230,551
Accumulated Depreciation	-48,198
	278,749
Allowance for Working Capital	
Inventory	-72,677
Working Cash Allowance	97,883
Security Deposits	351,502
	376,708
Utility Rate Base	655,457

NATURAL RESOURCE GAS LIMITED

Utility Capital Expenditures
2007 OEB Approved
($'s)

	OEB Approved 2007	Historic Year 2007
Mains - Additions	232,585	403,643
- Replacements	0	0
Services - Additions	91,628	50,874
- Replacements	2,279	0
Line Compressors	0	0
Meters	85,558	78,939
Regulators	43,029	16,317
Franchises	0	0
Land	0	0
Buildings	5,000	0
Furniture & Fixtures	5,000	864
Computer Equipment	9,000	18,270
Computer Software	3,000	0
Machinery & Equipment	15,000	8,816
Communication Equipment	2,000	7,137
Automotive	150,000	45,196
Water Softeners	2,250	0
Rental Water Heaters	183,328	237,721
Total Capital Expenditures	829,657	867,777

	Variance from Historic Year 2007
Mains - Additions	-171,058
- Replacements	0
Services - Additions	40,754
- Replacements	2,279
Line Compressors	0
Meters	6,620
Regulators	26,712
Franchises	0
Land	0
Buildings	5,000
Furniture & Fixtures	4,136
Computer Equipment	-9,270
Computer Software	3,000
Machinery & Equipment	6,184
Communication Equipment	-5,137
Automotive	104,804
Water Softeners	2,250
Rental Water Heaters	-54,393
Total Capital Expenditures	-38,120

NATURAL RESOURCE GAS LIMITED

Capital Projects
2007 OEB Approved
($'s)

Description	Cost
Main Additions	
Putnam Road south of Wilson Line	6,667
Seville to Richmond	114,339
Richmond Road from James to Walker Barns	36,051
Best Line from Highway 3 to PE near Corinth	17,772
Best Line west to Springer Hill Rd	6,725
Townline Rd east of Regional Rd 23	26,031
Small main extensions	25,000
Total Main Additions	232,585
Main Replacements	
No Replacements	0
Total Main Replacements	0
Service Additions	
Service additions - 400	91,628
Total Service Additions	91,628
Service Replacements	
Service replacements - 10	2,279
Total Service Replacements	2,279
Summary	
Total Main Additions	232,585
Total Main Replacements	0
Total Mains	232,585
Total Service Additions	91,628
Total Service Replacements	2,279
Total Services	93,907
Total Capital Projects	326,492

NATURAL RESOURCE GAS LIMITED

Aggregate Cost/Benefit Ratio for Main Additions
2007 OEB Approved
($'s)

Main Additions	NPV of Revenues	NPV of Costs	Project Ratio
Putnam Road south of Wilson Line	13,073	7,859	1.66
Seville to Richmond	215,421	129,356	1.67
Richmond Road from James to Walker Barns	105,200	42,832	2.46
Best Line from Highway 3 to PE near Corinth	33,587	19,660	1.71
Best Line west to Springer Hill Rd	15,451	8,195	1.89
Townline Rd east of Regional Rd 23	42,168	29,877	1.41
Short main extensions (1)	25,000	25,000	1.00
Total Main Additions	449,900	262,779	1.71

(1) An aid to construction is collected for any project with a benefit/cost ratio less than 1.00. As a result, the net present value of these projects in aggregate is at least equal to the net present value of the costs, resulting in a project ratio of at least 1.00.

NATURAL RESOURCE GAS LIMITED

Property, Plant & Equipment
Summary of Averages - 2007 OEB Approved
($'s)

Item	Gross Property Plant & Equip.	Accumulated Depreciation	Net Plant
Land	71,700	0	71,700
Buildings	689,831	99,638	590,193
Furniture & Fixtures	60,689	30,529	30,160
Computer Equipment	109,124	85,571	23,553
Computer Software	122,519	96,663	25,856
Machinery & Equipment	370,887	311,585	59,302
Communication Equipment	229,053	40,077	188,976
Automotive	477,959	103,682	374,277
Rental Equipment - Res	1,869,664	735,461	1,134,203
Rental Equipment - Com	57,688	18,471	39,217
Rental Equipment - Softeners	15,274	5,133	10,141
Meters	1,890,925	780,697	1,110,228
Regulators	1,175,829	630,000	545,829
Plastic Mains	6,602,972	2,235,007	4,367,965
Steel Mains	33,014	30,053	2,961
Line Compressor	0	0	0
Plastic Services	2,538,589	1,481,265	1,057,324
Franchises & Consents	151,094	82,912	68,182
Total	16,466,811	6,766,744	9,700,067

NATURAL RESOURCE GAS LIMITED

Gross Property, Plant and Equipment
2007 OEB Approved
($'s)

Asset Values at Cost	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	687,539	687,956	688,372	688,789	689,206	689,622	690,039	690,456	690,872	691,289	691,706	692,122	689,831
Furniture & Fixtures	58,398	58,814	59,231	59,648	60,064	60,481	60,898	61,314	61,731	62,148	62,564	62,981	60,689
Computer Equipment	109,582	109,499	109,416	109,332	109,249	109,166	109,082	108,999	108,916	108,832	108,749	108,666	109,124
Computer Software	123,435	123,269	123,102	122,935	122,769	122,602	122,435	122,269	122,102	121,935	121,769	121,602	122,519
Machinery & Equipment	368,595	369,012	369,429	369,845	370,262	370,679	371,095	371,512	371,929	372,345	372,762	373,179	370,887
Communication Equipment	228,136	228,303	228,469	228,636	228,803	228,969	229,136	229,303	229,469	229,636	229,803	229,969	229,053
Automotive	471,358	472,558	473,758	474,959	476,159	477,359	478,560	479,760	480,960	482,161	483,361	484,561	477,959
Rental Equipment - Res	1,824,393	1,832,624	1,840,855	1,849,086	1,857,318	1,865,549	1,873,780	1,882,011	1,890,242	1,898,473	1,906,704	1,914,935	1,869,664
Rental Equipment - Com	57,433	57,480	57,526	57,572	57,618	57,665	57,711	57,757	57,803	57,850	57,896	57,942	57,688
Rental Equipment - Softeners	14,242	14,430	14,617	14,805	14,992	15,180	15,367	15,555	15,742	15,930	16,117	16,305	15,274
Meters	1,851,710	1,858,840	1,865,970	1,873,100	1,880,230	1,887,360	1,894,490	1,901,619	1,908,749	1,915,879	1,923,009	1,930,139	1,890,925
Regulators	1,156,108	1,159,693	1,163,279	1,166,865	1,170,451	1,174,036	1,177,622	1,181,208	1,184,794	1,188,379	1,191,965	1,195,551	1,175,829
Plastic Mains	6,525,070	6,529,276	6,533,482	6,537,688	6,541,894	6,546,099	6,550,305	6,611,681	6,675,556	6,702,787	6,733,381	6,748,450	6,602,972
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
Line Compressors	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	2,496,006	2,503,749	2,511,491	2,519,233	2,526,975	2,534,718	2,542,460	2,550,202	2,557,944	2,565,687	2,573,429	2,581,171	2,538,589
Franchises & Consents	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094	151,094
Total Assets	16,227,815	16,261,311	16,294,806	16,328,302	16,361,797	16,395,293	16,428,788	16,519,453	16,612,618	16,669,140	16,729,023	16,773,381	16,466,811

NATURAL RESOURCE GAS LIMITED

Accumulated Depreciation Property, Plant and Equipment
2007 OEB Approved
($'s)

Accumulated Depreciation	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	0	0	0	0	0	0	0	0	0	0	0	0	0
Buildings	92,594	93,874	95,155	96,436	97,717	98,998	100,279	101,559	102,840	104,121	105,402	106,683	99,638
Furniture & Fixtures	28,575	28,930	29,286	29,641	29,996	30,352	30,707	31,063	31,418	31,773	32,129	32,484	30,529
Computer Equipment	86,844	86,613	86,381	86,150	85,918	85,687	85,455	85,223	84,992	84,760	84,529	84,297	85,571
Computer Software	96,677	96,675	96,672	96,669	96,667	96,664	96,661	96,659	96,656	96,653	96,651	96,648	96,663
Machinery & Equipment	300,390	302,425	304,461	306,496	308,532	310,567	312,603	314,638	316,674	318,709	320,745	322,780	311,585
Communication Equipment	31,926	33,408	34,890	36,372	37,854	39,336	40,818	42,300	43,782	45,264	46,746	48,228	40,077
Automotive	118,376	115,704	113,032	110,361	107,689	105,018	102,346	99,674	97,003	94,331	91,660	88,988	103,682
Rental Equipment - Res	704,748	710,332	715,916	721,501	727,085	732,669	738,253	743,837	749,421	755,006	760,590	766,174	735,461
Rental Equipment - Com	18,338	18,362	18,386	18,411	18,435	18,459	18,483	18,507	18,531	18,555	18,579	18,603	18,471
Rental Equipment - Softeners	4,664	4,749	4,835	4,920	5,005	5,091	5,176	5,262	5,347	5,432	5,518	5,603	5,133
Meters	748,613	754,447	760,280	766,113	771,947	777,780	783,613	789,447	795,280	801,113	806,947	812,780	780,697
Regulators	609,859	613,521	617,183	620,845	624,507	628,169	631,831	635,493	639,155	642,816	646,478	650,140	630,000
Plastic Mains	2,134,687	2,152,927	2,171,167	2,189,407	2,207,647	2,225,887	2,244,127	2,262,367	2,280,607	2,298,847	2,317,087	2,335,327	2,235,007
Steel Mains	28,018	28,388	28,758	29,128	29,498	29,868	30,238	30,608	30,978	31,348	31,718	32,088	30,053
Line Compressors	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	1,442,269	1,449,359	1,456,449	1,463,539	1,470,630	1,477,720	1,484,810	1,491,900	1,498,990	1,506,080	1,513,171	1,520,261	1,481,265
Franchises & Consents	79,580	80,186	80,792	81,397	82,003	82,609	83,215	83,821	84,427	85,033	85,638	86,244	82,912
Total Accum. Depreciation	6,526,157	6,569,900	6,613,643	6,657,385	6,701,128	6,744,871	6,788,614	6,832,357	6,876,099	6,919,842	6,963,585	7,007,328	6,766,744

NATURAL RESOURCE GAS LIMITED

Net Property, Plant and Equipment
2007 OEB Approved
($'s)

Net Fixed Asset Values	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	594,945	594,081	593,217	592,353	591,489	590,625	589,760	588,896	588,032	587,168	586,304	585,440	590,193
Furniture & Fixtures	29,823	29,884	29,945	30,007	30,068	30,129	30,190	30,252	30,313	30,374	30,435	30,497	30,160
Computer Equipment	22,738	22,886	23,034	23,183	23,331	23,479	23,627	23,776	23,924	24,072	24,220	24,369	23,553
Computer Software	26,758	26,594	26,430	26,266	26,102	25,938	25,774	25,610	25,446	25,282	25,118	24,954	25,856
Machinery & Equipment	68,206	66,587	64,968	63,349	61,730	60,112	58,493	56,874	55,255	53,636	52,017	50,399	59,302
Communication Equipment	196,210	194,894	193,579	192,264	190,949	189,633	188,318	187,003	185,688	184,372	183,057	181,742	188,976
Automotive	352,982	356,854	360,726	364,598	368,470	372,342	376,214	380,086	383,957	387,829	391,701	395,573	374,277
Rental Equipment - Res	1,119,645	1,122,292	1,124,939	1,127,586	1,130,233	1,132,880	1,135,527	1,138,174	1,140,821	1,143,468	1,146,114	1,148,761	1,134,203
Rental Equipment - Com	39,095	39,117	39,139	39,162	39,184	39,206	39,228	39,250	39,272	39,294	39,317	39,339	39,217
Rental Equipment - Softeners	9,579	9,681	9,783	9,885	9,987	10,089	10,191	10,293	10,395	10,497	10,600	10,702	10,141
Meters	1,103,097	1,104,393	1,105,690	1,106,986	1,108,283	1,109,580	1,110,876	1,112,173	1,113,469	1,114,766	1,116,062	1,117,359	1,110,228
Regulators	546,249	546,172	546,096	546,020	545,944	545,868	545,791	545,715	545,639	545,563	545,487	545,410	545,829
Plastic Mains	4,390,383	4,376,349	4,362,315	4,348,281	4,334,247	4,320,213	4,306,179	4,349,314	4,394,949	4,403,941	4,416,295	4,413,123	4,367,965
Steel Mains	4,997	4,627	4,257	3,887	3,517	3,147	2,777	2,407	2,037	1,667	1,297	927	2,961
Line Compressors	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	1,053,737	1,054,390	1,055,042	1,055,694	1,056,346	1,056,998	1,057,650	1,058,302	1,058,954	1,059,606	1,060,258	1,060,910	1,057,324
Franchises & Consents	71,514	70,908	70,302	69,696	69,090	68,484	67,879	67,273	66,667	66,061	65,455	64,849	68,182
Net Fixed Assets	9,701,658	9,691,411	9,681,163	9,670,916	9,660,669	9,650,422	9,640,175	9,687,097	9,736,519	9,749,297	9,765,438	9,766,053	9,700,067

NATURAL RESOURCE GAS LIMITED

Allowance for Working Capital
2007 OEB Approved
($'s)

Allowance for Working Capital	Inventory	Cash Working Capital	Security Deposits	Total Allowance
October	121,524	-38,977	-105,903	-23,356
November	121,524	-38,977	-105,903	-23,356
December	121,524	-38,977	-105,903	-23,356
January	121,524	-38,977	-105,903	-23,356
February	121,524	-38,977	-105,903	-23,356
March	121,524	-38,977	-105,903	-23,356
April	121,524	-38,977	-105,903	-23,356
May	121,524	-38,977	-105,903	-23,356
June	121,524	-38,977	-105,903	-23,356
July	121,524	-38,977	-105,903	-23,356
August	121,524	-38,977	-105,903	-23,356
September	121,524	-38,977	-105,903	-23,356
Total	121,524	-38,977	-105,903	-23,356

NATURAL RESOURCE GAS LIMITED

Cash Requirements for Working Capital
2007 OEB Approved
($'s)

	Annual Revenue	Allowance (Days)		
Revenue Lag				
Rate 1	10,566,820	31.1		
Rate 2	549,769	31.4		
Rate 3	689,969	32.2		
Rate 4	205,315	32.2		
Rate 5	360,480	35.5		
Weighted Revenue Lag		31.3		
Expense Lag	Annual Expense	Allowance (Days)	Net Lag (Days)	Cash Need
Gas Costs				
- Local Production A (Affiliate)	2,856,862	45.6	(14.3)	-111,926
- Local Production B (Other)	88,016	32.0	(0.7)	-169
- Dawn Deliveries	0	32.5	(1.2)	0
- Parkway Deliveries	2,832,849	40.3	(9.0)	-69,851
- Western Deliveries	1,245,708	36.4	(5.1)	-17,406
- Ontario Delivered	0	32.8	(1.5)	0
-TCPL	135,141	40.5	(9.2)	-3,406
- Union Gas	448,432	34.2	(2.9)	-3,563
Weighted Gas Cost Lag		41.2		-206,321
O & M Costs				
- Prepaid Insurance	273,911	(90.4)	121.7	91,329
- Labour	794,396	10.0	21.3	46,358
- Labour Related Costs	340,455	10.0	21.3	19,868
- Other Costs	1,404,851	30.0	1.3	5,004
Weighted O & M Cost Lag		10.2		162,559
GST Costs				
- Revenues	-742,341	30.9		-62,845
- O & M Expenses	64,225	15.6		2,745
- Capital Expenditures	49,779	15.6		2,128
- Gas Costs	456,420	36.9		46,142
Weighted GST Lag		25.1		-11,830
Total Working Cash Requirement				-55,592

NATURAL RESOURCE GAS LIMITED

Summary of Utility Rate Base
2008 Actual
($'s)

	Actual 2008	Last Year 2007
Property, Plant & Equipment		
Asset Values at Cost	16,891,153	16,236,261
Accumulated Depreciation	7,429,630	6,814,942
	9,461,523	9,421,319
Allowance for Working Capital		
Inventory	275,332	194,201
Working Cash Allowance	-126,297	-136,860
Security Deposits	-739,483	-457,405
	-590,448	-400,064
Utility Rate Base	8,871,075	9,021,255

	Variance from 2007
Property, Plant & Equipment	
Asset Values at Cost	654,892
Accumulated Depreciation	614,688
	40,204
Allowance for Working Capital	
Inventory	81,131
Working Cash Allowance	10,563
Security Deposits	-282,078
	-190,384
Utility Rate Base	-150,180

NATURAL RESOURCE GAS LIMITED

Utility Capital Expenditures
2008 Actual
($'s)

	Actual 2008	Actual 2007
Mains - Additions	346,658	403,643
- Replacements	0	0
Services - Additions	133,927	50,874
- Replacements	0	0
New Steel Mains	0	0
Meters	85,175	78,939
Regulators	10,383	16,317
Franchises	0	0
Land	0	0
Buildings	0	0
Furniture & Fixtures	242	864
Computer Equipment	11,879	18,270
Computer Software	8,575	0
Machinery & Equipment	6,417	8,816
Communication Equipment	56,133	7,137
Automotive	0	45,196
Water Softeners	0	0
Rental Water Heaters	245,961	237,721
Total Capital Expenditures	905,350	867,777

	Variance from 2007
Mains - Additions	-56,985
- Replacements	0
Services - Additions	83,052
- Replacements	0
New Steel Mains	0
Meters	6,236
Regulators	-5,934
Franchises	0
Land	0
Buildings	0
Furniture & Fixtures	-622
Computer Equipment	-6,391
Computer Software	8,575
Machinery & Equipment	-2,400
Communication Equipment	48,996
Automotive	-45,196
Water Softeners	0
Rental Water Heaters	8,241
Total Capital Expenditures	37,573

NATURAL RESOURCE GAS LIMITED

Capital Projects
2008
($'s)

Description	Cost
Main Additions	
Seville to Richmond 4" gas line installation	134,519
Richmond Road from James to Walker Barns 2 " gas line installation	45,372
Best Line - East of Culloden Rd Hwy 3 to Corinth 2" gas line installation	28,305
Best Line - West of Culloden Rd to Springer Hill 2" gas line installation	21,616
Richmond Road to Walker Barn	26,951
Small main extensions	89,895
Total Main Additions	346,658
Main Replacements	
No Replacements	0
Total Main Replacements	0
Service Additions	
Service additions	133,927
Total Service Additions	133,927
Service Replacements	
Service replacements	0
Total Service Replacements	0
Summary	
Total Main Additions	346,658
Total Main Replacements	0
Total Mains	346,658
Total Service Additions	133,927
Total Service Replacements	0
Total Services	133,927
Total Capital Projects	480,585

NATURAL RESOURCE GAS LIMITED

Aggregate Cost/Benefit Ratio for Main Additions
2008 Actual
($'s)

Main Additions	NPV of Revenues	NPV of Costs	Project Ratio
Seville to Richmond 4" gas line installation	27,691	108,190	0.26
Richmond Road from James to Walker Barns 2 " gas line in:	5,353	32,230	0.17
Best Line - East of Culloden Rd Hwy 3 to Corinth 2" gas line	-2,333	12,940	-0.18
Best Line - West of Culloden Rd to Springer Hill 2" gas line	2,135	12,610	0.17
Richmond Road to Walker Barn	30,734	15,530	1.98
Total Main Additions	63,580	181,500	0.35

(1) An aid to construction may be collected for any project with a benefit/cost ratio less than 1.00.

NATURAL RESOURCE GAS LIMITED

Financial Tests
2008 Actual

Attached

NATURAL RESOURCE GAS LIMITED **UPDATED** **March 8th, 2010**
Aid to Construct Calculator

Project Description:	**Project # 1 Seville to Richmond**
Planned for Fiscal:	
Date of Last Test:	**work 2007**
Nature of Project (MA, MR)	

Size	**Description**	**Quantity**	**Unit of Measure**	**Price**	**Total**
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 16.40	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	3,400	m	$ 5.83	19,822
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	3,740	m	$ 0.22	823
				Total	20,645

	Hours	**Hourly Rate**	**Total**
Labour			
	-	25.40	-
	-	25.40	-
	-	25.40	-
		Total	-

Capitalized Equipment	**Hours**	**Hourly Rate**	**Total**
Trucks	-	$ 4.90	-
Generator	-	$ 1.50	-
Trencher	-	$ 39.00	-
Compressor	-	$ 3.60	-
Kubota	-	$ 2.20	-
Plow	-	$ 22.10	-
		Total	-

Capitalized Depreciation	**Hours**	**Hourly Rate**	**Total**
Trucks	-	$ 1.20	-
Generator	-	$ 0.50	-
Trencher	-	$ -	-
Compressor	-	$ 4.20	-
Kubota	-	$ 4.80	-
Plow	-	$ 26.50	-
		Total	-

Subcontractors & Rentals	**Unit of Measure**	**Units**	**Hourly Rate**	**Total**
Lumpsum	m	1	$ 101,645.00	101,645
		-	$ -	-
			Total	101,645

Total Cost		**$ 122,290**
Contingency	10%	12,229
Total Project Cost		**$ 134,519**
Cost per Meter		$ 36.00
Benefit Cost Ratio		0
Aid to Construction		$ 80,499
Aid to Const (each)		$ 16,100
Payback (Years)		30

		Year					
Expected Customer Additions	**Potential**	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	10	3	2	-	-	-	5
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Project # 1 Seville to Richmond**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	3	2	-	-	-	5
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	3,400
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	3,740

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	108,190
NPV of revenue plus tax shield	27,691
AID TO CONSTRUCTION	80,499
BENEFIT/COST RATIO	0.256
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Project # 1 Seville to Richmond**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	-	-	-	-	-	-
Subcontractor & Rental Equipment						
Subcontractor	101,645					101,645
Contingency	12,229					12,229
Sub-total	113,874	-	-	-	-	113,874
Service Cost	570	380	-	-	-	950
Sub-total	570	380	-	-	-	950
Class 2 Pipelines	114,444	380	-	-	-	114,824
Meters & Regulators	503	335	-	-	-	838
Class 8 Equipment	503	335	-	-	-	838
Total Project Cost	114,946	715	-	-	-	115,661
NPV of Project Cost	$108,190					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 25,830	$ 211

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Project # 1 Seville to Richmond**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	6,000	4,000	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**6,000**	**4,000**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	6,000	10,000	10,000	10,000	10,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	6,000	**10,000**	**10,000**	**10,000**	**10,000**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	3	5	5	5	5
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Project # 1 Seville to Richmond**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

		Year					
Gas Sales Revenues ($)		**1**	**2**	**3**	**4**	**5**	
Residential		917	1,529	1,529	1,529	1,529	
Commercial		-	-	-	-	-	
Industrial Rate 1		-	-	-	-	-	
Industrial Rate 4		-	-	-	-	-	
Seasonal		-	-	-	-	-	
Industrial Rate 3 - Firm		-	-	-	-	-	
Industrial Rate 3 - Interruptible		-	-	-	-	-	
Sub-Total		917	1,529	1,529	1,529	1,529	
Plus: Fixed Revenue		-	-	-	-	-	
Sub-Total		-	-	-	-	-	
Less: M9 Delivery Costs		32	54	54	54	54	
Less: O&M Expense		-	-	-	-	-	
Less: Capital Tax		345	347	347	347	347	
Less Property Tax		884	884	884	884	884	
Sub-Total		1,261	1,285	1,285	1,285	1,285	
Pre Tax Revenue	-	344	244	244	244	244	
Less: Income Tax	-	119	85	85	85	85	
Net Revenue	-	225	160	160	160	160	160

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Project # 1 Seville to Richmond

Rate 1 - General Service Rate			Consumption Profile		
			Residential	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$	0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$	0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$	11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate			**Consumption Profile**
First 1,000 m3	$	0.145000	14.80%
Next 24,000 m3	$	0.100431	85.20%
All over 25,000 m3	$	0.065417	2.00%
Monthly Fixed Charge	$	12.75	100.00%

Rate 3 - Special Large Volume Contract Rate			**Consumption Profile**
Monthly Customer Charge	$	150.00	
FIRM CD PER M*3	$	0.255904	
FIRM COMMODITY	$	0.037310	
INT COMMODITY	$	0.092249	

Rate 4 - General Service Peakng			**Consumption Profile**
First 1,000 m3	$	0.185648	19.80%
All over 1,000 m3	$	0.166254	80.20%
Monthly Fixed Charge	$	12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate	6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Project # 1 Seville to Richmond

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Project # 1 Seville to Richmond

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED **UPDATED** **March 8th, 2010**
Aid to Construct Calculator

Project Description: **Richmond road Project # 2**
Planned for Fiscal:
Date of Last Test: **work done 2007** **Tie in loop**
Nature of Project (MA, MR)

Size	**Description**	**Quantity**	**Unit of Measure**	**Price**	**Total**
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe		m	$ 9.50	-
2"	P.E. Pipe	1,859	m	$ 5.83	10,838
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	2,045	m	$ 0.22	450
				Total	11,288

Labour	**Hours**	**Hourly Rate**	**Total**
	-	25.40	-
	-	25.40	-
	-	25.40	-
		Total	-

Capitalized Equipment	**Hours**	**Hourly Rate**	**Total**
Trucks	-	$ 4.90	-
Generator	-	$ 1.50	-
Trencher	-	$ 39.00	-
Compressor	-	$ 3.60	-
Kubota	-	$ 2.20	-
Plow	-	$ 22.10	-
		Total	-

Capitalized Depreciation	**Hours**	**Hourly Rate**	**Total**
Trucks	-	$ 1.20	-
Generator	-	$ 0.50	-
Trencher	-	$ -	-
Compressor	-	$ 4.20	-
Kubota	-	$ 4.80	-
Plow	-	$ 26.50	-
		Total	-

Subcontractors & Rentals	**Unit of Measure**	**Units**	**Hourly Rate**	**Total**
Lumpsum	m	1	$ 29,959.00	29,959
		-	$ -	-
			Total	29,959

Total Cost		**$ 41,247**
Contingency	10%	4,125
Total Project Cost		**$ 45,372**
Cost per Meter		$ 22.20
Benefit Cost Ratio		0
Aid to Construction		$ 26,877
Aid to Const (each)		$ 26,877
Payback (Years)		30

Expected Customer Additions	**Potential**	**Year 1**	**2**	**3**	**4**	**5**	**Total**
Residential	6	1	-	-	-	-	1
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Richmond road Project # 2**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	-	-	-	-	1
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	1,859
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	2,045

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	32,230
NPV of revenue plus tax shield	5,353
AID TO CONSTRUCTION	26,877
BENEFIT/COST RATIO	0.166
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Richmond road Project # 2**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	-	-	-	-	-	-
Subcontractor & Rental Equipment						
Subcontractor	29,959					29,959
Contingency	4,125					4,125
Sub-total	34,084	-	-	-	-	34,084
Service Cost	190	-	-	-	-	190
Sub-total	190	-	-	-	-	190
Class 2 Pipelines	34,274	-	-	-	-	34,274
Meters & Regulators	168	-	-	-	-	168
Class 8 Equipment	168	-	-	-	-	168
Total Project Cost	34,441	-	-	-	-	34,441
NPV of Project Cost	$32,230					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC x tax rate x CCA rate})}{(\text{CCA rate + discount rate})} \text{ x } \frac{(2+\text{discount rate})}{2\text{x}(1+\text{ disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 7,710	$ 42

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Richmond road Project # 2**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**2,000**	**-**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	2,000	2,000	2,000	2,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	2,000	**2,000**	**2,000**	**2,000**	**2,000**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	1	1	1	1	1
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Richmond road Project # 2**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	306	306	306	306	306	
Commercial	-	-	-	-	-	
Industrial Rate 1	-	-	-	-	-	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	306	306	306	306	306	
Plus: Fixed Revenue	-	-	-	-	-	
Sub-Total	-	-	-	-	-	
Less: M9 Delivery Costs	11	11	11	11	11	
Less: O&M Expense	-	-	-	-	-	
Less: Capital Tax	103	103	103	103	103	
Less Property Tax	483	483	483	483	483	
Sub-Total	597	597	597	597	597	
Pre Tax Revenue	- 292	- 292	- 292	- 292	- 292	
Less: Income Tax	- 101	- 101	- 101	- 101	- 101	
Net Revenue	- 191	- 191	- 191	- 191	- 191	-191

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Richmond road Project # 2

Rate 1 - General Service Rate		Consumption Profile: Residential	Commercial	Industrial Rate 1
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		Consumption Profile
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		Consumption Profile
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		Consumption Profile
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	Rate
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	Allocation	Cost of Debt/Capital
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate 6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Richmond road Project # 2

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted			**24-Jan-10**		Current
Pipeline		$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
	6" PE Pipe	$ -	$ 6.57	0.0%	21.54
	4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
	3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
	2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
	1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Richmond road Project # 2

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED **UPDATED** **March 8th, 2010**
Aid to Construct Calculator

Project Description: **Best line West of Culloden Project # 3**
Planned for Fiscal:
Date of Last Test: **work done 2007**
Nature of Project (MA, MR)

Size	**Description**	**Quantity**	**Unit of Measure**	**Price**	**Total**
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	1,400	m	$ 5.83	8,162
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	1,540	m	$ 0.22	339
				Total	8,501

Labour	**Hours**	**Hourly Rate**	**Total**
	-	25.40	-
	-	25.40	-
	-	25.40	-
		Total	-

Capitalized Equipment	**Hours**	**Hourly Rate**	**Total**
Trucks	-	$ 4.90	-
Generator	-	$ 1.50	-
Trencher	-	$ 39.00	-
Compressor	-	$ 3.60	-
Kubota	-	$ 2.20	-
Plow	-	$ 22.10	-
		Total	-

Capitalized Depreciation	**Hours**	**Hourly Rate**	**Total**
Trucks	-	$ 1.20	-
Generator	-	$ 0.50	-
Trencher	-	$ -	-
Compressor	-	$ 4.20	-
Kubota	-	$ 4.80	-
Plow	-	$ 26.50	-
		Total	-

Subcontractors & Rentals	**Unit of Measure**	**Units**	**Hourly Rate**	**Total**
Lumpsum	m	1	$ 11,150.00	11,150
		-	$ -	-
			Total	11,150

Total Cost		**$ 19,651**
Contingency	10%	1,965
Total Project Cost		**$ 21,616**
Cost per Meter		$ 14.00
Benefit Cost Ratio		0
Aid to Construction		$ 10,475
Aid to Const (each)		$ 10,475
Payback (Years)		30

Expected Customer Additions	**Potential**	**Year 1**	**2**	**3**	**4**	**5**	**Total**
Residential	3	1	-	-	-	-	1
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: Best line West of Culloden Project # 3
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	-	-	-	-	1
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	1,400
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	1,540

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	12,610
NPV of revenue plus tax shield	2,135
AID TO CONSTRUCTION	10,475
BENEFIT/COST RATIO	0.169
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: Best line West of Culloden Project # 3
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	-	-	-	-	-	-
Subcontractor & Rental Equipment						
Subcontractor	11,150					11,150
Contingency	1,965					1,965
Sub-total	13,115	-	-	-	-	13,115
Service Cost	190	-	-	-	-	190
Sub-total	190	-	-	-	-	190
Class 2 Pipelines	13,305	-	-	-	-	13,305
Meters & Regulators	168	-	-	-	-	168
Class 8 Equipment	168	-	-	-	-	168
Total Project Cost	13,473	-	-	-	-	13,473
NPV of Project Cost	$12,610					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 2,993	$ 42

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: Best line West of Culloden Project # 3
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)

	Per Year				
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**2,000**	**-**	**-**	**-**	**-**

	Cumulative				
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	2,000	2,000	2,000	2,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	2,000	**2,000**	**2,000**	**2,000**	**2,000**

	Cumulative				
Customers	**1**	**2**	**3**	**4**	**5**
Residential	1	1	1	1	1
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: Best line West of Culloden Project # 3
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	306	306	306	306	306	
Commercial	-	-	-	-	-	
Industrial Rate 1	-	-	-	-	-	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	306	306	306	306	306	
Plus: Fixed Revenue	-	-	-	-	-	
Sub-Total	-	-	-	-	-	
Less: M9 Delivery Costs	11	11	11	11	11	
Less: O&M Expense	-	-	-	-	-	
Less: Capital Tax	40	40	40	40	40	
Less Property Tax	364	364	364	364	364	
Sub-Total	415	415	415	415	415	
Pre Tax Revenue	- 109	- 109	- 109	- 109	- 109	
Less: Income Tax	- 38	- 38	- 38	- 38	- 38	
Net Revenue	- 71	- 71	- 71	- 71	- 71	-71

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Best line West of Culloden Project # 3

			Consumption Profile		
Rate 1 - General Service Rate			**Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$	0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$	0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$	11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate			**Consumption Profile**
First 1,000 m3	$	0.145000	14.80%
Next 24,000 m3	$	0.100431	85.20%
All over 25,000 m3	$	0.065417	2.00%
Monthly Fixed Charge	$	12.75	100.00%

Rate 3 - Special Large Volume Contract Rate			**Consumption Profile**
Monthly Customer Charge	$	150.00	
FIRM CD PER M*3	$	0.255904	
FIRM COMMODITY	$	0.037310	
INT COMMODITY	$	0.092249	

Rate 4 - General Service Peakng			**Consumption Profile**
First 1,000 m3	$	0.185648	19.80%
All over 1,000 m3	$	0.166254	80.20%
Monthly Fixed Charge	$	12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate 6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Best line West of Culloden Project # 3

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Best line West of Culloden Project # 3

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED **UPDATED** **March 8th, 2010**
Aid to Construct Calculator

Project Description: **Best line Hwy.# 3 to Corinth loop tie in**
Planned for Fiscal:
Date of Last Test: **work done 2007** **Project # 4**
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	2,385	m	$ 5.83	13,905
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	2,624	m	$ 0.22	577
				Total	14,482

Labour	Hours	Hourly Rate	Total
	-	25.40	-
	-	25.40	-
	-	25.40	-
		Total	-

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	-	$ 4.90	-
Generator	-	$ 1.50	-
Trencher	-	$ 39.00	-
Compressor	-	$ 3.60	-
Kubota	-	$ 2.20	-
Plow	-	$ 22.10	-
		Total	-

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	-	$ 1.20	-
Generator	-	$ 0.50	-
Trencher	-	$ -	-
Compressor	-	$ 4.20	-
Kubota	-	$ 4.80	-
Plow	-	$ 26.50	-
		Total	-

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	1	$ 11,250.00	11,250
		-	$ -	-
			Total	11,250

Total Cost		**$ 25,732**
Contingency	10%	2,573
Total Project Cost		**$ 28,305**
Cost per Meter		$ 10.80
Benefit Cost Ratio		- 0
Aid to Construction		$ 15,273
Aid to Const (each)		#DIV/0!
Payback (Years)		30

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	-	-	-	-	-	-	-
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description:	Best line Hwy.# 3 to Corinth loop tie in
Planned for Fiscal:	
Date of Last Test:	
Nature of Project (MA, MR)	

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	-	-	-	-	-	-
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	2,385
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	2,624

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	12,940
NPV of revenue plus tax shield	-2,333
AID TO CONSTRUCTION	15,273
BENEFIT/COST RATIO	-0.180
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: Best line Hwy.# 3 to Corinth loop tie in
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	-	-	-	-	-	-
Subcontractor & Rental Equipment						
Subcontractor	11,250					11,250
Contingency	2,573					2,573
Sub-total	13,823	-	-	-	-	13,823
Service Cost	-	-	-	-	-	-
Sub-total	-	-	-	-	-	-
Class 2 Pipelines	13,823	-	-	-	-	13,823
Meters & Regulators	-	-	-	-	-	-
Class 8 Equipment	-	-	-	-	-	-
Total Project Cost	13,823	-	-	-	-	13,823
NPV of Project Cost	$12,940					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{\text{UCC x tax rate x CCA rate}}{\text{CCA rate + discount rate}} \times \frac{\text{2+discount rate}}{\text{2x(1+ disc. rate)}}$$

	Class 2	*Class 8*
PV of tax shield =	$ 3,110	$ -

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: Best line Hwy.# 3 to Corinth loop tie in
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)

	Per Year				
Year	**1**	**2**	**3**	**4**	**5**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

	Cumulative				
Year	**1**	**2**	**3**	**4**	**5**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	-	**-**	**-**	**-**	**-**

	Cumulative				
Customers	**1**	**2**	**3**	**4**	**5**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: Best line Hwy.# 3 to Corinth loop tie in
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	-	-	-	-	-	
Commercial	-	-	-	-	-	
Industrial Rate 1	-	-	-	-	-	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	-	-	-	-	-	
Plus: Fixed Revenue	-	-	-	-	-	
Sub-Total	-	-	-	-	-	
Less: M9 Delivery Costs	-	-	-	-	-	
Less: O&M Expense	-	-	-	-	-	
Less: Capital Tax	41	41	41	41	41	
Less Property Tax	620	620	620	620	620	
Sub-Total	662	662	662	662	662	
Pre Tax Revenue	- 662	- 662	- 662	- 662	- 662	
Less: Income Tax	- 229	- 229	- 229	- 229	- 229	
Net Revenue	- 432	- 432	- 432	- 432	- 432	-432

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Best line Hwy.# 3 to Corinth loop tie in

Rate 1 - General Service Rate		Consumption Profile		
		Residential	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate	6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Best line Hwy.# 3 to Corinth loop tie in

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Best line Hwy.# 3 to Corinth loop tie in

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED **UPDATED** **March 8th, 2010**
Aid to Construct Calculator

Project Description: **Richmond road to Walker barn Project # 5**
Planned for Fiscal:
Date of Last Test: **work in 2007**
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	2,100	m	$ 5.83	12,243
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	2,310	m	$ 0.22	508
				Total	12,751

Labour	Hours	Hourly Rate	Total
	-	25.40	-
	-	25.40	-
	-	25.40	-
		Total	-

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	-	$ 4.90	-
Generator	-	$ 1.50	-
Trencher	-	$ 39.00	-
Compressor	-	$ 3.60	-
Kubota	-	$ 2.20	-
Plow	-	$ 22.10	-
		Total	-

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	-	$ 1.20	-
Generator	-	$ 0.50	-
Trencher	-	$ -	-
Compressor	-	$ 4.20	-
Kubota	-	$ 4.80	-
Plow	-	$ 26.50	-
		Total	-

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	1	$ 11,750.00	11,750
		-	$ -	-
			Total	11,750

Total Cost		**$ 24,501**
Contingency	10%	2,450
Total Project Cost		**$ 26,951**
Cost per Meter		$ 11.70
Benefit Cost Ratio		2
Aid to Construction		$ -
Aid to Const (each)		#DIV/0!
Payback (Years)		10

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	3	-	-	-	-	-	-
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	1	1	-	-	-	-	1
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description:
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Customer Additions	**Year** 1	2	3	4	5	**Total**
Residential	-	-	-	-	-	-
Commercial	-	-	-	-	-	-
Industrial Rate 1	1	-	-	-	-	1
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	2,100
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	2,310

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	15,530
NPV of revenue plus tax shield	30,734
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	1.979
Payback Period (Years)	10

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description:
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	-	-	-	-	-	-
Subcontractor & Rental Equipment						
Subcontractor	11,750					11,750
Contingency	2,450					2,450
Sub-total	14,200	-	-	-	-	14,200
Service Cost	250	-	-	-	-	250
Sub-total	250	-	-	-	-	250
Class 2 Pipelines	14,450	-	-	-	-	14,450
Meters & Regulators	2,150	-	-	-	-	2,150
Class 8 Equipment	2,150	-	-	-	-	2,150
Total Project Cost	16,600	-	-	-	-	16,600
NPV of Project Cost	$15,530					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{\text{UCC} \times \text{tax rate} \times \text{CCA rate}}{\text{CCA rate} + \text{discount rate}} \times \frac{2+\text{discount rate}}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 3,251	$ 541

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description:
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**35,400**	**-**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	35,400	35,400	35,400	35,400
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	35,400	**35,400**	**35,400**	**35,400**	**35,400**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	-	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	1	1	1	1	1
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**1**	**1**	**1**	**1**	**1**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description:
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	-	-	-	-	-	
Commercial	-	-	-	-	-	
Industrial Rate 1	4,044	4,044	4,044	4,044	4,044	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	4,044	4,044	4,044	4,044	4,044	
Plus: Fixed Revenue	138	138	138	138	138	
Sub-Total	138	138	138	138	138	
Less: M9 Delivery Costs	190	190	190	190	190	
Less: O&M Expense	115	115	115	115	115	
Less: Capital Tax	50	50	50	50	50	
Less Property Tax	552	552	552	552	552	
Sub-Total	908	908	908	908	908	
Pre Tax Revenue	3,275	3,275	3,275	3,275	3,275	
Less: Income Tax	1,134	1,134	1,134	1,134	1,134	
Net Revenue	2,141	2,141	2,141	2,141	2,141	2,141

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Richmond road to Walker barn Project # 5

			Consumption Profile		
Rate 1 - General Service Rate			**Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$	0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$	0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$	11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate			**Consumption Profile**
First 1,000 m3	$	0.145000	14.80%
Next 24,000 m3	$	0.100431	85.20%
All over 25,000 m3	$	0.065417	2.00%
Monthly Fixed Charge	$	12.75	100.00%

Rate 3 - Special Large Volume Contract Rate			**Consumption Profile**
Monthly Customer Charge	$	150.00	
FIRM CD PER M*3	$	0.255904	
FIRM COMMODITY	$	0.037310	
INT COMMODITY	$	0.092249	

Rate 4 - General Service Peakng			**Consumption Profile**
First 1,000 m3	$	0.185648	19.80%
All over 1,000 m3	$	0.166254	80.20%
Monthly Fixed Charge	$	12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate	6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Richmond road to Walker barn Project # 5

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Richmond road to Walker barn Project # 5

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED

Property, Plant & Equipment
Summary of Averages - 2008 Actual
($'s)

Item	Gross Property Plant & Equip.	Accumulated Depreciation	Net Plant
Land	71,700	0	71,700
Buildings	682,331	115,142	567,189
Furniture & Fixtures	55,035	33,823	21,212
Computer Equipment	150,192	124,721	25,471
Computer Software	138,633	114,406	24,227
Machinery & Equipment	395,621	362,048	33,573
Communication Equipment	67,902	27,732	40,170
Automotive	467,272	218,207	249,065
Rental Equipment - Res	1,894,558	708,865	1,185,693
Rental Equipment - Com	54,699	23,665	31,034
Rental Equipment - Softeners	11,627	5,581	6,046
Meters	1,947,102	853,743	1,093,359
Regulators	1,204,909	677,219	527,690
Plastic Mains	7,027,030	2,473,717	4,553,313
Steel Mains	33,014	32,672	342
New Steel Mains	0	0	0
Plastic Services	2,535,758	1,567,634	968,124
Franchises & Consents	153,770	90,455	63,315
Total	16,891,153	7,429,630	9,461,523

NATURAL RESOURCE GAS LIMITED

Gross Property, Plant and Equipment
2008 Actual
($'s)

Asset Values at Cost	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331
Furniture & Fixtures	55,005	55,011	55,016	55,021	55,026	55,031	55,035	55,039	55,043	55,047	55,051	55,089	55,035
Computer Equipment	146,186	146,186	146,675	146,697	149,298	150,103	150,264	152,298	152,530	153,077	153,304	155,685	150,192
Computer Software	136,472	136,472	136,472	136,986	137,010	137,282	139,318	139,440	139,557	140,097	141,314	143,181	138,633
Machinery & Equipment	393,709	393,709	393,709	393,709	395,609	396,188	396,293	396,393	396,489	396,580	396,667	398,396	395,621
Communication Equipment	63,155	63,155	63,155	63,155	63,155	63,155	63,155	69,139	69,411	69,671	69,919	94,603	67,902
Automotive	465,655	465,655	465,655	465,655	465,655	465,655	465,655	465,655	465,655	483,824	466,481	466,068	467,272
Rental Equipment - Res	1,903,725	1,899,968	1,896,382	1,892,959	1,889,691	1,886,572	1,883,595	1,880,753	1,878,040	1,875,451	1,876,028	1,971,531	1,894,558
Rental Equipment - Com	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699
Rental Equipment - Softeners	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627
Meters	1,917,091	1,917,091	1,927,137	1,927,593	1,928,029	1,928,445	1,938,566	1,967,246	1,969,296	1,971,253	1,981,561	1,991,913	1,947,102
Regulators	1,201,774	1,201,774	1,201,774	1,201,916	1,202,839	1,204,797	1,204,930	1,206,904	1,207,109	1,207,304	1,207,803	1,209,980	1,204,909
Plastic Mains	6,934,262	6,937,022	6,939,609	7,007,828	7,012,678	7,017,308	7,043,869	7,044,722	7,049,563	7,082,259	7,091,538	7,163,697	7,027,030
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	2,508,926	2,509,460	2,509,485	2,522,510	2,523,123	2,523,708	2,524,267	2,529,526	2,553,459	2,557,539	2,563,780	2,603,316	2,535,758
Franchises & Consents	151,094	151,094	151,094	151,094	151,094	151,094	151,094	157,744	158,046	158,334	158,610	154,852	153,770
Total Assets	16,730,424	16,729,967	16,739,533	16,818,493	16,826,576	16,832,708	16,869,410	16,918,229	16,947,569	17,003,808	17,015,426	17,261,681	16,891,153

NATURAL RESOURCE GAS LIMITED

Accumulated Depreciation Property, Plant and Equipment
2008 Actual
($'s)

Accumulated Depreciation	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	0	0	0	0	0	0	0	0	0	0	0	0	0
Buildings	108,252	109,514	110,776	112,039	113,301	114,563	115,826	117,088	118,350	119,613	120,875	121,506	115,142
Furniture & Fixtures	32,130	32,441	32,751	33,061	33,371	33,681	33,991	34,301	34,611	34,921	35,231	35,386	33,823
Computer Equipment	118,561	119,689	120,818	121,946	123,075	124,204	125,332	126,461	127,589	128,718	129,847	130,411	124,721
Computer Software	111,282	111,854	112,427	112,999	113,571	114,144	114,716	115,288	115,860	116,433	117,005	117,291	114,406
Machinery & Equipment	345,268	348,342	351,416	354,491	357,565	360,639	363,714	366,788	369,862	372,936	376,011	377,548	362,048
Communication Equipment	23,538	24,306	25,074	25,843	26,611	27,380	28,148	28,916	29,685	30,453	31,222	31,606	27,732
Automotive	186,078	191,964	197,850	203,737	209,623	215,509	221,395	227,281	233,168	239,054	244,940	247,883	218,207
Rental Equipment - Res	685,269	689,591	693,914	698,237	702,560	706,883	711,206	715,529	719,852	724,175	728,498	730,660	708,865
Rental Equipment - Com	21,823	22,161	22,498	22,835	23,173	23,510	23,847	24,185	24,522	24,859	25,197	25,365	23,665
Rental Equipment - Softeners	5,251	5,311	5,372	5,432	5,493	5,553	5,614	5,675	5,735	5,796	5,856	5,887	5,581
Meters	820,774	826,814	832,854	838,894	844,935	850,975	857,015	863,055	869,095	875,135	881,176	884,196	853,743
Regulators	656,983	660,691	664,398	668,105	671,812	675,519	679,227	682,934	686,641	690,348	694,055	695,909	677,219
Plastic Mains	2,366,715	2,386,318	2,405,922	2,425,525	2,445,128	2,464,732	2,484,335	2,503,938	2,523,542	2,543,145	2,562,748	2,572,550	2,473,717
Steel Mains	32,335	32,397	32,459	32,520	32,582	32,644	32,706	32,767	32,829	32,891	32,952	32,983	32,672
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	1,527,977	1,535,243	1,542,508	1,549,773	1,557,039	1,564,304	1,571,569	1,578,835	1,586,100	1,593,365	1,600,631	1,604,263	1,567,634
Franchises & Consents	87,152	87,757	88,362	88,967	89,572	90,177	90,782	91,387	91,992	92,597	93,202	93,505	90,455
Total Accum. Depreciation	7,129,389	7,184,394	7,239,400	7,294,406	7,349,412	7,404,417	7,459,423	7,514,429	7,569,435	7,624,440	7,679,446	7,706,949	7,429,630

NATURAL RESOURCE GAS LIMITED

Net Property, Plant and Equipment
2008 Actual
($'s)

Net Fixed Asset Values	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	574,079	572,817	571,554	570,292	569,030	567,767	566,505	565,243	563,981	562,718	561,456	560,825	567,189
Furniture & Fixtures	22,875	22,570	22,266	21,961	21,655	21,350	21,044	20,738	20,432	20,126	19,819	19,702	21,212
Computer Equipment	27,626	26,497	25,857	24,751	26,223	25,899	24,932	25,837	24,941	24,359	23,457	25,274	25,471
Computer Software	25,190	24,618	24,046	23,987	23,438	23,138	24,602	24,152	23,696	23,665	24,309	25,890	24,227
Machinery & Equipment	48,441	45,367	42,292	39,218	38,044	35,549	32,579	29,605	26,626	23,643	20,656	20,848	33,573
Communication Equipment	39,617	38,849	38,080	37,312	36,543	35,775	35,007	40,223	39,727	39,218	38,697	62,997	40,170
Automotive	279,577	273,691	267,804	261,918	256,032	250,146	244,259	238,373	232,487	244,770	221,540	218,184	249,065
Rental Equipment - Res	1,218,457	1,210,377	1,202,468	1,194,721	1,187,131	1,179,689	1,172,389	1,165,224	1,158,188	1,151,276	1,147,530	1,240,871	1,185,693
Rental Equipment - Com	32,875	32,538	32,201	31,863	31,526	31,189	30,851	30,514	30,177	29,839	29,502	29,333	31,034
Rental Equipment - Softeners	6,376	6,316	6,255	6,194	6,134	6,073	6,013	5,952	5,892	5,831	5,771	5,740	6,046
Meters	1,096,317	1,090,276	1,094,283	1,088,699	1,083,095	1,077,471	1,081,551	1,104,191	1,100,201	1,096,118	1,100,385	1,107,718	1,093,359
Regulators	544,791	541,084	537,376	533,811	531,026	529,278	525,703	523,970	520,468	516,956	513,748	514,071	527,690
Plastic Mains	4,567,547	4,550,703	4,533,688	4,582,303	4,567,550	4,552,577	4,559,534	4,540,783	4,526,021	4,539,114	4,528,790	4,591,147	4,553,313
Steel Mains	679	617	555	494	432	370	309	247	185	124	62	31	342
New Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
Plastic Services	980,949	974,218	966,977	972,736	966,084	959,404	952,697	950,691	967,359	964,174	963,149	999,053	968,124
Franchises & Consents	63,941	63,336	62,731	62,126	61,521	60,916	60,311	66,356	66,053	65,737	65,407	61,347	63,315
Net Fixed Assets	9,601,036	9,545,573	9,500,133	9,524,087	9,477,165	9,428,291	9,409,987	9,403,800	9,378,134	9,379,368	9,335,980	9,554,732	9,461,523

NATURAL RESOURCE GAS LIMITED

Allowance for Working Capital
2008 Actual
($'s)

Allowance for Working Capital	Inventory	Cash Working Capital	Security Deposits	Total Allowance
October	157,766	-126,297	-629,607	-598,138
November	187,110	-126,297	-680,720	-619,907
December	196,767	-126,297	-721,803	-651,333
January	244,023	-126,297	-732,685	-614,959
February	296,360	-126,297	-732,301	-562,238
March	323,587	-126,297	-745,088	-547,798
April	355,982	-126,297	-754,847	-525,162
May	378,135	-126,297	-759,604	-507,766
June	344,551	-126,297	-768,857	-550,603
July	309,101	-126,297	-786,538	-603,734
August	310,319	-126,297	-790,930	-606,908
September	200,285	-126,297	-770,814	-696,826
Total	275,332	-126,297	-739,483	-590,448

NATURAL RESOURCE GAS LIMITED

Cash Requirements for Working Capital
2008 Actual
($'s)

	Annual Revenue	Allowance (Days)
Revenue Lag		
Rate 1	9,556,389	31.1
Rate 2	453,622	31.4
Rate 3	1,222,560	32.2
Rate 4	186,788	32.2
Rate 5	310,192	35.5
Rate 6	0	32.2
Weighted Revenue Lag		31.4

Expense Lag	Annual Expense	Allowance (Days)	Net Lag (Days)	Cash Need
Gas Costs				
- Local Production A (Affiliate)	2,011,725	45.6	(14.2)	-78,264
- Local Production B (Other)	0	32.0	(0.6)	0
- Dawn Deliveries	2,226,071	32.5	(1.1)	-6,709
- Parkway Deliveries	2,602,368	40.3	(8.9)	-63,455
- Western Deliveries	5,316	36.4	(5.0)	-73
- Ontario Delivered	220,306	32.8	(1.4)	-845
-TCPL	253,254	40.5	(9.1)	-6,314
- Union Gas	409,678	34.2	(2.8)	-3,143
Weighted Gas Cost Lag		38.9		-158,803
O & M Costs				
- Prepaid Insurance	52,020	(90.4)	121.8	17,359
- Labour	255,964	10.0	21.4	15,007
- Labour Related Costs	109,699	10.0	21.4	6,432
- Other Costs	642,928	30.0	1.4	2,466
Weighted O & M Cost Lag		17.2		41,264
GST Costs				
- Revenues	-703,773	30.9		-59,580
- O & M Expenses	37,928	15.6		1,621
- Capital Expenditures	54,458	15.6		2,328
- Gas Costs	463,649	36.9		46,873
Weighted GST Lag		21.6		-8,758
Total Working Cash Requirement				-126,297

NATURAL RESOURCE GAS LIMITED

Summary of Utility Rate Base
2009 Actual
($'s)

	Actual 2009	Last Year 2008
Property, Plant & Equipment		
Asset Values at Cost	22,594,191	16,891,153
Accumulated Depreciation	8,259,632	7,429,630
	14,334,559	9,461,523
Allowance for Working Capital		
Inventory	129,616	275,332
Working Cash Allowance	-140,094	-126,297
Security Deposits	-617,526	-739,483
	-628,004	-590,448
Utility Rate Base	13,706,555	8,871,075

	Variance from 2008
Property, Plant & Equipment	
Asset Values at Cost	5,703,038
Accumulated Depreciation	830,002
	4,873,036
Allowance for Working Capital	
Inventory	-145,716
Working Cash Allowance	-13,797
Security Deposits	121,957
	-37,556
Utility Rate Base	4,835,480

NATURAL RESOURCE GAS LIMITED

Utility Capital Expenditures
2009 Actual
($'s)

	Actual 2009	Actual 2008
Mains - Additions	74,011	346,658
- Replacements	2,018	0
Services - Additions	76,958	133,927
- Replacements	0	0
New Steel Mains	5,073,000	0
Meters	48,590	85,175
Regulators	11,761	10,383
Franchises	261,963	0
Land	0	0
Buildings	0	0
Furniture & Fixtures	14,050	242
Computer Equipment	3,348	11,879
Computer Software	30,607	8,575
Machinery & Equipment	56,706	6,417
Communication Equipment	21,128	56,133
Automotive	55,828	0
Water Softeners	0	0
Rental Water Heaters	222,983	245,961
Total Capital Expenditures	5,952,951	905,350

	Variance from 2008
Mains - Additions	-272,647
- Replacements	2,018
Services - Additions	-56,969
- Replacements	0
New Steel Mains	5,073,000
Meters	-36,585
Regulators	1,378
Franchises	261,963
Land	0
Buildings	0
Furniture & Fixtures	13,807
Computer Equipment	-8,531
Computer Software	22,032
Machinery & Equipment	50,289
Communication Equipment	-35,005
Automotive	55,828
Water Softeners	0
Rental Water Heaters	-22,978
Total Capital Expenditures	5,047,601

NATURAL RESOURCE GAS LIMITED

Capital Projects
2009
($'s)

Description	Cost
Main Additions	
Glen Erie Corn Dryer	31,501
Main on Ostrander Road	36,052
Springerhill Road	5,482
Short Main Addition	976
Total Main Additions	74,011
Main Replacements	
Replacements	976
Total Main Replacements	976
Service Additions	
Service additions	76,958
Total Service Additions	76,958
Service Replacements	
Service replacements	0
Total Service Replacements	0
Summary	
Total Main Additions	74,011
Total Main Replacements	976
Total Mains	74,987
Total Service Additions	76,958
Total Service Replacements	0
Total Services	76,958
Total Capital Projects	151,945

NATURAL RESOURCE GAS LIMITED

Aggregate Cost/Benefit Ratio for Main Additions
2009 Actual
($'s)

Main Additions	NPV of Revenues	NPV of Costs	Project Ratio
Glen Erie Corn Dryer	101,603	31,920	3.18
Main on Ostrander Road	78,885	32,030	2.46
Springerhill Road	14,424	4,780	3.02
Total Main Additions	194,912	68,730	2.84

(1) An aid to construction may be collected for any project with a benefit/cost ratio less than 1.00.

NATURAL RESOURCE GAS LIMITED

Financial Tests
2009 Actual

Attached

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Main on Ostrander road**
Planned for Fiscal:
Date of Last Test: June 02 2009
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 20.00	
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	3,500	m	$ 4.83	16,905
1.25"	P.E. Pipe	-	m	$ -	-
1"	P.E. Pipe	-	m	$ 1.92	-
1/2"	P.E. Pipe	-	m	$ 0.92	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	3,850	m	$ 0.38	-
				Total	16,905

Labour	Hours	Hourly Rate	Total
	160	25.40	4,064
	-	25.40	-
	-	25.40	-
		Total	4,064

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	80	$ 4.90	392
Generator	10	$ 1.50	15
Trencher	-	$ 39.00	-
Compressor	4	$ 3.60	14
Kubota	50	$ 2.20	110
Plow	60	$ 22.10	1,326
		Total	1,857

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	80	$ 1.20	96
Generator	10	$ 0.50	5
Trencher	-	$ -	-
Compressor	4	$ 4.20	17
Kubota	50	$ 4.80	240
Plow	60	$ 26.50	1,590
		Total	1,948

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	400	$ 20.00	8,000
		-	$ -	-
			Total	8,000

Total Cost		**$ 32,774**
Contingency	10%	3,277
Total Project Cost		**$ 36,052**
Cost per Meter		$ 9.40
Benefit Cost Ratio		2
Aid to Construction		$ -
Aid to Const (each)		$ -
Payback (Years)		7

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	6	2			-	-	2
Commercial	1	1	-	-	-	-	1
Industrial Rate 1	2	2	-	-	-	-	2
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description:	**Main on Ostrander road**
Planned for Fiscal:	
Date of Last Test:	
Nature of Project (MA, MR)	

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	2	-	-	-	-	2
Commercial	1	-	-	-	-	1
Industrial Rate 1	2	-	-	-	-	2
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	3,500
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	3,850

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ 4.83
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	32,030
NPV of revenue plus tax shield	78,885
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	2.463
Payback Period (Years)	7

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Main on Ostrander road**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	16,905					16,905
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	16,905	-	-	-	-	16,905
Subcontractor & Rental Equipment						
Subcontractor	8,000					8,000
Contingency	3,277					3,277
Sub-total	11,277	-	-	-	-	11,277
Service Cost	1,070	-	-	-	-	1,070
Sub-total	1,070	-	-	-	-	1,070
Class 2 Pipelines	29,252	-	-	-	-	29,252
Meters & Regulators	4,803	-	-	-	-	4,803
Class 8 Equipment	4,803	-	-	-	-	4,803
Total Project Cost	34,055	-	-	-	-	34,055
NPV of Project Cost	$32,030					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{\text{UCC} \times \text{tax rate} \times \text{CCA rate}}{\text{CCA rate} + \text{discount rate}} \times \frac{2+\text{discount rate}}{2\times(1+\text{disc. rate})}$$

	Class 2	*Class 8*
PV of tax shield =	$ 4,972	$ 1,274

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Main on Ostrander road**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	4,000	-	-	-	-
Commercial	8,700	-	-	-	-
Industrial Rate 1	70,800	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**83,500**	**-**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	4,000	4,000	4,000	4,000	4,000
Commercial	8,700	8,700	8,700	8,700	8,700
Industrial Rate 1	70,800	70,800	70,800	70,800	70,800
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	83,500	**83,500**	**83,500**	**83,500**	**83,500**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	2	2	2	2	2
Commercial	1	1	1	1	1
Industrial Rate 1	2	2	2	2	2
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**3**	**3**	**3**	**3**	**3**

NATURAL RESOURCE GAS LIMITED **UPDATED** **March 8th, 2010**

Aid to Construct Calculator Worksheet

Project Description: **Main on Ostrander road**

Planned for Fiscal:

Date of Last Test:

Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	612	612	612	612	612	
Commercial	1,136	1,136	1,136	1,136	1,136	
Industrial Rate 1	8,089	8,089	8,089	8,089	8,089	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	9,836	9,836	9,836	9,836	9,836	
Plus: Fixed Revenue	414	414	414	414	414	
Sub-Total	414	414	414	414	414	
Less: M9 Delivery Costs	449	449	449	449	449	
Less: O&M Expense	231	231	231	231	231	
Less: Capital Tax	102	102	102	102	102	
Less Property Tax	929	929	929	929	929	
Sub-Total	1,712	1,712	1,712	1,712	1,712	
Pre Tax Revenue	8,539	8,539	8,539	8,539	8,539	
Less: Income Tax	3,074	3,074	3,074	3,074	3,074	
Net Revenue	5,465	5,465	5,465	5,465	5,465	5,465

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Main on Ostrander road

Rate 1 - General Service Rate		**Consumption Profile** Residential	Commercial	Industrial Rate 1
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	6.00%
Class 8 CCA Rate	20.00%
Marginal Tax Rate	36.00%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	60.00%	6.52%
Demand Debt	0.00%	0.00%
Short Term Debt	0.00%	0.00%
Equity	40.00%	9.57%
	100.00%	6.33%

Discount Rate 6.33%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Main on Ostrander road

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	77.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	77.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	77.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	77.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	77.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	77.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	181,480	45,370
Wages - Line Maintenance	12%	97,026	11,837
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	40,659	40,659
Wages - Sales	50%	90,126	45,063
Benefits (13.19% of Wages)	13%	464,609	61,282
Insurance	10%	122,123	12,212
Advertising & Promotion	100%	12,154	12,154
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	42,579	42,579
Repairs & Maintenance General	100%	46,821	46,821
Small Tools	100%	8,583	8,583
Automotive	100%	72,890	72,890
Mapping Expense	100%	156	156
Interest - Meter Deposits	100%	824	824
Bad Debts	100%	15,000	15,000
Bank Service Charges	100%	9,798	9,798
Collection Expense	100%	11,150	11,150
Miscellaneous	22%	13,673	2,981
Total			518,765
Average Customers			6,700
O&M Costs per Customer			$ 77.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-07**			Current
Pipeline		$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
	6" PE Pipe	$ -	$ 6.57	0.0%	21.54
	4" PE Pipe	$ 20.00	$ 4.42	0.0%	14.49
	3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
	2" PE Pipe	$ 4.83	$ 1.00	0.0%	3.29
	1.25" PE Pipe	$ -	$ 0.70	0.0%	2.30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Main on Ostrander road

1" PE Pipe	$ 1.92	$ 0.46	0.0%	1.52
.5" PE Pipe	$ 0.92	$ 0.19	0.0%	0.64
Tracer Wire	$ 0.38		0.0%	0.38

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Glen Erie corn dryer**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR) Project completed

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ -	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	2,800	m	$ 4.83	13,524
1.25"	P.E. Pipe	-	m	$ -	-
1"	P.E. Pipe	-	m	$ 1.92	-
1/2"	P.E. Pipe	-	m	$ 0.92	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	3,080	m	$ 0.38	1,170
				Total	14,694

Labour	Hours	Hourly Rate	Total
	124	25.40	3,150
	-	25.40	-
	-	25.40	-
		Total	3,150

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	24	$ 4.90	118
Generator	4	$ 1.50	6
Trencher	-	$ 39.00	-
Compressor	-	$ 3.60	-
Kubota	8	$ 2.20	18
Plow	12	$ 22.10	265
		Total	406

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	24	$ 1.20	29
Generator	4	$ 0.50	2
Trencher	-	$ -	-
Compressor	-	$ 4.20	-
Kubota	8	$ 4.80	38
Plow	12	$ 26.50	318
		Total	387

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	500	$ 20.00	10,000
		-	$ -	-
			Total	10,000

Total Cost		**$ 28,638**
Contingency	10%	2,864
Total Project Cost		**$ 31,501**
Cost per Meter		$ 10.20
Benefit Cost Ratio		3
Aid to Construction		$ -
Aid to Const (each)		$ -
Payback (Years)		5

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	1	1	-	-	-	-	1
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	3	3	-	-	-	-	3
Industrial Rate 4	-		-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Glen Erie corn dryer**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	-	-	-	-	1
Commercial	-	-	-	-	-	-
Industrial Rate 1	3	-	-	-	-	3
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	2,800
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	3,080

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ 4.83
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	31,920
NPV of revenue plus tax shield	101,603
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	3.183
Payback Period (Years)	5

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Glen Erie corn dryer**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	13,524					13,524
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	13,524	-	-	-	-	13,524
Subcontractor & Rental Equipment						
Subcontractor	10,000					10,000
Contingency	2,864					2,864
Sub-total	12,864	-	-	-	-	12,864
Service Cost	940	-	-	-	-	940
Sub-total	940	-	-	-	-	940
Class 2 Pipelines	27,328	-	-	-	-	27,328
Meters & Regulators	6,618	-	-	-	-	6,618
Class 8 Equipment	6,618	-	-	-	-	6,618
Total Project Cost	33,945	-	-	-	-	33,945
NPV of Project Cost	$31,920					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{\text{UCC} \times \text{tax rate} \times \text{CCA rate}}{\text{CCA rate} + \text{discount rate}} \times \frac{2+\text{discount rate}}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 4,645	$ 1,756

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Glen Erie corn dryer**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)	**Per Year**				
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	106,200	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**108,200**	**-**	**-**	**-**	**-**

	Cumulative				
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	2,000	2,000	2,000	2,000
Commercial	-	-	-	-	-
Industrial Rate 1	106,200	106,200	106,200	106,200	106,200
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	108,200	**108,200**	**108,200**	**108,200**	**108,200**

	Cumulative				
Customers	**1**	**2**	**3**	**4**	**5**
Residential	1	1	1	1	1
Commercial	-	-	-	-	-
Industrial Rate 1	3	3	3	3	3
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**3**	**3**	**3**	**3**	**3**

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**

Aid to Construct Calculator Worksheet

Project Description: **Glen Erie corn dryer**

Planned for Fiscal:

Date of Last Test:

Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	306	306	306	306	306	
Commercial	-	-	-	-	-	
Industrial Rate 1	12,133	12,133	12,133	12,133	12,133	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	12,439	12,439	12,439	12,439	12,439	
Plus: Fixed Revenue	414	414	414	414	414	
Sub-Total	414	414	414	414	414	
Less: M9 Delivery Costs	582	582	582	582	582	
Less: O&M Expense	231	231	231	231	231	
Less: Capital Tax	102	102	102	102	102	
Less Property Tax	747	747	747	747	747	
Sub-Total	1,662	1,662	1,662	1,662	1,662	
Pre Tax Revenue	11,191	11,191	11,191	11,191	11,191	
Less: Income Tax	4,029	4,029	4,029	4,029	4,029	
Net Revenue	7,162	7,162	7,162	7,162	7,162	7,162

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Glen Erie corn dryer

Rate 1 - General Service Rate		Consumption Profile: **Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	6.00%
Class 8 CCA Rate	20.00%
Marginal Tax Rate	36.00%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	60.00%	6.52%
Demand Debt	0.00%	0.00%
Short Term Debt	0.00%	0.00%
Equity	40.00%	9.57%
	100.00%	6.33%

Discount Rate 6.33%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Glen Erie corn dryer

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	77.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	77.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	77.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	77.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	77.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	77.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	181,480	45,370
Wages - Line Maintenance	12%	97,026	11,837
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	40,659	40,659
Wages - Sales	50%	90,126	45,063
Benefits (13.19% of Wages)	13%	464,609	61,282
Insurance	10%	122,123	12,212
Advertising & Promotion	100%	12,154	12,154
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	42,579	42,579
Repairs & Maintenance General	100%	46,821	46,821
Small Tools	100%	8,583	8,583
Automotive	100%	72,890	72,890
Mapping Expense	100%	156	156
Interest - Meter Deposits	100%	824	824
Bad Debts	100%	15,000	15,000
Bank Service Charges	100%	9,798	9,798
Collection Expense	100%	11,150	11,150
Miscellaneous	22%	13,673	2,981
Total			518,765
Average Customers			6,700
O&M Costs per Customer			$ 77.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-07**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ -	$ 4.42	0.0%	14.49
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 4.83	$ 1.00	0.0%	3.29
1.25" PE Pipe	$ -	$ 0.70	0.0%	2.30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Glen Erie corn dryer

1" PE Pipe	$ 1.92	$ 0.46	0.0%	1.52
.5" PE Pipe	$ 0.92	$ 0.19	0.0%	0.64
Tracer Wire	$ 0.38		0.0%	0.38

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Springerhill road (Hoover Plant)**
Planned for Fiscal:
Date of Last Test: May 04 2009
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ -	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	500	m	$ 4.83	2,415
1.25"	P.E. Pipe	-	m	$ -	-
1"	P.E. Pipe	-	m	$ 1.92	-
1/2"	P.E. Pipe	-	m	$ 0.92	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	550	m	$ 0.38	-
				Total	2,415

Labour	Hours	Hourly Rate	Total
	36	25.40	914
	-	25.40	-
	-	25.40	-
		Total	914

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	16	$ 4.90	78
Generator	2	$ 1.50	3
Trencher	-	$ 39.00	-
Compressor	1	$ 3.60	4
Kubota	8	$ 2.20	18
Plow	8	$ 22.10	177
		Total	279

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	16	$ 1.20	19
Generator	2	$ 0.50	1
Trencher	-	$ -	-
Compressor	1	$ 4.20	4
Kubota	8	$ 4.80	38
Plow	8	$ 26.50	212
		Total	275

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	55	$ 20.00	1,100
		-	$ -	-
			Total	1,100

Total Cost		**$ 4,984**
Contingency	10%	498
Total Project Cost		**$ 5,482**
Cost per Meter		$ 10.00
Benefit Cost Ratio		3
Aid to Construction		$ -
Aid to Const (each)		$ -
Payback (Years)		5

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	2	2	-	-	-	-	2
Commercial	1	1	-	-	-	-	1
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Springerhill road (Hoover Plant)**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	2	-	-	-	-	2
Commercial	1	-	-	-	-	1
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	500
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	550

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ 4.83
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	4,780
NPV of revenue plus tax shield	14,424
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	3.018
Payback Period (Years)	5

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Springerhill road (Hoover Plant)**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	2,415					2,415
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	2,415	-	-	-	-	2,415
Subcontractor & Rental Equipment						
Subcontractor	1,100					1,100
Contingency	498					498
Sub-total	1,598	-	-	-	-	1,598
Service Cost	570	-	-	-	-	570
Sub-total	570	-	-	-	-	570
Class 2 Pipelines	4,583	-	-	-	-	4,583
Meters & Regulators	503	-	-	-	-	503
Class 8 Equipment	503	-	-	-	-	503
Total Project Cost	5,086	-	-	-	-	5,086
NPV of Project Cost	$4,780					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\text{x}(1+ \text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 779	$ 133

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Springerhill road (Hoover Plant)**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	4,000	-	-	-	-
Commercial	8,700	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**12,700**	**-**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	4,000	4,000	4,000	4,000	4,000
Commercial	8,700	8,700	8,700	8,700	8,700
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	12,700	**12,700**	**12,700**	**12,700**	**12,700**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	2	2	2	2	2
Commercial	1	1	1	1	1
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**1**	**1**	**1**	**1**	**1**

NATURAL RESOURCE GAS LIMITED **UPDATED March 8th, 2010**
Aid to Construct Calculator Worksheet

Project Description: **Springerhill road (Hoover Plant)**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	612	612	612	612	612	
Commercial	1,136	1,136	1,136	1,136	1,136	
Industrial Rate 1	-	-	-	-	-	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	1,747	1,747	1,747	1,747	1,747	
Plus: Fixed Revenue	138	138	138	138	138	
Sub-Total	138	138	138	138	138	
Less: M9 Delivery Costs	68	68	68	68	68	
Less: O&M Expense	77	77	77	77	77	
Less: Capital Tax	15	15	15	15	15	
Less Property Tax	136	136	136	136	136	
Sub-Total	297	297	297	297	297	
Pre Tax Revenue	1,588	1,588	1,588	1,588	1,588	
Less: Income Tax	572	572	572	572	572	
Net Revenue	1,017	1,017	1,017	1,017	1,017	1,017

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Springerhill road (Hoover Plant)

			Consumption Profile		
Rate 1 - General Service Rate			**Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$	0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$	0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$	11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate			**Consumption Profile**
First 1,000 m3	$	0.145000	14.80%
Next 24,000 m3	$	0.100431	85.20%
All over 25,000 m3	$	0.065417	2.00%
Monthly Fixed Charge	$	12.75	100.00%

Rate 3 - Special Large Volume Contract Rate			**Consumption Profile**
Monthly Customer Charge	$	150.00	
FIRM CD PER M*3	$	0.255904	
FIRM COMMODITY	$	0.037310	
INT COMMODITY	$	0.092249	

Rate 4 - General Service Peakng			**Consumption Profile**
First 1,000 m3	$	0.185648	19.80%
All over 1,000 m3	$	0.166254	80.20%
Monthly Fixed Charge	$	12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	6.00%
Class 8 CCA Rate	20.00%
Marginal Tax Rate	36.00%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	60.00%	6.52%
Demand Debt	0.00%	0.00%
Short Term Debt	0.00%	0.00%
Equity	40.00%	9.57%
	100.00%	6.33%

Discount Rate	6.33%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Springerhill road (Hoover Plant)

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	77.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	77.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	77.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	77.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	77.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	77.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	181,480	45,370
Wages - Line Maintenance	12%	97,026	11,837
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	40,659	40,659
Wages - Sales	50%	90,126	45,063
Benefits (13.19% of Wages)	13%	464,609	61,282
Insurance	10%	122,123	12,212
Advertising & Promotion	100%	12,154	12,154
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	42,579	42,579
Repairs & Maintenance General	100%	46,821	46,821
Small Tools	100%	8,583	8,583
Automotive	100%	72,890	72,890
Mapping Expense	100%	156	156
Interest - Meter Deposits	100%	824	824
Bad Debts	100%	15,000	15,000
Bank Service Charges	100%	9,798	9,798
Collection Expense	100%	11,150	11,150
Miscellaneous	22%	13,673	2,981
Total			518,765
Average Customers			6,700
O&M Costs per Customer			$ 77.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted **24-Jan-07** Current

Pipeline		$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
	6" PE Pipe	$ -	$ 6.57	0.0%	21.54
	4" PE Pipe	$ -	$ 4.42	0.0%	14.49
	3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
	2" PE Pipe	$ 4.83	$ 1.00	0.0%	3.29
	1.25" PE Pipe	$ -	$ 0.70	0.0%	2.30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Springerhill road (Hoover Plant)

1" PE Pipe	$ 1.92	$ 0.46	0.0%	1.52
.5" PE Pipe	$ 0.92	$ 0.19	0.0%	0.64
Tracer Wire	$ 0.38		0.0%	0.38

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED

Property, Plant & Equipment
Summary of Averages - 2009 Actual
($'s)

Item	Gross Property Plant & Equip.	Accumulated Depreciation	Net Plant
Land	71,700	0	71,700
Buildings	682,331	130,290	552,041
Furniture & Fixtures	60,241	38,054	22,187
Computer Equipment	165,067	136,435	28,632
Computer Software	147,508	123,829	23,679
Machinery & Equipment	410,359	401,564	8,795
Communication Equipment	130,097	37,832	92,265
Automotive	474,721	297,416	177,305
Rental Equipment - Res	2,106,551	746,019	1,360,532
Rental Equipment - Com	54,699	27,712	26,987
Rental Equipment - Softeners	11,627	6,308	5,319
Meters	2,020,439	927,172	1,093,267
Regulators	1,217,757	721,937	495,820
Plastic Mains	7,251,011	2,709,852	4,541,159
Steel Mains	33,014	33,014	0
New Steel Mains	4,861,625	136,513	4,725,112
Plastic Services	2,672,497	1,656,640	1,015,857
Franchises & Consents	222,947	129,045	93,902
Total	22,594,191	8,259,632	14,334,559

NATURAL RESOURCE GAS LIMITED

Gross Property, Plant and Equipment
2009 Actual
($'s)

Asset Values at Cost	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331
Furniture & Fixtures	55,127	55,127	55,127	55,520	59,198	60,713	61,126	62,296	62,897	63,598	65,049	67,112	60,241
Computer Equipment	159,045	159,089	159,136	165,261	165,693	166,156	166,657	167,267	167,895	168,628	170,180	165,796	165,067
Computer Software	145,670	145,698	145,728	145,759	145,793	145,828	145,867	146,706	146,854	147,026	147,558	161,606	147,508
Machinery & Equipment	400,126	400,126	403,097	402,931	403,086	403,251	403,431	407,385	410,052	412,883	433,013	444,923	410,359
Communication Equipment	119,288	119,288	120,157	130,249	131,079	131,817	132,617	132,997	133,924	135,006	136,358	138,387	130,097
Automotive	465,655	465,655	465,655	465,655	465,655	465,655	465,655	480,161	481,974	484,090	486,734	504,109	474,721
Rental Equipment - Res	2,072,688	2,074,678	2,080,355	2,085,314	2,090,668	2,102,040	2,109,757	2,112,830	2,119,764	2,131,677	2,141,435	2,157,405	2,106,551
Rental Equipment - Com	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699
Rental Equipment - Softeners	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627
Meters	2,007,825	2,009,363	2,009,693	2,013,901	2,014,511	2,018,023	2,018,970	2,020,772	2,022,939	2,028,758	2,036,724	2,043,790	2,020,439
Regulators	1,213,407	1,215,558	1,215,723	1,215,896	1,216,080	1,216,278	1,216,492	1,219,264	1,219,845	1,220,524	1,221,373	1,222,646	1,217,757
Plastic Mains	7,236,221	7,236,238	7,238,312	7,238,445	7,239,141	7,239,680	7,239,960	7,247,613	7,256,154	7,266,826	7,278,397	7,295,140	7,251,011
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	2,536,500	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	4,861,625
Plastic Services	2,648,410	2,651,853	2,663,535	2,666,845	2,662,391	2,666,053	2,670,180	2,676,048	2,679,903	2,685,574	2,692,843	2,706,327	2,672,497
Franchises & Consents	151,094	151,094	151,094	151,093	162,543	163,361	152,797	152,627	267,733	382,839	383,401	405,694	222,947
Total Assets	20,064,426	22,610,136	22,633,982	22,663,240	22,682,209	22,705,226	22,709,881	22,752,336	22,896,306	23,053,800	23,119,436	23,239,305	22,594,191

NATURAL RESOURCE GAS LIMITED

Accumulated Depreciation Property, Plant and Equipment
2009 Actual
($'s)

Accumulated Depreciation	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	0	0	0	0	0	0	0	0	0	0	0	0	0
Buildings	123,400	124,662	125,924	127,186	128,449	129,711	130,973	132,236	133,498	134,760	136,023	136,654	130,290
Furniture & Fixtures	35,931	36,320	36,709	37,098	37,487	37,876	38,265	38,654	39,043	39,433	39,822	40,016	38,054
Computer Equipment	131,821	132,666	133,511	134,357	135,202	136,048	136,893	137,738	138,584	139,429	140,275	140,697	136,435
Computer Software	118,545	119,513	120,481	121,449	122,417	123,385	124,353	125,321	126,289	127,257	128,225	128,709	123,829
Machinery & Equipment	382,595	386,105	389,615	393,125	396,635	400,145	403,655	407,165	410,675	412,883	417,044	419,125	401,564
Communication Equipment	32,895	33,799	34,704	35,608	36,513	37,417	38,322	39,226	40,131	41,035	41,940	42,392	37,832
Automotive	258,040	265,254	272,468	279,682	286,896	294,109	301,323	308,537	315,751	322,965	330,179	333,786	297,416
Rental Equipment - Res	734,865	736,908	738,952	740,995	743,039	745,082	747,125	749,169	751,212	753,255	755,299	756,321	746,019
Rental Equipment - Com	25,871	26,209	26,546	26,883	27,220	27,558	27,895	28,232	28,570	28,907	29,244	29,413	27,712
Rental Equipment - Softeners	5,977	6,038	6,098	6,159	6,220	6,280	6,341	6,401	6,462	6,522	6,583	6,613	6,308
Meters	893,402	899,589	905,776	911,963	918,149	924,336	930,523	936,710	942,896	949,083	955,270	958,363	927,172
Regulators	701,506	705,249	708,992	712,735	716,478	720,222	723,965	727,708	731,451	735,194	738,937	740,809	721,937
Plastic Mains	2,602,094	2,621,836	2,641,578	2,661,320	2,681,062	2,700,804	2,720,546	2,740,288	2,760,030	2,779,772	2,799,514	2,809,385	2,709,852
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	21,138	42,275	63,413	84,550	105,688	126,825	147,963	169,100	190,238	211,375	232,513	243,081	136,513
Plastic Services	1,615,443	1,622,991	1,630,538	1,638,086	1,645,633	1,653,181	1,660,728	1,668,276	1,675,823	1,683,371	1,690,918	1,694,692	1,656,640
Franchises & Consents	99,264	104,720	110,176	115,632	121,088	126,544	132,001	137,457	142,913	148,369	153,825	156,553	129,045
Total Accum. Depreciation	7,815,800	7,897,147	7,978,495	8,059,842	8,141,190	8,222,537	8,303,885	8,385,232	8,466,580	8,546,626	8,628,624	8,669,623	8,259,632

NATURAL RESOURCE GAS LIMITED

Net Property, Plant and Equipment
2009 Actual
($'s)

Net Fixed Asset Values	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	558,931	557,669	556,407	555,144	553,882	552,620	551,357	550,095	548,833	547,570	546,308	545,677	552,041
Furniture & Fixtures	19,196	18,807	18,418	18,422	21,711	22,837	22,861	23,641	23,853	24,165	25,227	27,096	22,187
Computer Equipment	27,224	26,423	25,625	30,904	30,490	30,108	29,764	29,529	29,311	29,199	29,905	25,099	28,632
Computer Software	27,125	26,185	25,247	24,310	23,375	22,443	21,514	21,385	20,565	19,769	19,334	32,898	23,679
Machinery & Equipment	17,531	14,021	13,482	9,806	6,451	3,106	-224	220	-622	0	15,969	25,798	8,795
Communication Equipment	86,393	85,489	85,454	94,641	94,566	94,400	94,295	93,771	93,794	93,971	94,419	95,995	92,265
Automotive	207,614	200,401	193,187	185,973	178,759	171,545	164,331	171,624	166,223	161,125	156,556	170,323	177,305
Rental Equipment - Res	1,337,823	1,337,769	1,341,403	1,344,319	1,347,629	1,356,958	1,362,632	1,363,661	1,368,552	1,378,422	1,386,136	1,401,084	1,360,532
Rental Equipment - Com	28,827	28,490	28,153	27,815	27,478	27,141	26,804	26,466	26,129	25,792	25,454	25,286	26,987
Rental Equipment - Softeners	5,649	5,589	5,528	5,468	5,407	5,347	5,286	5,226	5,165	5,104	5,044	5,014	5,319
Meters	1,114,423	1,109,774	1,103,917	1,101,938	1,096,362	1,093,687	1,088,447	1,084,063	1,080,042	1,079,675	1,081,454	1,085,426	1,093,267
Regulators	511,901	510,309	506,731	503,161	499,602	496,056	492,527	491,556	488,394	485,330	482,435	481,837	495,820
Plastic Mains	4,634,128	4,614,402	4,596,735	4,577,125	4,558,079	4,538,876	4,519,414	4,507,325	4,496,124	4,487,053	4,478,883	4,485,755	4,541,159
Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
New Steel Mains	2,515,363	5,030,725	5,009,588	4,988,450	4,967,313	4,946,175	4,925,038	4,903,900	4,882,763	4,861,625	4,840,488	4,829,919	4,725,112
Plastic Services	1,032,967	1,028,862	1,032,997	1,028,759	1,016,758	1,012,873	1,009,452	1,007,772	1,004,080	1,002,203	1,001,925	1,011,635	1,015,857
Franchises & Consents	51,830	46,374	40,918	35,461	41,455	36,817	20,797	15,170	124,820	234,470	229,575	249,141	93,902
Net Fixed Assets	12,248,626	14,712,989	14,655,487	14,603,398	14,541,019	14,482,689	14,405,997	14,367,104	14,429,726	14,507,175	14,490,812	14,569,682	14,334,559

NATURAL RESOURCE GAS LIMITED

Allowance for Working Capital
Actual 2009
($'s)

Allowance for Working Capital	Inventory	Cash Working Capital	Security Deposits	Total Allowance
October	94,890	-140,094	-753,994	-799,198
November	101,507	-140,094	-745,551	-784,138
December	105,537	-140,094	-727,362	-761,919
January	123,434	-140,094	-700,136	-716,797
February	149,444	-140,094	-674,531	-665,182
March	144,270	-140,094	-648,041	-643,865
April	133,320	-140,094	-618,754	-625,528
May	135,530	-140,094	-594,991	-599,555
June	139,054	-140,094	-553,159	-554,199
July	140,979	-140,094	-500,908	-500,023
August	142,054	-140,094	-464,159	-462,200
September	145,380	-140,094	-428,725	-423,439
Total	129,616	-140,094	-617,526	-628,004

NATURAL RESOURCE GAS LIMITED

Cash Requirements for Working Capital
2009 Actual
($'s)

	Annual Revenue	Allowance (Days)		
Revenue Lag				
Rate 1	10,281,302	31.1		
Rate 2	228,421	31.4		
Rate 3	2,376,694	32.2		
Rate 4	218,752	32.2		
Rate 5	514,314	35.5		
Rate 6	0	32.2		
Weighted Revenue Lag		31.5		
Expense Lag	Annual Expense	Allowance (Days)	Net Lag (Days)	Cash Need
Gas Costs				
- Local Production A (Affiliate)	2,011,720	45.6	(14.1)	-77,713
- Local Production B (Other)	0	32.0	(0.5)	0
- Dawn Deliveries	2,151,324	32.5	(1.0)	-5,894
- Parkway Deliveries	2,602,368	40.3	(8.8)	-62,742
- Western Deliveries	1,929	36.4	(4.9)	-26
- Ontario Delivered	79,940	32.8	(1.3)	-285
-TCPL	109,265	40.5	(9.0)	-2,694
- Union Gas	799,742	34.2	(2.7)	-5,916
Weighted Gas Cost Lag		38.8		-155,270
O & M Costs				
- Prepaid Insurance	52,020	(90.4)	121.9	17,373
- Labour	255,964	10.0	21.5	15,077
- Labour Related Costs	109,699	10.0	21.5	6,462
- Other Costs	-584,591	30.0	1.5	-2,402
Weighted O & M Cost Lag		111.3		36,510
GST Costs				
- Revenues	-817,169	30.9		-69,180
- O & M Expenses	-35,723	15.6		-1,527
- Capital Expenditures	54,458	15.6		2,328
- Gas Costs	465,350	36.9		47,045
Weighted GST Lag		23.4		-21,334
Total Working Cash Requirement				-140,094

NATURAL RESOURCE GAS LIMITED

Summary of Utility Rate Base
2010 Bridge Year
($'s)

	Bridge 2010	Last Year 2009
Property, Plant & Equipment		
Asset Values at Cost	23,714,819	22,594,191
Accumulated Depreciation	9,349,713	8,259,632
	14,365,106	14,334,559
Allowance for Working Capital		
Inventory	129,337	129,616
Working Cash Allowance	-94,052	-140,094
Security Deposits	-329,926	-617,526
	-294,641	-628,004
Utility Rate Base	14,070,465	13,706,555

	Variance from 2009
Property, Plant & Equipment	
Asset Values at Cost	1,120,628
Accumulated Depreciation	1,090,081
	30,547
Allowance for Working Capital	
Inventory	-279
Working Cash Allowance	46,042
Security Deposits	287,600
	333,363
Utility Rate Base	363,910

NATURAL RESOURCE GAS LIMITED

Utility Capital Expenditures
2010 Bridge Year
($'s)

	Bridge 2010	Actual 2009
Mains - Additions	199,334	74,011
- Replacements	2,000	2,018
Services - Additions	71,995	76,958
- Replacements	0	0
New Steel Mains	0	5,073,000
Meters	140,000	48,590
Regulators	18,000	11,761
Franchises	0	261,963
Land	0	0
Buildings	0	0
Furniture & Fixtures	1,500	14,050
Computer Equipment	6,000	3,348
Computer Software	7,803	30,607
Machinery & Equipment	6,200	56,706
Communication Equipment	20,000	21,128
Automotive	65,000	55,828
Water Softeners	0	0
Rental Water Heaters	193,009	222,983
Total Capital Expenditures	730,840	5,952,951

	Variance from 2009
Mains - Additions	125,323
- Replacements	-18
Services - Additions	-4,963
- Replacements	0
New Steel Mains	-5,073,000
Meters	91,410
Regulators	6,239
Franchises	-261,963
Land	0
Buildings	0
Furniture & Fixtures	-12,550
Computer Equipment	2,652
Computer Software	-22,804
Machinery & Equipment	-50,506
Communication Equipment	-1,128
Automotive	9,172
Water Softeners	0
Rental Water Heaters	-29,975
Total Capital Expenditures	-5,222,111

NATURAL RESOURCE GAS LIMITED

Capital Projects
2010
($'s)

Description	Cost
Main Additions	
Ostrander Road loop to Wilson	30,830
Springerhill Road Extension	11,645
Glencolin 2 inch extension	14,294
Heritage Line West	35,051
Short Main Extensions	107,514
Total Main Additions	199,334
Main Replacements	
No Replacements	2,000
Total Main Replacements	2,000
Service Additions	
Service additions - 105	71,995
Total Service Additions	71,995
Service Replacements	
Service replacements	0
Total Service Replacements	0
Summary	
Total Main Additions	199,334
Total Main Replacements	2,000
Total Mains	201,334
Total Service Additions	71,995
Total Service Replacements	0
Total Services	71,995
Total Capital Projects	273,329

NATURAL RESOURCE GAS LIMITED

Aggregate Cost/Benefit Ratio for Main Additions
2010 Bridge Year
($'s)

Main Additions	NPV of Revenues	NPV of Costs	Project Ratio
Ostrander Road loop to Wilson	-33	22,460	0.00
Springerhill Road Extension	37,081	12,630	2.94
Glencolin 2 inch extension	34,094	13,750	2.48
Heritage Line West	41,866	33,290	1.26
Main Additions	113,008	82,130	1.38

(1) An aid to construction may be collected for any project with a benefit/cost ratio less than 1.00.

March 8, 2010
EB-2010-0018
Exhibit B7
Tab 2
Schedule 4
Updated

NATURAL RESOURCE GAS LIMITED

Financial Tests
2010 Bridge Year

Attached

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Sprinerhill extention (greenhouse north west corner)**
Planned for Fiscal:
Date of Last Test: Oct. 26 2009 work done January 2010
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ -	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	380	m	$ 4.83	1,835
1.25"	P.E. Pipe	-	m	$ -	-
1"	P.E. Pipe	-	m	$ 1.92	-
1/2"	P.E. Pipe	-	m	$ 0.92	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	418	m	$ 0.38	-
				Total	1,835

Labour	Hours	Hourly Rate	Total
	18	25.40	457
	-	25.40	-
	-	25.40	-
		Total	457

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	9	$ 4.90	44
Generator	3	$ 1.50	5
Trencher	-	$ 39.00	-
Compressor	1	$ 3.60	4
Kubota	8	$ 2.20	18
Plow	8	$ 22.10	177
		Total	247

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	9	$ 1.20	11
Generator	3	$ 0.50	2
Trencher	-	$ -	-
Compressor	1	$ 4.20	4
Kubota	8	$ 4.80	38
Plow	8	$ 26.50	212
		Total	267

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	349	$ 20.00	6,980
		1	$ 800.00	800
			Total	7,780

Total Cost		**$ 10,586**
Contingency	10%	1,059
Total Project Cost		**$ 11,645**
Cost per Meter		$ 27.90
Benefit Cost Ratio		3
Aid to Construction		
Aid to Const (each)		$ -
Payback (Years)		5

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	1	1	-	-	-	-	1
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	1	1	-	-	-	-	1
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Sprinerhill extention (greenhouse north west corner)**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	-	-	-	-	1
Commercial	-	-	-	-	-	-
Industrial Rate 1	1	-	-	-	-	1
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	380
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	418

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ 4.83
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	12,630
NPV of revenue plus tax shield	37,081
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	2.936
Payback Period (Years)	5

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Sprinerhill extention (greenhouse north west corner)**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	1,835					1,835
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	1,835	-	-	-	-	1,835
Subcontractor & Rental Equipment						
Subcontractor	7,780					7,780
Contingency	1,059					1,059
Sub-total	8,839	-	-	-	-	8,839
Service Cost	440	-	-	-	-	440
Sub-total	440	-	-	-	-	440
Class 2 Pipelines	11,114	-	-	-	-	11,114
Meters & Regulators	2,318	-	-	-	-	2,318
Class 8 Equipment	2,318	-	-	-	-	2,318
Total Project Cost	13,432	-	-	-	-	13,432
NPV of Project Cost	$12,630					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{\text{UCC} \times \text{tax rate} \times \text{CCA rate}}{\text{CCA rate} + \text{discount rate}} \times \frac{2+\text{discount rate}}{2\times(1+\text{disc. rate})}$$

	Class 2	*Class 8*
PV of tax shield =	$ 1,889	$ 615

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description:	**Sprinerhill extention (greenhouse north west corner)**
Planned for Fiscal:	
Date of Last Test:	
Nature of Project (MA, MR)	

Sales Volumes (m3)	**Per Year**				
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**37,400**	**-**	**-**	**-**	**-**

	Cumulative				
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	2,000	2,000	2,000	2,000
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	35,400	35,400	35,400	35,400
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	37,400	**37,400**	**37,400**	**37,400**	**37,400**

	Cumulative				
Customers	**1**	**2**	**3**	**4**	**5**
Residential	1	1	1	1	1
Commercial	-	-	-	-	-
Industrial Rate 1	1	1	1	1	1
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**1**	**1**	**1**	**1**	**1**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Sprinerhill extention (greenhouse north west corner)**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	306	306	306	306	306	
Commercial	-	-	-	-	-	
Industrial Rate 1	4,044	4,044	4,044	4,044	4,044	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	4,350	4,350	4,350	4,350	4,350	
Plus: Fixed Revenue	138	138	138	138	138	
Sub-Total	138	138	138	138	138	
Less: M9 Delivery Costs	201	201	201	201	201	
Less: O&M Expense	77	77	77	77	77	
Less: Capital Tax	40	40	40	40	40	
Less Property Tax	105	105	105	105	105	
Sub-Total	424	424	424	424	424	
Pre Tax Revenue	4,065	4,065	4,065	4,065	4,065	
Less: Income Tax	1,463	1,463	1,463	1,463	1,463	
Net Revenue	2,601	2,601	2,601	2,601	2,601	2,601

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Sprinerhill extention (greenhouse north west corner)

Rate 1 - General Service Rate		Consumption Profile: **Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	6.00%
Class 8 CCA Rate	20.00%
Marginal Tax Rate	36.00%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	60.00%	6.52%
Demand Debt	0.00%	0.00%
Short Term Debt	0.00%	0.00%
Equity	40.00%	9.57%
	100.00%	6.33%

Discount Rate 6.33%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Sprinerhill extention (greenhouse north west corner)

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	77.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	77.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	77.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	77.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	77.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	77.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	181,480	45,370
Wages - Line Maintenance	12%	97,026	11,837
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	40,659	40,659
Wages - Sales	50%	90,126	45,063
Benefits (13.19% of Wages)	13%	464,609	61,282
Insurance	10%	122,123	12,212
Advertising & Promotion	100%	12,154	12,154
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	42,579	42,579
Repairs & Maintenance General	100%	46,821	46,821
Small Tools	100%	8,583	8,583
Automotive	100%	72,890	72,890
Mapping Expense	100%	156	156
Interest - Meter Deposits	100%	824	824
Bad Debts	100%	15,000	15,000
Bank Service Charges	100%	9,798	9,798
Collection Expense	100%	11,150	11,150
Miscellaneous	22%	13,673	2,981
Total			518,765
Average Customers			6,700
O&M Costs per Customer			$ 77.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-07**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ -	$ 4.42	0.0%	14.49
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 4.83	$ 1.00	0.0%	3.29
1.25" PE Pipe	$ -	$ 0.70	0.0%	2.30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Sprinerhill extention (greenhouse north west corner)

1" PE Pipe	$ 1.92	$ 0.46	0.0%	1.52
.5" PE Pipe	$ 0.92	$ 0.19	0.0%	0.64
Tracer Wire	$ 0.38		0.0%	0.38

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Glencolin 2" main extention**
Planned for Fiscal:
Date of Last Test: April 2 2009 **Up dated January 21 2010**
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	1,700	m	$ 3.16	5,372
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	1,870	m	$ 0.22	411
				Total	5,783

Labour	Hours	Hourly Rate	Total
	96	25.40	2,438
	-	25.40	-
	-	25.40	-
		Total	2,438

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	32	$ 4.90	157
Generator	5	$ 1.50	8
Trencher	2	$ 39.00	78
Compressor	1	$ 3.60	4
Kubota	32	$ 2.20	70
Plow	30	$ 22.10	663
		Total	979

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	32	$ 1.20	38
Generator	5	$ 0.50	3
Trencher	2	$ -	-
Compressor	1	$ 4.20	4
Kubota	32	$ 4.80	154
Plow	30	$ 26.50	795
		Total	994

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	100	$ 20.00	2,000
		1	$ 800.00	800
			Total	2,800

Total Cost		**$ 12,995**
Contingency	10%	1,299
Total Project Cost		**$ 14,294**
Cost per Meter		$ 7.60
Benefit Cost Ratio		2
Aid to Construction		$ -
Aid to Const (each)		$ -
Payback (Years)		9

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	17	1	5	3	3	5	17
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Glencolin 2" main extention**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	5	3	3	5	17
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	1,700
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	1,870

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ 3.16
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	13,750
NPV of revenue plus tax shield	34,094
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	2.480
Payback Period (Years)	9

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Glencolin 2" main extention**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	5,372					5,372
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	5,372	-	-	-	-	5,372
Subcontractor & Rental Equipment						
Subcontractor	2,800					2,800
Contingency	1,299					1,299
Sub-total	4,099	-	-	-	-	4,099
Service Cost	190	950	570	570	950	3,230
Sub-total	190	950	570	570	950	3,230
Class 2 Pipelines	9,661	950	570	570	950	12,701
Meters & Regulators	168	838	503	503	838	2,848
Class 8 Equipment	168	838	503	503	838	2,848
Total Project Cost	9,829	1,788	1,073	1,073	1,788	15,549
NPV of Project Cost	$13,750					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 2,857	$ 716

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Glencolin 2" main extention**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	10,000	6,000	6,000	10,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**2,000**	**10,000**	**6,000**	**6,000**	**10,000**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	12,000	18,000	24,000	34,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	2,000	**12,000**	**18,000**	**24,000**	**34,000**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	1	6	9	12	17
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Glencolin 2" main extention**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

		Year					
Gas Sales Revenues ($)		**1**	**2**	**3**	**4**	**5**	
Residential		306	1,835	2,752	3,670	5,199	
Commercial		-	-	-	-	-	
Industrial Rate 1		-	-	-	-	-	
Industrial Rate 4		-	-	-	-	-	
Seasonal		-	-	-	-	-	
Industrial Rate 3 - Firm		-	-	-	-	-	
Industrial Rate 3 - Interruptible		-	-	-	-	-	
Sub-Total		306	1,835	2,752	3,670	5,199	
Plus: Fixed Revenue		-	-	-	-	-	
Sub-Total		-	-	-	-	-	
Less: M9 Delivery Costs		11	65	97	129	183	
Less: O&M Expense		-	-	-	-	-	
Less: Capital Tax		29	35	38	41	47	
Less Property Tax		442	442	442	442	442	
Sub-Total		482	541	577	612	671	
Pre Tax Revenue	-	176	1,293	2,175	3,057	4,527	
Less: Income Tax	-	61	448	753	1,059	1,568	
Net Revenue	-	115	846	1,422	1,999	2,959	2,959

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Glencolin 2" main extention

Rate 1 - General Service Rate		Consumption Profile: Residential	Commercial	Industrial Rate 1
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		Consumption Profile
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		Consumption Profile
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		Consumption Profile
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	Rate
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	Allocation	Cost of Debt/Capital
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate 6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Glencolin 2" main extention

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted **24-Jan-10** Current

Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Glencolin 2" main extention

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Heritage line west from reg.rd. 23**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR) **up dated January 21 2010**

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	2,800	m	$ 3.16	8,848
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	3,080	m	$ 0.22	678
				Total	9,526

Labour	Hours	Hourly Rate	Total
	120	25.40	3,048
	-	25.40	-
	-	25.40	-
		Total	3,048

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	40	$ 4.90	196
Generator	10	$ 1.50	15
Trencher	10	$ 39.00	390
Compressor	5	$ 3.60	18
Kubota	25	$ 2.20	55
Plow	20	$ 22.10	442
		Total	1,116

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	40	$ 1.20	48
Generator	10	$ 0.50	5
Trencher	10	$ -	-
Compressor	5	$ 4.20	21
Kubota	25	$ 4.80	120
Plow	20	$ 26.50	530
		Total	724

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	875	$ 20.00	17,500
		-	$ -	-
			Total	17,500

Total Cost		**$ 31,914**
Contingency	10%	3,191
Total Project Cost		**$ 35,105**
Cost per Meter		$ 11.40
Benefit Cost Ratio		1
Aid to Construction		$ -
Aid to Const (each)		$ -
Payback (Years)		28

Expected Customer Additions	Potential	Year 1	2	3	4	5	Total
Residential	28	8	4	4	2	-	18
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Heritage line west from reg.rd. 23**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Customer Additions	**Year 1**	**2**	**3**	**4**	**5**	**Total**
Residential	8	4	4	2	-	18
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	2,800
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	3,080

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ 3.16
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	33,290
NPV of revenue plus tax shield	41,866
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	1.258
Payback Period (Years)	28

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Heritage line west from reg.rd. 23**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	8,848					8,848
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	8,848	-	-	-	-	8,848
Subcontractor & Rental Equipment						
Subcontractor	17,500					17,500
Contingency	3,191					3,191
Sub-total	20,691	-	-	-	-	20,691
Service Cost	1,520	760	760	380	-	3,420
Sub-total	1,520	760	760	380	-	3,420
Class 2 Pipelines	31,059	760	760	380	-	32,959
Meters & Regulators	1,340	670	670	335	-	3,015
Class 8 Equipment	1,340	670	670	335	-	3,015
Total Project Cost	32,399	1,430	1,430	715	-	35,974
NPV of Project Cost	$33,290					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 7,414	$ 758

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Heritage line west from reg.rd. 23**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	16,000	8,000	8,000	4,000	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**16,000**	**8,000**	**8,000**	**4,000**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	16,000	24,000	32,000	36,000	36,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	16,000	**24,000**	**32,000**	**36,000**	**36,000**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	8	12	16	18	18
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Heritage line west from reg.rd. 23**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	2,446	3,670	4,893	5,504	5,504	
Commercial	-	-	-	-	-	
Industrial Rate 1	-	-	-	-	-	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	2,446	3,670	4,893	5,504	5,504	
Plus: Fixed Revenue	-	-	-	-	-	
Sub-Total	-	-	-	-	-	
Less: M9 Delivery Costs	86	129	172	194	194	
Less: O&M Expense	-	-	-	-	-	
Less: Capital Tax	97	101	106	108	108	
Less Property Tax	728	728	728	728	728	
Sub-Total	911	959	1,006	1,030	1,030	
Pre Tax Revenue	1,535	2,711	3,887	4,475	4,475	
Less: Income Tax	532	939	1,346	1,550	1,550	
Net Revenue	1,004	1,772	2,541	2,925	2,925	2,925

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Heritage line west from reg.rd. 23

Rate 1 - General Service Rate		**Consumption Profile** Residential	Commercial	Industrial Rate 1
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate 6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Heritage line west from reg.rd. 23

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted **24-Jan-10** Current

Pipeline		$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
	6" PE Pipe	$ -	$ 6.57	0.0%	21.54
	4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
	3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
	2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
	1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Heritage line west from reg.rd. 23

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Wilson line loop to Ostrander**
Planned for Fiscal: **High pressure feed**
Date of Last Test: **(July 24 2009)** **update January 21 2010**
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	-	m	$ 11.30	-
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	3,400	m	$ 3.16	10,744
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	3,740	m	$ 0.22	823
				Total	11,567

Labour	Hours	Hourly Rate	Total
	160	25.40	4,064
	-	25.40	-
	-	25.40	-
		Total	4,064

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	40	$ 4.90	196
Generator	5	$ 1.50	8
Trencher	4	$ 39.00	156
Compressor	2	$ 3.60	7
Kubota	25	$ 2.20	55
Plow	35	$ 22.10	774
		Total	1,195

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	40	$ 1.20	48
Generator	5	$ 0.50	3
Trencher	4	$ -	-
Compressor	2	$ 4.20	8
Kubota	25	$ 4.80	120
Plow	35	$ 26.50	928
		Total	1,106

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	380	$ 20.00	7,600
		1	$ 2,500.00	2,500
			Total	10,100

Total Cost		**$ 28,032**
Contingency	10%	2,803
Total Project Cost		**$ 30,836**
Cost per Meter		$ 8.20
Benefit Cost Ratio		- 0
Aid to Construction		$ 22,493
Aid to Const (each)		$ 22,493
Payback (Years)		30

Expected Customer Additions	Potential	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Residential	1	1	-	-	-	-	1
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description:	**Wilson line loop to Ostrander**
Planned for Fiscal:	
Date of Last Test:	
Nature of Project (MA, MR)	

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	1	-	-	-	-	1
Commercial	-	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	-
3"	-
2"	3,400
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	3,740

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ -
3"	$ -
2"	$ 3.16
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	22,460
NPV of revenue plus tax shield	-33
AID TO CONSTRUCTION	22,493
BENEFIT/COST RATIO	-0.001
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Wilson line loop to Ostrander**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	-					-
3"	-					-
2"	10,744					10,744
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	10,744	-	-	-	-	10,744
Subcontractor & Rental Equipment						
Subcontractor	10,100					10,100
Contingency	2,803					2,803
Sub-total	12,903	-	-	-	-	12,903
Service Cost	190	-	-	-	-	190
Sub-total	190	-	-	-	-	190
Class 2 Pipelines	23,837	-	-	-	-	23,837
Meters & Regulators	168	-	-	-	-	168
Class 8 Equipment	168	-	-	-	-	168
Total Project Cost	24,005	-	-	-	-	24,005
NPV of Project Cost	$22,460					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 5,362	$ 42

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Wilson line loop to Ostrander**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	-	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**2,000**	**-**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	2,000	2,000	2,000	2,000	2,000
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	2,000	**2,000**	**2,000**	**2,000**	**2,000**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	1	1	1	1	1
Commercial	-	-	-	-	-
Industrial Rate 1	-	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**-**	**-**	**-**	**-**	**-**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Wilson line loop to Ostrander**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

			Year			
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	306	306	306	306	306	
Commercial	-	-	-	-	-	
Industrial Rate 1	-	-	-	-	-	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	306	306	306	306	306	
Plus: Fixed Revenue	-	-	-	-	-	
Sub-Total	-	-	-	-	-	
Less: M9 Delivery Costs	11	11	11	11	11	
Less: O&M Expense	-	-	-	-	-	
Less: Capital Tax	72	72	72	72	72	
Less Property Tax	884	884	884	884	884	
Sub-Total	967	967	967	967	967	
Pre Tax Revenue	- 661	- 661	- 661	- 661	- 661	
Less: Income Tax	- 229	- 229	- 229	- 229	- 229	
Net Revenue	- 432	- 432	- 432	- 432	- 432	-432

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Wilson line loop to Ostrander

			Consumption Profile		
Rate 1 - General Service Rate			**Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$	0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$	0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$	11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate			**Consumption Profile**
First 1,000 m3	$	0.145000	14.80%
Next 24,000 m3	$	0.100431	85.20%
All over 25,000 m3	$	0.065417	2.00%
Monthly Fixed Charge	$	12.75	100.00%

Rate 3 - Special Large Volume Contract Rate			**Consumption Profile**
Monthly Customer Charge	$	150.00	
FIRM CD PER M*3	$	0.255904	
FIRM COMMODITY	$	0.037310	
INT COMMODITY	$	0.092249	

Rate 4 - General Service Peakng			**Consumption Profile**
First 1,000 m3	$	0.185648	19.80%
All over 1,000 m3	$	0.166254	80.20%
Monthly Fixed Charge	$	12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate	6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Wilson line loop to Ostrander

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
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Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
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3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Wilson line loop to Ostrander

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED

Property, Plant & Equipment
Summary of Averages - 2010 Bridge Year
($'s)

Item	Gross Property Plant & Equip.	Accumulated Depreciation	Net Plant
Land	71,700	0	71,700
Buildings	682,331	145,490	536,841
Furniture & Fixtures	69,989	42,795	27,194
Computer Equipment	164,663	144,784	19,879
Computer Software	178,472	134,226	44,246
Machinery & Equipment	460,290	443,861	16,429
Communication Equipment	149,915	49,561	100,354
Automotive	562,219	390,127	172,092
Rental Equipment - Res	2,269,208	852,195	1,417,013
Rental Equipment - Com	54,699	31,774	22,925
Rental Equipment - Softeners	11,627	7,037	4,590
Meters	2,120,370	1,004,416	1,115,954
Regulators	1,232,856	767,369	465,487
Plastic Mains	7,411,851	2,951,113	4,460,738
Steel Mains	33,014	33,014	0
New Steel Mains	5,073,000	391,044	4,681,956
Plastic Services	2,755,558	1,748,823	1,006,735
Franchises & Consents	413,057	212,084	200,973
Total	23,714,819	9,349,713	14,365,106

March 8, 2010
EB-2010-0018
Exhibit B7
Tab 3
Schedule 2
Updated

NATURAL RESOURCE GAS LIMITED

Gross Property, Plant and Equipment
2010 Bridge
($'s)

Asset Values at Cost	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331	682,331
Furniture & Fixtures	69,176	69,426	69,676	69,676	69,676	69,926	70,176	70,176	70,176	70,426	70,676	70,676	69,989
Computer Equipment	161,913	162,413	162,913	163,413	163,913	164,413	164,913	165,413	165,913	166,413	166,913	167,413	164,663
Computer Software	175,654	175,654	175,654	176,955	178,255	178,255	178,255	179,556	180,856	180,856	180,856	180,856	178,472
Machinery & Equipment	456,832	456,832	456,832	456,832	457,432	460,532	463,032	463,032	463,032	463,032	463,032	463,032	460,290
Communication Equipment	140,415	142,415	144,415	144,415	146,415	148,415	150,415	152,415	154,415	156,415	158,415	160,415	149,915
Automotive	521,483	521,483	521,483	521,483	536,483	568,983	586,483	586,483	586,483	604,652	604,652	586,483	562,219
Rental Equipment - Res	2,181,416	2,197,500	2,213,584	2,229,668	2,245,752	2,261,836	2,277,920	2,294,004	2,310,088	2,326,172	2,342,256	2,350,298	2,269,208
Rental Equipment - Com	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699
Rental Equipment - Soften	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627
Meters	2,056,689	2,068,356	2,080,022	2,091,689	2,103,356	2,115,022	2,126,689	2,138,356	2,150,022	2,161,689	2,173,356	2,179,189	2,120,370
Regulators	1,224,668	1,226,168	1,227,668	1,229,168	1,230,668	1,232,168	1,233,668	1,235,168	1,236,668	1,238,168	1,239,668	1,240,418	1,232,856
Plastic Mains	7,320,272	7,337,050	7,353,828	7,370,605	7,387,383	7,404,161	7,420,939	7,437,717	7,454,495	7,471,272	7,488,050	7,496,439	7,411,851
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000
Plastic Services	2,722,811	2,728,810	2,734,810	2,740,809	2,746,809	2,752,809	2,758,808	2,764,808	2,770,807	2,776,807	2,782,806	2,785,806	2,755,558
Franchises & Consents	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057
Total Assets	23,370,757	23,425,535	23,480,313	23,534,141	23,605,570	23,695,948	23,770,726	23,826,555	23,882,384	23,955,331	24,010,109	24,020,454	23,714,819

March 8, 2010
EB-2010-0018
Exhibit B7
Tab 3
Schedule 3
Updated

NATURAL RESOURCE GAS LIMITED

Accumulated Depreciation Property, Plant and Equipment
2010 Bridge
($'s)

Accumulated Depreciation	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	0	0	0	0	0	0	0	0	0	0	0	0	0
Buildings	138,547	139,810	141,072	142,334	143,597	144,859	146,121	147,383	148,646	149,908	151,170	152,433	145,490
Furniture & Fixtures	40,608	41,006	41,403	41,801	42,199	42,596	42,994	43,391	43,789	44,186	44,584	44,981	42,795
Computer Equipment	141,684	142,247	142,811	143,375	143,938	144,502	145,066	145,629	146,193	146,756	147,320	147,884	144,784
Computer Software	129,967	130,741	131,516	132,290	133,065	133,839	134,613	135,388	136,162	136,936	137,711	138,485	134,226
Machinery & Equipment	424,690	428,176	431,662	435,147	438,633	442,118	445,604	449,089	452,575	456,061	459,546	463,032	443,861
Communication Equipment	43,877	44,911	45,944	46,978	48,011	49,044	50,078	51,111	52,144	53,178	54,211	55,244	49,561
Automotive	345,506	353,619	361,732	369,845	377,958	386,071	394,184	402,297	410,410	418,523	426,636	434,749	390,127
Rental Equipment - Res	771,935	786,528	801,120	815,713	830,306	844,898	859,491	874,084	888,676	903,269	917,862	932,455	852,195
Rental Equipment - Com	29,919	30,256	30,594	30,931	31,268	31,605	31,943	32,280	32,617	32,955	33,292	33,629	31,774
Rental Equipment - Soften	6,704	6,765	6,825	6,886	6,946	7,007	7,067	7,128	7,189	7,249	7,310	7,370	7,037
Meters	968,066	974,675	981,284	987,893	994,502	1,001,111	1,007,720	1,014,329	1,020,938	1,027,548	1,034,157	1,040,766	1,004,416
Regulators	746,479	750,277	754,075	757,873	761,671	765,470	769,268	773,066	776,864	780,662	784,461	788,259	767,369
Plastic Mains	2,839,542	2,859,828	2,880,114	2,900,399	2,920,685	2,940,971	2,961,256	2,981,542	3,001,828	3,022,113	3,042,399	3,062,685	2,951,113
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	274,788	295,925	317,063	338,200	359,338	380,475	401,613	422,750	443,888	465,025	486,163	507,300	391,044
Plastic Services	1,706,213	1,713,960	1,721,707	1,729,455	1,737,202	1,744,949	1,752,696	1,760,444	1,768,191	1,775,938	1,783,686	1,791,433	1,748,823
Franchises & Consents	167,405	175,529	183,652	191,776	199,899	208,023	216,146	224,270	232,393	240,517	248,640	256,764	212,084
Total Accum. Depreciation	8,808,944	8,907,266	9,005,587	9,103,909	9,202,230	9,300,552	9,398,874	9,497,195	9,595,517	9,693,839	9,792,160	9,890,482	9,349,713

NATURAL RESOURCE GAS LIMITED

Net Property, Plant and Equipment
2010 Bridge
($'s)

Net Fixed Asset Values	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	543,784	542,521	541,259	539,997	538,734	537,472	536,210	534,947	533,685	532,423	531,160	529,898	536,841
Furniture & Fixtures	28,568	28,420	28,273	27,875	27,478	27,330	27,182	26,785	26,387	26,240	26,092	25,695	27,194
Computer Equipment	20,229	20,166	20,102	20,038	19,975	19,911	19,847	19,784	19,720	19,657	19,593	19,529	19,879
Computer Software	45,687	44,913	44,139	44,665	45,191	44,416	43,642	44,168	44,694	43,920	43,146	42,371	44,246
Machinery & Equipment	32,141	28,656	25,170	21,685	18,799	18,413	17,428	13,942	10,457	6,971	3,486	0	16,429
Communication Equipment	96,538	97,505	98,471	97,438	98,405	99,371	100,338	101,305	102,271	103,238	104,205	105,171	100,354
Automotive	175,977	167,864	159,751	151,638	158,525	182,912	192,299	184,186	176,073	186,130	178,017	151,734	172,092
Rental Equipment - Res	1,409,481	1,410,972	1,412,464	1,413,955	1,415,446	1,416,938	1,418,429	1,419,920	1,421,412	1,422,903	1,424,395	1,417,844	1,417,013
Rental Equipment - Com	24,780	24,442	24,105	23,768	23,430	23,093	22,756	22,419	22,081	21,744	21,407	21,069	22,925
Rental Equipment - Soften	4,923	4,862	4,802	4,741	4,681	4,620	4,559	4,499	4,438	4,378	4,317	4,257	4,590
Meters	1,088,623	1,093,681	1,098,738	1,103,796	1,108,854	1,113,911	1,118,969	1,124,026	1,129,084	1,134,141	1,139,199	1,138,423	1,115,954
Regulators	478,190	475,891	473,593	471,295	468,997	466,699	464,400	462,102	459,804	457,506	455,208	452,159	465,487
Plastic Mains	4,480,730	4,477,222	4,473,714	4,470,206	4,466,698	4,463,191	4,459,683	4,456,175	4,452,667	4,449,159	4,445,651	4,433,754	4,460,738
Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
New Steel Mains	4,798,213	4,777,075	4,755,938	4,734,800	4,713,663	4,692,525	4,671,388	4,650,250	4,629,113	4,607,975	4,586,838	4,565,700	4,681,956
Plastic Services	1,016,598	1,014,850	1,013,102	1,011,355	1,009,607	1,007,859	1,006,112	1,004,364	1,002,616	1,000,869	999,121	994,373	1,006,735
Franchises & Consents	245,652	237,528	229,405	221,281	213,157	205,034	196,910	188,787	180,663	172,540	164,416	156,293	200,973
Net Fixed Assets	14,561,813	14,518,269	14,474,726	14,430,233	14,403,340	14,395,396	14,371,853	14,329,360	14,286,867	14,261,493	14,217,949	14,129,972	14,365,106

NATURAL RESOURCE GAS LIMITED

Allowance for Working Capital
Bridge Year 2010
($'s)

Allowance for Working Capita	Inventory	Cash Working Capital	Security Deposits	Total Allowance
October	97,737	-94,052	-403,191	-399,506
November	104,552	-94,052	-389,870	-379,370
December	108,703	-94,052	-376,549	-361,898
January	127,137	-94,052	-363,228	-330,143
February	153,927	-94,052	-349,907	-290,032
March	146,579	-94,052	-336,586	-284,060
April	133,281	-94,052	-323,265	-284,036
May	134,867	-94,052	-309,944	-269,129
June	135,521	-94,052	-296,623	-255,154
July	132,485	-94,052	-283,302	-244,869
August	133,719	-94,052	-269,981	-230,314
September	143,541	-94,052	-256,660	-207,172
Total	129,337	-94,052	-329,926	-294,641

NATURAL RESOURCE GAS LIMITED

Cash Requirements for Working Capital
2010 Bridge
($'s)

	Annual Revenue	Allowance (Days)
Revenue Lag		
Rate 1	10,422,371	31.1
Rate 2	223,513	31.4
Rate 3	831,819	32.2
Rate 4	220,789	32.2
Rate 5	502,407	35.5
Rate 6	1,580,588	32.2
Weighted Revenue Lag		31.5

Expense Lag	Annual Expense	Allowance (Days)	Net Lag (Days)	Cash Need
Gas Costs				
- Local Production A (Affiliate)	664,584	45.6	(14.1)	-25,673
- Local Production B (Other)	217,944	32.0	(0.5)	-299
- Dawn Deliveries	2,047,931	32.5	(1.0)	-5,611
- Parkway Deliveries	2,653,545	40.3	(8.8)	-63,976
- Western Deliveries	0	36.4	(4.9)	0
- Ontario Delivered	0	32.8	(1.3)	0
-TCPL	364,884	40.5	(9.0)	-8,997
- Union Gas	823,456	34.2	(2.7)	-6,091
Weighted Gas Cost Lag		37.5		-110,647
O & M Costs				
- Prepaid Insurance	52,020	(90.4)	121.9	17,373
- Labour	262,209	10.0	21.5	15,445
- Labour Related Costs	112,375	10.0	21.5	6,619
- Other Costs	676,952	30.0	1.5	2,782
Weighted O & M Cost Lag		17.5		42,219
GST Costs				
- Revenues	-826,889	30.9		-70,002
- O & M Expenses	39,969	15.6		1,708
- Capital Expenditures	37,216	15.6		1,591
- Gas Costs	406,341	36.9		41,079
Weighted GST Lag		27.2		-25,624
Total Working Cash Requirement				-94,052

NATURAL RESOURCE GAS LIMITED

Summary of Utility Rate Base
2011 Test Year
($'s)

	Test 2011	Bridge 2010
Property, Plant & Equipment		
Asset Values at Cost	24,437,860	23,714,819
Accumulated Depreciation	10,594,789	9,349,713
	13,843,071	14,365,106
Allowance for Working Capital		
Inventory	145,095	129,337
Working Cash Allowance	-98,602	-94,052
Security Deposits	-270,833	-329,926
	-224,340	-294,641
Utility Rate Base	13,618,731	14,070,465

	Variance from 2010
Property, Plant & Equipment	
Asset Values at Cost	723,041
Accumulated Depreciation	1,245,076
	-522,035
Allowance for Working Capital	
Inventory	15,758
Working Cash Allowance	-4,550
Security Deposits	59,093
	70,301
Utility Rate Base	-451,734

NATURAL RESOURCE GAS LIMITED

Utility Capital Expenditures
2011 Test Year
($'s)

	Test 2011	Bridge 2010
Mains - Additions	199,239	199,334
- Replacements	2,000	2,000
Services - Additions	75,293	71,995
- Replacements	0	0
New Steel Mains	0	0
Meters	140,000	140,000
Regulators	20,000	18,000
Franchises	0	0
Land	0	0
Buildings	40,000	0
Furniture & Fixtures	1,500	1,500
Computer Equipment	6,000	6,000
Computer Software	23,682	7,803
Machinery & Equipment	44,631	6,200
Communication Equipment	20,000	20,000
Automotive	35,000	65,000
Water Softeners	0	0
Rental Water Heaters	202,659	193,009
Total Capital Expenditures	810,004	730,841

	Variance from 2010
Mains - Additions	-95
- Replacements	0
Services - Additions	3,297
- Replacements	0
New Steel Mains	0
Meters	0
Regulators	2,000
Franchises	0
Land	0
Buildings	40,000
Furniture & Fixtures	0
Computer Equipment	0
Computer Software	15,879
Machinery & Equipment	38,431
Communication Equipment	0
Automotive	-30,000
Water Softeners	0
Rental Water Heaters	9,650
Total Capital Expenditures	79,163

08/03/2010
EB-2010-0018
Exhibit B8
Tab 2
Schedule 2
Updated

NATURAL RESOURCE GAS LIMITED

Capital Projects
2011
($'s)

Description	Cost
Main Additions	
Culloden Line North	76,461
Prouse Road to Avon Drive (tie-in)	101,775
Short Main Extensions	23,003
Total Main Additions	201,239
Main Replacements	
Replacements	2,000
Total Main Replacements	2,000
Service Additions	
Service additions - 105	75,293
Total Service Additions	75,293
Service Replacements	
Service replacements	0
Total Service Replacements	0
Summary	
Total Main Additions	201,239
Total Main Replacements	2,000
Total Mains	203,239
Total Service Additions	75,293
Total Service Replacements	0
Total Services	75,293
Total Capital Projects	278,532

NATURAL RESOURCE GAS LIMITED

Aggregate Cost/Benefit Ratio for Main Additions
2011 Test Year
($'s)

Main Additions	NPV of Revenues	NPV of Costs	Project Ratio
Culloden Line North	72,396	69,510	1.04
Prouse Road to Avon Drive (tie-in)	79,327	95,940	0.83
Total Main Additions	151,723	165,450	0.92

(1) An aid to construction may be collected for any project with a benefit/cost ratio less than 1.00.

NATURAL RESOURCE GAS LIMITED

Financial Tests
2011 Test Year

Attached

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Culloden to Prouse road**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR) Nov.02 2009 **up dated January 21 2010**

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	3,000	m	$ 15.10	45,300
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	-	m	$ 3.16	-
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	3,300	m	$ 0.22	726
				Total	46,026

Labour	Hours	Hourly Rate	Total
	180	25.40	4,572
	-	25.40	-
	-	25.40	-
		Total	4,572

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	60	$ 4.90	294
Generator	10	$ 1.50	15
Trencher	20	$ 39.00	780
Compressor	10	$ 3.60	36
Kubota	30	$ 2.20	66
Plow	30	$ 22.10	663
		Total	1,854

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	60	$ 1.20	72
Generator	10	$ 0.50	5
Trencher	20	$ -	-
Compressor	10	$ 4.20	42
Kubota	30	$ 4.80	144
Plow	30	$ 26.50	795
		Total	1,058

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	800	$ 20.00	16,000
		-	$ -	-
			Total	16,000

Total Cost		**$ 69,510**
Contingency	10%	6,951
Total Project Cost		**$ 76,461**
Cost per Meter		$ 23.20
Benefit Cost Ratio		1
Aid to Construction		$ -
Aid to Const (each)		$ -
Payback (Years)		30

		Year					
Expected Customer Additions	**Potential**	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	4	2	2	-	-	-	4
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	2	1	1	-	-	-	2
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Culloden to Prouse road**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	2	2	-	-	-	4
Commercial	-	-	-	-	-	-
Industrial Rate 1	1	1	-	-	-	2
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	3,000
3"	-
2"	-
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	3,300

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ 15.10
3"	$ -
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	69,510
NPV of revenue plus tax shield	72,396
AID TO CONSTRUCTION	0
BENEFIT/COST RATIO	1.042
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Culloden to Prouse road**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	45,300					45,300
3"	-					-
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	45,300	-	-	-	-	45,300
Subcontractor & Rental Equipment						
Subcontractor	16,000					16,000
Contingency	6,951					6,951
Sub-total	22,951	-	-	-	-	22,951
Service Cost	630	630	-	-	-	1,260
Sub-total	630	630	-	-	-	1,260
Class 2 Pipelines	68,881	630	-	-	-	69,511
Meters & Regulators	2,485	2,485	-	-	-	4,970
Class 8 Equipment	2,485	2,485	-	-	-	4,970
Total Project Cost	71,366	3,115	-	-	-	74,481
NPV of Project Cost	$69,510					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{\text{UCC} \times \text{tax rate} \times \text{CCA rate}}{\text{CCA rate} + \text{discount rate}} \times \frac{2+\text{discount rate}}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 15,637	$ 1,250

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Culloden to Prouse road**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	4,000	4,000	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	35,400	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**39,400**	**39,400**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	4,000	8,000	8,000	8,000	8,000
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	70,800	70,800	70,800	70,800
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	39,400	**78,800**	**78,800**	**78,800**	**78,800**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	2	4	4	4	4
Commercial	-	-	-	-	-
Industrial Rate 1	1	2	2	2	2
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**1**	**2**	**2**	**2**	**2**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Culloden to Prouse road**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	612	1,223	1,223	1,223	1,223	
Commercial	-	-	-	-	-	
Industrial Rate 1	4,044	8,089	8,089	8,089	8,089	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	4,656	9,312	9,312	9,312	9,312	
Plus: Fixed Revenue	138	276	276	276	276	
Sub-Total	138	276	276	276	276	
Less: M9 Delivery Costs	212	424	424	424	424	
Less: O&M Expense	115	230	230	230	230	
Less: Capital Tax	214	223	223	223	223	
Less Property Tax	1,626	1,633	1,633	1,633	1,633	
Sub-Total	2,167	2,510	2,510	2,510	2,510	
Pre Tax Revenue	2,627	7,078	7,078	7,078	7,078	
Less: Income Tax	910	2,451	2,451	2,451	2,451	
Net Revenue	1,717	4,627	4,627	4,627	4,627	4,627

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Culloden to Prouse road

		Consumption Profile		
Rate 1 - General Service Rate		**Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate	6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Culloden to Prouse road

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Culloden to Prouse road

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator

Project Description: **Prouse road to Avon tie in**
Planned for Fiscal:
Date of Last Test: Nov. 02 2009 **up date January 21 2010**
Nature of Project (MA, MR)

Size	Description	Quantity	Unit of Measure	Price	Total
6"	P.E. Pipe	-	m	$ -	-
4"	P.E. Pipe	4,500	m	$ 15.10	67,950
3"	P.E. Pipe	-	m	$ 9.50	-
2"	P.E. Pipe	-	m	$ 3.16	-
1.25"	P.E. Pipe	-	m	$ 1.93	-
1"	P.E. Pipe	-	m	$ 1.33	-
1/2"	P.E. Pipe	-	m	$ 0.53	-
1/2"	service risers	-	m	$ -	-
	Tracer Wire	4,950	m	$ 0.22	1,089
				Total	69,039

Labour	Hours	Hourly Rate	Total
	180	25.40	4,572
	-	25.40	-
	-	25.40	-
		Total	4,572

Capitalized Equipment	Hours	Hourly Rate	Total
Trucks	60	$ 4.90	294
Generator	10	$ 1.50	15
Trencher	20	$ 39.00	780
Compressor	10	$ 3.60	36
Kubota	30	$ 2.20	66
Plow	30	$ 22.10	663
		Total	1,854

Capitalized Depreciation	Hours	Hourly Rate	Total
Trucks	60	$ 1.20	72
Generator	10	$ 0.50	5
Trencher	20	$ -	-
Compressor	10	$ 4.20	42
Kubota	30	$ 4.80	144
Plow	30	$ 26.50	795
		Total	1,058

Subcontractors & Rentals	Unit of Measure	Units	Hourly Rate	Total
Lumpsum	m	800	$ 20.00	16,000
		-	$ -	-
			Total	16,000

Total Cost		**$ 92,523**
Contingency	10%	9,252
Total Project Cost		**$ 101,775**
Cost per Meter		$ 20.60
Benefit Cost Ratio		1
Aid to Construction		$ 16,613
Aid to Const (each)		$ 831
Payback (Years)		30

		Year					
Expected Customer Additions	**Potential**	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	20	10	10	-	-	-	20
Commercial	-	-	-	-	-	-	-
Industrial Rate 1	1	1	-	-	-	-	1
Industrial Rate 4	-	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-	-

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Prouse road to Avon tie in**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Customer Additions	**1**	**2**	**3**	**4**	**5**	**Total**
Residential	10	10	-	-	-	20
Commercial	-	-	-	-	-	-
Industrial Rate 1	1	-	-	-	-	1
Industrial Rate 4	-	-	-	-	-	-
Seasonal	-	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-	-
(FIRM CD - M*3)	-	-	-	-	-	

Pipe (Meters)	**Meters**
6"	-
4"	4,500
3"	-
2"	-
1.25"	-
1"	-
1/2"	-
1/2" Service Risers	-
Tracer Wire	4,950

Pipe (Cost per Meter)	**Cost Per Meter**
6"	$ -
4"	$ 15.10
3"	$ -
2"	$ -
1.25"	$ -
1"	$ -
1/2"	$ -
1/2" Service Risers	$ -
Tracer Wire	$ -

NPV OF COSTS	95,940
NPV of revenue plus tax shield	79,327
AID TO CONSTRUCTION	16,613
BENEFIT/COST RATIO	0.827
Payback Period (Years)	30

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Prouse road to Avon tie in**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Project Cost	**Year**					
Size	**1**	**2**	**3**	**4**	**5**	**Total**
6"	-					-
4"	67,950					67,950
3"	-					-
2"	-					-
1.25"	-					-
1"	-					-
1/2"	-					-
1/2" Service Risers	-					-
Tracer Wire	-					-
Sub-total	67,950	-	-	-	-	67,950
Subcontractor & Rental Equipment						
Subcontractor	16,000					16,000
Contingency	9,252					9,252
Sub-total	25,252	-	-	-	-	25,252
Service Cost	2,150	1,900	-	-	-	4,050
Sub-total	2,150	1,900	-	-	-	4,050
Class 2 Pipelines	95,352	1,900	-	-	-	97,252
Meters & Regulators	3,825	1,675	-	-	-	5,500
Class 8 Equipment	3,825	1,675	-	-	-	5,500
Total Project Cost	99,177	3,575	-	-	-	102,752
NPV of Project Cost	$95,940					

Tax Shield
Formula based on the following

$$\text{Tax shield} = \frac{(\text{UCC} \times \text{tax rate} \times \text{CCA rate})}{(\text{CCA rate} + \text{discount rate})} \times \frac{(2+\text{discount rate})}{2\times(1+\text{disc. rate})}$$

	Class 2	***Class 8***
PV of tax shield =	$ 21,877	$ 1,383

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Prouse road to Avon tie in**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

Sales Volumes (m3)			**Per Year**		
Year	**1**	**2**	**3**	**4**	**5**
Residential	20,000	20,000	-	-	-
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	-	-	-	-
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**55,400**	**20,000**	**-**	**-**	**-**

			Cumulative		
Year	**1**	**2**	**3**	**4**	**5**
Residential	20,000	40,000	40,000	40,000	40,000
Commercial	-	-	-	-	-
Industrial Rate 1	35,400	35,400	35,400	35,400	35,400
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
	55,400	**75,400**	**75,400**	**75,400**	**75,400**

			Cumulative		
Customers	**1**	**2**	**3**	**4**	**5**
Residential	10	20	20	20	20
Commercial	-	-	-	-	-
Industrial Rate 1	1	1	1	1	1
Industrial Rate 4	-	-	-	-	-
Seasonal	-	-	-	-	-
Industrial Rate 3 - Firm	-	-	-	-	-
Industrial Rate 3 - Interruptible	-	-	-	-	-
Total	**1**	**1**	**1**	**1**	**1**

NATURAL RESOURCE GAS LIMITED
Aid to Construct Calculator Worksheet

Project Description: **Prouse road to Avon tie in**
Planned for Fiscal:
Date of Last Test:
Nature of Project (MA, MR)

	Year					
Gas Sales Revenues ($)	**1**	**2**	**3**	**4**	**5**	
Residential	3,058	6,116	6,116	6,116	6,116	
Commercial	-	-	-	-	-	
Industrial Rate 1	4,044	4,044	4,044	4,044	4,044	
Industrial Rate 4	-	-	-	-	-	
Seasonal	-	-	-	-	-	
Industrial Rate 3 - Firm	-	-	-	-	-	
Industrial Rate 3 - Interruptible	-	-	-	-	-	
Sub-Total	7,102	10,160	10,160	10,160	10,160	
Plus: Fixed Revenue	138	138	138	138	138	
Sub-Total	138	138	138	138	138	
Less: M9 Delivery Costs	298	406	406	406	406	
Less: O&M Expense	115	115	115	115	115	
Less: Capital Tax	298	308	308	308	308	
Less Property Tax	2,436	2,436	2,436	2,436	2,436	
Sub-Total	3,147	3,265	3,265	3,265	3,265	
Pre Tax Revenue	4,094	7,033	7,033	7,033	7,033	
Less: Income Tax	1,418	2,436	2,436	2,436	2,436	
Net Revenue	2,676	4,598	4,598	4,598	4,598	4,598

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Prouse road to Avon tie in

Rate 1 - General Service Rate		Consumption Profile: **Residential**	**Commercial**	**Industrial Rate 1**
First 1,000 m3	$ 0.152999	99.80%	54.10%	20.80%
All over 1,000 m3	$ 0.104073	0.20%	45.90%	79.20%
Monthly Fixed Charge	$ 11.50	100.00%	100.00%	100.00%

Rate 2 - Seasonal Rate		**Consumption Profile**
First 1,000 m3	$ 0.145000	14.80%
Next 24,000 m3	$ 0.100431	85.20%
All over 25,000 m3	$ 0.065417	2.00%
Monthly Fixed Charge	$ 12.75	100.00%

Rate 3 - Special Large Volume Contract Rate		**Consumption Profile**
Monthly Customer Charge	$ 150.00	
FIRM CD PER M*3	$ 0.255904	
FIRM COMMODITY	$ 0.037310	
INT COMMODITY	$ 0.092249	

Rate 4 - General Service Peakng		**Consumption Profile**
First 1,000 m3	$ 0.185648	19.80%
All over 1,000 m3	$ 0.166254	80.20%
Monthly Fixed Charge	$ 12.75	100.00%

Income Taxation Rates	**Rate**
Class 2 CCA Rate	14.00%
Class 8 CCA Rate	20.63%
Marginal Tax Rate	34.63%
Federal Capital Tax Rate	-
Provincial Capital Tax Rate	0.0030

Debt/Equity	**Allocation**	**Cost of Debt/Capital**
Long Term Debt	79.00%	5.80%
Demand Debt	0.00%	0.00%
Short Term Debt	-21.00%	0.00%
Equity	42.00%	9.20%
	100.00%	6.86%

Discount Rate 6.86%

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Prouse road to Avon tie in

M9 Delivery Commodity Charge	**Union Contract (SA 1550)**
Residential	$ 0.005378
Commercial	$ 0.005378
Industrial Rate 1	$ 0.005378
Industrial Rate 4	$ 0.005378
Seasonal	$ 0.005378
Industrial Rate 3 - Firm	$ 0.005378
Industrial Rate 3 - Interruptible	$ 0.005378

Property Tax Assessment Rates

	Size		
	6"	$ 1.15	$ 44.65
	4"	$ 0.54	$ 21.05
	3"	$ 0.45	$ 17.35
	2"	$ 0.26	$ 10.30
		$ 6.43	$ 250.00
Average rate			0.0257

	Meters & Regulators (Each)	**Service Connection Cost**	**Average Consumption per Customer**	**Average Selling Price per Customer ($/m3)**	**O&M Expense per Customer**
Residential	$ 168	$ 190	2,000	$ 0.152901	115.00
Commercial	$ 168	$ 190	8,700	$ 0.130542	115.00
Industrial Rate 1	$ 2,150	$ 250	35,400	$ 0.114250	115.00
Industrial Rate 4	$ 2,560	$ 450	13,200	$ 0.170094	115.00
Seasonal	$ 2,560	$ 575	28,000	$ 0.172444	115.00
Industrial Rate 3 & Rate 5	$ -	$ -	-	$ -	115.00

O&M Costs	**Allocation %**	**2008**	**Allocation**
Wages - Office	25%	298,632	74,658
Wages - Line Maintenance	12%	100,011	12,201
Wages - Operations Manager	100%	55,318	55,318
Wages - Meter Reading	100%	49,576	49,576
Wages - Sales	50%	87,298	43,649
Benefits (13.19% of Wages)	13%	590,835	77,931
Insurance	10%	197,396	19,740
Advertising & Promotion	100%	38,263	38,263
Office, Supplies & Stationary	100%	24,088	24,088
Postage & Courier	100%	115,429	115,429
Repairs & Maintenance General	100%	110,269	110,269
Small Tools	100%	8,583	8,583
Automotive	100%	69,528	69,528
Mapping Expense	100%	1,013	1,013
Interest - Meter Deposits	100%	5,843	5,843
Bad Debts	100%	51,982	51,982
Bank Service Charges	100%	16,618	16,618
Collection Expense	100%	14,308	14,308
Miscellaneous	22%	13,673	2,981
Total			791,977
Average Customers			6,869
O&M Costs per Customer			$ 115.00

Calcuation of O&M Costs Per Customer
- Based on actual costs from fiscal 2003
- Based on average cost for categories most likely to be affected by Customer additions
- Incremental costs are likley to be lower than average costs

Construction Costs

Last Date Quoted		**24-Jan-10**		Current
Pipeline	$ Per Meter (incl. PST)	$ per foot (incl. PST)	Inflation Rate	Cost per meter (incl. PST)
6" PE Pipe	$ -	$ 6.57	0.0%	21.54
4" PE Pipe	$ 11.30	$ 3.22	0.0%	10.56
3" PE Pipe	$ 9.50	$ 2.07	0.0%	6.79
2" PE Pipe	$ 3.16	$ 0.90	0.0%	2.95
1.25" PE Pipe	$ 1.93	$ 0.55	0.0%	1.80

NATURAL RESOURCE GAS LIMITED
Aid to Construct Variables
Prouse road to Avon tie in

1" PE Pipe	$ 1.33	$ 0.38	0.0%	1.25
.5" PE Pipe	$ 0.53	$ 0.15	0.0%	0.49
Tracer Wire	$ 0.22		0.0%	0.22

Average Labour rate	$ 25.40

Capitalized Expenses	Overhead	Amortization
Trucks	$ 4.90	$ 1.20
Generator	$ 1.50	$ 0.50
Trencher	$ 39.00	$ -
Compressor	$ 3.60	$ 4.20
Kubota	$ 2.20	$ 4.80
Plow	$ 22.10	$ 26.50

08/03/2010
EB-2010-0018
Exhibit B8
Tab 3
Schedule 1
Updated

NATURAL RESOURCE GAS LIMITED

Property, Plant & Equipment
Summary of Averages - 2011 Test Year
($'s)

Item	Gross Property Plant & Equip.	Accumulated Depreciation	Net Plant
Land	71,700	0	71,700
Buildings	707,331	161,119	546,212
Furniture & Fixtures	71,364	47,620	23,744
Computer Equipment	170,330	151,409	18,921
Computer Software	194,838	143,357	51,481
Machinery & Equipment	481,891	481,891	0
Communication Equipment	171,249	62,798	108,451
Automotive	608,469	490,630	117,839
Rental Equipment - Res	2,419,228	1,084,068	1,335,160
Rental Equipment - Com	54,699	35,822	18,877
Rental Equipment - Softeners	11,627	7,764	3,863
Meters	2,260,856	1,086,470	1,174,386
Regulators	1,251,918	813,345	438,573
Plastic Mains	7,613,837	3,198,073	4,415,764
Steel Mains	33,014	33,014	0
New Steel Mains	5,073,000	644,694	4,428,306
Plastic Services	2,829,452	1,843,148	986,304
Franchises & Consents	413,057	309,567	103,490
Total	24,437,860	10,594,789	13,843,071

NATURAL RESOURCE GAS LIMITED

Gross Property, Plant and Equipment
2011 Test
($'s)

Asset Values at Cost	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	682,331	682,331	682,331	682,331	702,331	722,331	722,331	722,331	722,331	722,331	722,331	722,331	707,331
Furniture & Fixtures	70,676	70,676	70,926	71,176	71,176	71,176	71,426	71,676	71,676	71,676	71,926	72,176	71,364
Computer Equipment	167,413	167,413	167,413	168,413	169,413	169,413	170,413	171,413	172,413	173,413	173,413	173,413	170,330
Computer Software	184,957	186,457	187,957	190,904	192,351	193,851	195,351	196,798	199,746	201,246	202,746	205,693	194,838
Machinery & Equipment	463,032	463,032	463,032	463,032	463,032	475,532	488,032	488,032	497,032	506,032	506,032	506,847	481,891
Communication Equipment	160,415	162,415	164,415	166,415	168,415	170,415	172,415	174,415	176,415	178,415	180,415	180,415	171,249
Automotive	586,483	586,483	586,483	586,483	586,483	603,983	621,483	621,483	621,483	639,652	639,652	621,483	608,469
Rental Equipment - Res	2,370,786	2,379,594	2,388,401	2,397,209	2,406,016	2,414,824	2,423,632	2,432,439	2,441,247	2,450,054	2,458,862	2,467,669	2,419,228
Rental Equipment - Com	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699	54,699
Rental Equipment - Softeners	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627	11,627
Meters	2,196,689	2,208,356	2,220,022	2,231,689	2,243,356	2,255,022	2,266,689	2,278,356	2,290,022	2,301,689	2,313,356	2,325,022	2,260,856
Regulators	1,242,752	1,244,418	1,246,085	1,247,752	1,249,418	1,251,085	1,252,752	1,254,418	1,256,085	1,257,752	1,259,418	1,261,085	1,251,918
Plastic Mains	7,521,602	7,538,372	7,555,142	7,571,912	7,588,682	7,605,452	7,622,221	7,638,991	7,655,761	7,672,531	7,689,301	7,706,071	7,613,837
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000	5,073,000
Plastic Services	2,794,943	2,801,217	2,807,492	2,813,766	2,820,041	2,826,315	2,832,589	2,838,864	2,845,138	2,851,412	2,857,687	2,863,961	2,829,452
Franchises & Consents	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057	413,057
Total Assets	24,099,176	24,147,861	24,196,796	24,248,178	24,317,810	24,416,496	24,496,431	24,546,313	24,606,445	24,683,300	24,732,235	24,763,263	24,437,860

NATURAL RESOURCE GAS LIMITED

Accumulated Depreciation Property, Plant and Equipment
2011 Test
($'s)

Accumulated Depreciation	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	0	0	0	0	0	0	0	0	0	0	0	0	0
Buildings	153,769	155,105	156,442	157,778	159,114	160,451	161,787	163,123	164,459	165,796	167,132	168,468	161,119
Furniture & Fixtures	45,387	45,793	46,199	46,605	47,011	47,417	47,823	48,229	48,635	49,041	49,447	49,853	47,620
Computer Equipment	148,426	148,969	149,511	150,053	150,596	151,138	151,681	152,223	152,766	153,308	153,850	154,393	151,409
Computer Software	139,235	139,984	140,734	141,483	142,233	142,982	143,732	144,481	145,231	145,980	146,730	147,480	143,357
Machinery & Equipment	466,751	466,751	466,751	466,751	466,751	475,532	488,032	488,032	497,032	506,032	506,032	506,847	481,891
Communication Equipment	56,406	57,569	58,731	59,893	61,055	62,217	63,379	64,542	65,704	66,866	68,028	69,190	62,798
Automotive	443,346	451,943	460,540	469,137	477,735	486,332	494,929	503,526	512,123	520,720	529,318	537,915	490,630
Rental Equipment - Res	955,780	979,105	1,002,430	1,025,755	1,049,080	1,072,405	1,095,730	1,119,055	1,142,381	1,165,706	1,189,031	1,212,356	1,084,068
Rental Equipment - Com	33,967	34,304	34,641	34,979	35,316	35,653	35,990	36,328	36,665	37,002	37,340	37,677	35,822
Rental Equipment - Softeners	7,431	7,491	7,552	7,612	7,673	7,734	7,794	7,855	7,915	7,976	8,036	8,097	7,764
Meters	1,047,797	1,054,829	1,061,860	1,068,891	1,075,923	1,082,954	1,089,986	1,097,017	1,104,048	1,111,080	1,118,111	1,125,143	1,086,470
Regulators	792,118	795,978	799,837	803,696	807,556	811,415	815,274	819,134	822,993	826,852	830,712	834,571	813,345
Plastic Mains	3,083,514	3,104,343	3,125,172	3,146,001	3,166,830	3,187,659	3,208,488	3,229,317	3,250,146	3,270,975	3,291,804	3,312,633	3,198,073
Steel Mains	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014	33,014
New Steel Mains	528,438	549,575	570,713	591,850	612,988	634,125	655,263	676,400	697,538	718,675	739,813	760,950	644,694
Plastic Services	1,799,389	1,807,345	1,815,301	1,823,258	1,831,214	1,839,170	1,847,126	1,855,082	1,863,039	1,870,995	1,878,951	1,886,907	1,843,148
Franchises & Consents	264,888	273,011	281,135	289,258	297,382	305,505	313,629	321,752	329,876	337,999	346,123	354,247	309,567
Total Accum. Depreciation	9,999,655	10,105,108	10,210,562	10,316,016	10,421,469	10,535,704	10,653,657	10,759,111	10,873,565	10,988,018	11,093,472	11,199,741	10,594,789

NATURAL RESOURCE GAS LIMITED

Net Property, Plant and Equipment
2011 Test
($'s)

Net Fixed Asset Values	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Land	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700	71,700
Buildings	528,562	527,225	525,889	524,553	543,217	561,880	560,544	559,208	557,871	556,535	555,199	553,862	546,212
Furniture & Fixtures	25,289	24,883	24,727	24,571	24,165	23,759	23,603	23,447	23,041	22,635	22,479	22,323	23,744
Computer Equipment	18,987	18,444	17,902	18,360	18,817	18,275	18,732	19,190	19,647	20,105	19,563	19,020	18,921
Computer Software	45,723	46,473	47,224	49,421	50,119	50,869	51,620	52,317	54,515	55,265	56,016	58,213	51,481
Machinery & Equipment	-3,719	-3,719	-3,719	-3,719	-3,719	0	0	0	0	0	0	0	0
Communication Equipment	104,009	104,847	105,685	106,522	107,360	108,198	109,036	109,874	110,712	111,549	112,387	111,225	108,451
Automotive	143,137	134,540	125,943	117,345	108,748	117,651	126,554	117,957	109,360	118,932	110,335	83,568	117,839
Rental Equipment - Res	1,415,007	1,400,489	1,385,971	1,371,454	1,356,936	1,342,419	1,327,901	1,313,384	1,298,866	1,284,348	1,269,831	1,255,313	1,335,160
Rental Equipment - Com	20,732	20,395	20,057	19,720	19,383	19,045	18,708	18,371	18,034	17,696	17,359	17,022	18,877
Rental Equipment - Softeners	4,196	4,136	4,075	4,014	3,954	3,893	3,833	3,772	3,712	3,651	3,591	3,530	3,863
Meters	1,148,892	1,153,527	1,158,162	1,162,798	1,167,433	1,172,068	1,176,703	1,181,339	1,185,974	1,190,609	1,195,244	1,199,880	1,174,386
Regulators	450,633	448,441	446,248	444,055	441,863	439,670	437,477	435,284	433,092	430,899	428,706	426,514	438,573
Plastic Mains	4,438,088	4,434,029	4,429,970	4,425,911	4,421,852	4,417,793	4,413,734	4,409,674	4,405,615	4,401,556	4,397,497	4,393,438	4,415,764
Steel Mains	0	0	0	0	0	0	0	0	0	0	0	0	0
New Steel Mains	4,544,563	4,523,425	4,502,288	4,481,150	4,460,013	4,438,875	4,417,738	4,396,600	4,375,463	4,354,325	4,333,188	4,312,050	4,428,306
Plastic Services	995,554	993,872	992,190	990,509	988,827	987,145	985,463	983,781	982,100	980,418	978,736	977,054	986,304
Franchises & Consents	148,169	140,045	131,922	123,798	115,675	107,551	99,428	91,304	83,181	75,057	66,934	58,810	103,490
Net Fixed Assets	14,099,521	14,042,753	13,986,234	13,932,163	13,896,341	13,880,792	13,842,773	13,787,202	13,732,881	13,695,282	13,638,763	13,563,522	13,843,071

NATURAL RESOURCE GAS LIMITED

Allowance for Working Capital
Test Year 2011
($'s)

Allowance for Working Capital	Inventory	Cash Working Capital	Security Deposits	Total Allowance
October	145,095	-98,602	-500,000	-453,507
November	145,095	-98,602	-250,000	-203,507
December	145,095	-98,602	-250,000	-203,507
January	145,095	-98,602	-250,000	-203,507
February	145,095	-98,602	-250,000	-203,507
March	145,095	-98,602	-250,000	-203,507
April	145,095	-98,602	-250,000	-203,507
May	145,095	-98,602	-250,000	-203,507
June	145,095	-98,602	-250,000	-203,507
July	145,095	-98,602	-250,000	-203,507
August	145,095	-98,602	-250,000	-203,507
September	145,095	-98,602	-250,000	-203,507
Total	145,095	-98,602	-270,833	-224,340

NATURAL RESOURCE GAS LIMITED

Cash Requirements for Working Capital
2011 Test
($'s)

	Annual Revenue	Allowance (Days)
Revenue Lag		
Rate 1	10,197,646	31.1
Rate 2	218,924	31.4
Rate 3	776,996	32.2
Rate 4	207,309	32.2
Rate 5	332,575	35.5
Rate 6	1,580,588	32.2
Weighted Revenue Lag		31.4

Expense Lag	Annual Expense	Allowance (Days)	Net Lag (Days)	Cash Need
Gas Costs				
- Local Production A (Affiliate)	1,024,260	45.6	(14.2)	-39,848
- Local Production B (Other)	0	32.0	(0.6)	0
- Dawn Deliveries	2,266,752	32.5	(1.1)	-6,831
- Parkway Deliveries	2,901,368	40.3	(8.9)	-70,746
- Western Deliveries	0	36.4	(5.0)	0
- Ontario Delivered	109,723	32.8	(1.4)	-421
- TCPL	0	40.5	(9.1)	0
- Union Gas	899,744	34.2	(2.8)	-6,902
Weighted Gas Cost Lag		37.7		-124,748
O & M Costs				
- Prepaid Insurance	52,020	(90.4)	121.8	17,359
- Labour	261,330	10.0	21.4	15,322
- Labour Related Costs	111,998	10.0	21.4	6,566
- Other Costs	888,660	30.0	1.4	3,409
Weighted O & M Cost Lag		19.6		42,656
GST Costs				
- Revenues	-665,702	30.9		-56,357
- O & M Expenses	43,893	15.6		1,876
- Capital Expenditures	36,656	15.6		1,567
- Gas Costs	360,092	36.9		36,404
Weighted GST Lag		26.8		-16,510
Total Working Cash Requirement				-98,602

NATURAL RESOURCE GAS LIMITED

OPERATING REVENUE

NRG's total operating revenue is divided into two components – gas distribution and transportation revenue, and other operating revenue (net). This latter category is made up of the rental equipment program, contract work program, service work program, merchandise sales, direct purchase fees, delayed payment charges, interest revenue and transfer/connect charges.

Gas distribution and transportation revenue has been calculated using the most recently approved rates. In particular, delivery rates are based on the RP-2005-0544 Rate Order, dated September 28, 2006. Distribution and transportation revenue does not include the gas supply charge related to the PGCVA reference price, the GPRA recovery or the gas commodity recovery charge. Distribution and transportation revenues do, however, include the portion of the gas supply charge related to the system gas supply cost.

Fiscal 2011 Test Year

NRG's operating revenue is forecast to be $6,144,773 in Fiscal 2011, as shown in Exhibit C8, Tab 1, Schedule 1. Gas distribution and transportation revenue totals $5,480,613 or 89.2% of total revenues. Other operating revenue (net) accounts for the remaining revenue of $664,160.

Comparison to Fiscal 2010 Bridge Year

As shown in Exhibit C8, Tab 1, Schedule 2, total operating revenue is expected to be $100,290 above the bridge year level in fiscal 2011. This increase is the result of an increase of $65,799 in gas distribution and transportation revenue and an increase of $34,491 in other operating revenue (net).

The change in distribution and transportation revenue is driven by changes in throughput volumes. These changes are detailed in Exhibit C8, Tab 2, Schedule 4.

Fiscal 2010 Bridge Year

Total operating revenue is expected to be $6,044,483 in fiscal 2010, on a normalized basis, as shown in Exhibit C7, Tab 1, Schedule 1.

On a normalized basis, gas distribution and transportation revenue totals $5,414,814, or 89.4% of total operating revenue. The rental equipment programs continued to be the largest contributor to the other operating revenue (net).

Comparison to Fiscal 2009 Actual

Exhibit C7, Tab 1, Schedule 2, provides a comparison of the normalized operating revenue from the 2010 bridge year to 2009 actual (on a non-weather normalized basis). Total operating revenue is forecast to be $117,797 or 2.0% higher in fiscal 2010 than in fiscal 2009. This increase is the result of increased revenue from IGPC and marginally lower other distribution revenue from other customer classes. A $60,477 increase in Ancillary Services revenue is largely due to increased Rental Equipment revenue.

Fiscal 2009 Historical Year

Exhibit C6, Tab 1, Schedule 1 shows that in fiscal 2009, normalized operating revenues totaled $5,926,685. Distribution and transportation revenue totaled $5,357,493, or 90.4% of the total. The remaining $569,192 was contributed by other operating revenue (net).

Comparison to Fiscal 2008 Actual

Exhibit C6, Tab 1, Schedule 2, provides a comparison of the normalized operating revenue from the 2009 actual to 2008 actual (on a normalized basis). Total operating revenue is forecast to be $1,437,223 or 32.0% greater in fiscal 2009 than in fiscal 2008. Distribution revenues were $1,365,734 greater in 2009 than in 2008. This increase is primarily due to the recovery of revenues from IGPC through the application of Rate 3 rates. Other Revenues were $71,489 greater in 2009 than in 2008. This increase is mainly due to changes in Service Work Program revenues.

Fiscal 2008 Historical Year

Exhibit C5, Tab 1, Schedule 1 shows that in fiscal 2008, operating revenues totaled $4,489,462. Distribution and transportation revenue totaled $3,991,759, or 89.4% of the total. The remaining $497,704 was contributed by other operating revenue (net).

Comparison to Fiscal 2007 Actual

Exhibit C5, Tab 1, Schedule 2, provides a comparison of the normalized operating revenue from the 2008 actual to 2007 actual. Total operating revenue is forecast to be $158,967 or 3.7% greater in fiscal 2008 than in fiscal 2007. Distribution revenues were $240,088 greater in 2008 than in 2007. This increase is primarily due to the recovery of revenues from IGPC through the application of Rate 3 rates. Other Revenues were $81,120 lower in 2008 than in 2007. This decrease is mainly due to reduced Contract Work Program, Delayed Payment and Interest revenues.

Fiscal 2007 Historical Year

Exhibit C4, Tab 1, Schedule 1 shows that in fiscal 2007, operating revenues totaled $4,330,495. Distribution and transportation revenue totaled $3,751,671, or 86.6% of the total. The remaining $578,824 was contributed by Ancillary Services and Interest Revenue.

Comparison to Fiscal 2006 Actual

Exhibit C4, Tab 1, Schedule 2, provides a comparison of the actual operating revenue from the 2007 actual to 2006 actual. Total operating revenue is forecast to be $162,257 or 3.9% greater in fiscal 2007 than in fiscal 2006. Distribution revenues were $221,956 greater in 2007 than in 2006. This increase is primarily due to increased revenues recovered from Rate 1-Residential and Rate 1-Commercial customers. Other Revenues were $59,699 lower in 2007 than in 2006. This decrease is mainly due to reduced Contract Work Program revenues.

Fiscal 2007 actual operating revenues were $239,590 lower than the Board Approved RP-2005-0544 level. $137,388 of this decrease was in distribution and transportation revenues with the remainder of the difference coming from a reduction in other operating revenues (net). The decrease in distribution and transportation revenues was mainly attributable to lower volumes for Rate 1 residential customers. Other Revenues were $102,202 lower than the authorized level. This information is shown in Exhibit C4.1, Tab 1, Schedule 2.

Fiscal 2006 Historical Year

As shown in Exhibit C3, Tab 1, Schedule 1, operating revenues totaled $4,168,238 in fiscal 2006. Distribution and transportation revenues totaled $3,529,715, or 84.7% of the total. Other operating revenue (net) totaled $638,523.

Exhibit C3, Tab 1, Schedule 2 provides a comparison of fiscal 2006 to fiscal 2005. Total operating revenue fell by $188,501 in 2006. This was the result of a $185,240 decrease in distribution and transportation revenue due mainly to reduced revenues from Rate 1- Residential and Rate 3- Contract customers. It also reflects a $3,261 reduction in Ancillary Services revenue that is chiefly due to $122,990 lower Rental Equipment Program revenues and $39,509 higher Contract Work Program revenues.

NATURAL RESOURCE GAS LIMITED

THROUGHPUT VOLUME

The purpose of the evidence contained in Tab 2 of Exhibits C3, C4, C5, C6, C7 and C8 is to provide the Board with a review of NRG's actual and forecasted gas sales customers, volumes and revenues for the historical, bridge and test years. The forecast was prepared in November of 2009. Test year revenues have been calculated using the approved RP-2005-0544 Rate Order (dated September 28, 2006).

Fiscal 2011 Test Year

As shown in Exhibit C8, Tab 2, Schedule 1, normalized gas sales and transportation volumes are forecast to be 53,375,045 m^3. This will result in gas distribution and transportation revenues of $5,480,613. By the end of fiscal 2011, NRG expects to be providing gas service to 7,145 customers.

Comparison to Fiscal 2010 Bridge Year

Exhibit C8, Tab 2, Schedule 2 provides a comparison of year-end customers in 2011 as compared to 2010. NRG is forecasting the net addition of 139 customers, including 137 residential customers and 2 commercial customers.

Exhibit C8, Tab 2, Schedule 3 provides a comparison of the normalized throughput in 2011 as compared to 2010. Total throughput is expected to increase by 298,997 m^3 or 0.6%. The increase is the result of increased throughput to newly added residential customers.

Fiscal 2010 Bridge Year

As shown in Exhibit C7, Tab 2, Schedule 1, NRG expects to have 7,006 customers at year end of fiscal 2010. Throughput is forecast to be 53,076,048 m^3 with associated revenues of $5,414,814.

Comparison to Fiscal 2009 Actual

NRG has forecast a net addition of 136 customers in 2010 as compared to 2009, as shown in Exhibit C7, Tab 2, Schedule 2. This increase is concentrated in residential customers with the addition of 131 customers. Four commercial and one small industrial customer additions are also forecast.

Total throughput is forecast to fall by 222,113 m^3 or 0.4% in 2010 on a normalized basis. Increases in Residential Rate 1 and in Rate 4 volumes are more than offset by declines in Rates 2 and 5. These changes are shown in Exhibit C7, Tab 2, Schedule 3.

Fiscal 2009 Historical Year

As shown in Exhibit C6, Tab 2, Schedule 1, normalized volumes in fiscal 2009 totaled 53,298,161 m^3, with an associated normalized distribution and transportation revenue of $5,357,493. At the end of fiscal 2009, NRG served a total of 6,869 customers.

Comparison to Fiscal 2008 Actual

NRG experienced the net addition of 111 customers in 2009 as compared to 2008, as shown in Exhibit C6, Tab 2, Schedule 2. This increase is concentrated in residential customers with the addition of 129 customers. NRG also experienced the loss of two Rate 1 – Commercial, one Rate 1 – Industrial and 17 Rate 2 – Seasonal customers.

Total throughput increased by 32,209,089 m^3 or more than 250% in 2009 on a normalized basis. This reflects a full year of deliveries to IGPC. These changes are shown in Exhibit C6, Tab 2, Schedule 3.

<u>Fiscal 2008 Historical Year</u>

As shown in Exhibit C5, Tab 2, Schedule 1, actual volumes in fiscal 2008 totaled 21,301,279 m^3, with an associated normalized distribution and transportation revenue of $3,991,759. At the end of fiscal 2008, NRG served a total of 6,759 customers.

<u>Comparison to Fiscal 2007 Actual</u>

NRG experienced the net addition of 177 customers in 2008 as compared to 2007, as shown in Exhibit C5, Tab 2, Schedule 2. This increase is concentrated in residential customers, with the addition of 180 customers, and in Rate – Commercial, with the addition of 9 customers. NRG also experienced the loss of two Rate 1-Industrial, 9 Rate 2-Seasonal and one Rate 3-Contract customers.

Total throughput decreased by 1,731,634 m^3 or 7.6% in 2008. Decreases in Rate 2 – Seasonal and Rate 3-Contract were not offset by increases in other classes. These changes are shown in Exhibit C5, Tab 2, Schedule 3.

<u>Fiscal 2007 Historical Year</u>

As shown in Exhibit C4, Tab 2, Schedule 1, actual volumes in fiscal 2007 totaled 22,820,706 m^3, with an associated actual distribution and transportation revenue of $3,751,671. At the end of fiscal 2007, NRG served a total of 6,582 customers.

Comparison to Fiscal 2006 Actual

NRG experienced the net addition of 145 customers in 2007 as compared to 2006, as shown in Exhibit C4, Tab 2, Schedule 2. This increase reflects the net addition of 154 new Rate 1-Residential, four Rate 1-Commercial and one Rate 1-Industrial customers. NRG experienced the loss of fourteen Rate 2-Seasonal customers in the period.

Total throughput increased by 94,132 m^3 or 0.4% in 2007. Increases in Rate 1, 4 and 5 deliveries were nearly offset by declines in Rate 2-Seasonal of 1,406,699 m3. These changes are shown in Exhibit C4, Tab 2, Schedule 3.

Fiscal 2007 versus Board Authorized Levels

Exhibit C4.1, Tab 2, Schedule 3 provides a comparison of the 2007 throughput volumes with the Board Approved RP-2005-0544 forecast. Lower than forecast volumes were recorded in the Rate 1-Residential, Rate 1-Industrial, and Rate 4 customer classes. These decreases were not offset by increased delivery volumes to Rate 1-Commercial accounts. NRG did not realize its forecast Rate 1-Residential customer count.

Fiscal 2006 Historical Year

As shown in Exhibit C3, Tab 2, Schedule 4, actual volumes in fiscal 2006 totaled 22,726,574 m^3, with an associated normalized distribution and transportation revenue of $3,529,715. At the end of fiscal 2006, NRG served a total of 6,437 customers.

As shown in Exhibit C3, Tab 2, Schedule 2, the number of customers served by NRG at year-end was 257 higher than the number served in 2005 and reflects the addition of 248 Rate 1-Residential customers, fifteen Rate 1-Commercial and two Rate 1-Industrial customers as well as the loss of eight Rate 2-Seasonal customers.

NATURAL RESOURCE GAS LIMITED

RATE OF RETURN ON ANCILLARY SERVICES

The evidence contained in Tab 3 of Exhibits C3, C4, C5, C6, C7 and C8 provides the Board with a review of NRG's actual and forecasted rate of return on ancillary services. The programs included in ancillary services in the 2011 TY are service work, merchandise sales, rental equipment and direct purchase fees. As of 2010, revenues from the Rental Equipment Program and from the Contract Work Program have been consolidated.

The costs associated with each of the above programs include all costs that are directly assigned to each of the programs and all costs allocated from the Board-approved Fully Allocated Costing (FAC) Study. Rate base items assigned to the various programs also correspond to the assets allocated to ancillary services in the FAC Study. The FAC Study does not allocate costs between the various ancillary programs. A portion of the delayed payment charges are also allocated to ancillary services, as determined by the FAC Study.

A summary of the ancillary services is presented in Exhibit C1, Tab 1, Schedule 6, which is a summary of the information provided in Tab 3, Schedule 1 of Exhibits C3, C4, C5, C6, C7 and C8.

Fiscal 2011 Test Year

The forecasted rate of return in the 2011 TY on ancillary programs is 15.6%, as shown in Exhibit C8, Tab 3, Schedule 1. Rate base is expected to be $1,712,395. Gross revenue is forecast to be $1,108,592 with direct costs totaling $340,085. Allocated costs total a further $505,804.

Fiscal 2010 Bridge Year

As shown in Exhibit C7, Tab 3, Schedule 1, the overall rate of return for the ancillary programs is forecast to be 18.1% on a rate base of $1,817,023. Total gross revenues are $1,058,803 with direct costs totaling $330,180. Allocated costs total a further $392,732.

Fiscal 2009 Historic Year

As shown in Exhibit C6, Tab 3, Schedule 1, the overall rate of return for the ancillary programs is estimated to be 11.1% on a rate base of $1,609,024. Total gross revenues were $955,609 with direct costs totaling $320,563. Allocated costs total a further $417,659.

Fiscal 2008 Historic Year

As shown in Exhibit C5, Tab 3, Schedule 1, the overall rate of return for the ancillary programs is 13.7% on a rate base of $1,514,450. Total gross revenues were $1,103,536 with direct costs totaling $552,687. Allocated costs total a further $321,566.

Fiscal 2007 Historic Year

As shown in Exhibit C4, Tab 3, Schedule 1, the overall rate of return for the ancillary programs is 12.3% on a rate base of $1,506,481. Total gross revenues were $1,053,909 with direct costs totaling $484,570. Allocated costs total a further $379,325.

As shown in Exhibit C4.1, Tab 3, Schedule 1, the overall rate of return of 9.3% slightly exceeded the forecast Test Year return. While the rate base was $34,520 lower direct costs were $183,460 lower and allocated costs were $50,004 higher.

<u>Fiscal 2006 Historic Year</u>

As shown in Exhibit C3, Tab 3, Schedule 1, the overall rate of return for the ancillary programs was 14.1% on a rate base of $1,443,707. Total gross revenues were $1,162,544 and direct costs totaled $504,951. Allocated costs totaled a further $446,481.

NATURAL RESOURCE GAS LIMITED

LOAD FORECAST AND WEATHER NORMALIZATION

The purpose of this section of the evidence is to provide the Board with a review of NRG's actual and forecasted gas volumes and customers for the historical, bridge and test years. The forecast was prepared in September/October of 2009.

A review of the degree day forecast methodology is provided below, followed by a review of the forecasting and normalization methodology and forecast assumptions. We then summarize the throughput and customer forecast for the 2010 bridge year and 2011 test year, as well as provide historical and normalized throughput and customer data for the 2009 historical fiscal year.

Degree Day Forecast

NRG continues to use a five year weighted average forecast methodology to predict heating degree days over the bridge and test years. The formula used is as follows and is unchanged from that used in EB-2005-0544 (which in turn was unchanged from RP-2004-0167):

$$W_t = (5 \text{ x } D_{t-12} + 4 \text{ x } D_{t-24} + 3 \text{ x } D_{t-36} + 2 \text{ x } D_{t-48} + 1 \text{ x } D_{t-60}) / 15$$

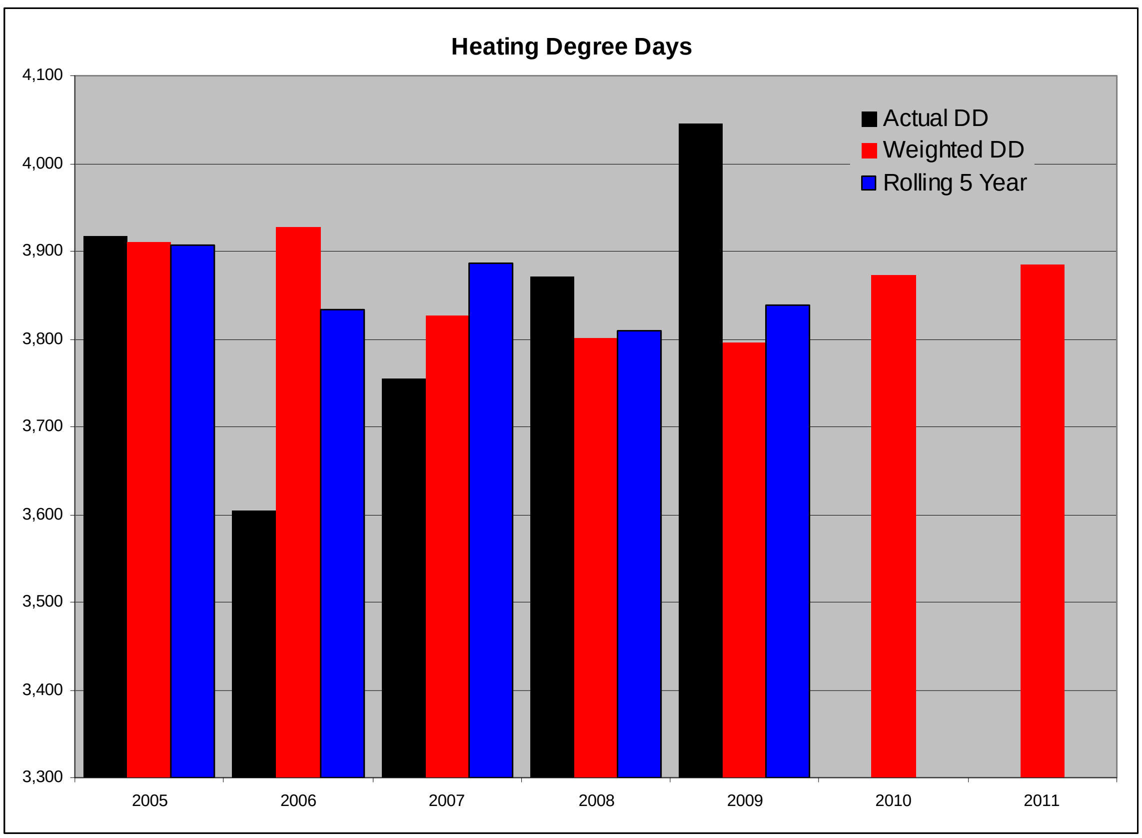
Where: W is the weighted five year average,
D is the monthly heating degree days measured at London, Ont, and
t is current monthly time period.

The following table provides the most recent five years of actual annual data and the historical weighted average and weighted average forecast for 2010 and 2011.

The forecast for 2010 and 2011 uses actual data for 2009 or part of 2009, where available. The table also compares the weighted 5 year average with a simple rolling 5 year average.

	Fiscal 2005	**Fiscal 2006**	**Fiscal 2007**	**Fiscal 2008**	**Fiscal 2009**	**Fiscal 2010**	**Fiscal 2011**
Actual Heating Degree Days	3,918	3,605	3,754	3,872	4,045		
Weighted 5 Year Average HDD	3,910	3,927	3,827	3,800	3,795	3,873	3,885
Simple Rolling 5 Year Average	3,908	3,834	3,887	3,810	3,839		

These values are depicted graphically in the chart below:

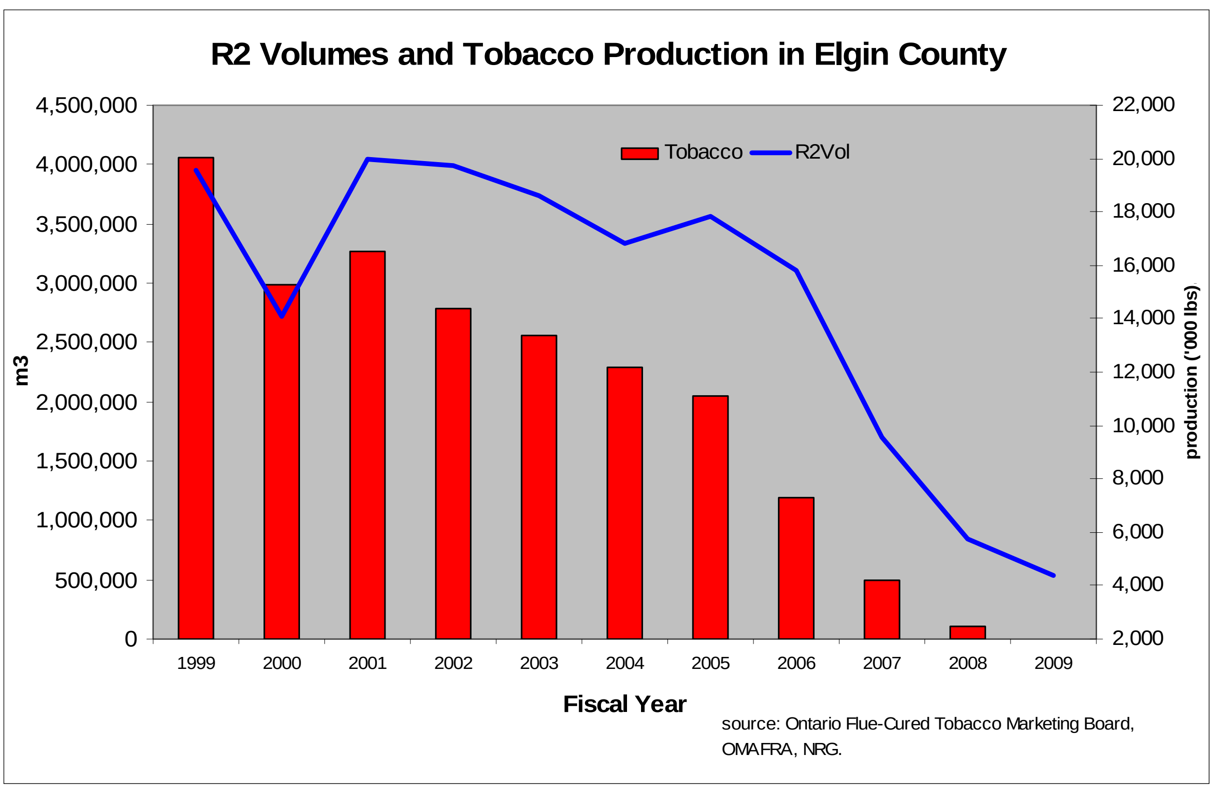


<u>Forecasting and Normalization Methodology</u>

The forecasting and normalization methodology used by NRG to determine 2011 volumes follows as closely as possible the methodology used previously in EB-2005-0544 (which in turn was unchanged from RP-2004-0167). Residential, commercial, and industrial (R1) volumes as well as heating related contract volumes (R3, exclusive of IGPC) are normalized using a use per customer per degree day approach. An actual average monthly use per customer is calculated for each of the weather sensitive customer classes based on actual consumption and the actual number of customers. The average use is then reduced by an estimate of the average base load (non-heating load) use per customer. This base load is based on the average use in the various classes in the summer months. For contract accounts (R3) that are normalized, the actual monthly consumption is reduced by an estimate of the base load, which is also based on use in the summer months.

The remaining non-base load use per customer is determined by using the estimated monthly degree day sensitivity of weather sensitive customer use by customer class and the normal degree days forecast using the weighted degree day methodology described previously. The average base load is then added back and this sum is then multiplied by the actual number of customers to arrive at an estimate of the normalized volumes. The regression equations used to determine monthly degree day sensitivity are displayed in the last section of this schedule.

The approach to seasonal volumes (R2) has changed from EB-2005-0544. R2 volumes result from flue-cured tobacco operations. The previous methodology used in EB-2005-0544 forecast annual use per customer based on data on the portion of the tobacco quota allocated to growers in NRG service area, growing degree days, and a dummy variable. However, on March 31, 2009, the Ontario Flue-Cured Tobacco Growers' Marketing Board ("Marketing Board") removed the quota system for growers. This was in response to the Federal Governments' Tobacco Transition Program ("TTP") which, among other things, replaces the quota system with a licensing system. The purpose of the TTP was to help producers exit the industry and offered to buy out the quota of producers who exit the industry. According to the Marketing Board, a total of 99.5% of holders of BPQ (Basic Production Quota) accepted the TTP and relinquished their opportunity to obtain a license to produce.[1] The number of customers in the R2 class has steadily declined over the past few years, and the volume has declined even more sharply. R2 volume in 2009 is less than 15% of the 2005 volume (approximately 530,000 m^3 in 2009 compared to over 3.5 million m^3 in 2005). Newly licensed producers are likely producing much smaller amounts of flue-cured tobacco, as evidenced by the declining production. The following chart depicts production of flue-cured tobacco in Elgin County since 1999 and R2 volumes.



[1] 2009 Annual Report of the Ontario Flue-Cured Tobacco Growers' Marketing Board.

The above chart shows a distinct relationship between tobacco production and consumption in the R2 class. In recent years, it is the size of the tobacco crop produced and not weather that has the major influence R2 volumes. For this reason, we do not consider R2 use to be degree day dependent and these volumes are not in need of normalization on a degree day basis. While broader weather conditions, such as soil moisture conditions and sunlight may affect the size of the marketed crop, economic factors, such as the market for flue-cured tobacco are likely more of a factor.

Due to the fact that the tobacco quota system has been discontinued and that licensed producers must now contract directly with purchasers, there is no longer any publicly available information on tobacco production. We are also assuming that those producers that have decided not to exit the industry will continue to operate for the 2010-2011 time horizon (this is verified by the 73 remaining customers in the R2 class at the end of fiscal 2009). We therefore will assume 73 customers for 2010 and 2011 with a monthly use per customer profile similar to 2009.

The approach for industrial (R4) and contract (R5) also differs from that used in EB-2005-0544. These accounts are primarily grain dryers except for one fairly large R4 account which is a tomato cannery. These classes are also seasonal in nature with the majority of use in the fall months and very little consumption in the other months. Previous methodology used variables such as the moisture content of corn to forecast use per customer. However, this variable is no longer available. Other potential explanatory variables such as production of grain corn in Elgin County and sales of field tomatoes to processors have been examined and do not provide any explanation for year-to-year variance in use per customer or total volumes. However, there is significant year-to-year fluctuation of R4 and R5 use per customer (due to the significant fluctuation in annual volumes). We have adopted a weighted-average methodology identical to the normalization and forecasting of degree days described previously (weighted 5 year average) to normalize and forecast monthly use per customer in the R4 and R5 consumption classes.

<u>Customer Additions</u>

As of September 2009, NRG had 6,331 R1 residential customers, 408 R1 commercial customers, 25 R1 industrial customers, 73 R2 seasonal customers, 4 R3 customers (excluding IGPC), 23 R4 customers and 5 R5 customers. Since 2007, there have been two major changes involving the R3 class. As of July 2007, Imperial Tobacco ceased operations in Aylmer. Imperial Tobacco was the largest R3 class customer. In September 2008, IGPC (Integrated Grain Processors Cooperative) Ethanol began operations, reaching full output in October 2008. For the purpose of this load forecast, IGPC is being accounted for separately and is not being included in the R3 customer count or volumes.

In the first half of this decade, NRG saw reasonably strong customer growth in the residential class, on the order of 3.5% to 4.5% per year on an annual average basis. This growth peaked in Fiscal 2005 (at 4.7%) and has slowed substantially in the past 2-3 years, likely resulting from stagnating economic conditions and slower or stagnating growth in surrounding areas, such as the London Census Metropolitan Area, which has suffered from the decline in the automotive and manufacturing sectors. Since Fiscal 2007, annual average growth in residential customers has been under 3%. In Fiscal 2009, 129 residential customers were attached. NRG expects only a modest increase in residential attachments in 2010 and 2011 (132 and 137, respectively). This is consistent with the outlook for housing starts in the London area as forecast by Canada Mortgage and Housing Corp (CMHC).[2] The annual customer count forecast is allocated into monthly additions using the historical weight of monthly addition patterns observed in the most recent complete historical fiscal year (Fiscal 2008).

[2] CMHC Housing Market Outlook, London CMA, Fall 2009, p.5.

NRG does not expect any significant change in any of the other classes over the 2010 to 2011 period. The average number of commercial customers is expected to increase by 2 in each of 2010 and 2011 (to 412 and 414, respectively) and the average number of industrial customers is expected to hold at 26. A summary of historical and forecast R1 customers by fiscal year is presented in the following table:

NRG Rate 1 Average Annual Customer Count

	Residential	*%chg*	Commercial	*%chg*	Industrial	*%chg*
Fiscal 2000	4,587		323		15	
Fiscal 2001	4,797	*4.6%*	331	*2.5%*	19	*26.7%*
Fiscal 2002	4,943	*3.0%*	350	*5.7%*	21	*10.5%*
Fiscal 2003	5,091	*3.0%*	363	*3.7%*	21	*0.0%*
Fiscal 2004	5,326	*4.6%*	376	*3.6%*	23	*9.5%*
Fiscal 2005	5,577	*4.7%*	383	*1.9%*	24	*4.3%*
Fiscal 2006	5,811	*4.2%*	396	*3.4%*	27	*12.5%*
Fiscal 2007	5,979	*2.9%*	404	*2.0%*	28	*3.7%*
Fiscal 2008	6,151	*2.9%*	408	*1.0%*	28	*0.0%*
Fiscal 2009	6,318	*2.7%*	410	*0.5%*	26	*-7.1%*
Fiscal 2010	6,425	*1.7%*	412	*0.5%*	26	*0.0%*
Fiscal 2011	6,560	*2.1%*	414	*0.5%*	26	*0.0%*

NRG expects the number of customers in the R3, R4 and R5 classes to hold steady. There has been no change in the number of monthly customers in R3 or R5 since 2004 (except the previously mentioned Imperial Tobacco/IGPC changes). The R4 class added 1 customer in November 2008 and there had not been a change in customer count in this class previously since December 2004.

The number of customers in the R2 seasonal class has been declining since peaking in 2006, but is expected to stabilize at the September 2009 level in the aftermath of the TTP and newly licensed producers. Therefore, the number of customers for 2010 and 2011 is forecast to be 73. The IGPC consumption forecast is based on the monthly average consumption seen in the first year of full operation. IGPC monthly consumption varies very little month-to-month.

A complete summary of annual forecast bridge and test years and recent historical years is shown in the table below:

Annual Summary, NRG Historical, Historical Normalized, Bridge (2010), and Test Year (2011) Forecasts

	Fiscal 2007 Actual	Fiscal 2008 Actual	*Fiscal 2008 Normalized*	Fiscal 2009 Actual	*Fiscal 2009 Normalized*	*Fiscal 2010*	*Fiscal 2011*
Volumes (m^3)							
R1- Residential	11,420,495	11,901,312	*11,809,513*	12,739,773	*12,589,966*	*12,827,985*	*13,103,581*
R1-Commercial	3,824,675	4,255,370	*4,219,103*	4,140,590	*4,085,657*	*4,109,387*	*4,131,750*
R1-Industrial	596,669	532,997	*538,845*	593,738	*579,399*	*580,368*	*580,997*
R2-Seasonal	1,704,357.0	838,429	*838,429*	531,925	*531,925*	*502,859*	*502,859*
Contract R3[1]	3,770,749	2,435,587	*2,430,609*	2,262,834	*2,170,640*	*2,192,257*	*2,195,299*
Industrial R4	441,064	378,573	*441,990*	439,909	*438,172*	*459,488*	*454,263*
Contract R5	1,062,864	746,780	*966,576*	1,130,257	*896,326*	*944,570*	*947,162*
IGPC	-	212,207	*212,207*	31,459,135	*31,459,135*	*31,459,135*	*31,459,135*
Total m^3	22,820,873	21,301,255	*21,457,272*	53,298,161	*52,751,219*	*53,076,048*	*53,375,045*
Heating Degree Days	3,754	3,872	*3,800*	4,045	*3,795*	*3,873*	*3,885*
Number of Customers (Average)							
R1- Residential	5,979	6,151	*6,151*	6,318	*6,318*	*6,425*	*6,560*
R1-Commercial	404	408	*408*	410	*410*	*412*	*414*
R1-Industrial	28	28	*28*	26	*26*	*26*	*26*
R2-Seasonal	108	95	*95*	83	*83*	*73*	*73*
Contract R3[1]	5	4	*4*	4	*4*	*4*	*4*
Industrial R4	22	22	*22*	23	*23*	*23*	*23*
Contract R5	5	5	*5*	5	*5*	*5*	*5*
IGPC	-	Sept startup		1	*1*	*1*	*1*
Total Customers	6,551	6,713	*6,713*	6,870	*6,870*	*6,969*	*7,106*

Note: [1] exclusive of IGPC

Use Per Customer							
R1- Residential	1,910	1,935	*1,920*	2,016	*1,993*	*1,997*	*1,998*
R1-Commercial	9,465	10,419	*10,330*	10,093	*9,959*	*9,974*	*9,980*
R1-Industrial	21,697	19,265	*19,476*	22,763	*22,213*	*22,322*	*22,346*
R2-Seasonal	15,818	8,841	*8,841*	6,422	*6,422*	*6,888*	*6,888*
Contract R3[1]	754,150	608,897	*607,652*	565,709	*542,660*	*548,064*	*548,825*
Industrial R4	20,048	17,208	*20,090*	19,196	*19,120*	*19,978*	*19,751*

Contract R5	212,573	149,356	*193,315*	226,051	*179,265*	*188,914*	*189,432*
IGPC		-					

Note: [1] exclusive of IGPC

Regression Equations

The following pages present the regression equations used to forecast average use per customer for rate 1 (residential, commercial and small industrial) and rate 3 (excluding IGPC). As outlined above, these equations have followed as closely as possible the approach used in EB-2005-0544. In certain cases, data is no longer available (e.g., residential water heater penetration). In these cases, adjustments have been made as appropriate.

Definitions of the variables used in the equations are as follows:

NAME	DEFINITION
UseRes	Residential (rate 1) use per customer
UseCom	Commercial (rate 1) use per customer
UseSmInd	Small industrial (rate 1) use per customer
VolOPC	Volume for a rate 3 customer
VolEESS	Volume for a rate 3 customer
VolColdspring	Volume for a rate 3 customer
VolSchlegel	Volume for a rate 3 customer
DDSLON	Heating degree days – London, Ont.
Dmth	Dummy variable (mth=OCT,NOV,DEC,JAN,FEB,MAR,APR,MAY,JUN, JUL,AUG, SEP)
DOPC	Dummy variable used for a rate 3 customer
ln()	Natural logarithm

```
UseRes:
Prais-Winsten, using observations 1999:08-2009:07 (T = 120)
Dependent variable: ln(UseRes)

                    coefficient   std. error   t-ratio    p-value
  ------------------------------------------------------------------
  const               3.70909      0.0300442    123.5     6.03e-119 ***
  DOCT*ln(DDSLON)     0.185707     0.00862419    21.53    4.58e-041 ***
  DNOV*ln(DDSLON)     0.266476     0.00809173    32.93    1.80e-058 ***
  DDEC*ln(DDSLON)     0.314605     0.00757639    41.52    1.23e-068 ***
  DJAN*ln(DDSLON)     0.325344     0.00745028    43.67    6.91e-071 ***
  DFEB*ln(DDSLON)     0.317957     0.00755839    42.07    3.24e-069 ***
  DMAR*ln(DDSLON)     0.302283     0.00774978    39.01    7.35e-066 ***
  DAPR*ln(DDSLON)     0.248452     0.00844112    29.43    1.09e-053 ***
  DMAY*ln(DDSLON)     0.145661     0.00931304    15.64    1.27e-029 ***
  DJUN*ln(DDSLON)     0.0599635    0.0125130      4.792   5.25e-06  ***
  DSEP*ln(DDSLON)     0.0596327    0.0104129      5.727   9.16e-08  ***

Statistics based on the rho-differenced data:

Mean dependent var   4.824461   S.D. dependent var   0.826886
Sum squared resid    1.528842   S.E. of regression   0.118432
R-squared            0.981215   Adjusted R-squared   0.979491
F(10, 109)           359.4798   P-value(F)           1.38e-78
rho                 -0.052881   Durbin-Watson        1.988179

UseCom:
Prais-Winsten, using observations 1999:08-2009:07 (T = 120)
Dependent variable: ln(UseCom)

                    coefficient   std. error   t-ratio    p-value
  ------------------------------------------------------------------
  const               5.05682      0.0472027    107.1     1.11e-110 ***
  DOCT*ln(DDSLON)     0.212274     0.0103762     20.46    9.02e-039 ***
  DNOV*ln(DDSLON)     0.288158     0.00968062    29.77    1.40e-053 ***
  DDEC*ln(DDSLON)     0.343111     0.00905712    37.88    8.11e-064 ***
  DJAN*ln(DDSLON)     0.358655     0.00890561    40.27    1.78e-066 ***
  DFEB*ln(DDSLON)     0.352922     0.00903469    39.06    3.79e-065 ***
  DMAR*ln(DDSLON)     0.334848     0.00926288    36.15    8.50e-062 ***
  DAPR*ln(DDSLON)     0.264345     0.0100931     26.19    2.39e-048 ***
  DMAY*ln(DDSLON)     0.166634     0.0111855     14.90    7.53e-028 ***
  DJUN*ln(DDSLON)     0.0952844    0.0156250      6.098   1.73e-08  ***
  DJUL*ln(DDSLON)     0.100513     0.0250884      4.006   0.0001    ***
  DAUG*ln(DDSLON)     0.0889184    0.0219927      4.043   9.97e-05  ***
  DSEP*ln(DDSLON)     0.119875     0.0130665      9.174   3.77e-015 ***

Statistics based on the rho-differenced data:

Mean dependent var   6.341648   S.D. dependent var   0.836276
Sum squared resid    1.181923   S.E. of regression   0.105100
R-squared            0.985800   Adjusted R-squared   0.984207
```

```
F(12, 107)            366.6677   P-value(F)          5.23e-81
rho                  -0.023424   Durbin-Watson       2.015293

UseSmInd:
Prais-Winsten, using observations 2005:08-2009:07 (T = 48)
Dependent variable: ln(UseSmInd)

                  coefficient   std. error   t-ratio    p-value
  -------------------------------------------------------------
  const               5.85293      0.0631978    92.61     2.12e-045 ***
  DOCT*ln(DDSLON)     0.378000     0.0160101    23.61     6.59e-024 ***
  DNOV*ln(DDSLON)     0.388570     0.0154735    25.11     7.67e-025 ***
  DDEC*ln(DDSLON)     0.337267     0.0149668    22.53     3.32e-023 ***
  DJAN*ln(DDSLON)     0.303891     0.0150061    20.25     1.29e-021 ***
  DFEB*ln(DDSLON)     0.304318     0.0149614    20.34     1.11e-021 ***
  DMAR*ln(DDSLON)     0.319357     0.0152663    20.92     4.28e-022 ***
  DAPR*ln(DDSLON)     0.283965     0.0163825    17.33     2.39e-019 ***
  DMAY*ln(DDSLON)     0.193279     0.0172340    11.21     1.84e-013 ***
  DJUN*ln(DDSLON)     0.119633     0.0214539     5.576    2.35e-06  ***
  DSEP*ln(DDSLON)     0.0793618    0.0179282     4.427    8.16e-05  ***

Statistics based on the rho-differenced data:

Mean dependent var   7.179340   S.D. dependent var   0.900119
Sum squared resid    0.651193   S.E. of regression   0.132664
R-squared            0.982901   Adjusted R-squared   0.978280
F(10, 37)            110.1531   P-value(F)           2.09e-24
rho                  0.036420   Durbin-Watson        1.908341

OPC:
Prais-Winsten, using observations 1999:08-2009:07 (T = 120)
Dependent variable: ln(VolOPC)

                  coefficient   std. error   t-ratio    p-value
  -------------------------------------------------------------
  const               9.97816      0.116779     85.44     1.39e-099 ***
  DOCT*ln(DDSLON)     0.248766     0.0177004    14.05     5.81e-026 ***
  DNOV*ln(DDSLON)     0.301592     0.0179631    16.79     1.25e-031 ***
  DDEC*ln(DDSLON)     0.323689     0.0175131    18.48     6.16e-035 ***
  DJAN*ln(DDSLON)     0.344890     0.0175723    19.63     4.40e-037 ***
  DFEB*ln(DDSLON)     0.330141     0.0178524    18.49     5.89e-035 ***
  DMAR*ln(DDSLON)     0.322249     0.0179932    17.91     7.78e-034 ***
  DAPR*ln(DDSLON)     0.279260     0.0188959    14.78     1.68e-027 ***
  DMAY*ln(DDSLON)     0.224457     0.0193233    11.62     1.29e-020 ***
  DJUN*ln(DDSLON)     0.148969     0.0240882     6.184    1.19e-08  ***
  DJUL*ln(DDSLON)     0.204025     0.0374751     5.444    3.39e-07  ***
  DAUG*ln(DDSLON)     0.0885104    0.0318649     2.778    0.0065    ***
  DSEP*ln(DDSLON)     0.150847     0.0203476     7.413    3.16e-011 ***
  DOPC                0.365698     0.0782402     4.674    8.73e-06  ***

Statistics based on the rho-differenced data:
```

```
Mean dependent var   11.32423   S.D. dependent var   0.783489
Sum squared resid    3.463031   S.E. of regression   0.180749
R-squared            0.952751   Adjusted R-squared   0.946957
F(13, 106)           77.69066   P-value(F)           5.59e-48
rho                 -0.118604   Durbin-Watson        2.208928

EESS:
OLS, using observations 1999:08-2009:07 (T = 120)
Dependent variable: ln(VolEESS)

                 coefficient   std. error   t-ratio    p-value
  -------------------------------------------------------------
  const             7.38544      0.0521581    141.6     2.14e-125 ***
  DOCT*ln(DDSLON)   0.413189     0.0164097     25.18    3.07e-047 ***
  DNOV*ln(DDSLON)   0.496639     0.0150969     32.90    2.00e-058 ***
  DDEC*ln(DDSLON)   0.534476     0.0140672     37.99    1.06e-064 ***
  DJAN*ln(DDSLON)   0.539169     0.0138177     39.02    7.07e-066 ***
  DFEB*ln(DDSLON)   0.526589     0.0140183     37.56    3.36e-064 ***
  DMAR*ln(DDSLON)   0.519137     0.0143901     36.08    1.99e-062 ***
  DAPR*ln(DDSLON)   0.456991     0.0157522     29.01    4.42e-053 ***
  DMAY*ln(DDSLON)   0.252528     0.0177336     14.24    1.26e-026 ***
  DJUN*ln(DDSLON)   0.108442     0.0260337      4.165   6.24e-05  ***
  DSEP*ln(DDSLON)   0.119382     0.0216599      5.512   2.40e-07  ***

Mean dependent var   9.364344   S.D. dependent var   1.408029
Sum squared resid    6.024175   S.E. of regression   0.235091
R-squared            0.974466   Adjusted R-squared   0.972123
F(10, 109)           415.9735   P-value(F)           6.13e-82
Log-likelihood       9.230045   Akaike criterion     3.539911
Schwarz criterion    34.20232   Hannan-Quinn         15.99206
rho                  0.142523   Durbin-Watson        1.710524

Coldspring:
Prais-Winsten, using observations 1999:08-2009:04 (T = 117)
Dependent variable: ln(VolColdspring)

                 coefficient   std. error   t-ratio    p-value
  -------------------------------------------------------------
  const             8.85200      0.0584081    151.6     9.64e-126 ***
  DOCT*ln(DDSLON)   0.216061     0.0159614     13.54    7.58e-025 ***
  DNOV*ln(DDSLON)   0.255673     0.0151313     16.90    7.61e-032 ***
  DDEC*ln(DDSLON)   0.298579     0.0142246     20.99    1.51e-039 ***
  DJAN*ln(DDSLON)   0.295711     0.0140066     21.11    9.19e-040 ***
  DFEB*ln(DDSLON)   0.288739     0.0142109     20.32    2.41e-038 ***
  DMAR*ln(DDSLON)   0.284974     0.0145550     19.58    5.39e-037 ***
  DAPR*ln(DDSLON)   0.235875     0.0158029     14.93    8.23e-028 ***
  DMAY*ln(DDSLON)   0.171388     0.0177664      9.647   3.50e-016 ***
  DJUN*ln(DDSLON)   0.0590405    0.0238402      2.477   0.0148    **
  DSEP*ln(DDSLON)   0.0989384    0.0187967      5.264   7.43e-07  ***
```

Statistics based on the rho-differenced data:

Mean dependent var	9.964653	S.D. dependent var	0.766472
Sum squared resid	4.875332	S.E. of regression	0.214461
R-squared	0.928464	Adjusted R-squared	0.921716
F(10, 106)	80.71932	P-value(F)	6.57e-45
rho	-0.010303	Durbin-Watson	2.018540

Schlegel:
OLS, using observations 1999:08-2009:07 (T = 120)
Dependent variable: ln(VolSchlegel)

	coefficient	std. error	t-ratio	p-value	
const	8.43616	0.0937544	89.98	7.60e-105	***
DOCT*ln(DDSLON)	0.129446	0.0339752	3.810	0.0002	***
DNOV*ln(DDSLON)	0.128797	0.0312556	4.121	7.34e-05	***
DDEC*ln(DDSLON)	0.173181	0.0291239	5.946	3.30e-08	***
DJAN*ln(DDSLON)	0.183395	0.0286074	6.411	3.72e-09	***
DFEB*ln(DDSLON)	0.129266	0.0290225	4.454	2.03e-05	***
DMAR*ln(DDSLON)	0.166432	0.0297922	5.586	1.70e-07	***
DAPR*ln(DDSLON)	0.122192	0.0326123	3.747	0.0003	***
DMAY*ln(DDSLON)	0.0972713	0.0367166	2.649	0.0093	***
DJUN*ln(DDSLON)	0.0875079	0.0539336	1.623	0.1076	

Mean dependent var	9.036505	S.D. dependent var	0.651645
Sum squared resid	29.21507	S.E. of regression	0.515356
R-squared	0.421854	Adjusted R-squared	0.374551
F(9, 110)	8.918147	P-value(F)	5.30e-10
Log-likelihood	-85.50420	Akaike criterion	191.0084
Schwarz criterion	218.8833	Hannan-Quinn	202.3285
rho	0.120995	Durbin-Watson	1.746924

NATURAL RESOURCE GAS LIMITED

Operating Revenue
2006 Actual and Normalized
($'s)

		Actual Forecast	Adjust-ments	Normalized Forecast
Distribution and Transportation Revenue				
Rate 1	Residential	2,397,667	35,313	2,432,980
	Commercial	474,200	9,239	483,439
	Industrial	65,167	1,473	66,641
Rate 2	Seasonal	281,768	0	281,768
Rate 3	Contract	229,289	9,348	238,637
Rate 4	Industrial	33,249	30,772	64,021
Rate 5	Contract	48,375	11,146	59,521
Rate 6	Contract	0	0	0
Total		3,529,715	97,291	3,627,006
Other Operating Revenue (Net)				
Rental Equipment Program		366,002	0	366,002
Contract Work Program		109,817	0	109,817
Transfer/Connect Charges		56,519	0	56,519
Direct Purchase		2,928	0	2,928
Delayed Payment Charges, Interests		103,257	0	103,257
Total		638,523	0	638,523
Total Operating Revenue		4,168,238	97,291	4,265,529

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2006 Actual
($'s)

		Actual 2006	Actual 2005
Distribution and Transportation Revenue			
Rate 1	Residential	2,397,667	2,516,253
	Commercial	474,200	494,107
	Industrial	65,167	64,447
Rate 2	Seasonal	281,768	273,287
Rate 3	Contract	229,289	250,300
Rate 4	Industrial	33,249	50,463
Rate 5	Contract	48,375	66,098
Rate 6	Contract	0	0
Total		3,529,715	3,714,955
Other Operating Revenue (Net)			
Rental Equipment Program		366,002	488,992
Contract Work Program		109,817	70,308
Transfer/Connect Charges		56,519	30,786
Direct Purchase		2,928	3,347
Delayed Payment Charges		103,257	48,351
Total		638,523	641,784
Total Operating Revenue		4,168,238	4,356,739

		Variance from 2005
Distribution and Transportation Revenue		
Rate 1	Residential	-118,586
	Commercial	-19,907
	Industrial	720
Rate 2	Seasonal	8,481
Rate 3	Contract	-21,011
Rate 4	Industrial	-17,214
Rate 5	Contract	-17,723
Rate 6	Contract	0
Total		-185,240
Other Operating Revenue (Net)		
Rental Equipment Program		-122,990
Contract Work Program		39,509
Transfer/Connect Charges		25,733
Direct Purchase		-419
Delayed Payment Charges		54,906
Total		-3,261
Total Operating Revenue		-188,501

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2006 Normalized
($'s)

		Actual 2006	Actual 2005
Distribution and Transportation Revenue			
Rate 1	Residential	2,432,980	2,516,253
	Commercial	483,439	494,107
	Industrial	66,641	64,447
Rate 2	Seasonal	281,768	273,287
Rate 3	Contract	238,637	250,300
Rate 4	Industrial	64,021	50,463
Rate 5	Contract	59,521	66,098
Rate 6	Contract	0	0
Total		3,627,006	3,714,955
Other Operating Revenue (Net)			
Rental Equipment Program		366,002	488,992
Contract Work Program		109,817	47,402
Service Work Program		0	17,126
Merchandise Sales		0	5,780
Transfer/Connect Charges		56,519	30,786
Direct Purchase		2,928	3,347
Delayed Payment Charges		103,257	48,351
Total		638,523	641,784
Total Operating Revenue		4,265,529	4,356,739

		Variance from 2005
Distribution and Transportation Revenue		
Rate 1	Residential	-83,273
	Commercial	-10,668
	Industrial	2,194
Rate 2	Seasonal	8,481
Rate 3	Contract	-11,663
Rate 4	Industrial	13,558
Rate 5	Contract	-6,577
Rate 6	Contract	0
Total		-87,949
Other Operating Revenue (Net)		
Rental Equipment Program		-122,990
Contract Work Program		62,415
Service Work Program		-17,126
Merchandise Sales		-5,780
Transfer/Connect Charges		25,733
Direct Purchase		-419
Delayed Payment Charges		54,906
Total		-3,261
Total Operating Revenue		-91,210

NATURAL RESOURCE GAS LIMITED

Gross Margin Analysis by Sales Class
2006 Actual

		Total Gas Margin ($)	Total Volume (M*3)	Gross Unit Margin ($/M*3)
Rate 1	Residential	2,397,667	10,737,023	0.2233
	Commercial	474,200	3,517,804	0.1348
	Industrial	65,167	628,195	0.1037
Rate 2	Seasonal	281,768	3,111,056	0.0906
Rate 3	Contract	229,289	3,723,756	0.0616
Rate 4	Industrial	33,249	319,520	0.1041
Rate 5	Contract	48,375	689,220	0.0702
Rate 6	Contract	0	0	0.0000
Total		3,529,715	22,726,574	0.1553

NATURAL RESOURCE GAS LIMITED

Summary of Gas Sales and Transportation
2006 Actual and Normalized

		Customers (Year-end)	Volumes (M*3)	Distribution Revenues ($)	Normalized Volumes (M*3)	Normalized Distribution Revenues ($)
Rate 1	Residential	5,868	10,737,023	2,397,667	10,954,158	2,432,980
	Commercial	397	3,517,804	474,200	3,594,313	483,439
	Industrial	27	628,195	65,167	643,369	66,641
Rate 2	Seasonal	113	3,111,056	281,768	3,111,056	281,768
Rate 3	Contract	5	3,723,756	229,289	3,978,151	238,637
Rate 4	Industrial	22	319,520	33,249	448,680	64,021
Rate 5	Contract	5	689,220	48,375	981,285	59,521
Rate 6		0	0	0	0	0
Total		6,437	22,726,574	3,529,715	23,711,013	3,627,006

NATURAL RESOURCE GAS LIMITED

Customers by Rate Class
2006 Actual
(Year-end)

		Actual 2006	Actual 2005
Rate 1	Residential	5,868	5,620
	Commercial	397	382
	Industrial	27	25
Rate 2	Seasonal	113	121
Rate 3	Contract	5	5
Rate 4	Industrial	22	22
Rate 5	Contract	5	5
Rate 6		0	0
Total		6,437	6,180

		Variance from 2005
Rate 1	Residential	248
	Commercial	15
	Industrial	2
Rate 2	Seasonal	-8
Rate 3	Contract	0
Rate 4	Industrial	0
Rate 5	Contract	0
Rate 6		0
Total		257

NATURAL RESOURCE GAS LIMITED

Gas Sales and Transportation Volume
2006 Actual and 2005 Actual
(M*3)

		Actual 2006	Actual 2005	Variance
Rate 1	Residential	10,737,023	11,725,720	-988,697
	Commercial	3,517,804	3,741,410	-223,606
	Industrial	628,195	618,049	10,146
Rate 2	Seasonal	3,111,056	3,068,301	42,755
Rate 3	Contract	3,723,756	3,907,494	-183,738
Rate 4	Industrial	319,520	541,701	-222,181
Rate 5	Contract	689,220	961,458	-272,238
Rate 6		0	0	0
Total		22,726,574	24,564,133	-1,837,559

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2006 Actual Customers, Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Customers														
Rate 1	Residential	5,674	5,728	5,758	5,784	5,822	5,827	5,850	5,856	5,854	5,855	5,854	5,868	5,811
	Commercial	386	390	394	397	400	398	400	398	398	396	395	397	396
	Industrial	25	26	26	26	27	27	27	27	27	27	27	27	27
Rate 2	Seasonal	122	122	119	117	116	116	116	116	114	114	126	113	118
Rate 3	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 4	Industrial	22	22	22	22	22	22	22	22	22	22	22	22	22
Rate 5	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		6,239	6,298	6,329	6,356	6,397	6,400	6,425	6,429	6,425	6,424	6,434	6,437	6,383
														Total
Volumes (M*3)														
Rate 1	Residential	538,659	1,183,674	1,825,872	1,692,496	1,677,282	1,530,918	846,544	454,249	267,399	201,162	219,250	299,518	10,737,023
	Commercial	168,650	390,351	610,474	564,043	557,760	497,665	260,609	138,532	84,747	56,940	78,577	109,456	3,517,804
	Industrial	70,069	86,353	93,707	87,311	80,775	76,971	54,798	31,949	16,116	8,283	8,170	13,693	628,195
Rate 2	Seasonal	636,394	52,066	17,017	7,128	8,649	29,498	26,512	6,508	1,493	7,804	875,507	1,442,480	3,111,056
Rate 3	Contract	223,279	365,191	561,254	537,672	510,851	503,328	307,942	188,850	138,278	117,232	123,994	145,885	3,723,756
Rate 4	Industrial	108,554	74,943	13,439	8,311	5,015	2,902	1,972	817	310	7,635	29,357	66,265	319,520
Rate 5	Contract	405,029	233,929	3,634	7,607	6,593	4,930	169	85	28	11,749	15,270	197	689,220
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		2,150,634	2,386,507	3,125,397	2,904,568	2,846,925	2,646,212	1,498,546	820,990	508,371	410,805	1,350,125	2,077,494	22,726,574
														Total
Distribution Revenues ($'s)														
Rate 1	Residential	138,200	246,640	351,789	330,878	328,499	304,669	190,658	126,886	98,268	87,660	88,408	105,112	2,397,667
	Commercial	25,503	50,535	74,822	70,400	69,915	64,078	37,043	22,457	15,196	11,582	15,055	17,613	474,200
	Industrial	6,856	8,497	9,061	8,553	7,654	7,861	5,918	3,885	2,190	1,354	1,239	2,100	65,167
Rate 2	Seasonal	57,257	9,483	4,274	2,554	2,811	3,946	4,405	2,232	1,423	2,379	37,599	153,405	281,768
Rate 3	Contract	16,022	21,206	28,397	27,507	26,526	26,251	19,114	14,764	12,916	24,718	4,207	7,660	229,289
Rate 4	Industrial	9,990	7,125	1,698	1,388	1,145	762	527	363	282	1,167	1,886	6,916	33,249
Rate 5	Contract	25,188	15,041	723	1,000	921	817	510	505	501	3,364	195	(390)	48,375
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		279,016	358,527	470,764	442,280	437,471	408,384	258,176	171,091	130,775	132,224	148,589	292,417	3,529,715

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2006 Normalized Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Normalized Volumes (M*3)														
Rate 1	Residential	548,177	1,189,558	1,775,058	1,864,208	1,707,332	1,555,040	868,359	461,328	268,191	201,162	219,250	296,495	10,954,158
	Commercial	171,843	392,430	592,057	627,108	568,791	506,270	267,454	140,713	84,990	56,940	78,834	106,884	3,594,313
	Industrial	73,713	87,029	90,885	95,662	82,158	78,261	56,560	32,810	16,302	8,283	8,170	13,538	643,369
Rate 2	Seasonal	636,394	52,066	17,017	7,128	8,649	29,498	26,512	6,508	1,493	7,804	875,507	1,442,480	3,111,056
Rate 3	Contract	226,829	366,340	551,814	570,413	516,293	508,047	312,508	454,077	86,164	117,231	123,994	144,442	3,978,151
Rate 3	Industrial													-
Rate 4	Industrial	108,388	151,741	76,406	6,761	5,508	3,623	3,221	1,174	144	3,563	13,625	74,525	448,680
Rate 5	Contract	299,923	571,487	85,741	4,001	248	687	379	237	-	4,702	12,374	1,506	981,285
Total		2,065,267	2,810,650	3,188,979	3,175,281	2,888,979	2,681,426	1,534,993	1,096,846	457,283	399,685	1,331,754	2,079,870	23,711,013
														Total
Normalized Revenues ($'s)														
Rate 1	Residential	139,712	247,601	343,500	358,929	333,405	308,605	194,152	128,007	98,397	87,660	88,408	104,604	2,432,980
	Commercial	25,918	50,785	72,675	77,857	71,224	65,121	37,918	22,751	15,229	11,582	15,092	17,288	483,439
	Industrial	7,201	8,562	8,796	9,347	7,781	7,988	6,100	3,983	2,212	1,354	1,239	2,079	66,641
Rate 2	Seasonal	57,257	9,483	4,274	2,554	2,811	3,946	4,405	2,232	1,423	2,379	37,599	153,405	281,768
Rate 3	Contract	16,152	21,248	28,052	28,703	26,725	26,423	19,281	24,454	11,013	24,718	4,207	7,662	238,637
Rate 3	Industrial													-
Rate 4	Industrial	27,184	14,183	8,543	1,173	1,234	892	713	418	258	671	1,002	7,749	64,021
Rate 5	Contract	18,781	36,024	5,761	763	516	544	523	513	500	1,646	253	(6,303)	59,521
Total		292,204	387,886	471,601	479,327	443,696	413,520	263,092	182,357	129,031	130,009	147,800	286,484	3,627,006

NATURAL RESOURCE GAS LIMITED

Average Gas Consumption Per Customer
2006 Actual and Normalized
(M*3)

Actual Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	95	207	317	293	288	263	145	78	46	34	37	51	1,853
	Commercial	437	1,001	1,549	1,421	1,394	1,250	652	348	213	144	199	276	8,884
	Industrial	2,803	3,321	3,604	3,358	2,992	2,851	2,030	1,183	597	307	303	507	23,855
Rate 2	Seasonal	5,216	427	143	61	75	254	229	56	13	68	6,948	12,765	26,256
Rate 3	Contract	44,656	73,038	112,251	107,534	102,170	100,666	61,588	37,770	27,656	23,446	24,799	29,177	744,751
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	4,934	3,407	611	378	228	132	90	37	14	347	1,334	3,012	14,524
Rate 5	Contract	81,006	46,786	727	1,521	1,319	986	34	17	6	2,350	3,054	39	137,844

Normalized Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	97	208	308	322	293	267	148	79	46	34	37	51	1,890
	Commercial	445	1,006	1,503	1,580	1,422	1,272	669	354	214	144	200	269	9,076
	Industrial	2,949	3,347	3,496	3,679	3,043	2,899	2,095	1,215	604	307	303	501	24,437
Rate 2	Seasonal	5,216	427	143	61	75	254	229	56	13	68	6,948	12,765	26,256
Rate 3	Contract	45,366	73,268	110,363	114,083	103,259	101,609	62,502	90,815	17,233	23,446	24,799	28,888	795,630
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	4,927	6,897	3,473	307	250	165	146	53	7	162	619	3,388	20,395
Rate 5	Contract	59,985	114,297	17,148	800	50	137	76	47	-	940	2,475	301	196,257

NATURAL RESOURCE GAS LIMITED

Rate of Return on Ancillary Services
2006 Actual
($'s)

	Ancillary Services
Total Gross Revenue	1,162,544
Less Direct Cost of Sales	504,951
Total Net Revenue	657,592
Delayed Payment Charges	5,597
Total Ancillary Services Revenue	663,189
Allocated Costs	
Operations & Maintenance	278,582
Capital Taxes	168
Property Taxes	5,690
Net Depreciation Expense	162,041
Total	446,481
Income Before Tax	216,707
Income Tax Provision	12,476
Income After Tax	204,232
Value of Assets Employed	
Inventory	101,290
Working Cash	14,394
General Plant	1,328,022
Total Assets	1,443,707
Rate of Return	14.1%

NATURAL RESOURCE GAS LIMITED

Operating Revenue
2007 Actual and Normalized
($'s)

		Actual Forecast	Adjust-ments	Normalized Forecast
Distribution and Transportation Revenue				
Rate 1	Residential	2,550,168	6,560	2,556,727
	Commercial	541,539	1,734	543,274
	Industrial	72,159	285	72,444
Rate 2	Seasonal	198,176	0	198,176
Rate 3	Contract	249,253	-1,214	248,040
Rate 4	Industrial	63,718	-3,284	60,434
Rate 5	Contract	76,657	-9,847	66,810
Rate 6	Contract	0	0	0
Total		3,751,671	-5,766	3,745,905
Other Operating Revenue (Net)				
Rental Equipment Program		409,422	0	409,422
Contract Work Program		2,163	0	2,163
Transfer/Connect Charges		40,062	0	40,062
Direct Purchase		5,065	0	5,065
Delayed Payment Charges, Interests		122,111	0	122,111
Total		578,824	0	578,824
Total Operating Revenue		4,330,495	-5,766	4,324,729

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2007 Actual
($'s)

		Actual 2007	Actual 2006
Distribution and Transportation Revenue			
Rate 1	Residential	2,550,168	2,397,667
	Commercial	541,539	474,200
	Industrial	72,159	65,167
Rate 2	Seasonal	198,176	281,768
Rate 3	Contract	249,253	229,289
Rate 4	Industrial	63,718	33,249
Rate 5	Contract	76,657	48,375
Rate 6	Contract	0	0
Total		3,751,671	3,529,715
Other Operating Revenue (Net)			
Rental Equipment Program		409,422	366,002
Contract Work Program		2,163	109,817
Transfer/Connect Charges		40,062	56,519
Direct Purchase		5,065	2,928
Delayed Payment Charges		122,111	103,257
Total		578,824	638,523
Total Operating Revenue		4,330,495	4,168,238

		Variance from 2006
Distribution and Transportation Revenue		
Rate 1	Residential	152,501
	Commercial	67,339
	Industrial	6,992
Rate 2	Seasonal	-83,591
Rate 3	Contract	19,964
Rate 4	Industrial	30,469
Rate 5	Contract	28,282
Rate 6	Contract	0
Total		221,956
Other Operating Revenue (Net)		
Rental Equipment Program		43,420
Contract Work Program		-107,654
Service Work Program		0
Merchandise Sales		0
Transfer/Connect Charges		-16,457
Direct Purchase		2,138
Delayed Payment Charges		18,854
Total		-59,699
Total Operating Revenue		162,257

Notes:

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2007 Normalized
($'s)

		Normalized 2007	Normalized 2006
Distribution and Transportation Revenue			
Rate 1	Residential	2,556,727	2,432,980
	Commercial	543,274	483,439
	Industrial	72,444	66,641
Rate 2	Seasonal	198,176	281,768
Rate 3	Contract	248,040	238,637
Rate 4	Industrial	60,434	64,021
Rate 5	Contract	66,810	59,521
Rate 6	Contract	0	0
Total		3,745,905	3,627,006
Other Operating Revenue (Net)			
Rental Equipment Program		409,422	366,002
Contract Work Program		2,163	109,817
Transfer/Connect Charges		40,062	56,519
Direct Purchase		5,065	2,928
Delayed Payment Charges		122,111	103,257
Total		578,824	638,523
Total Operating Revenue		4,324,729	4,265,529

		Variance from 2006
Distribution and Transportation Revenue		
Rate 1	Residential	123,748
	Commercial	59,835
	Industrial	5,803
Rate 2	Seasonal	-83,591
Rate 3	Contract	9,403
Rate 4	Industrial	-3,586
Rate 5	Contract	7,288
Rate 6	Contract	0
Total		118,899
Other Operating Revenue (Net)		
Rental Equipment Program		43,420
Contract Work Program		-107,654
Service Work Program		0
Merchandise Sales		0
Transfer/Connect Charges		-16,457
Direct Purchase		2,138
Delayed Payment Charges		18,854
Total		-59,699
Total Operating Revenue		59,200

NATURAL RESOURCE GAS LIMITED

Gross Margin Analysis by Sales Class
2007 Actual

		Total Gas Margin ($)	Total Volume (M*3)	Gross Unit Margin ($/M*3)
Rate 1	Residential	2,550,168	11,420,496	0.2233
	Commercial	541,539	3,824,675	0.1416
	Industrial	72,159	596,669	0.1209
Rate 2	Seasonal	198,176	1,704,357	0.1163
Rate 3	Contract	249,253	3,770,581	0.0661
Rate 4	Industrial	63,718	441,064	0.1445
Rate 5	Contract	76,657	1,062,864	0.0721
Rate 6	Contract	0	0	0.0000
Total		3,751,671	22,820,706	0.1644

NATURAL RESOURCE GAS LIMITED

Summary of Gas Sales and Transportation
2007 Actual and Normalized

		Customers (Year-end)	Volumes (M*3)	Distribution Revenues ($)	Normalized Volumes (M*3)	Normalized Distribution Revenues ($)
Rate 1	Residential	6,022	11,420,496	2,550,168	11,466,204	2,556,727
	Commercial	401	3,824,675	541,539	3,837,521	543,274
	Industrial	28	596,669	72,159	599,159	72,444
Rate 2	Seasonal	99	1,704,357	198,176	1,704,357	198,176
Rate 3	Contract	5	3,770,581	249,253	3,738,626	248,040
Rate 4	Industrial	22	441,064	63,718	426,049	60,434
Rate 5	Contract	5	1,062,864	76,657	908,294	66,810
Rate 6		0	0	0	0	0
Total		6,582	22,820,706	3,751,671	22,680,209	3,745,905

NATURAL RESOURCE GAS LIMITED

Customers by Rate Class
2007 Actual
(Year-end)

		Actual 2007	Actual 2006
Rate 1	Residential	6,022	5,868
	Commercial	401	397
	Industrial	28	27
Rate 2	Seasonal	99	113
Rate 3	Contract	5	5
Rate 4	Industrial	22	22
Rate 5	Contract	5	5
Rate 6		0	0
Total		6,582	6,437

		Variance from 2006
Rate 1	Residential	154
	Commercial	4
	Industrial	1
Rate 2	Seasonal	-14
Rate 3	Contract	0
Rate 4	Industrial	0
Rate 5	Contract	0
Rate 6		0
Total		145

NATURAL RESOURCE GAS LIMITED

Gas Sales and Transportation Volume
2007 Actual and 2006 Actual
(M*3)

		Actual 2007	Actual 2006	Variance
Rate 1	Residential	11,420,496	10,737,023	683,473
	Commercial	3,824,675	3,517,804	306,871
	Industrial	596,669	628,195	-31,526
Rate 2	Seasonal	1,704,357	3,111,056	-1,406,699
Rate 3	Contract	3,770,581	3,723,756	46,825
Rate 4	Industrial	441,064	319,520	121,544
Rate 5	Contract	1,062,864	689,220	373,644
Rate 6		0	0	0
Total		22,820,706	22,726,574	94,132

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2007 Actual Customers, Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Customers														
Rate 1	Residential	5,896	5,928	5,933	5,967	5,978	5,994	6,007	6,011	6,001	6,006	6,010	6,022	5,979
	Commercial	399	405	406	407	406	405	405	405	403	403	404	401	404
	Industrial	27	27	27	27	27	27	28	28	28	28	28	28	28
Rate 2	Seasonal	113	112	112	111	110	110	110	109	105	101	101	99	108
Rate 3	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 4	Industrial	22	22	22	22	22	22	22	22	22	22	22	22	22
Rate 5	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		6,467	6,504	6,510	6,544	6,553	6,568	6,582	6,585	6,569	6,570	6,575	6,582	6,551
														Total
Volumes (M*3)														
Rate 1	Residential	757,232	1,157,359	1,419,180	1,916,986	2,067,830	1,674,521	1,051,397	448,389	244,466	227,280	211,220	244,636	11,420,496
	Commercial	233,844	361,670	466,956	643,240	747,231	558,916	327,325	145,800	77,788	88,185	70,350	103,370	3,824,675
	Industrial	74,915	92,044	92,946	61,870	74,210	70,886	52,685	26,089	14,848	10,002	12,115	14,059	596,669
Rate 2	Seasonal	299,039	57,052	18,369	6,226	6,142	7,410	29,132	5,466	3,127	5,156	465,941	801,297	1,704,357
Rate 3	Contract	300,447	338,285	377,588	565,565	588,498	433,006	345,554	254,355	179,158	163,015	113,541	111,569	3,770,581
Rate 4	Industrial	114,922	181,694	37,105	6,931	6,395	4,536	3,775	1,831	451	2,592	15,017	65,815	441,064
Rate 5	Contract	242,184	718,409	82,071	8,001	4,282	2,761	366	113	-	3,775	620	282	1,062,864
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		2,022,583	2,906,513	2,494,215	3,208,819	3,494,588	2,752,036	1,810,234	882,043	519,838	500,005	888,804	1,341,028	22,820,706
														Total
Distribution Revenues ($'s)														
Rate 1	Residential	182,844	242,328	283,319	359,822	388,301	318,415	225,348	136,741	105,496	102,835	100,384	104,335	2,550,168
	Commercial	35,538	51,579	64,439	84,501	95,972	74,872	47,509	24,182	15,161	16,546	14,127	17,113	541,539
	Industrial	8,714	10,608	10,705	7,419	8,663	8,485	6,605	3,637	2,197	1,269	1,803	2,053	72,159
Rate 2	Seasonal	32,977	10,952	3,737	2,503	2,541	2,735	4,801	811	1,605	1,961	50,032	83,522	198,176
Rate 3	Contract	20,227	21,654	23,121	30,141	31,121	25,246	21,925	18,523	15,717	15,115	13,269	13,195	249,253
Rate 4	Industrial	18,271	25,711	4,394	1,473	1,425	1,059	816	539	347	633	1,903	7,148	63,718
Rate 5	Contract	16,027	46,634	5,965	1,256	1,020	927	773	758	750	989	789	770	76,657
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		314,596	409,465	395,680	487,115	529,044	431,740	307,776	185,191	141,271	139,349	182,307	228,137	3,751,671

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2007 Normalized Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Normalized Volumes (M*3)														
Rate 1	Residential	739,057	1,166,570	1,512,966	1,963,194	1,971,277	1,708,932	1,018,297	457,908	244,817	227,280	211,220	244,687	11,466,204
	Commercial	227,729	364,706	500,406	660,294	708,380	571,609	316,659	149,181	77,822	86,856	70,350	103,529	3,837,521
	Industrial	70,550	93,217	99,886	63,175	71,018	72,399	50,781	26,951	14,994	10,002	12,115	14,071	599,159
Rate 2	Seasonal	299,039	57,052	18,369	6,226	6,142	7,410	29,132	5,466	3,127	5,156	465,941	801,297	1,704,357
Rate 3	Contract	295,531	339,862	392,921	574,196	573,774	438,080	338,567	262,510	152,767	145,311	112,996	112,110	3,738,626
Rate 3	Industrial													-
Rate 4	Industrial	109,373	137,674	62,970	7,797	5,726	3,615	2,904	1,103	201	5,054	19,519	70,112	426,049
Rate 5	Contract	331,544	479,416	64,845	5,096	2,382	2,109	340	207	9	7,419	13,959	967	908,294
Total		2,072,824	2,638,497	2,652,362	3,279,978	3,338,699	2,804,154	1,756,680	903,326	493,737	487,078	906,100	1,346,773	22,680,209
Normalized Revenues ($'s)														
Rate 1	Residential	180,052	243,722	297,570	366,861	373,353	323,553	220,316	138,189	105,549	102,835	100,384	104,343	2,556,727
	Commercial	34,727	51,974	68,725	86,619	91,223	76,467	46,111	24,637	15,166	16,366	14,127	17,133	543,274
	Industrial	8,224	10,740	11,481	7,569	8,304	8,660	6,378	3,746	2,215	1,269	1,803	2,054	72,444
Rate 2	Seasonal	32,977	10,952	3,737	2,503	2,541	2,735	4,801	811	1,605	1,961	50,032	83,522	198,176
Rate 3	Contract	20,024	21,712	23,693	30,464	30,569	25,436	21,665	18,827	14,732	14,455	13,249	13,215	248,040
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	17,402	19,549	7,262	1,622	1,305	901	692	436	310	969	2,389	7,597	60,434
Rate 5	Contract	21,755	31,370	4,870	1,072	900	885	771	764	750	1,219	1,634	818	66,810
Total		315,162	390,020	417,338	496,709	508,195	438,637	300,734	187,410	140,327	139,074	183,618	228,681	3,745,905

NATURAL RESOURCE GAS LIMITED

Average Gas Consumption Per Customer
2007 Actual and Normalized
(M*3)

Actual Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	128	195	239	321	346	279	175	75	41	38	35	41	1,913
	Commercial	586	893	1,150	1,580	1,840	1,380	808	360	193	219	174	258	9,442
	Industrial	2,775	3,409	3,442	2,291	2,749	2,625	1,882	932	530	357	433	502	21,927
Rate 2	Seasonal	2,646	509	164	56	56	67	265	50	30	51	4,613	8,094	16,602
Rate 3	Contract	60,089	67,657	75,518	113,113	117,700	86,601	69,111	50,871	35,832	32,603	22,708	22,314	754,116
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	5,224	8,259	1,687	315	291	206	172	83	21	118	683	2,992	20,048
Rate 5	Contract	48,437	143,682	16,414	1,600	856	552	73	23	-	755	124	56	212,573

Normalized Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	125	197	255	329	330	285	170	76	41	38	35	41	1,921
	Commercial	571	901	1,233	1,622	1,745	1,411	782	368	193	216	174	258	9,473
	Industrial	2,613	3,452	3,699	2,340	2,630	2,681	1,814	963	535	357	433	503	22,021
Rate 2	Seasonal	2,646	509	164	56	56	67	265	50	30	51	4,613	8,094	16,602
Rate 3	Contract	59,106	67,972	78,584	114,839	114,755	87,616	67,713	52,502	30,553	29,062	22,599	22,422	747,725
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	15,070	6,258	2,862	354	260	164	132	50	9	230	887	3,187	29,465
Rate 5	Contract	66,309	95,883	12,969	1,019	476	422	68	41	2	1,484	2,792	193	181,659

NATURAL RESOURCE GAS LIMITED

Rate of Return on Ancillary Services
2007 Actual
($'s)

	Ancillary Services
Total Gross Revenue	1,053,909
Less Direct Cost of Sales	484,570
Total Net Revenue	569,339
Delayed Payment Charges	4,589
Total Ancillary Services Revenue	573,927
Allocated Costs	
Operations & Maintenance	222,272
Capital Taxes	5,699
Property Taxes	5,437
Net Depreciation Expense	145,916
Total	379,325
Income Before Tax	194,603
Income Tax Provision	10,017
Income After Tax	184,586
Value of Assets Employed	
Inventory	38,181
Working Cash	51,512
General Plant	1,416,788
Total Assets	1,506,481
Rate of Return	12.3%

NATURAL RESOURCE GAS LIMITED

Operating Revenue
2007 OEB Approved
($'s)

		2007 OEB Approved
Distribution and Transportation Revenue		
Rate 1	Residential	2,842,183
	Commercial	505,310
	Industrial	100,670
Rate 2	Seasonal	119,990
Rate 3	Contract	210,426
Rate 4	Industrial	49,476
Rate 5	Contract	61,003
Total		3,889,059
Other Operating Revenue (Net)		
Rental Equipment Program		506,554
Contract Work Program		70,374
Transfer/Connect Charges		30,000
Direct Purchase		3,221
Delayed Payment Charges, Interests		70,876
Total		681,026
Total Operating Revenue		4,570,085

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2007 OEB Approved
($'s)

		OEB Approved 2007	Historic Year 2007
Distribution and Transportation Revenue			
Rate 1	Residential	2,842,183	2,550,168
	Commercial	505,310	541,539
	Industrial	100,670	72,159
Rate 2	Seasonal	119,990	198,176
Rate 3	Contract	210,426	249,253
Rate 4	Industrial	49,476	63,718
Rate 5	Contract	61,003	76,657
Total		3,889,059	3,751,671
Other Operating Revenue (Net)			
Rental Equipment Program		506,554	409,422
Contract Work Program		70,374	2,163
Transfer/Connect Charges		30,000	40,062
Direct Purchase		3,221	5,065
Delayed Payment Charges		70,876	122,111
Total		681,026	578,824
Total Operating Revenue		4,570,085	4,330,495

		Variance from Historic Year 2007
Distribution and Transportation Revenue		
Rate 1	Residential	292,016
	Commercial	-36,230
	Industrial	28,512
Rate 2	Seasonal	-78,186
Rate 3	Contract	-38,827
Rate 4	Industrial	-14,242
Rate 5	Contract	-15,654
Total (1)		137,388
Other Operating Revenue (Net)		
Rental Equipment Program		97,132
Contract Work Program		68,211
Transfer/Connect Charges		-10,062
Direct Purchase		-1,844
Delayed Payment Charges		-51,235
Total (2)		102,202
Total Operating Revenue		239,590

Notes:

(1) Changes related to sales and transportation volumes (See Exhibit C6, Tab 2, Schedule 3, Updated).

(2) Changes related to number of rental units and level of delayed payment charges.

NATURAL RESOURCE GAS LIMITED

Gross Margin Analysis by Sales Class
2007 OEB Approved

		Total Gas Margin ($)	Total Volume (M*3)	Gross Unit Margin ($/M*3)
Rate 1	Residential	2,842,183	12,917,890	0.2200
	Commercial	505,310	3,681,059	0.1373
	Industrial	100,670	977,883	0.1029
Rate 2	Seasonal	119,990	1,261,551	0.0951
Rate 3	Contract	210,426	3,391,247	0.0620
Rate 4	Industrial	49,476	457,440	0.1082
Rate 5	Contract	61,003	879,071	0.0694
Total		3,889,059	23,566,141	0.1650

NATURAL RESOURCE GAS LIMITED

Summary of Gas Sales and Transportation
2007 OEB Approved

		Customers (Year-end)	Volumes (M*3)	Distribution Revenues ($)	Normalized Volumes (M*3)	Normalized Distribution Revenues ($)
Rate 1	Residential	6,361	12,917,890	2,842,183	12,917,890	2,842,183
	Commercial	391	3,681,059	505,310	3,681,059	505,310
	Industrial	35	977,883	100,670	977,883	100,670
Rate 2	Seasonal	50	1,261,551	119,990	1,261,551	119,990
Rate 3	Contract	4	3,391,247	210,426	3,391,247	210,426
Rate 4	Industrial	26	457,440	49,476	457,440	49,476
Rate 5	Contract	5	879,071	61,003	879,071	61,003
Total		6,872	23,566,141	3,889,059	23,566,141	3,889,059

NATURAL RESOURCE GAS LIMITED

Customers by Rate Class
2007 OEB Approved
(Year-end)

		OEB Approved 2007	Historic Year 2007
Rate 1	Residential	6,361	6,022
	Commercial	391	401
	Industrial	35	28
Rate 2	Seasonal	50	99
Rate 3	Contract	4	5
Rate 4	Industrial	26	22
Rate 5	Contract	5	5
Total		6,872	6,582

		Variance from Historic Year 2007
Rate 1	Residential	339
	Commercial	-10
	Industrial	7
Rate 2	Seasonal	-49
Rate 3	Contract	-1
Rate 4	Industrial	4
Rate 5	Contract	0
Total		290

NATURAL RESOURCE GAS LIMITED

Gas Sales and Transportation Volume
2007 OEB Approved vs. 2007 (Normalized) Historic Year
(M*3)

		OEB Approved 2007	Normalized 2007	Variance
Rate 1	Residential	12,917,890	11,466,204	1,451,686
	Commercial	3,681,059	3,837,521	-156,462
	Industrial	977,883	599,159	378,724
Rate 2	Seasonal	1,261,551	1,704,357	-442,806
Rate 3	Contract	3,391,247	3,738,626	-347,379
Rate 4	Industrial	457,440	426,049	31,391
Rate 5	Contract	879,071	908,294	-29,223
Total		23,566,141	22,680,209	885,932

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2007 OEB Approved Customers, Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	
Customers														
Rate 1	Residential	6,065	6,155	6,218	6,251	6,280	6,283	6,301	6,311	6,315	6,314	6,326	6,361	
	Commercial	390	390	390	391	391	391	391	391	391	391	391	391	
	Industrial	31	32	32	33	34	34	35	35	35	35	35	35	
Rate 2	Seasonal	77	77	77	77	77	77	77	65	60	55	50	50	
Rate 3	Contract	5	5	5	5	5	5	5	5	5	4	4	4	
Rate 4	Industrial	24	25	25	25	25	25	25	25	25	25	25	26	
Rate 5	Contract	5	5	5	5	5	5	5	5	5	5	5	5	
Total		6,597	6,689	6,752	6,787	6,817	6,820	6,839	6,837	6,836	6,829	6,836	6,872	
														Total
Volumes (M*3)														
Rate 1	Residential	720,257	1,094,026	1,980,461	2,298,893	2,157,866	1,712,346	1,216,959	615,787	295,402	255,346	215,325	355,222	12,917,890
	Commercial	195,371	341,569	565,121	658,793	593,336	524,624	293,233	171,093	84,665	72,983	74,866	105,405	3,681,059
	Industrial	47,077	89,300	128,205	143,274	145,227	156,656	115,331	66,315	24,969	17,245	20,900	23,384	977,883
Rate 2	Seasonal	106,065	10,422	2,972	2,583	2,265	3,595	7,801	2,237	958	17,275	463,301	642,077	1,261,551
Rate 3	Contract	224,087	356,277	541,443	563,022	504,842	473,312	313,125	192,216	134,321	27,828	25,637	35,137	3,391,247
Rate 4	Industrial	97,726	162,548	89,499	7,151	5,496	3,305	2,383	1,179	793	3,949	11,426	71,985	457,440
Rate 5	Contract	235,104	498,046	118,252	10,008	474	313	194	112	13	3,098	6,842	6,615	879,071
Total		1,625,687	2,552,188	3,425,953	3,683,724	3,409,506	2,874,151	1,949,026	1,048,939	541,121	397,724	818,297	1,239,825	23,566,141
														Total
Distribution Revenues ($'s)														
Rate 1	Residential	190,200	237,357	382,609	436,019	413,199	340,330	259,236	160,509	108,305	101,462	95,116	117,841	2,842,183
	Commercial	32,834	46,328	70,508	80,641	74,366	67,784	42,615	27,908	15,880	14,193	14,272	17,981	505,310
	Industrial	6,431	9,060	11,835	13,189	14,054	14,622	11,767	7,567	3,466	2,596	2,842	3,241	100,670
Rate 2	Seasonal	13,572	2,074	1,225	1,219	1,150	1,343	1,848	1,067	814	2,698	39,719	53,261	119,990
Rate 3	Contract	17,681	20,879	27,673	28,519	26,342	25,197	19,304	14,886	12,772	5,662	5,582	5,929	210,426
Rate 4	Industrial	13,739	14,410	7,829	1,558	1,249	828	526	441	390	866	1,419	6,221	49,476
Rate 5	Contract	15,957	31,085	7,762	1,115	529	519	512	507	501	690	920	906	61,003
Total		290,415	361,193	509,441	562,260	530,889	450,623	335,808	212,885	142,128	128,167	159,870	205,380	3,889,059

NATURAL RESOURCE GAS LIMITED

Average Gas Consumption Per Customer
2007 OEB Approved
(M*3)

Actual Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	118.8	177.8	318.5	367.8	343.6	272.5	193.1	97.6	46.8	40.4	34.0	55.8	2,066.7
	Commercial	501.0	875.8	1,449.0	1,684.9	1,517.5	1,341.8	750.0	437.6	216.5	186.7	191.5	269.6	9,421.7
	Industrial	1,518.6	2,790.6	4,006.4	4,341.6	4,271.4	4,607.5	3,295.2	1,894.7	713.4	492.7	597.1	668.1	29,197.4
Rate 2	Seasonal	1,377.5	135.4	38.6	33.6	29.4	46.7	101.3	34.4	16.0	314.1	9,266.0	12,841.5	24,234.4
Rate 3	Contract	44,817.4	71,255.4	108,288.6	112,604.4	100,968.4	94,662.4	62,625.0	38,443.2	26,864.2	6,957.0	6,409.3	8,784.3	682,679.5
Rate 4	Industrial	4,071.9	6,501.9	3,580.0	286.0	219.8	132.2	95.3	47.2	31.7	158.0	457.0	2,768.7	18,349.7
Rate 5	Contract	47,020.8	99,609.2	23,650.4	2,001.6	94.8	62.6	38.8	22.4	2.6	619.6	1,368.4	1,323.0	175,814.2

Normalized Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	118.8	177.8	318.5	367.8	343.6	272.5	193.1	97.6	46.8	40.4	34.0	55.8	2,066.7
	Commercial	501.0	875.8	1,449.0	1,684.9	1,517.5	1,341.8	750.0	437.6	216.5	186.7	191.5	269.6	9,421.7
	Industrial	1,518.6	2,790.6	4,006.4	4,341.6	4,271.4	4,607.5	3,295.2	1,894.7	713.4	492.7	597.1	668.1	29,197.4
Rate 2	Seasonal	1,377.5	135.4	38.6	33.6	29.4	46.7	101.3	34.4	16.0	314.1	9,266.0	12,841.5	24,234.4
Rate 3	Contract	44,817.4	71,255.4	108,288.6	112,604.4	100,968.4	94,662.4	62,625.0	38,443.2	26,864.2	6,957.0	6,409.3	8,784.3	682,679.5
Rate 4	Industrial	4,071.9	6,501.9	3,580.0	286.0	219.8	132.2	95.3	47.2	31.7	158.0	457.0	2,768.7	18,349.7
Rate 5	Contract	47,020.8	99,609.2	23,650.4	2,001.6	94.8	62.6	38.8	22.4	2.6	619.6	1,368.4	1,323.0	175,814.2

NATURAL RESOURCE GAS LIMITED

Rate of Return on Ancillary Services
2007 OEB Approved
($'s)

	Ancillary Services
Total Gross Revenue	1,248,180
Less Direct Cost of Sales	668,030
Total Net Revenue	580,150
Delayed Payment Charges	7,017
Total Ancillary Services Revenue	587,167
Allocated Costs	
Operations & Maintenance	251,220
Capital Taxes	0
Property Taxes	6,354
Net Depreciation Expense	171,755
Total	429,329
Income Before Tax	157,837
Income Tax Provision	20,770
Income After Tax	137,068
Value of Assets Employed	
Inventory	37,045
Working Cash	26,226
General Plant	1,408,690
Total Assets	1,471,961
Rate of Return	9.3%

NATURAL RESOURCE GAS LIMITED

Operating Revenue
2008 Actual and Normalized
($'s)

		Actual Forecast	Adjust-ments	Normalized Forecast
Distribution and Transportation Revenue				
Rate 1	Residential	2,643,039	-14,225	2,628,814
	Commercial	589,499	-4,270	585,229
	Industrial	64,937	661	65,598
Rate 2	Seasonal	109,991	0	109,991
Rate 3	Contract	481,160	-52,683	428,477
Rate 4	Industrial	45,698	7,648	53,346
Rate 5	Contract	57,434	14,802	72,236
Rate 6	Contract	0	0	0
Total		3,991,759	-48,066	3,943,693
Other Operating Revenue (Net)				
Rental Equipment Program		418,994	0	418,994
Contract Work Program		-35,725	0	-35,725
Transfer/Connect Charges		30,043	0	30,043
Direct Purchase		3,991	0	3,991
Delayed Payment Charges, Interests		80,402	0	80,402
Total		497,704	0	497,704
Total Operating Revenue		4,489,462	-48,066	4,441,396

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2008 Actual
($'s)

		Actual 2008	Actual 2007
Distribution and Transportation Revenue			
Rate 1	Residential	2,643,039	2,550,168
	Commercial	589,499	541,539
	Industrial	64,937	72,159
Rate 2	Seasonal	109,991	198,176
Rate 3	Contract	481,160	249,253
Rate 4	Industrial	45,698	63,718
Rate 5	Contract	57,434	76,657
Rate 6	Contract	0	0
Total		3,991,759	3,751,671
Other Operating Revenue (Net)			
Rental Equipment Program		418,994	409,422
Contract Work Program		-35,725	2,163
Transfer/Connect Charges		30,043	40,062
Direct Purchase		3,991	5,065
Delayed Payment Charges		80,402	122,111
Total		497,704	578,824
Total Operating Revenue		4,489,462	4,330,495

		Variance from 2007
Distribution and Transportation Revenue		
Rate 1	Residential	92,871
	Commercial	47,960
	Industrial	-7,222
Rate 2	Seasonal	-88,185
Rate 3	Contract	231,907
Rate 4	Industrial	-18,021
Rate 5	Contract	-19,223
Rate 6	Contract	0
Total		240,088
Other Operating Revenue (Net)		
Rental Equipment Program		9,572
Contract Work Program		-37,889
Transfer/Connect Charges		-10,019
Direct Purchase		-1,075
Delayed Payment Charges		-41,709
Total		-81,120
Total Operating Revenue		158,967

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2008 Normalized
($'s)

		Normalized 2008	Normalized 2007
Distribution and Transportation Revenue			
Rate 1	Residential	2,628,814	2,556,727
	Commercial	585,229	543,274
	Industrial	65,598	72,444
Rate 2	Seasonal	109,991	198,176
Rate 3	Contract	428,477	248,040
Rate 4	Industrial	53,346	60,434
Rate 5	Contract	72,236	66,810
Rate 6	Contract	0	0
Total		3,943,693	3,745,905
Other Operating Revenue (Net)			
Rental Equipment Program		418,994	409,422
Contract Work Program		-35,725	2,163
Transfer/Connect Charges		30,043	40,062
Direct Purchase		3,991	5,065
Delayed Payment Charges		80,402	122,111
Total		497,704	578,824
Total Operating Revenue		4,441,396	4,324,729

		Variance from 2007
Distribution and Transportation Revenue		
Rate 1	Residential	72,087
	Commercial	41,956
	Industrial	-6,845
Rate 2	Seasonal	-88,185
Rate 3	Contract	180,438
Rate 4	Industrial	-7,088
Rate 5	Contract	5,427
Rate 6	Contract	0
Total		197,788
Other Operating Revenue (Net)		
Rental Equipment Program		9,572
Contract Work Program		-37,889
Service Work Program		0
Merchandise Sales		0
Transfer/Connect Charges		-10,019
Direct Purchase		-1,075
Delayed Payment Charges		-41,709
Total		-81,120
Total Operating Revenue		116,668

NATURAL RESOURCE GAS LIMITED

Gross Margin Analysis by Sales Class
2008 Actual

		Total Gas Margin ($)	Total Volume (M*3)	Gross Unit Margin ($/M*3)
Rate 1	Residential	2,643,039	11,901,311	0.2221
	Commercial	589,499	4,255,370	0.1385
	Industrial	64,937	532,995	0.1218
Rate 2	Seasonal	109,991	838,429	0.1312
Rate 3	Contract	481,160	2,647,821	0.1817
Rate 4	Industrial	45,698	378,573	0.1207
Rate 5	Contract	57,434	746,780	0.0769
Rate 6	Contract	0	212,207	0.0000
Total		3,991,759	21,513,486	0.1855

NATURAL RESOURCE GAS LIMITED

Summary of Gas Sales and Transportation
2008 Actual and Normalized

		Customers (Year-end)	Volumes (M*3)	Distribution Revenues ($)	Normalized Volumes (M*3)	Normalized Distribution Revenues ($)
Rate 1	Residential	6,202	11,901,311	2,643,039	11,809,513	2,628,814
	Commercial	410	4,255,370	589,499	4,219,103	585,229
	Industrial	26	532,995	64,937	538,845	65,598
Rate 2	Seasonal	90	838,429	109,991	838,429	109,991
Rate 3	Contract	4	2,647,821	481,160	2,430,609	428,477
Rate 4	Industrial	22	378,573	45,698	441,990	53,346
Rate 5	Contract	5	746,780	57,434	966,576	72,236
Rate 6		0	0	0		0
Total		6,759	21,301,279	3,991,759	21,245,065	3,943,693

NATURAL RESOURCE GAS LIMITED

Customers by Rate Class
2008 Actual
(Year-end)

		Actual 2008	Actual 2007
Rate 1	Residential	6,202	6,022
	Commercial	410	401
	Industrial	26	28
Rate 2	Seasonal	90	99
Rate 3	Contract	4	5
Rate 4	Industrial	22	22
Rate 5	Contract	5	5
Rate 6		0	0
Total		6,759	6,582

		Variance from 2007
Rate 1	Residential	180
	Commercial	9
	Industrial	-2
Rate 2	Seasonal	-9
Rate 3	Contract	-1
Rate 4	Industrial	0
Rate 5	Contract	0
Rate 6		0
Total		177

NATURAL RESOURCE GAS LIMITED

Gas Sales and Transportation Volume
2008 Actual and 2007 Actual
(M*3)

		Actual 2008	Actual 2007	Variance
Rate 1	Residential	11,901,311	11,420,496	480,815
	Commercial	4,255,370	3,824,675	430,695
	Industrial	532,995	596,669	-63,674
Rate 2	Seasonal	838,429	1,704,357	-865,928
Rate 3	Contract	2,435,614	3,770,581	-1,334,967
Rate 4	Industrial	378,573	441,064	-62,491
Rate 5	Contract	746,780	1,062,864	-316,084
Rate 6		212,207	0	212,207
Total		21,089,072	22,820,706	-1,731,634

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2008 Actual Customers, Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Customers														
Rate 1	Residential	6,058	6,090	6,096	6,131	6,139	6,156	6,174	6,179	6,196	6,197	6,198	6,202	6,151
	Commercial	402	408	407	410	410	410	409	409	409	408	409	410	408
	Industrial	28	28	28	28	28	28	28	28	28	27	27	26	28
Rate 2	Seasonal	97	97	96	96	96	96	95	95	95	95	90	90	95
Rate 3	Contract	5	4	4	4	4	4	4	4	4	4	4	4	4
Rate 4	Industrial	22	22	22	22	22	22	22	22	22	22	22	22	22
Rate 5	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		6,617	6,654	6,658	6,696	6,704	6,721	6,737	6,742	6,759	6,758	6,755	6,759	6,713
														Total
Volumes (M*3)														
Rate 1	Residential	535,925	1,271,719	1,812,347	1,988,041	2,015,652	1,816,490	917,711	533,249	299,320	213,474	226,744	270,639	11,901,311
	Commercial	193,583	440,868	656,876	734,017	759,993	664,934	307,998	164,367	97,059	61,729	82,381	91,565	4,255,370
	Industrial	64,716	84,717	67,449	58,884	65,026	74,548	46,656	25,441	14,200	9,213	10,030	12,115	532,995
Rate 2	Seasonal	179,553	52,066	10,452	6,480	6,508	6,565	18,708	9,128	7,043	2,000	238,098	301,828	838,429
Rate 3	Contract	159,775	279,655	296,897	347,019	362,318	327,072	213,953	166,903	103,089	72,633	41,275	277,232	2,647,821
Rate 4	Industrial	127,572	99,539	15,017	3,775	4,254	4,423	3,015	1,352	366	16,510	17,890	84,860	378,573
Rate 5	Contract	348,061	319,803	9,579	902	1,014	1,521	592	254	28	44,036	18,088	2,902	746,780
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-		-
Total		1,609,185	2,548,367	2,868,617	3,139,118	3,214,765	2,895,553	1,508,633	900,694	521,105	419,595	634,506	1,041,141	21,301,279
														Total
Distribution Revenues ($'s)														
Rate 1	Residential	145,666	261,804	345,389	372,422	376,496	346,103	209,569	151,241	115,822	102,707	104,508	111,312	2,643,039
	Commercial	30,752	60,322	86,107	94,415	96,575	86,850	44,539	26,861	17,833	12,498	15,639	17,108	589,499
	Industrial	7,580	9,803	7,652	6,852	7,665	8,801	5,857	3,527	2,190	1,529	1,628	1,851	64,937
Rate 2	Seasonal	21,482	9,954	3,075	2,418	2,406	2,396	3,541	2,385	1,817	1,093	26,508	32,916	109,991
Rate 3	Contract	14,994	15,811	16,454	18,324	18,895	17,580	13,360	11,605	9,223	66,156	140,643	138,114	481,160
Rate 4	Industrial	14,098	11,076	2,068	959	1,063	1,039	724	474	333	2,299	2,327	9,238	45,698
Rate 5	Contract	22,829	22,049	1,373	806	813	845	788	766	752	3,566	1,912	933	57,434
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		257,402	390,819	462,119	496,197	503,914	463,615	278,377	196,860	147,971	189,847	293,166	311,473	3,991,759

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2008 Normalized Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
NormalizedVolumes (M*3)														
Rate 1	Residential	571,501	1,224,927	1,776,877	2,032,787	1,955,179	1,759,982	956,197	521,048	299,862	213,474	226,744	270,935	11,809,513
	Commercial	209,174	423,268	642,730	752,456	734,389	641,796	321,777	160,360	97,311	61,729	82,329	91,783	4,219,103
	Industrial	78,100	79,946	66,095	60,021	63,273	72,158	48,952	24,670	14,252	9,213	10,030	12,135	538,845
Rate 2	Seasonal	179,553	52,066	10,452	6,480	6,508	6,565	18,708	9,128	7,043	2,000	238,098	301,828	838,429
Rate 3	Contract	180,386	266,737	290,341	355,818	350,258	315,472	225,600	158,937	104,459	75,726	41,209	65,667	2,430,609
Rate 3	Industrial													
Rate 4	Industrial	111,440	158,780	57,955	7,949	6,129	4,018	3,239	1,336	284	4,442	19,618	66,800	441,990
Rate 5	Contract	295,750	568,516	73,271	5,849	3,306	2,481	355	180	7	6,700	9,643	518	966,576
Total		1,625,905	2,774,239	2,917,720	3,221,360	3,119,043	2,802,471	1,574,827	875,660	523,218	373,284	627,671	809,667	21,245,065
Normalized Revenues ($'s)														
Rate 1	Residential	150,788	254,705	339,990	379,234	367,301	337,517	215,416	149,387	115,905	102,707	104,508	111,357	2,628,814
	Commercial	32,862	58,098	84,353	96,670	93,479	83,991	46,322	26,320	17,867	12,498	15,632	17,138	585,229
	Industrial	9,081	9,269	7,505	6,978	7,467	8,529	6,129	3,430	2,197	1,529	1,628	1,854	65,598
Rate 2	Seasonal	21,482	9,954	3,075	2,418	2,406	2,396	3,541	2,385	1,817	1,093	26,508	32,916	109,991
Rate 3	Contract	15,763	15,329	16,210	18,653	18,445	17,147	13,795	11,307	9,275	68,744	140,472	83,337	428,477
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	12,351	17,501	7,178	1,709	1,408	969	757	472	322	824	2,525	7,332	53,346
Rate 5	Contract	19,511	38,613	5,519	1,115	957	905	772	762	751	1,178	1,370	783	72,236
Total		261,839	403,468	463,830	506,777	491,464	451,455	286,732	194,063	148,132	188,572	292,643	254,716	3,943,693

NATURAL RESOURCE GAS LIMITED

Average Gas Consumption Per Customer
2008 Actual and Normalized
(M*3)

Actual Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	88	209	297	324	328	295	149	86	48	34	37	44	1,940
	Commercial	482	1,081	1,614	1,790	1,854	1,622	753	402	237	151	201	223	10,410
	Industrial	2,311	3,026	2,409	2,103	2,322	2,662	1,666	909	507	341	371	466	19,094
Rate 2	Seasonal	1,851	537	109	68	68	68	197	96	74	21	2,646	3,354	9,088
Rate 3	Contract	31,955	69,914	74,224	86,755	90,580	81,768	53,488	41,726	25,772	18,158	10,319	69,308	653,967
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	5,799	4,525	683	172	193	201	137	61	17	750	813	3,857	17,208
Rate 5	Contract	69,612	63,961	1,916	180	203	304	118	51	6	8,807	3,618	580	149,356

Normalized Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	94	201	291	332	318	286	155	84	48	34	37	44	1,925
	Commercial	520	1,037	1,579	1,835	1,791	1,565	787	392	238	151	201	224	10,322
	Industrial	2,789	2,855	2,361	2,144	2,260	2,577	1,748	881	509	341	371	467	19,303
Rate 2	Seasonal	1,851	537	109	68	68	68	197	96	74	21	2,646	3,354	9,088
Rate 3	Contract	36,077	66,684	72,585	88,954	87,564	78,868	56,400	39,734	26,115	18,932	10,302	16,417	598,633
Rate 3	Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
Rate 4	Industrial	5,065	7,217	2,634	361	279	183	147	61	13	202	892	3,036	20,090
Rate 5	Contract	59,150	113,703	14,654	1,170	661	496	71	36	1	1,340	1,929	104	193,315

NATURAL RESOURCE GAS LIMITED

Rate of Return on Ancillary Services
2008 Actual
($'s)

	Ancillary Services
Total Gross Revenue	1,103,536
Less Direct Cost of Sales	552,687
Total Net Revenue	550,849
Delayed Payment Charges	4,182
Total Ancillary Services Revenue	555,031
Allocated Costs	
Operations & Maintenance	148,531
Capital Taxes	3,087
Property Taxes	6,358
Net Depreciation Expense	163,590
Total	321,566
Income Before Tax	233,465
Income Tax Provision	25,720
Income After Tax	207,745
Value of Assets Employed	
Inventory	187,450
Working Cash	-47,692
General Plant	1,374,692
Total Assets	1,514,450
Rate of Return	13.7%

NATURAL RESOURCE GAS LIMITED

Operating Revenue
2009 Actual and Normalized
($'s)

		Actual Forecast	Adjust-ments	Normalized Forecast
Distribution and Transportation Revenue				
Rate 1	Residential	2,796,930	-22,680	2,774,249
	Commercial	578,961	-6,747	572,215
	Industrial	72,816	-1,614	71,202
Rate 2	Seasonal	73,285	0	73,285
Rate 3	Contract	1,701,134	-1,550,530	150,604
Rate 4	Industrial	52,893	-71	52,822
Rate 5	Contract	81,474	-15,014	66,460
Rate 6	Contract	0	1,546,815	1,546,815
Total		5,357,493	-49,841	5,307,652
Other Operating Revenue (Net)				
Rental Equipment Program		437,065	0	437,065
Contract Work Program		36,660	0	36,660
Transfer/Connect Charges		29,769	0	29,769
Direct Purchase		3,680	0	3,680
Delayed Payment Charges, Interests		62,019	0	62,019
Total		569,192	0	569,192
Total Operating Revenue		5,926,685	-49,841	5,876,845

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2009 Actual
($'s)

		Actual 2009	Actual 2008
Distribution and Transportation Revenue			
Rate 1	Residential	2,796,930	2,643,039
	Commercial	578,961	589,499
	Industrial	72,816	64,937
Rate 2	Seasonal	73,285	109,991
Rate 3	Contract	1,701,134	481,160
Rate 4	Industrial	52,893	45,698
Rate 5	Contract	81,474	57,434
Rate 6	Contract	0	0
Total		5,357,493	3,991,759
Other Operating Revenue (Net)			
Rental Equipment Program		437,065	418,994
Contract Work Program		36,660	-35,725
Transfer/Connect Charges		29,769	30,043
Direct Purchase		3,680	3,991
Delayed Payment Charges		62,019	80,402
Total		569,192	497,704
Total Operating Revenue		5,926,685	4,489,462

		Variance from 2008
Distribution and Transportation Revenue		
Rate 1	Residential	153,891
	Commercial	-10,538
	Industrial	7,879
Rate 2	Seasonal	-36,707
Rate 3	Contract	1,219,974
Rate 4	Industrial	7,195
Rate 5	Contract	24,040
Rate 6	Contract	0
Total		1,365,734
Other Operating Revenue (Net)		
Rental Equipment Program		18,072
Contract Work Program		72,385
Transfer/Connect Charges		-274
Direct Purchase		-311
Delayed Payment Charges		-18,383
Total		71,489
Total Operating Revenue		1,437,223

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2009 Normalized
($'s)

		Normalized 2009	Normalized 2008
Distribution and Transportation Revenue			
Rate 1	Residential	2,774,249	2,628,814
	Commercial	572,215	585,229
	Industrial	71,202	65,598
Rate 2	Seasonal	73,285	109,991
Rate 3	Contract	150,604	428,477
Rate 4	Industrial	52,822	53,346
Rate 5	Contract	66,460	72,236
Rate 6	Contract*	1,546,815	0
Total		5,307,652	3,943,693
Other Operating Revenue (Net)			
Rental Equipment Program		437,065	418,994
Contract Work Program		36,660	-35,725
Transfer/Connect Charges		29,769	30,043
Direct Purchase		3,680	3,991
Delayed Payment Charges		62,019	80,402
Total		569,192	497,704
Total Operating Revenue		5,876,845	4,441,396

		Variance from 2008
Distribution and Transportation Revenue		
Rate 1	Residential	145,435
	Commercial	-13,015
	Industrial	5,603
Rate 2	Seasonal	-36,707
Rate 3	Contract	-277,873
Rate 4	Industrial	-524
Rate 5	Contract	-5,776
Rate 6	Contract	1,546,815
Total		1,363,959
Other Operating Revenue (Net)		
Rental Equipment Program		18,072
Contract Work Program		72,385
Service Work Program		44,032
Merchandise Sales		-699
Transfer/Connect Charges		-274
Direct Purchase		-311
Delayed Payment Charges		-18,383
Total		114,822
Total Operating Revenue		1,478,781

NATURAL RESOURCE GAS LIMITED

Gross Margin Analysis by Sales Class
2009 Actual

		Total Gas Margin ($)	Total Volume (M*3)	Gross Unit Margin ($/M*3)
Rate 1	Residential	2,796,930	12,739,773	0.2195
	Commercial	578,961	4,140,590	0.1398
	Industrial	72,816	593,738	0.1226
Rate 2	Seasonal	73,285	531,925	0.1378
Rate 3	Contract	1,701,134	33,721,969	0.0504
Rate 4	Industrial	52,893	439,909	0.1202
Rate 5	Contract	81,474	1,130,257	0.0721
Rate 6*	Contract	0	0	0.0000
Total		5,357,493	53,298,161	0.1005

* IGPC revenues and volumes included in Rate 3.

NATURAL RESOURCE GAS LIMITED

Summary of Gas Sales and Transportation
2009 Actual and Normalized

		Customers (Year-end)	Volumes (M*3)	Distribution Revenues ($)	Normalized Volumes (M*3)	Normalized Distribution Revenues ($)
Rate 1	Residential	6,331	12,739,773	2,796,930	12,589,966	2,774,249
	Commercial	408	4,140,590	578,961	4,085,657	572,215
	Industrial	25	593,738	72,816	579,399	71,202
Rate 2	Seasonal	73	531,925	73,285	531,925	73,285
Rate 3	Contract	4	33,721,969	1,701,134	33,629,774	150,604
Rate 4	Industrial	23	439,909	52,893	438,172	52,822
Rate 5	Contract	5	1,130,257	81,474	896,326	66,460
Rate 6*		1	0	0	0	1,546,815
Total		6,869	53,298,161	5,357,493	52,751,219	3,760,838

* Results included in Rate 3.

NATURAL RESOURCE GAS LIMITED

Customers by Rate Class
2009 Actual
(Year-end)

		Actual 2009	Actual 2008
Rate 1	Residential	6,331	6,202
	Commercial	408	410
	Industrial	25	26
Rate 2	Seasonal	73	90
Rate 3	Contract	4	4
Rate 4	Industrial	23	22
Rate 5	Contract	5	5
Rate 6		1	0
Total		6,870	6,759

		Variance from 2008
Rate 1	Residential	129
	Commercial	-2
	Industrial	-1
Rate 2	Seasonal	-17
Rate 3	Contract	0
Rate 4	Industrial	1
Rate 5	Contract	0
Rate 6		1
Total		111

NATURAL RESOURCE GAS LIMITED

Gas Sales and Transportation Volume
2009 Actual and 2008 Actual
(M*3)

		Actual 2009	Actual 2008	Variance
Rate 1	Residential	12,739,773	11,901,311	838,462
	Commercial	4,140,590	4,255,370	-114,780
	Industrial	593,738	532,995	60,743
Rate 2	Seasonal	531,925	838,429	-306,504
Rate 3	Contract	33,721,969	2,435,614	31,286,355
Rate 4	Industrial	439,909	378,573	61,336
Rate 5	Contract	1,130,257	746,780	383,477
Rate 6		0	212,207	-212,207
Total		53,298,161	21,089,072	32,209,089

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2009 Actual Customers, Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Customers														
Rate 1	Residential	6,256	6,293	6,307	6,317	6,332	6,341	6,341	6,331	6,332	6,315	6,321	6,331	6,318
	Commercial	411	411	411	412	414	413	411	407	410	407	408	408	410
	Industrial	26	26	27	26	26	26	27	26	26	26	26	25	26
Rate 2	Seasonal	90	88	88	86	86	86	83	80	79	78	77	73	83
Rate 3	Contract	4	4	4	4	4	4	4	4	4	4	4	4	4
Rate 4	Industrial	22	23	23	23	23	23	23	23	23	23	23	23	23
Rate 5	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 6	-	1	1	1	1	1	1	1	1	1	1	1	1	1
Total		6,815	6,851	6,866	6,874	6,891	6,899	6,895	6,877	6,880	6,859	6,865	6,870	6,870

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Volumes (M*3)														
Rate 1	Residential	681,501	1,374,609	2,114,233	2,378,843	1,954,880	1,676,212	982,343	502,878	275,964	238,577	226,350	333,383	12,739,773
	Commercial	225,448	440,359	685,022	794,901	648,199	545,026	295,207	151,632	86,720	83,198	74,802	110,076	4,140,590
	Industrial	84,522	139,123	81,592	65,223	56,686	61,870	41,331	19,158	11,636	8,988	8,001	15,608	593,738
Rate 2	Seasonal	52,150	31,555	9,213	8,030	3,888	6,508	14,481	4,311	873	958	139,208	260,750	531,925
Rate 3	Contract	132,089	221,746	288,238	325,821	269,337	284,207	178,077	126,414	117,102	127,656	99,567	92,580	2,262,834
Rate 4	Industrial	149,238	176,989	52,798	11,072	5,015	3,747	2,761	902	423	12,171	6,677	18,116	439,909
Rate 5	Contract	272,696	663,864	120,726	12,819	8,368	704	282	56	-	15,468	34,795	479	1,130,257
Rate 6	-	2,516,726	2,665,317	2,669,007	2,604,742	2,540,900	2,807,933	2,587,753	2,754,430	2,613,222	2,562,115	2,533,856	2,603,136	31,459,135
Total		4,114,370	5,713,562	6,020,829	6,201,451	5,487,273	5,386,207	4,102,235	3,559,781	3,105,940	3,049,131	3,123,256	3,434,128	53,298,161

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Distribution Revenues ($'s)														
Rate 1	Residential	173,074	278,759	392,404	433,339	369,780	327,482	223,123	148,417	113,932	108,045	106,100	122,475	2,796,930
	Commercial	34,114	60,564	89,026	101,763	85,059	73,677	43,114	24,950	16,510	15,978	14,769	19,437	578,961
	Industrial	9,627	15,497	10,610	7,904	6,818	7,423	5,174	2,775	1,879	1,510	1,368	2,232	72,816
Rate 2	Seasonal	7,271	6,283	2,752	2,558	1,791	2,239	2,847	1,586	1,098	1,106	15,754	28,000	73,285
Rate 3	Contract	144,032	143,961	149,858	151,260	138,905	149,707	142,332	143,820	140,057	143,866	114,194	139,142	1,701,134
Rate 4	Industrial	16,303	19,320	6,433	2,028	1,206	964	691	417	353	1,794	1,133	2,252	52,893
Rate 5	Contract	18,193	43,350	8,505	1,577	1,279	795	767	754	751	1,753	2,972	780	81,474
Rate 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total		402,613	567,734	659,587	700,428	604,838	562,287	418,048	322,717	274,581	274,053	256,290	314,319	5,357,493

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2009 Normalized Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Normalized Volumes (M*3)														
Rate 1	Residential	663,012	1,339,381	2,070,392	2,209,099	2,035,364	1,711,595	982,704	506,427	274,425	238,577	226,350	332,641	12,589,966
	Commercial	218,491	428,248	669,579	732,539	677,910	557,761	295,319	152,772	86,160	82,508	74,802	109,569	4,085,657
	Industrial	78,388	133,345	79,817	61,141	58,768	63,213	41,348	19,317	11,524	8,988	8,001	15,548	579,399
Rate 2	Seasonal	52,150	31,555	9,213	8,030	3,888	6,508	14,481	4,311	873	958	139,208	260,750	531,925
Rate 3	Contract	126,893	214,926	281,624	299,439	281,822	291,326	178,157	128,347	109,229	106,000	97,855	55,021	2,170,640
Rate 3	Industrial	2,516,726	2,665,317	2,669,007	2,604,742	2,540,900	2,807,933	2,587,753	2,754,430	2,613,222	2,562,115	2,533,856	2,603,136	31,459,135
Rate 4	Industrial	114,973	150,272	45,633	7,108	5,707	4,338	3,318	1,417	344	8,739	21,017	75,306	438,172
Rate 5	Contract	304,386	497,160	52,899	4,532	2,866	2,259	425	194	15	19,250	11,148	1,191	896,326
Total		4,075,019	5,460,205	5,878,164	5,926,630	5,607,226	5,444,934	4,103,504	3,567,215	3,095,791	3,027,134	3,112,236	3,453,162	52,751,219
Normalized Revenues ($'s)														
Rate 1	Residential	170,288	273,435	385,753	407,522	382,040	332,873	223,179	148,956	113,697	108,045	106,100	122,362	2,774,249
	Commercial	33,204	59,024	87,122	94,142	88,745	75,290	43,129	25,102	16,434	15,884	14,769	19,369	572,215
	Industrial	8,950	14,866	10,386	7,428	7,057	7,578	5,176	2,795	1,864	1,510	1,368	2,225	71,202
Rate 2	Seasonal	7,271	6,283	2,752	2,558	1,791	2,239	2,847	1,586	1,098	1,106	15,754	28,000	73,285
Rate 3	Contract	10,854	13,790	16,654	17,607	16,145	16,521	12,574	10,473	9,820	9,906	8,554	7,707	150,604
Rate 3	Industrial	132,960	129,910	132,943	132,590	123,230	133,455	129,761	133,421	129,929	133,070	105,587	129,959	1,546,815
Rate 4	Industrial	12,624	16,446	5,600	1,407	1,333	1,069	771	487	342	1,371	2,937	8,436	52,822
Rate 5	Contract	20,220	32,652	4,148	1,043	931	894	776	762	750	1,999	1,462	823	66,460
Total		396,371	546,406	645,357	664,297	621,272	569,918	418,212	323,583	273,934	272,890	256,531	318,882	5,307,652

NATURAL RESOURCE GAS LIMITED

Average Gas Consumption Per Customer
2009 Actual
(M*3)

Actual Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	109	218	335	377	309	264	155	79	44	38	36	53	2,016
	Commercial	549	1,071	1,667	1,929	1,566	1,320	718	373	212	204	183	270	10,061
	Industrial	3,251	5,351	3,022	2,509	2,180	2,380	1,531	737	448	346	308	624	22,685
Rate 2	Seasonal	579	359	105	93	45	76	174	54	11	12	1,808	3,572	6,888
Rate 3	Contract	33,022	55,437	72,060	81,455	67,334	71,052	44,519	31,604	29,276	31,914	24,892	23,145	565,709
Rate 3	Industrial	2,516,726	2,665,317	2,669,007	2,604,742	2,540,900	2,807,933	2,587,753	2,754,430	2,613,222	2,562,115	2,533,856	2,603,136	31,459,135
Rate 4	Industrial	6,784	7,695	2,296	481	218	163	120	39	18	529	290	788	19,421
Rate 5	Contract	54,539	132,773	24,145	2,564	1,674	141	56	11	-	3,094	6,959	96	226,051

Normalized Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	106	213	328	350	321	270	155	80	43	38	36	53	1,993
	Commercial	532	1,042	1,629	1,778	1,637	1,351	719	375	210	203	183	269	9,927
	Industrial	3,015	5,129	2,956	2,352	2,260	2,431	1,531	743	443	346	308	622	22,136
Rate 2	Seasonal	579	359	105	93	45	76	174	54	11	12	1,808	3,572	6,888
Rate 3	Contract	31,723	53,732	70,406	74,860	70,456	72,832	44,539	32,087	27,307	26,500	24,464	13,755	542,660
Rate 3	Industrial	2,516,726	2,665,317	2,669,007	2,604,742	2,540,900	2,807,933	2,587,753	2,754,430	2,613,222	2,562,115	2,533,856	2,603,136	31,459,135
Rate 4	Industrial	5,226	6,534	1,984	309	248	189	144	62	15	380	914	3,274	19,278
Rate 5	Contract	60,877	99,432	10,580	906	573	452	85	39	3	3,850	2,230	238	179,265

NATURAL RESOURCE GAS LIMITED

Rate of Return on Ancillary Services
2009 Actual
($'s)

	Ancillary Services
Total Gross Revenue	955,609
Less Direct Cost of Sales	320,563
Total Net Revenue	635,047
Delayed Payment Charges	3,393
Total Ancillary Services Revenue	638,439
Allocated Costs	
Operations & Maintenance	243,311
Capital Taxes	2,309
Property Taxes	6,435
Net Depreciation Expense	165,604
Total	417,659
Income Before Tax	220,780
Income Tax Provision	41,889
Income After Tax	178,891
Value of Assets Employed	
Inventory	38,097
Working Cash	16,797
General Plant	1,554,130
Total Assets	1,609,024
Rate of Return	11.1%

NATURAL RESOURCE GAS LIMITED

Operating Revenue
2010 Bridge
($'s)

		Forecast
Distribution and Transportation Revenue		
Rate 1	Residential	2,837,447
	Commercial	576,370
	Industrial	71,275
Rate 2	Seasonal	68,376
Rate 3	Contract	156,259
Rate 4	Industrial	54,931
Rate 5	Contract	69,568
Rate 6	Contract	1,580,588
Total		5,414,814
Other Operating Revenue (Net)		
Rental Equipment Program		515,498
Contract Work Program		29,558
Transfer/Connect Charges		29,769
Direct Purchase		3,680
Delayed Payment Charges		51,164
Total		629,669
Total Operating Revenue		6,044,483

Notes:

(1) No adjustments required.

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2010 Bridge
($'s)

		Bridge Year 2010	Actual 2009
Distribution and Transportation Revenue			
Rate 1	Residential	2,837,447	2,796,930
	Commercial	576,370	578,961
	Industrial	71,275	72,816
Rate 2	Seasonal	68,376	73,285
Rate 3	Contract	156,259	1,701,134
Rate 4	Industrial	54,931	52,893
Rate 5	Contract	69,568	81,474
Rate 6	Contract	1,580,588	0
Total		5,414,814	5,357,493
Other Operating Revenue (Net)			
Rental Equipment Program		515,498	437,065
Contract Work Program		29,558	36,660
Transfer/Connect Charges		29,769	29,769
Direct Purchase		3,680	3,680
Delayed Payment Charges		51,164	62,019
Total		629,669	569,192
Total Operating Revenue		6,044,483	5,926,685

		Variance from 2009
Distribution and Transportation Revenue		
Rate 1	Residential	40,517
	Commercial	-2,591
	Industrial	-1,541
Rate 2	Seasonal	-4,908
Rate 3	Contract	-1,544,875
Rate 4	Industrial	2,037
Rate 5	Contract	-11,907
Rate 6	Contract	1,580,588
Total (1)		57,321
Other Operating Revenue (Net)		
Rental Equipment Program		78,433
Contract Work Program		-7,102
Transfer/Connect Charges		0
Direct Purchase		0
Delayed Payment Charges		-10,855
Total (2)		60,477
Total Operating Revenue		117,797

NATURAL RESOURCE GAS LIMITED

Gross Margin Analysis by Sales Class
2010 Bridge Year

		Total Gas Margin ($)	Total Volume (M*3)	Gross Unit Margin ($/M*3)
Rate 1	Residential	2,837,447	12,827,985	0.2212
	Commercial	576,370	4,109,387	0.1403
	Industrial	71,275	580,368	0.1228
Rate 2	Seasonal	68,376	502,859	0.1360
Rate 3	Contract	156,259	2,192,257	0.0713
Rate 4	Industrial	54,931	459,488	0.1195
Rate 5	Contract	69,568	944,570	0.0737
Rate 6	Contract	1,580,588	31,459,135	0.0000
Total		5,414,814	53,076,048	0.1020

NATURAL RESOURCE GAS LIMITED

Summary of Gas Sales and Transportation
2010 Bridge Year

		Customers (Year-end)	Volumes (M*3)	Distribution Revenues ($)	Normalized Volumes (M*3)	Normalized Distribution Revenues ($)
Rate 1	Residential	6,462	12,827,985	2,837,447	12,827,985	2,837,447
	Commercial	412	4,109,387	576,370	4,109,387	576,370
	Industrial	26	580,368	71,275	580,368	71,275
Rate 2	Seasonal	73	502,859	68,376	502,859	68,376
Rate 3	Contract	4	2,192,257	156,259	2,192,257	156,259
Rate 4	Industrial	23	459,488	54,931	459,488	54,931
Rate 5	Contract	5	944,570	69,568	944,570	69,568
Rate 6		1	31,459,135	1,580,588	31,459,135	1,580,588
Total		7,006	53,076,048	5,414,814	53,076,048	5,414,814

NATURAL RESOURCE GAS LIMITED

Customers by Rate Class
2010 Bridge Year
(Year-end)

		Bridge Year 2010	Actual 2009
Rate 1	Residential	6,462	6,331
	Commercial	412	408
	Industrial	26	25
Rate 2	Seasonal	73	73
Rate 3	Contract	4	4
Rate 4	Industrial	23	23
Rate 5	Contract	5	5
Rate 6		1	1
Total		7,006	6,870

		Variance from 2009
Rate 1	Residential	131
	Commercial	4
	Industrial	1
Rate 2	Seasonal	0
Rate 3	Contract	0
Rate 4	Industrial	0
Rate 5	Contract	0
Rate 6		0
Total		136

NATURAL RESOURCE GAS LIMITED

Gas Sales and Transportation Volume
2010 Bridge and 2009 Actual
(M*3)

		Bridge Year 2010	Actual 2009	Variance
Rate 1	Residential	12,827,985	12,739,773	88,212
	Commercial	4,109,387	4,140,590	-31,203
	Industrial	580,368	593,738	-13,370
Rate 2	Seasonal	502,859	531,925	-29,066
Rate 3	Contract	2,192,257	33,721,969	-31,529,712
Rate 4	Industrial	459,488	439,909	19,579
Rate 5	Contract	944,570	1,130,257	-185,687
Rate 6	Contract	31,459,135	0	31,459,135
Total		53,076,048	53,298,161	-222,113

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2010 Bridge Year Customers, Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Customers														
Rate 1	Residential	6,357	6,380	6,384	6,410	6,416	6,428	6,441	6,445	6,457	6,458	6,459	6,462	6,425
	Commercial	412	412	412	412	412	412	412	412	412	412	412	412	412
	Industrial	26	26	26	26	26	26	26	26	26	26	26	26	26
Rate 2	Seasonal	73	73	73	73	73	73	73	73	73	73	73	73	73
Rate 3	Contract	4	4	4	4	4	4	4	4	4	4	4	4	4
Rate 4	Industrial	23	23	23	23	23	23	23	23	23	23	23	23	23
Rate 5	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 6	Contract	1	1	1	1	1	1	1	1	1	1	1	1	1
Total		6,900	6,923	6,927	6,953	6,959	6,971	6,984	6,988	7,000	7,001	7,002	7,005	6,968
														Total
Volumes (M*3)														
Rate 1	Residential	678,807	1,372,385	2,110,714	2,290,993	2,041,868	1,725,824	997,256	514,591	280,411	243,979	231,292	339,863	12,827,985
	Commercial	220,908	434,211	676,453	750,360	667,190	553,130	295,748	154,344	86,783	83,854	75,535	110,872	4,109,387
	Industrial	80,024	135,679	77,440	62,313	58,245	62,867	39,774	19,275	11,564	8,988	8,001	16,198	580,368
Rate 2	Seasonal	42,299	26,176	7,643	6,816	3,300	5,524	12,736	3,934	807	897	131,976	260,750	502,859
Rate 3	Contract	128,293	217,686	283,863	306,955	278,674	289,486	177,950	127,835	112,031	115,960	98,322	55,201	2,192,257
Rate 4	Industrial	132,736	154,254	42,461	8,272	5,126	4,077	3,108	1,288	392	10,288	21,279	76,208	459,488
Rate 5	Contract	295,757	533,655	69,261	7,143	4,825	1,857	355	124	11	19,500	10,773	1,308	944,570
Rate 6	Contract	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	31,459,135
Total		4,200,421	5,495,640	5,889,430	6,054,447	5,680,824	5,264,359	4,148,521	3,442,985	3,113,594	3,105,060	3,198,773	3,481,994	53,076,048
														Total
Distribution Revenues ($'s)														
Rate 1	Residential	176,336	282,077	394,405	422,121	384,304	336,379	225,730	152,375	116,899	111,370	109,452	125,998	2,837,447
	Commercial	32,666	59,631	90,256	99,599	89,085	74,665	42,127	24,250	15,709	15,339	14,287	18,755	576,370
	Industrial	9,632	16,123	9,331	7,566	7,092	7,631	4,938	2,547	1,648	1,347	1,232	2,188	71,275
Rate 2	Seasonal	5,470	5,459	2,253	2,110	1,502	1,886	2,297	1,353	1,017	1,027	15,092	28,910	68,376
Rate 3	Contract	10,938	14,362	16,898	17,782	16,699	17,113	12,840	10,920	10,315	10,465	9,790	8,138	156,259
Rate 4	Industrial	14,854	17,215	4,951	1,677	1,151	975	634	435	336	1,422	2,628	8,653	54,931
Rate 5	Contract	19,715	34,969	5,191	1,208	1,059	869	773	758	751	2,000	1,441	834	69,568
Rate 6	Contract	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	1,580,588
Total		401,325	561,552	655,001	683,779	632,607	571,235	421,055	324,353	278,391	274,687	285,638	325,191	5,414,814

NATURAL RESOURCE GAS LIMITED

Average Gas Consumption Per Customer
2010 Bridge Year
(M*3)

Actual Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	107	215	331	357	318	268	155	80	43	38	36	53	2,001
	Commercial	536	1,054	1,642	1,821	1,619	1,343	718	375	211	204	183	269	9,974
	Industrial	3,078	5,218	2,978	2,397	2,240	2,418	1,530	741	445	346	308	623	22,322
Rate 2	Seasonal	579	359	105	93	45	76	174	54	11	12	1,808	3,572	6,888
Rate 3	Contract	32,073	54,421	70,966	76,739	69,669	72,372	44,487	31,959	28,008	28,990	24,581	13,800	548,064
Rate 3	Industrial	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	31,459,135
Rate 4	Industrial	5,771	6,707	1,846	360	223	177	135	56	17	447	925	3,313	19,978
Rate 5	Contract	59,151	106,731	13,852	1,429	965	371	71	25	2	3,900	2,155	262	188,914

Normalized Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	107	215	331	357	318	268	155	80	43	38	36	53	2,001
	Commercial	536	1,054	1,642	1,821	1,619	1,343	718	375	211	204	183	269	9,974
	Industrial	3,078	5,218	2,978	2,397	2,240	2,418	1,530	741	445	346	308	623	22,322
Rate 2	Seasonal	579	359	105	93	45	76	174	54	11	12	1,808	3,572	6,888
Rate 3	Contract	32,073	54,421	70,966	76,739	69,669	72,372	44,487	31,959	28,008	28,990	24,581	13,800	548,064
Rate 3	Industrial	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	31,459,135
Rate 4	Industrial	5,771	6,707	1,846	360	223	177	135	56	17	447	925	3,313	19,978
Rate 5	Contract	59,151	106,731	13,852	1,429	965	371	71	25	2	3,900	2,155	262	188,914

NATURAL RESOURCE GAS LIMITED

Rate of Return on Ancillary Services
2010 Bridge
($'s)

	Ancillary Services
Total Gross Revenue	1,058,803
Less Direct Cost of Sales	330,180
Total Net Revenue	728,623
Delayed Payment Charges	4,978
Total Ancillary Services Revenue	733,601
Allocated Costs	
Operations & Maintenance	202,540
Capital Taxes	4,046
Property Taxes	6,259
Net Depreciation Expense	179,887
Total	392,732
Income Before Tax	340,869
Income Tax Provision	11,366
Income After Tax	329,503
Value of Assets Employed	
Inventory	188,398
Working Cash	22,235
General Plant	1,606,390
Total Assets	1,817,023
Rate of Return	18.1%

NATURAL RESOURCE GAS LIMITED

Operating Revenue
2011 Test Year
($'s)

		Forecast	Adjust-ments	Adjusted Forecast
Distribution and Transportation Revenue				
Rate 1	Residential	2,898,012	0	2,898,012
	Commercial	579,473	0	579,473
	Industrial	71,348	0	71,348
Rate 2	Seasonal	68,376	0	68,376
Rate 3	Contract	158,380	0	158,380
Rate 4	Industrial	61,544	0	61,544
Rate 5	Contract	62,891	0	62,891
Rate 6	Contract	1,580,588	0	1,580,588
Total		5,480,613	0	5,480,613
Other Operating Revenue (Net)				
Rental Equipment Program		542,674	0	542,674
Contract Work Program		34,445	0	34,445
Transfer/Connect Charges		30,662	0	30,662
Direct Purchase		3,680	0	3,680
Delayed Payment Charges		52,699	0	52,699
Total		664,160	0	664,160
Total Operating Revenue		6,144,773	0	6,144,773

Notes:

(1) No adjustments required.

NATURAL RESOURCE GAS LIMITED

Summary of Operating Revenue
2011 Test Year
($'s)

		Test Year 2011	Bridge 2010
Distribution and Transportation Revenue			
Rate 1	Residential	2,898,012	2,837,447
	Commercial	579,473	576,370
	Industrial	71,348	71,275
Rate 2	Seasonal	68,376	68,376
Rate 3	Contract	158,380	156,259
Rate 4	Industrial	61,544	54,931
Rate 5	Contract	62,891	69,568
Rate 6	Contract	1,580,588	1,580,588
Total		5,480,613	5,414,814
Other Operating Revenue (Net)			
Rental Equipment Program		542,674	515,498
Contract Work Program		34,445	29,558
Transfer/Connect Charges		30,662	29,769
Direct Purchase		3,680	3,680
Delayed Payment Charges		52,699	51,164
Total		664,160	629,669
Total Operating Revenue		6,144,773	6,044,483

		Variance from 2010
Distribution and Transportation Revenue		
Rate 1	Residential	60,565
	Commercial	3,103
	Industrial	73
Rate 2	Seasonal	0
Rate 3	Contract	2,121
Rate 4	Industrial	6,614
Rate 5	Contract	-6,677
Rate 6	Contract	0
Total (1)		65,799
Other Operating Revenue (Net)		
Rental Equipment Program		27,176
Contract Work Program		4,887
Transfer/Connect Charges		893
Direct Purchase		0
Delayed Payment Charges		1,535
Total (2)		34,491
Total Operating Revenue		100,290

Notes:
(1) Changes related to sales and transportation volumes (See Exhibit C8, Tab 2, Schedule 3).
(2) Changes related to number of rental units and level of delayed payment charges.

NATURAL RESOURCE GAS LIMITED

Gross Margin Analysis by Sales Class
2011 Test Year

		Total Gas Margin ($)	Total Volume (M*3)	Gross Unit Margin ($/M*3)
Rate 1	Residential	2,898,012	13,103,581	0.2212
	Commercial	579,473	4,131,750	0.1402
	Industrial	71,348	580,997	0.1228
Rate 2	Seasonal	68,376	502,859	0.1360
Rate 3	Contract	158,380	2,195,299	0.0721
Rate 4	Industrial	61,544	454,263	0.1355
Rate 5	Contract	62,891	947,162	0.0664
Rate 6	Contract	1,580,588	31,459,135	0.0000
Total		5,480,613	53,375,045	0.1027

NATURAL RESOURCE GAS LIMITED

Summary of Gas Sales and Transportation
2011 Test Year

		Customers (Year-end)	Volumes (M*3)	Distribution Revenues ($)	Normalized Volumes (M*3)	Normalized Distribution Revenues ($)
Rate 1	Residential	6,599	13,103,581	2,898,012	13,103,581	2,898,012
	Commercial	414	4,131,750	579,473	4,131,750	579,473
	Industrial	26	580,997	71,348	580,997	71,348
Rate 2	Seasonal	73	502,859	68,376	502,859	68,376
Rate 3	Contract	4	2,195,299	158,380	2,195,299	158,380
Rate 4	Industrial	23	454,263	61,544	454,263	61,544
Rate 5	Contract	5	947,162	62,891	947,162	62,891
Rate 6		1	31,459,135	1,580,588	31,459,135	1,580,588
Total		7,145	53,375,045	5,480,613	53,375,045	5,480,613

NATURAL RESOURCE GAS LIMITED

Customers by Rate Class
2011 Test Year
(Year-end)

		Test Year 2011	Bridge 2010
Rate 1	Residential	6,599	6,462
	Commercial	414	412
	Industrial	26	26
Rate 2	Seasonal	73	73
Rate 3	Contract	4	4
Rate 4	Industrial	23	23
Rate 5	Contract	5	5
Rate 6		1	1
Total		7,145	7,006

		Variance from 2010
Rate 1	Residential	137
	Commercial	2
	Industrial	0
Rate 2	Seasonal	0
Rate 3	Contract	0
Rate 4	Industrial	0
Rate 5	Contract	0
Rate 6		0
Total		139

NATURAL RESOURCE GAS LIMITED

Gas Sales and Transportation Volume
2011 Test and 2010 Bridge
(M*3)

		Test Year 2011	Bridge Year 2010	Variance
Rate 1	Residential	13,103,581	12,827,985	275,596
	Commercial	4,131,750	4,109,387	22,363
	Industrial	580,997	580,368	629
Rate 2	Seasonal	502,859	502,859	0
Rate 3	Contract	2,195,299	2,192,257	3,042
Rate 4	Industrial	454,263	459,488	-5,225
Rate 5	Contract	947,162	944,570	2,591
Rate 6	Contract	31,459,135	31,459,135	0
Total		53,375,045	53,076,048	298,997

NATURAL RESOURCE GAS LIMITED

Monthly Throughput Data
2011 Test Year Customers, Volumes, Revenues

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Average
Customers														
Rate 1	Residential	6,489	6,513	6,518	6,544	6,550	6,563	6,577	6,581	6,594	6,595	6,596	6,599	6,560
	Commercial	414	414	414	414	414	414	414	414	414	414	414	414	414
	Industrial	26	26	26	26	26	26	26	26	26	26	26	26	26
Rate 2	Seasonal	73	73	73	73	73	73	73	73	73	73	73	73	73
Rate 3	Contract	4	4	4	4	4	4	4	4	4	4	4	4	4
Rate 4	Industrial	23	23	23	23	23	23	23	23	23	23	23	23	23
Rate 5	Contract	5	5	5	5	5	5	5	5	5	5	5	5	5
Rate 6	Contract	1	1	1	1	1	1	1	1	1	1	1	1	1
Total		7,035	7,059	7,064	7,090	7,096	7,109	7,123	7,127	7,140	7,141	7,142	7,145	7,106
														Total
Volumes (M*3)														
Rate 1	Residential	693,114	1,404,325	2,154,698	2,343,817	2,085,901	1,759,516	1,017,927	525,309	286,476	249,155	236,198	347,146	13,103,581
	Commercial	222,058	437,433	679,627	755,757	670,925	554,924	297,067	155,048	87,244	84,304	75,902	111,462	4,131,750
	Industrial	80,091	136,206	77,428	62,428	58,280	62,773	39,757	19,269	11,572	8,988	8,001	16,204	580,997
Rate 2	Seasonal	42,299	26,176	7,643	6,816	3,300	5,524	12,736	3,934	807	897	131,976	260,750	502,859
Rate 3	Contract	128,351	218,308	283,817	307,692	278,883	288,989	177,867	127,761	112,591	117,274	98,525	55,242	2,195,299
Rate 4	Industrial	136,111	149,978	37,482	8,045	5,176	4,117	3,066	1,265	405	11,020	20,578	77,020	454,263
Rate 5	Contract	300,210	530,259	68,382	7,554	5,053	1,808	372	128	11	20,719	11,282	1,385	947,162
Rate 6	Contract	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	31,459,135
Total		4,223,828	5,524,280	5,930,670	6,113,702	5,729,112	5,299,246	4,170,388	3,454,308	3,120,700	3,113,951	3,204,056	3,490,803	53,375,045
														Total
Distribution Revenues ($'s)														
Rate 1	Residential	180,030	288,464	402,635	431,695	392,541	343,055	230,438	155,569	119,397	113,733	111,774	128,681	2,898,012
	Commercial	32,834	60,062	90,680	100,305	89,580	74,915	42,317	24,362	15,791	15,419	14,357	18,852	579,473
	Industrial	9,640	16,184	9,329	7,580	7,096	7,620	4,936	2,546	1,649	1,347	1,232	2,189	71,348
Rate 2	Seasonal	5,470	5,459	2,253	2,110	1,502	1,886	2,297	1,353	1,017	1,027	15,092	28,910	68,376
Rate 3	Contract	11,162	14,518	16,962	17,853	16,778	17,155	13,009	11,140	10,574	10,748	10,049	8,434	158,380
Rate 4	Industrial	15,685	21,133	5,550	1,904	1,159	982	630	432	338	1,770	2,778	9,183	61,544
Rate 5	Contract	19,539	30,364	3,989	969	1,074	866	774	758	751	1,810	1,246	750	62,891
Rate 6	Contract	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	131,716	1,580,588
Total		406,075	567,900	663,115	694,131	641,446	578,195	426,116	327,876	281,231	277,571	288,244	328,715	5,480,613

NATURAL RESOURCE GAS LIMITED

Average Gas Consumption Per Customer
2011 Test Year
(M*3)

Average Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	107	216	331	358	318	268	155	80	43	38	36	53	2,002
	Commercial	536	1,057	1,642	1,826	1,621	1,340	718	375	211	204	183	269	9,980
	Industrial	3,080	5,239	2,978	2,401	2,242	2,414	1,529	741	445	346	308	623	22,346
Rate 2	Seasonal	579	359	105	93	45	76	174	54	11	12	1,808	3,572	6,888
Rate 3	Contract	32,088	54,577	70,954	76,923	69,721	72,247	44,467	31,940	28,148	29,319	24,631	13,810	548,825
Rate 3	Industrial	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	31,459,135
Rate 4	Industrial	5,918	6,521	1,630	350	225	179	133	55	18	479	895	3,349	19,751
Rate 5	Contract	60,042	106,052	13,676	1,511	1,011	362	74	26	2	4,144	2,256	277	189,432

Normalized Use Per Customer

		Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Rate 1	Residential	107	216	331	358	318	268	155	80	43	38	36	53	2,002
	Commercial	536	1,057	1,642	1,826	1,621	1,340	718	375	211	204	183	269	9,980
	Industrial	3,080	5,239	2,978	2,401	2,242	2,414	1,529	741	445	346	308	623	22,346
Rate 2	Seasonal	579	359	105	93	45	76	174	54	11	12	1,808	3,572	6,888
Rate 3	Contract	32,088	54,577	70,954	76,923	69,721	72,247	44,467	31,940	28,148	29,319	24,631	13,810	548,825
Rate 3	Industrial	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	31,459,135
Rate 4	Industrial	5,918	6,521	1,630	350	225	179	133	55	18	479	895	3,349	19,751
Rate 5	Contract	60,042	106,052	13,676	1,511	1,011	362	74	26	2	4,144	2,256	277	189,432

NATURAL RESOURCE GAS LIMITED

Rate of Return on Ancillary Services
2011 Test Year
($'s)

	Ancillary Services
Total Gross Revenue	1,108,592
Less Direct Cost of Sales	340,085
Total Net Revenue	768,506
Delayed Payment Charges	4,448
Total Ancillary Services Revenue	772,954
Allocated Costs	
Operations & Maintenance	260,990
Capital Taxes	0
Property Taxes	7,615
Net Depreciation Expense	216,696
Total	485,301
Income Before Tax	287,653
Income Tax Provision	20,503
Income After Tax	267,150
Value of Assets Employed	
Inventory	187,862
Working Cash	16,322
General Plant	1,508,211
Total Assets	1,712,395
Rate of Return	15.6%

NATURAL RESOURCE GAS LIMITED

COST OF SERVICE

This Schedule provides a written summary of NRG's cost of service set out in the numerical Schedules. The cost of service does not include the commodity cost of gas.

Fiscal 2011 Test Year

Exhibit D8, Tab 1, Schedule 1 provides the fiscal 2011 test year forecast detail for the cost of service. NRG is forecasting that the cost of service will total $5,249,180 in the fiscal 2011 Test Year. Operation, Maintenance and Administration costs total $2,859,299, or approximately 54.5% of the total cost of service. Depreciation and amortization total $1,206,523, or 23.0% of the cost of service. Property, capital and income taxes account for $451,028 or 8.6% of the cost of service. Gas transportation costs account for the remaining $732,331 or 14.0% of the cost of service.

Comparison to Fiscal 2010 Bridge Year

As shown in Exhibit D8, Tab 1, Schedule 2 the total cost of service is expected to increase by $344,797 or 7.0% in the 2011 test year as compared to the 2010 bridge year. This increase reflects a $465,179 increase in Operation, Maintenance and Administration costs and a $34,081 increase in depreciation and amortization costs.

Fiscal 2010 Bridge Year

The total cost of service in the bridge year is estimated to be $4,904,383. Operation and maintenance costs total $2,394,120 or 48.8% of the total. Depreciation and amortization total $1,172,442 or 23.9% with property and income taxes accounting for a further $514,366 or 10.5% of the total. Gas transportation costs total $823,456 or 16.8% of the total. These figures are shown in Exhibit D7, Tab 1, Schedule 1.

Comparison to Fiscal 2009 Actual

As shown in Exhibit D7, Tab 1, Schedule 2, the total cost of service in the 2010 bridge year is $142,046 lower than the cost of service in fiscal 2009. This is mainly the result of increased depreciation and amortization expense of $67,380 and increased Operations, Maintenance and Administration costs of $272,990.

Fiscal 2009 Historical Year

The total cost of service in 2009 totaled $4,759,945. Operation and maintenance costs totalled $2,121,130 or 44.6% of the total. Depreciation and amortization totaled $1,105,062 or 23.2% and gas transportation costs totaled $799,742 or 16.8% of the total. Taxes (property and income) totaled $734,011, representing 15.4% of the total cost of service. These figures are shown in Exhibit D6, Tab 1, Schedule 1.

Exhibit D6, Tab 1, Schedule 2 also provides a comparison of the 2009 cost of service to that of 2008. The 2008 cost of service was $985,904 lower than that recorded in 2009. This difference reflects $344,637 of increased depreciation and amortization costs, $376,844 of increased gas transportation costs and $211,960 of decreased Income Taxes.

<u>Fiscal 2008 Historical Year</u>

The total cost of service in 2008 totaled $3,774,041. Operation and maintenance costs totaled $2,139,440 or 57.1% of the total. Depreciation and amortization totaled $760,425 or 20.9% and gas transportation costs totaled $422,897 or 12.2% of the total. Property taxes totaled $355,812, representing 9.8% of the total cost of service. These figures are shown in Exhibit D5, Tab 1, Schedule 1.

Exhibit D5, Tab 1, Schedule 2 also provides a comparison of the 2008 cost of service to that of 2007. The 2008 cost of service was $260,325 higher than that recorded in 2007. This difference reflects increased OM&A of $152,746 and increased depreciation and amortization costs of $33,117.

<u>Fiscal 2007 Historical Year</u>

The total cost of service in 2007 totaled $3,513,716. Operation and maintenance costs totaled $1,986,694 or 56.5% of the total. Depreciation and amortization totaled $727,308 or 20.7% and gas transportation costs totaled $394,141 or 11.2% of the total. Taxes (property, capital and income) totaled $405,574, representing 11.5% of the total cost of service. These figures are shown in Exhibit D4, Tab 1, Schedule 1.

Exhibit D4, Tab 1, Schedule 2 also provides a comparison of the 2007 cost of service to that of 2006. The 2007 cost of service was $31,891 lower than that recorded in 2006. This difference reflects decreased OM&A costs of $154,375 and decreased gas transportation costs of $17,087. The largest increase was $51,858 in Property and Capital Taxes.

Exhibit D4.1, Tab 1, Schedule 2 provides a comparison of the cost of service to that approved in RP-2005-0544. The total cost of service was $275,561 lower than the Board approved figure. This was principally due to lower than projected Operations, Maintenance and Administration costs of $158,889.

Fiscal 2006 Historical Year

As shown in Exhibit D3, Tab 1, Schedule 1, the total cost of service was $3,545,607 in fiscal 2006. Operation and maintenance costs represented 60.4% or $2,141,069 of this total. Depreciation and amortization costs totaled $697,844 or 19.7% of the total with property and capital taxes accounting for a further $272,222 or 7.7%. $411,228 or 11.6% was related to gas transportation costs.

Exhibit D3, Tab 1, Schedule 2 also provides a comparison of the 2006 cost of service to that of 2005. The 2006 cost of service was $113,846 lower than that recorded in 2005. This reduction was the result of lower gas transportation costs and lower property and capital taxes.

NATURAL RESOURCE GAS LIMITED

GAS COSTS

The purpose of the evidence contained in Tab 2 of Exhibits D3, D4. D5, D6, D7 and D8 is to provide the Board with a review of NRG's gas commodity costs and gas transportation costs.

Gas Commodity Costs

Gas commodity costs have been forecast based on the costs from NRG's most recent Board approved QRAM Decision and Order, EB-2009-0407 dated December 22, 2009.

NRG has been a Bundled-T customer on the Union Gas system since October of 1996. NRG is forecasting that it will remain a Bundled-T customer throughout the forecast period.

No additional customers have been forecast to switch to direct purchase in 2011 TY.

The gas commodity costs calculated are used only for calculation of the working capital allowance component of rate base. The gas commodity cost has an impact on delivery rates through its impact on the working cash allowance. Through the cost allocation process the gas cost related working cash allowance impact on rate base and the subsequent return on rate base is recovered through the system gas supply charge that is a component of the gas supply commodity charge. This is explained in further detail in the cost allocation evidence (Exhibit G).

Gas Transportation Costs

The gas transportation costs are the costs paid by NRG to Union Gas for storage, load balancing and transportation across the Union Gas system to NRG.

NRG continues to take service from Union Gas under the M9 rate under two contracts. Under one contract NRG's contract demand is 168,100 m3/day and supports gas delivery to NRG's customers in Rate classes 1 through 5. Under the other contract NRG's contract demand is

108,188 m3/day and supports gas delivery to IGPC exclusively. For the purpose of calculating gas transportation, storage and load balancing costs, NRG has used Union's M9 rates that were in effect as of January 1, 2010. These costs are recovered through the distribution delivery rates.

Fiscal 2011Test Year

Exhibit D8, Tab 2, Schedule 1 provides the fiscal 2011 forecast for the gas commodity costs and the gas transportation costs. The gas commodity costs are forecast to total $6,199,675 with the gas transportation costs forecast to be $732,331.

NRG is requesting that the Board authorize two reference prices for use in the PGTVA account for the fiscal 2011 test year – one reference price will be set at $0.010500/m3 and will apply to IGPC exclusively the other reference price will be set at $0.023909/m3 and will apply to rate 1 through rate 5 customers. The calculation of the requested 2011 reference prices is shown in Exhibit D8, Tab 2, Schedule 3.

NATURAL RESOURCE GAS LIMITED

OPERATING AND MAINTENANCE COSTS

This Schedule provides a written summary of NRG's Operating and Maintenance ("O & M") costs. Specific details regarding certain operating and maintenance costs follow in subsequent Schedules.

Fiscal 2011 Test Year

The 2011 test year O & M forecast is shown in Exhibit D8, Tab 3, Schedule 1. The total net cost is expected to be $2,859,299. Net wages and benefits make up approximately 44.1% of the total net O & M costs. Insurance costs and Repair and Maintenance costs respectively represent 10.0% and 10.1% of the total.

Comparison to Fiscal 2010 Bridge Year

Exhibit D8, Tab 3, Schedule 1 provides a comparison of the 2011 test year forecast of O & M expenses to that forecast for the 2010 bridge year. Total net O & M costs are forecast to increase $465,179 or 19.4%. The resulting cost per customer increases by $58.78 or 17.1%.

The increase in the forecast for 2011 is driven by four areas. Regulatory costs increase $125,000 reflecting the 5 year amortization of the 2011 rates case commencing in fiscal 2011 versus no rate case costs for fiscal 2010. Advertising costs increase by $59,000. Repairs and Maintenance costs increase by $126,404 and reflect the appropriate provision of maintenance on the IGPC pipeline. Net wages and benefits increase $40,685 or 3.3% reflecting both increases for inflation and professional upgrades. The increased advertising expense is discussed in Exhibit D1, Tab 3, Schedule 3.

Fiscal 2010 Bridge Year

The total net O & M cost associated with the fiscal 2006 bridge year is forecast to be $2,394,120, as shown in Exhibit D7, Tab 3, Schedule 1. Net wages and benefits account for 51.0% of the net O & M expenses. Insurance represents 9.5% of the total with net Management Fees representing a further 19.1%. Repair and Maintenance costs total $162,662, or 6.8%.

Comparison to Fiscal 2009 Actual

Exhibit D7, Tab 3, Schedule 1 provides a comparison of the 2010 costs with those incurred in 2009. Total net expenses are forecast to increase by $272,989 or 12.9% over the fiscal 2009 actual costs. The largest cost increases occurred in four categories: net wages and benefits ($107,936), insurance ($29,475), repair and maintenance ($52,393) and consulting fees ($25,728). Cost decreases occurred in Regulatory ($11,211) and automotive ($8,128).

The increase in wages is related to an increase for inflation and professional upgrades for employees in fiscal 2010. Regulatory costs are lower as a result of there being no rate case for fiscal 2009 and because no franchise renewals were the subject of an oral proceeding convened by the Board.

On a cost per customer basis, total O&M costs are projected to increase by $27.64 or 8.7% in 2010.

Fiscal 2009 Historical Year

As shown in Exhibit D6, Tab 3, Schedule 1, total net O & M costs totaled $2,121,130 in fiscal 2009. Net wages and benefits account for 52.4% of the net expenses, with insurance accounting for a further 9.3%. Office and Postage costs accounted for a further 5.4%.

Comparison to Fiscal 2008 Actual

Exhibit D6, Tab 3, Schedule 1 provides a comparison of the 2009 costs with those incurred in 2008. Total net expenses decreased by $18,310 or 0.9% over the fiscal 2008 actual costs. The largest cost increases occurred in four categories: Regulatory ($27,866), Bad Debts ($14,743), legal ($39,282) and net management fees ($75,625). The largest costs decreases occurred in the following four categories: Wages ($51,062), Repair and Maintenance ($16,126), Automotive ($22,887), Consulting Fees ($78,715).

Regulatory costs were higher because the Aylmer franchise renewal application was the subject of an oral proceeding convened by the Board.

Fiscal 2008 Historical Year

As shown in Exhibit D5, Tab 3, Schedule 1, total net O & M costs totaled $2,139,440 in fiscal 2008. Net wages and benefits account for 54.2% of the net expenses, with insurance accounting for a further 8.4%. Repairs and Maintenance costs accounted for a further 5.9%.

Comparison to Fiscal 2007 Actual

Exhibit D5, Tab 3, Schedule 1 provides a comparison of the 2008 costs with those incurred in 2007. Total net expenses increased by $152,746 or 7.7% over the fiscal 2007 actual costs. The largest cost increases occurred in the following four categories: net management fee ($50,875), repair and maintenance ($62,858), Bad Debts ($37,239) and Automotive ($32,105). The largest costs decreases occurred in: regulatory ($44,214), legal ($43,618) and consulting fees ($11,907).

Fiscal 2007 Historical Year

As shown in Exhibit D4, Tab 3, Schedule 1, total net O & M costs totaled $1,986,694 in fiscal 2007. Net wages and benefits account for 57.0% of the net expenses, with insurance accounting for a further 9.3%. Consulting Fees accounted for a further 6.5%.

Comparison to Fiscal 2006 Actual

Exhibit D4, Tab 3, Schedule 1 provides a comparison of the 2007 costs with those incurred in 2006. Total net expenses decreased by $154,375 or 7.2% over the fiscal 2006 actual costs. The largest cost increases occurred in the following four categories: net wages and benefits ($109,679), consulting fees ($70,200), travel and entertainment ($12,451) and telephone ($12,411). The largest costs decreases occurred in the following four categories: regulatory ($117,421), legal ($73,553), repair and maintenance ($68,220) and insurance ($50,575).

The increase in wages is related to an increase for inflation and professional upgrades for employees in fiscal 2007. Regulatory costs were lower because a rate rebasing application was not adjudicated that year.

Comparison to EB-2005-0544

Exhibit D4.1, Tab 3, Schedule 1 provides a comparison of the 2007 actual O & M costs to that approved in RP-2005-0544. Total O & M costs were $158,889 or 8.0% lower than the Board approved level. The main drivers of this variance were wages and benefits ($88,231), insurance ($88,712), consulting fees ($86,614) and repair and Maintenance ($85,779).

Fiscal 2006 Historical Year

Exhibit D3, Tab 3, Schedule 1 provides the actual O & M costs recorded in fiscal 2006 of $2,141,069. Net wages and benefits accounted for 47.7% of the total, insurance for 11.1%, and regulatory costs for 7.8%.

Exhibit D3, Tab 3, Schedule 1 also provides a comparison between the fiscal 2006 costs and fiscal 2005. Actual 2006 costs were $132,273 or 6.6% higher and is attributed to legal, wages and benefits and consulting fee increases.

NATURAL RESOURCE GAS LIMITED

ADVERTISING COSTS

NRG proposes to recover $98,000 through rates in the 2011TY for advertising costs. In its last rates case (EB-2005-0544), the Board approved $70,871 as an advertising cost. NRG's actual expenditures since EB-2005-0544 have not reached the $70,000 threshold. It was NRG's belief at the time of the EB-2005-0544 that most of the $70,000 would be spent in the form of promotional rebates to customers for switching to natural gas-burning equipment. These promotions remain in place, but to date there has not been the uptake expected on the promotional rebates. Most of the actual advertising expenses incurred by NRG in the past few years relate to local advertising to generate sales and fill employment positions, and local sponsorship.

NRG is planning to initiate a new programme in the near future to encourage natural gas conversion for vehicles. NRG is proposing to offer a $1,000 rebate to customers that convert their vehicles to natural gas (which involves changes to the vehicle and installation of a unit at the customer's home). This past October, NRG converted its vehicle fleet to natural gas and has enjoyed fuel cost savings since.

In addition, NRG plans to launch a webpage for better customer communications.

NATURAL RESOURCE GAS LIMITED

MANAGEMENT FEE

NRG proposes to recover $235,157 through rates to offset the Management Fee charged by Ayerswood Development Corporation ("Ayerswood") to NRG. As noted in NRG's last rate proceeding, Ayerswood is technically not an "affiliate" within the meaning of the *Business Corporations Act* (Ontario) (which definition is incorporated into the *Affiliate Relationships Code for Gas Utilities*), but Ayerswood is nevertheless not at arms-length from NRG.

Nature of the Management Fee

The Management Fee is comprised of services typically provided by senior management, finance and accounting staff within any company. The Management Fee also includes an appropriate allocation of Ayerswood facilities, computer, telecommunications and other overhead costs. The provision of these services by Ayerswood allows NRG to have access to appropriately trained and experienced staff without having to incur the annualized costs of these staff.

Historic Levels of Management Fees

In NRG's last rate proceeding (EB-2005-0544), the Board approved a $90,000 Management Fee to be incorporated into NRG's rates. The net Management Fee incurred by NRG has approached or exceeded the $90,000 Board-approved amount in three of the last four years since the last rate proceeding:

$103,500 in fiscal 2006

$89,750 in fiscal 2007

$140,625 in fiscal 2008

$216,250 in fiscal 2009

The significant increase in 2009 resulted in large part from moving the Controller and Assistant Controller functions from NRG to Ayerswood at the end of the first quarter of 2009. NRG plans to keep these functions within Ayerswood through the IRM period.

NATURAL RESOURCE GAS LIMITED

REGULATORY COSTS

In the 2011TY, NRG is proposing to recover approximately $146,000 in regulatory expenses through rates. The $126,000 is comprised of:

Amortization of 2011 TY Rates Application Costs	$125,000
OEB Cost Assessment	$ 12,000
QRAM Regulatory Costs	$ 9,000

Each item is discussed in further detail below.

Amortization of 2011TY Rates Application Costs

The external regulatory costs associated with the preparation and disposition of this rates application is expected to be $625,000, which is comprised of: (a) $100,000 of legal costs; (b) $350,000 of consulting costs; (c) a provision of $50,000 for OEB costs, intervenor costs, court reporting, Notice of Application publication and other miscellaneous costs; (d) a provision of $50,000 for expert evidence; and (e) a provision of $75,000 of annual costs to administer the proposed IRM over a term of 5 years. NRG proposes to amortize these amounts over the five year period that corresponds to the term of NRG's proposed IRM. This results in a regulatory expense in the 2011TY of $125,000.

The regulatory costs associated with this rate application are higher than past rate applications for a number of reasons, as follows:

(a) NRG's First Multi-Year IR Application

This application is NRG's first multi-year IR application. In the past, NRG has filed relatively straightforward cost-of-service applications for future test years. In some cases, NRG has simply let those rates remain in place for years subsequent to the test year, as has been the case since NRG's last rate application (EB-2005-0544). This is NRG's first multi-year IRM application, and has required additional regulatory work to come up with a IRM formula that is suitable for NRG and its customers. In order to prepare this application, NRG has retained a new regulatory consulting firm (Elenchus Research Associates) to prepare the evidence and devise a simplified IRM formula. If NRG's proposed IRM is appropriate (in that it provides NRG with a fair return on its capital invested and results in just and reasonable rates for NRG's customers), then in the medium- to long-term this can be expected to result in regulatory cost savings.

(b) Large Amount of Data to Be Filed

Given that NRG has not been before the Board with a rate application in a number of years, the preparation of this rate application involved the presentation of six years of data (four years of historical data, a 2010 bridge year, as well as the 2011TY).

(c) Unique Issues

Since NRG's last rates case, NRG has added a single customer (IGPC Ethanol Inc., "IGPC") that necessitated a major capital addition, and doubled NRG's throughput. The addition of a customer the size of IGPC has raised issues regarding financing of the pipeline construction, provision of costs to maintain the pipeline and associated stations, allocation of utility common costs to IGPC, and the establishment of a new customer rate class unique to IGPC.

In addition, the unusually short renewal granted by the Board (in EB-2008-0413) for NRG's primary franchise area (the Town of Aylmer) has also raised issues related to financing and amortization periods.

OEB Cost Assessment

NRG has estimated its 2011TY OEB cost assessment based on the amount levied in past periods.

QRAM Regulatory Costs

NRG's QRAM is prepared by a third party consultant with appropriate support provided by NRG internal staff. These applications require that the NRG staff prepare the required data in an appropriate format, review all aspects of the submission and implement the Board's Order.

NATURAL RESOURCE GAS LIMITED

IGPC PERIOD COSTS

This Schedule sets out the costs that NRG expects to incur annually due to the ongoing operation, maintenance and administration of the NPS 6 extra high pressure steel pipeline that serves IGPC. These costs include: OM&A, deprecation, Union Gas delivery charges, and the appropriate allocation of property and income taxes and Administrative and General costs. In total these costs are expected to amount to $1,309.1k in the 2011 Test Year.

Maintenance Costs – Transfer Stations

NRG has entered into a contractual arrangement with a third party to perform the following maintenance activities with respect to the transfer stations associated with the IGPC pipeline: emergency support, preventative and reliability maintenance (monthly, semi-annual and annual), control system spares and warranty support. These maintenance services will cost $43,050 in 2011.

Maintenance Costs - Pipeline

NRG has solicited a quote for maintenance of the IGPC pipeline from a third party provider. The proposed annual cost is $112,107 and covers the provision of the following services: pipeline valve maintenance, above-grade piping and fitting maintenance, pipeline marker audits and replacement, pre-testing emergency pipe, pipeline repair/relocation, leakage detection, odour level testing, cathodic protection survey, interval surveys, anode replacement, pipeline locate service, weekly inspections, third party observation, depth of cover surveys, snow and weed control, development encroachment survey, training, and emergency response.

NRG expects to incur $2,000 of costs annually for spare parts.

<u>Insurance Costs</u>

Existing General Liability - Prior to the IGPC pipeline coming into service, NRG had $15 million of general liability and umbrella coverage policy. In fiscal 2009, the annual premium for this insurance was $189,690.

Additional General Liability specifically required for IGPC - Following the coming into service of the IGPC pipeline, NRG procured $5 million of additional liability and property insurance to appropriately manage and mitigate its incremental risks associated with the IGPC pipeline. This additional insurance coverage is required to appropriately protect NRG from the consequences of a catastrophic failure of the IGPC pipeline and from the associated liabilities to the general public and the environment. The pipeline's guaranty period has expired and NRG is solely responsible for the management and mitigation of these risks.

During the process of securing this additional $5 million of insurance, NRG was able to reduce its existing insurance costs significantly. In fiscal 2010, NRG's $20 million of general liability insurance will cost $184,264. In addition to securing $5 million of additional insurance, NRG also undertook an assessment of its insurance coverage and determined that an additional $5 million of coverage should be purchased in the near future. Purchasing an additional $5 million of insurance in the 2011TY is expected to cost an additional $21,131.

Transfer Stations - NRG also incurred insurance coverage for the transfer stations of $33,702 in fiscal 2010.

Business Interruption – NRG's assessment of its insurance coverage also determined the need for business interruption insurance in the event of a failure to the IGPC pipeline, NRG needs to insure it will be covered for its' fixed expenses relating to the pipeline. This insurance is expected to cost $25,579 for 2011 Test Year.

IGPC's portion - NRG proposes to allocate 59% of the premium relating to $15M general liability insurance coverage to IGPC (based on throughput) and 100% of the insurance on the transfer stations to IGPC, the additional general liability coverage of $10m relating to IGPC risk and the business interruption insurance premiums. A 5% increase in rates has been incorporated in the 2011TY insurance cost. All of the above would bring NRG's 2011 insurance costs to <u>$284,925</u>, of which <u>$197,962</u> is attributable to IGPC.

<u>Administrative and General Expenses</u>

NRG proposes to allocate approximately <u>$256.0k</u> of Administrative and General expenses to IGPC. This amount was determined by relying on NRG's existing methodology in its Fully Allocated Cost study.

<u>Property and Income Tax</u>

NRG has identified that IGPC is responsible for $60,026 of Property Tax expense in the 2011TY. This amount was estimated by applying an inflation adjusted Property Tax rate to the eligible capital cost of the IGPC pipeline.

NRG will also allocate approximately <u>$53,020</u> of its projected <u>$163,058</u> 2011 Test Year Income Taxes to IGPC. Consistent with the Fully Allocated Cost Study, NRG has allocated its projected Income Tax in direct proportion with rate base.

<u>Depreciation Expense</u>

NRG proposes to recover $253,650 of depreciation expense from IGPC.

When developing an appropriate distribution rate for IGPC, NRG had to balance the need to fully recover its invested capital over a reasonable time horizon with the need to set a fair rate for its largest volume customer. In order to protect its other ratepayers against the risk of having to pay for an unused and unneeded pipeline if IGPC stopped taking gas, NRG had to select a revenue horizon that would match the expected economic life of the IGPC ethanol plant. This was not straightforward, because it was tied to issues of government support for the ethanol industry and the long-term viability of ethanol production.

One alternative that was considered was to match the economic life of the IGPC pipeline with the duration of the government subsidies. A similar approach has been used in Ontario when connecting gas-fired generation plants with the economic life of the related pipelines being set at 20 years (i.e., equal to the term of the supporting Ontario Power Authority contracts). In IGPC's case, this approach would have protected the other ratepayers but it would have produced a much higher rate than IGPC is currently paying, because the pipeline would have been depreciated over a 7 to 10 year period. This may not be appropriate.

At the other extreme, the use of a 40-year depreciation life was not considered appropriate either since while it would lower the IGPC rate, it would expose the other ratepayers to higher risk of potentially paying for a pipeline that was not required to serve them. A 40-year depreciation life is more appropriate for pipelines that are part of the integrated distribution network as those assets are used by a wide range of customers.

The determining factors in setting a depreciation rate for NRG were the size, configuration and use of the IGPC pipeline. The IGPC pipeline as built was a dedicated high-pressure line to serve a single customer producing a single customer producing a single product line. The nature of the ethanol business and the fact that no other customers are expected to connect to the new line means that in the event of IGPC going out of business, the cost to maintain the line and any residual costs would fall on the remaining customers in NRG's service area.

To address these concerns and provide a fair rate to IGPC, NRG is proposing a 20-year depreciation of the IGPC pipeline. This timing was selected to match the approved approach to economic feasibility in EBO 188 where the Board set the customer revenue horizon for dedicated pipelines at 20 years. This timeframe has been applied by the Board in similar situations when connecting natural gas generation plants and it seems appropriate for IGPC.

Union Transportation Charges

NRG has estimated that IGPC will cause NRG to incur an incremental $330,466 of Union transportation charges. This amount was estimated by applying NRG's contracted deliveries to IGPC of 108,188/day by the applicable M9 delivery rate that was authorized effective January 1, 2010.

NATURAL RESOURCE GAS LIMITED

DEPRECIATION

The depreciation rates used in this pre-filed written evidence are those approved by the Board in RP-2005-0544. However, as noted in the Application and Specific Approvals Requested (Exhibit A1, Tab 2, Schedule 1), NRG has submitted (for illustrative purposes) a rate schedule demonstrating what rates would be if NRG's application utilized depreciation rates that correspond to the Board's Decision in EB-2008-0413. The remainder of this Schedule, however, reflects the Board's previously approved depreciation rates for NRG.

Fiscal 2011 Test Year

Exhibit D8, Tab 4, Schedule 1 contains the forecast of the depreciation expense for the 2007 test year. Depreciation costs are forecast to total $1,206,523 net of capitalized depreciation.

Comparison to Fiscal 2010 Bridge Year

Exhibit D8, Tab 4, Schedule 2 provides a comparison of the 2011 test year depreciation expense as compared to that of the 2010 bridge year. The total depreciation expense is forecast to increase $34,081 or 2.9% in 2011. The increase is the result of continuing growth in the asset base of the company.

Fiscal 2010 Bridge Year

Exhibit D7, Tab 4, Schedule 1 provides the calculation of the 2010 bridge year depreciation expense of $1,172,442.

Comparison to Fiscal 2009 Actual

Exhibit D7, Tab 4, Schedule 2 provides a comparison of the 2010 bridge year expense with that of 2009. The 2010 expense is $67,380 or 6.1% higher than in 2009. The decrease reflects the effect of capital spending to add new customers and routine capital spending on asset renewal.

Fiscal 2009 Historical Year

Exhibit D6, Tab 4, Schedule 1 shows the calculation of the depreciation expense of $1,105,062 for fiscal 2009.

Comparison to Fiscal 2008 Actual

Exhibit D6, Tab 4, Schedule 2 contains a comparison between the 2009 actual depreciation expense with that of 2008. The 2009 expense is $344,637, 45.3% greater than in 2008. The increase reflects the first full year of depreciation of the IGPC pipeline.

Fiscal 2008 Historical Year

Exhibit D5, Tab 4, Schedule 1 shows the calculation of the depreciation expense of $760,425 for fiscal 2008.

Comparison to Fiscal 2007 Actual

Exhibit D5, Tab 4, Schedule 2 contains a comparison between the 2008 actual depreciation expense with that of 2007. The 2008 expense is $33,117 or 4.6% greater than in 2006. The increase reflects ongoing capital spending to attach new customers and to renew assets.

Fiscal 2007 Historical Year

Exhibit D4, Tab 4, Schedule 1 shows the calculation of the depreciation expense of $727,308 for fiscal 2007.

Comparison to Fiscal 2006 Actual

Exhibit D4, Tab 4, Schedule 2 contains a comparison between the 2007 actual depreciation expense with that of 2006. The 2007 expense is $29,464 or 4.2% greater than in 2006. The increase reflects ongoing capital spending to attach new customers and to renew assets.

Comparison to Board Decision EB-2005-0544

The 2007 Board authorized depreciation expense is $3,196 or 0.4% lower than the actual 2007 depreciation expense.

Fiscal 2006 Historical Year

Exhibit D3, Tab 4, Schedule 1 shows the calculation of the depreciation expense of $697,844 for fiscal 2006.

Comparison to Fiscal 2005 Actual

Exhibit D3, Tab 4, Schedule 2 contains a comparison between the 2006 actual depreciation expense with that of 2005. The 2006 expense is $34,259 or 5.2% greater than in 2005.

NATURAL RESOURCE GAS LIMITED

PROPERTY AND CAPITAL TAXES

The forecast of property taxes is based on the assessed market value of pipeline assets in the previous year adjusted for the addition of pipelines and customers in the previous year. The previous year average tax rate is adjusted for forecast increases and multiplied by the assessed market value to arrive at the forecast for property taxes.

Fiscal 2011 Test Year

Property taxes are forecast to total $400,776 in fiscal 2011, as shown in Exhibit D8, Tab 5, Schedule 1. No capital taxes are forecast for the 2011 test year because they will be eliminated prior to the beginning of the period.

Comparison to Fiscal 2010 Bridge Year

As shown in Exhibit D8, Tab 5, Schedule 1, property taxes are forecast to increase by $11,673 in fiscal 2011 from the fiscal 2010 level. This reflects an increase in the assessed values of pipelines due to main additions and incremental customer additions forecast for 2011 and that the property tax rate increases by 3%.

Fiscal 2010 Bridge Year

Exhibit D7, Tab 5, Schedule 1 provides the total property and capital tax costs for the 2010 bridge year. These costs are expected to total $425,283; this amount is the sum of property taxes of $389,103 and provincial capital tax of $36,180.

Comparison to Fiscal 2009 Actual

As shown in Exhibit D7, Tab 5, Schedule 1, property and capital taxes are forecast to be $1,301 or 0.3% lower than the level recorded in fiscal 2009. The current year increase in property taxes is driven by a $68,251 increase in the assessed value resulting from main additions and customer additions in 2009 as well as a forecasted 2.5% increase in the tax rate.

Fiscal 2009 Historical Year

As shown in Exhibit D6, Tab 5, Schedule 1, total property and capital taxes totaled $426,584 in fiscal 2009. As shown in the same schedule, this was an increase of $70,772 compared to fiscal 2008. This increase is entirely due to increase property tax due chiefly to the inclusion of the IGPC Pipeline.

Fiscal 2008 Historical Year

As shown in Exhibit D5, Tab 5, Schedule 1, total property and capital taxes totaled $355,812 in fiscal 2008. As shown in the same schedule, this was an increase of $31,732 compared to fiscal 2007. This increase reflects increased property tax of $48,432 and a decrease in provincial capital tax of $16,700. The increase in property tax is chiefly due to the IGPC Pipeline.

Fiscal 2007 Historical Year

As shown in Exhibit D4, Tab 5, Schedule 1, total property and capital taxes totaled $324,080 in fiscal 2007. As shown in the same schedule, this was an increase of $51,585 compared to fiscal 2006. This increase reflects increased property tax of $24,766 and increased provincial capital tax of $27,082.

As shown in Exhibit D4.1, Tab 5, Schedule 1, the Board approved property and capital taxes for the 2007 TY totaled $334,437 and reflects property taxes only. Actual 2007 property tax expense was $286,180, which is $48,257 lower than the Board approved amount. Actual 2007 provincial capital taxes were $37,900.

Fiscal 2006 Historical Year

As shown in Exhibit D3, Tab 5, Schedule 1, total property and capital taxes totaled $272,222 in fiscal 2006. As shown in the same schedule, this was a decrease of $37,589 compared to fiscal 2005. The difference reflects decreased property tax of $23,883 and decreased provincial capital tax of $13,706.

NATURAL RESOURCE GAS LIMITED

INCOME TAXES

A summary of income taxes is presented in Exhibit D1, Tab 6, Schedule 2, which is a summary of the information provided in Tab 6, Schedule 1 of Exhibits D3, D4, D5, D6, D7 and D8.

NRG has calculated its income taxes payable on a stand alone basis. The following paragraphs explain the various tax rates used in the test year. These tax rates reflect the anticipated rates based on current data available.

The federal corporate tax rate for a Canadian Controlled Private Corporation (CCPC) with taxable income of less than $10 million is 16.875%.

The provincial corporate tax rates and thresholds that apply to NRG in the test year are as follows:

- first $500,000 of taxable income is taxable at 4.50%;
- taxable income in excess of $500,000 is taxable at 11.875%.

Fiscal 2011 Test Year

Exhibit D8, Tab 6, Schedule 1 provides the forecast income tax expense for the 2011 Test Year. Corporate income tax based on revenues recovered through current rates is forecast to total $50,252 in the 2011 test year. This estimate is based on the forecast of revenues and expenses (gas transportation costs, operating & maintenance costs, property and capital taxes). Interest costs are based on the carrying costs estimated in Exhibit E6, Tab 1, Schedule 3. The capital cost allowance deduction is calculated in Exhibit D8, Tab 4, Schedule 3.

Comparison to Fiscal 2010 Bridge Year

Income taxes are forecast to be $38,831 lower in the 2011 test year as compared to the forecast 2010 bridge year, as shown in Exhibit D7, Tab 6, Schedule 1. This reduction is attributed to higher Operations, Maintenance and Administration costs and deemed interest costs in the test year that more than offset increased revenues.

Fiscal 2010 Bridge Year

The 2010 estimated corporate income tax, shown in Exhibit D7, Tab 6, Schedule 1, is forecast to be $89,083 in fiscal 2010.

Comparison to Fiscal 2009 Actual

Compared to fiscal 2009, income taxes are $220,737 lower in fiscal 2009 as shown in Exhibit D7, Tab 6, Schedule 1. This is mainly attributable to increased Operations, Maintenance and Administration costs, increased gas transportation costs and a higher CCA deduction in the 2009 fiscal year.

Fiscal 2009 Historical Year

As shown in Exhibit D6, Tab 6, Schedule 1, total income taxes were $310,016 in fiscal 2009 on a normalized basis. This was a $214,353 increase from the 2008 level. This increase was driven by higher revenues attributed to a full year of recovery of distribution revenues from IGPC net of lower Operations, Maintenance and Administration costs and higher Union Gas gas transportation costs.

<u>Fiscal 2008 Historical Year</u>

As shown in Exhibit D5, Tab 6, Schedule 1, total income taxes were $95,467 in fiscal 2008 on a normalized basis. This was a $13,973 increase from the 2007 level. The increase was driven by higher revenues of $258,967 that were more than offset by increased Operations, Maintenance and Administration costs of $152,746, increased Property and Capital Taxes of $31,732 and a $26,473 increase in the CCA Allowance.

<u>Fiscal 2007 Historical Year</u>

As shown in Exhibit D4, Tab 6, Schedule 1, total income taxes were $81,494 in fiscal 2007 on a normalized basis. This was a $58,250 greater than the 2006 level. The increase was driven by higher revenues of $162,257, lower Operations, Maintenance and Administration costs of $154,375 and a $21,355 increase in the CCA Allowance.

Income taxes in fiscal 2007 were approximately $34,173 lower than the OEB approved level in RP-2005-0544. This results from lower than forecast revenues and lower operating and maintenance expenses.

<u>Fiscal 2006 Historical Year</u>

Exhibit D3, Tab 6, Schedule 1 provides the calculation of the normalized taxes payable in fiscal 2006 of $23,244. The fiscal 2006 total was approximately $111,540 lower than that recorded in fiscal 2005.

NATURAL RESOURCE GAS LIMITED

DEFERRAL AND VARIANCE ACCOUNTS

This evidence deals with the balance, disposition and continuance of NRG's deferral and variance accounts. NRG currently has four deferral/variance accounts. These accounts are the Purchased Gas Commodity Variance Account (PGCVA), the Purchased Gas Transportation Variance Account (PGTVA), the Gas Purchase Rebalancing Account (GPRA) and the Regulatory Expenses Deferral Account (REDA). NRG seeks Board authorization to establish a new deferral account to track the costs incurred to convert to the International Financial Reporting Standard ("IFRS").

Purchased Gas Commodity Variance Account (PGCVA)

The balance in the PGCVA as of September 30, 2009 was a credit of $226,202 including a debit of $51,146 in accumulated interest. NRG disposes of the PGCVA balance on a prospective 12 month basis through the Quarterly Rate Adjustment Mechanism (QRAM) and does not propose any clearance of this account as part of this proceeding.

NRG proposes that the PGCVA be continued in the 2011 test year. The reference price will continue to be adjusted on a quarterly basis through the QRAM process. Simple interest would be calculated on the monthly opening balances at the Board-approved short-term interest rate (see below).

Purchased Gas Transportation Variance Account (PGTVA)

The balance in the PGTVA as of September 30, 2009 was a credit of $35,258, including a credit of $3,199.73 in accumulated interest for the customers in rate classes 1 through 5. The balance as of the same date with respect to IGPC was a credit of $167,146, including a credit of $31 for interest.

PGTVA Reference Price

The PGTVA reference price of $0.019029/m^3, approved as part of the RP-2005-0544 Decision with Reasons dated September 28, 2005 for fiscal 2007 rates, remains in effect for fiscal 2010. Typically, the balance recorded in the PGTVA is disposed of annually pursuant to the Board's routine review of the balances recorded in NRG's non-commodity variance/deferral accounts. The Board's most recent review, however, did not authorize disposition through rates (EB-2009-0020).

NRG proposes to reset the reference price for the PGTVA fiscal 2011 and to replace the single reference price with two reference prices:

A reference price of <u>$0.023909/m^3</u> applicable to all customers in classes 1 through 5;

A reference price of $0.0105000/m^3 applicable to IGPC exclusively.

The proposed references prices are set out in Exhibit D8, Tab 2, Schedule 3, and demonstrates that these proposed reference prices can be expected to result in a PGTVA balance at the end of the 2011TY that is reasonably close to 0 and the disposition of any balance can be expected to avoid undue cross-subsidization between IGPC and all other customers. As documented in NRG's application for final disposition of 2008 variance and deferral account balances (EB-2009-0020), IGPC is a high load factor customer whose average cost of delivery service on a per m3 basis is lower than that of NRG's other customers. NRG notes that average PGTVA reference price for all customers is <u>$0.015170/m^3</u> and, if relied on, would result in an inappropriate recovery from all customers.

NRG has two delivery contracts with Union Gas – one provides for 168,100 m3/day of demand and is relied on to supply NRG's customers in Rates 1 through 5 while the other provides for 108,188 m3/day of demand to serve IGPC exclusively.

NRG proposes continuing the PGTVA in fiscal 2011 TY, and NRG proposes to apply a PGTVA Simple interest would be calculated on the monthly opening PGTVA balances at the Board-approved short-term interest rate (see below).

Regulatory Expenses Deferral Account (REDA)

The projected balance in this account at the end of fiscal 2009 is a debit of $280,318, including a debit of $156 in accumulated interest. NRG proposes to dispose of $113,318 of the balance in this account at this time. The amount to be disposed of are the costs NRG incurred in connection with OEB's adjudication of Union's Cessation of Service application, participation in the development of the natural gas incentive mechanism.

NRG also proposes that the REDA be continued in the 2011 test year and that it continue to record costs associated with participating in generic hearings and in Union Gas proceedings including, if applicable, a main rates case for Union Gas. Simple interest would be calculated on the monthly opening balances at the Board-approved short-term interest rate (see below).

IFRS Deferral Account ("IFRSDA")

NRG seeks an order of the Board authorizing it to establish a deferral account to record the costs incurred to convert to the IFRS standard. NRG submits that these costs are eligible for inclusion in a deferral account because:

- they are not included in the costs proposed to be recovered through distribution rates;
- the need to incur the costs is beyond management's control;
- the costs are expected to be material; and
- NRG will take appropriate steps to prudently incur costs associated with this activity.

Deferral/Variance Account Interest Rate

Currently the interest rate approved for use in deferral and variance accounts is the most recent Board-approved short-term interest rate. NRG proposes to continue its current practice of adjusting the carrying cost rate consistent with the Board's quarterly determination.

Proposed Disposition of PGTVA and REDA Through Rates of the September Deferral/Variance Account Balances

NRG proposes to dispose of the net balance recorded in the REDA and in the PGTVA as of September 30, 2009, being $156,545, plus accumulated carrying charges, through a rate rider that will operate for the 2011TY. These costs were prudently incurred, are beyond NRG's control and were not previously recovered through rates. NRG has correctly computed the balances recorded in these accounts.

NRG previously sought a Board Order authorizing the disposition of these amounts through rates (Board docket EB-2009-0020). The Board did not grant that application. This is the first opportunity since that Decision was issued to seek disposition. NRG notes that no party took issue with either the amounts to be disposed of or the proposed disposition through rates.

NRG assumes that the Board will continue its long standing practice of clearing the non-commodity variance/deferral account balances annually. NRG acknowledges that its proposed disposition of the balances recorded in these accounts as of September 30, 2009 during the 2011 rate year can be expected to overlap with the disposition through rates of the balances recorded as of September 30, 2010. NRG notes that the net balance to be disposed of is likely not material in context of NRG's customer base – approximately 7,000.

NRG notes that further delay in disposing of these balances through rates will result in further carrying costs and risks recovering the balances from customers who did not cause the costs to be incurred. To minimize the carrying costs disposed of through rates and to preserve the ability to recover the costs from the customer who caused them NRG proposes to dispose of the balances during the 2011TY. NRG proposes to assign responsibility for the PGTVA balance by assigning IGPC its appropriate share of the balance and developing a fixed charge rate rider. NRG proposes to assign responsibility to all other customers as follows:

- Responsibility for the remaining PGTVA balance will be assigned based on volumetric deliveries in the 2010BY;
- Responsibility for the REDA account balance will be assigned equally to each customer
- The net amount will be recovered from each customer equally over the 12 months of the 2011TY through a fixed charge rate rider.

This approach is not expected to result in rate shock to NRG's customers.

The derivation of the proposed rate riders is provided at Exhibit D1, Tab 7, Schedule 2.

NRG proposed to dispose of the balance allocated to customer classes 1 through 5 by way of a rate rider that will operate over the 2011 Test Year. NRG is in discussions with IGPC over the disposition of the balance allocated to them.

Natural Resource Gas Limited

Allocation of Balances to Customer Classes

REDA

Proceeding	Incurred Cost	Proposed Amount for Disposition	Recoverable from Rates 1-6	Recoverable from Rates 1-5	Recoverable from Rate 6
Natural Gas Incentive Program	6,881	-	-		
Commodity Pricing	51,210	51,210		51,210	
Cessation of Service	95,753	62,108	62,108		
Preapproval of Long Term Gas Supply, Transportation Contracts	1,487		-		
IFRS	280	-	-		
Carrying Charges	156	156	86	70	
Sub-total	155,767	113,474	62,194	51,280	-

PGTVA	Recorded Balance	Amount for Disposition	Recoverable from Rates 1-6	Recoverable from Rates 1-5	Recoverable from Rate 6
Principal	-198,811	-198,811		-31,696	-167,115
Carrying Charges	-3,390	-3,390		-3,359	-31
Sub-total	-202,201	-202,201		-35,055	-167,146

Computation of Carrying Charges - REDA

		Amount for Disposition	Recoverable from Rates 1-6	Recoverable from Rates 1-5	Recoverable from Rate 6
Amount to be Disposed of		113,318	62,108	51,210	0
Carrying Charges - Opening Balance	0	156	86	70	0
Period Carrying Charges		779	427	351	0
Total Amount for Disposition		114,097	62,535	51,561	0

Computation of Carrying Charges - PGTVA

Amount to be Disposed of	-198,811	-198,811	0	-31,696	-167,115
Carrying Charges - Opening Balance	-3,390	-3,390	0	-3,359	-31
Period Carrying Charges		-4,483	0	-3,533	-950

Total Amount for Disposition		-203,294	0	-35,229	-168,065

		Amount for Disposition	Recoverable from Rates 1-6	Recoverable from Rates 1-5	Recoverable from Rate 6
Total		-89,197	62,535	16,332	-168,065

Natural Resource Gas Limited

REDA and PGTVA Dispositions

	Recoverable from Rates 1-6	Recoverable from Rates 1-5	Recoverable from Rate 6	Total
REDA	62,535	51,561	0	114,096
PGTVA	0	-35,229	-168,065	-203,294
Total	62,535	16,332	-168,065	-89,198

Allocation Statistics

	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6
A&G allocation	56.14%	2.94%	2.54%	0.84%	1.78%	35.76%
Transportation allocation	81.27%	2.32%	10.01%	2.07%	4.32%	

Allocated Balances

	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Total
Allocated REDA balance	80,167	4,201	3,632	1,193	2,545	22,360	114,096
Allocated PGTVA balance	-28,631	-819	-3,528	-730	-1,522	-168,065	-203,294
Total	51,536	3,382	104	463	1,023	-145,705	-89,198

Charge Parameter Statistics

Gas Delivery Volumes	17,816,328	509,371	2,195,299	454,263	947,162	33,416,816
Number of customers	7,000	73	4	23	5	1

Proposed Rate Rider

Scenario A - Volumetric	0.002893	0.00664	0.000048	0.001018	0.00108	-0.00436
Scenario B - Fixed	1	4	2	2	17	-12,142

Scenario C - Lump Sum per customer	7	46	26	20	205	-145,705

NATURAL RESOURCE GAS LIMITED

Cost of Service
2006 Actual and Normalized
($'s)

	Actual Forecast	Adjust-ments	Normalized Forecast
Gas Transportation Costs	411,228	0	411,228
Operation and Maintenance	2,141,069		2,141,069
Depreciation and Amortization	697,844		697,844
Property and Capital Taxes	272,222		272,222
Income Taxes	23,244	16,938	40,182
Total Cost of Service	3,545,607		3,562,545

NATURAL RESOURCE GAS LIMITED

Summary of Cost of Service
2006 Actual
($'s)

	Actual 2006	Actual 2005
Gas Transportation Costs	411,228	542,477
Operation and Maintenance	2,141,069	2,008,796
Depreciation and Amortization	697,844	663,585
Property and Capital Taxes	272,222	309,811
Income Taxes	23,244	134,784
Total Cost of Service	3,545,607	3,659,453

	Variance from 2005
Gas Transportation Costs	-131,249
Operation and Maintenance	132,273
Depreciation and Amortization	34,259
Property and Capital Taxes	-37,589
Income Taxes	-111,540
Total Cost of Service	-113,846

NATURAL RESOURCE GAS LIMITED

Cost of Gas
2006 Actual

Gas Commodity	Period Covered	M*3	$'s	$/M*3
Local Production - A (Affiliate)	Oct. 1/05 - Sept. 30/06	8,218,634	4,114,002	0.500570
Local Production - B	Oct. 1/05 - Sept. 30/06	155,073	71,082	0.000000
Western (FT + Dawn)	Oct. 1/05 - Sept. 30/06	3,915,559	1,612,310	0.411770
Parkway	Oct. 1/05 - Sept. 30/06	8,355,135	3,635,125	0.435077
Ontario Delivered	Oct. 1/05 - Sept. 30/06	-929,615	0	0.000000
GCDRA Transfer		0	0	
Gas Inventory Revaluation			83,508	
PGCVA - Fiscal 2006			-1,011,358	
Total Gas Commodity Cost		19,714,786	17,262,412	0.875607

Gas Transportation	Period Covered	M*3	$'s	$/M*3
Union Gas	Oct. 1/05 - Sept. 30/06		411,228	
PGTVA - Fiscal 2006			83,508	
Total Gas Transportation Cost		22,673,821	494,736	0.021820
Total Gas Commodity and Transportation Cost			17,757,149	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Commodity Variance Account Calculation
2006 Actual

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Purchased (M*3)													
Local Production - A - Affiliate	605,515	527,812	568,382	567,424	559,085	814,256	768,897	658,820	449,967	588,442	1,026,012	1,084,022	8,218,634
Local Production - B	32,926	31,864	32,926	0	25,452	19,198	11,126	1,581	0	0	0	0	155,073
Western (FT + Dawn)	332,554	321,827	332,554	332,554	300,372	332,554	321,827	332,554	321,827	332,554	332,554	321,827	3,915,559
Parkway	732,608	708,975	732,608	732,608	661,710	732,608	708,975	732,608	708,975	732,608	732,608	438,247	8,355,135
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	-929,615	-929,615
Total	1,703,603	1,590,478	1,666,470	1,632,586	1,546,619	1,898,616	1,810,825	1,725,562	1,480,769	1,653,604	2,091,174	914,481	19,714,786
Commodity Cost													
Local Production - A - Affiliate	303,103	264,207	284,515	284,035	279,861	407,592	384,887	329,786	225,240	294,556	513,591	542,629	4,114,002
Local Production - B	19,356	14,928	18,687	0	8,857	5,386	3,393	475	0	0	0	0	71,082
Western (FT + Dawn)	140,945	154,769	180,073	157,135	133,650	140,529	119,220	121,992	114,607	118,551	122,414	108,426	1,612,310
Parkway	313,287	362,212	387,001	376,976	337,576	371,715	261,515	271,392	250,808	255,586	267,071	179,985	3,635,125
GCDRA Transfer	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Commodity Cost	776,691	796,116	870,276	818,146	759,944	925,223	769,015	723,644	590,655	668,694	903,076	831,040	9,432,519
Average Cost ($/M*3)													
Reference Price	0.400710	0.400710	0.400710	0.499494	0.499494	0.499494	0.419787	0.419787	0.419787	0.384383	0.384383	0.384383	
Actual Price	0.455911	0.500551	0.522227	0.501135	0.491358	0.487314	0.424677	0.419367	0.398884	0.404386	0.431851	0.908756	
Rate Difference	(0.055201)	(0.099841)	(0.121517)	(0.001641)	0.008136	0.012180	(0.004890)	0.000420	0.020903	(0.020003)	(0.047468)	(0.524373)	
PGCVA Balance ($'s)													
PGCVA	-94,041	-158,795	-202,504	-2,679	12,583	23,125	-8,855	725	30,953	-33,077	-99,264	-479,529	-1,011,358
Year-to-Date	-196,662	-355,457	-557,961	-560,640	-548,057	-524,932	-533,787	-533,062	-502,109	-535,186	-634,450	-1,113,979	-1,113,979
Interest	-470	-901	-1,629	-2,557	-2,570	-2,512	-2,406	-2,447	-2,443	-2,301	-2,453	-2,908	
Year-to-Date	-2,415	-3,316	-4,946	-7,503	-10,073	-12,585	-14,990	-17,437	-19,880	-22,182	-24,634	-27,542	-27,542
Total Balance	-199,077	-358,773	-562,907	-568,143	-558,129	-537,516	-548,777	-550,499	-521,990	-557,368	-659,085	-1,141,522	-1,141,522
Interest Rate	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2006 Actual

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Transported (M*3)													
Total Transported	2,279,447	2,297,618	3,311,730	2,860,748	3,039,946	2,626,857	1,422,228	783,163	464,258	590,017	1,407,643	2,096,422	23,180,077
Transportation Cost													
Union Gas - Demand	31,415	31,415	31,415	29,057	29,057	29,057	29,057	29,057	29,057	29,057	29,057	29,057	355,762
Union Gas - Delivery	7,541	8,045	12,468	10,463	11,332	8,277	3,098	592	69	8	1,848	4,878	68,619
Union Gas - Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transportation Cost	38,956	39,460	43,883	39,520	40,389	37,334	32,156	29,650	29,126	29,066	30,905	33,935	424,381
Average Cost ($/M*3)													
Reference Price	0.021848	0.021848	0.021848	0.021848	0.021848	0.021848	0.021848	0.021848	0.021848	0.021848	0.021848	0.021848	
Actual Price	0.017090	0.017174	0.013251	0.013815	0.013286	0.014212	0.022609	0.037859	0.062737	0.049263	0.021955	0.016187	
Rate Difference	0.004758	0.004674	0.008597	0.008033	0.008562	0.007636	(0.000761)	(0.016011)	(0.040889)	(0.027415)	(0.000107)	0.005661	
PGTVA Balance ($'s)													
PGTVA	-10,846	-10,739	-28,471	-22,980	-26,028	-20,059	1,082	12,539	18,983	16,175	151	-11,868	-82,060
Year-to-Date	-78,878	-89,617	-118,088	-141,068	-167,096	-187,155	-186,073	-173,534	-154,551	-138,375	-138,225	-150,092	-150,092
Interest	-362	-362	-411	-541	-647	-766	-858	-853	-795	-708	-634	-634	
Year-to-Date	-15,259	-15,621	-16,032	-16,573	-17,219	-17,985	-18,843	-19,696	-20,491	-21,200	-21,834	-22,467	-22,467
Total Balance	-94,137	-105,238	-134,120	-157,641	-184,316	-205,140	-204,916	-193,229	-175,042	-159,575	-160,058	-172,560	-172,560
Interest Rate	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	

NATURAL RESOURCE GAS LIMITED

Operating and Maintenance Expense
2006 Actual
($'s)

	Actual 2006	Actual 2005	Variance from 2005
Expense Category			
Wages	896,687	863,486	33,201
Employee Benefits	126,485	129,604	-3,119
Insurance	235,774	263,750	-27,976
Utilities	16,565	14,263	2,302
Advertising	36,612	29,889	6,723
Telephone	41,658	39,366	2,292
Office & Postage	96,400	82,181	14,219
Repair & Maintenance	131,757	135,331	-3,574
Automotive	83,866	98,519	-14,653
Dues & Fees	20,054	22,543	-2,489
Mapping Expense	357	0	357
Regulatory	165,980	150,256	15,724
Bad Debts	13,500	8,000	5,500
Office Rent	9,600	9,600	0
Interest - Security Deposits	1,376	992	384
Bank Charges	12,897	10,366	2,531
Collection Expense	11,820	14,072	-2,252
Travel & Ent.	2,158	6,787	-4,629
Legal	125,361	74,827	50,534
Audit	20,086	30,500	-10,414
Consulting Fees	59,254	35,800	23,454
Management Fees (Net)	103,500	87,000	16,500
Miscellaneous	0	23,467	-23,467
Total O & M Expenses	2,211,746	2,130,599	81,147
Capitalized Expenses			
Wages	53,575	90,113	-36,538
Equipment	17,102	31,690	-14,588
Total Capitalized Expenses	70,677	121,803	-51,126
Total Net Expenses	2,141,069	2,008,796	132,273
Average Number of Customers	6,383	6,135	248
Net Expense per Customer	335.45	327.43	8.02

NATURAL RESOURCE GAS LIMITED

Regulatory Expenses
2006 Actual
($'s)

Category	Expense
Main Rates Case	131,700
QRAM	12,000
RRR	12,000
Miscellaneous	12,000
Sub-Total - Rate Case & Other Applications	167,700
Plus OEB Fixed Costs	26,000
Total Regulatory Costs	193,700

January-29-10
EB-2010-0018
Exhibit D3
Tab 4
Schedule 1

NATURAL RESOURCE GAS LIMITED

Depreciation Expense
2006 Actual
($'s)

	Assets At Cost Oct 1/05	Acc. Dep. Oct 1/05	Net Book Value Oct 1/05	Additions F2006	Disposals F2006	Adjusted Cost Base	Dep'n Rate	Depreciation Expense F2006	Adjustments Accumulated Depreciation F2006	Accumulated Depreciation Sept 30/06	Net Book Value Sept 30/06
Fixed Assets											
Land	71,700	-	71,700	-	-	71,700	0.00%	-	-	-	71,700
Buildings	682,331	76,694	605,637	-	-	682,331	2.22%	15,148	-	91,842	590,489
Furniture & Fixtures	53,189	24,469	28,720	831	-	54,020	6.75%	3,646	-	28,116	25,905
Computer Equipment	106,064	90,629	15,435	21,852	-	127,916	33.33%	12,428	-	103,057	24,859
Computer Software	106,519	96,219	10,300	29,954	-	136,472	20.00%	8,051	-	104,269	32,203
Machinery & Equipment	366,687	270,406	96,281	18,205	-	384,892	9.22%	35,487	-	305,894	78,999
Communication Equipment	41,353	13,557	27,796	14,665	-	56,017	7.73%	4,330	-	17,887	38,130
Automotive	455,714	79,522	376,193	35,661	45,360	446,015	16.60%	74,039	(28,891)	124,669	321,346
Rental Equip - Residential	1,744,666	659,255	1,085,411	210,458	117,457	1,837,667	7.40%	135,987	(103,695)	691,548	1,146,119
Rental Equip - Commercial	55,031	16,079	38,952	2,645	2,977	54,699	7.40%	4,048	(2,688)	17,438	37,260
Rental Equip - Water Softeners	11,965	3,737	8,228	(338)	-	11,627	6.25%	727	-	4,463	7,163
Meters	1,688,208	678,794	1,009,414	149,944	-	1,838,152	3.62%	66,541	-	745,335	1,092,817
Regulators	1,113,259	565,665	547,594	72,199	-	1,185,458	3.67%	43,506	-	609,171	576,287
Plastic Mains	6,360,086	1,914,222	4,445,863	125,468	-	6,485,554	3.24%	210,132	(43)	2,124,311	4,361,243
Steel Mains	33,014	23,393	9,621	-	-	33,014	13.45%	4,440	-	27,833	5,181
New Steel Mains	-	-	-	-	-	-	0.00%	-	-	-	-
Plastic Services	2,407,938	1,356,736	1,051,202	50,146	33	2,458,052	3.33%	82,342	(1,115)	1,437,964	1,020,088
IGPC	-	-	-	-	-	-	0.00%	-	-	-	-
Franchises	151,094	72,007	79,087	-	-	151,094	0.37%	7,270	-	79,277	71,817
Total Fixed Assets	15,448,818	5,941,384	9,507,434	731,690	165,827	16,014,680		708,123	(136,432)	6,513,074	9,501,606
Less:											
Capitalized Depreciation							-	10,279			
Total	**15,448,818**	**5,941,384**	**9,507,434**	**731,690**	**165,827**	**16,014,680**		**697,844**	**-136,432**	**6,513,074**	**9,501,606**

NATURAL RESOURCE GAS LIMITED

Summary of Depreciation Expense
2006 Actual
($'s)

	Actual 2006	Actual 2005
Fixed Assets		
Land	0	0
Buildings	15,148	15,148
Furniture & Fixtures	3,646	3,590
Computer Equipment	12,428	7,716
Computer Software	8,051	2,575
Machinery & Equipment	35,487	33,809
Communication Equipment	4,330	3,197
Automotive	74,039	75,649
Rental Equip - Residential	135,987	129,105
Rental Equip - Commercial	4,048	4,072
Rental Equip - Water Softeners	727	748
Meters	66,541	61,113
Regulators	43,506	40,857
Plastic Mains	210,132	205,150
Steel Mains	4,440	4,440
New Steel Mains	0	0
Plastic Services	82,342	80,184
Franchises	7,270	7,270
Total Fixed Assets	708,123	674,623
Less:		
Capitalized Depreciation	10,279	11,038
Total	697,844	663,585

	Variance from 2005
Fixed Assets	
Land	0
Buildings	-0
Furniture & Fixtures	56
Computer Equipment	4,712
Computer Software	5,476
Machinery & Equipment	1,678
Communication Equipment	1,133
Automotive	-1,610
Rental Equip - Residential	6,882
Rental Equip - Commercial	-24
Rental Equip - Water Softeners	-21
Meters	5,428
Regulators	2,649
Plastic Mains	4,982
Steel Mains	0
New Steel Mains	0
Services - Plastic	2,158
Franchises	0
Total Fixed Assets	33,500
Less:	
Capitalized Depreciation	-759
Total	34,259

NATURAL RESOURCE GAS LIMITED

Capital Cost Allowance
2006 Actual
($'s)

Class	UCC at End of Fiscal 2006	Add: Cost of Additions	Adjustments	Deduct: Lesser of Cost and Proceeds from Disposal	UCC Before CCA	CCA Claimed: Rate (%)	CCA Claimed: Amount	UCC at End of Year
1	6,168,862	-	-	-	6,168,862	4%	246,755	5,922,107
2	586,305	-	-	-	586,305	6%	35,178	551,127
3	-	-	-	-	-	5%	0	0
6	5,746	-	-	-	5,746	10%	575	5,171
7	-	-	-	-	-	15%	0	0
8	638,142	212,765	-	12,926	837,981	20%	147,612	690,369
8	130,662	33,701	-	-	164,363	20%	29,502	134,861
10	186,411	35,661	-	-	222,072	30%	61,272	160,800
10.1	24,772	-	-	-	24,772	30%	4,618	20,154
49	268,558	397,756	-	-	666,314	8%	37,395	628,919
45	17,942	21,852	-	-	39,794	45%	12,991	26,803
12	6,438	29,954	-	-	36,392	100%	21,415	14,977
14	-	-	-	-	-	4%	0	0
50	-	-	-	-	-	55%	0	0
51	-	-	-	-	-	6%	0	0
17	42,145	-	-	-	42,145	8%	3,372	38,773
	8,075,983	731,689	-	12,926	8,794,746		600,685	8,194,061

NATURAL RESOURCE GAS LIMITED

Summary of Capital Cost Allowance
2006 Actual
($'s)

Class	Actual 2006	Actual 2005
1	246,755	257,647
2	35,178	37,424
3	-	-
6	575	639
7	-	-
8	147,612	138,951
8	29,502	26,548
10	61,272	60,111
10.1	4,618	10,617
49	37,395	-
45	12,991	5,209
12	21,415	6,437
14	-	3,891
50	-	-
51	-	-
17	3,372	3,665
Total	600,685	551,139

Class	Variance from 2005
1	(10,892)
2	(2,246)
3	-
6	(64)
7	-
8	8,661
8	2,954
10	1,161
10.1	(5,999)
45	7,782
12	14,978
14	(3,891)
17	(293)
Total	12,151

NATURAL RESOURCE GAS LIMITED

Property and Capital Taxes
2006 Actual
($'s)

Property Taxes	Actual 2006	Actual 2005
Prepaid Previous Year	-	62,305
Add Current Year Taxes	261,404	287,636
Less Prepaid Current Year	-	(64,654)
Total Property Tax	261,404	285,287
Provincial Capital Tax	10,818	24,524
Federal Capital Tax	-	-
Total Property & Capital Taxes	272,222	309,811

Property Taxes	Variance from 2005
Prepaid Previous Year	(62,305)
Add Current Year Taxes	(26,232)
Less Prepaid Current Year	64,654
Total Property Tax	(23,883)
Provincial Capital Tax	(13,706)
Federal Capital Tax	-
Total Property & Capital Taxes	(37,589)

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2006 Actual and Normalized
($'s)

				Actual 2006	Normalized 2006	Actual 2005
Taxable Income						
Operating Revenue				4,168,238	4,265,529	4,356,739
Less:						
Gas Transportation Costs				411,228	411,228	542,477
Operation & Maintenance				2,141,069	2,141,069	2,008,796
Property & Capital Taxes				272,222	272,222	309,811
Subtotal				1,343,718	1,441,009	1,495,655
Add Back:						
Federal Capital Tax (non-deductible)				0	0	0
Meals & Ent. (non-deductible portion)				591	591	494
Subtotal				1,344,309	1,441,600	1,496,149
Deduct:						
Interest				603,723	603,723	426,135
Capital Cost Allowance				600,685	600,685	551,139
Taxable Income				139,901	237,192	518,875
Corporate Income Tax						
Federal Income Tax						
Tax on first	$400,000	@	11.63%	16,270	27,585	32,244
Clawback on	($12,368)	@	9.00%	-1,113	-1,113	6,573
Tax on all over	$400,000	@	20.63%	0	0	45,963
Federal Surtax		@	0.28%	392	664	5,811
Total Federal Income Tax				15,549	27,136	90,591
Provincial Income Tax						
Tax on first	$400,000	@	5.50%	7,695	13,046	22,000
Clawback on next	$728,519	@	4.67%	0	0	5,551
Tax on all over	$400,000	@	14.00%	0	0	16,642
Total Provincial Income Tax				7,695	13,046	44,193
Total Income Tax				23,244	40,182	134,784

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2006 Actual
($'s)

				Variance from 2005
Taxable Income				
Normalized Operating Revenue				-188,501
Less:				
Gas Transportation Costs				-131,249
Operation & Maintenance				132,273
Property & Capital Taxes				-37,589
Subtotal				-151,937
Add Back:				
Federal Capital Tax (non-deductible)				0
Meals & Ent. (non-deductible portion)				97
Subtotal				-151,840
Deduct:				
Interest				177,588
Capital Cost Allowance				49,546
Normalized Taxable Income				-378,974
Corporate Income Tax				
Federal Income Tax				
Tax on first	$400,000	@	11.63%	-15,974
Clawback on	($12,368)	@	9.00%	-7,686
Tax on all over	$400,000	@	20.63%	-45,963
Federal Surtax		@	0.28%	-5,419
Total Federal Income Tax				-75,042
Provincial Income Tax				
Tax on first	$400,000	@	5.50%	-14,305
Clawback on n	$728,519	@	4.67%	-5,551
Tax on all over	$400,000	@	14.00%	-16,642
Total Provincial Income Tax				-36,498
Total Income Tax				-111,540

NATURAL RESOURCE GAS LIMITED

Other Deferral and Variance Accounts
2006 Actual
($'s)

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Regulatory Expenses Deferral Account (REDA)													
Closing Account Balance	126	126	126	126	126	126	126	126	126	126	126	126	126
Interest rate	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	
Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Year-to-Date	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18
Total Balance	160	160	160	160	160	160	160	160	160	160	160	160	160
Opening Balance													
REDA	126.05												
Interest	34.18												

Gas Cost Difference Recovery Variance Account (GCDRVA) - Not applicable

System Gas Sales (m3)	19,854,199	Opening Account Balance	0.00
Rate ($/m3)	0.000000	Current Year Recovery Variance	-13,864.94
Recovery ($)	163,400.06	Closing Account Balance	-13,864.94
Approved Recovery	177,265.00	Interest on Opening Balance	0.00
Recovery Variance	-13,864.94	Accumulated Interest	0.00
		Total Account Balance	-13,864.94

NATURAL RESOURCE GAS LIMITED

Cost of Service
2007 Actual
($'s)

	Actual Forecast	Adjust-ments	Normalized Forecast
Gas Transportation Costs	394,141	0	394,141
Operation and Maintenance	1,986,694		1,986,694
Depreciation and Amortization	727,308		727,308
Property and Capital Taxes	324,080		324,080
Income Taxes	81,495	-2,282	79,213
Total Cost of Service	3,513,717		3,511,435

NATURAL RESOURCE GAS LIMITED

Summary of Cost of Service
2007 Actual
($'s)

	Actual 2007	Actual 2006
Gas Transportation Costs	394,141	411,228
Operation and Maintenance	1,986,694	2,141,069
Depreciation and Amortization	727,308	697,844
Property and Capital Taxes	324,080	272,222
Income Taxes	81,494	23,244
Total Cost of Service	3,513,716	3,545,607

	Variance from 2006
Gas Transportation Costs	-17,087
Operation and Maintenance	-154,375
Depreciation and Amortization	29,464
Property and Capital Taxes	51,858
Income Taxes	58,250
Total Cost of Service	-31,891

NATURAL RESOURCE GAS LIMITED

Cost of Gas
2007 Actual

Gas Commodity	Period Covered	M*3	$'s	$/M*3
Local Production - A (Affiliate)	Oct. 1/07 - Sept. 30/08	8,654,796	2,606,825	0.301200
Local Production - B	Oct. 1/07 - Sept. 30/08	130,729	36,818	0.000000
Western (FT + Dawn)	Oct. 1/07 - Sept. 30/08	3,125,250	1,046,155	0.334743
Parkway	Oct. 1/07 - Sept. 30/08	6,315,406	2,136,707	0.338333
Ontario Delivered	Oct. 1/07 - Sept. 30/08	0	0	0.000000
GCDRA Transfer		0	0	
Gas Inventory Revaluation			-11	
PGCVA - Fiscal 2007			928,406	
Total Gas Commodity Cost		18,226,181	13,889,139	0.762043
Gas Transportation				
Union Gas	Oct. 1/07 - Sept. 30/08		394,141	
PGTVA - Fiscal 2008			45,487	
Total Gas Transportation Cost		23,637,581	439,629	0.018599
Total Gas Commodity and Transportation Cost			14,328,768	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Commodity Variance Account Calculation
2007 Actual

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Purchased (M*3)													
Local Production - A - Affilia	954,535	865,590	849,249	663,666	686,262	721,564	697,532	621,660	521,585	487,072	768,136	817,945	8,654,796
Local Production - B	32,935	31,889	32,952	32,952	0	0	0	0	0	0	0	0	130,729
Western (FT + Dawn)	297,238	269,466	253,734	253,734	229,179	252,910	257,212	265,785	257,212	265,785	265,785	257,212	3,125,250
Parkway	608,473	589,158	608,796	608,796	549,880	608,796	592,147	392,468	379,808	392,468	392,468	592,147	6,315,406
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,893,180	1,756,103	1,744,731	1,559,148	1,465,321	1,583,270	1,546,891	1,279,913	1,158,604	1,145,325	1,426,389	1,667,304	18,226,181
Commodity Cost													
Local Production - A - Affilia	287,506	260,716	255,794	199,896	206,702	217,335	210,097	187,244	157,101	146,706	231,363	246,365	2,606,825
Local Production - B	6,204	9,516	11,309	9,790	0	0	0	0	0	0	0	0	36,818
Western (FT + Dawn)	96,315	96,681	97,452	94,375	87,438	97,137	84,816	84,311	84,514	78,998	73,671	70,447	1,046,155
Parkway	211,764	203,844	224,248	206,012	199,474	220,437	193,766	127,140	124,495	127,178	127,178	171,173	2,136,707
GCDRA Transfer	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Commodity Cost	601,789	570,756	588,802	510,073	493,614	534,909	488,679	398,695	366,110	352,882	432,211	487,985	5,826,505
Average Cost ($/M*3)													
Reference Price	0.407875	0.407875	0.407875	0.355763	0.355763	0.355763	0.365402	0.365402	0.365402	0.344251	0.344251	0.344251	
Actual Price	0.317872	0.325013	0.337474	0.327148	0.336864	0.337851	0.315910	0.311502	0.315992	0.308106	0.303011	0.292679	
Rate Difference	0.090003	0.082862	0.070401	0.028615	0.018899	0.017912	0.049492	0.053900	0.049410	0.036145	0.041240	0.051572	
PGCVA Balance ($'s)													
PGCVA	170,392	145,514	122,831	44,615	27,693	28,360	76,559	68,987	57,247	41,398	58,824	85,986	928,406
Year-to-Date	1,121,662	1,267,177	1,390,007	1,434,622	1,462,316	1,490,675	1,567,234	1,636,221	1,693,468	1,734,866	1,793,690	1,879,676	1,879,676
Interest	3,639	4,290	4,847	5,317	5,487	5,593	5,702	5,995	6,259	6,478	6,636	6,861	
Year-to-Date	30,861	35,151	39,998	45,315	50,802	56,396	62,097	68,092	74,351	80,828	87,464	94,325	94,325
Total Balance	1,152,523	1,302,328	1,430,005	1,479,937	1,513,118	1,547,071	1,629,331	1,704,313	1,767,818	1,815,694	1,881,154	1,974,001	1,974,001
Interest Rate	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2007 Actual

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Transported (M*3)													
Total Transported	1,928,060	2,876,227	2,740,766	3,092,377	3,747,197	2,627,929	1,901,463	814,765	528,178	489,044	873,873	1,401,314	23,021,193
Transportation Cost													
Union Gas - Demand	29,057	29,057	29,057	28,729	28,729	28,729	28,729	28,729	28,729	28,729	28,729	28,729	345,730
Union Gas - Delivery	4,960	10,522	9,800	13,035	16,428	10,211	6,375	1,036	35	11	567	3,131	76,112
Union Gas - Adjustments	-1,156	-2,451	-2,283	-3,043	-3,835	-2,384	-1,613	-262	-9	-1	-70	-387	-17,494
Total Transportation Cost	32,862	37,128	36,575	38,720	41,321	36,556	33,491	29,503	28,755	28,738	29,226	31,473	404,347
Average Cost ($/M*3)													
Reference Price	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	
Actual Price	0.017044	0.012909	0.013345	0.012521	0.011027	0.013910	0.017613	0.036210	0.054442	0.058763	0.033444	0.022459	
Rate Difference	0.001985	0.006120	0.005684	0.006508	0.008002	0.005119	0.001416	(0.017181)	(0.035413)	(0.039734)	(0.014415)	(0.003430)	
PGTVA Balance ($'s)													
PGTVA	-3,827	-17,603	-15,579	-20,125	-29,985	-13,452	-2,692	13,998	18,704	19,432	12,597	4,807	-33,725
Year-to-Date	-87,335	-104,937	-120,516	-140,641	-170,626	-184,078	-186,771	-172,772	-154,068	-134,636	-122,040	-117,233	-117,233
Interest	-319	-334	-401	-461	-538	-653	-704	-714	-661	-589	-515	-467	
Year-to-Date	-4,099	-4,434	-4,835	-5,296	-5,834	-6,486	-7,191	-7,905	-8,566	-9,155	-9,670	-10,137	-10,137
Total Balance	-91,434	-109,371	-125,351	-145,937	-176,460	-190,565	-193,962	-180,677	-162,634	-143,792	-131,710	-127,370	-127,370
Interest Rate	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	

NATURAL RESOURCE GAS LIMITED

Operating and Maintenance Expense
2007 Actual
($'s)

	Actual 2007	Actual 2006	Variance from 2006
Expense Category			
Wages	1,019,249	896,687	122,562
Employee Benefits	113,602	126,485	-12,883
Insurance	185,199	235,774	-50,575
Utilities	14,541	16,565	-2,024
Advertising	16,651	36,612	-19,960
Telephone	54,070	41,658	12,411
Office & Postage	108,098	96,400	11,698
Repair & Maintenance	63,537	131,757	-68,220
Automotive	60,309	83,866	-23,557
Dues & Fees	18,082	20,054	-1,972
Mapping Expense	403	357	46
Regulatory	48,559	165,980	-117,421
Bad Debts	0	13,500	-13,500
Office Rent	9,600	9,600	0
Interest - Security Deposits	4,274	1,376	2,899
Bank Charges	17,713	12,897	4,816
Collection Expense	8,755	11,820	-3,064
Travel & Ent.	14,609	2,158	12,451
Legal	51,808	125,361	-73,553
Audit	15,500	20,086	-4,586
Consulting Fees	129,454	59,254	70,200
Management Fees (Net)	89,750	103,500	-13,750
Miscellaneous	0	103,500	-103,500
Total O & M Expenses	2,043,764	2,315,246	-271,482
Capitalized Expenses			
Wages	41,918	0	41,918
Equipment	15,152	53,575	-38,423
Total Capitalized Expenses	57,071	53,575	3,496
Total Net Expenses	1,986,694	2,261,671	-274,977
Average Number of Customers	6,551	0	6,551
Net Expense per Customer	303.28	#DIV/0!	#DIV/0!

NATURAL RESOURCE GAS LIMITED

Regulatory Expenses
2007 Test Year
($'s)

Category	Expense
Total Regulatory Costs	48,559

NATURAL RESOURCE GAS LIMITED

Depreciation Expense
2007 Actual
($'s)

	Assets At Cost Oct 1/06	Acc. Dep. Oct 1/06	Net Book Value Oct 1/06	Additions F2007	Disposals F2007	Adjusted Cost Base	Dep'n Rate (1)	Depreciation Expense F2007	Adjustments Accumulated Depreciation F2007 (2)	Accumulated Depreciation Sept 30/07	Net Book Value Sept 30/07
Fixed Assets											
Land	71,700	-	71,700	-	-	71,700	0.00%	-	-	-	71,700
Buildings	682,331	91,842	590,489	-	-	682,331	2.22%	15,148	-	106,989	575,341
Furniture & Fixtures	54,020	28,116	25,905	864	-	54,884	6.75%	3,705	-	31,820	23,064
Computer Equipment	127,916	103,057	24,859	18,270	-	146,186	33.33%	14,375	-	117,432	28,754
Computer Software	136,472	104,269	32,203	-	-	136,472	20.00%	6,441	-	110,710	25,762
Machinery & Equipment	384,892	305,894	78,999	8,816	-	393,709	9.22%	36,300	-	342,193	51,515
Communication Equipment	56,017	17,887	38,130	7,137	-	63,155	7.73%	4,882	-	22,769	40,385
Automotive	446,015	124,669	321,346	45,196	25,556	465,655	16.60%	77,299	(21,776)	180,192	285,463
Rental Equip - Residential	1,837,667	691,548	1,146,119	237,721	168,069	1,907,319	7.40%	141,142	(151,744)	680,946	1,226,373
Rental Equip - Commercial	54,699	17,438	37,260	-	-	54,699	7.40%	4,048	-	21,486	33,213
Rental Equip - Water Softeners	11,627	4,463	7,163	-	-	11,627	6.25%	727	-	5,190	6,437
Meters	1,838,152	745,335	1,092,817	78,939	-	1,917,091	3.62%	69,399	-	814,734	1,102,357
Regulators	1,185,458	609,171	576,287	16,317	-	1,201,774	3.67%	44,105	-	653,276	548,498
Plastic Mains	6,485,554	2,124,311	4,361,243	403,643	-	6,889,197	3.24%	223,210	(409)	2,347,112	4,542,085
Steel Mains	33,014	27,833	5,181	-	-	33,014	13.45%	4,440	-	32,274	740
New Steel Mains	-	-	-	-	-	-	0.00%	-	-	-	-
Plastic Services	2,458,052	1,437,474	1,020,577	50,874	-	2,508,926	3.33%	83,547	(309)	1,520,712	988,214
IGPC	-	-	-	-	-	-	0.00%	-	-	-	-
Franchises	151,094	79,277	71,817	-	-	151,094	0.37%	7,271	-	86,547	64,546
Total Fixed Assets	16,014,680	6,512,585	9,502,095	867,776	193,625	16,688,831		736,036	(174,239)	7,074,383	9,614,449
Less:											
Capitalized Depreciation								8,729			
Total	**16,014,680**	**6,512,585**	**9,502,095**	**867,776**	**193,625**	**16,688,831**		**727,308**	**-174,239**	**7,074,383**	**9,614,449**

NATURAL RESOURCE GAS LIMITED

Summary of Depreciation Expense
2007 Actual
($'s)

	Actual 2007	Actual 2006
Fixed Assets		
Land	0	0
Buildings	15,148	15,148
Furniture & Fixtures	3,705	3,646
Computer Equipment	14,375	12,428
Computer Software	6,441	8,051
Machinery & Equipment	36,300	35,487
Communication Equipment	4,882	4,330
Automotive	77,299	74,039
Rental Equip - Residential	141,142	135,987
Rental Equip - Commercial	4,048	4,048
Rental Equip - Water Softeners	727	727
Meters	69,399	66,541
Regulators	44,105	43,506
Plastic Mains	223,210	210,132
Steel Mains	4,440	4,440
New Steel Mains	0	0
Plastic Services	83,547	82,342
Franchises	7,271	7,270
Total Fixed Assets	736,036	708,123
Less:		
Capitalized Depreciation	8,729	10,279
Total	727,308	697,844

	Variance from 2006
Fixed Assets	
Land	0
Buildings	0
Furniture & Fixtures	58
Computer Equipment	1,947
Computer Software	-1,610
Machinery & Equipment	813
Communication Equipment	552
Automotive	3,260
Rental Equip - Residential	5,154
Rental Equip - Commercial	0
Rental Equip - Water Softeners	0
Meters	2,858
Regulators	599
Plastic Mains	13,078
Steel Mains	0
New Steel Mains	0
Services - Plastic	1,205
Franchises	0
Total Fixed Assets	27,914
Less:	
Capitalized Depreciation	-1,550
Total	29,464

January-29-10
EB-2010-0018
Exhibit D4
Tab 4
Schedule 3

NATURAL RESOURCE GAS LIMITED

Capital Cost Allowance
2007 Actual
($'s)

Class	UCC at End of Fiscal 2006	Add: Cost of Additions	Adjustments	Deduct: Lesser of Cost and Proceeds from Disposal	UCC Before CCA	CCA Claimed: Rate (%)	Amount	UCC at End of Year
1	5,922,107	-	-	-	5,922,107	4%	236,884	5,685,223
2	551,127	-	-	-	551,127	6%	33,068	518,059
3	-	-	-	-	-	5%	0	0
6	5,171	-	-	-	5,171	10%	517	4,654
7	-	-	-	-	-	15%	0	0
8	690,369	237,721	-	16,325	911,765	20%	160,213	751,552
8	134,861	16,817	-	-	151,678	20%	28,654	123,024
10	160,799	45,196	-	3,780	202,215	30%	54,452	147,763
10.1	4,211	-	-	-	4,211	30%	1,263	2,948
49	628,919	549,772	-	-	1,178,691	8%	72,304	1,106,387
45	26,803	9,586	-	-	36,389	45%	14,218	22,171
12	14,977	-	-	-	14,977	100%	14,977	0
14	-	-	-	-	-	4%	0	0
50	-	8,684	-	-	8,684	55%	2,388	6,296
51	-	-	-	-	-	6%	0	0
17	38,773	-	-	-	38,773	8%	3,102	35,671
	8,178,117	867,776	-	20,105	9,025,788		622,040	8,403,748

NATURAL RESOURCE GAS LIMITED

Summary of Capital Cost Allowance
2007 Actual
($'s)

Class	Actual 2007	Actual 2006
1	236,884	246,755
2	33,068	35,178
3	-	-
6	517	575
7	-	-
8	160,213	147,612
8	28,654	29,502
10	54,452	61,272
10.1	1,263	4,618
49	72,304	37,395
45	14,218	12,991
12	14,977	21,415
14	-	-
50	2,388	-
51	-	-
17	3,102	3,372
Total	622,040	600,685

Class	Variance from 2006
1	(9,871)
2	(2,110)
3	-
6	(58)
7	-
8	12,601
8	(848)
10	(6,820)
10.1	(3,355)
45	1,227
12	(6,438)
14	-
17	(270)
Total	(15,942)

NATURAL RESOURCE GAS LIMITED

Property and Capital Taxes
2007 Actual
($'s)

Property Taxes	Actual 2007	Actual 2006
Prepaid Previous Year	-	-
Add Current Year Taxes	287,510	261,404
Less Prepaid Current Year	(1,330)	-
		-
Total Property Tax	286,180	261,404
		-
Provincial Capital Tax	37,900	10,818
		-
Federal Capital Tax	-	-
		-
Total Property & Capital Taxes	324,080	272,222

Property Taxes	Variance from 2006
Prepaid Previous Year	-
Add Current Year Taxes	26,106
Less Prepaid Current Year	(1,330)
Total Property Tax	24,776
Provincial Capital Tax	27,082
Federal Capital Tax	-
Total Property & Capital Taxes	51,858

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2007 Actual
($'s)

				Actual 2007	Normalized 2007	Actual 2006 (1)
Taxable Income						
Normalized Operating Revenue				4,330,495	4,324,729	4,168,238
Less:						
Gas Transportation Costs				394,141	394,141	411,228
Operation & Maintenance				1,986,694	1,986,694	2,141,069
Property & Capital Taxes				324,080	324,080	272,222
Subtotal				1,625,580	1,619,814	1,343,718
Add Back:						
Federal Capital Tax (non-deductible)				0	0	0
Meals & Ent. (non-deductible portion)				1,248	1,248	591
Subtotal				1,626,828	1,621,061	1,344,309
Deduct:						
Interest				573,398	573,393	603,723
Capital Cost Allowance				622,040	622,040	600,685
Normalized Taxable Income				431,390	425,628	139,901
Corporate Income Tax						
Federal Income Tax						
Tax on first	$400,000	@	11.63%	46,520	46,520	16,270
Clawback on	($6,344)	@	9.00%	-571	-571	-1,113
Tax on all over	$400,000	@	20.63%	6,476	5,287	0
Federal Surtax		@	0.28%	1,208	1,192	392
Total Federal Income Tax				53,633	52,428	15,549
Provincial Income Tax						
Tax on first	$400,000	@	5.50%	22,000	22,000	7,695
Clawback on nex	$728,519	@	4.67%	1,466	1,197	0
Tax on all over	$400,000	@	14.00%	4,395	3,588	0
Total Provincial Income Tax				27,861	26,785	7,695
Total Income Tax				81,494	79,213	23,244

(1) Income taxes based on tax rates in place during the year.

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2007 Actual
($'s)

				Variance from 2006
Taxable Income				
Normalized Operating Revenue				156,491
Less:				
Gas Transportation Costs				-17,087
Operation & Maintenance				-154,375
Property & Capital Taxes				51,858
Subtotal				276,095
Add Back:				
Federal Capital Tax (non-deductible)				0
Meals & Ent. (non-deductible portion)				657
Subtotal				276,752
Deduct:				
Interest				-30,330
Capital Cost Allowance				21,355
Normalized Taxable Income				285,727
Corporate Income Tax				
Federal Income Tax				
Tax on first	$400,000	@	11.63%	30,250
Clawback on	($6,344)	@	9.00%	542
Tax on all over	$400,000	@	20.63%	5,287
Federal Surtax		@	0.28%	800
Total Federal Income Tax				36,879
Provincial Income Tax				
Tax on first	$400,000	@	5.50%	14,305
Clawback on n	$728,519	@	4.67%	1,197
Tax on all over	$400,000	@	14.00%	3,588
Total Provincial Income Tax				19,090
Total Income Tax				55,969

NATURAL RESOURCE GAS LIMITED

Other Deferral and Variance Accounts
2007 Actual
($'s)

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Regulatory Expenses Deferral Account (REDA)													
Closing Account Balance	126	126	126	126	126	126	126	126	126	126	126	126	126
Interest rate	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%	
Interest	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Year-to-Date	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18	34.18
Total Balance	160	160	160	160	160	160	160	160	160	160	160	160	160
Opening Balance													
REDA	126.05												
Interest	34.18												

Gas Cost Difference Recovery Variance Account (GCDRVA) - Not applicable

System Gas Sales (m3)	20,941,477	Opening Account Balance	0.00
Rate ($/m3)	0.000000	Current Year Recovery Variance	-4,916.64
Recovery ($)	172,348.36	Closing Account Balance	-4,916.64
Approved Recovery	177,265.00	Interest on Opening Balance	0.00
Recovery Variance	-4,916.64	Accumulated Interest	0.00
		Total Account Balance	-4,916.64

NATURAL RESOURCE GAS LIMITED

Cost of Service
2007 OEB Approved
($'s)

	2007 OEB Approved	Adjust-ments	Adjusted OEB Approved
Gas Transportation Costs	448,437	0	448,437
Operation and Maintenance	2,145,582	0	2,145,582
Depreciation and Amortization	730,504	0	730,504
Property and Capital Taxes	334,437	0	334,437
Income Taxes	130,317	0	130,317
Total Cost of Service	3,789,278		3,789,278

NATURAL RESOURCE GAS LIMITED

Summary of Cost of Service
2007 OEB Approved
($'s)

	OEB Approved 2007	Historic Year 2007
Gas Transportation Costs	448,437	394,141
Operation and Maintenance	2,145,582	1,986,694
Depreciation and Amortization	730,504	727,308
Property and Capital Taxes	334,437	324,080
Income Taxes	130,317	81,494
Total Cost of Service	3,789,278	3,513,716

	Variance from Historic Year 2007
Gas Transportation Costs	54,296
Operation and Maintenance	158,889
Depreciation and Amortization	3,197
Property and Capital Taxes	10,357
Income Taxes	48,823
Total Cost of Service	275,561

NATURAL RESOURCE GAS LIMITED

Cost of Gas
2007 OEB Approved

Gas Commodity	Period Covered	M*3	$'s	$/M*3
Local Production - A (Affiliate)	Oct. 1/06 - Sept. 30/07	8,218,301	2,856,862	0.347622
Local Production - B	Oct. 1/06 - Sept. 30/07	253,193	88,016	0.347622
Firm Transportation	Oct. 1/06 - Sept. 30/07	3,915,560	1,380,849	0.352657
Parkway	Oct. 1/06 - Sept. 30/07	8,625,863	2,832,849	0.328413
Dawn	Oct. 1/06 - Sept. 30/07	0	0	0.000000
Ontario Delivered	Oct. 1/06 - Sept. 30/07	0	0	0.000000
Gas Inventory Revaluation			-24,338	
PGCVA - Fiscal 2007			2	
Total Gas Commodity Cost		21,012,917	7,134,239	0.339517
Gas Transportation				
Union Gas	Oct. 1/06 - Sept. 30/07		448,432	
PGTVA - Fiscal 2007			5	
Total Gas Transportation Cost		23,637,581	448,437	0.018971
Total Gas Commodity and Transportation Cost			7,582,677	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Commodity Variance Account Calculation
2007 OEB Approved

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Purchased (M*3)													
Local Production - A - Affiliat	605,482	527,787	568,330	567,415	559,064	814,227	768,851	658,812	449,906	588,416	1,026,041	1,083,971	8,218,301
Local Production - B	38,524	26,660	41,760	23,612	22,907	17,278	10,013	1,423	58	0	25,696	45,262	253,193
Firm Transportation	332,554	321,827	332,554	332,554	300,372	332,554	321,827	332,554	321,827	332,554	332,554	321,827	3,915,560
Parkway	732,608	708,975	732,608	732,608	661,710	732,608	708,975	732,608	708,975	732,608	732,608	708,975	8,625,863
Dawn	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,709,168	1,585,249	1,675,251	1,656,189	1,544,053	1,896,667	1,809,666	1,725,397	1,480,766	1,653,578	2,116,900	2,160,034	21,012,917
Commodity Cost													
Local Production - A - Affiliat	210,479	183,470	197,564	197,246	194,343	283,043	267,269	229,018	156,397	204,546	356,674	376,812	2,856,862
Local Production - B	13,392	9,268	14,517	8,208	7,963	6,006	3,481	495	20	0	8,933	15,734	88,016
Firm Transportation	116,588	112,826	116,588	117,510	106,138	117,510	113,720	117,510	113,720	117,510	117,510	113,720	1,380,849
Parkway	262,229	230,894	238,590	238,590	215,501	238,590	230,894	238,590	230,894	238,590	238,590	230,894	2,832,849
Dawn	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Commodity Cost	602,687	536,458	567,259	561,554	523,945	645,150	615,364	585,612	501,031	560,647	721,707	737,160	7,158,576
Average Cost ($/M*3)													
Reference Price	0.340675	0.340675	0.340675	0.340675	0.340675	0.340675	0.340675	0.340675	0.340675	0.340675	0.340675	0.340675	
Actual Price	0.352620	0.338406	0.338611	0.339064	0.339331	0.340149	0.340043	0.339407	0.338360	0.339051	0.340927	0.341272	
Rate Difference	(0.011945)	0.002269	0.002064	0.001611	0.001344	0.000526	0.000632	0.001268	0.002315	0.001624	(0.000252)	(0.000597)	
PGCVA Balance ($'s)													
PGCVA	-20,416.01	3,596.93	3,457.72	2,668.12	2,075.21	997.64	1,143.71	2,187.80	3,427.97	2,685.41	-533.45	-1,289.53	1.52
Year-to-Date (1)	1,859,260.06	1,862,856.99	1,866,314.71	1,868,982.83	1,871,058.03	1,872,055.67	1,873,199.38	1,875,387.18	1,878,815.16	1,881,500.57	1,880,967.12	1,879,677.59	1,879,677.59
Interest (5.50%)	8,615.18	8,521.61	8,538.09	8,553.94	8,566.17	8,575.68	8,580.26	8,585.50	8,595.52	8,611.24	8,623.54	8,621.10	
Year-to-Date (2)	102,940.01	111,461.62	119,999.71	128,553.65	137,119.82	145,695.50	154,275.76	162,861.26	171,456.78	180,068.02	188,691.56	197,312.66	197,312.66
Total Balance	1,962,200.07	1,974,318.61	1,986,314.42	1,997,536.48	2,008,177.85	2,017,751.17	2,027,475.14	2,038,248.44	2,050,271.94	2,061,568.59	2,069,658.68	2,076,990.25	2,076,990.25

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2007 OEB Approved

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Transported (M*3)													
Total Transported	1,625,687	2,552,188	3,425,953	3,683,724	3,409,506	2,874,151	1,949,026	1,048,939	541,121	397,724	818,297	1,239,825	23,566,141
Transportation Cost													
Union Gas - Demand	29,596	29,596	29,596	31,664	31,664	31,664	31,664	31,664	31,664	31,664	31,664	31,664	373,761
Union Gas - Delivery	4,064	8,271	11,658	16,855	15,410	11,132	6,377	2,118	497	-1,039	-1,272	603	74,674
Union Gas - Adjustments	0	0	0	0	0	0	0	0	0	0	0	-3	-3
Total Transportation Cost	33,660	37,866	41,253	48,519	47,074	42,796	38,041	33,782	32,161	30,625	30,392	32,264	448,432
Average Cost ($/M*3)													
Reference Price	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	
Actual Price	0.020705	0.014837	0.012041	0.013171	0.013807	0.014890	0.019518	0.032206	0.059433	0.077000	0.037140	0.026023	
Rate Difference	(0.001676)	0.004192	0.006988	0.005858	0.005222	0.004139	(0.000489)	(0.013177)	(0.040404)	(0.057971)	(0.018111)	(0.006994)	
PGTVA Balance ($'s)													
PGTVA	-2,724.65	10,698.77	23,940.56	21,579.26	17,804.44	11,896.11	-953.07	-13,821.87	-21,863.45	-23,056.46	-14,820.18	-8,671.34	5.12
Year-to-Date (1)	-2,724.65	7,974.12	31,914.68	53,493.94	71,298.38	83,194.49	82,241.41	68,419.54	46,556.09	23,499.63	8,679.46	8.12	8.12
Interest (5.50%)	0.00	-12.49	36.55	146.28	245.18	326.78	381.31	376.94	313.59	213.38	107.71	39.78	
Year-to-Date (2)	0.00	-12.49	24.06	170.34	415.52	742.30	1,123.61	1,500.55	1,814.14	2,027.52	2,135.23	2,175.01	2,175.01
Total Balance	-2,724.65	7,961.63	31,938.74	53,664.28	71,713.90	83,936.79	83,365.02	69,920.09	48,370.23	25,527.15	10,814.69	2,183.13	2,183.13

NATURAL RESOURCE GAS LIMITED

Operating and Maintenance Expense
2007 OEB Approved
($'s)

	OEB Approved 2007	Historic Year 2007	Variance from Historic Year 2007
Expense Category			
Wages	911,623	1,019,249	-107,626
Employee Benefits	132,997	113,602	19,395
Insurance	273,911	185,199	88,712
Utilities	16,428	14,541	1,887
Advertising	70,871	16,651	54,220
Telephone	33,758	54,070	-20,312
Office & Postage	90,657	108,098	-17,441
Repair & Maintenance	149,316	63,537	85,779
Automotive	99,551	60,309	39,242
Dues & Fees	23,256	18,082	5,174
Mapping Expense	0	403	-403
Regulatory	193,700	48,559	145,141
Bad Debts	15,828	0	15,828
Office Rent	9,600	9,600	0
Interest - Security Deposits	1,224	4,274	-3,050
Bank Charges	10,968	17,713	-6,745
Collection Expense	11,940	8,755	3,185
Travel & Ent.	7,464	14,609	-7,145
Legal	30,000	51,808	-21,808
Audit	35,700	15,500	20,200
Consulting Fees	42,840	129,454	-86,614
Management Fees (net)	90,576	89,750	826
Miscellaneous	8,136	0	8,136
Total O & M Expenses	2,260,344	2,043,764	216,580
Capitalized Expenses			
Wages	81,497	41,918	39,579
Equipment	33,265	15,152	18,113
Total Capitalized Expenses	114,762	57,071	57,692
Total Net Expenses	2,145,582	1,986,694	158,889
Average Number of Customers	6,793	6,551	242
Net Expense per Customer	315.85	303.28	12.57

NATURAL RESOURCE GAS LIMITED

Regulatory Expenses
2007 OEB Approved
($'s)

Category	Expense
Main Rates Case	131,700
QRAM	12,000
RRR	12,000
Miscellaneous	12,000
Sub-Total - Rate Case & Other Applications	167,700
Plus OEB Fixed Costs	26,000
Total Regulatory Costs	193,700

NATURAL RESOURCE GAS LIMITED

Depreciation Expense
2007 OEB Approved
($'s)

	Assets At Cost Oct 1/06	Acc. Dep. Oct 1/06	Net Book Value Oct 1/06	Additions F2007	Disposals F2007	Adjusted Cost Base	Dep'n Rate (1)	Depreciation Expense F2007	Adjustments Accumulated Depreciation F2007 (2)	Accumulated Depreciation Sept 30/07	Net Book Value Sept 30/07
Fixed Assets											
Land	71,700	0	71,700	0	0	71,700	0.00%	0	0	0	71,700
Buildings	687,331	91,953	595,378	5,000	0	692,331	2.22%	15,370	0	107,323	585,008
Furniture & Fixtures	58,189	28,397	29,792	5,000	0	63,189	6.75%	4,265	0	32,662	30,527
Computer Equipment	109,624	86,960	22,664	9,000	10,000	108,624	33.33%	7,221	-10,000	84,181	24,443
Computer Software	123,519	96,679	26,840	3,000	5,000	121,519	20.00%	4,968	-5,000	96,647	24,872
Machinery & Equipment	368,387	299,372	69,015	15,000	10,000	373,387	9.22%	34,426	-10,000	323,798	49,589
Communication Equipment	228,053	31,186	196,867	2,000	0	230,053	7.73%	17,783	0	48,969	181,084
Automotive	470,757	119,711	351,046	150,000	135,596	485,161	16.60%	80,537	-112,596	87,652	397,509
Rental Equip - Residential	1,820,278	701,956	1,118,322	178,773	80,000	1,919,051	7.40%	142,010	-75,000	768,966	1,150,085
Rental Equip - Commercial	57,410	18,326	39,084	4,555	4,000	57,965	7.40%	4,289	-4,000	18,615	39,350
Rental Equip - Water Softene	14,149	4,621	9,528	2,250	0	16,399	6.25%	1,025	0	5,646	10,753
Meters	1,848,145	745,697	1,102,449	85,558	0	1,933,704	3.62%	70,000	0	815,697	1,118,007
Regulators	1,154,315	608,028	546,287	43,029	0	1,197,344	3.67%	43,943	0	651,971	545,372
Plastic Mains	6,494,675	2,116,596	4,378,079	232,586	0	6,727,261	3.24%	217,963	0	2,334,560	4,392,701
Steel Mains	33,014	27,833	5,182	0	0	33,014	13.45%	4,440	0	32,273	742
Line Compressors	0	0	0	0	0	0	0.00%	0	0	0	0
Plastic Services	2,492,135	1,438,724	1,053,411	93,907	1,000	2,585,042	3.33%	86,082	-1,000	1,523,806	1,061,237
Franchises	151,094	79,277	71,817	0	0	151,094		7,270	0	86,547	64,546
Total Fixed Assets	16,182,775	6,495,315	9,687,460	829,658	245,596	16,766,837		741,593	-217,596	7,019,312	9,747,525
Less:											
Capitalized Depreciation								11,088			
Total	16,182,775	6,495,315	9,687,460	829,658	245,596	16,766,837		730,504	-217,596	7,019,312	9,747,525

(1) All depreciation rates are applied on a straight line basis, except declining balance basis for computer equipment and computer software and amortization of franchises
(2) Book value plus removal costs less salvage value.

NATURAL RESOURCE GAS LIMITED

Summary of Depreciation Expense
2007 OEB Approved
($'s)

	OEB Approved 2007	Historic Year 2007
Fixed Assets		
Land	0	0
Buildings	15,370	15,148
Furniture & Fixtures	4,265	3,705
Computer Equipment	7,221	14,375
Computer Software	4,968	6,441
Machinery & Equipment	34,426	36,300
Communication Equipment	17,783	4,882
Automotive	80,537	77,299
Rental Equip - Residential	142,010	141,142
Rental Equip - Commercial	4,289	4,048
Rental Equip - Water Softeners	1,025	727
Meters	70,000	69,399
Regulators	43,943	44,105
Plastic Mains	217,963	223,210
Steel Mains	4,440	4,440
Line Compressors	0	0
Plastic Services	86,082	83,547
Franchises	7,270	7,271
Total Fixed Assets	741,593	736,036
Less:		
Capitalized Depreciation	11,088	8,729
Total	730,504	727,308

	Variance from Historic Year 2007
Fixed Assets	
Land	0
Buildings	222
Furniture & Fixtures	560
Computer Equipment	-7,154
Computer Software	-1,473
Machinery & Equipment	-1,874
Communication Equipment	12,901
Automotive	3,238
Rental Equip - Residential	868
Rental Equip - Commercial	241
Rental Equip - Water Softeners	298
Meters	601
Regulators	-162
Plastic Mains	-5,247
Steel Mains	-0
Line Compressors	0
Services - Plastic	2,535
Franchises	-0
Total Fixed Assets	5,556
Less:	
Capitalized Depreciation	2,360
Total	3,197

NATURAL RESOURCE GAS LIMITED

Capital Cost Allowance
2007 OEB Approved
($'s)

		Add		Deduct		CCA Claimed		
Class	UCC at End of Fiscal 2006	Cost of Additions	Adjustments	Lesser of Cost and Proceeds from Disposal	UCC Before CCA	Rate (%)	Amount	UCC at End of Year
1	5,927,007	5,000	0	0	5,932,007	4%	237,180	5,694,827
2	551,127	0	0	0	551,127	6%	33,068	518,059
3	0	0	0	0	0	5%	0	0
6	5,171	0	0	0	5,171	10%	517	4,654
7	0	0	0	0	0	15%	0	0
8	670,871	185,578	0	0	856,449	20%	152,732	703,717
8	283,090	22,000	0	0	305,090	20%	58,818	246,272
10	158,538	150,000	0	19,000	289,538	30%	67,211	222,327
10.1	31,751	0	0	0	31,751	30%	9,525	22,226
49	678,182	455,080	0	0	1,133,262	8%	72,458	1,060,804
45	20,377	9,000	0	0	29,377	45%	11,195	18,182
12	11,000	3,000	0	0	14,000	100%	12,500	1,500
14	89,659	0	0	0	89,659	4%	3,586	86,073
17	38,773	0	0	0	38,773	8%	3,102	35,671
	8,465,545	829,658	0	19,000	9,276,203		661,892	8,614,311
							625975	

NATURAL RESOURCE GAS LIMITED

Summary of Capital Cost Allowance
2007 OEB Approved
($'s)

Class	OEB Approved 2007	Historic Year 2007
1	237,180	236,884
2	33,068	33,068
3	0	0
6	517	517
7	0	0
8	152,732	160,213
8	58,818	28,654
10	67,211	54,452
10.1	9,525	1,263
49	72,458	72,304
45	11,195	14,218
12	12,500	14,977
14	3,586	0
50		2,388
51		0
17	3,102	3,102
Total	661,892	622,040

Class	Variance from Historic Year 2007
1	296
2	0
3	0
6	0
7	0
8	-7,481
8	30,164
10	12,759
10.1	8,262
49	154
45	-3,023
12	-2,477
14	3,586
50	-2,388
51	0
17	0
Total	39,852

NATURAL RESOURCE GAS LIMITED

Property and Capital Taxes
2007 OEB Approved
($'s)

Property Taxes	OEB Approved 2007	Historic Year 2007
Prepaid Previous Year	78,282	0
Add Current Year Taxes	331,734	287,510
Less Prepaid Current Year	-75,579	-1,330
Total Property Tax	334,437	286,180
Provincial Capital Tax	0	37,900
Federal Capital Tax	0	0
Total Property & Capital Taxes	334,437	324,080

Property Taxes	Variance from Historic Year 2007
Prepaid Previous Year	78,282
Add Current Year Taxes	44,224
Less Prepaid Current Year	-74,249
Total Property Tax	48,257
Provincial Capital Tax	-37,900
Federal Capital Tax	0
Total Property & Capital Taxes	10,357

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2007 OEB Approved
($'s)

				OEB Approved 2007	Historic Year 2007
Taxable Income					(1)
Normalized Operating Revenue				4,570,085	4,330,495
Less:					
Gas Transportation Costs				448,437	394,141
Operation & Maintenance				2,145,582	1,986,694
Property & Capital Taxes				334,437	324,080
Subtotal				1,641,629	1,625,580
Add Back:					
Federal Capital Tax (non-deductible)				0	0
Meals & Ent. (non-deductible portion)				612	1,248
Subtotal				1,642,241	1,626,828
Deduct:					
Interest				484,938	573,398
Capital Cost Allowance				625,975	622,040
Normalized Taxable Income				531,328	431,390
Corporate Income Tax					
Federal Income Tax					
Tax on first	$374,795	@	12.00%	44,975	46,520
Tax on next	$0	@	21.00%	0	-571
Tax on all over	$374,795	@	21.00%	32,872	6,476
Federal Surtax		@	1.12%	5,951	1,208
Total Federal Income Tax				83,798	53,633
Provincial Income Tax					
Tax on first	$400,000	@	5.50%	22,000	22,000
Clawback on next	$728,519	@	4.67%	6,133	1,466
Tax on all over	$400,000	@	14.00%	18,386	4,395
Total Provincial Income Tax				46,519	27,861
Total Income Tax				130,317	81,494

(1) Income taxes based on tax rates in place during the year.

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2007 OEB Approved
($'s)

				Variance from Historic Year 2007
Taxable Income				
Normalized Operating Revenue				239,590
Less:				
Gas Transportation Costs				54,296
Operation & Maintenance				158,889
Property & Capital Taxes				10,357
Subtotal				16,049
Add Back:				
Federal Capital Tax (non-deductible)				0
Meals & Ent. (non-deductible portion)				-636
Subtotal				15,413
Deduct:				
Interest				-88,460
Capital Cost Allowance				39,852
Normalized Taxable Income				64,021
Corporate Income Tax				
Federal Income Tax				
Tax on first	$374,795	@	12.00%	-1,545
Tax on next	$0	@	21.00%	571
Tax on all over	$374,795	@	21.00%	18,853
Federal Surtax		@	1.12%	4,341
Total Federal Income Tax				22,220
Provincial Income Tax				
Tax on first	$400,000	@	5.50%	0
Clawback on n	$728,519	@	4.67%	2,990
Tax on all over	$400,000	@	14.00%	8,963
Total Provincial Income Tax				11,953
Total Income Tax				34,173

NATURAL RESOURCE GAS LIMITED

Other Deferral and Variance Accounts
2007 OEB Approved
($'s)

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Regulatory Expenses Deferral Account (REDA)													
Closing Account Balance	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00	126.00
Interest (6.00%)	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	7.56
Year-to-Date	34.81	35.44	36.07	36.70	37.33	37.96	38.59	39.22	39.85	40.48	41.11	41.74	41.74
Total Balance	160.81	161.44	162.07	162.70	163.33	163.96	164.59	165.22	165.85	166.48	167.11	167.74	167.74

Gas Cost Difference Recovery Variance Account (GCDRVA)

System Gas Sales (m3)	20,941,477	Opening Account Balance	0.00
Rate ($/m3)	0.008230	Current Year Recovery Variance	-4,916.64
Recovery ($)	172,348.36	Closing Account Balance	-4,916.64
Approved Recovery	177,265.00	Interest (6.00%) of Opening Balance	0.00
Recovery Variance	-4,916.64	Accumulated Interest	0.00
		Total Account Balance	-4,916.64

NATURAL RESOURCE GAS LIMITED

Cost of Service
2008 Actual and Normalized
($'s)

	Actual Forecast	Adjust-ments	Normalized Forecast
Gas Transportation Costs	422,897	0	422,897
Operation and Maintenance	2,139,440		2,139,440
Depreciation and Amortization	760,425		760,425
Property and Capital Taxes	355,812		355,812
Income Taxes	113,167	-19,026	94,141
Total Cost of Service	3,791,741		3,772,715

NATURAL RESOURCE GAS LIMITED

Summary of Cost of Service
2008 Actual
($'s)

	Actual 2008	Actual 2007
Gas Transportation Costs	422,897	394,141
Operation and Maintenance	2,139,440	1,986,694
Depreciation and Amortization	760,425	727,308
Property and Capital Taxes	355,812	324,080
Income Taxes	95,467	81,494
Total Cost of Service	3,774,041	3,513,716

	Variance from 2007
Gas Transportation Costs	28,756
Operation and Maintenance	152,746
Depreciation and Amortization	33,117
Property and Capital Taxes	31,732
Income Taxes	13,973
Total Cost of Service	260,325

NATURAL RESOURCE GAS LIMITED

Cost of Gas
2008 Actual

Gas Commodity	Period Covered	M*3	$'s	$/M*3
Local Production - A (Affiliate)	Oct. 1/07 - Sept. 30/08	6,679,010	2,011,718	0.301200
Local Production - B	Oct. 1/07 - Sept. 30/08	0	0	0.000000
Western (FT + Dawn)	Oct. 1/07 - Sept. 30/08	5,654,528	2,108,754	0.372932
Parkway	Oct. 1/07 - Sept. 30/08	6,871,630	2,602,368	0.378712
Ontario Delivered	Oct. 1/07 - Sept. 30/08	0	0	0.000000
GCDRA Transfer		0	27,261	
Gas Inventory Revaluation			23,813	
PGCVA - Fiscal 2008			515	
Total Gas Commodity Cost		19,810,022	14,322,505	0.722993

Gas Transportation				
Union Gas	Oct. 1/07 - Sept. 30/08		422,897	
PGTVA - Fiscal 2008			23,813	
Total Gas Transportation Cost		20,772,939	446,710	0.021504
Total Gas Commodity and Transportation Cost			14,769,216	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Commodity Variance Account Calculation
2008 Actual

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Purchased (M*3)													
Local Production - A - Affiliate	779,434	699,645	650,537	638,338	587,090	581,511	577,482	548,406	376,320	361,473	442,190	436,584	6,679,010
Local Production - B	0	0	0	0	0	0	0	0	0	0	0	0	0
Western (FT + Dawn)	481,063	463,934	479,399	477,745	446,923	477,745	461,930	477,328	465,992	479,920	478,708	463,841	5,654,528
Parkway	611,886	590,099	609,768	607,666	568,435	607,666	587,549	607,134	592,717	610,433	439,983	438,294	6,871,630
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,872,383	1,753,678	1,739,704	1,723,749	1,602,448	1,666,922	1,626,961	1,632,868	1,435,029	1,451,826	1,360,881	1,338,720	19,205,168
Commodity Cost													
Local Production - A - Affiliate	234,766	210,733	195,942	192,267	176,832	175,151	173,938	165,180	113,348	108,876	133,188	131,499	2,011,718
Local Production - B	0	0	0	0	0	0	0	0	0	0	0	0	0
Western (FT + Dawn)	126,876	144,820	155,422	155,131	147,762	164,936	178,373	206,428	205,793	219,318	207,779	196,116	2,108,754
Parkway	179,342	194,314	205,360	205,239	197,751	219,452	219,705	255,018	262,365	281,409	193,006	189,408	2,602,368
GCDRA Transfer	27,261	0	0	0	0	0	0	0	0	0	0	0	27,261
Total Commodity Cost	568,245	549,867	556,723	552,637	522,344	559,539	572,015	626,626	581,506	609,603	533,973	517,023	6,750,101
Average Cost ($/M*3)													
Reference Price	0.326729	0.326729	0.326729	0.305418	0.305418	0.305418	0.351880	0.351880	0.351880	0.438512	0.438512	0.438512	
Actual Price	0.303488	0.313551	0.320010	0.320602	0.325966	0.335672	0.351585	0.383758	0.405222	0.419887	0.392373	0.386207	
Rate Difference	0.023241	0.013178	0.006719	(0.015184)	(0.020548)	(0.030254)	0.000295	(0.031878)	(0.053342)	0.018625	0.046139	0.052305	
PGCVA Balance ($'s)													
PGCVA	43,516	23,110	11,689	-26,173	-32,927	-50,431	480	-52,053	-76,547	27,040	62,790	70,022	515
Year-to-Date	39,095	62,205	73,894	47,721	14,794	-35,637	-35,157	-87,210	-163,757	-136,717	-73,927	-3,905	-3,905
Interest	-19	167	266	317	204	50	-121	-120	-297	-557	-382	-206	
Year-to-Date	45,980	46,147	46,414	46,730	46,935	46,985	46,864	46,744	46,448	45,891	45,509	45,303	45,303
Total Balance	85,075	108,353	120,308	94,451	61,729	11,348	11,707	-40,465	-117,309	-90,826	-28,418	41,398	41,398
Interest Rate	5.14%	5.14%	5.14%	5.14%	4.08%	4.08%	4.08%	4.08%	4.08%	3.35%	3.35%	3.35%	

March 8, 2010
EB-2010-0018
Exhibit D5
Tab 2
Schedule 3
Updated

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2010 Bridge

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL	
Volumes Transported (M*3)														
Total Transported	4,200,421	5,495,640	5,889,430	6,054,447	5,680,824	5,264,359	4,148,521	3,442,985	3,113,594	3,105,060	3,198,773	3,481,994	53,076,048	
Transportation Cost														
Union Gas - Demand	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	561,028	
Union Gas - Delivery	22,108	21,771	22,006	22,002	21,324	22,004	21,778	22,004	21,778	22,004	22,004	21,778	262,561	
Union Gas - Adjustments	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-134	
Total Transportation Cost	68,849	68,512	68,747	68,744	68,065	68,746	68,519	68,746	68,519	68,746	68,746	68,519	823,456	
Average Cost ($/M*3)														
Reference Price	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029		
Actual Price	0.016391	0.012467	0.011673	0.011354	0.011982	0.013059	0.016516	0.019967	0.022006	0.022140	0.021491	0.019678		
Rate Difference	0.002638	0.006562	0.007356	0.007675	0.007047	0.005970	0.002513	(0.000938)	(0.002977)	(0.003111)	(0.002462)	(0.000649)		
PGTVA Balance ($'s)														Per T/B
PGTVA	-11,081	-36,062	-43,323	-46,468	-40,033	-31,428	-10,425	3,230	9,269	9,660	7,875	2,260	-186,526	-
Year-to-Date (1)	-209,892	-245,955	-289,277	-335,745	-375,778	-407,206	-417,631	-414,402	-405,133	-395,473	-387,597	-385,338	-385,338	
Interest	-96	-96	-113	-133	-154	-172	-187	-191	-190	-186	-181	-178	-1,876	
Year-to-Date (2)	-3,486	-3,582	-3,695	-3,827	-3,981	-4,153	-4,340	-4,531	-4,721	-4,907	-5,088	-5,266	-5,266	-
Total Balance	-213,378	-249,536	-292,972	-339,572	-379,759	-411,359	-421,971	-418,933	-409,854	-400,380	-392,686	-390,603	-390,603	
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%		

(1) Includes balance of (198,811.45) from Fiscal 2009 PGTVA. Assumes disposition of Fiscal 2009 balance based on 2010 deliveries.
(2) Includes balance of (3,389.51) from Fiscal 2009 PGTVA. Assumes disposition of Fiscal 2009 balance based on 2010 deliveries.

NATURAL RESOURCE GAS LIMITED

Operating and Maintenance Expense
2008 Actual
($'s)

	Actual 2008	Actual 2007	Variance from 2007
Expense Category			
Wages	1,014,410	1,019,249	-4,839
Employee Benefits	146,885	113,602	33,283
Insurance	180,659	185,199	-4,540
Utilities	13,879	14,541	-661
Advertising	42,939	16,651	26,288
Telephone	61,834	54,070	7,764
Office & Postage	111,403	108,098	3,305
Repair & Maintenance	126,395	63,537	62,858
Automotive	92,415	60,309	32,105
Dues & Fees	23,288	18,082	5,206
Mapping Expense	220	403	-183
Regulatory	4,345	48,559	-44,214
Bad Debts	37,239	0	37,239
Office Rent	9,600	9,600	0
Interest - Security Deposits	7,666	4,274	3,392
Bank Charges	17,078	17,713	-635
Collection Expense	13,338	8,755	4,583
Travel & Ent.	6,862	14,609	-7,747
Legal	8,190	51,808	-43,618
Audit	5,878	15,500	-9,622
Consulting Fees	117,547	129,454	-11,907
Management Fees (Net)	140,625	89,750	50,875
Miscellaneous	0	0	0
Total O & M Expenses	2,182,695	2,043,764	138,931
Capitalized Expenses			
Wages	31,820	41,918	-10,099
Equipment	11,436	15,152	-3,716
Total Capitalized Expenses	43,255	57,071	-13,815
Total Net Expenses	2,139,440	1,986,694	152,746
Average Number of Customers	6,713	6,551	163
Net Expense per Customer	318.69	303.28	15.41

NATURAL RESOURCE GAS LIMITED

Regulatory Expenses
2008 Test Year
($'s)

Category	Actual	Budget
Main Rates Case	0	0
QRAM	5,551	12,000
RRR	0	12,000
Miscellaneous	0	12,000
Sub-Total - Rate Case & Other Applications	5,551	36,000
Plus OEB Fixed Costs	15,062	26,000
Total Regulatory Costs	20,613	62,000

NATURAL RESOURCE GAS LIMITED

Depreciation Expense
2008 Actual
($'s)

	Assets At Cost Oct 1/07	Acc. Dep. Oct 1/07	Net Book Value Oct 1/07	Additions F2008	Disposals F2008	Adjusted Cost Base	Dep'n Rate	Depreciation Expense F2008	Adjustments Accumulated Depreciation F2008	Accumulated Depreciation Sept 30/08	Net Book Value Sept 30/08
Fixed Assets											
Land	71,700	-	71,700	-	-	71,700	0.00%	-	-	-	71,700
Buildings	682,331	106,989	575,341	-	-	682,331	2.22%	15,148	-	122,137	560,194
Furniture & Fixtures	54,884	31,820	23,064	242	-	55,127	6.75%	3,721	-	35,541	19,585
Computer Equipment	146,186	117,432	28,754	11,879	-	158,065	33.33%	13,543	-	130,975	27,090
Computer Software	136,472	110,710	25,762	8,575	-	145,047	20.00%	6,867	-	117,577	27,470
Machinery & Equipment	393,709	342,193	51,515	6,417	-	400,126	9.22%	36,892	-	379,085	21,041
Communication Equipment	63,155	22,769	40,385	56,133	-	119,288	7.73%	9,221	-	31,990	87,298
Automotive	465,655	180,192	285,463	-	-	465,655	16.60%	70,635	-	250,826	214,828
Rental Equip - Residential	1,907,319	680,946	1,226,373	245,961	86,246	2,067,034	7.40%	158,816	(106,940)	732,821	1,334,213
Rental Equip - Commercial	54,699	21,486	33,213	-	-	54,699	7.40%	4,048	-	25,534	29,165
Rental Equip - Water Softeners	11,627	5,190	6,437	-	-	11,627	6.25%	727	-	5,917	5,710
Meters	1,917,091	814,734	1,102,357	85,175	-	2,002,265	3.62%	72,482	-	887,216	1,115,050
Regulators	1,201,774	653,276	548,498	10,383	-	1,212,157	3.67%	44,486	-	697,763	514,394
Plastic Mains	6,889,197	2,347,112	4,542,085	346,658	-	7,235,855	3.24%	235,240	-	2,582,351	4,653,503
Steel Mains	33,014	32,274	740	-	-	33,014	13.45%	740	-	33,014	0
New Steel Mains	-	-	-	-	-	-	5.00%	-	-	-	-
Plastic Services	2,508,926	1,520,712	988,214	133,927	-	2,642,853	3.33%	87,184	-	1,607,896	1,034,957
IGPC	-	-	-		-	-		-	-	-	-
Franchises	151,094	86,547	64,546	-	-	151,094	0.37%	7,260	-	93,807	57,286
Total Fixed Assets	16,688,831	7,074,383	9,614,449	905,350	86,246	17,507,936		767,009	(106,940)	7,734,452	9,773,484
Less:											
Capitalized Depreciation								6,584			
Total	16,688,831	7,074,383	9,614,449	905,350	86,246	17,507,936		760,425	-106,940	7,734,452	9,773,484

NATURAL RESOURCE GAS LIMITED

Summary of Depreciation Expense
2008 Actual
($'s)

	Actual 2008	Actual 2007
Fixed Assets		
Land	0	0
Buildings	15,148	15,148
Furniture & Fixtures	3,721	3,705
Computer Equipment	13,543	14,375
Computer Software	6,867	6,441
Machinery & Equipment	36,892	36,300
Communication Equipment	9,221	4,882
Automotive	70,635	77,299
Rental Equip - Residential	158,816	141,142
Rental Equip - Commercial	4,048	4,048
Rental Equip - Water Softeners	727	727
Meters	72,482	69,399
Regulators	44,486	44,105
Plastic Mains	235,240	223,210
Steel Mains	740	4,440
New Steel Mains	0	0
Plastic Services	87,184	83,547
Franchises	7,260	7,271
Total Fixed Assets	767,009	736,036
Less:		
Capitalized Depreciation	6,584	8,729
Total	760,425	727,308

	Variance from 2007
Fixed Assets	
Land	0
Buildings	0
Furniture & Fixtures	16
Computer Equipment	-832
Computer Software	427
Machinery & Equipment	592
Communication Equipment	4,339
Automotive	-6,664
Rental Equip - Residential	17,674
Rental Equip - Commercial	0
Rental Equip - Water Softeners	0
Meters	3,083
Regulators	381
Plastic Mains	12,030
Steel Mains	-3,700
New Steel Mains	0
Services - Plastic	3,637
Franchises	-11
Total Fixed Assets	30,973
Less:	
Capitalized Depreciation	-2,145
Total	33,117

NATURAL RESOURCE GAS LIMITED

Capital Cost Allowance
2008 Actual
($'s)

		Add		Deduct		CCA Claimed		
Class	UCC at End of Fiscal 2007	Cost of Additions	Adjustments	Lesser of Cost and Proceeds from Disposal	UCC Before CCA	Rate (%)	Amount	UCC at End of Year
1	5,685,223	-	-	-	5,685,223	4%	227,409	5,457,814
2	518,059	-	-	-	518,059	6%	31,084	486,975
3	-	-	-	-	-	5%	0	0
6	4,654	-	-	-	4,654	10%	465	4,189
7	-	-	-	-	-	15%	0	0
8	751,552	245,962	20,694	-	1,018,208	20%	179,045	839,163
8	123,024	35,527	-	-	158,551	20%	28,157	130,394
10	147,763	-	-	-	147,763	30%	44,329	103,434
10.1	2,948	-	-	-	2,948	30%	884	2,064
49	1,106,387	-	-	-	1,106,387	8%	88,511	1,017,876
45	22,171	-	-	-	22,171	45%	9,977	12,194
12	-	8,575	-	-	8,575	100%	4,287	4,288
14	-	-	-	-	-	4%	0	0
50	6,296	39,144	-	-	45,440	55%	14,227	31,213
51	-	576,143	-	-	576,143	6%	17,284	558,859
17	35,671	-	-	-	35,671	8%	2,854	32,817
	8,403,748	905,351	20,694	-	9,329,793		648,513	8,681,280

NATURAL RESOURCE GAS LIMITED

Summary of Capital Cost Allowance
2008 Actual
($'s)

Class	Actual 2008	Actual 2007
1	227,409	236,884
2	31,084	33,068
3	-	-
6	465	517
7	-	-
8	179,045	160,213
8	28,157	28,654
10	44,329	54,452
10.1	884	1,263
49	88,511	72,304
45	9,977	14,218
12	4,287	14,977
14	-	-
50	14,227	2,388
51	17,284	-
17	2,854	3,102
Total	648,513	622,040

Class	Variance from 2007
1	(9,475)
2	(1,984)
3	-
6	(52)
7	-
8	18,832
8	(497)
10	(10,123)
10	(379)
45	(4,241)
12	(10,690)
14	-
17	(248)
Total	(18,857)

NATURAL RESOURCE GAS LIMITED

Property and Capital Taxes
2008 Actual
($'s)

Property Taxes	Actual 2008	Actual 2007
Prepaid Previous Year	1,330	-
Add Current Year Taxes	329,073	287,510
Less Prepaid Current Year	4,209	(1,330)
Total Property Tax	334,612	286,180
Provincial Capital Tax	21,200	37,900
Federal Capital Tax	-	-
Total Property & Capital Taxes	355,812	324,080

Property Taxes	Variance from 2007
Prepaid Previous Year	1,330
Add Current Year Taxes	41,563
Less Prepaid Current Year	5,539
Total Property Tax	48,432
Provincial Capital Tax	(16,700)
Federal Capital Tax	-
Total Property & Capital Taxes	31,732

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2008 Normalized
($'s)

				Actual 2008	Normalized 2008	Actual 2007
Taxable Income						
Operating Revenue				4,489,462	4,441,396	4,324,729
Less:						
Gas Transportation Costs				422,897	422,897	394,141
Operation & Maintenance				2,139,440	2,139,440	1,986,694
Property & Capital Taxes				355,812	355,812	324,080
Subtotal				1,571,313	1,523,247	1,619,814
Add Back:						
Federal Capital Tax (non-deductible)				0	0	0
Meals & Ent. (non-deductible portion)				694	694	1,248
Subtotal				1,572,007	1,523,941	1,621,061
Deduct:						
Interest				458,241	413,525	573,398
Capital Cost Allowance				648,513	648,513	622,040
Taxable Income				465,253	461,903	425,623
Corporate Income Tax						
Federal Income Tax						
Tax on first	$400,000	@	11.63%	46,520	46,520	46,520
Clawback on	$0	@	9.00%	0	0	-571
Tax on all over	$400,000	@	20.63%	13,462	12,771	6,476
Federal Surtax		@	0.28%	1,303	1,293	1,208
Total Federal Income Tax				61,285	60,584	53,633
Provincial Income Tax						
Tax on first	$400,000	@	5.50%	22,000	22,000	22,000
Clawback on next	$728,519	@	4.67%	3,047	2,891	1,466
Tax on all over	$400,000	@	14.00%	9,135	8,666	4,395
Total Provincial Income Tax				34,182	33,557	27,861
Total Income Tax				95,467	94,141	81,494

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2008 Actual
($'s)

				Variance from 2007
Taxable Income				
Normalized Operating Revenue				158,967
Less:				
Gas Transportation Costs				28,756
Operation & Maintenance				152,746
Property & Capital Taxes				31,732
Subtotal				-54,267
Add Back:				
Federal Capital Tax (non-deductible)				0
Meals & Ent. (non-deductible portion)				-553
Subtotal				-54,820
Deduct:				
Interest				-115,157
Capital Cost Allowance				26,473
Normalized Taxable Income				33,864
Corporate Income Tax				
Federal Income Tax				
Tax on first	$400,000	@	11.63%	0
Clawback on	$0	@	9.00%	571
Tax on all over	$400,000	@	20.63%	6,986
Federal Surtax		@	0.28%	95
Total Federal Income Tax				7,652
Provincial Income Tax				
Tax on first	$400,000	@	5.50%	0
Clawback on n	$728,519	@	4.67%	1,581
Tax on all over	$400,000	@	14.00%	4,740
Total Provincial Income Tax				6,321
Total Income Tax				13,973

NATURAL RESOURCE GAS LIMITED

Other Deferral and Variance Accounts
2008 Actual
($'s)

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Regulatory Expenses Deferral Account (REDA)													
Closing Account Balance	126	126	126	126	126	126	126	126	126	5,505	36,994	71,675	71,675
Interest rate	5.14%	5.14%	5.14%	5.14%	4.08%	4.08%	4.08%	4.08%	4.08%	3.35%	3.35%	3.35%	
Interest	0.54	0.54	0.54	0.54	0.43	0.43	0.43	0.43	0.43	0.35	15.37	103.27	123.30
Year-to-Date	34.72	35.26	35.80	36.34	36.77	37.20	37.63	38.05	38.48	38.83	54.20	157.48	157.48
Total Balance	161	161	162	162	163	163	164	164	165	5,544	37,048	71,832	71,832
Opening Balance													
REDA	126.05												
Interest	34.18												

Gas Cost Difference Recovery Variance Account (GCDRVA) - Not applicable

System Gas Sales (m3)	20,032,007	Opening Account Balance	0.00
Rate ($/m3)	0.000000	Current Year Recovery Variance	-12,401.58
Recovery ($)	164,863.42	Closing Account Balance	-12,401.58
Approved Recovery	177,265.00	Interest on Opening Balance	0.00
Recovery Variance	-12,401.58	Accumulated Interest	0.00
		Total Account Balance	-12,401.58

NATURAL RESOURCE GAS LIMITED

Cost of Service
2009 Actual
($'s)

	Forecast	Adjust-ments	Note	Adjusted Forecast
Gas Transportation Costs	799,742	-	(1)	799,742
Operation and Maintenance	2,121,131	-		2,121,131
Depreciation and Amortization	1,105,062	-		1,105,062
Property and Capital Taxes	426,584	-		426,584
Income Taxes	296,407	-197	(2)	307,427
Total Cost of Service	4,748,926			4,759,946

Notes:
(1) Based on Union Gas M9 delivery commodity charge
(2) See Exhibit D6, Tab 6, Schedule 1

NATURAL RESOURCE GAS LIMITED

Summary of Cost of Service
2009 Actual
($'s)

	Actual 2009	Actual 2008
Gas Transportation Costs	799,742	422,897
Operation and Maintenance	2,121,131	2,139,440
Depreciation and Amortization	1,105,062	760,425
Property and Capital Taxes	426,584	355,812
Income Taxes	307,427	95,467
Total Cost of Service	4,759,946	3,774,041

	Variance from 2008
Gas Transportation Costs	376,844
Operation and Maintenance	-18,309
Depreciation and Amortization	344,637
Property and Capital Taxes	70,772
Income Taxes	211,960
Total Cost of Service	985,905

NATURAL RESOURCE GAS LIMITED

Cost of Gas
2009 Actual

Gas Commodity	Period Covered	M*3	$'s	$/M*3
Local Production - A (Affiliate)	Oct. 1/08 - Sept. 30/09	6,679,010	2,011,718	0.301200
Local Production - B	Oct. 1/08 - Sept. 30/09	0	0	0.000000
Western (FT + Dawn)	Oct. 1/08 - Sept. 30/09	5,654,528	2,108,754	0.372932
Parkway	Oct. 1/08 - Sept. 30/09	6,871,630	2,602,368	0.378712
Dawn	Oct. 1/08 - Sept. 30/09			0.000000
Ontario Delivered	Oct. 1/08 - Sept. 30/09	0	0	0.000000
GCDRA Transfer		0	27,261	
Gas Inventory Revaluation			301,010	
PGCVA - Fiscal 2008			-272,377	
Total Gas Commodity Cost		19,205,168	6,778,733	0.352964

Gas Transportation				
Union Gas	Oct. 1/08 - Sept. 30/09		799,742	
PGTVA - Fiscal 2009			198,811	
Total Gas Transportation Cost		20,772,939	998,553	0.048070
Total Gas Commodity and Transportation Cost			7,777,287	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Commodity Variance Account Calculation
2009Actual

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Purchased (M*3)													
Local Production - A - Affiliate	779,434	699,645	650,537	638,338	587,090	581,511	577,482	548,406	376,320	361,473	442,190	436,584	6,679,010
Local Production - B	0	0	0	0	0	0	0	0	0	0	0	0	0
Western (FT + Dawn)	481,063	463,934	479,399	477,745	446,923	477,745	461,930	477,328	465,992	479,920	478,708	463,841	5,654,528
Parkway	611,886	590,099	609,768	607,666	568,435	607,666	587,549	607,134	592,717	610,433	439,983	438,294	6,871,630
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,872,383	1,753,678	1,739,704	1,723,749	1,602,448	1,666,922	1,626,961	1,632,868	1,435,029	1,451,826	1,360,881	1,338,720	19,205,168
Commodity Cost													
Local Production - A - Affiliate	234,766	210,733	195,942	192,267	176,832	175,151	173,938	165,180	113,348	108,876	133,188	131,499	2,011,718
Local Production - B	0	0	0	0	0	0	0	0	0	0	0	0	0
Western (FT + Dawn)	126,876	144,820	155,422	155,131	147,762	164,936	178,373	206,428	205,793	219,318	207,779	196,116	2,108,754
Parkway	179,342	194,314	205,360	205,239	197,751	219,452	219,705	255,018	262,365	281,409	193,006	189,408	2,602,368
GCDRA Transfer	27,261	0	0	0	0	0	0	0	0	0	0	0	27,261
Total Commodity Cost	568,245	549,867	556,723	552,637	522,344	559,539	572,015	626,626	581,506	609,603	533,973	517,023	6,750,101
Average Cost ($/M*3)													
Reference Price	0.373181	0.373181	0.373181	0.347919	0.347919	0.347919	0.315331	0.315331	0.315331	0.302953	0.302953	0.302953	
Actual Price	0.303488	0.313551	0.320010	0.320602	0.325966	0.335672	0.351585	0.383758	0.405222	0.419887	0.392373	0.386207	
Rate Difference	0.069693	0.059630	0.053171	0.027317	0.021953	0.012247	(0.036254)	(0.068427)	(0.089891)	(0.116934)	(0.089420)	(0.083254)	
PGCVA Balance ($'s)													
PGCVA	130,492	104,572	92,502	47,088	35,179	20,415	-58,984	-111,732	-128,996	-169,768	-121,690	-111,454	-272,377
Year-to-Date	125,521	230,093	322,595	369,683	404,861	425,276	366,292	254,560	125,564	-44,204	-165,894	-277,348	-277,348
Interest	-14	350	642	901	755	827	868	305	212	105	-18	-76	
Year-to-Date	46,276	46,626	47,269	48,169	48,924	49,751	50,619	50,924	51,136	51,241	51,222	51,146	51,146
Total Balance	171,797	276,719	369,864	417,852	453,785	475,026	416,911	305,484	176,700	7,037	-114,672	-226,202	-226,202
Interest Rate	3.35%	3.35%	3.35%	2.45%	2.45%	2.45%	1.00%	1.00%	1.00%	0.50%	0.55%	0.55%	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2009 Actual

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Transported (M*3)													
Total Transported	1,410,010	2,380,290	2,954,819	3,231,555	3,306,417	2,928,631	1,355,278	909,244	479,521	413,093	610,230	793,851	20,772,939
Transportation Cost													
Union Gas - Demand	28,729	28,729	28,729	28,833	28,833	28,833	28,227	28,227	28,227	46,394	46,394	46,394	396,549
Union Gas - Delivery	3,384	9,020	12,367	13,944	14,623	12,620	4,186	2,175	321	405	904	3,268	77,217
Union Gas - Adjustments	-409	-1,089	-1,493	-29,172	-1,621	-1,399	-349	-1,928	-27	-13,382	-0	-1	-50,868
Total Transportation Cost	31,704	36,660	39,603	13,605	41,835	40,054	32,065	28,474	28,522	33,417	47,298	49,662	422,897
Average Cost ($/M*3)													
Reference Price	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	
Actual Price	0.022485	0.015401	0.013403	0.004210	0.012653	0.013677	0.023659	0.031317	0.059479	0.080895	0.077508	0.062558	
Rate Difference	(0.003456)	0.003628	0.005626	0.014819	0.006376	0.005352	(0.004630)	(0.012288)	(0.040450)	(0.061866)	(0.058479)	(0.043529)	
PGTVA Balance ($'s)													
PGTVA	4,873	-8,636	-16,624	-47,888	-21,082	-15,674	6,275	11,173	19,397	25,556	35,686	34,556	27,611
Year-to-Date (1)	-23,492	-32,128	-48,752	-96,640	-117,722	-133,396	-127,121	-115,948	-96,552	-70,995	-35,310	-754	-754
Interest	-122	-101	-138	-209	-414	-400	-454	-432	-394	-328	-198	-99	
Year-to-Date (2)	-2,207	-2,307	-2,445	-2,654	-3,068	-3,468	-3,921	-4,354	-4,748	-5,076	-5,274	-5,373	-5,373
Total Balance	-25,699	-34,435	-51,197	-99,294	-120,790	-136,864	-131,043	-120,302	-101,300	-76,072	-40,584	-6,127	-6,127
Interest Rate	5.14%	5.14%	5.14%	5.14%	4.08%	4.08%	4.08%	4.08%	4.08%	3.35%	3.35%	3.35%	

NATURAL RESOURCE GAS LIMITED

Operating and Maintenance Expense
2009 Actual
($'s)

Expense Category	Actual 2009	Actual 2008	Variance from 2008
Wages	963,348	1,014,410	-51,062
Employee Benefits	148,883	146,885	1,999
Insurance	197,396	180,659	16,737
Utilities	12,658	13,879	-1,221
Advertising	38,263	42,939	-4,676
Telephone	59,776	61,834	-2,058
Office & Postage	115,429	111,403	4,025
Repair & Maintenance	110,269	126,395	-16,126
Automotive	69,528	92,415	-22,887
Dues & Fees	19,424	23,288	-3,864
Mapping Expense	1,013	220	793
Regulatory	32,211	4,345	27,866
Bad Debts	51,982	37,239	14,743
Office Rent	0	9,600	-9,600
Interest - Security Deposits	5,843	7,666	-1,823
Bank Charges	16,618	17,078	-460
Collection Expense	14,308	13,338	969
Travel & Ent.	3,371	6,862	-3,491
Legal	47,472	8,190	39,282
Audit	15,577	5,878	9,700
Consulting Fees	38,832	117,547	-78,715
Management Fees (Net)	216,250	140,625	75,625
Miscellaneous		0	0
Total O & M Expenses	2,178,451	2,182,695	-4,244
Capitalized Expenses			
Wages	39,365	31,820	7,546
Equipment	17,956	11,436	6,520
Total Capitalized Expenses	57,321	43,255	14,066
Total Net Expenses	2,121,130	2,139,440	-18,309
Average Number of Customers	6,869	6,713	156
Net Expense per Customer	308.79	318.69	-9.90

NATURAL RESOURCE GAS LIMITED

Regulatory Expenses
2009 Historic Year
($'s)

Category	Actual	Budget
Main Rates Case	0	0
QRAM	5,551	12,000
RRR	0	12,000
Miscellaneous	0	12,000
Sub-Total - Rate Case & Other Applications	5,551	36,000
Plus OEB Fixed Costs	15,062	26,000
Total Regulatory Costs	20,613	62,000

NATURAL RESOURCE GAS LIMITED

Depreciation Expense
2009 Actual
($'s)

	Assets At Cost Oct 1/08	Acc. Dep. Oct 1/08	Net Book Value Oct 1/08	Additions F2009	Disposals F2009	Adjusted Cost Base	Dep'n Rate	Depreciation Expense F2009	Adjustments Accumulated Depreciation F2009	Accumulated Depreciation Sept 30/09	Net Book Value Sept 30/09
Fixed Assets							(1)		(2)		
Land	71,700	-	71,700	-	-	71,700	0.00%	-	-	-	71,700
Buildings	682,331	122,137	560,194	-	-	682,331	2.22%	15,148	-	137,285	545,046
Furniture & Fixtures	55,127	35,541	19,585	14,050	-	69,176	6.75%	4,669	-	40,211	28,965
Computer Equipment	158,065	130,975	27,090	3,348	-	161,413	33.33%	10,145	-	141,120	20,293
Computer Software	145,047	117,577	27,470	30,607	-	175,654	20.00%	11,615	-	129,193	46,462
Machinery & Equipment	400,126	379,085	21,041	56,706	-	456,832	9.22%	42,120	-	421,205	35,627
Communication Equipment	119,288	31,990	87,298	21,128	-	140,415	7.73%	10,854	-	42,844	97,571
Automotive	465,655	250,826	214,828	55,828	-	521,483	16.60%	86,566	-	337,393	184,090
Rental Equip - Residential	2,067,035	732,822	1,334,213	222,983	116,644	2,173,374	7.40%	160,830	(136,309)	757,342	1,416,032
Rental Equip - Commercial	54,699	25,534	29,165	-	-	54,699	7.40%	4,048	-	29,582	25,117
Rental Equip - Water Softener	11,627	5,917	5,710	-	-	11,627	6.25%	727	-	6,643	4,983
Meters	2,002,265	887,216	1,115,050	48,590	-	2,050,856	3.62%	74,241	-	961,457	1,089,399
Regulators	1,212,157	697,763	514,394	11,761	-	1,223,918	3.67%	44,918	-	742,680	481,238
Plastic Mains	7,235,855	2,582,351	4,653,503	76,028	-	7,311,883	3.24%	236,905	-	2,819,256	4,492,627
Steel Mains	33,014	33,014	0	-	-	33,014	13.45%	0	-	33,014	-
New Steel Mains	-	-	-	5,073,000	-	5,073,000	5.00%	253,650	-	253,650	4,819,350
Plastic Services	2,642,853	1,607,896	1,034,957	76,958	-	2,719,811	3.33%	90,570	-	1,698,466	1,021,345
IGPC	-	-	-		-		5.00% -		-	-	-
Franchises	151,094	93,807	57,286	261,963	-	413,057	0.39%	65,474	-	159,281	253,775
Total Fixed Assets	17,507,936	7,734,452	9,773,484	5,952,950	116,644	23,344,242		1,112,479	(136,309)	8,710,622	14,633,620
Less:											
Capitalized Depreciation								7,418			
Total	**17,507,936**	**7,734,452**	**9,773,484**	**5,952,950**	**116,644**	**23,344,242**		**1,105,062**	**-136,309**	**8,710,622**	**14,633,620**

NATURAL RESOURCE GAS LIMITED
Summary of Depreciation Expense
2009 Actual
($'s)

	Actual 2009	Actual 2008
Fixed Assets		
Land	0	0
Buildings	15,148	15,148
Furniture & Fixtures	4,669	3,721
Computer Equipment	10,145	13,543
Computer Software	11,615	6,867
Machinery & Equipment	42,120	36,892
Communication Equipment	10,854	9,221
Automotive	86,566	70,635
Rental Equip - Residential	160,830	158,816
Rental Equip - Commercial	4,048	4,048
Rental Equip - Water Softeners	727	727
Meters	74,241	72,482
Regulators	44,918	44,486
Plastic Mains	236,905	235,240
Steel Mains	0	740
New Steel Mains	253,650	0
Plastic Services	90,570	87,184
Franchises	65,474	7,260
Total Fixed Assets	1,112,479	767,009
Less:		
Capitalized Depreciation	7,418	6,584
Total	1,105,062	760,425

	Variance from 2008
Fixed Assets	
Land	0
Buildings	0
Furniture & Fixtures	948
Computer Equipment	-3,398
Computer Software	4,748
Machinery & Equipment	5,228
Communication Equipment	1,633
Automotive	15,931
Rental Equip - Residential	2,014
Rental Equip - Commercial	-0
Rental Equip - Water Softeners	-0
Meters	1,759
Regulators	431
Plastic Mains	1,665
Steel Mains	-740
New Steel Mains	253,650
Services - Plastic	3,386
Franchises	58,214
Total Fixed Assets	345,470
Less:	
Capitalized Depreciation	834
Total	344,637

NATURAL RESOURCE GAS LIMITED

Capital Cost Allowance
2009 Actual
($'s)

Class	UCC at End of Fiscal 2008	Add: Cost of Additions	Adjustments	Deduct: Lesser of Cost and Proceeds from Disposal	UCC Before CCA	CCA Claimed: Rate (%)	Amount	UCC at End of Year
1	5,457,814	-	-	-	5,457,814	4%	222,580	5,235,234
2	486,975	4,514,141	-	-	5,001,116	6%	164,643	4,836,473
3	-	-	-	-	-	5%	0	0
6	4,189	-	-	-	4,189	10%	419	3,770
7	-	-	-	-	-	15%	0	0
8	839,163	222,983	116,644	-	1,178,791	20%	213,460	965,331
8	130,394	91,883	-	-	222,277	20%	35,267	187,010
10	103,434	55,828	-	-	159,262	30%	39,404	119,858
10.1	2,064	-	-	-	2,064	30%	619	1,445
49	1,017,876	213,338	-	-	1,231,214	8%	89,964	1,141,250
45	12,194	-	-	-	12,194	45%	5,487	6,707
12	4,288	30,607	-	-	34,895	100%	19,591	15,304
14	-	-	-	-	-	4%	0	0
50	31,213	3,348	-	-	34,561	55%	18,088	16,473
51	558,859	4,514,141	-	-	5,073,000	6%	168,956	4,904,044
17	32,817	-	-	-	32,817	8%	2,625	30,192
	8,681,280	9,646,269	116,644	-	18,444,194		981,103	17,463,091

NATURAL RESOURCE GAS LIMITED

Summary of Capital Cost Allowance
2009 Actual
($'s)

Class	Actual 2009	Actual 2008
1	222,580	227,409
2	164,643	31,084
3	-	-
6	419	465
7	-	-
8	213,460	179,045
8	35,267	28,157
10	39,404	44,329
10.1	619	884
49	89,964	88,511
45	5,487	9,977
12	19,591	4,287
14	-	-
50	18,088	14,227
51	168,956	17,284
17	2,625	2,854
Total	981,103	648,513

Class	Variance from 2008
1	(4,829)
2	133,559
3	-
6	(46)
7	-
8	34,415
8	7,110
10	(4,925)
10.1	(265)
45	(4,490)
12	15,304
14	-
17	(229)
Total	175,604

NATURAL RESOURCE GAS LIMITED

Property and Capital Taxes
2009 Actual
($'s)

Property Taxes	Actual 2009	Actual 2008
Prepaid Previous Year	(4,209)	1,330
Add Current Year Taxes	320,852	329,073
Less Prepaid Current Year	(73,761)	(4,209)
Total Property Tax	390,404	334,612
Provincial Capital Tax	36,180	21,200
Federal Capital Tax	-	-
Total Property & Capital Taxes	426,584	355,812

Property Taxes	Variance from 2008
Prepaid Previous Year	(5,539)
Add Current Year Taxes	(8,221)
Less Prepaid Current Year	(69,552)
Total Property Tax	55,792
Provincial Capital Tax	14,980
Federal Capital Tax	-
Total Property & Capital Taxes	70,772

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2009 Actual
($'s)

				Actual 2009	Adjusted Actual 2009	Adjusted Actual 2008
Taxable Income						(1)
Normalized Operating Revenue				5,926,685	5,926,685	4,489,462
Less:						
Gas Transportation Costs				799,742	799,742	422,897
Operation & Maintenance				2,121,130	2,121,130	2,139,440
Property & Capital Taxes				426,584	426,584	355,812
Subtotal				2,579,229	2,579,229	1,571,313
Add Back:						
Federal Capital Tax (non-deductible)				0	0	0
Meals & Ent. (non-deductible portion)				497	0	694
Subtotal				2,579,727	2,579,229	1,572,007
Deduct:						
Interest				667,670	667,670	458,241
Capital Cost Allowance				981,103	981,103	648,513
Normalized Taxable Income				930,954	930,456	465,253
Corporate Income Tax						
Federal Income Tax						
Tax on first	$500,000	@	11.63%	58,150	58,150	46,520
Clawback on	$430,954	@	9.00%	38,786	38,786	0
Tax on all over	$500,000	@	20.63%	88,906	88,803	13,462
Federal Surtax		@	0.28%	2,607	2,605	1,303
Total Federal Income Tax				188,449	188,344	61,285
Provincial Income Tax						
Tax on first	$500,000	@	5.50%	27,500	27,500	22,000
Clawback on next	$430,954	@	4.67%	20,126	20,102	3,047
Tax on all over	$500,000	@	14.00%	60,333	60,264	9,135
Total Provincial Income Tax				107,959	107,866	34,182
Total Income Tax				296,408	296,210	95,467

(1) Income taxes based on tax rates in place during the year.

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
Actual 2009
($'s)

				Variance from 2009
Taxable Income				
Normalized Operating Revenue				1,437,223
Less:				
Gas Transportation Costs				376,844
Operation & Maintenance				-18,310
Property & Capital Taxes				70,772
Subtotal				1,007,916
Add Back:				
Federal Capital Tax (non-deductible)				0
Meals & Ent. (non-deductible portion)				-694
Subtotal				1,007,222
Deduct:				
Interest				209,429
Capital Cost Allowance				332,590
Normalized Taxable Income				465,203
Corporate Income Tax				
Federal Income Tax				
Tax on first	$500,000	@	11.63%	11,630
Clawback on	$430,954	@	9.00%	38,786
Tax on all over	$500,000	@	20.63%	75,341
Federal Surtax		@	0.28%	1,302
Total Federal Income Tax				127,059
Provincial Income Tax				
Tax on first	$500,000	@	5.50%	5,500
Clawback on n	$430,954	@	4.67%	17,055
Tax on all over	$500,000	@	14.00%	51,129
Total Provincial Income Tax				73,684
Total Income Tax				200,743

NATURAL RESOURCE GAS LIMITED

Other Deferral and Variance Accounts
2009 Actual
($'s)

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Regulatory Expenses Deferral Account (REDA)													
Closing Account Balance	79,267	99,716	148,199	163,478	248,644	318,639	352,380	352,636	235,508	250,126	284,050	254,527	254,527
Interest rate	5.14%	5.14%	5.14%	5.14%	4.08%	4.08%	4.08%	4.08%	4.08%	3.35%	3.35%	3.35%	
Interest	339.53	339.53	427.11	634.78	555.82	845.39	1,083.37	1,198.09	1,198.96	657.46	698.27	792.97	8,771.30
Year-to-Date	8,317.85	8,657.38	9,084.50	9,719.28	10,275.10	11,120.49	12,203.87	13,401.96	14,600.92	15,258.38	15,956.65	16,749.62	16,749.62
Total Balance	87,585	108,373	157,283	173,197	258,919	329,760	364,584	366,038	250,109	265,384	300,007	271,276	271,276
Opening Balance													
REDA	79,267.30												
Interest	7,978.32												

Gas Cost Difference Recovery Variance Account (GCDRVA) - Not applicable

System Gas Sales (m3)	20,032,007	Opening Account Balance	0.00
Rate ($/m3)	0.000000	Current Year Recovery Variance	-12,401.58
Recovery ($)	164,863.42	Closing Account Balance	-12,401.58
Approved Recovery	177,265.00	Interest on Opening Balance	0.00
Recovery Variance	-12,401.58	Accumulated Interest	0.00
		Total Account Balance	-12,401.58

NATURAL RESOURCE GAS LIMITED

Cost of Service
2010 Bridge
($'s)

	Forecast	Adjust-ments	Note	Adjusted Forecast
Gas Transportation Costs	823,456	0	(1)	823,456
Operation and Maintenance	2,394,120			2,394,120
Depreciation and Amortization	1,172,442			1,172,442
Property and Capital Taxes	425,283			425,283
Income Taxes	89,083	0	(2)	89,083
Total Cost of Service	4,904,383			4,904,383

NATURAL RESOURCE GAS LIMITED

Summary of Cost of Service
2010 Bridge Year
($'s)

	Bridge Year 2010	Actual 2009
Gas Transportation Costs	823,456	799,742
Operation and Maintenance	2,394,120	2,121,130
Depreciation and Amortization	1,172,442	1,105,062
Property and Capital Taxes	425,283	426,584
Income Taxes	89,083	309,820
Total Cost of Service	4,904,383	4,762,338

	Variance from 2009
Gas Transportation Costs	23,714
Operation and Maintenance	272,990
Depreciation and Amortization	67,380
Property and Capital Taxes	-1,301
Income Taxes	-220,737
Total Cost of Service	142,046

NATURAL RESOURCE GAS LIMITED

Cost of Gas
2010 Bridge

Gas Commodity	Period Covered	M*3	$'s	$/M*3
Local Production - A (Affiliate)	Oct. 1/09 - Sept. 30/10	2,206,453	664,584	0.301200
Local Production - B	Oct. 1/09 - Sept. 30/10	1,026,197	217,944	0.212380
Western (FT + Dawn)	Oct. 1/09 - Sept. 30/10	6,334,768	2,047,931	0.323284
Parkway	Oct. 1/09 - Sept. 30/10	9,079,053	2,653,545	0.292271
Ontario Delivered	Oct. 1/09 - Sept. 30/10	0	0	0.000000
GCDRA Transfer		0	0	
Gas Inventory Revaluation			0	
PGCVA - Fiscal 2009			-178,483	
Total Gas Commodity Cost		18,646,471	5,405,520	0.289895

Gas Transportation				
Union Gas	Oct. 1/09 - Sept. 30/10		823,456	
PGTVA - Fiscal 2009			0	
Total Gas Transportation Cost		53,076,048	823,456	0.015515
Total Gas Commodity and Transportation Cost			6,228,976	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Commodity Variance Account Calculation
2010 Bridge Year

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Purchased (M*3)													
Local Production - A - Affiliate	150,759	209,792	261,934	231,968	144,000	172,000	172,000	200,000	168,000	144,000	176,000	176,000	2,206,453
Local Production - B	0	0	0	0	1,026,197	0	0	0	0	0	0	0	1,026,197
Western (FT + Dawn)	555,035	518,691	536,602	536,348	484,573	536,491	519,185	536,491	519,185	536,491	536,491	519,185	6,334,768
Parkway	771,794	745,519	771,263	770,897	696,481	771,103	746,229	771,103	746,229	771,103	771,103	746,229	9,079,053
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,477,588	1,474,002	1,569,799	1,539,213	2,351,251	1,479,594	1,437,414	1,507,594	1,433,414	1,451,594	1,483,594	1,441,414	18,646,471
Commodity Cost													
Local Production - A - Affiliate	45,409	63,189	78,895	69,869	43,373	51,806	51,806	60,240	50,602	43,373	53,011	53,011	664,584
Local Production - B	0	0	0	0	217,944	0	0	0	0	0	0	0	217,944
Western (FT + Dawn)	149,246	166,225	176,506	185,187	168,253	186,280	166,596	172,149	166,596	172,149	172,149	166,596	2,047,931
Parkway	184,353	232,119	246,670	248,146	223,167	245,737	208,511	215,752	208,793	215,752	215,752	208,793	2,653,545
GCDRA Transfer	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Commodity Cost	379,008	461,533	502,070	503,201	652,737	483,824	426,913	448,141	425,990	431,274	440,912	428,400	5,584,003
Average Cost ($/M*3)													
Reference Price	0.274213	0.274213	0.274213	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	
Actual Price	0.256505	0.313116	0.319831	0.326921	0.277612	0.326998	0.297001	0.297256	0.297186	0.297104	0.297192	0.297208	
Rate Difference	0.017708	(0.038903)	(0.045618)	(0.032006)	0.017303	(0.032083)	(0.002086)	(0.002341)	(0.002271)	(0.002189)	(0.002277)	(0.002293)	
PGCVA Balance ($'s)													
PGCVA	26,165	-57,343	-71,611	-49,264	40,684	-47,470	-2,998	-3,529	-3,255	-3,178	-3,378	-3,305	-178,483
Year-to-Date (1)	26,165	-31,178	-102,789	-152,053	-111,369	-158,839	-161,838	-165,367	-168,622	-171,800	-175,178	-178,483	-178,483
Interest	0	12	-14	-47	-70	-51	-73	-74	-76	-77	-79	-80	
Year-to-Date (2)	0	12	-2	-49	-119	-170	-243	-317	-393	-470	-549	-629	-629
Total Balance	26,165	-31,166	-102,791	-152,103	-111,489	-159,009	-162,081	-165,684	-169,015	-172,270	-175,727	-179,112	-179,112
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2010 Bridge

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Transported (M*3)													
Total Transported	4,491,012	5,163,076	5,731,877	6,155,640	5,515,253	5,352,096	4,240,479	3,517,486	3,125,761	2,985,710	3,165,761	3,349,283	52,793,434
Transportation Cost													
Union Gas - Demand	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	46,752	561,028
Union Gas - Delivery	21,678	21,671	21,894	21,894	21,224	21,894	21,671	21,894	21,671	21,894	21,894	21,671	260,950
Union Gas - Adjustments	17,064	26,083	33,847	39,637	30,488	28,633	13,457	3,957	-1,833	-4,057	-1,167	1,339	187,448
Total Transportation Cost	85,494	94,506	102,494	108,284	98,465	97,280	81,880	72,603	66,590	64,590	67,480	69,762	1,009,426
Average Cost ($/M*3)													
Reference Price	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	
Actual Price	0.019037	0.018304	0.017881	0.017591	0.017853	0.018176	0.019309	0.020641	0.021304	0.021633	0.021316	0.020829	
Rate Difference	(0.000008)	0.000725	0.001148	0.001438	0.001176	0.000853	(0.000280)	(0.001612)	(0.002275)	(0.002604)	(0.002287)	(0.001800)	
PGTVA Balance ($'s)													
PGTVA	36	-3,743	-6,580	-8,852	-6,486	-4,565	1,187	5,670	7,111	7,775	7,240	6,029	4,822
Year-to-Date (1)	36	-3,707	-10,287	-19,139	-25,625	-30,191	-29,003	-23,333	-16,222	-8,447	-1,207	4,822	4,822
Interest	0	0	-2	-5	-9	-12	-14	-13	-11	-7	-4	-1	
Year-to-Date (2)	0	0	-2	-6	-15	-27	-41	-54	-65	-72	-76	-77	-77
Total Balance	36	-3,707	-10,289	-19,146	-25,640	-30,217	-29,044	-23,387	-16,287	-8,519	-1,283	4,745	4,745
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	

NATURAL RESOURCE GAS LIMITED

Operating and Maintenance Expense
2009 Actual
($'s)

	Bridge 2010	Actual 2009	Variance from 2009
Expense Category			
Wages	1,065,863	963,348	102,515
Employee Benefits	154,305	148,883	5,421
Insurance	226,871	197,396	29,475
Utilities	17,604	12,658	4,946
Advertising	39,000	38,263	737
Telephone	62,056	59,776	2,280
Office & Postage	125,863	115,429	10,435
Repair & Maintenance	162,662	110,269	52,393
Automotive	61,400	69,528	-8,128
Dues & Fees	41,705	19,424	22,281
Mapping Expense	919	1,013	-94
Regulatory	21,000	32,211	-11,211
Bad Debts	50,000	51,982	-1,982
Office Rent	0	0	0
Interest - Security Deposits	6,432	5,843	588
Bank Charges	17,749	16,618	1,130
Collection Expense	20,000	14,308	5,692
Travel & Ent.	4,150	3,371	779
Legal	54,432	47,472	6,960
Audit	20,000	15,577	4,423
Consulting Fees	64,560	38,832	25,728
Management Fees (Net)	225,637	216,250	9,387
Miscellaneous	0	0	0
Total O & M Expenses	2,442,208	2,178,452	263,756
Capitalized Expenses			
Wages	34,454	39,365	-4,911
Equipment	13,634	17,956	-4,322
Total Capitalized Expenses	-48,088	57,321	-105,409
Total Net Expenses	2,394,120	2,121,131	272,989
Average Number of Customers	6,968	6,713	254
Net Expense per Customer	343.60	315.96	27.64

NATURAL RESOURCE GAS LIMITED

Regulatory Expenses
2010 Bridge Year
($'s)

Category	Actual	Budget
Main Rates Case	0	
QRAM	5,551	12,000
RRR	0	12,000
Miscellaneous	0	12,000
Sub-Total - Rate Case & Other Applications	5,551	36,000
Plus OEB Fixed Costs	15,062	26,000
Total Regulatory Costs	20,613	62,000

NATURAL RESOURCE GAS LIMITED

Depreciation Expense
2010 Bridge Year
($'s)

Fixed Assets	Assets At Cost Oct 1/09	Acc. Dep. Oct 1/09	Net Book Value Oct 1/09	Additions F2010	Disposals F2010	Adjusted Cost Base	Dep'n Rate (1)	Depreciation Expense F2010	Adjustments Accumulated Depreciation F2010 (2)	Accumulated Depreciation Sept 30/10	Net Book Value Sept 30/10
Land	71,700	-	71,700	-	-	71,700	0.00%	-	-	-	71,700
Buildings	682,331	137,285	545,046	-	-	682,331	2.22%	15,148	-	152,433	529,898
Furniture & Fixtures	69,176	40,211	28,965	1,500	-	70,676	6.75%	4,771	-	44,981	25,695
Computer Equipment	161,413	141,120	20,293	6,000	-	167,413	33.33%	6,764	-	147,884	19,529
Computer Software	175,654	129,193	46,462	7,803	-	183,457	20.00%	9,292	-	138,485	44,972
Machinery & Equipment	456,832	421,205	35,627	6,200	-	463,032	9.22%	41,827	-	463,032	-
Communication Equipment	140,415	42,844	97,571	20,000	-	160,415	7.73%	12,400	-	55,244	105,171
Automotive	521,483	337,393	184,090	65,000	-	586,483	16.60%	97,356	-	434,749	151,734
Rental Equip - Residential	2,173,374	757,342	1,416,032	193,009	-	2,366,382	7.40%	175,112	-	932,455	1,433,928
Rental Equip - Commercial	54,699	29,582	25,117	-	-	54,699	7.40%	4,048	-	33,629	21,069
Rental Equip - Water Soften	11,627	6,643	4,983	-	-	11,627	6.25%	727	-	7,370	4,257
Meters	2,050,856	961,457	1,089,399	140,000	-	2,190,856	3.62%	79,309	-	1,040,766	1,150,090
Regulators	1,223,918	742,680	481,238	18,000	-	1,241,918	3.67%	45,578	-	788,259	453,659
Plastic Mains	7,311,883	2,819,256	4,492,627	201,334	-	7,513,217	3.24%	243,428	-	3,062,685	4,450,532
Steel Mains	33,014	33,014	-	-	-	33,014	13.45%	-	-	33,014	-
New Steel Mains	5,073,000	253,650	4,819,350	-	-	5,073,000	5.00%	253,650	-	507,300	4,565,700
Plastic Services	2,719,811	1,698,466	1,021,345	71,995	-	2,791,806	3.33%	92,967	-	1,791,433	1,000,373
IGPC	-	-	-		-		5.00%	-	-	-	-
Franchises	413,057	159,281	253,775	-	-	413,057	0.37%	97,483	-	256,764	156,293
Total Fixed Assets	23,344,242	8,710,622	14,633,620	730,841	-	24,075,083		1,179,859	-	9,890,482	14,184,601
Less:											
Capitalized Depreciation								7,418			
Total	**23,344,242**	**8,710,622**	**14,633,620**	**730,841**	**0**	**24,075,083**		**1,172,442**	**0**	**9,890,482**	**14,184,601**

(1) All depreciation rates are applied on a straight line basis, except declining balance basis for computer equipment and computer software and amortization of franchises
(2) Book value plus removal costs less salvage value.

NATURAL RESOURCE GAS LIMITED
Summary of Depreciation Expense
2010 Bridge Year
($'s)

	Bridge 2010	Actual 2009
Fixed Assets		
Land	0	0
Buildings	15,148	15,148
Furniture & Fixtures	4,771	4,669
Computer Equipment	6,764	10,145
Computer Software	9,292	11,615
Machinery & Equipment	41,827	42,120
Communication Equipment	12,400	10,854
Automotive	97,356	86,566
Rental Equip - Residential	175,112	160,830
Rental Equip - Commercial	4,048	4,048
Rental Equip - Water Softeners	727	727
Meters	79,309	74,241
Regulators	45,578	44,918
Plastic Mains	243,428	236,905
Steel Mains	0	0
New Steel Mains	253,650	253,650
Plastic Services	92,967	90,570
Franchises	97,483	65,474
Total Fixed Assets	1,179,859	1,112,479
Less:		
Capitalized Depreciation	7,418	7,418
Total	1,172,442	1,105,062

	Variance from 2009
Fixed Assets	
Land	0
Buildings	0
Furniture & Fixtures	101
Computer Equipment	-3,381
Computer Software	-2,323
Machinery & Equipment	-293
Communication Equipment	1,546
Automotive	10,790
Rental Equip - Residential	14,283
Rental Equip - Commercial	0
Rental Equip - Water Softeners	0
Meters	5,068
Regulators	661
Plastic Mains	6,523
Steel Mains	-0
New Steel Mains	0
Services - Plastic	2,397
Franchises	32,009
Total Fixed Assets	67,380
Less:	
Capitalized Depreciation	0
Total	67,380

NATURAL RESOURCE GAS LIMITED

Capital Cost Allowance
2010 Bridge Year
($'s)

Class	UCC at End of Fiscal 2009	Add: Cost of Additions	Adjustments	Deduct: Lesser of Cost and Proceeds from Disposal	UCC Before CCA	CCA Claimed: Rate (%)	CCA Claimed: Amount	UCC at End of Year
1	5,448,572	-	-	-	5,448,572	4%	226,569	5,222,003
2	4,836,473	-	-	-	4,836,473	6%	290,188	4,546,285
3	-	-	-	-	-	5%	0	0
6	3,770	-	-	-	3,770	10%	377	3,393
7	-	-	-	-	-	15%	0	0
8	965,331	193,009	-	-	1,158,339	20%	212,367	945,972
8	187,010	27,700	-	-	214,710	20%	40,172	174,538
10	119,858	65,000	-	-	184,858	30%	45,707	139,151
10.1	1,445	-	-	-	1,445	30%	434	1,011
49	1,141,250	431,329	-	-	1,572,579	8%	108,553	1,464,026
45	6,707	-	-	-	6,707	45%	3,018	3,689
12	15,304	7,803	-	-	23,107	100%	19,205	3,902
14	-	-	-	-	-	4%	0	0
50	16,473	6,000	-	-	22,473	55%	10,710	11,763
51	4,904,044	-	-	-	4,904,044	6%	294,243	4,609,801
17	30,192	-	-	-	30,192	8%	2,415	27,777
	17,676,428	730,841	-	-	18,407,269		1,253,958	17,153,311

NATURAL RESOURCE GAS LIMITED

Summary of Capital Cost Allowance
2010 Bridge
($'s)

Class	Bridge 2010	Actual 2009
1	226,569	222,580
2	290,188	164,643
3	-	-
6	377	419
7	-	-
8	212,367	213,460
8	40,172	35,267
10	45,707	39,404
10.1	434	619
49	108,553	89,964
45	3,018	5,487
12	19,205	19,591
14	-	-
50	10,710	18,088
51	294,243	168,956
17	2,415	2,625
Total	1,253,958	981,103

Class	Variance from 2009
1	3,989
2	125,545
3	-
6	(42)
7	-
8	(1,093)
8	4,905
10	6,303
10	(185)
45	(2,469)
12	(386)
14	-
17	(210)
Total	136,357

NATURAL RESOURCE GAS LIMITED

Property and Capital Taxes
2010 Bridge
($'s)

Property Taxes	Bridge 2010	Actual 2009
Prepaid Previous Year	(73,761)	(4,209)
Add Current Year Taxes	389,103	320,852
Less Prepaid Current Year	(73,761)	(73,761)
		-
Total Property Tax	389,103	390,404
Provincial Capital Tax	36,180	36,180
Federal Capital Tax	-	-
Total Property & Capital Taxes	425,283	426,584

Property Taxes	Variance from 2009
Prepaid Previous Year	(69,552)
Add Current Year Taxes	68,251
Less Prepaid Current Year	-
Total Property Tax	(1,301)
Provincial Capital Tax	-
Federal Capital Tax	-
Total Property & Capital Taxes	(1,301)

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2010 Bridge Year
($'s)

				Bridge 2010	Adjusted Bridge 2010	Adjusted Actual 2009
Taxable Income						(1)
Normalized Operating Revenue				6,044,483	6,044,483	5,926,685
Less:						
Gas Transportation Costs				823,456	823,456	799,742
Operation & Maintenance				2,394,120	2,394,120	2,121,130
Property & Capital Taxes				425,283	425,283	426,584
Subtotal				2,401,624	2,401,624	2,579,229
Add Back:						
Federal Capital Tax (non-deductible)				0	0	0
Meals & Ent. (non-deductible portion)				497	497	0
Subtotal				2,402,121	2,402,121	2,579,229
Deduct:						
Interest				631,697	631,697	639,657
Capital Cost Allowance				1,253,958	1,253,958	981,103
Normalized Taxable Income				516,466	516,466	958,469
Corporate Income Tax						
Federal Income Tax						
Tax on first	$500,000	@	11.00%	55,000	55,000	58,150
Clawback on	$16,466	@	3.18%	523	523	41,307
Tax on all over	$500,000	@	19.00%	3,129	3,129	94,582
Federal Surtax		@	0.28%	1,446	1,446	2,684
Total Federal Income Tax				60,098	60,098	196,723
Provincial Income Tax						
Tax on first	$500,000	@	5.25%	26,240	26,240	27,500
Clawback on next	$16,466	@	3.18%	523	523	21,411
Tax on all over	$500,000	@	13.50%	2,222	2,222	64,186
Total Provincial Income Tax				28,985	28,985	113,097
Total Income Tax				89,083	89,083	309,820

(1) Income taxes based on tax rates in place during the year.

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
Bridge 2010
($'s)

				Variance from 2009
Taxable Income				
Normalized Operating Revenue				117,797
Less:				
Gas Transportation Costs				23,714
Operation & Maintenance				272,990
Property & Capital Taxes				-1,301
Subtotal				-177,605
Add Back:				
Federal Capital Tax (non-deductible)				0
Meals & Ent. (non-deductible portion)				497
Subtotal				-177,108
Deduct:				
Interest				-7,960
Capital Cost Allowance				272,855
Normalized Taxable Income				-442,003
Corporate Income Tax				
Federal Income Tax				
Tax on first	$500,000	@	11.00%	-3,150
Clawback on	$16,466	@	3.18%	-40,784
Tax on all over	$500,000	@	19.00%	-91,453
Federal Surtax		@	0.28%	-1,238
Total Federal Income Tax				-136,625
Provincial Income Tax				
Tax on first	$500,000	@	5.25%	-1,260
Clawback on n	$16,466	@	3.18%	-20,888
Tax on all over	$500,000	@	13.50%	-61,964
Total Provincial Income Tax				-84,112
Total Income Tax				-220,737

NATURAL RESOURCE GAS LIMITED

Other Deferral and Variance Accounts
2010 Bridge
($'s)

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Regulatory Expenses Deferral Account (REDA)													
Closing Account Balance	254,527	254,527	254,527	254,527	254,527	254,527	254,527	254,527	254,527	254,527	254,527	254,527	254,527
Interest rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	
Interest	0.06	116.66	116.66	116.66	116.66	116.66	116.66	116.66	116.66	116.66	116.66	116.66	1,283.30
Year-to-Date	34.24	150.90	267.55	384.21	500.87	617.53	734.19	850.84	967.50	1,084.16	1,200.82	1,317.48	1,317.48
Total Balance	254,561	254,677	254,794	254,911	255,027	255,144	255,261	255,377	255,494	255,611	255,727	255,844	255,844
Opening Balance													
REDA	126.05												
Interest	34.18												

NATURAL RESOURCE GAS LIMITED

Cost of Service
2011 Test Year
($'s)

	Forecast	Adjust-ments	Adjusted Forecast
Gas Transportation Costs	732,331	0	732,331
Operation and Maintenance	2,859,299		2,859,299
Depreciation and Amortization	1,206,523		1,206,523
Property and Capital Taxes	400,776		400,776
Income Taxes	50,252	0	50,252
Total Cost of Service	5,249,180		5,249,180

NATURAL RESOURCE GAS LIMITED

Summary of Cost of Service
2011 Test Year
($'s)

	Test Year 2011	Bridge Year 2010
Gas Transportation Costs	732,331	823,456
Operation and Maintenance	2,859,299	2,394,120
Depreciation and Amortization	1,206,523	1,172,442
Property and Capital Taxes	400,776	425,283
Income Taxes	50,252	89,083
Total Cost of Service	5,249,180	4,904,383

	Variance from 2010
Gas Transportation Costs	-91,125
Operation and Maintenance	465,179
Depreciation and Amortization	34,081
Property and Capital Taxes	-24,507
Income Taxes	-38,831
Total Cost of Service	344,797

NATURAL RESOURCE GAS LIMITED

Cost of Gas
2011 Test Year

Gas Commodity	Period Covered	M*3	$'s	$/M*3
Local Production - A (Affiliate)	Oct. 1/10 - Sept. 30/11	3,424,818	1,031,555	0.301200
Local Production - B	Oct. 1/10 - Sept. 30/11	0	0	0.000000
Western (FT + Dawn)	Oct. 1/10 - Sept. 30/11	6,316,750	2,266,752	0.358848
Parkway	Oct. 1/10 - Sept. 30/11	9,079,118	2,901,368	0.319565
Ontario Delivered	Oct. 1/10 - Sept. 30/11	500,000	109,723	0.219446
GCDRA Transfer		0	0	
Gas Inventory Revaluation			0	
PGCVA - Fiscal 2011			-501,714	
Total Gas Commodity Cost		19,320,686	5,807,684	0.300594

Gas Transportation				
Union Gas	Oct. 1/10 - Sept. 30/11		732,331	
PGTVA - Fiscal 2011			0	
Total Gas Transportation Cost		17,991,092	732,331	0.040705
Total Gas Commodity and Transportation Cost			6,540,015	

NATURAL RESOURCE GAS LIMITED

Purchased Gas Commodity Variance Account Calculation
2011 Test Year

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Purchased (M*3)													
Local Production - A - Affiliate	186,000	174,000	174,000	174,000	144,000	172,000	400,136	400,136	400,136	400,136	400,136	400,136	3,424,818
Local Production - B	0	0	0	0	0	0	0	0	0	0	0	0	0
Western (FT + Dawn)	536,491	519,185	536,491	536,491	484,573	536,491	519,185	536,491	519,185	536,491	536,491	519,185	6,316,750
Parkway	771,103	746,229	771,103	771,103	696,481	771,103	746,229	771,103	746,229	771,103	771,103	746,229	9,079,118
Dawn	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario Delivered	0	0	0	0	0	0	0	0	0	0	0	500,000	500,000
Total	1,493,594	1,439,414	1,481,594	1,481,594	1,325,054	1,479,594	1,665,550	1,707,730	1,665,550	1,707,730	1,707,730	2,165,550	19,320,686
Commodity Cost													
Local Production - A - Affiliate	56,023	52,409	52,409	52,409	43,373	51,806	120,521	120,521	120,521	120,521	120,521	120,521	1,031,555
Local Production - B	0	0	0	0	0	0	0	0	0	0	0	0	0
Western (FT + Dawn)	172,149	188,138	194,409	194,409	175,596	194,409	188,138	194,409	188,138	194,409	194,409	188,138	2,266,752
Parkway	215,752	241,223	249,264	249,264	225,142	249,264	241,223	249,264	241,223	249,264	249,264	241,223	2,901,368
Dawn	0	0	0	0	0	0	0	0	0	0	0	0	0
GCDRA Transfer	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Commodity Cost	443,924	481,770	496,082	496,082	444,110	495,479	549,882	564,194	549,882	564,194	564,194	549,882	6,199,675
Average Cost ($/M*3)													
Reference Price	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	0.294915	
Actual Price	0.297219	0.334699	0.334830	0.334830	0.335164	0.334875	0.330150	0.330376	0.330150	0.330376	0.330376	0.253923	0.320882739
Rate Difference	(0.002304)	(0.039784)	(0.039915)	(0.039915)	(0.040249)	(0.039960)	(0.035235)	(0.035461)	(0.035235)	(0.035461)	(0.035461)	0.040992	
PGCVA Balance ($'s)													
PGCVA	-3,441	-57,266	-59,138	-59,138	-53,332	-59,125	-58,686	-60,558	-58,686	-60,558	-60,558	88,770	-501,714
Year-to-Date (1)	-3,441	-60,707	-119,845	-178,983	-232,315	-291,439	-350,125	-410,683	-469,368	-529,926	-590,484	-501,714	-501,714
Interest	0	-2	-28	-55	-82	-106	-134	-160	-188	-215	-243	-271	
Year-to-Date (2)	0	-2	-29	-84	-166	-273	-406	-567	-755	-970	-1,213	-1,484	-1,484
Total Balance	-3,441	-60,708	-119,874	-179,067	-232,481	-291,712	-350,531	-411,250	-470,124	-530,896	-591,697	-503,198	-503,198
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	

(1) Includes balance of - from Fiscal 2010 PGCVA
(2) Includes balance of - from Fiscal 2010 PGCVA

Revised Reference Price 0.320882739

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2011 Test Year

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
Volumes Transported (M*3)													
Non-IGPC loads	1,313,777	2,640,908	2,939,458	3,061,423	3,171,808	2,116,566	1,059,721	315,492	105,863	21,954	114,451	-46,769	16,814,651
IGPC	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	2,621,595	31,459,135
Total Transported	3,935,371	5,262,502	5,561,053	5,683,017	5,793,403	4,738,160	3,681,316	2,937,086	2,727,457	2,643,548	2,736,046	2,574,825	48,273,786
Transportation Cost													
Union Gas - Demand													
Non-IGPC loads	28,642	28,642	28,642	28,642	28,642	28,642	28,642	28,642	28,642	28,642	28,642	28,642	343,709
IGPC	18,434	18,434	18,434	18,434	18,434	18,434	18,434	18,434	18,434	18,434	18,434	18,434	221,209
Total	47,076	47,076	47,076	47,076	47,076	47,076	47,076	47,076	47,076	47,076	47,076	47,076	564,917
Union Gas - Delivery													
Non-IGPC loads	4,563	9,172	10,209	10,632	11,016	7,351	3,680	1,096	368	76	397	-162	58,397
IGPC	9,105	9,105	9,105	9,105	9,105	9,105	9,105	9,105	9,105	9,105	9,105	9,105	109,258
Total	13,668	18,277	19,314	19,737	20,120	16,456	12,785	10,201	9,472	9,181	9,502	8,942	167,655
Union Gas - Adjustments													
Non-IGPC loads	-7	-13	-15	-15	-16	-11	-5	-2	-1	-0	-1	0	-84
IGPC	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-13	-157
Total	-20	-26	-28	-28	-29	-24	-18	-15	-14	-13	-14	-13	-241
Total Transportation Cost	60,724	65,327	66,362	66,785	67,168	63,508	59,843	57,262	56,535	56,244	56,565	56,006	732,331
Average Cost ($/M*3)													
Currently Authorized Reference	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	0.019029	
Average Actual Price	0.015430	0.012414	0.011933	0.011752	0.011594	0.013404	0.016256	0.019496	0.020728	0.021276	0.020674	0.021751	
Rate Difference	0.003599	0.006615	0.007096	0.007277	0.007435	0.005625	0.002773	(0.000467)	(0.001699)	(0.002247)	(0.001645)	(0.002722)	
PGTVA Balance ($'s) - at Currently Authorized Reference Price													
PGTVA	-14,163	-34,811	-39,461	-41,355	-43,074	-26,652	-10,208	1,372	4,634	5,940	4,501	7,009	-186,271
Year-to-Date (1)	-399,501	-434,312	-473,774	-515,129	-558,203	-584,855	-595,063	-593,692	-589,058	-583,118	-578,617	-571,608	-571,608
Interest	-177	-183	-199	-217	-236	-256	-268	-273	-272	-270	-267	-265	-2,883
Year-to-Date (2)	-5,443	-5,626	-5,825	-6,042	-6,278	-6,534	-6,802	-7,075	-7,347	-7,617	-7,884	-8,149	-8,149
Total Balance	-404,943	-439,938	-479,598	-521,171	-564,481	-591,389	-601,865	-600,766	-596,404	-590,734	-586,501	-579,757	-579,757
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	
Calculation of Revised Reference Price													
Non-IGPC loads	0.023909												
IGPC	0.010500												
Average	0.015170												

NATURAL RESOURCE GAS LIMITED

Purchased Gas Transportation Variance Account Calculation
2011 Test Year

Non-IGPC PGTVA Balance ($'s) - at Revised Reference Price

Average Cost ($/M*3)

Revised Reference Price	0.023909	0.023909	0.023909	0.023909	0.023909	0.023909	0.023909	0.023909	0.023909	0.023909	0.023909	0.023909	
Average Actual Price	0.025270	0.014314	0.013212	0.012824	0.012498	0.017000	0.030496	0.094254	0.274029	1.308144	0.253727	(0.608951)	
Rate Difference	(0.001361)	0.009595	0.010697	0.011085	0.011411	0.006909	(0.006587)	(0.070345)	(0.250120)	(1.284235)	(0.229818)	0.632860	
PGTVA	-1,787	25,340	31,443	33,936	36,193	14,622	-6,981	-22,193	-26,478	-28,194	-26,303	-29,598	-0
Year-to-Date (1)	-387,125	-361,785	-330,341	-296,405	-260,213	-245,590	-252,571	-274,764	-301,243	-329,436	-355,739	-385,338	-385,338
Interest	0	-177	-166	-151	-136	-119	-113	-116	-126	-138	-151	-163	
Year-to-Date (2)	0	-177	-343	-495	-631	-750	-862	-978	-1,104	-1,242	-1,393	-1,556	-1,556
Total Balance	-387,125	-361,962	-330,685	-296,900	-260,843	-246,340	-253,433	-275,742	-302,347	-330,678	-357,132	-386,894	-386,894
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	

IGPC PGTVA Balance ($'s) - at Revised Reference Price

Average Cost ($/M*3)

Revised Reference Price	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500
Average Actual Price	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500	0.010500
Rate Difference	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
PGTVA	0	0	0	0	0	0	0	0	0	0	0	0
Year-to-Date (1)	0	0	0	0	0	0	0	0	0	0	0	0
Interest	0	0	0	0	0	0	0	0	0	0	0	0
Year-to-Date (2)	0	0	0	0	0	0	0	0	0	0	0	0
Total Balance	0	0	0	0	0	0	0	0	0	0	0	0
Interest Rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%

(1) Includes balance of (385,337.56) from Fiscal 2010 PGTVA.
(2) Includes balance of (5,265.92) from Fiscal 2010 PGTVA.

NATURAL RESOURCE GAS LIMITED

Unaccounted For Gas Levels
1982 - 2009 Actuals

Fiscal Year	Volume (m3)	As % of Gas Deliveries
1982	1,493,222	16.8%
1983	416,975	4.8%
1984	790,562	8.4%
1985	907,682	9.3%
1986	609,883	5.2%
1987	359,219	3.3%
1988	434,190	4.0%
1989	207,530	1.6%
1990	-87,114	-1.0%
1991	1,409	0.0%
1992	-15,524	-0.1%
1993	79,873	0.5%
1994	298,140	1.8%
1995	375,306	2.2%
1996	593,204	3.0%
1997	451,460	2.1%
1998	194,315	0.8%
1999	268,498	1.2%
2000	197,132	0.9%
2001	52,150	0.2%
2002	126,614	0.5%
2003	-159,605	-0.6%
2004	35,499	0.1%
2005	-69,703	-0.3%
2006	628,624	2.7%
2007	1,592,116	0.0%
2008	-3,537,502	87.9%
2009	1,481,479	4.71%
2010	0	0%
2011	0	0

NATURAL RESOURCE GAS LIMITED

Operating and Maintenance Expense
2011 Test Year
($'s)

	Test Year 2011	Bridge Year 2010	Variance from 2010
Expense Category			
Wages	1,101,919	1,065,863	36,056
Employee Benefits	158,934	154,305	4,629
Insurance	284,925	226,871	58,054
Utilities	18,061	17,604	457
Advertising	98,000	39,000	59,000
Telephone	65,159	62,056	3,103
Office & Postage	127,928	125,863	2,064
Repair & Maintenance	289,066	162,662	126,404
Automotive	71,000	61,400	9,600
Dues & Fees	41,705	41,705	0
Mapping Expense	919	919	0
Regulatory	146,000	21,000	125,000
Bad Debts	75,000	50,000	25,000
Office Rent	0	0	0
Interest - Security Deposits	6,432	6,432	0
Bank Charges	17,749	17,749	0
Collection Expense	20,000	20,000	0
Travel & Ent.	4,150	4,150	0
Legal	54,432	54,432	0
Audit	20,000	20,000	0
Consulting Fees	64,560	64,560	0
Management Fees (Net)	235,157	225,637	9,520
Miscellaneous	0		0
Total O & M Expenses	2,901,095	2,442,208	458,887
Capitalized Expenses			
Wages	30,294	34,454	-4,160
Equipment	11,502	13,634	-2,132
Total Capitalized Expenses	41,796	48,088	-6,292
Total Net Expenses	2,859,299	2,394,120	465,179
Average Number of Customers	7,106	6,968	138
Net Expense per Customer	402.38	343.60	58.78

NATURAL RESOURCE GAS LIMITED

Regulatory Expenses
2011 Test Year
($'s)

Category	Proposed	Budget
Main Rates Case	125,000	5,999
QRAM	5,000	12,000
RRR	1,000	12,000
Miscellaneous	0	12,000
Sub-Total - Rate Case & Other Applications	131,000	41,999
Plus OEB Fixed Costs	15,000	26,000
Total Regulatory Costs	146,000	67,999

NATURAL RESOURCE GAS LIMITED

Depreciation Expense
2011 Test Year
($'s)

	Assets At Cost Oct 1/10	Acc. Dep. Oct 1/10	Net Book Value Oct 1/10	Additions F2011	Disposals F2011	Adjusted Cost Base	Dep'n Rate (1)	Depreciation Expense F2011	Adjustments Accumulated Depreciation F2011 (2)	Accumulated Depreciation Sept 30/11	Net Book Value Sept 30/11
Fixed Assets											
Land	71,700	-	71,700	-	-	71,700	0.00%	-	-	-	71,700
Buildings	682,331	152,433	529,898	40,000	-	722,331	2.22%	16,036	-	168,468	553,862
Furniture & Fixtures	70,676	44,981	25,695	1,500	-	72,176	6.75%	4,872	-	49,853	22,323
Computer Equipment	167,413	147,884	19,529	6,000	-	173,413	33.33%	6,509	-	154,393	19,020
Computer Software	183,457	138,485	44,972	23,682	-	207,140	20.00%	8,994	-	147,480	59,660
Machinery & Equipment	463,032	463,032	-	44,631	-	507,663	9.22%	44,631	-	507,663	-
Communication Equipment	160,415	55,244	105,171	20,000	-	180,415	7.73%	13,946	-	69,190	111,225
Automotive	586,483	434,749	151,734	35,000	-	621,483	16.60%	103,166	-	537,915	83,568
Rental Equip - Residential	2,366,382	932,455	1,433,928	202,659	96,968	2,472,073	7.40%	182,933	(96,968)	1,018,420	1,453,653
Rental Equip - Commercial	54,699	33,629	21,069	-	-	54,699	7.40%	4,048	-	37,677	17,022
Rental Equip - Water Softeners	11,627	7,370	4,257	-	-	11,627	6.25%	727	-	8,097	3,530
Meters	2,190,856	1,040,766	1,150,090	140,000	-	2,330,856	3.62%	84,377	-	1,125,143	1,205,713
Regulators	1,241,918	788,259	453,659	20,000	-	1,261,918	3.67%	46,312	-	834,571	427,347
Plastic Mains	7,513,217	3,062,685	4,450,532	201,239	-	7,714,456	3.24%	249,948	-	3,312,633	4,401,823
Steel Mains	33,014	33,014	-	-	-	33,014	13.45%	-	-	33,014	-
New Steel Mains	5,073,000	507,300	4,565,700	-	-	5,073,000	5.00%	253,650	-	760,950	4,312,050
Plastic Services	2,791,806	1,791,433	1,000,373	75,293	-	2,867,098	3.33%	95,474	-	1,886,907	980,191
IGPC	-	-	-		-		5.00%	-	-	-	-
Franchises	413,057	256,764	156,293	-	-	413,057	0.37%	97,483	-	354,247	58,810
Total Fixed Assets	24,075,083	9,890,482	14,184,601	810,004	96,968	24,788,118		1,213,107	(96,968)	11,006,621	13,781,498
Less:											
Capitalized Depreciation								6,584			
Total	**24,075,083**	**9,890,482**	**14,184,601**	**810,004**	**96,968**	**24,788,118**		**1,206,523**	**-96,968**	**11,006,621**	**13,781,498**

(1) All depreciation rates are applied on a straight line basis, except declining balance basis for computer equipment and computer software and amortization of franchises.
(2) Book value plus removal costs less salvage value.

NATURAL RESOURCE GAS LIMITED

Summary of Depreciation Expense
2011 Test Year
($'s)

	Test Year 2011	Bridge Year 2010
Fixed Assets		
Land	0	0
Buildings	16,036	15,148
Furniture & Fixtures	4,872	4,771
Computer Equipment	6,509	6,764
Computer Software	8,994	9,292
Machinery & Equipment	44,631	41,827
Communication Equipment	13,946	12,400
Automotive	103,166	97,356
Rental Equip - Residential	182,933	175,112
Rental Equip - Commercial	4,048	4,048
Rental Equip - Water Softeners	727	727
Meters	84,377	79,309
Regulators	46,312	45,578
Plastic Mains	249,948	243,428
Steel Mains	0	0
New Steel Mains	253,650	253,650
Plastic Services	95,474	92,967
Franchises	97,483	97,483
Total Fixed Assets	1,213,107	1,179,859
Less:		
Capitalized Depreciation	6,584	7,418
Total	1,206,523	1,172,442

	Variance from 2010
Fixed Assets	
Land	0
Buildings	888
Furniture & Fixtures	101
Computer Equipment	-255
Computer Software	-298
Machinery & Equipment	2,804
Communication Equipment	1,546
Automotive	5,810
Rental Equip - Residential	7,821
Rental Equip - Commercial	0
Rental Equip - Water Softeners	0
Meters	5,068
Regulators	734
Plastic Mains	6,520
Steel Mains	0
New Steel Mains	0
Services - Plastic	2,507
Franchises	0
Total Fixed Assets	33,248
Less:	
Capitalized Depreciation	-834
Total	34,081

08/03/2010
EB-2010-0018
Exhibit D8
Tab 4
Schedule 3
Updated

NATURAL RESOURCE GAS LIMITED

Capital Cost Allowance
2011 Test Year
($'s)

Class	UCC at End of Fiscal 2010	Add: Cost of Additions	Adjustments	Deduct: Lesser of Cost and Proceeds from Disposal	UCC Before CCA	CCA Claimed: Rate (%)	Amount	UCC at End of Year
1	5,653,332	40,000	-	-	5,693,332	4%	235,664	5,457,668
2	4,546,285	-	-	-	4,546,285	6%	272,777	4,273,508
3	-	-	-	-	-	5%	0	0
6	3,393	-	-	-	3,393	10%	339	3,054
7	-	-	-	-	-	15%	0	0
8	945,972	202,659	96,968	-	1,245,600	20%	228,854	1,016,746
8	174,538	66,131	-	-	240,669	20%	41,521	199,148
10	139,151	35,000	-	-	174,151	30%	46,995	127,156
10.1	1,011	-	-	-	1,011	30%	303	708
49	1,464,026	436,532	-	-	1,900,557	8%	134,583	1,765,974
45	3,689	-	-	-	3,689	45%	1,660	2,029
12	3,902	23,682	-	-	27,584	100%	15,743	11,841
14	-	-	-	-	-	4%	0	0
50	11,763	6,000	-	-	17,763	55%	8,119	9,644
51	4,609,801	-	-	-	4,609,801	6%	276,588	4,333,213
17	27,777	-	-	-	27,777	8%	2,222	25,555
	17,584,640	810,004	96,968	-	18,491,612		1,265,368	17,226,244

NATURAL RESOURCE GAS LIMITED

Summary of Capital Cost Allowance
2011 Test YearActual
($'s)

Class	Test Year 2011	Bridge Year 2010
1	235,664	226,569
2	272,777	290,188
3	-	-
6	339	377
7	-	-
8	228,854	212,367
8	41,521	40,172
10	46,995	45,707
10.1	303	434
49	134,583	108,553
45	1,660	3,018
12	15,743	19,205
14	-	-
50	8,119	10,710
51	276,588	294,243
17	2,222	2,415
Total	1,265,368	1,253,958

Class	Variance from 2010
1	9,095
2	(17,411)
3	-
6	(38)
7	-
8	16,487
8	1,349
10	1,288
10.1	(131)
49	26,030
45	(1,358)
12	(3,462)
14	-
50	(2,591)
51	(17,655)
17	(193)
Total	11,410

NATURAL RESOURCE GAS LIMITED

Property and Capital Taxes
2011 Test Year
($'s)

Property Taxes	Test Year 2011	Bridge Year 2010
Prepaid Previous Year	(73,761)	(73,761)
Add Current Year Taxes	400,776	389,103
Less Prepaid Current Year	(73,761)	(73,761)
Total Property Tax	400,776	389,103
Provincial Capital Tax	-	36,180
Federal Capital Tax	-	-
Total Property & Capital Taxes	400,776	425,283

Property Taxes	Variance from 2010
Prepaid Previous Year	-
Add Current Year Taxes	11,673
Less Prepaid Current Year	-
Total Property Tax	11,673
Provincial Capital Tax	(36,180)
Federal Capital Tax	-
Total Property & Capital Taxes	(24,507)

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
2011 Test Year
($'s)

				Test Year 2011	Adjusted Test Year 2011	Bridge 2010
Taxable Income						(1)
Normalized Operating Revenue				6,144,773	6,144,773	6,044,483
Less:						
Gas Transportation Costs				732,331	732,331	823,456
Operation & Maintenance				2,859,299	2,859,299	2,394,120
Property & Capital Taxes				400,776	400,776	425,283
Subtotal				2,152,367	2,152,367	2,401,624
Add Back:						
Federal Capital Tax (non-deductible)				0	0	0
Meals & Ent. (non-deductible portion)				694	694	497
Subtotal				2,153,061	2,153,061	2,402,121
Deduct:						
Interest				652,595	652,595	631,697
Capital Cost Allowance				1,265,368	1,265,368	1,253,958
Normalized Taxable Income				235,099	235,099	516,466
Corporate Income Tax						
Federal Income Tax						
Tax on first	$500,000	@	16.88%	39,673	39,673	55,000
Tax on next $100,000	$0	@	16.88%	0	0	523
Tax on all over	$500,000	@	16.88%	0	0	3,129
Federal Surtax		@	0.00%	0	0	1,446
Total Federal Income Tax				39,673	39,673	60,098
Provincial Income Tax						
Tax on first	$500,000	@	4.50%	10,579	10,579	26,240
Clawback on next	$0	@	4.25%	0	0	523
Tax on all over	$500,000	@	11.88%	0	0	2,222
Total Provincial Income Tax				10,579	10,579	28,985
Total Income Tax				50,252	50,252	89,083

(1) Income taxes based on tax rates in place during the year.

NATURAL RESOURCE GAS LIMITED

Income Taxes Payable
Test 2011
($'s)

				Variance from 2010
Taxable Income				
Normalized Operating Revenue				100,290
Less:				
Gas Transportation Costs				-91,125
Operation & Maintenance				465,179
Property & Capital Taxes				-24,507
Subtotal				-249,257
Add Back:				
Federal Capital Tax (non-deductible)				0
Meals & Ent. (non-deductible portion)				197
Subtotal				-249,060
Deduct:				
Interest				20,898
Capital Cost Allowance				11,410
Normalized Taxable Income				-281,367
Corporate Income Tax				
Federal Income Tax				
Tax on first	$500,000	@	16.88%	-15,327
Clawback on	$0	@	16.88%	-523
Tax on all over	$500,000	@	16.88%	-3,129
Federal Surtax		@	0.00%	-1,446
Total Federal Income Tax				-20,425
Provincial Income Tax				
Tax on first	$500,000	@	4.50%	-15,661
Clawback on next	$0	@	4.25%	-523
Tax on all over	$500,000	@	11.88%	-2,222
Total Provincial Income Tax				-18,406
Total Income Tax				-38,831

NATURAL RESOURCE GAS LIMITED

Other Deferral and Variance Accounts
2011 Projection
($'s)

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Regulatory Expenses Deferral Account (REDA)													
Closing Account Balance	126	126	126	126	126	126	126	126	126	5,505	36,994	71,675	71,675
Interest rate	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	0.55%	
Interest	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	2.52	16.96	20.06
Year-to-Date	34.24	34.30	34.35	34.41	34.47	34.53	34.58	34.64	34.70	34.76	37.28	54.24	54.24
Total Balance	160	160	160	160	161	161	161	161	161	5,540	37,031	71,729	71,729
Opening Balance													
REDA	126.05												
Interest	34.18												

Gas Cost Difference Recovery Variance Account (GCDRVA) - Not applicable

System Gas Sales (m3)	20,646,638	Opening Account Balance	0.00
Rate ($/m3)	0.000000	Current Year Recovery Variance	-7,343.17
Recovery ($)	169,921.83	Closing Account Balance	-7,343.17
Approved Recovery	177,265.00	Interest on Opening Balance	0.00
Recovery Variance	-7,343.17	Accumulated Interest	0.00
		Total Account Balance	-7,343.17

NATURAL RESOURCE GAS LIMITED

CAPITAL STRUCTURE

NRG's is seeking Board approval for new distribution rates for its 2011 Test Year based on an ROE of <u>10.35%</u> applied to a deemed equity ratio of 42%. This is the same level of equity that the Board approved in NRG's last rates case (EB-2005-0544) in conjunction with a risk premium of 50 basis points over the Board approved return on equity ("ROE") of Enbridge Gas Distribution ("Enbridge"). As part of that decision, the Board determined that NRG's actual equity ratio was 41.5% in the 2007 Test Year and that the actual equity ratio should be used unless the actual ratio was unreasonable.

In a prior decision (RP-2004-0167) dealing with NRG's 2005 Test Year, the Board deemed an equity ratio of 50% for NRG (15 percentage points above Enbridge's deemed equity ratio) and approved the same ROE for both companies. The Board has approved 50% deemed equity ratios in NRG's two previous rate cases dealing with four other test years going back to 1998.[1]

Given the unique circumstances impacting its capital structure in the current application, NRG has proposed a deemed equity ratio of 42% for its 2011 Test Year on the recommendation of its cost of capital expert, Kathleen C. McShane. Since its last rates case, NRG's capital structure has been impacted by an extraordinary increase in capital expenditures in 2008 to service a new ethanol plant locating in NRG's franchise area. The resulting impact on NRG's equity ratio is significant but temporary as it will self correct over the IRP term as the principal on NRG's total debt is repaid. NRG does not expect another customer addition of this magnitude over the next five years.

[1] RP-2002-0147, 2004 and 2003 test years; and, E.B.R.O. 496, 1998 and 1999 test years.

In order to provide service to the ethanol plant developed by the Integrated Grain Processors Co-operative ("IGPC") NRG was required to construct a dedicated high-pressure pipeline, resulting in a 50% increase in the company's rate base in 2008. The associated increase in debt financing and a special dividend reduced the company's actual equity ratio to 32%, well below Enbridge's deemed equity ratio. Since then principal repayments have reduced the company's total long-term debt ("LTD") from $11.1 million in 2009 to $9.9 million forecast for the 2011 test year. By the end of the 5-year IRP term, the LTD will be reduced to approximately $7.0 million and the actual equity ratios over the period are expected to average 47% well above the deemed equity ratio proposed for the 2011 Test Year.

Given the significant changes in its capital structure, NRG retained Ms. McShane to review potential changes in risk since the last rates case and recommend an equity ratio and risk premium for the purposes of determining its cost of capital for the 2011 Test Year. Based on a review of the current conditions, NRG's last rates decision and the most current ROE from the Board's Cost of Capital Report, Ms. McShane concluded that a ROE of 10.35%[2] and a deemed equity ratio of 42% would provide an appropriate basis for NRG's 2011 cost of capital.

As noted in the Board's Cost of Capital Report the capital structure of a natural gas distributor normally includes a small unfunded portion of short-term debt ("STD") which is used to true-up the utility's actual and deemed capitalization.[3] In the current application, NRG has also included a compensating balance in the STD to reflect the need to maintain a Guaranteed Investment Certificate ("GIC") of $2,751,130[4] in order to meet its bank loan covenants. Ms. McShane will comment on the appropriateness of using a compensating balance in the STD component of the capital structure.

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[2] Based on adding 50 basis points to the 9.85% ROE update provided by the Board on February 24, 2010
[3] Bottom of page 55 of the Board's Cost of Capital Report
[4] Closing balance from 2009

A summary of the capital structure is presented in Exhibit E1, Tab 1, Schedule 4. The components of the capital structure have been calculated using the average of the monthly balances throughout the year. The unfunded debt portion of the short-term debt in each fiscal year is the amount necessary to balance the required capital to the rate base.

NATURAL RESOURCE GAS LIMITED

COST OF DEBT

In its recent Cost of Capital Report, the Board confirmed that it plans to continue use the weighted cost of embedded debt and any new approved debt when determining the cost of capital for rate regulated natural gas distributors in Ontario.[1] The Board also noted that the debt cost will include an unfunded portion of short-term debt which is used to true-up the deemed capitalization to the utility's actual capitalization[2].

In the current application, NRG has also included an additional compensating balance in the Short Term Debt ("STD") which is required to meet the loan covenants imposed by the bank. Rather than showing this financing requirement as a cash deposit and the long-term debt at full value, the company has included the Guaranteed Investment Certificate ("GIC") in the STD to balance the capital structure at representative level close to NRG's actual equity ratio. Ms. McShane will comment on the appropriateness of including a compensating balance in the capital structure.

The 2010 Bridge Year and 2011 Test Year debt costs are shown in Tab 1, Schedule 3 of Exhibits E7 and E8, respectively. A summary of the cost of debt is presented in Exhibit E1, Tab 1, Schedule 4.

Bank of Nova Scotia Loans

NRG continues to rely on financing obtained from the Bank of Nova Scotia. This financing consists of three components: a fixed-rate loan, which will be renewed in the 2011 Test Year; a variable-rate loan which will be renegotiated during the IRP term; and, a revolving line of credit, which is not being utilized. In addition, NRG maintains a compensating balance in the form of a GIC with the Bank of Nova Scotia in order to

[1] *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, top of page 51.
[2] *Ibid*, bottom of p. 55.

ensure that the restrictive covenants that the bank has placed on the three outstanding debt instruments will not be breached.

NRG's line of credit has a maximum of $1.0 million which is payable at an interest rate equal to the prime lending rate of the Bank of Nova Scotia. This facility is to be used for general operating requirements. The fixed-rate debt has a principal of $6.5 million and an interest rate of 7.52% and has a five year term. In the 2011 Test Year the average value of this loan will be $5,964,863. The variable debt principal is $5,200,000 and carries a carries a floating interest rate of prime plus 0.25% that currently totals 2.75%. The prime lending rate for the 2011 Test Year has been forecast by Ms. McShane at 3.85%. In the 2011 test year the average value of this loan is forecast to be $3,943,333. The payments made on both loans are substantial, with the principal on the variable debt being repaid at $520,000 per annum.

Financing and Refinancing Costs

NRG has incurred financing costs associated with obtaining the Bank of Nova Scotia loan and refinancing costs associated with the retirement of previous debt instruments with Imperial Life and Banco Securities. Retirement costs totaling $204,712.66 were approved for recovery in EB-2005-0544.

Fiscal 2011 Test Year

The overall cost of the deemed debt forecast for the test year is 8.26%, as shown in Exhibit E8, Tab 1, Schedule 2. The calculations for the long-term and short-term debt costs are shown in detail in Exhibit E8, Tab 1, Schedule 3. The overall deemed debt rate reflects a 6.69% cost for long-term debt, 0.50% for short-term debt, and 0.50% for the compensating balance of the GIC.

The long-term debt cost of 6.69% reflects a 7.52% interest rate on one of the Bank of Nova Scotia loans, the forecast interest rate of 4.10% on the other Bank of Nova Scotia loan plus the continuing amortization of the financing costs associated with obtaining the replacement financing and the amortization of the redeployment and other related costs associated with the debt that has been replaced.

NRG plans to refinance the outstanding balance of the fixed rate loan during the test year at approximately the same rate and terms as the existing loan. The variable rate loan will be refinanced during the IRM term. The cost of obtaining replacement debt for the two Bank of Nova Scotia loans has not been added to the refinancing and redeployment costs previously approved by the Board. These costs are currently being amortized and included in the cost of debt as shown in Exhibit E8, Tab 1, Schedule 3.

NRG's average long term debt is forecast to decline from $10,551,662 in 2010 to $9,908,196 in 2011. The level of short-term debt is forecast to continue to decline from $2,390,792 in the 2010 Bridge Year to $2,009,332 in the 2011 Test Year. The short-term debt continues to reflect the sum of compensating cash balance held by NRG as a GIC and the ~~gross~~ unfunded debt. The average cost of unfunded debt for rate making purposes is unchanged from the projected 2010 level of 0.50%.

NATURAL RESOURCE GAS LIMITED

COST OF EQUITY

For the purposes of calculating proposed rates for its 2011 Test Year, NRG has used a cost of equity of 10.35% as shown in Tab 1, Schedule 1 of Exhibit E8. This proposed return was based on the most current rate of 9.85% from the Board's revised return of equity formula[1] ("ROE Formula") plus a 50 basis point premium matching the risk adjustment approved by the Board in NRG's last rates case[2] and reconfirmed as being appropriate for setting NRG's cost of equity the 2011 Test Year by the company's cost of capital witness, Kathleen C. McShane of Foster Associates, Inc.

Based on the Board's Cost of Capital Review (EB-2009-0084), NRG expects that the ROE approved in this application will be determined by the Board using the ROE Formula to reflect the most current market conditions and that the proposed 50 basis point risk premium, if approved by the Board, will be added to the adjusted ROE and the resulting ROE will be applied to a 42% equity ratio to provide an appropriate cost of capital for inclusion in NRG's 2011 rates. This approach is consistent with the Board's previous decision on an appropriate risk premium and equity ratio. Further detail on the equity ratio is provided in the Capital Structure section, Exhibit E1, Tab 1 Schedule 1.

If instead of applying a risk premium, the Board decides to approve a higher deemed equity ratio as it did in the previous NRG decision[3] to adjust for the difference in business and financial risk between Enbridge Gas Distribution, Ms. McShane has determined that a deemed equity ratio ranging from 46% to 49% would be comparable to the return produced by the 50 basis point risk premium proposed by the company.

[1] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009
[2] EB-2005-0544, where the Board approved a 50 bp risk premium and an equity ratio of 42%
[3] In RP-2002-0147 the Board approved a deemed equity ratio for NRG which was 15 percentage points above Enbridge's and the same ROE for both utilities.

NRG is seeking approval for a deemed equity ratio of 42% and an ROE based on the most current output from the Board's ROE Formula plus 50 basis points to adjust for the difference in risk between NRG and Enbridge as previously approved by the Board. If the Board decides that it would prefer to adjusted NRG's deemed equity ratio, NRG recommends that the Board approve a deemed equity ratio to 46% and an ROE based on the most current output from the Board's ROE Formula.

Exhibit E1, Tab 1, Schedule 4 includes a summary of the return on equity for fiscal 2006 through 2011, including the EB-2005-0544 Board approved return for fiscal 2007 which was 9.20% on an equity component of 42%.

NATURAL RESOURCE GAS LIMITED

Summary of Capital
($'s)

Capital Structure

	Actual 2006	Actual 2007	EB-2005-0544 Board Approved	Actual 2008	Actual 2009	Bridge 2010	Test 2011
Long-Term Debt	54.21%	71.02%	66.21%	71.12%	78.44%	74.99%	72.80%
Short-Term Debt							
Operating Loan	1.04%	0.00%	0.00%	0.00%	-20.07%	-19.55%	-20.20%
Unfunded Debt	22.75%	6.98%	-8.21%	-13.12%	-0.37%	2.56%	5.40%
Total Debt	78.00%	78.00%	58.00%	58.00%	58.00%	58.00%	58.00%
Common Equity	22.00%	22.00%	42.00%	42.00%	42.00%	42.00%	42.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Cost of Debt

	Actual 2006	Actual 2007	EB-2005-0544 Board Approved	Actual 2008	Actual 2009	Bridge 2010	Test 2011
Long-Term Debt	8.58%	8.36%	8.31%	8.37%	6.10%	6.10%	6.69%
Short-Term Debt							
Operating Loan	8.00%	6.00%	6.00%	6.00%	0.50%	0.50%	0.50%
Unfunded Debt	8.00%	6.00%	6.00%	6.00%	0.50%	0.50%	0.50%
Total Overall Debt	8.40%	8.15%	8.64%	8.91%	8.05%	7.74%	8.26%

Return on Equity

	Actual 2006	Actual 2007	EB-2005-0544 Board Approved	Actual 2008	Actual 2009	Bridge 2010	Test 2011
Return on Equity	9.20%	9.20%	9.20%	9.20%	9.20%	9.20%	10.35%
Actual Return	-1.21%	9.84%	9.20%	7.29%	9.16%	8.60%	4.25%

EB-2010-0018

March 12, 2010

Exhibit E2

Tab 1

Schedule 1

OPINION

ON

CAPITAL STRUCTURE AND EQUITY RISK PREMIUM

FOR

NATURAL RESOURCE GAS

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

March 2010

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. Please state your name, business address, occupation and educational background and experience.

A. My name is Kathleen C. McShane and my business address is 4550 Montgomery Avenue, Suite 350N, Bethesda, Maryland 20814. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and the Chartered Financial Analyst designation (1989). I have testified on issues related to cost of capital and various ratemaking issues on behalf of local gas distribution utilities, pipelines, electric utilities and telephone companies in more than 200 proceedings in Canada and the U.S., including the Ontario Energy Board. My professional experience is provided in Appendix A.

Q. What is the purpose of your testimony?

A. I have been asked by Natural Resource Gas (NRG) to evaluate the reasonableness of certain elements of its forecast cost of debt and to recommend a common equity ratio and equity risk premium for the Company.

Q. Please summarize your conclusions.

A. In my opinion, the proposed test year cost rates for both the variable and fixed rate loans are reasonable based on current and anticipated capital market conditions. With respect to the capital structure and equity risk premium, in its *Decision with Reasons* in EB-2005-0544 dated September 20, 2006, the Ontario Energy Board (OEB) adopted a common equity ratio of 42% and an incremental equity risk premium of 0.50% above that applicable to Enbridge Gas Distribution. In my opinion, the 42% common equity ratio previously adopted by the Board remains appropriate for NRG. The benchmark ROE was recently reviewed, and the automatic adjustment formula refined, by the OEB in EB-2009-0085 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities,* issued December 11, 2009. In conjunction with a common equity ratio of 42%, a return on equity (ROE) that represents a risk premium of 0.50% above the benchmark ROE as updated is warranted for the 2011 test year.

II. BACKGROUND

The OEB first adopted a formula-based approach to establishing the cost of capital for Ontario's natural gas utilities in March 1997. In its first decision implementing this approach, it approved a base ROE of 10.65% for Enbridge Gas Distribution at a long-term Canada bond yield of 7.25% (EBRO 495, August 1997). In EBRO 496 (August 1998), the OEB adopted a deemed common equity ratio for NRG of 50%, and allowed the same risk premium as applicable to Enbridge Gas.[1] The same deemed equity ratio was adopted in three subsequent rate decisions, along with a risk premium equivalent to Enbridge Gas's (RP-2000-0126, RP-2002-0147, and RP-2004-0167).

In EB-2005-0544 (September 2006), following a refinancing of NRG's capital structure, the OEB adopted an equity ratio of 42%, approximately equal to the actual equity ratio and allowed an equity risk premium 50 basis points above that applicable to Enbridge Gas.[2] In that decision, relevant conceptual considerations include the Board's determinations that (1) the actual equity ratio should be used unless the actual equity ratio is unreasonable; and (2) risk premiums are appropriate in certain cases. With specific respect to NRG, the Board concluded

[1] The formula-based approach expanded to the electricity sector in 1999, and an equity risk premium established for the electricity distributors equal to that applicable to Enbridge Gas.

[2] In its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, December 20, 2006, the OEB adopted an equity ratio of 40% for all of the electricity distributors and confirmed the allowed ROE at a level equivalent to that allowed for Enbridge Gas.

that NRG's risk had declined, but NRG is a more risky utility than Enbridge or Union.

In March 2009, the Board initiated a consultative process to review the methods by which the cost of capital was established for Ontario's regulated utilities. In December 2009, the Board issued its cost of capital policy report, in which it:

(1) Confirmed its capital structure policy. Specifically, the Board stated that for gas utilities, the deemed capital structure is determined on a case-by-case basis, that the draft guidelines assume the base capital structure will remain relatively constant over time, and the capital structure would only be fully reassessed in the event of significant changes in the company's business and/or financial risk;

(2) Established a new base ROE of 9.75%, subsequently updated to 9.85%[3]; and

(3) Refined the automatic adjustment formula.

In light of the OEB's cost of capital policy report, the base ROE of 9.75%, as adjusted using the refined automatic adjustment formula prior to new rates becoming effective (currently 9.85% for rates effective May 1, 2010), should be the point of departure for establishing NRG's ROE for the test year. The principal issues to be addressed with respect to capital structure and ROE are whether there has been any change in circumstances that would alter either the capital structure and/or the company-specific risk premium that were adopted by the OEB for NRG in EB-2005-0544.

[3] Ontario Energy Board, *Cost of Capital Updates for 2010 Cost of Service Applications*, February 24, 2010.

III. COST OF DEBT

Q. Please describe NRG's debt instruments whose test year cost rates you have evaluated.

A. NRG's debt financing includes a fixed rate loan, a variable loan and a revolving line of credit, all from the Bank of Nova Scotia. The revolving line of credit is not currently being utilized and is not forecast to be utilized during the test period. The fixed rate loan is a five-year term note payable with an initial principal amount of $6.5 million, obtained in 2006. Interest on the loan is payable monthly, and principal is to be repaid over the life of the loan according to a 25-year amortization schedule, with the unpaid balance due at the end of the five-year term. The fixed rate on the loan is 7.52%. The five-year term expires during the test year (March 2011) and the remaining outstanding principal on the loan is expected to be refinanced at that time. The variable rate loan, obtained in 2009, is a term note payable with an initial principal amount of $5.2 million. It is also payable monthly in blended interest and principal installments. The repayment amounts total $520,000 annually. The variable rate loan, which matures in 2017, carries a rate equal to prime plus 0.25%.

As conditions of the term notes payable financing, NRG is required to maintain: 1) a ratio of Earnings before Interest, Taxes, Depreciation and Amortization to Interest plus the current portion of long-term debt of 1.25 times or higher; 2) a ratio of current assets to current liabilities (excluding the current portion of long-term debt) of 1:1 or better; and 3) a ratio of total debt to tangible net worth of less than 3:1. To ensure maintenance of these requirements, NRG purchased a $2.75 million Guarantee Investment Certificate (GIC) which it maintains as a compensating balance.

Q. NRG's application includes a forecast cost of refinancing the fixed rate loan during the test period equal to the fixed rate of 7.52% obtained in 2006. Please explain why the same rate of 7.52% is a reasonable estimate of the rate at which NRG would able to refinance the loan in 2011.

A. NRG fixed the rate on the five-year term loan in March 2006. On average during March 2006, the yield on the five-year Government of Canada bond was 4.1%. The 7.52% rate thus represented a spread of approximately 3.4 percentage points above the corresponding term Government of Canada bond yield. A review of available forecasts of five-year Government of Canada bond yields for the first quarter of 2011 as shown in the table below indicates that the yield is expected to be approximately 3.65% at the time NRG must refinance the loan.

Table 1

Forecast	**Forecast 5-year Canada 1Q 2011**
BMO	3.30%
Desjardins	3.55%
National Bank[1/]	3.60%
RBC	3.75%
ScotiaBank	3.85%
TD Bank	3.70%
Average	**3.63%**
Median	**3.65%**

[1/] For all of 2011

Sources:
BMO Capital Markets, *Rates Scenario*, Feb. 1, 2010
Desjardins Economic Studies, *The Yield Curve*, Feb. 1, 2010
National Bank Financial Group, *Monthly Economic Monitor*, February 2010
RBC, *Financial Markets Monthly*, Feb. 5, 2010
ScotiaBank Group, *Global Forecast Update*, Feb. 3, 2010
TD Bank Financial Group, *Quarterly Economic Forecast*, Dec.17, 2009

While the five-year Canada bond yield is expected to be approximately 0.45% lower in first quarter 2011 than it was during March 2006, bond yield spreads are higher than they were in early 2006. At the end of March 2006, the spread between long-term Canadian corporate[4] and the 30-year benchmark Government of Canada bond yields was 113 basis points; the corresponding spread at the end of January 2010 was 181 basis points, or approximately 70 basis points higher.[5] Based on current spreads, the increase in spread would more than offset the expected lower five-year Canada bond yield. However, some further contraction in spreads could reasonably be expected as the economy continues to recover from the recession. Even allowing for some further contraction of spreads, it is reasonable to expect the cost at which NRG could refinance the fixed rate loan to be similar to the cost incurred when the fixed rate loan was initially issued.

Q. What would be a reasonable estimate of the yield on the variable rate loan for the test period?

A. As noted above, the variable rate debt carries a cost of prime plus 0.25%. The prime rate follows the overnight rate. The overnight rate is the interest rate at which major financial institutions borrow and lend one-day funds among themselves and for which the Bank of Canada sets a target level. Economists typically do not forecast the prime rate, but they do forecast the overnight rate. The prime rate has historically been approximately 200 basis points higher than the overnight rate and the correlation between the overnight rate and the prime rate is close to 100%. The table below summarizes recent available forecasts for the overnight right for NRG's test year.

[4] Based on the DEX Long-term Corporate Index, formerly the Scotia Capital All Corporates-Long-term, which was used by the OEB to establish deemed long-term debt rates for the Ontario electricity distributors prior to the December 2009 *Report of the Board*.

[5] There are no publicly available indices for shorter-term bonds and/or specifically for Canadian bonds rated in the BBB or lower categories that would allow the change in spread for a shorter-term lower rated utility bond to be estimated more precisely. For some further perspective, however, the increase in spread between Moody's U.S. Baa rated intermediate term utility bond yields and the average of the seven and ten year Treasury yields between March 2006 and January 2010 was also close to 70 basis points.

Table 2

Forecast	4Q 2010	1Q 2011	2Q 2011	3Q 2011	Average
BMO	1.10%	1.60%	2.10%	2.60%	1.85%
CIBC	1.00%	1.00%	1.50%	N/A	1.17%
Desjardins	0.75%	1.25%	1.75%	2.25%	1.50%
National Bank [1/]	1.75%			2.25%	2.13%
RBC [2/]	1.25%	2.75%	2.75%	3.50%	2.56%
ScotiaCapital	1.25%	1.75%	2.25%	2.25%	1.88%
TD Bank	0.75%	1.50%	2.00%	2.75%	1.75%
Average					**1.83%**
Median					**1.85%**

[1/] 3Q 2011 rate is for all of 2011

[2/] 3Q 2011 is for second half of 2011

Sources:

BMO Capital Markets, *Rates Scenario*, Feb. 1, 2010
CIBC World Markets, *Economic Insights*, Jan. 28, 2010
Desjardins Economic Studies, *The Yield Curve*, Feb. 1, 2010
National Bank Financial Group, *Monthly Economic Monitor*, February 2010
RBC, *Financial Markets Monthly*, Feb. 5, 2010
ScotiaBank Group, *Global Forecast Update*, Feb. 3, 2010
TD Bank Financial Group, *Quarterly Economic Forecast*, Dec.17, 2009

The indicated consensus overnight rate is approximately 1.85%. Adding 200 basis points to the consensus view would result in a prime rate of approximately 3.85%. Since the variable rate issue carries a cost of prime plus 0.25%, a reasonable estimate of the cost for the test year is 4.1%.

IV. CONCEPTUTAL CONSIDERATIONS IN THE EVALUATION OF THE CAPITAL STRUCTURE AND EQUITY RISK PREMIUM FOR NRG

Q. Please summarize the basic financial principles that underpin the determination of a reasonable capital structure and return on equity for a regulated utility.

A. The determination starts with the proposition that the fair return (which in this context encompasses both capital structure and ROE) for a utility should be determined on a stand-alone basis. The stand-alone principle encompasses the notion that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the utility raising capital in the public markets on the strength of its own business and financial parameters. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources and avoid cross-subsidies. The stand-alone principle has been respected by virtually every Canadian regulator, including the OEB in setting both regulated capital structures and allowed ROEs.

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk relates largely to the assets of the firm. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested.

The cost of capital is also a function of financial risk. Financial risk refers to the additional risk that is borne by the equity shareholder because the firm uses debt to finance a portion of its assets. The capital structure, comprised of debt and common equity, can be viewed as a summary measure of the financial risk of the firm. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

There are effectively two approaches that can be used to determine a fair rate of return on rate base. The first is to assess the "subject" utility's business risks, then establish a capital structure that (a) is compatible with its business risks; (b) would permit it to access the debt markets on reasonable terms and conditions; and (c) would approximately equate the level of the specific utility's total (business and financial) risk to that of the proxies (or benchmarks) used to estimate the cost of equity. This approach, which fully adjusts for differences in business risk among utilities through capital structure, permits the application of a single "benchmark" cost of equity to the subject utility, that is, without any adjustment (e.g., an incremental risk premium) to the benchmark ROE.

The second approach relies on acceptance of the utility's actual or proposed deemed capital structure for regulatory purposes. The actual or deemed capital structure then becomes the key measure of the utility's financial risks. The utility's level of total risk (business plus financial) is then compared against that faced by the proxy firms used to estimate the ROE requirement. If the total risk of the benchmark sample is higher or lower than that of the subject utility, an adjustment to the cost of equity would be required when setting the subject utility's allowed ROE.

Both of these approaches have been taken by regulators in Canada. The OEB has used both approaches, the latter for NRG in its last rates decision, as well as for Enbridge Gas and Union Gas. It used the first approach for Ontario Power Generation in *Decision with Reasons* in EB-2007-0905 (November 1, 2008), where it established an ROE comparable to those allowed for other Ontario regulated energy utilities and reflected the difference in risk through a higher common equity ratio.

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard. Both approaches used by Canadian regulators are equally valid as long as the combination of capital structure and return on equity result in an overall return which satisfies all three fair return standards.

The same principle underpins the two options: there is a trade-off between capital structure and return on equity. Thus, the evaluation of the various components of the cost of capital cannot be undertaken in isolation. The cost of equity is a function of the business risks and financial risks of the firm. Simplistically, there is an inverse relationship between the cost of equity and the common equity ratio. All other things equal, the higher the common equity ratio, the lower the cost of equity.

V. CAPITAL STRUCTURE

A. Principles

Q. What principles should underpin the determination of the capital structure (as well as the overall cost of capital?

A. The capital structure and equity risk premium for NRG should:

(1) respect the stand-alone principle;
(2) be consistent with NRG's business risks;
(3) allow NRG to access the capital markets on reasonable terms and conditions; and

(4) result in an overall return that is comparable to the returns of comparable risk companies.

The stand-alone principle encompasses the notion that the cost of capital incurred by a utility should be equivalent to that which would be faced if it was raising capital in the public markets on the strength of its own business and financial parameters; in other words, as if it were operating as an independent entity. The cost of capital for the company should reflect neither subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone principle is intended to promote efficient allocation of capital resources among the various activities of the firm. The stand-alone principle applies to both the capital structure and the ROE.

The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested. The fundamental business risks of a utility include demand, competitive, supply, operating, technology-related and political risks. Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between the utility's customers and its investors.

With respect to access to capital, the allowed capital structure and ROE for NRG should provide the basis for the utility to be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. In contrast to unregulated companies, utilities do not have the same flexibility to defer financing new assets. Utilities are required to provide service on demand, and must access the capital markets when service requirements demand it. For the larger investor-owned regulated Canadian utilities, a target debt rating in the A category is optimal from both a cost and market access perspective. However, NRG is too small to be rated and too small to access the public debt markets. Nevertheless, estimates of credit metrics for NRG and comparisons with those achieved by utilities whose debt is rated can provide some assistance in establishing whether the proposed capital structure, in conjunction with the allowed ROE, would produce adequate financing flexibility.

With respect to comparable returns, the Board has explicitly recognized that the comparable investment requirement of the fair return standard must be met in setting the allowed return. To satisfy the comparable investment requirement of the fair return standard, the return allowed must be comparable to the return available from the application of invested capital to other enterprises of like risk. (*Report of the Board, 2009*, pages 18 and 21).

B. Actual Capital Structure

Q. In approving an equity ratio of 42% for NRG in EB-2005-0544, the Board commented that the actual equity ratio should be used unless the actual ratio was unreasonable and that the actual ratio at the time was 41.5%, close to the approved ratio. Has NRG's capital structure changed since that decision?

A. Yes. As noted in Chapter IV, since its last rate decision, NRG added a new industrial customer on whose behalf the Company incurred over $5 million in capital expenditures, increasing its rate base by approximately 50% between 2008 and 2009. NRG financed the capital expenditures largely with a new debt issue from the Bank of Nova Scotia with a principal amount of $5.2 million. At the end of 2009, the actual capital structure, measured using gross debt[6] and equity only, comprised 68% debt and 32% equity. However, as noted in Chapter III, to ensure compliance with the terms and conditions of its debt financing, NRG purchased a GIC. The 2009 year-end actual capital structure ratios, measured using total debt net of the GIC plus equity, were 61.3% debt and 38.7% equity.

[6] Gross debt is equal to the outstanding balances of the fixed and variable rates notes payable; i.e., it excludes the $2.75 million GIC compensating balance held by NRG.

Because NRG is required to make monthly repayments of principal on both debt issues, the gross amount of debt outstanding will decline over time. As the debt is paid off, and earnings are retained, the actual equity ratio will rise. By the end of the 2011 test year, with the required debt repayments, a planned refinancing of the outstanding principal amount of the fixed rate loan in March 2011, and no dividend payments forecast, the actual equity ratio measured using gross debt and equity is expected to reach approximately 38%. Measured based on net debt and equity, the equity ratio will exceed 46%. As part of this application, NRG is requesting a five-year incentive regulation plan (IRP). Over the term of the proposed IRP, assuming NRG earns its allowed return, no dividends are paid and the principal amounts of debt are repaid as required, the actual equity ratio would average above 47% based on gross debt and, assuming the GIC remains in place at the 2011 level, approximately 57% based on net debt.

Q. Is it reasonable to measure the actual capital structure by deducting the forecast amount of the GIC from the gross debt?

A. Yes, based on my understanding of the rationale for carrying the GIC. It is my understanding that the GIC is required in order to meet the terms and conditions of its loan agreement with the Bank of Nova Scotia. The GIC ensures that the requirements of the loan agreement set out above are met and functions as a sinking fund that ensures that funds are available to meet the repayment obligations. The GIC (or a sinking fund) effectively reduces the gross amount of the debt outstanding and should be subtracted from the gross proceeds of the debt for purposes of calculating the actual capital structure. Similarly, in calculating the cost of debt, the interest on the gross amount of the debt outstanding should be reduced by the earnings on the GIC.

Q. Are you aware of any utilities which have sinking fund debt whose capital structures and cost of debt are calculated in this manner?

A. Yes, there are several, including BC Hydro, Hydro-Québec Distribution and Transmission, NB Power Transmission, Newfoundland and Labrador Hydro and Northwest Territories Power Corporation.[7] The methodology was recently reviewed in detail for Northwest Territories Power Corporation and confirmed as appropriate by the regulator.[8]

Q. Given the likelihood that NRG's actual capital structure will continue to evolve as the outstanding debt is repaid, what do you recommend that the Board do for purposes of establishing a capital structure for ratemaking purposes?

A. In my opinion, the Board should adopt a deemed capital structure that, in conjunction with the ROE, is consistent with the company's business risks, will allow the utility access to capital on reasonable terms and conditions, and meets the comparable investment requirement of the fair return standard. As noted above, in EB-2005-0544, the Board adopted a common equity ratio for NRG of 42%. The section below assesses the trend in NRG's business risk since that decision for the purpose of determining whether changes in business risk warrant a change in the capital structure.

C. Trend in Business Risk

Q. Please explain your understanding of the term "business risks".

A. As noted above, the business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested.

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[7] The debt rating agencies, DBRS and Standard & Poor's, calculate the debt ratios of BC Hydro, Hydro-Québec and Newfoundland and Labrador Hydro net of sinking fund assets, temporary investments and financial assets related to debt.

[8] The Public Utilities Board of the Northwest Territories, *Decision 13-2007*, August 29, 2007.

Business risk arises from demand, competitive, supply, operating, political and regulatory factors. While different business risk categories can be identified, they are inter-related. The regulatory framework, for example, is frequently designed around the inherent demand/competitive risks.

Business risks have both short-term and longer-term aspects. Short-term business risks relate primarily to year-to-year variability in earnings due to the combination of fundamental underlying economic factors and the existing regulatory framework. Long-term risks are important because utility assets are long-lived. Long-term business risks comprise factors that may negatively impact the long-run viability of the utility and impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon. As utilities represent capital-intensive investments with very limited alternative uses, whose committed capital is recovered over an extended period of time, it is the long-term risks that are of primary concern to the investor.

Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between ratepayers and shareholders. Regulatory risk can be considered either as a component of business risk or as a separate risk category. The regulatory framework is dynamic: it is subject to change as a result of shifts in underlying fundamental risk factors including the competitive environment, energy policy, and regulatory philosophy.

Because regulated firms are generally regulated on the basis of annual revenue requirements, there has been a tendency to downplay longer-term risks, essentially on the grounds that the regulatory framework provides the regulator an opportunity to compensate the shareholder for the longer-term risks when they are experienced. This premise may not hold. First, competitive factors and ratepayer resistance may forestall higher return awards when the risk materializes. Second, no regulator can bind his or her successors and thus guarantee that investors will be compensated for longer-term risks when they are incurred in the future.

Q. Do you see any evidence that the business risk of NRG relative to Enbridge Gas has changed materially since NRG's last rate proceeding?

A. No. The principal distinction between NRG and Enbridge continues to be the size of their operations and diversity of their markets. As it was the last time the Board evaluated its business risks, NRG remains a very small gas distribution utility serving a predominantly rural area southeast of London, Ontario, with franchise agreements with six municipalities, with a total population of approximately 60,000. Table 3 below provides some perspective on NRG's relative size compared to the major Canadian gas distributors. As the table indicates, NRG is less than 1% of the size of the major gas distributors on all three measures, customers, deliveries and rate base.

Table 3

Gas Distributor	Customers (Thousands)	Deliveries (10^6 m^3)	Rate Base (Millions of $)
NRG [1/]	7	53	13
ATCO Gas	1,260	6,200	1,035
Enbridge Gas	1,900	12,200	3,800
Gaz Métro	175	5,800	1,850
Terasen Gas	845	4,300	2,500
Union Gas	1,310	13,900	3,200

[1/] Test year forecast

A small utility cannot diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated. Negative events are likely to have greater impact on the earnings or viability of a smaller company. The impact of smaller size for utilities with rated debt is frequently exhibited in lower debt ratings for these companies despite financial parameters that are stronger than their larger peers.[9]

[9] See also discussion of small size premium in Chapter V.

To illustrate, in its June 2009 rating report for FortisBC, an electric utility, DBRS called the company's small size a "challenge" and stated,

> "FortisBC is a small utility compared with the dominant utility in the province, the Crown-owned BC Hydro, and serves a rural and low-population density region in south-central British Columbia. To some extent, the small size and franchise area limit opportunities for growth, operating efficiencies, and economies of scale as they relate to PBR."

FortisBC, which had a rate base of over $900 million in 2009, despite better credit metrics than Terasen Gas, the benchmark BC utility, due to an allowed common equity ratio of 40% and an allowed ROE that is 40 basis points higher than Terasen Gas's, is rated BBB(High) by DBRS and Baa2 by Moody's. Terasen Gas, by comparison, has ratings of A by DBRS and A3 by Moody's.[10]

The economic base of the Company's service area is largely agricultural, as reflected in its industrial customer makeup. The preponderance of its approximately 130 industrial customers operate agriculture-related businesses, including tobacco processing and curing, grain drying, canning, greenhouse heating, and livestock (poultry and cattle) operations. Since the last rate proceeding in 2006, what historically was NRG's single largest industry, tobacco processing and curing, has continued to contract, as the production of tobacco has fallen in response to declines in consumption and government policy. In 2009, the quota system for tobacco production was replaced with a licensing system and the federal government implemented a program to assist tobacco growers to exit the industry. The number of customers in NRG's Rate 2 class, which is made up primarily of tobacco dryers, has fallen from 121 in 2005 to a forecast 73 in test year 2011. As tobacco farmers have ceased production, reduced the size of their operations or switched to production of other crops, volumes to the Rate 2

[10] In Decision 2009-216, *2009 Generic Cost of Capital*, dated November 12, 2009, the Alberta Utilities Commission stated (page 98), "The Commission is persuaded that due to its small size, AltaGas is more risky than ATCO Gas." The Commission set the allowed common equity ratio for AltaGas at 43%, compared to 39% for ATCO Gas, of which one percentage point of the differential can be attributed to ATCO Gas's weather normalization deferral account.

customer class have declined by close to 85% since 2005. In the absence of the addition of one new large industrial customer (discussed below), NRG's total volumes (inclusive of Rate 2 volumes) between 2005 and 2011 would have fallen by over 10%.

In Decision 2005-0544, in concluding that NRG's business risk had declined since the previous assessment, the Board pointed to the tripling of customers since 1991 and the forecast strong growth in residential customers in 2007. Between 1993 and 2005, NRG experienced approximately 6.5% annual growth in customers. Customer growth has moderated materially since the last Board decision, particularly as a result of recessionary conditions not only in NRG's franchise area, but also in the greater London Economic Region.

The London Economic area was particularly hard hit by the downturn in the manufacturing and automotive sectors. Unemployment in the London Economic Region reached hit close to 11% in 2009, at the time the second highest rate in Ontario. The Daimler Sterling Trucks assembly plant in St. Thomas closed in 2009; the Ford St. Thomas assembly plant is slated for closure in 2011. These closures have secondary effects, e.g., parts manufacturer Lear Seating (which manufactures seats and electronics for GM and Ford in its St. Thomas plant) declared bankruptcy in 2009. Magna International laid off close to 1250 workers at its St. Thomas truck frame plant between 2008 and 2009. While the unemployment rate in the area has declined since its peak (8.4% in January 2010), the labour force has declined and the quality of jobs has also declined.

Over the whole period since NRG's last rate application (2005-2009) annual total customer growth averaged 2.7%; residential customer growth averaged 3.0%. However, in 2009, NRG's customer additions fell by 38% and growth in residential customers from 2009 to 2011 is expected to be relatively modest, at 2.1% per year, reflecting relatively slow growth in housing starts.[11]

Since NRG's last rate decision in 2006, the Company has added a new industrial customer, IGPC Ethanol Inc. (IGPC), which produces ethanol from corn. The addition of the new customer, for which a dedicated pipeline was constructed, increased NRG's rate base by approximately 50%, and more than doubled its throughput. As compared to 2005, when approximately 19% of NRG's gross margin was derived from its industrial rate classes, in 2011, inclusive of IGPC, that percentage is expected to be over 35%, of which close to 30% is derived from IGPC. The comparative proportion of Enbridge's gross margin derived from industrial customers is approximately 9%. However, the risk associated with NRG's high reliance on a single industrial customer is mitigated by a long-term contract, a security deposit for commodity costs, and an irrevocable letter of credit which covers the net book value of the dedicated plant.

With respect to Enbridge Gas, DBRS considers it to have a "Strong franchise area with a large customer base"[12]; Standard & Poor's concludes that "supporting Enbridge Gas' excellent business risk profile is one of the most attractive gas utility franchises in Canada, which itself is characterized by favorable growth prospects, a high population density, and a fair regulatory system."[13] Since NRG's last rate proceeding, Enbridge's debt ratings have remained A (Stable) by DBRS and A- (Stable) by S&P.

With respect to the regulatory system referenced by S&P, both NRG and Enbridge are subject to the jurisdiction of the OEB and a similar regulatory system. Both are subject to weather risk, in contrast to a number of Canadian distributors who have access to weather normalization or deferral accounts.

[11] In Fall 2009, Canada Housing and Mortgage Corporation was projecting a 2.7% increase in housing starts in the London CMA.
[12] DBRS, *Rating Report: Enbridge Gas Distribution Inc.*, January 11, 2010.
[13] Standard and Poor's, *Enbridge Gas Distribution Inc.*, November 10, 2009.

Enbridge has in its incentive regulation plan a true-up mechanism for declining average customer use for general service customers. NRG's proposed incentive regulation plan is intended to account for reductions in average customer use through the price cap. Similar to virtually all North American gas distributors, both are protected from variances in gas costs, one of the largest and most variable cost categories. As regards variances from forecast costs for other cost categories, I see no significant difference between the two utilities' access to deferral or variance accounts.

In sum, in my opinion, NRG faces no less business risk than at the time of EB-2005-0544 and there is no evidence that its business risk relative to that of Enbridge Gas has changed materially since that time.

D. Allowed Capital Structures of Other Smaller Canadian Utilities

Q. Since most smaller utilities that would be most comparable to NRG do not have debt ratings or access the public capital markets, and thus do not have capital structures that are "tested" by the markets, how can you judge the reasonableness of the common equity ratio that was previously adopted by the Board for NRG?

A. While admittedly somewhat circular, the capital structures that have been adopted by regulators for other small utilities in Canada provide a perspective on whether the previously approved capital structure continues to be reasonable.

Q. How does the capital structure previously approved by the Board for NRG compare to capital structures adopted for other smaller gas and electricity distributors in Canada?

A. The table below summarizes the most recently adopted capital structures for smaller Canadian gas and electricity distributors. However, a number of the capital structures shown in the table below are subject to change, as indicated in the footnotes to the table. Based on the most recently adopted capital structures, the 42% common equity ratio previously adopted by the Board is within the range allowed for other smaller gas and electric utilities.

Table 4

Company	Allowed Equity Ratio	Rate Base ($ million)
AltaGas Utilities (Alberta)	43.0%	$166
Gazifère Inc.	40.0%	$68
Ontario Electricity LDCs	40.0%	all sizes
Maritime Electric	40.5%[1/]	$300
Northland Utilities (YK)	43.5%	$34
Northland Utilities (NWT)	44.0%	$12
Pacific Northern Gas (N.E.)	36.0% [2/]	$37
Pacific Northern Gas-West	40.0% [2/]	$131
Terasen Gas (Whistler)	40.0% [3/]	$38
Terasen Gas (Vancouver Island)	40.0% [3/]	$555
Yukon Electrical	40.0%	$43

[1/] Based on actual forecast for 2009; target of 45%.
[2/] Currently applying for 42.5% for PNG (N.E.) and 47.5% for PNG-West.
[3/] In its Order G-158-09 dated December 2009, in which it raised the common equity ratio of the benchmark utility, Terasen Gas, from 35% to 40%, the BCUC directed Terasen Gas (Whistler) and Terasen Gas (Vancouver Island) to file in their next revenue requirements proceeding the equity ratio that best reflects their long-term business risks.

E. Recommended Capital Structure for NRG

Q. Based on the above considerations, what capital structure should the Board adopt for NRG?

A. Given the evolving nature of NRG's capital structure, the trend in business risks, and the capital structures that have been adopted for other smaller Canadian gas and electric utilities, I recommend that the Board adopt a deemed capital structure for NRG at the same equity ratio that it approved in EB-2005-0544.

VI. EQUITY RISK PREMIUM FOR NRG

Q. If the Board adopts the same capital structure as approved in EB-2005-0544, is an incremental equity risk premium to the benchmark ROE adopted in *Decision of the Board, 2009* also warranted?

A. Yes. The *Decision of the Board, 2009* reset the benchmark equity risk premium to recognize that the existing automatic adjustment formula was not producing ROEs that met the fair return standard. The reset of the benchmark ROE was not based on a change in the relative risk of Ontario utilities since the formula was last reviewed (in 2006), but rather on the recognition that the formula as constructed was not tracking changes in the cost of equity and was producing returns that could not be reconciled with the ROEs for a low risk proxy group. As stated above, there is no evidence that the business risk of NRG has declined since the Board adopted a common equity ratio of 42% <u>and</u> an incremental equity risk premium of 0.50% above that applicable to Enbridge Gas (and implicitly 0.50% above that applicable to the electricity distributors, as the two were identical). Consequently, an incremental equity risk premium for NRG is still warranted.

Q. How do you assess whether the previously adopted incremental equity risk premium of 0.50% for NRG remains appropriate?

A. The quantification of any adjustment to a benchmark ROE requires two proxy samples of companies, one facing a relatively similar level of business risk to the benchmark utility and one facing a relatively similar level of business risk to the subject company, in this case, NRG. The difference in the two samples' costs of equity, adjusted as required to recognize differences in financial risk between the two samples and NRG at its proposed 42% deemed common equity ratio, would provide an estimate of the adjustment to the benchmark ROE required by NRG.

Q. What were your selection criteria for the samples to be used in the evaluation of the incremental risk premium for NRG?

A. The estimate of the incremental ROE or equity risk premium that would apply to NRG relative to the benchmark utility ROE of 9.75% established by the OEB in *Report of the Board, 2009* and subsequently updated to 9.85% starts with the premise that a benchmark Canadian (and Ontario) utility is, like the majority of Canadian utilities, a relatively low risk "pipes" or "wires" utility. Thus as a proxy for the benchmark utility, a sample of utilities is required which is representative criteria of relatively low risk, distribution (gas and electric) utilities.

In Canada, there are only seven publicly-traded Canadian utilities, six with conventional corporate structures,[14] and Gaz Métro, which trades as a limited partnership.[15] These companies are relatively heterogeneous in terms of both operations[16] and size.[17] The relatively small and heterogeneous universe of publicly-traded Canadian utilities means that it is impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility. Therefore, a sample of low risk U.S. distribution utilities was selected to serve as a proxy for estimating the fair return for the benchmark utility, comprised of all gas and electric distribution utilities satisfying the following criteria:

[14] Canadian Utilities, Emera, Enbridge, Fortis, Pacific Northern Gas and TransCanada Corporation.
[15] Gaz Métro's partnership unit prices were negatively impacted by the October 2006 announced change in the income tax treatment of income trusts with the result that its recent betas are not strictly comparable to those estimated for the conventional corporate regulated companies.
[16] Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.
[17] Ranging from an equity market capitalization of approximately $66 million (Pacific Northern Gas) to $24 billion (TransCanada).

Gas Distribution Utility Criteria:

1. Classified by *Value Line* as a gas distributor;

2. Greater than 80% of assets in gas operations;

3. Consistent history of I/B/E/S [18] analysts' forecasts;

4. Standard & Poor's and Moody's debt ratings of BBB+/Baa1 or higher;

5. Paid dividends in 2009.

Electric Distribution Utility Criteria:

1. Classified by *Value Line* as an electric utility;

2. Has more than 80% of its assets in electric or gas distribution operations, less than 5% of its total assets devoted to electricity generation and is not a pure electric transmission utility;

3. Consistent history of I/B/E/S analysts' forecasts;

4. Standard & Poor's and Moody's debt ratings of BBB+/Baa1 or higher;

5. Paid dividends in 2009.

The selected sample of nine utilities and their corresponding risk measures are found on Schedule 2. The benchmark sample of distribution companies, with a median business risk profile ranking of "Excellent" by Standard & Poor's, is in

[18] I/B/E/S is a leading provider of earnings expectations data. The data are collected from over 7,000 analysts at over 1,000 institutions worldwide, and cover companies in more than 60 countries.

the same business risk category as the typical Canadian utility[19] and are rated no lower than BBB+/Baa1 by both Standard & Poor's and Moody's. The average debt ratings of the sample are A (S&P) and A3 (Moody's), similar to those of the universe of Canadian utilities with rated debt (Schedule 1). The median *Value Line* Safety rank of the U.S. distribution utility sample is 1; the Safety ranks of both of the two Canadian regulated companies covered by *Value Line* (TransCanada Corp. and Enbridge Inc.) are higher, at 2.[20]

Q. How did you select a sample of utilities designed to be of a relatively similar level of risk to NRG?

A. The selection started with the conclusion that, given its business risk characteristics, small size and a common equity ratio of 42%, NRG would be not able to achieve an investment grade debt rating (i.e., a debt rating of BBB (low)/BBB- or better). However, the impact of size on the cost of capital is partly a result of the lack of liquidity in small debt issues and the absence of institutional interest rather than fundamental business risk factors. Liquidity and institutional interest issues aside, NRG would still be most likely to be assigned no higher than a BBB debt rating at the proposed capital structure. Consequently, a sample of BBB rated utilities was selected to serve as a proxy, albeit a conservative one, for NRG. As with the selection of the benchmark distribution sample, U.S. utilities were utilized. The sample of BBB rated utilities was selected according to the following criteria:

1. Classified as a gas or electric utility by *Value Line*;

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[19] There are six S&P business risk profile rankings, ranging from "Excellent" to "Vulnerable". All of the utilities in the proxy sample of U.S. utilities have an "Excellent" business profile, as do the majority of Canadian utilities whose debt is rated by S&P; see Schedule 1.

[20] The Safety rank represents Value Line's assessment of the relative total risk of the stocks. The ranks range from "1" to "5", with stocks ranked "1" and "2" most suitable for conservative investors. The most important influences on the Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

2. Rated BBB-/Baa3 to BBB+/Baa1 by both Standard & Poor's and Moody's;

3. Financial Risk Profile of "Significant" or better by Standard & Poor's.[21]

The 21 companies which met the selection criteria are shown on Schedule 3. The selected sample of companies has a median business risk profile ranking of "Strong",[22] one notch lower than the benchmark sample, debt ratings of BBB by S&P and Baa2 by Moody's, and a Safety rank of 2 by *Value Line*.

Q. What approaches were used to estimate the difference in the cost of equity for a benchmark utility and that which would be applicable to NRG?

A. Both the Capital Asset Pricing Model (CAPM) and Discounted Cash Flow (DCF) test were applied to the two samples to estimate the difference in the cost of equity between the benchmark utility and the cost of equity applicable to NRG.

Q. Please describe how you used the CAPM to distinguish between the costs of equity for the two samples.

A. The Capital Asset Pricing Model holds that the equity investor requires a return on a security equal to:

[21] In addition to business risk profile rankings, Standard & Poor's assigns financial risk profile rankings to all the utilities that it rates. There are six financial risk profile rankings, ranging from "Minimal" to "Highly Leveraged." Utilities in the two highest financial risk categories, "Aggressive" and "Highly Leveraged" were excluded in order to minimize the differences in cost of equity between the BBB and benchmark samples due solely to differences in financial risk.

[22] Canadian utilities with an S&P business risk profile ranking of "Strong" or "Satisfactory" (one category below "Strong") include Maritime Electric, Nova Scotia Power, TransCanada Pipelines, Trans Quebec and Maritimes Pipeline, Union Gas and Westcoast Energy.

$$\mathbf{R_F} \quad + \quad \boldsymbol{\beta}\ (\mathbf{R_M - R_F}),$$

Where:

$\mathbf{R_F}$	=	risk-free rate
$\boldsymbol{\beta}$	=	investment risk beta
$\mathbf{R_M}$	=	return on the market
$\mathbf{R_M - R_F}$	=	market risk premium

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns and the returns on individual stocks or portfolios of stocks.

Within the context of the CAPM, the differential in betas between the two samples, as adjusted for differences in financial risk, can be used to estimate the incremental return on equity for the BBB sample relative to the benchmark utility sample at a particular market risk premium.

Q. What have been the betas for the two samples?

A. The table below compares the investment risk betas of the benchmark utility sample and the BBB rated sample with their corresponding book value common equity ratios.

Table 5

Sample	***Value Line* Beta (4th Quarter 2009) (Median)**	***Value Line* Beta (2005-2009) (Average of Annual Medians)**	**Common Equity Ratio (2004-2008) (Average of Annual Medians)**
Benchmark	0.65	0.75	46%
BBB rated	0.75	0.82	46%

Source: Schedules 4 and 5.

A comparison of the betas indicates that the most recent five-year betas for the BBB rated utilities were approximately 0.10 higher than the benchmark utility betas; over the past five-years the differential was, on average, approximately 0.07.[23]

Q. Does the differential in betas of 0.07-0.10 require an adjustment to capture the differences in financial risk as between the BBB rated sample and the benchmark utility sample?

A. No. The investment risk beta, in principle, measures both business and financial risk, where the latter is represented by the capital structure. If the common equity ratios of the two samples were materially different, the investment risk betas of the two samples would need to be decomposed into separate business and financial risk components to estimate the differences in the cost of equity due to business risk and to financial risk. In other words, the financial risk component of the samples' beta would have to be removed (that is, the beta would have to be "delevered") to derive business risk-only betas for the samples to be able to estimate the difference in the cost of equity arising from differences in business risk. Since the book value capital structures of the two samples are identical, the differences in the samples' cost of equity can be attributed to business risk differences, rather than financial risk differences. In other words, no adjustments to the costs of equity for the samples need to be made to account for differences in financial risk.

Q. Having established the differential in betas between the two samples at 0.07-0.10, what is your estimate of the incremental equity risk premium required for the BBB sample relative to the benchmark sample based on the CAPM?

[23] The *Value Line* betas are adjusted betas based on weekly price changes. The betas are adjusted toward the market mean beta of 1.0 by giving approximately 2/3 weight to the "raw" calculated beta and 1/3 weight to the market mean beta. The calculations of the sample betas and the sample differences are sensitive to the period over which the betas are calculated, the price interval chosen to estimate the betas (e.g., weekly versus monthly) and the market index selected (e.g., S&P 500 versus the NYSE Index). The betas calculated using monthly data are systematically lower than the betas calculated using weekly data for both samples, and the differentials between the two samples are larger.

A. Based on the CAPM, the difference in the cost of equity between the two samples is approximately 0.50%-0.675%, which represents the difference in betas of 0.07-0.10 multiplied by an equity market risk premium of 6.75%.[24]

Q. Please describe your application of the DCF method.[25]

A. The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return, that is, the rate that equates the price of the stock to the discounted value of future cash flows.

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock. To estimate the difference in the DCF cost of equity between the two samples, I applied the three models to both samples, a constant growth model using the consensus of analysts' earnings forecasts, a constant growth model using estimates of sustainable growth and a three-stage growth model. The three models are described in Appendix B.

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[24] A market risk premium of 6.75% represents the market risk premium I would use for purposes of applying the CAPM were I estimating the cost of equity for NRG from first principles. A market risk premium of 6.75% is in line with the market risk premium that could reasonably be inferred from the revised benchmark utility ROE adopted in the *Report of the Board, 2009*.

[25] See Appendix B for a full discussion of the DCF method and its application.

Q. How do the DCF costs of equity compare between your two samples?

A. Table 6 below compares the DCF costs of equity for the benchmark sample of distribution utilities and the sample of BBB rated utilities based on the three separate models.

Table 6

Sample	DCF Cost of Equity (Medians)		
	Constant Growth (Analysts' Forecasts)	Constant Growth (Sustainable Growth)	Three-Stage
Benchmark	10.0%	9.9%	9.7%
BBB rated	10.8%	10.4%	10.2%
Difference in Cost of Equity	0.8%	0.5%	0.5%

Source: Schedules 6 through 11

Based on the results of the DCF tests, the difference in the cost of equity between the two samples is in the range of 50 to 80 basis points.

Q. What are your conclusions based on the results of both the CAPM and DCF models.

A. The application of both the CAPM and DCF models indicates a difference between the cost of equity for the benchmark and BBB rated samples in the range of 0.50%-0.80%. As stated above, the cost of equity estimated for the BBB rated sample represents a conservative estimate of the cost of equity applicable for NRG at a 42% equity ratio. Therefore, the comparison of the costs of equity for the two samples supports an equity risk premium for NRG of no less than 50 basis points.

Q. Did you examine any other data in assessing the reasonableness of maintaining the previously approved equity risk premium of 0.50% for NRG?

A. Yes. I compared the risk premiums indicated by the cost of equity comparisons to the results of the studies on small size and returns conducted by Ibbotson Associates Inc.[26] These studies have quantified the impact of a firm's small size on the required return by an analysis of the relationship between betas and historic returns for companies of different sizes. The analyses indicate that small companies tend to exhibit higher betas than larger companies. In the Ibbotson classification of stocks, if NRG were a stand-alone publicly traded stock, it would be a Micro-Cap stock (market value of equity of less than $450 million). By comparison, both the typical publicly-traded Canadian regulated company and benchmark U.S. distribution utility used as baselines to estimate the incremental equity risk premium for NRG are Mid-Cap stocks (market value of equity in the range of approximately $1.8-$7.4 billion). Ibbotson's analysis indicates the betas of Micro-Cap stocks have been approximately 0.32 higher than those of Mid-Cap stocks. An incremental beta of 0.32, when applied to a market risk premium of 6.75%, supports an incremental equity risk premium of over 200 basis points (6.75% x 0.32) for a Micro-Cap company, e.g., NRG.[27] On this basis, an equity risk premium of 50 basis points for NRG at a deemed capital structure of 42% equity is conservative.

Q. Based on your analysis, what is your conclusion regarding the incremental risk premium for NRG?

A. Based on my analysis, an incremental equity risk premium relative to the benchmark ROE 0.50% is warranted for NRG. With an incremental equity risk premium of 0.50%, the ROE for NRG for test year 2011, based on the initial rebased benchmark return and the recent ROE update, is 10.35%.

[26] Morningstar, *Ibbotson SBBI 2009 Valuation Yearbook: Market Results for Stocks, Bonds, Bills and Inflation, 1926-2008*, pages 89-110.
[27] Ibbotson's industry-by-industry analysis shows that the conclusions regarding the firm size effect apply to regulated companies as well as unregulated companies. Based on 82 years of data, Ibbotson's analysis shows that the returns for small publicly-traded electric, gas and sanitary utilities have been approximately 1.5 and 3 percentage points higher on a compound and arithmetic average basis respectively than those of large utilities. Morningstar, Ibbotson SBBI, *2008 Valuation Yearbook: Market Results for Stocks, Bonds, Bills and Inflation, 1926-2007*, pages 154-155.

Q. You stated above that differences in business risk could be reflected in capital structure as well as in a combination of capital structure and ROE. If the Board concludes that it is preferable to recognize the difference in risk between NRG and the benchmark solely through the deemed capital structure, what deemed capital structure would be consistent with the benchmark ROE?

A. The rationale for the difference in the required ROE at different capital structures begins with the recognition that the overall cost of capital for a firm is primarily a function of business risk. Theoretically, the sum of the cash flows, which are available to both the debt holders and equity holders, does not change when debt is added to the capital structure. In the absence of the deductibility of interest expense for tax purposes and costs (bankruptcy, financial distress, deterioration in financial flexibility) associated with the use of excessive debt, the overall cost of capital to a firm would not change materially if the firm were to change its capital structure. In other words, the cost of capital is constant regardless of capital structure.

The existence of corporate income taxes and the deductibility of interest for income tax purposes, in conjunction with the costs associated with potential bankruptcy or loss of financial flexibility, alter the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the assumption of debt. When interest expense is deductible for income tax purposes, the after-tax cost of capital is reduced when debt is used. However, as the proportion of debt in the capital structure increases, the cost of capital tends to increase due to the loss of financial flexibility and increased potential for bankruptcy, partly offsetting this advantage. In addition, although interest expense is tax deductible at the corporate level, interest income is taxable to investors at a higher rate than equity income (dividends and capital gains). Thus, although debt is less expensive than equity, the higher income tax rate paid by taxable investors on interest income than on equity income offsets some of the net after-tax advantage of increasing the debt component of the capital structure. In other words, all other things equal, the higher the personal income tax rate on interest income relative to equity income, the greater the incentive firms have to employ equity financing rather than debt financing. Further, in the specific case of regulated companies, the benefits from the tax deductibility of interest expense largely flow through to customers rather than investors.

While it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in either case the costs of the components of the capital structure do change. An increase in financial risk will be accompanied by an increase in the cost of equity. The amount by which the cost of common equity increases for a given increase in the debt ratio can be estimated under each of the two theories.

Theory 1

The cost of capital remains unchanged as the capital structure changes.

Theory 2

The cost of capital declines as the percentage of debt in the capital structure increases.

Schedule 12 provides the formulas required to estimate the change in the cost of equity under each theory.

To estimate the required increase in common equity ratio to compensate for the difference between an ROE of 9.85% (i.e., the updated benchmark ROE) and an ROE of 10.35% (the most current benchmark ROE plus an equity risk premium of 0.50%), the following steps were taken:

(1) Estimate NRG's weighted average cost of capital using a deemed common equity ratio of 42%, a cost of new long-term debt of 6.3%,[28] an ROE of 10.35%, and the marginal statutory federal/provincial corporate income tax rate for 2011 of 28.75%.

(2) Estimate the increase in common equity ratio required to account for the difference between the current benchmark ROE of 9.85% and the benchmark ROE plus an incremental risk premium of 0.50%.

To summarize the results found on Schedule 12, based on Theory 1 (no change in cost of capital as the equity ratio declines), the difference in an ROE of 10.35% at an equity ratio of 42% and an ROE of 9.85% translates into an increase in the required equity ratio to approximately 46%. Based on Theory 2 (cost of capital declines as the equity ratio declines), the difference in an ROE of 10.35% and an ROE of 9.85% translates into an increase in the common equity ratio to approximately 49%. Since both theories have merit, it is reasonable to give weight to both. The mid-point of the range of the two theories is an increase in the equity ratio to a range of 46% to 49%, or a mid-point of approximately 48%.

VII. CREDIT METRICS

a. A reasonable capital structure, in conjunction with the returns allowed on the various sources of capital, should allow a utility to access the debt markets on reasonable terms. Did you consider NRG's stand-alone utility credit metrics in your analysis?

A. Yes. The following table summarizes four of the key credit metrics relied on by DBRS, Standard & Poor's and Moody's. As the debt rating agencies are most concerned with cash flow ratios, three of the four ratios presented (all but EBIT coverage) are different measures of cash flow adequacy.

[28] Based on forecast costs of fixed and variable rate issues of 7.52% and 4.1% respectively and assuming an average mix over the next five years of approximately 65%/35%.

The ratios for NRG were estimated on the following assumptions:

(1) NRG's forecast costs of debt and return on the GIC;

(2) Interest coverage ratios based on net (of GIC return) interest;

(3) The statutory income tax rates utilized by NRG; timing differences were ignored;

(4) Forecast 2011 depreciation expense;

(5) A deemed common equity ratio of 42% and an ROE of 10.35%, equal to the most recent revised benchmark utility ROE plus the previously approved 0.50% risk premium.

Table 7

Credit Metric	Estimate for NRG
EBIT Interest Coverage [1/]	2.2X
EBITDA Interest Coverage [2/]	4.0X
Funds from Operations/Net Debt [3/]	23%
Funds from Operations Interest Coverage [4/]	3.8X

1/ Earnings before Net Interest and Taxes divided by Net Interest
2/ Earnings before Interest, Taxes, Depreciation and Amortization divided by Interest
3/ Net Income plus Depreciation divided by Net Debt
4/ Net Income plus Depreciation plus Net Interest Divided by Net Interest

Q. To put these estimated ratios in perspective, how do they compare to ratios that have been achieved by Canadian utilities with rated debt?

A. Table 8 below summarizes the ratios achieved by Canadian utilities with rated debt over the most recent three year period (Schedule 13).

Table 8

Credit Metric	Medians (2006-2008)		
	Gas Distributors	All Utilities	Investor-Owned Utilities
EBIT Interest Coverage	2.3X	2.3X	2.3X
EBITDA Interest Coverage	3.5X	3.7X	3.6X
Funds from Operations(FFO) /Debt	14.4%	16.4%	13.5%
Funds from Operations Interest Coverage	2.8X	3.3X	3.0X

The two tables indicate that the estimated EBIT coverage ratio for NRG would be approximately 2.2X, which, while relatively weak, is very similar to the average achieved by Canadian utilities with rated debt (2.3X). The three cash flow metrics are higher for NRG than have been achieved by most Canadian utilities with rated debt, largely due to NRG's relatively high proportion of cash flow from depreciation expense compared to the proportion of cash flow from net income.[29] Based on the estimated credit metrics, the proposed capital structure and ROE should provide the basis for NRG on a utility stand-alone basis to maintain adequate access to debt capital.

VIII. CONCLUSIONS

Q. Please summarize your conclusions.

A. In my opinion, the proposed test year cost rates for both the variable and fixed rate loans are reasonable based on current and anticipated capital market conditions. With respect to the capital structure and equity risk premium, in its

[29] Based on NRG's forecast of depreciation expense and rate base, at a 42% deemed equity ratio and a 10.35% ROE, depreciation accounts for over two-thirds of cash flow (net income plus depreciation, compared to, for example, Enbridge and Union, whose depreciation expense accounts for slightly more than 50% of total cash flow.

Decision with Reasons in EB-2005-0544 dated September 20, 2006, the Ontario Energy Board (OEB) adopted a common equity ratio of 42% and an incremental equity risk premium of 0.50% above that applicable to Enbridge Gas Distribution. In my opinion, the 42% common equity ratio previously adopted by the Board remains appropriate for NRG. The benchmark ROE was recently reviewed, and the automatic adjustment formula refined, by the OEB in EB-2009-0085 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities,* issued December 11, 2009. In conjunction with a common equity ratio of 42%, a return on equity (ROE) that represents a risk premium of 0.50% above the benchmark ROE as updated is warranted for the 2011 test year.

APPENDICES

Prepared by

KATHLEEN C. McSHANE

FOSTER ASSOCIATES, INC.

March 2010

APPENDIX A

QUALIFICATIONS OF KATHLEEN C. McSHANE

Kathleen McShane is President and senior consultant with Foster Associates, Inc., where she has been employed since 1981. She holds an M.B.A. degree in Finance from the University of Florida, and M.A. and B.A. degrees from the University of Rhode Island. She has been a CFA charterholder since 1989.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian gas distributors and pipelines, electric utilities and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

PUBLICATIONS, PAPERS AND PRESENTATIONS

- *Utility Cost of Capital: Canada vs. U.S.,* presented at the CAMPUT Conference, May 2003.

- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.

- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.

- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.

- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

Client	Date
Alberta Natural Gas	1994
AltaGas Utilities	2000
Ameren (Central Illinois Public Service)	2000, 2002, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Central Illinois Light Company)	2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Illinois Power)	2004, 2005, 2007 (2 cases), 2009 (2 cases)
Ameren (Union Electric)	2000 (2 cases), 2002 (2 cases), 2003, 2006 (2 cases)
ATCO Electric	1989, 1991, 1993, 1995, 1998, 1999, 2000, 2003
ATCO Gas	2000, 2003, 2007
ATCO Pipelines	2000, 2003, 2007
ATCO Utilities	2008
Bell Canada	1987, 1993
Benchmark Utility Cost of Equity (British Columbia)	1999
Canadian Western Natural Gas	1989, 1996, 1998, 1999
Centra Gas B.C.	1992, 1995, 1996, 2002
Centra Gas Ontario	1990, 1991, 1993, 1994, 1995
Direct Energy Regulated Services	2005
Dow Pool A Joint Venture	1992
Edmonton Water/EPCOR Water Services	1994, 2000, 2006, 2008
Electricity Distributors Association	2009
Enbridge Gas Distribution	1988, 1989, 1991-1997, 2001, 2002
Enbridge Gas New Brunswick	2000
Enbridge Pipelines (Line 9)	2007, 2009
Enbridge Pipelines (Southern Lights)	2007

FortisBC	1995, 1999, 2001, 2004
Gas Company of Hawaii	2000, 2008
Gaz Metropolitain	1988
Gazifère	1993, 1994, 1995, 1996, 1997, 1998
Generic Cost of Capital, Alberta (ATCO and AltaGas Utilities)	2003
Heritage Gas	2004, 2008
Hydro One	1999, 2001, 2006 (2 cases)
Insurance Bureau of Canada (Newfoundland)	2004
Laclede Gas Company	1998, 1999, 2001, 2002, 2005
Laclede Pipeline	2006
Mackenzie Valley Pipeline	2005
Maritimes NRG (Nova Scotia) and (New Brunswick)	1999
MidAmerican Energy Company	2009
Multi-Pipeline Cost of Capital Hearing (National Energy Board)	1994
Natural Resource Gas	1994, 1997, 2006
New Brunswick Power Distribution	2005
Newfoundland & Labrador Hydro	2001, 2003
Newfoundland Power	1998, 2002, 2007, 2009
Newfoundland Telephone	1992
Northland Utilities	2008 (2 cases)
Northwestel, Inc.	2000, 2006
Northwestern Utilities	1987, 1990
Northwest Territories Power Corp.	1990, 1992, 1993, 1995, 2001, 2006
Nova Scotia Power Inc.	2001, 2002, 2005, 2008
Ontario Power Generation	2007
Ozark Gas Transmission	2000
Pacific Northern Gas	1990, 1991, 1994, 1997, 1999, 2001, 2005, 2009
Plateau Pipe Line Ltd.	2007
Platte Pipeline Co.	2002
St. Lawrence Gas	1997, 2002

Southern Union Gas	1990, 1991, 1993
Stentor	1997
Tecumseh Gas Storage	1989, 1990
Telus Québec	2001
Terasen Gas	1992, 1994, 2005, 2009
Terasen Gas (Whistler)	2008
TransCanada PipeLines	1988, 1989, 1991 (2 cases), 1992, 1993
TransGas and SaskEnergy LDC	1995
Trans Québec & Maritimes Pipeline	1987
Union Gas	1988, 1989, 1990, 1992, 1994, 1996, 1998, 2001
Westcoast Energy	1989, 1990, 1992 (2 cases), 1993, 2005
Yukon Electrical Company	1991, 1993, 2008
Yukon Energy	1991, 1993

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

Client	Issue	Date
Nova Scotia Power	Calculation of ROE	2009
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998
Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Metro/ Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

APPENDIX B

DISCOUNTED CASH FLOW TEST

1. DCF MODELS

a. Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth model is expressed as follows:

$$\text{Cost of Equity } (\mathbf{k}) = \frac{\mathbf{D_1}}{\mathbf{P_o}} + \mathbf{g},$$

where,

$\mathbf{D_1}$ = next expected dividend[30]
$\mathbf{P_o}$ = current price
$\mathbf{g}$ = constant growth rate

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

[30]Alternatively expressed as D_o (1 + g), where D_o is the most recently paid dividend.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

b. Three-Stage Model

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1), to migrate to the expected long-run rate of growth in the economy (GDP Growth) (Stage 2) and to equal expected long-term GDP growth in the long term (Stage 3).

The use of forecast GDP growth as the proxy for the expected long-term growth is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal GDP growth for conventional corporations in its standard DCF models for gas and oil pipelines.

The use of forecast long-term growth in the economy as the proxy for long-term growth in the DCF model recognizes that, while all industries go through various stages in their life cycle, mature industries are those whose growth parallels that of the overall economy. Utilities are considered to be the quintessential mature industry.

Using the three-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor where the cash flows are defined as follows:

The cash flow per share in Year 1 is equal to:

Last Paid Annualized Dividend x (1 + Stage 1 Growth)

For Years 2 through 5, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 1 Growth)

For Years 6 through 10, cash flow is defined as:

Cash Flow $_{t-1}$ x (1 + Stage 2 Growth)

Cash flows from Year 11 onward are estimated as:

Cash Flow $_{t-1}$ x (1 + GDP Growth)

3. SELECTION OF PROXY SAMPLES OF UTILITIES

Two samples of utilities were selected, a benchmark utility sample and a sample of utilities with debt ratings in the BBB category. The criteria for sample selection are found in Chapter VI of the Opinion. The utilities in the two samples are identified on Schedules 2 and 3.

4. APPLICATION OF THE DCF MODELS

a. Constant Growth Model

The constant growth DCF model was applied to both the sample of U.S. low risk gas and electric distribution utilities and the BBB rated sample using the following inputs to calculate the dividend yield:

(1) the most recent annualized dividend paid as of January 26, 2010 as D_o; and,

(2) the average of the monthly high and low prices for the period November 1, 2009 to January 26, 2010 as P_o.

The constant growth model was applied using two estimates of long-term growth, the consensus of investment analysts' long-term earnings growth forecasts compiled by I/B/E/S and estimates of sustainable growth. For the model based on investment analysts' earnings forecasts, the December 2009 I/B/E/S consensus (mean) earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The results of the constant growth model using analysts' long-term earnings growth forecasts for the two samples are found on Schedules 6 and 9.

The sustainable growth rate was derived from *Value Line* forecasts. Sustainable growth, or earnings retention growth, is premised on the notion that future dividend growth depends on both internal and external financing. Internal growth is achieved by the firm retaining a portion of its earnings in order to produce earnings and dividends in the future. External growth measures the long-run expected stock financing undertaken by the utility and the percentage of funds from that investment that are expected to accrue to existing investors. The internal growth rate is estimated as the fraction of earnings (b) expected to be retained multiplied by expected return on equity (r). The external growth rate is estimated by the forecast growth in common stock outstanding (s) multiplied by the fraction of the investment expected to be retained (v). The sustainable growth rate is then calculated as the sum of br and sv. The external growth component recognizes that investors may expect future growth to be achieved not only through the retention of earnings but also through the issuance of additional equity capital which is invested in projects that are accretive to earnings.

The results of the sustainable growth model for both samples are found on Schedules 7 and 10.

b. Three-Stage Model

The three-stage model relies on the I/B/E/S consensus of analysts' earnings forecasts for the first five years (Stage 1), the average of the I/B/E/S and the forecast long-term growth in the economy for the next five years (Stage 2) and the long-term growth in the economy thereafter (Stage 3). The long-run (2011-2020) expected nominal rate of growth in GDP is 5.0% based on the consensus of economists' forecasts (published twice annually) found in Blue Chip *Financial Forecasts*, December 1, 2009.

The three-stage DCF model estimates of the cost of equity for the two samples are found on Schedules 8 and 11.

DEBT AND COMMON STOCK QUALITY RATINGS
OF CANADIAN UTILITIES

Company	Debt Rated	Bond Rating DBRS	Bond Rating Moody's	Bond Rating S&P	S&P Business Risk Profile	CBS Stock Ranking
Gas Distributors						
Enbridge Gas Distribution	Senior Unsecured	A		A-	Excellent	Very conservative
Gaz Metropolitain	Senior Secured	A		A-	Excellent	
Pacific Northern Gas	Senior Secured	BBB(low)		NR [1/]		Average
Terasen Gas	Senior Unsecured	A	A3	A	Excellent	Very conservative
Union Gas Limited	Senior Unsecured	A		BBB+	Strong	Very conservative
Electric Utilities						
AltaLink L.P.	Senior Secured	A		A-	Excellent	
CU Inc.	Senior Unsecured	A(high)		A	Excellent	Very conservative
Enersource	Issuer	A				
ENMAX	Unsecured	A(low)		BBB+	Strong	
EPCOR Utilities Inc	Senior Unsecured	A(low)		BBB+	Strong	
FortisAlberta Inc.	Senior Unsecured	A(low)	Baa1	A-	Excellent	Very conservative
FortisBC Inc	Senior Unsecured	BBB(high)	Baa2			Very conservative
Hamilton Utilities	Senior Unsecured			A+	Excellent	
Hydro One	Senior Unsecured	A(high)	Aa3	A+	Excellent	
Hydro Ottawa Holding Inc.	Senior Unsecured	A		A	Excellent	
London Hydro	Issuer			A	Excellent	
Maritime Electric	Issuer			BBB+	Satisfactory	Very conservative
	Senior Secured			A		
Newfoundland Power	Senior Secured	A	A2	NR [1/]		Very conservative
Nova Scotia Power	Senior Unsecured	A(low)	Baa1	BBB+	Strong	Very conservative
Toronto Hydro	Senior Unsecured	A(high)		A	Excellent	
Veridian Corp.	Issuer	A				
Pipelines						
Enbridge Pipelines	Senior Unsecured	A(high)		A-	Excellent	Very conservative
NOVA Gas Transmission	Senior Unsecured	A	A3	A-	Strong	Very conservative
Trans Quebec & Maritimes	Senior Unsecured	A(low)		BBB+	Satisfactory	
TransCanada PipeLines	Senior Unsecured	A	A3	A-	Strong	Very conservative
Westcoast Energy	Senior Unsecured	A(low)		BBB+	Strong	Very conservative
Medians						
Gas Distributors		**A**	**A3**	**A-**	**Excellent**	**Very conservative**
All Companies		**A**	**A3**	**A-**	**Excellent**	**Very conservative**

[1/] Withdrawn by company; BB- prior to withdrawal.

Note: Debt ratings are for utility; Stock rankings are for parent.

Source: DBRS Bond Ratings, www.moodys.com, Standard & Poor's, The Blue Book of CBS Stock Reports.

INDIVIDUAL COMPANY RISK DATA FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES

	Value Line							S & P		Moody's
	Safety	Forecast Common Equity Ratio 2012-2014	Forecast Return On Average Common Equity 2012-2014	Dividend Payout Forecast 2012-2014	2009 Q4 Beta	Calculated Weekly Betas 1/	Common Equity Ratio 2008	Business Risk Profile	Debt Rating	Debt Rating 2/
AGL Resources	2	49.0%	13.6%	57.0%	0.75	0.67	39.4%	Excellent	A-	Baa1
Consolidated Edison	1	51.5%	9.5%	63.4%	0.65	0.45	48.5%	Excellent	A-	Baa1
New Jersey Resources	1	66.5%	11.7%	53.3%	0.65	0.53	51.2%	Excellent	A	Aa3
Nicor Inc.	3	74.0%	12.0%	60.0%	0.75	0.71	44.0%	Excellent	AA	A2
Northwest Nat. Gas	1	53.0%	11.6%	61.4%	0.60	0.46	45.3%	Excellent	AA-	A3
NSTAR	1	53.5%	15.2%	60.0%	0.65	0.52	36.8%	Excellent	A+	A2
Piedmont Natural Gas	2	52.0%	14.3%	58.6%	0.65	0.55	41.9%	Excellent	A	A3
South Jersey Inds.	2	63.5%	14.9%	50.8%	0.65	0.52	47.5%	Excellent	BBB+	Baa1
WGL Holdings Inc.	1	64.0%	10.8%	59.3%	0.65	0.55	51.7%	Excellent	AA-	A2
Mean	**2**	**58.6%**	**12.6%**	**58.2%**	**0.67**	**0.55**	**45.1%**	**Excellent**	**A**	**A3**
Median	**1**	**53.5%**	**12.0%**	**59.3%**	**0.65**	**0.53**	**45.3%**	**Excellent**	**A**	**A3**

1/ "Raw" betas calculated using weekly data against the NYSE Composite (260 weeks ending December 28, 2009).
2/ Rating for New Jersey Resources is New Jersey Natural Gas. Rating for South Jersey Industries is South Jersey Gas Co. Rating for WGL Holdings is Washington Gas Light. Rating for Nicor Inc. is for Northern Illinois Gas.

Source: Standard and Poor's Research Insight, Value Line (November and December 2009), January 8, 2010 Value Line Index, www.moodys.com, www.yahoo.com,
Standard and Poor's, *Issuer Ranking: U.S. Invester-Owned Electric Utilities, Strongest To Weakest* (December 28, 2009) and
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (January 12, 2010).

INDIVIDUAL COMPANY RISK DATA FOR BBB RATED SAMPLE OF U.S. UTILITIES

	Value Line							S & P		Moody's
	Safety	Forecast Common Equity Ratio 2012-2014	Forecast Return On Average Common Equity 2012-2014	Dividend Payout Forecast 2012-2014	2009 Q4 Beta	Calculated Weekly Betas [1/]	Common Equity Ratio 2008	Business Risk Profile	Debt Rating	Debt Rating [2/]
ALLETE	2	51.0%	9.9%	69.1%	0.70	0.58	57.8%	Strong	BBB+	Baa1
Alliant Energy	2	58.5%	10.2%	61.9%	0.70	0.69	56.0%	Excellent	BBB+	Baa1
Ameren Corp.	3	54.0%	8.2%	56.7%	0.80	0.78	45.6%	Satisfactory	BBB-	Baa3
Atmos Energy	2	51.0%	9.5%	56.0%	0.65	0.60	45.4%	Excellent	BBB+	Baa2
Black Hills	3	59.5%	9.6%	52.0%	0.80	0.77	46.5%	Satisfactory	BBB-	Baa3
Constellation Energy	3	53.0%	10.0%	28.6%	0.80	0.65	26.7%	Satisfactory	BBB-	Baa3
DTE Energy	3	45.0%	10.2%	58.8%	0.75	0.73	40.4%	Strong	BBB	Baa2
Entergy Corp.	2	42.0%	14.5%	45.0%	0.70	0.56	38.8%	Strong	BBB	Baa3
Exelon Corp.	1	57.0%	20.0%	48.0%	0.85	0.86	45.5%	Strong	BBB	Baa1
FirstEnergy Corp.	2	47.5%	14.5%	52.0%	0.80	0.69	37.2%	Strong	BBB	Baa3
Hawaiian Elec.	3	55.5%	10.6%	70.9%	0.70	0.61	41.9%	Strong	BBB	Baa1
OGE Energy	2	46.5%	12.0%	49.2%	0.75	0.77	43.5%	Strong	BBB+	Baa1
Pepco Holdings	3	48.0%	7.8%	67.5%	0.80	0.92	41.4%	Strong	BBB	Baa3
PG&E Corp.	2	54.0%	12.2%	51.8%	0.55	0.45	43.8%	Excellent	BBB+	Baa1
Pinnacle West Capital	3	52.0%	8.8%	67.7%	0.75	0.64	47.0%	Strong	BBB-	Baa3
Portland General	2	50.0%	8.6%	60.0%	0.70	0.57	47.3%	Strong	BBB+	Baa2
PPL Corp.	3	45.5%	20.2%	50.7%	0.70	0.68	36.5%	Satisfactory	BBB	Baa2
Public Serv. Enterprise	3	57.0%	16.3%	45.3%	0.80	0.66	46.0%	Strong	BBB	Baa2
Sempra Energy	2	57.0%	12.2%	35.0%	0.85	0.75	50.6%	Strong	BBB+	Baa1
South Jersey Inds.	2	63.5%	14.9%	50.8%	0.65	0.52	47.5%	Excellent	BBB+	Baa1
Xcel Energy Inc.	2	48.5%	10.8%	55.0%	0.65	0.48	44.0%	Excellent	BBB+	Baa1
Mean	**2**	**52.2%**	**11.9%**	**53.9%**	**0.74**	**0.67**	**44.3%**	**Strong**	**BBB**	**Baa2**
Median	**2**	**52.0%**	**10.6%**	**52.0%**	**0.75**	**0.66**	**45.4%**	**Strong**	**BBB**	**Baa2**

1/ "Raw" betas calculated using weekly data against the NYSE Composite (260 weeks ending December 28, 2009). Portland General only has data for 187 weeks.
2/ Rating for South Jersey Industries is South Jersey Gas Co.

Source: Standard and Poor's Research Insight, Value Line (November and December 2009), January 8, 2010 Value Line Index, www.moodys.com, www.yahoo.com,
Standard and Poor's, *Issuer Ranking: U.S. Regulated Electric Utilities, Strongest To Weakest* (December 28, 2009) and
Standard and Poor's, *Issuer Ranking: U.S. Natural Gas Distributors And Integrated Gas Companies, Strongest To Weakest* (January 12, 2010).
Standard and Poor's, *Issuer Ranking: U.S. Energy Merchants/Power Developers/Trading and Marketing Companies, Strongest to Weakest (November 5, 2009).*

VALUE LINE BETAS FOR BENCHMARK AND BBB RATED SAMPLES OF U.S. UTILITIES

Company	4Q 2005	4Q 2006	4Q 2007	4Q 2008	4Q 2009	Average
Benchmark Sample						
AGL Resources	0.90	0.95	0.85	0.75	0.75	0.84
Consolidated Edison	0.60	0.75	0.75	0.65	0.65	0.68
New Jersey Resources	0.75	0.80	0.85	0.70	0.65	0.75
Nicor Inc.	1.10	1.30	1.00	0.70	0.75	0.97
Northwest Nat. Gas	0.70	0.75	0.90	0.60	0.60	0.71
NSTAR	0.75	0.80	0.75	0.70	0.65	0.73
Piedmont Natural Gas	0.75	0.80	0.85	0.70	0.65	0.75
South Jersey Inds.	0.65	0.70	0.85	0.75	0.65	0.72
WGL Holdings Inc.	0.80	0.85	0.85	0.75	0.65	0.78
Mean	**0.78**	**0.86**	**0.85**	**0.70**	**0.67**	**0.77**
Median	**0.75**	**0.80**	**0.85**	**0.70**	**0.65**	**0.75**
Average of Annual Medians						**0.75**
BBB Rated Sample						
ALLETE	nmf	0.90	0.95	0.75	0.70	0.83
Alliant Energy	0.85	0.95	0.80	0.70	0.70	0.80
Ameren Corp.	0.75	0.75	0.80	0.80	0.80	0.78
Atmos Energy	0.70	0.80	0.85	0.65	0.65	0.73
Black Hills	1.00	1.05	1.10	0.85	0.80	0.96
Constellation Energy	0.95	0.95	0.85	0.75	0.80	0.86
DTE Energy	0.70	0.75	0.80	0.70	0.75	0.74
Entergy Corp.	0.80	0.85	0.85	0.75	0.70	0.79
Exelon Corp.	0.75	0.90	0.90	0.90	0.85	0.86
FirstEnergy Corp.	0.75	0.80	0.85	0.85	0.80	0.81
Hawaiian Elec.	0.70	0.70	0.70	0.75	0.70	0.71
OGE Energy	0.75	0.75	0.85	0.75	0.75	0.77
Pepco Holdings	0.90	0.90	0.95	0.75	0.80	0.86
PG&E Corp.	1.10	1.15	0.95	0.85	0.55	0.92
Pinnacle West Capital	0.90	1.00	1.00	0.75	0.75	0.88
Portland General	na	nmf	nmf	0.70	0.70	0.70
PPL Corp.	1.00	0.95	0.90	0.80	0.70	0.87
Public Serv. Enterprise	0.90	1.00	0.95	0.85	0.80	0.90
Sempra Energy	1.00	1.10	1.00	0.90	0.85	0.97
South Jersey Inds.	0.65	0.70	0.85	0.75	0.65	0.72
Xcel Energy Inc.	0.80	0.90	1.05	0.75	0.65	0.83
Mean	**0.84**	**0.89**	**0.90**	**0.78**	**0.74**	**0.82**
Median	**0.80**	**0.90**	**0.88**	**0.75**	**0.75**	**0.83**
Average of Annual Medians						**0.82**

Source: *Value Line* 4th Quarter Issues

COMMON EQUITY RATIOS FOR BENCHMARK AND BBB RATED SAMPLES OF U.S. UTILITIES

Company	2004	2005	2006	2007	2008	Average
Benchmark Sample						
AGL Resources	41%	41%	43%	42%	39%	41%
Consolidated Edison	49%	46%	47%	49%	48%	48%
New Jersey Resources	44%	47%	50%	50%	51%	48%
Nicor Inc.	43%	42%	51%	52%	44%	46%
Northwest Nat. Gas	49%	47%	48%	47%	45%	47%
NSTAR	37%	34%	34%	36%	37%	36%
Piedmont Natural Gas	53%	52%	47%	46%	42%	48%
South Jersey Inds.	45%	45%	44%	50%	47%	46%
WGL Holdings Inc.	52%	56%	52%	54%	52%	53%
Mean	**46%**	**46%**	**46%**	**47%**	**45%**	**46%**
Median	**45%**	**46%**	**47%**	**49%**	**45%**	**47%**
Average of Annual Medians						**46%**
BBB Rated Sample						
ALLETE	62%	61%	63%	64%	58%	61%
Alliant Energy	48%	48%	58%	59%	56%	54%
Ameren Corp.	49%	52%	50%	47%	46%	49%
Atmos Energy	57%	41%	39%	46%	45%	46%
Black Hills	48%	50%	50%	57%	47%	50%
Constellation Energy	46%	49%	47%	50%	27%	44%
DTE Energy	39%	40%	39%	41%	40%	40%
Entergy Corp.	50%	44%	46%	41%	39%	44%
Exelon Corp.	41%	39%	43%	42%	45%	42%
FirstEnergy Corp.	43%	45%	44%	43%	37%	43%
Hawaiian Elec.	28%	29%	27%	29%	42%	31%
OGE Energy	45%	50%	54%	51%	44%	49%
Pepco Holdings	36%	39%	39%	43%	41%	40%
PG&E Corp.	47%	40%	43%	44%	44%	44%
Pinnacle West Capital	47%	53%	51%	49%	47%	50%
Portland General	58%	57%	53%	50%	47%	53%
PPL Corp.	35%	37%	39%	41%	37%	38%
Public Serv. Enterprise	29%	32%	37%	42%	46%	37%
Sempra Energy	47%	49%	56%	58%	51%	52%
South Jersey Inds.	45%	45%	44%	50%	47%	46%
Xcel Energy Inc.	42%	42%	44%	44%	44%	43%
Mean	**45%**	**45%**	**46%**	**47%**	**44%**	**45%**
Median	**46%**	**45%**	**44%**	**46%**	**45%**	**44%**
Average of Annual Medians						**46%**

Source: Standard and Poor's Research Insight

DCF COST OF EQUITY FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield [1/]	Average I/B/E/S/ Long-Term EPS Forecasts	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
AGL Resources	1.72	35.70	5.0	4.0	9.0
Consolidated Edison	2.36	43.77	5.6	3.4	9.0
New Jersey Resources	1.36	36.53	4.0	7.0	11.0
Nicor Inc.	1.86	40.42	4.8	4.4	9.2
Northwest Nat. Gas	1.66	44.08	4.0	6.0	10.0
NSTAR	1.60	34.44	4.9	5.6	10.5
Piedmont Natural Gas	1.08	25.15	4.6	6.6	11.2
South Jersey Inds.	1.32	37.31	3.9	11.5	15.4
WGL Holdings Inc.	1.47	32.80	4.7	5.0	9.7
Mean	**1.60**	**36.69**	**4.6**	**5.9**	**10.6**
Median	**1.60**	**36.53**	**4.7**	**5.6**	**10.0**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, www.yahoo.com and I/B/E/S (December 2009)

DCF COSTS OF EQUITY FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES (SUSTAINABLE GROWTH)

Company	Annualized Last Dividend Paid	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield 1/	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth 2/ (4th Qtr.2009)	SV Growth 3/ (4th Qtr. 2009)	Sustainable Growth 4/ (4th Qtr. 2009)	DCF Cost of Equity 5/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL Resources	1.72	35.70	5.1	13.6	43.0	5.8	0.38	6.2	11.3
Consolidated Edison	2.36	43.77	5.6	9.5	36.6	3.5	0.15	3.6	9.2
New Jersey Resources	1.36	36.53	3.9	11.7	46.7	5.4	0.51	5.9	9.9
Nicor Inc.	1.86	40.42	4.8	12.0	40.0	4.8	0.08	4.9	9.7
Northwest Nat. Gas	1.66	44.08	4.0	11.6	38.6	4.5	0.57	5.0	9.0
NSTAR	1.60	34.44	4.9	15.2	40.0	6.1	0.00	6.1	11.0
Piedmont Natural Gas	1.08	25.15	4.5	14.3	41.4	5.9	-0.54	5.4	9.9
South Jersey Inds.	1.32	37.31	3.8	14.9	49.2	7.3	0.72	8.1	11.9
WGL Holdings Inc.	1.47	32.80	4.7	10.8	40.7	4.4	0.01	4.4	9.1
Mean	**1.60**	**36.69**	**4.60**	**12.62**	**41.80**	**5.31**	**0.21**	**5.5**	**10.1**
Median	**1.60**	**36.53**	**4.68**	**12.00**	**40.73**	**5.44**	**0.15**	**5.4**	**9.9**

1/ Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
2/ BR Growth = Col (4) * (Col (5) / 100)
3/ SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [1- B/M].
4/ Col (6) + Col (7)
5/ Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: Standard and Poor's Research Insight, *Value Line* (November and December 2009) , www.yahoo.com

DCF COSTS OF EQUITY FOR BENCHMARK SAMPLE OF U.S. DISTRIBUTION UTILITIES
(THREE-STAGE MODEL)

			Growth Rates			
Company	**Annualized Last Paid Dividend**	**Average High/Low Monthly Close Prices 11/1/2009-1/26/2010**	**Stage 1: I/B/E/S EPS Forecasts**	**Stage 2: Average of Stage 1 & 3**	**Stage 3: GDP Growth 1/**	**DCF Cost of Equity 2/**
	(1)	(2)	(3)	(4)		(5)
AGL Resources	1.72	35.70	4.0	4.5	5.0	9.7
Consolidated Edison	2.36	43.77	3.4	4.2	5.0	10.1
New Jersey Resources	1.36	36.53	7.0	6.0	5.0	9.3
Nicor Inc.	1.86	40.42	4.4	4.7	5.0	9.6
Northwest Nat. Gas	1.66	44.08	6.0	5.5	5.0	9.1
NSTAR	1.60	34.44	5.6	5.3	5.0	10.0
Piedmont Natural Gas	1.08	25.15	6.6	5.8	5.0	9.9
South Jersey Inds.	1.32	37.31	11.5	8.3	5.0	10.4
WGL Holdings Inc.	1.47	32.80	5.0	5.0	5.0	9.6
Mean	**1.60**	**36.69**	**5.9**	**5.5**	**5.0**	**9.8**
Median	**1.60**	**36.53**	**5.6**	**5.3**	**5.0**	**9.7**

1/ Forecast nominal rate of GDP growth, 2011-20
2/ Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Standard & Poor's Research Insight; www.yahoo.com; Blue Chip Financial Forecasts (December 2009); I/B/E/S (December 2009)

DCF COST OF EQUITY FOR BBB RATED SAMPLE OF U.S. UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)

Company	Annualized Last Paid Dividend	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield [1/]	Average I/B/E/S/ Long-Term EPS Forecasts	DCF Cost of Equity [2/]
	(1)	(2)	(3)	(4)	(5)
ALLETE	1.76	32.95	5.6	4.0	9.6
Alliant Energy	1.50	29.46	5.3	4.3	9.6
Ameren Corp.	1.54	26.35	6.0	3.0	9.0
Atmos Energy	1.34	28.64	4.9	5.0	9.9
Black Hills	1.42	25.45	5.9	6.0	11.9
Constellation Energy	0.96	33.35	3.3	14.8	18.1
DTE Energy	2.12	41.53	5.3	3.0	8.3
Entergy Corp.	3.00	80.19	4.0	6.8	10.8
Exelon Corp.	2.10	48.40	4.4	2.2	6.6
FirstEnergy Corp.	2.20	44.53	5.1	3.3	8.4
Hawaiian Elec.	1.24	20.22	6.8	10.5	17.3
OGE Energy	1.45	35.30	4.4	6.0	10.4
Pepco Holdings	1.08	16.44	6.9	5.5	12.4
PG&E Corp.	1.68	43.49	4.1	7.3	11.5
Pinnacle West Capital	2.10	35.56	6.4	8.0	14.4
Portland General	1.02	19.91	5.5	6.8	12.3
PPL Corp.	1.38	31.17	4.9	11.5	16.4
Public Serv. Enterprise	1.33	31.92	4.4	5.3	9.7
Sempra Energy	1.56	53.45	3.1	7.0	10.1
South Jersey Inds.	1.32	37.31	3.9	11.5	15.4
Xcel Energy Inc.	0.98	20.63	5.1	7.3	12.4
Mean	**1.58**	**35.06**	**5.0**	**6.6**	**11.6**
Median	**1.45**	**32.95**	**5.1**	**6.0**	**10.8**

[1/] Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))
[2/] Expected Dividend Yield (Col (3)) + I/B/E/S Growth Forecast (Col (4))

Source: Standard and Poor's Research Insight, www.yahoo.com and I/B/E/S (December 2009)

DCF COSTS OF EQUITY FOR BBB RATED SAMPLE OF U.S. UTILITIES
(SUSTAINABLE GROWTH)

Company	Annualized Last Dividend Paid	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010	Expected Dividend Yield 1/	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth 2/ (4th Qtr.2009)	SV Growth 3/ (4th Qtr. 2009)	Sustainable Growth 4/ (4th Qtr. 2009)	DCF Cost of Equity 5/
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
ALLETE	1.76	32.95	5.6	9.9	30.9	3.1	1.53	4.6	10.2
Alliant Energy	1.50	29.46	5.3	10.2	38.1	3.9	0.22	4.1	9.4
Ameren Corp.	1.54	26.35	6.1	8.2	43.3	3.6	0.02	3.6	9.6
Atmos Energy	1.34	28.64	4.9	9.5	44.0	4.2	0.90	5.1	10.0
Black Hills	1.42	25.45	5.8	9.6	48.0	4.6	0.01	4.6	10.5
Constellation Energy	0.96	33.35	3.1	10.0	71.4	7.1	0.14	7.3	10.4
DTE Energy	2.12	41.53	5.3	10.2	41.2	4.2	0.27	4.5	9.8
Entergy Corp.	3.00	80.19	4.0	14.5	55.0	8.0	-0.48	7.5	11.5
Exelon Corp.	2.10	48.40	4.8	20.0	52.0	10.4	-0.43	10.0	14.8
FirstEnergy Corp.	2.20	44.53	5.3	14.5	48.0	6.9	0.00	6.9	12.2
Hawaiian Elec.	1.24	20.22	6.3	10.6	29.1	3.1	0.19	3.3	9.6
OGE Energy	1.45	35.30	4.4	12.0	50.8	6.1	0.50	6.6	11.0
Pepco Holdings	1.08	16.44	6.7	7.8	32.5	2.5	-0.72	1.8	8.5
PG&E Corp.	1.68	43.49	4.1	12.2	48.2	5.9	0.51	6.4	10.5
Pinnacle West Capital	2.10	35.56	6.1	8.8	32.3	2.9	0.22	3.1	9.2
Portland General	1.02	19.91	5.3	8.6	40.0	3.4	0.25	3.7	9.0
PPL Corp.	1.38	31.17	4.9	20.2	49.3	10.0	-0.14	9.8	14.7
Public Serv. Enterprise	1.33	31.92	4.5	16.3	54.7	8.9	-0.30	8.6	13.2
Sempra Energy	1.56	53.45	3.2	12.2	65.0	7.9	0.21	8.1	11.3
South Jersey Inds.	1.32	37.31	3.8	14.9	49.2	7.3	0.72	8.1	11.9
Xcel Energy Inc.	0.98	20.63	5.0	10.8	45.0	4.9	0.06	4.9	9.9
Mean	**1.58**	**35.06**	**4.97**	**11.95**	**46.10**	**5.66**	**0.17**	**5.8**	**10.8**
Median	**1.45**	**32.95**	**4.98**	**10.61**	**48.00**	**4.85**	**0.19**	**5.1**	**10.4**

1/ Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))
2/ BR Growth = Col (4) * (Col (5) / 100)
3/ SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [1- B/M].
4/ Col (6) + Col (7)
5/ Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: Standard and Poor's Research Insight, *Value Line* (November and December 2009) , www.yahoo.com

DCF COSTS OF EQUITY FOR BBB RATED SAMPLE OF U.S. UTILITIES
(THREE-STAGE MODEL)

Company	Annualized Last Paid Dividend (1)	Average High/Low Monthly Close Prices 11/1/2009-1/26/2010 (2)	Growth Rates: Stage 1: I/B/E/S EPS Forecasts (3)	Growth Rates: Stage 2: Average of Stage 1 & 3 (4)	Growth Rates: Stage 3: GDP Growth 1/	DCF Cost of Equity 2/ (5)
ALLETE	1.76	32.95	4.0	4.5	5.0	10.2
Alliant Energy	1.50	29.46	4.3	4.7	5.0	10.1
Ameren Corp.	1.54	26.35	3.0	4.0	5.0	10.4
Atmos Energy	1.34	28.64	5.0	5.0	5.0	9.9
Black Hills	1.42	25.45	6.0	5.5	5.0	11.2
Constellation Energy	0.96	33.35	14.8	9.9	5.0	10.4
DTE Energy	2.12	41.53	3.0	4.0	5.0	9.7
Entergy Corp.	3.00	80.19	6.8	5.9	5.0	9.3
Exelon Corp.	2.10	48.40	2.2	3.6	5.0	8.7
FirstEnergy Corp.	2.20	44.53	3.3	4.2	5.0	9.6
Hawaiian Elec.	1.24	20.22	10.5	7.8	5.0	13.7
OGE Energy	1.45	35.30	6.0	5.5	5.0	9.5
Pepco Holdings	1.08	16.44	5.5	5.3	5.0	12.1
PG&E Corp.	1.68	43.49	7.3	6.2	5.0	9.6
Pinnacle West Capital	2.10	35.56	8.0	6.5	5.0	12.3
Portland General	1.02	19.91	6.8	5.9	5.0	11.0
PPL Corp.	1.38	31.17	11.5	8.2	5.0	11.7
Public Serv. Enterprise	1.33	31.92	5.3	5.2	5.0	9.4
Sempra Energy	1.56	53.45	7.0	6.0	5.0	8.3
South Jersey Inds.	1.32	37.31	11.5	8.3	5.0	10.4
Xcel Energy Inc.	0.98	20.63	7.3	6.1	5.0	10.7
Mean	**1.58**	**35.06**	**6.6**	**5.8**	**5.0**	**10.4**
Median	**1.45**	**32.95**	**6.0**	**5.5**	**5.0**	**10.2**

1/ Forecast nominal rate of GDP growth, 2011-20
2/ Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Standard & Poor's Research Insight; www.yahoo.com; Blue Chip Financial Forecasts (December 2009); I/B/E/S (December 2009)

QUANTIFICATION OF IMPACT ON EQUITY RATIO REQUIREMENT TO EQUATE FOR DIFFERENCE BETWEEN BENCHMARK EQUITY RETURN AND EQUITY RETURN WITH AN EQUITY RISK PREMIUM

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases, but the $WACC_{AT}$ stays the same.

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)
ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Market Cost of Debt for NRG
	=	6.30%
Equity Cost	=	ROE for NRG at 42.0% Equity
	=	10.35%
Tax Rate	=	28.75%
CEQ Ratio	(1)	42.0%
Debt Ratio	(1)	58.0%
CEQ Ratio	(2)	45.9%
Debt Ratio	(2)	54.1%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sample (common equity ratio of 42.0%)

$WACC_{AT}$ = (6.30%)(1-.2875)(58.0%) + (10.35%)(42.0%)
= 6.95%

2. Estimate Cost of Equity for sample at 45.9% common equity ratio with $WACC_{AT}$ unchanged at 6.95%
Tax Rate Declines to Canadian Level

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
6.95% = (6.30%)(1-.2875)(54.1%) + (X)(45.9%)
Cost of Equity at 45.9% Equity Ratio = 9.85%

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Market Cost of Debt for NRG
	=	6.30%
Equity Cost	=	ROE for NRG at 42.0% Equity
	=	10.35%
Tax Rate	=	28.75%
CEQ Ratio	(1)	42.0%
Debt Ratio	(1)	58.0%
CEQ Ratio	(2)	49.1%
Debt Ratio	(2)	50.9%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 42.0%)

$$WACC_{AT} = (6.30\%)(1-.2875)(58.0\%) + (10.35\%)(42.0\%)$$
$$= 6.95\%$$

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 49.1%)
Tax Rate Declines to Canadian Level

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1\text{-t} \times \text{Debt Ratio}_{ML})/(1\text{-t} \times \text{Debt Ratio}_{LL})$$

$$WACC_{AT(ML)} = 6.95\% \times \frac{(1-.2875 \times 50.9\%)}{(1-.2875 \times 58.0\%)}$$

$$WACC_{AT(ML)} = 7.12\%$$

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$$WACC_{AT(ML)} = (\text{Debt Cost})(1\text{-tax rate})(\text{Debt Ratio}_{ML}) + (\text{Equity Cost})(\text{Equity Ratio}_{ML})$$

7.12% = (6.30%)(1-.288)(50.9%) + (X)(49.1%)

Cost of Equity at 49.1% Equity Ratio = 9.85%

ESTIMATE OF IMPACT OF CHANGE IN COST OF EQUITY ON CAPITAL STRUCTURE
45.9%-49.1% Cost of Equity (Midpoint of 47.5%)

FINANCIAL METRICS
FOR CANADIAN UTILITIES
2006-2008

Company	EBIT Coverage	EBITDA Coverage	FFO/ Total Debt	FFO Coverage
Gas Distributors				
Enbridge Gas Distribution	2.2	3.3	13.0	2.8
Gaz Metropolitain	2.3	3.8	19.2	4.7
Pacific Northern Gas [2/]	2.4	3.7	11.6	2.2
Terasen Gas	1.9	2.7	9.0	2.4
Union Gas	2.2	3.4	12.4	2.9
Electric Utilities				
AltaLink L.P.	2.2	4.7	13.3	3.1
CU Inc.	2.3	3.9	17.6	3.4
Enersource [1/]	2.3	3.9	17.8	3.3
ENMAX Corp.	6.9	12.9	47.3	3.8
EPCOR Utilities Inc. [2/]	2.8	3.9	23.2	3.4
FortisAlberta Inc.	2.0	4.1	17.0	4.1
FortisBC Inc.	2.1	3.1	11.3	2.8
Hamilton Utilities	3.6	5.9	34.3	5.0
Hydro One Inc.	2.8	4.9	16.5	3.7
Hydro Ottawa Holding Inc.	3.9	7.0	23.8	5.9
London Hydro	3.1	5.7	24.5	4.5
Maritime Electric	2.4	3.3	14.9	2.9
Newfoundland Power	2.3	3.4	13.6	2.8
Nova Scotia Power	2.6	3.9	18.0	3.5
Toronto Hydro	2.1	4.0	17.8	3.5
Veridian [2/]	3.3	5.3	34.4	N/A
Pipelines				
Enbridge Pipelines Inc.	2.9	3.6	12.2	3.1
Nova Gas Transmission Ltd.	2.3	3.6	17.3	3.2
Trans Quebec & Maritimes	2.4	3.8	12.0	2.9
TransCanada PipeLines Ltd.	2.5	3.6	16.7	2.9
Westcoast Energy Inc.	2.4	3.6	16.8	3.6
Medians				
Gas Distributors	**2.2**	**3.4**	**12.4**	**2.8**
All Companies	**2.4**	**3.8**	**16.9**	**3.3**
Investor-Owned Companies	**2.3**	**3.6**	**13.6**	**2.9**

[1/] EBIT Coverage, EBITDA Coverage and FFO/Debt for 2005-2007

[2/] 2008 EBIT Coverage, EBITDA Coverage and FFO/Debt for 12 months ending September

Source: DBRS, Standard and Poor's and company annual reports

NATURAL RESOURCE GAS LIMITED

Capital Structure - Cost of Capital
2006 Actual

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-Term Debt	4,993,015	54.21%	8.58%	4.65%
Short-Term Debt				
Operating Loan	95,750	1.04%	8.00%	0.08%
Unfunded Debt	2,095,778	22.75%	8.00%	1.82%
Common Equity	2,026,410	22.00%	9.20%	2.02%
Total	9,210,953	100.00%		8.57%

Calculation of the Cost Rates for Capital Structure Components

Long-Term Debt	Calculated Cost Rate (Exhibit E3, Tab 1, Schedule 3)	8.58%
Short-Term Debt		
Operating Loan	Calculated Cost Rate (Exhibit E3, Tab 1, Schedule 3)	8.00%
Common Equity	Requested Rate of Return	9.20%

NATURAL RESOURCE GAS LIMITED

Analysis of Cost of Capital
2006 Actual

Actual 2005	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	2,899,258	30.84%	11.41%	3.52%	330,811
Short-Term Debt					
Operating Loan	78,670	0.84%	5.29%	0.04%	4,164
Unfunded Debt	1,722,274	18.32%	5.29%	0.97%	91,160
Total Debt	4,700,202	50.00%	9.07%	4.53%	426,135
Common Equity	4,700,203	50.00%	9.57%	4.79%	449,809
Total	9,400,405	100.00%		9.32%	875,944

Actual 2006	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	4,993,015	54.21%	8.58%	4.65%	428,401
Short-Term Debt					
Operating Loan	95,750	1.04%	8.00%	0.08%	7,660
Unfunded Debt	2,095,778	22.75%	8.00%	1.82%	167,662
Total Debt	7,184,543	78.00%	8.40%	6.55%	603,723
Common Equity	2,026,410	22.00%	9.20%	2.02%	186,430
Total	9,210,953	100.00%		8.57%	790,153

NATURAL RESOURCE GAS LIMITED

Cost of Debt - Summary Schedule
2006 Actual

	Avg. of Avgs. Principal ($'s)	Carrying Cost ($'s)	Calculated Cost Rate (%)
Long-Term Debt			
Refinancing Cost Amortization		33,780	
Financing Cost Amortization		9,559	
Banco Securities Loan	435,875	45,164	
Imperial Life	707,544	87,509	
Banco Securities Debenture	69,239	8,719	
Bank of Nova Scotia	3,780,357	243,692	
Total	4,993,015	428,423	8.58%
Short-Term Debt			
Operating Loan	95,750	7,659	8.00%
Unfunded Debt	2,095,778	167,640	8.00%
Total	2,191,528	175,299	8.00%

NATURAL RESOURCE GAS LIMITED

Cost of Long-Term Debt - Average of Monthly Averages
2006 Actual
($'s)

Outstanding Principal	Banco Debenture	Imperial Life	Banco Loan	Bank of Nova Scotia	Total
October	155,442	1,609,656	951,000	0	2,716,098
November	153,455	1,580,541	951,000	0	2,684,996
December	151,450	1,551,632	951,000	0	2,654,082
January	149,950	1,522,441	951,000	0	2,623,391
February	147,385	1,491,526	951,000	0	2,589,911
March	73,180	734,738	475,500	6,500,000	7,783,418
April	0	0	0	6,496,266	6,496,266
May	0	0	0	6,488,775	6,488,775
June	0	0	0	6,481,237	6,481,237
July	0	0	0	6,473,652	6,473,652
August	0	0	0	6,466,019	6,466,019
September	0	0	0	6,458,338	6,458,338
Average	69,239	707,544	435,875	3,780,357	4,993,015
Carrying Cost	8,719	87,509	45,164	243,692	385,085
Interest Rate	11.58%	11.43%	9.50%	6.45%	7.71%

NATURAL RESOURCE GAS LIMITED

Cost of Short-Term Debt - Average of Monthly Averages
2006 Actual
($'s)

Outstanding Principal	Operating Loan	Total
October	118,000	118,000
November	218,000	218,000
December	318,000	318,000
January	268,000	268,000
February	168,000	168,000
March	59,000	59,000
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September	0	0
Average	95,750	95,750
Carrying Cost	7,659	7,659
Interest Rate	8.00%	8.00%

NATURAL RESOURCE GAS LIMITED

Capital Structure - Cost of Capital
2007 Actual

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-Term Debt	6,406,924	71.02%	8.36%	5.94%
Short-Term Debt				
Operating Loan	0	0.00%	6.00%	0.00%
Unfunded Debt	629,655	6.98%	6.00%	0.42%
Common Equity	1,984,676	22.00%	9.20%	2.02%
Total	9,021,255	100.00%		8.38%

Calculation of the Cost Rates for Capital Structure Components

Long-Term Debt	Calculated Cost Rate (Exhibit E4, Tab 1, Schedule 3)	8.36%
Short-Term Debt		
Operating Loan	Calculated Cost Rate (Exhibit E4, Tab 1, Schedule 3)	6.00%
Common Equity	Requested Rate of Return	9.20%

NATURAL RESOURCE GAS LIMITED

Analysis of Cost of Capital
2007 Actual

Actual 2006	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	4,993,015	54.21%	8.58%	4.65%	428,401
Short-Term Debt					
Operating Loan	95,750	1.04%	8.00%	0.08%	7,660
Unfunded Debt	2,095,778	22.75%	8.00%	1.82%	167,662
Total Debt	7,184,543	78.00%	8.40%	6.55%	603,723
Common Equity	2,026,410	22.00%	9.20%	2.02%	186,430
Total	9,115,203	100.00%		8.57%	790,153

Actual 2007	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	6,406,924	71.02%	8.36%	5.94%	535,619
Short-Term Debt					
Operating Loan	0	0.00%	6.00%	0.00%	0
Unfunded Debt	629,655	6.98%	6.00%	0.42%	37,779
Total Debt	7,036,579	78.00%	8.15%	6.36%	573,398
Common Equity	1,984,676	22.00%	9.20%	2.02%	182,590
Total	9,021,255	100.00%		8.38%	755,988

NATURAL RESOURCE GAS LIMITED

Cost of Debt - Summary Schedule
2007 Actual

	Avg. of Avgs. Principal ($'s)	Carrying Cost ($'s)	Calculated Cost Rate (%)
Long-Term Debt			
Refinancing Cost Amortization		42,650	
Financing Cost Amortization		9,559	
Banco Securities Loan	0	0	
Imperial Life	0	0	
Banco Securities Debenture	0	0	
Bank of Nova Scotia	6,406,924	483,490	
Total	6,406,924	535,699	8.36%
Short-Term Debt			
Operating Loan	0	0	6.00%
Unfunded Debt	629,655	37,779	6.00%
Total	629,655	37,779	6.00%

NATURAL RESOURCE GAS LIMITED

Cost of Long-Term Debt - Average of Monthly Averages
2007 Actual
($'s)

Outstanding Principal	Banco Debenture	Bank of Nova Scotia	Banco Loan	Bank of Nova Scotia	Total
October	0	0	0	6,450,607	6,450,607
November	0	0	0	6,442,830	6,442,830
December	0	0	0	6,435,003	6,435,003
January	0	0	0	6,427,128	6,427,128
February	0	0	0	6,419,203	6,419,203
March	0	0	0	6,411,229	6,411,229
April	0	0	0	6,403,205	6,403,205
May	0	0	0	6,395,130	6,395,130
June	0	0	0	6,387,005	6,387,005
July	0	0	0	6,378,829	6,378,829
August	0	0	0	6,370,601	6,370,601
September	0	0	0	6,362,322	6,362,322
Average	0	0	0	6,406,924	6,406,924
Carrying Cost	0	0	0	483,490	483,490
Interest Rate	0.00%	0.00%	0.00%	7.55%	7.55%

NATURAL RESOURCE GAS LIMITED

Cost of Short-Term Debt - Average of Monthly Averages
2007 Actual
($'s)

Outstanding Principal	Operating Loan	Total
October	0	0
November	0	0
December	0	0
January	0	0
February	0	0
March	0	0
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September	0	0
Average	0	0
Carrying Cost	0	0
Interest Rate	0.00%	0.00%

NATURAL RESOURCE GAS LIMITED

Capital Structure - Cost of Capital
2007 OEB Approved

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-Term Debt	6,406,924	66.21%	8.31%	5.50%
Short-Term Debt				
Operating Loan	0	0.00%	6.00%	0.00%
Unfunded Debt	-794,431	-8.21%	6.00%	-0.49%
Common Equity	4,064,219	42.00%	9.20%	3.86%
Total	9,676,712	100.00%		8.87%

Calculation of the Cost Rates for Capital Structure Components

Long-Term Debt	Calculated Cost Rate (Exhibit E4.1, Tab 1, Schedule 3)	8.31%
Short-Term Debt		
Operating Loan	Calculated Cost Rate (Exhibit E4.1, Tab 1, Schedule 3)	6.00%
Common Equity	Requested Rate of Return	9.20%

NATURAL RESOURCE GAS LIMITED

Analysis of Cost of Capital
2007 OEB Approved

2007 Historic Year Year	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	6,406,924	71.02%	8.36%	5.94%	535,619
Short-Term Debt					
Operating Loan	0	0.00%	6.00%	0.00%	0
Unfunded Debt	629,655	6.98%	6.00%	0.42%	37,779
Total Debt	7,036,579	78.00%	8.15%	6.36%	573,398
Common Equity	1,984,676	22.00%	9.20%	2.02%	182,590
Total	9,021,255	100.00%		8.38%	755,988
2007 OEB Approved Year					
Long-Term Debt	6,406,924	66.21%	8.31%	5.50%	532,604
Short-Term Debt					
Operating Loan	0	0.00%	6.00%	0.00%	0
Unfunded Debt	-794,431	-8.21%	6.00%	-0.49%	-47,666
Total Debt	5,612,493	58.00%	8.64%	5.01%	484,938
Common Equity	4,064,219	42.00%	9.20%	3.86%	373,908
Total	9,676,712	100.00%		8.87%	858,846

Analysis
The reduction in the overall cost of capital is the result of the combination of a higher debt component at a lower cost of debt and a lower equity component with a higher return on equity.

NATURAL RESOURCE GAS LIMITED

Cost of Debt - Summary Schedule
2007 OEB Approved

	Avg. of Avgs. Principal ($'s)	Carrying Cost ($'s)	Calculated Cost Rate (%)	Notes
Long-Term Debt				
Refinancing Cost Amortization		49,611		(1)
Financing Cost Amortization		890		(2)
Banco Securities Loan	0	0		
Imperial Life	0	0		
Banco Securities Debenture	0	0		
Bank of Nova Scotia	6,406,924	482,102	7.52%	
Total	6,406,924	532,604	8.31%	
Short-Term Debt				
Operating Loan	0	0	6.00%	
Unfunded Debt	-794,431	-47,666	6.00%	
Total	-794,431	-47,666	6.00%	

Notes:

(1) Costs and Interest at the end of Fiscal 2007 transferred from deferral account and amortized over remaining length of new loan (53 months).
(2) Financing costs amortized over 5 years.

NATURAL RESOURCE GAS LIMITED

Cost of Long-Term Debt - Average of Monthly Averages
2007 OEB Approved
($'s)

Outstanding Principal	Banco Debenture	Imperial Life	Banco Loan	Bank of Nova Scotia	Total
October	0	0	0	6,450,607	6,450,607
November	0	0	0	6,442,830	6,442,830
December	0	0	0	6,435,003	6,435,003
January	0	0	0	6,427,128	6,427,128
February	0	0	0	6,419,203	6,419,203
March	0	0	0	6,411,229	6,411,229
April	0	0	0	6,403,205	6,403,205
May	0	0	0	6,395,130	6,395,130
June	0	0	0	6,387,005	6,387,005
July	0	0	0	6,378,829	6,378,829
August	0	0	0	6,370,601	6,370,601
September	0	0	0	6,362,322	6,362,322
Average	0	0	0	6,406,924	6,406,924
Carrying Cost	0	0	0	482,102	482,102
Interest Rate	0.00%	0.00%	0.00%	7.52%	7.52%

NATURAL RESOURCE GAS LIMITED

Cost of Short-Term Debt - Average of Monthly Averages
2007 OEB Approved
($'s)

Outstanding Principal	Operating Loan	Total
October	0	0
November	0	0
December	0	0
January	0	0
February	0	0
March	0	0
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September	0	0
Average	0	0
Carrying Cost	0	0
Interest Rate	0.00%	0.00%

NATURAL RESOURCE GAS LIMITED

Capital Structure - Cost of Capital
2008 Actual

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-Term Debt	6,309,161	71.12%	8.37%	5.95%
Short-Term Debt				
Operating Loan	0	0.00%	6.00%	0.00%
Unfunded Debt	-1,163,938	-13.12%	6.00%	-0.79%
Common Equity	3,725,852	42.00%	9.20%	3.86%
Rate Base	8,871,075	100.00%		9.02%

Calculation of the Cost Rates for Capital Structure Components

Long-Term Debt	Calculated Cost Rate (Exhibit E5, Tab 1, Schedule 3)	8.37%
Short-Term Debt		
Operating Loan	Calculated Cost Rate (Exhibit E5, Tab 1, Schedule 3)	6.00%
Common Equity	Requested Rate of Return	9.20%

NATURAL RESOURCE GAS LIMITED

Analysis of Cost of Capital
2008 Actual

Actual 2007	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	6,406,924	71.02%	8.36%	5.94%	535,619
Short-Term Debt					
Operating Loan	0	0.00%	6.00%	0.00%	0
Unfunded Debt	629,655	6.98%	6.00%	0.42%	37,779
Total Debt	7,036,579	78.00%	8.15%	6.36%	573,398
Common Equity	1,984,676	22.00%	9.20%	2.02%	182,590
Total	9,021,255	100.00%		8.38%	755,988

Actual 2008	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	6,309,161	71.12%	8.37%	5.95%	528,077
Short-Term Debt					
Operating Loan	0	0.00%	6.00%	0.00%	0
Unfunded Debt	-1,163,938	-13.12%	6.00%	-0.79%	-69,836
Total Debt	5,145,223	58.00%	8.91%	5.16%	458,241
Common Equity	3,725,852	42.00%	9.20%	3.86%	342,778
Total	8,871,075	100.00%		9.02%	801,019

NATURAL RESOURCE GAS LIMITED

Cost of Debt - Summary Schedule
2008 Actual

	Avg. of Avgs. Principal ($'s)	Carrying Cost ($'s)	Calculated Cost Rate (%)
Long-Term Debt			
Refinancing Cost Amortization		42,641	
Financing Cost Amortization		9,559	
Banco Securities Loan	0	0	
Bank of Nova Scotia	0	0	
Banco Securities Debenture	0	0	
Bank of Nova Scotia	6,309,161	476,109	
Total	6,309,161	528,309	8.37%
Short-Term Debt			
Operating Loan	0	0	6.00%
Unfunded Debt	-1,163,938	-69,836	6.00%
Total	-1,163,938	-69,836	6.00%

NATURAL RESOURCE GAS LIMITED

Cost of Long-Term Debt - Average of Monthly Averages
2008 Actual
($'s)

Outstanding Principal	Banco Debenture	Bank of Nova Scotia	Banco Loan	Bank of Nova Scotia	Total
October	0	0	0	6,355,364	6,355,364
November	0	0	0	6,346,990	6,346,990
December	0	0	0	6,338,563	6,338,563
January	0	0	0	6,330,083	6,330,083
February	0	0	0	6,322,202	6,322,202
March	0	0	0	6,314,271	6,314,271
April	0	0	0	6,305,640	6,305,640
May	0	0	0	6,296,953	6,296,953
June	0	0	0	6,288,213	6,288,213
July	0	0	0	6,279,418	6,279,418
August	0	0	0	6,270,567	6,270,567
September	0	0	0	6,261,662	6,261,662
Average	0	0	0	6,309,161	6,309,161
Carrying Cost	0	0	0	476,109	476,109
Interest Rate	0.00%	0.00%	0.00%	7.55%	7.55%

NATURAL RESOURCE GAS LIMITED

Cost of Short-Term Debt - Average of Monthly Averages
2008 Actual
($'s)

Outstanding Principal	Operating Loan	Total
October	0	0
November	0	0
December	0	0
January	0	0
February	0	0
March	0	0
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September	0	0
Average	0	0
Carrying Cost	0	0
Interest Rate	0.00%	0.00%

NATURAL RESOURCE GAS LIMITED

Capital Structure - Cost of Capital
2009 Actual

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-Term Debt	10,751,057	78.44%	6.08%	4.77%
Short-Term Debt				
Compensating Balance	-2,751,130	-20.07%	0.50%	-0.10%
Unfunded Debt	-50,125	-0.37%	0.50%	0.00%
Common Equity	5,756,753	42.00%	9.20%	3.86%
Property Plant & Eqpmt	13,706,555	99.99%		8.53%

Calculation of the Cost Rates for Capital Structure Components

Long-Term Debt	Calculated Cost Rate (Exhibit E6, Tab 1, Schedule 3)	6.08%
Short-Term Debt		
Compensating Balance	Calculated Cost Rate (Exhibit E6, Tab 1, Schedule 3)	0.50%
Common Equity	Requested Rate of Return	9.20%

NATURAL RESOURCE GAS LIMITED

Analysis of Cost of Capital
2009 Actual

Actual 2008	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	6,309,161	71.12%	8.37%	5.95%	528,077
Short-Term Debt					
Compensating Balance	0	0.00%	6.00%	0.00%	0
Unfunded Debt	-1,163,938	-13.12%	6.00%	-0.79%	-69,836
Total Debt	5,145,223	58.00%	8.91%	5.16%	458,241
Common Equity	3,725,852	42.00%	9.20%	3.86%	342,778
Total	8,871,075	100.00%		9.02%	801,019

Actual 2009	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	10,751,057	78.44%	6.08%	4.77%	653,664
Short-Term Debt					
Compensating Balance	-2,751,130	-20.07%	0.50%	-0.10%	-13,756
Unfunded Debt	-50,125	-0.37%	0.50%	0.00%	-251
Total Debt	7,949,802	58.00%	8.05%	4.67%	639,657
Common Equity	5,756,753	42.00%	9.20%	3.86%	529,621
Total	13,706,555	100.00%		8.53%	1,169,278

Analysis
The reduction in the overall cost of capital is the result of the combination of a higher debt component at a lower cost of debt and a lower equity component with a higher return on equity.

NATURAL RESOURCE GAS LIMITED

Cost of Debt - Summary Schedule
2009 Actual

	Avg. of Avgs. Principal ($'s)	Carrying Cost ($'s)	Calculated Cost Rate (%)
Long-Term Debt			
Refinancing Cost Amortization		49,814	
Financing Cost Amortization			
Bank of Nova Scotia	4,548,194	135,785	
Bank of Nova Scotia	6,202,863	468,068	
Total	10,751,057	653,667	6.08%
Short-Term Debt			
Compensating Balance	-2,751,130	-13,756	0.50%
Unfunded Debt	-50,125	-251	0.50%
Total	-2,801,255	-14,007	0.50%

NATURAL RESOURCE GAS LIMITED

Cost of Long-Term Debt - Average of Monthly Averages
2009 Actual
($'s)

Outstanding Principal	Bank of Nova Scotia	Bank of Nova Scotia	Total
October	0	6,252,696	6,252,696
November	5,178,333	6,243,675	11,422,009
December	5,135,000	6,234,598	11,369,598
January	5,091,667	6,225,464	11,317,131
February	5,048,333	6,216,924	11,265,258
March	5,005,000	6,208,331	11,213,331
April	4,961,667	6,199,033	11,160,699
May	4,918,333	6,189,676	11,108,009
June	4,875,000	6,180,260	11,055,260
July	4,831,667	6,170,785	11,002,452
August	4,788,333	6,161,252	10,949,585
September	4,745,000	6,151,658	10,896,658
Average	4,548,194	6,202,863	10,751,057
Carrying Cost	135,785	468,068	603,853
Interest Rate	2.99%	7.55%	5.62%

NATURAL RESOURCE GAS LIMITED

Cost of Short-Term Debt - Average of Monthly Averages
Actual 2009
($'s)

Outstanding Principal	Compensating Balance	Total
October	-2,751,130	-2,751,130
November	-2,751,130	-2,751,130
December	-2,751,130	-2,751,130
January	-2,751,130	-2,751,130
February	-2,751,130	-2,751,130
March	-2,751,130	-2,751,130
April	-2,751,130	-2,751,130
May	-2,751,130	-2,751,130
June	-2,751,130	-2,751,130
July	-2,751,130	-2,751,130
August	-2,751,130	-2,751,130
September	-2,751,130	-2,751,130
Average	-2,751,130	-2,751,130
Carrying Cost	-13,756	-13,756
Interest Rate	0.50%	0.00%

NATURAL RESOURCE GAS LIMITED

Capital Structure - Cost of Capital
2010 Bridge Year

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-Term Debt	10,551,662	74.99%	6.10%	4.57%
Short-Term Debt				
Compensating Balance	-2,751,130	-19.55%	0.50%	-0.10%
Unfunded Debt	360,338	2.56%	0.50%	0.01%
Common Equity	5,909,595	42.00%	9.20%	3.86%
Property Plant & Eqpmt	14,070,465	100.00%		8.34%

Calculation of the Cost Rates for Capital Structure Components

Long-Term Debt	Calculated Cost Rate (Exhibit E7, Tab 1, Schedule 3)	6.10%
Short-Term Debt		
Compensating Balance	Calculated Cost Rate (Exhibit E7, Tab 1, Schedule 3)	0.50%
Deemed Short Term Debt Cost		0.50%
Common Equity	Authorized Rate of Return	9.20%

March 8, 2010
EB-2010-0018
Exhibit E7
Tab 1
Schedule 2
Updated

NATURAL RESOURCE GAS LIMITED

Analysis of Cost of Capital
2010 Bridge Year

Actual 2009	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	10,751,057	78.44%	6.08%	4.77%	653,664
Short-Term Debt					
Compensating Balance	-2,751,130	-20.07%	0.50%	-0.10%	-13,756
Unfunded Debt	-50,125	-0.37%	0.50%	0.00%	-251
Total Debt	7,949,802	58.00%	8.05%	4.67%	639,657
Common Equity	5,756,753	42.00%	9.20%	3.86%	529,621
Total	13,706,555	100.00%		8.53%	1,169,278
Bridge 2010					
Long-Term Debt	10,551,662	74.99%	6.10%	4.57%	643,651
Short-Term Debt					
Compensating Balance	-2,751,130	-19.55%	0.50%	-0.10%	-13,756
Unfunded Debt	360,338	2.56%	0.50%	0.01%	1,802
Total Debt	8,160,870	58.00%	7.74%	4.48%	631,697
Common Equity	5,909,595	42.00%	9.20%	3.86%	543,683
Total	14,070,465	100.00%		8.34%	1,175,380

NATURAL RESOURCE GAS LIMITED

Cost of Debt - Summary Schedule
2010 Actual

	Avg. of Avgs. Principal ($'s)	Carrying Cost ($'s)	Calculated Cost Rate (%)
Long-Term Debt			
Refinancing Cost Amortization		49,814	
Financing Cost Amortization			
Bank of Nova Scotia	4,463,333	134,550	
Bank of Nova Scotia	6,088,329	459,518	
Total	10,551,662	643,882	6.10%
Short-Term Debt			
Compensating Balance	-2,751,130	-13,756	0.50%
Unfunded Debt	360,338	1,802	0.50%
Total	-2,390,792	-11,954	0.50%

NATURAL RESOURCE GAS LIMITED

Cost of Long-Term Debt - Average of Monthly Averages
2010 Bridge Year
($'s)

Outstanding Principal	Bank of Nova Scotia	Bank of Nova Scotia	Total
October	4,701,667	6,142,041	10,843,707
November	4,658,333	6,132,330	10,790,663
December	4,615,000	6,122,557	10,737,557
January	4,571,667	6,112,724	10,684,391
February	4,528,333	6,103,481	10,631,814
March	4,485,000	6,094,180	10,579,180
April	4,441,667	6,084,168	10,525,835
May	4,398,333	6,074,094	10,472,428
June	4,355,000	6,063,957	10,418,957
July	4,311,667	6,053,757	10,365,424
August	4,268,333	6,043,492	10,311,826
September	4,225,000	6,033,163	10,258,164
Average	4,463,333	6,088,329	10,551,662
Carrying Cost	134,550	459,518	594,068
Interest Rate	3.01%	7.55%	5.63%

NATURAL RESOURCE GAS LIMITED

Cost of Short-Term Debt - Average of Monthly Averages
2010 Bridge Year
($'s)

	Outstanding Principal	Compensating Balance	Total
October		-2,751,130	-2,751,130
November		-2,751,130	-2,751,130
December		-2,751,130	-2,751,130
January		-2,751,130	-2,751,130
February		-2,751,130	-2,751,130
March		-2,751,130	-2,751,130
April		-2,751,130	-2,751,130
May		-2,751,130	-2,751,130
June		-2,751,130	-2,751,130
July		-2,751,130	-2,751,130
August		-2,751,130	-2,751,130
September		-2,751,130	-2,751,130
Average		-2,751,130	-2,751,130
Carrying Cost		-13,756	-13,756
Interest Rate		0.50%	0.50%

NATURAL RESOURCE GAS LIMITED

Capital Structure - Cost of Capital
2011 Test Year

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-Term Debt	9,908,196	72.80%	6.69%	4.87%
Short-Term Debt				
Compensating Balance	-2,751,130	-20.20%	0.50%	-0.10%
Unfunded Debt	741,798	5.40%	0.50%	0.03%
Common Equity	5,719,867	42.00%	10.35%	4.35%
Rate Base	13,618,731	100.00%		9.14%

Calculation of the Cost Rates for Capital Structure Components

Long-Term Debt	Calculated Cost Rate (Exhibit E8, Tab 1, Schedule 3)	6.69%
Short-Term Debt		
Compensating Balance	Calculated Cost Rate (Exhibit E8, Tab 1, Schedule 3)	0.50%
Deemed Short Term Debt		0.50%
Common Equity	Requested Rate of Return	10.35%

NATURAL RESOURCE GAS LIMITED

Analysis of Cost of Capital
2011 Test Year

Bridge 2010	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)	Return ($'s)
Long-Term Debt	10,551,662	74.99%	6.10%	4.57%	643,651
Short-Term Debt					
Compensating Balance	-2,751,130	-19.55%	0.50%	-0.10%	-13,756
Unfunded Debt	360,338	2.56%	0.50%	0.01%	1,802
Total Debt	8,160,870	58.00%	7.74%	4.48%	631,697
Common Equity	5,909,595	42.00%	9.20%	3.86%	543,683
Total	14,070,465	100.00%		8.34%	1,175,380
Test 2011					
Long-Term Debt	9,908,196	72.80%	6.69%	4.87%	662,642
Short-Term Debt					
Compensating Balance	-2,751,130	-20.20%	0.50%	-0.10%	-13,756
Unfunded Debt	741,798	5.40%	0.50%	0.03%	3,709
Total Debt	7,898,864	58.00%	8.26%	4.80%	652,595
Common Equity	5,719,867	42.00%	10.35%	4.35%	592,006
Total	13,618,731	100.00%		9.15%	1,244,601

NATURAL RESOURCE GAS LIMITED

Cost of Debt - Summary Schedule
2011 BridgeActual

	Avg. of Avgs. Principal ($'s)	Carrying Cost ($'s)	Calculated Cost Rate (%)
Long-Term Debt			
Refinancing Cost Amortization		49,814	
Financing Cost Amortization			
Bank of Nova Scotia	3,943,333	162,565	
Bank of Nova Scotia	5,964,863	450,263	
Total	9,908,196	662,642	6.69%
Short-Term Debt			
Compensating Balance	-2,751,130	-13,756	0.50%
Unfunded Debt	741,798	3,709	0.50%
Total	-2,009,332	-10,047	0.50%

NATURAL RESOURCE GAS LIMITED

Cost of Long-Term Debt - Average of Monthly Averages
2011 Test Year
($'s)

Outstanding Principal	Bank of Nova Scotia	Bank of Nova Scotia	Total
October	4,181,667	6,022,773	10,204,440
November	4,138,333	6,012,314	10,150,648
December	4,095,000	6,001,790	10,096,790
January	4,051,667	5,991,200	10,042,867
February	4,008,333	5,981,195	9,989,528
March	3,965,000	5,971,127	9,936,128
April	3,921,667	5,960,345	9,882,012
May	3,878,333	5,949,495	9,827,829
June	3,835,000	5,938,577	9,773,577
July	3,791,667	5,927,591	9,719,258
August	3,748,333	5,916,536	9,664,869
September	3,705,000	5,905,412	9,610,412
Average	3,943,333	5,964,863	9,908,196
Carrying Cost	162,565	450,263	612,828
Interest Rate	4.12%	7.55%	6.19%

NATURAL RESOURCE GAS LIMITED

Cost of Short-Term Debt - Average of Monthly Averages
2011 Test Year
($'s)

Outstanding Principal	Compensating Balance	Total
October	-2,751,130	-2,751,130
November	-2,751,130	-2,751,130
December	-2,751,130	-2,751,130
January	-2,751,130	-2,751,130
February	-2,751,130	-2,751,130
March	-2,751,130	-2,751,130
April	-2,751,130	-2,751,130
May	-2,751,130	-2,751,130
June	-2,751,130	-2,751,130
July	-2,751,130	-2,751,130
August	-2,751,130	-2,751,130
September	-2,751,130	-2,751,130
Average	-2,751,130	-2,751,130
Carrying Cost	-13,756	-13,756
Interest Rate	0.50%	0.50%

NATURAL RESOURCE GAS LIMITED

REVENUE (DEFICIENCY)/SUFFICIENCY

Fiscal 2011 Test Year

The 2011 Test Year revenue deficiency is shown in Exhibit F8, Tab 1, Schedule 1. The estimated gross revenue deficiency is $462,417 or $0.0087 per m^3. As shown in the same exhibit, this deficiency compares to an estimated deficiency of $52,727 or $0.0010 per m^3 for the fiscal 2010 Bridge Year. The increased deficiency reflects increased revenues of $100,290 and higher Operations, Maintenance and Administration costs of $465,179.

Fiscal 2010 Bridge Year

A gross revenue deficiency of $52,727 or $0.0010 per m^3 is forecast for the 2010 Bridge Year, as shown in Exhibit F7, Tab 1, Schedule 1. This is $48,190 higher than the 2009 deficiency and is chiefly due to increased gas transportation costs of $23,714 and increased Operations, Maintenance and Administration costs of $272,990 coupled with increased rate base of $363,910.

Fiscal 2009 Historical Year

A gross revenue deficiency of $4,537 or $0.0001 per m^3 was recorded in fiscal 2009, as shown in Exhibit F6, Tab 1, Schedule 1. This deficiency was the primarily the result of $4,835,480 of higher rate base due chiefly to the inclusion of the IGPC pipeline.

It is $136,413 greater than the deficiency recorded in 2008. A favourable variance in utility income was sufficient to offset the effect of a $4,835,480 increase in rate base due to the inclusion of the IGPC pipeline coupled with increased period costs of $773,944.

<u>Fiscal 2008 Historical Year</u>

A gross revenue deficiency of $140,950 or $0.0067 per m^3 was recorded in fiscal 2008, as shown in Exhibit F5, Tab 1, Schedule 1. It is $240,986 greater than the deficiency incurred in 2007 due to reduced utility income of $101,158 that is principally due to increased revenue or $158,967, that is more than offset by Cost of Service increases of $246,352. It also reflects decreased rate base of $150,180.

<u>Fiscal 2007 Historical Year</u>

A gross revenue sufficiency of $100,036 or $0.0044 per m^3 was recorded in fiscal 2007, as shown in Exhibit F4, Tab 1, Schedule 1. This sufficiency was incurred because revenues increased by $162,257 and period costs declined by $90,141 and rate base declined by $189,698.

The 2007 sufficiency is $230,781 greater than the deficiency authorized by the Board.

<u>Fiscal 2006 Historical Year</u>

A gross revenue deficiency of $201,862 or $0.0089 per m^3 was recorded in fiscal 2006, as shown in Exhibit F3, Tab 1, Schedule 1. This is $58,974 greater than the deficiency recorded in 2005 and is due to the combination of $188,500 lower revenues, lower income tax expense of $111,540 and a $189,452 reduction in rate base.

NATURAL RESOURCE GAS LIMITED

Calculation of Revenue (Deficiency) / Sufficiency
2006 Actual

	Actual 2006	Actual 2005
Utility Income	$622,631	$697,283
Utility Rate Base	$9,210,953	$9,400,405
Indicated Rate of Return	6.76%	7.42%
Requested/Approved Rate of Return	8.57%	8.32%
(Deficiency)/Sufficiency in Return	-1.81%	-0.90%
Net Revenue (Deficiency)/Sufficiency	($166,718)	($84,604)
Provision for Income Taxes	($35,144)	($58,284)
Gross Revenue (Deficiency)/Sufficiency	($201,862)	($142,888)
Normalized Gas Sales and Transportation (M*	22,726,574	24,564,133
Gross Revenue (Deficiency)/Sufficiency per M	($0.0089)	($0.0058)
Return on Deemed Equity	0.93%	5.85%

	Variance from 2005
Utility Income	($74,652)
Utility Rate Base	($189,452)
Indicated Rate of Return	-0.66%
Approved Rate of Return	0.25%
(Deficiency)/Sufficiency in Return	-0.91%
Net Revenue (Deficiency)/Sufficiency	($82,114)
Provision for Income Taxes	$23,140
Gross Revenue (Deficiency)/Sufficiency	($58,974)
Normalized Gas Sales and Transportation (M*3)	-1,837,559
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0031)

NATURAL RESOURCE GAS LIMITED

Statement of Adjusted Utility Income
2006 Actual

	Actual 2006	Actual 2005
Revenue		
Distribution Revenue	3,529,715	3,714,954
Other Operating Revenue (Net)	638,523	641,784
Total Revenue	4,168,238	4,356,738
Costs and Expenses		
Gas Transportation Costs	411,228	542,477
Operation & Maintenance	2,141,069	2,008,796
Depreciation & Amortization	697,844	663,586
Property & Capital Taxes	272,222	309,812
Total Costs and Expenses	3,522,363	3,524,671
Utility Income Before Income Taxes	645,875	832,067
Income Taxes	23,244	134,784
Utility Income	622,631	697,283

	Variance from 2005
Revenue	
Distribution Revenue	-185,239
Other Operating Revenue (Net)	-3,261
Total Revenue	-188,500
Costs and Expenses	
Gas Transportation Costs	-131,249
Operation & Maintenance	132,273
Depreciation & Amortization	34,258
Property & Capital Taxes	-37,590
Total Costs and Expenses	-2,308
Utility Income Before Income Taxes	-186,192
Income Taxes	-111,540
Utility Income	-74,652

NATURAL RESOURCE GAS LIMITED

Calculation of Revenue (Deficiency) / Sufficiency
2007 Actual

	Actual 2007	Actual 2006
Utility Income	$816,779	$622,631
Utility Rate Base	$9,021,255	$9,210,953
Indicated Rate of Return	9.05%	6.76%
Requested/Approved Rate of Return	8.38%	8.57%
(Deficiency)/Sufficiency in Return	0.67%	-1.81%
Net Revenue (Deficiency)/Sufficiency	$60,442	($166,718)
Provision for Income Taxes	$39,594	($35,144)
Gross Revenue (Deficiency)/Sufficiency	$100,036	($201,862)
Normalized Gas Sales and Transportation (M*3)	22,820,706	22,726,574
Gross Revenue (Deficiency)/Sufficiency per M*3	$0.0044	($0.0089)
Return on Deemed Equity	12.26%	0.93%

	Variance from 2006
Utility Income	$194,148
Utility Rate Base	($189,698)
Indicated Rate of Return	2.29%
Approved Rate of Return	-0.19%
(Deficiency)/Sufficiency in Return	2.48%
Net Revenue (Deficiency)/Sufficiency	$227,160
Provision for Income Taxes	$74,738
Gross Revenue (Deficiency)/Sufficiency	$301,898
Normalized Gas Sales and Transportation (M*3)	94,132
Gross Revenue (Deficiency)/Sufficiency per M*3	0.0133

NATURAL RESOURCE GAS LIMITED

Statement of Adjusted Utility Income
2007 Actual

	Actual 2007	Actual 2006
Revenue		
Distribution Revenue	3,751,671	3,529,715
Other Operating Revenue (Net)	578,824	638,523
Total Revenue	4,330,495	4,168,238
Costs and Expenses		
Gas Transportation Costs	394,141	411,228
Operation & Maintenance	1,986,694	2,141,069
Depreciation & Amortization	727,308	697,844
Property & Capital Taxes	324,080	272,222
Total Costs and Expenses	3,432,222	3,522,363
Utility Income Before Income Taxes	898,273	645,875
Income Taxes	81,494	23,244
Utility Income	816,779	622,631

	Variance from 2006
Revenue	
Distribution Revenue	221,956
Other Operating Revenue (Net)	-59,699
Total Revenue	162,257
Costs and Expenses	
Gas Transportation Costs	-17,087
Operation & Maintenance	-154,375
Depreciation & Amortization	29,464
Property & Capital Taxes	51,858
Total Costs and Expenses	-90,141
Utility Income Before Income Taxes	252,398
Income Taxes	58,250
Utility Income	194,148

NATURAL RESOURCE GAS LIMITED

Calculation of Revenue (Deficiency) / Sufficiency
2007 OEB Approved

	OEB Approved 2007	Historic Year 2007
Utility Income	$780,808	$816,779
Utility Rate Base	$9,676,712	$9,021,255
Indicated Rate of Return	8.07%	9.05%
Requested/Approved Rate of Return	8.87%	8.38%
(Deficiency)/Sufficiency in Return	-0.80%	0.67%
Net Revenue (Deficiency)/Sufficiency	($77,414)	$60,442
Provision for Income Taxes	($53,331)	$39,594
Gross Revenue (Deficiency)/Sufficiency	($130,745)	$100,036
Normalized Gas Sales and Transportation (M*3)	23,566,141	22,820,706
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0055)	$0.0044
Return on Deemed Equity	7.28%	12.26%

	Variance from Historic Year 2007
Utility Income	($35,971)
Utility Rate Base	$655,457
Indicated Rate of Return	-0.98%
Approved Rate of Return	0.49%
(Deficiency)/Sufficiency in Return	-1.47%
Net Revenue (Deficiency)/Sufficiency	($137,856)
Provision for Income Taxes	($92,925)
Gross Revenue (Deficiency)/Sufficiency	($230,781)
Normalized Gas Sales and Transportation (M*3)	745,435
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0099)

NATURAL RESOURCE GAS LIMITED

Statement of Adjusted Utility Income
2007 OEB Approved

	OEB Approved 2007	Adjusted Historic Year 2007
Revenue		
Distribution Revenue	3,889,059	3,751,671
Other Operating Revenue (Net)	681,026	512,132
Total Revenue	4,570,085	4,263,803
Costs and Expenses		
Gas Transportation Costs	448,437	394,141
Operation & Maintenance	2,145,582	1,986,694
Depreciation & Amortization	730,504	727,308
Property & Capital Taxes	334,437	324,080
Total Costs and Expenses	3,658,961	3,432,222
Utility Income Before Income Taxes	911,125	831,581
Income Taxes	130,317	62,922
Utility Income	780,808	768,659

	Variance from Historic Year 2007
Revenue	
Distribution Revenue	137,388
Other Operating Revenue (Net)	168,894
Total Revenue	306,282
Costs and Expenses	
Gas Transportation Costs	54,296
Operation & Maintenance	158,889
Depreciation & Amortization	3,197
Property & Capital Taxes	10,357
Total Costs and Expenses	226,738
Utility Income Before Income Taxes	79,544
Income Taxes	67,395
Utility Income	12,149

NATURAL RESOURCE GAS LIMITED

Calculation of Revenue (Deficiency) / Sufficiency
2008 Actual

	Actual 2008	Actual 2007
Utility Income	$715,421	$816,779
Utility Rate Base	$8,871,075	$9,021,255
Indicated Rate of Return	8.06%	9.05%
Requested/Approved Rate of Return	9.02%	8.38%
(Deficiency)/Sufficiency in Return	-0.96%	0.67%
Net Revenue (Deficiency)/Sufficiency	($85,162)	$60,442
Provision for Income Taxes	($55,788)	$39,594
Gross Revenue (Deficiency)/Sufficiency	($140,950)	$100,036
Normalized Gas Sales and Transportation (M*3)	21,089,072	22,820,706
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0067)	$0.0044
Return on Deemed Equity	6.90%	12.26%

	Variance from 2007
Utility Income	($101,357)
Utility Rate Base	($150,180)
Indicated Rate of Return	-0.99%
Approved Rate of Return	0.64%
(Deficiency)/Sufficiency in Return	-1.63%
Net Revenue (Deficiency)/Sufficiency	($145,604)
Provision for Income Taxes	($95,382)
Gross Revenue (Deficiency)/Sufficiency	($240,986)
Normalized Gas Sales and Transportation (M*3)	-1,731,634
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0111)

NATURAL RESOURCE GAS LIMITED

Statement of Adjusted Utility Income
2008 Actual

	Actual 2008	Actual 2007
Revenue		
Distribution Revenue	3,991,759	3,751,671
Other Operating Revenue (Net)	497,704	578,824
Total Revenue	4,489,462	4,330,495
Costs and Expenses		
Gas Transportation Costs	422,897	394,141
Operation & Maintenance	2,139,440	1,986,694
Depreciation & Amortization	760,425	727,308
Property & Capital Taxes	355,812	324,080
Total Costs and Expenses	3,678,574	3,432,222
Utility Income Before Income Taxes	810,888	898,273
Income Taxes	95,467	81,494
Utility Income	715,421	816,779

	Variance from 2007
Revenue	
Distribution Revenue	240,088
Other Operating Revenue (Net)	-81,120
Total Revenue	158,967
Costs and Expenses	
Gas Transportation Costs	28,756
Operation & Maintenance	152,746
Depreciation & Amortization	33,117
Property & Capital Taxes	31,732
Total Costs and Expenses	246,352
Utility Income Before Income Taxes	-87,384
Income Taxes	13,973
Utility Income	-101,357

NATURAL RESOURCE GAS LIMITED

Calculation of Revenue (Deficiency)/Sufficiency
2009 Actual

	Actual 2009	Actual 2008
Utility Income	$1,166,741	$715,421
Utility Rate Base	$13,706,555	$8,871,075
Indicated Rate of Return	8.51%	8.06%
Estimated Allowed Rate of Return	8.53%	9.02%
(Deficiency)/Sufficiency in Return	-0.02%	-0.96%
Net Revenue (Deficiency)/Sufficiency	($2,741)	($85,162)
Provision for Income Taxes	($1,796)	($55,788)
Gross Revenue (Deficiency)/Sufficiency	($4,537)	($140,950)
Normalized Gas Sales and Transportation (M*3)	53,298,161	21,089,072
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0001)	($0.0067)
Return on Deemed Equity	9.16%	6.90%

	Variance from 2008
Utility Income	$451,319
Utility Rate Base	$4,835,480
Indicated Rate of Return	0.45%
Approved Rate of Return	-0.49%
(Deficiency)/Sufficiency in Return	0.94%
Net Revenue (Deficiency)/Sufficiency	$82,421
Provision for Income Taxes	$53,992
Gross Revenue (Deficiency)/Sufficiency	$136,413
Normalized Gas Sales and Transportation (M*3)	32,209,089
Gross Revenue (Deficiency)/Sufficiency per M*3	$0.0066

NATURAL RESOURCE GAS LIMITED

Statement of Adjusted Utility Income
2009 Actual

	Actual 2009	Actual 2008
Revenue		
Distribution Revenue	5,357,493	3,991,759
Other Operating Revenue (Net)	569,192	497,704
Total Revenue	5,926,685	4,489,462
Costs and Expenses		
Gas Transportation Costs	799,742	422,897
Operation & Maintenance	2,121,130	2,139,440
Depreciation & Amortization	1,105,062	760,425
Property & Capital Taxes	426,584	355,812
Total Costs and Expenses	4,452,518	3,678,574
Utility Income Before Income Taxes	1,474,168	810,888
Income Taxes	307,427	95,467
Utility Income	1,166,741	715,421

	Variance from 2008
Revenue	
Distribution Revenue	1,365,734
Other Operating Revenue (Net)	71,489
Total Revenue	1,437,223
Costs and Expenses	
Gas Transportation Costs	376,844
Operation & Maintenance	-18,310
Depreciation & Amortization	344,637
Property & Capital Taxes	70,772
Total Costs and Expenses	773,944
Utility Income Before Income Taxes	663,279
Income Taxes	211,960
Utility Income	451,319

NATURAL RESOURCE GAS LIMITED

Calculation of Revenue (Deficiency)/Sufficiency
2010 Bridge

	Bridge Year 2010	Actual 2009
Utility Income	$1,140,099	$1,166,741
Utility Rate Base	$14,070,465	$13,706,555
Indicated Rate of Return	8.10%	8.51%
Requested/Approved Rate of Return	8.34%	8.53%
(Deficiency)/Sufficiency in Return	-0.24%	-0.02%
Net Revenue (Deficiency)/Sufficiency	($33,769)	($2,741)
Provision for Income Taxes	($18,958)	($1,796)
Gross Revenue (Deficiency)/Sufficiency	($52,727)	($4,537)
Normalized Gas Sales and Transportation (M*3)	53,076,048	53,298,161
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0010)	($0.0001)
Return on Deemed Equity	8.60%	9.16%

	Variance from 2009
Utility Income	($26,641)
Utility Rate Base	$363,910
Indicated Rate of Return	-0.41%
Approved Rate of Return	-0.19%
(Deficiency)/Sufficiency in Return	-0.22%
Net Revenue (Deficiency)/Sufficiency	($31,028)
Provision for Income Taxes	($17,162)
Gross Revenue (Deficiency)/Sufficiency	($48,190)
Normalized Gas Sales and Transportation (M*3)	-222,113
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0009)

NATURAL RESOURCE GAS LIMITED

Statement of Adjusted Utility Income
2010 Bridge

	Bridge 2010	Actual 2009
Revenue		
Distribution Revenue	5,414,814	5,357,493
Other Operating Revenue (Net)	629,669	569,192
Total Revenue	6,044,483	5,926,685
Costs and Expenses		
Gas Transportation Costs	823,456	799,742
Operation & Maintenance	2,394,120	2,121,130
Depreciation & Amortization	1,172,442	1,105,062
Property & Capital Taxes	425,283	426,584
Total Costs and Expenses	4,815,300	4,452,518
Utility Income Before Income Taxes	1,229,182	1,474,168
Income Taxes	89,083	307,427
Utility Income	1,140,099	1,166,741

	Variance from 2009
Revenue	
Distribution Revenue	57,321
Other Operating Revenue (Net)	60,477
Total Revenue	117,797
Costs and Expenses	
Gas Transportation Costs	23,714
Operation & Maintenance	272,990
Depreciation & Amortization	67,380
Property & Capital Taxes	-1,301
Total Costs and Expenses	362,783
Utility Income Before Income Taxes	-244,985
Income Taxes	-218,344
Utility Income	-26,641

NATURAL RESOURCE GAS LIMITED

Calculation of Revenue (Deficiency)/Sufficiency
2011 Test Year

	Test Year 2011	Bridge Year 2010	
Utility Income	$895,593	$1,140,099	
Utility Rate Base	$13,618,731	$14,070,465	
Indicated Rate of Return	6.576182%	8.10%	
Requested/Approved Rate of Return	9.143320%	8.34%	*
(Deficiency)/Sufficiency in Return	-2.567138%	-0.24%	
Net Revenue (Deficiency)/Sufficiency	($349,612)	($33,769)	
Provision for Income Taxes	($112,805)	($18,958)	*
Gross Revenue (Deficiency)/Sufficiency	($462,417)	($52,727)	
Normalized Gas Sales and Transportation (M*3)	53,375,045	53,076,048	
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0087)	($0.0010)	
Return on Deemed Equity	4.25%	8.60%	

	Variance from 2010
Utility Income	($244,507)
Utility Rate Base	($451,734)
Indicated Rate of Return	-1.52%
Approved Rate of Return	0.80%
(Deficiency)/Sufficiency in Return	-2.33%
Net Revenue (Deficiency)/Sufficiency	($315,843)
Provision for Income Taxes	($93,847)
Gross Revenue (Deficiency)/Sufficiency	($409,690)
Normalized Gas Sales and Transportation (M*3)	298,997
Gross Revenue (Deficiency)/Sufficiency per M*3	($0.0077)

NATURAL RESOURCE GAS LIMITED

Statement of Adjusted Utility Income
2011 Test Year

	Test Year 2011	Bridge Year 2010
Revenue		
Distribution Revenue	5,480,613	5,414,814
Other Operating Revenue (Net)	664,160	629,669
Total Revenue	6,144,773	6,044,483
Costs and Expenses		
Gas Transportation Costs	732,331	823,456
Operation & Maintenance	2,859,299	2,394,120
Depreciation & Amortization	1,206,523	1,172,442
Property & Capital Taxes	400,776	425,283
Total Costs and Expenses	5,198,928	4,815,300
Utility Income Before Income Taxes	945,845	1,229,182
Income Taxes	50,252	89,083
Utility Income	895,593	1,140,099

	Variance from 2010
Revenue	
Distribution Revenue	65,799
Other Operating Revenue (Net)	34,491
Total Revenue	100,290
Costs and Expenses	
Gas Transportation Costs	-91,125
Operation & Maintenance	465,179
Depreciation & Amortization	34,081
Property & Capital Taxes	-24,507
Total Costs and Expenses	383,628
Utility Income Before Income Taxes	-283,338
Income Taxes	-38,831
Utility Income	-244,507

NATURAL RESOURCE GAS LIMITED

SUMMARY OF PROPOSED METHODOLOGY

NRG'S cost allocation model has been modified from that approved and used in RP-2005-0544 to:

- reflect the 2011 Test Year revenue requirement;
- incorporate updated information;
- reflect the allocation of 15% of Marketing Expense to Ancillary Services;
- support estimating an Incremental System Gas Fee; and
- support estimating an IGPC specific proposed rate (Rate 6) based on directly assigned costs and appropriately allocated common costs.

The changes and updates to the cost allocation model are presented in Exhibit G2, Tab 1, Schedule 1.

NRG's derivation of an incremental System Gas rate is presented in Exhibit A1, Tab 4, Schedule 1.

NRG's methodology for directly assigning cost responsibility to IGPC is presented in Exhibit G1, Tab 2, Schedule 1.

NRG's contingency plan with respect to the continuity or elimination of Rate 2 is presented in Exhibit A1, Tab 4, Schedule 1.

NRG has not made any other changes to the methodology used in its Fully Allocated Costing Study. The allocation factors have been updated to reflect NRG's current 2011 Test Year load forecast. NRG has adapted its Fully Allocated Costing Study to support the direct assignment of identifiable costs to the proposed customer class 6 that will deal with IGPC exclusively.

The fiscal 2011 Test Year allocations are presented in Exhibit G3. Tab 1 of that Exhibit provides the results of the current methodology while Tab 2 of the exhibit presents the cost allocations with the proposed methodology under two scenarios:

- Scenario 1: NRG's distribution system is amortized at currently authorized amortization rates; and
- Scenario 2: NRG's distribution system is amortized over the remaining life of its Aylmer franchise agreement is provided for illustrative purposes.

The net impact of the updates/changes outlined above on the various rate class and service classification categories can be found by comparing the cost based rates at line 12 of Sheet 3.3 in Exhibit G3, Tab 2, Schedule 1 to those of Exhibit G3, Tab 1, Schedule 1 for the fiscal 2011 test year. The results are summarized in the table below.

NET IMPACT OF COST ALLOCATION UPDATES AND CHANGES

2011 TEST YEAR

RATE CLASS	PROPOSED METHODOLOGY – Scenario 1 (‘000’s $’s)	PROPOSED METHODOLOGY – Scenario 2 (‘000’s $’s)	CURRENT METHODOLOGY (‘000’s $’s)
Rate 1 – Residential	3,116.2	9,925.6	3,639.7
Rate 1 – Commercial	417.9	1,374.7	465.6
Rate 1 – Industrial	89.9	351.3	96.6
Rate 2 – Seasonal	175.8	891.6	180.7
Rate 3 – Firm	184.6	684.4	1,314.5
Rate 3 – Interruptible	0.0	0.0	0.0
Rate 4 – Interruptible	50.2	256.5	51.5
Rate 5 – Interruptible	113.2	495.5	112.9
Rate 6 - Firm	1,718.0	4,951.4	N/A
Ancillary Programs	657.9	655.0	662.4
Total	6,523.8	19,586.1	6,523.9

NATURAL RESOURCE GAS LIMITED

SUMMARY OF RECOGNITION OF COSTS DIRECTLY ALLOCATED TO IGPC AND ESTIMATION OF FULLY ALLOCATED COMMON COSTS

The purpose of this evidence is to summarize NRG's allocation of costs to the proposed Rate 6.

Background

NRG commenced delivery of natural gas to IGPC for testing and commissioning on July 15, 2008. Conventional operations commenced as of October 2008. The costs of the pipeline and related facilities incurred by NRG and proposed to be included in rate base are presented in Exhibit B6, Tab 2, Schedule 1. NRG's ongoing costs incurred in connection with its operation, maintenance, administration, depreciation, property taxes and Union delivery charges are presented in Exhibit D1, Tab 3, Schedule 7.

Applicable Cost Allocation Principles

The cost causality principle requires that the customer or customer class that causes the utility to incur a cost should pay rates that recover those costs and that no other customer or customer class bear responsibility for such costs.

Application of the Cost Causality Principle

NRG has identified the costs it incurred to provide service to IGPC. They are summarized in the table below.

OM&A	$ 355,852
Administrative and General	$ 256,000
Union Delivery	$ 330,466
Property Tax	$ 60,026
Depreciation	$ 253,650
Return	$ 404,894
Income Tax	$ 53,020
Total	$1,713,908

NRG incorporated these costs into its Cost Allocation by augmenting the spreadsheets to include a new column headed "Direct Allocation – IGPC". The only data entered in this column is drawn from the table provided above.

IGPC's responsibility for Administrative and General ("A&G") costs was estimated using the Fully Allocated Cost Study. It quantifies the Administrative and General costs recoverable through rates in the penultimate step of the Classification stage of the Fully Allocated Cost Study. The final step of the Classification stage is to further classify the computed Administrative and General costs to the identified Classifications in direct proportion to the non-A&G revenue requirement. NRG relied on this methodology and included the estimated IGPC non-A&G revenue requirement to appropriately prorate this amount across all Classifications. Under this approach, IGPC is determined to be responsible for the recovery through rates of approximately $262,900 of Administrative and General costs. This treatment is proposed to ensure that IGPC's distribution rate will recover the costs that IGPC caused NRG to incur and that no other customer class inappropriately bears responsibility for these costs.

It was also necessary to compute IGPC's share of allocable common costs. This was achieved using the following steps:

- NRG's 2011 Test Year Rate Base, except for the IGPC pipeline, was functionalized and classified using NRG's legacy methodology and factors;

- NRG's 2011 Test Year Cost of Service, except for the forecast 2011 Test Year period costs of serving IGPC, was functionalized and classified using NRG's legacy methodology and factors.

The classified common costs were allocated to IGPC using NRG's legacy allocation factors.

Each allocation factor was estimated two ways:

- Using the data from the legacy customer Rate classes 1 through 5

- Using the legacy customer Rate classes 1 through 5 data augmented to include IGPC data.

Certain of NRG's allocation factors are estimated using legacy weighting factors. To compute the augmented Allocation factor NRG applied the factor relied on by Rate 3 to the proposed Rate 6. This was considered reasonable as these legacy weighting factors were found acceptable for rate making purposes when NRG served Imperial Tobacco, another large load, and it was included in Rate 3.

NRG inspected each Classified cost to ascertain whether it represented commonly incurred costs or not. Commonly incurred costs were allocated to all customer classes using augmented Allocators; examples of such common costs include Accounting/Billing. To ensure that IGPC did not attract responsibility for costs it did not cause (eg., non-IGPC Mains costs) NRG relied on the allocation factors estimated using the legacy customer classes 1 through 5.

The directly assigned and fully allocated costs were then summed to estimate IGPC's 2011 Test Year revenue requirement.

NATURAL RESOURCE GAS LIMITED

PROPOSED CHANGES TO THE FULLY ALLOCATED COSTS STUDY DATA

The purpose of this evidence is to present the changes made to the data input to the Fully Allocated Cost ("FAC") Study.

NRG has input it 2011 Test Year costs and load forecast data into the FAC. In order to render the FAC to be consistent with the 2011 Test Year the Rate 3 Interruptible statistics attributable to Imperial Tobacco were removed. As described at Exhibit G1, Tab 2, Schedule 1 NRG augmented the FAC to support the introduction of a new customer class for IGPC.

NRG used a 15% factor to assign Ancillary Services 15% of Advertising expense.

The FAC System Gas Supply costs were amended to reflect the application of an incremental costing methodology. This is described at Exhibit A1, Tab 4, Schedule 1.

NRG identified the components of the Revenue Requirement that were recovered through the System Gas Fee. Each component was identified as common or specifically incurred in connection with the provision of System Gas. Any common costs were removed from the System Gas revenue requirement by eliminating the functionalization, classification or allocation of costs.

Proposed Recoveries through the Estimated Incremental System Gas Fee

Under the proposed $0.000348/m^3 rate NRG will recover:

- The return on the portion of the 2011 Test Year Working Cash Allowance related to Gas Commodity: this amount is a credit of $86.0k and reduces the revenue requirement by $7.9k;

- The 2011 Test Year income tax expense associated with the ($86.0k) of Working Cash Allowance, being ($1.0k);

- 2011 Test Year Regulatory and Consulting Fee expenses totaling $15.0k, representing the costs of QRAM submissions;

- $1.1k of assigned Administrative and General expenses.

The revenue requirement totals $7.2k.

This revenue requirement is applied to projected 2011TY System Gas sales volumes of 20,646,638 m^3 to estimate the average incremental System Gas Fee of $0.000348/$m^3$.

SHEET 1.1

FUNCTIONALIZATION OF RATE BASE
$ 000

	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Distribution		Customer Service		Administrative				Direct Assignment	Other Assignment	Ancillary Services
				Measrmnt	Mains	Services	Meters	Billing/ Accounting	Promotion	Bad Debt/ Collection	A&G			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
DISTRIBUTION PLANT														
Meters	1,174.4	0.0	0.0	271.4	0.0	0.0	903.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulators	438.6	0.0	0.0	39.3	0.0	399.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Plastic	4,415.8	0.0	0.0	0.0	4,415.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Steel	4,428.3	0.0	0.0	0.0	4,428.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Services - Plastic	986.3	0.0	0.0	0.0	0.0	986.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Line Compressors		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Steel Mains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Distribution Plant	11,443.3	0.0	0.0	310.7	8,844.1	1,385.5	903.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GENERAL PLANT														
Land	71.7	0.0	0.0	0.0	13.1	7.5	2.3	17.5	5.0	1.9	12.0	0.0	0.0	12.5
Buildings & Imprs.	546.2	0.0	0.0	0.0	99.5	56.9	17.4	133.6	37.8	14.5	91.4	0.0	0.0	95.0
Furniture & Fixtures	23.7	0.0	0.0	0.0	4.3	2.5	0.8	5.8	1.6	0.6	4.0	0.0	0.0	4.1
Computer Equipmt.	18.9	0.0	0.0	0.0	0.0	0.0	0.0	8.7	0.0	0.0	8.7	0.0	0.0	1.6
Computer Software	51.5	0.0	0.0	0.0	0.0	0.0	0.0	23.6	0.0	0.0	23.6	0.0	0.0	4.3
Mach. & Equipmt	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Communication Equip.	108.5	0.0	0.0	0.0	24.8	24.8	0.0	0.0	0.0	0.0	49.6	0.0	0.0	9.2
Rental Equipmt	1,357.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,357.9
Automotive	117.8	0.0	0.0	0.0	124.2	(29.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.6
Total General Plant	2,296.2	0.0	0.0	0.0	266.0	61.8	20.5	189.1	44.4	17.0	189.2	0.0	0.0	1,508.2
OTHER ITEMS														
Franchises	103.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.5	0.0	0.0	0.0
Appraisal Surplus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Other	103.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.5	0.0	0.0	0.0
WORKING CAPITAL														
Inv - Construction	(35.2)	0.0	0.0	0.0	(31.7)	(11.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.5
Inv - Anc. Svces.	180.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	180.3
PPE - Insurance	17.4	0.0	0.0	0.0	1.1	(0.2)	0.0	0.1	0.0	0.0	15.9	0.0	0.0	0.5
PPE - Rent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cash - Ancillary Programs	13.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.7
Cash - Transfer/connect	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0
Cash - Delayed Payment	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	0.0	0.0	0.0	(0.0)
Cash - Gas Commodity	(86.0)	(86.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cash - Wages	11.5	0.0	0.0	0.0	2.1	1.2	0.4	2.8	0.8	0.3	1.9	0.0	0.0	2.2
Cash - Transportation	(2.4)	0.0	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cash - Other	(52.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(52.5)	0.0	0.0	0.0
Security Deposits	(270.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(270.8)	0.0
Total Working Capital	(224.3)	(86.0)	(2.4)	0.0	(28.5)	(10.1)	0.4	2.7	0.8	0.1	(34.7)	0.0	(270.8)	204.2
TOTAL RATE BASE	13,618.7	(86.0)	(2.4)	310.7	9,081.5	1,437.2	923.8	191.8	45.2	17.1	258.0	0.0	(270.8)	1,712.4

SHEET 1.2

FUNCTIONALIZATION OF DEPRECIATION EXPENSE
$ 000

		Gas Supply	Union	Distribution		Customer Service		Administrative						
			Transportation/					Billing/		Bad Debt/		Direct	Other	Ancillary
	Total		Load Bal/Storage	Measrmnt	Mains	Services	Meters	Accounting	Promotion	Collection	A&G	Assignment	Assignment	Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
<u>DISTRIBUTION PLANT</u>														
Meters	84.4	0.0	0.0	19.5	0.0	0.0	64.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulators	46.3	0.0	0.0	4.2	0.0	42.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Plastic	249.9	0.0	0.0	0.0	249.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Steel	253.7	0.0	0.0	0.0	253.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Services - Plastic	95.5	0.0	0.0	0.0	0.0	95.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Line Compressors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Steel Mains	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Distribution Plant	729.8	0.0	0.0	23.7	503.6	137.6	64.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<u>GENERAL PLANT</u>														
Buildings & Imprs.	16.0	0.0	0.0	0.0	2.9	1.7	0.5	3.9	1.1	0.4	2.7	0.0	0.0	2.8
Furniture & Fixtures	4.9	0.0	0.0	0.0	0.9	0.5	0.2	1.2	0.3	0.1	0.8	0.0	0.0	0.8
Computer Equipmt.	6.5	0.0	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	3.0	0.0	0.0	0.5
Computer Software	9.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1	0.0	0.0	4.1	0.0	0.0	0.8
Mach. & Equipmt	44.6	0.0	0.0	0.0	55.9	-13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
Communication Equip.	13.9	0.0	0.0	0.0	3.2	3.2	0.0	0.0	0.0	0.0	6.4	0.0	0.0	1.2
Rental Equipmt	187.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	187.7
Automotive	103.2	0.0	0.0	0.0	108.7	-26.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total General Plant	385.9	0.0	0.0	0.0	171.6	-34.3	0.7	12.2	1.4	0.6	17.0	0.0	0.0	216.7
Franchises	97.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	97.5	0.0	0.0	0.0
Capitalized Dep'n	-6.6	0.0	0.0	0.0	-6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET DEPRECIATION	1,206.5	0.0	0.0	23.7	668.6	103.4	65.5	12.2	1.4	0.6	114.5	0.0	0.0	216.7

SHEET 1.3

FUNCTIONALIZATION OF REVENUE REQUIREMENT
$ 000

	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Distribution Measrmnt	Distribution Mains	Customer Service Services	Customer Service Meters	Administrative Billing/ Accounting	Administrative Promotion	Administrative Bad Debt/ Collection	Administrative A&G	Direct Assignment	Other Assignment	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
GAS SUPPLY & TRANSPORTATION														
Firm Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Union Gas Delivery	167.7	0.0	167.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Union Gas Demand	564.7	0.0	564.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Local Production - A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Local Production - B	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unaccted For Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	732.3	0.0	732.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Gas Supply														
O&M EXPENSES														
Wages and Benefits	1,260.9	0.0	0.0	0.0	226.2	129.4	39.6	303.5	85.9	32.9	207.6	0.0	0.0	235.7
Insurance	284.9	0.0	0.0	0.0	18.6	(3.9)	0.1	1.0	0.3	0.1	260.4	0.0	0.0	8.1
Utilities	18.1	0.0	0.0	0.0	3.3	1.9	0.6	4.4	1.3	0.5	3.0	0.0	0.0	3.1
Marketing/Promotion	98.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	83.3	0.0	0.0	0.0	0.0	14.7
Telephone	65.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.6	0.0	0.0	2.5
Office/Postage	127.9	0.0	0.0	0.0	0.0	0.0	0.0	117.1	0.0	0.0	0.0	0.0	0.0	10.8
R&M General	289.1	0.0	0.0	0.0	272.5	(59.4)	1.2	21.7	1.3	0.5	20.3	0.0	0.0	31.0
Automotive	71.0	0.0	0.0	0.0	74.8	(18.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.2
Dues & Fees	41.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.6	0.0	0.0	2.1
Mapping Exps	0.9	0.0	0.0	0.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory	146.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	121.7	0.0	0.0	12.3
Bad Debts	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.7	0.0	0.0	0.0	6.3
Office Rent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sec Dep Interest	6.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0
Bank Charges	17.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3	0.0	0.0	1.5
Collection Exps	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.3	0.0	0.0	0.0	1.7
Travel & Ent.	4.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	0.0	0.4
Legal	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.4	0.0	0.0	0.0
Audit	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.3	0.0	0.0	1.7
Consulting	64.6	3.0	0.0	0.0	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Management Fees	457.0	0.0	0.0	0.0	0.0	0.0	0.0	381.4	0.0	0.0	45.0	0.0	0.0	30.6
Demand Side Management		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous	(221.8)	0.0	0.0	0.0	(138.1)	33.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(117.0)
	2,901.1	15.0	0.0	0.0	518.1	83.7	41.5	829.1	172.1	121.0	853.1	0.0	6.4	261.0
Total O&M Costs														
CAPITALIZED EXPENSES														
Wages	(30.3)	0.0	0.0	0.0	(31.8)	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Equipment	(11.5)	0.0	0.0	0.0	(15.2)	3.7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0
Total Capitalized Expenses	(41.8)	0.0	0.0	0.0	(47.0)	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net O&M Costs	3,591.6	15.0	732.3	0.0	471.2	88.9	41.5	829.1	172.1	121.0	853.1	0.0	6.4	261.0
Capital Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Property Taxes	400.8	0.0	0.0	0.0	311.7	62.7	1.1	8.5	2.4	0.9	5.8	0.0	0.0	7.6
Net Depreciation Expense	1,206.5	0.0	0.0	23.7	668.6	103.4	65.5	12.2	1.4	0.6	114.5	0.0	0.0	216.7
Total Expenses	5,198.9	15.0	732.3	23.7	1,451.4	254.9	108.2	849.8	175.9	122.5	973.4	0.0	6.4	485.3
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Return on Rate Base	1,245.2	(7.9)	(0.2)	28.4	830.3	131.4	84.5	17.5	4.1	1.6	23.6	0.0	(24.8)	156.6
Income Taxes	163.1	(1.0)	(0.0)	3.7	108.7	17.2	11.1	2.3	0.5	0.2	3.1	0.0	(3.2)	20.5
REVENUE REQUIREMENT	6,607.2	6.1	732.1	55.8	2,390.5	403.5	203.7	869.7	180.6	124.3	1,000.0	0.0	(21.6)	662.4

SHEET 1.4 **FUNCTIONALIZATION FACTORS**

		Gas Supply	Union	Distribution		Customer Service		Administrative						
			Transportation					Billing/		Bad Debt/		Direct	Other	Ancillary
	Total		Load Bal/Storag	Measrmnt	Mains	Services	Meters	Accounting	Promotion	Collection	A&G	Assignment	Assignment	Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
F1: Meters	100.00%	0.00%	0.00%	23.11%	0.00%	0.00%	76.89%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F2: Regulators	100.00%	0.00%	0.00%	8.97%	0.00%	91.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F3: Computers	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	50.00%	0.00%	0.00%	50.00%	0.00%	0.00%	0.00%
F4: Bldgs & Impr.	100.00%	0.00%	0.00%	0.00%	22.06%	12.62%	3.86%	29.60%	8.38%	3.21%	20.25%	0.00%	0.00%	0.00%
F5: Mains/Svces - C. E.	100.00%	0.00%	0.00%	0.00%	131.73%	-31.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F6: Auto Rate Base	100.00%	0.00%	0.00%	0.00%	131.73%	-31.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F7: Wages/Benefits	100.00%	0.00%	0.00%	0.00%	17.94%	10.26%	3.14%	24.07%	6.82%	2.61%	16.47%	0.00%	0.00%	18.69%
F8: Marketing	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F9: R&M General	100.00%	0.00%	0.00%	0.00%	94.28%	-20.54%	0.42%	7.50%	0.45%	0.17%	7.01%	0.00%	0.00%	10.71%
F10: Mains/Svces - C. L.	100.00%	0.00%	0.00%	0.00%	105.04%	-5.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F11: Mapping	100.00%	0.00%	0.00%	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F12: Auto Expenses	100.00%	0.00%	0.00%	0.00%	131.73%	-31.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F13: Communications	100.00%	0.00%	0.00%	0.00%	25.00%	25.00%	0.00%	0.00%	0.00%	0.00%	50.00%	0.00%	0.00%	0.00%
F14: Travel & Ent.	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
F15: Mains/Svces - M.	100.00%	0.00%	0.00%	0.00%	74.21%	25.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F16: Small Tools	100.00%	0.00%	0.00%	0.00%	45.00%	45.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F17: Mains/Svces - C.D.	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F18: Insurance	99.97%	0.00%	0.00%	0.00%	6.73%	-1.40%	0.05%	0.37%	0.10%	0.04%	94.08%	0.00%	0.00%	0.00%
F19: Property Taxes	100.00%	0.00%	0.00%	0.00%	79.27%	15.94%	0.28%	2.17%	0.62%	0.24%	1.49%	0.00%	0.00%	0.00%
F20: Management Fees	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	89.44%	0.00%	0.00%	10.56%	0.00%	0.00%	0.00%

SHEET 1.5

FUNCTIONALIZATION OF EMPLOYMENT COSTS

$ 000

				Distribution		Customer Service		Administrative						
	Total	Gas Supply	Union Transportation/ Load Bal/Storag	Measrmnt	Mains	Services	Meters	Billing/ Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment	Other Assignment	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
Management	100.00%	0.00%	0.00%	0.00%	10.00%	10.00%	10.00%	5.00%	7.50%	5.00%	44.06%	0.00%	0.00%	8.44%
Office Personnel	100.00%	0.00%	0.00%	0.00%	2.50%	2.50%	0.00%	50.00%	5.00%	5.00%	12.60%	0.00%	0.00%	22.40%
Operations Manager	100.00%	0.00%	0.00%	0.00%	93.80%	-4.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.70%
Line Maint.	100.00%	0.00%	0.00%	0.00%	105.04%	-5.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
System Maintenance	100.00%	0.00%	0.00%	0.00%	102.83%	-4.93%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.10%
Meter Reading	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Service & Install.	100.00%	0.00%	0.00%	0.00%	0.00%	52.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	48.00%
Sales	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	46.10%	0.00%	0.00%	0.00%	0.00%	53.90%
Management	346.2	0.0	0.0	0.0	34.6	34.6	34.6	17.3	26.0	17.3	152.5	0.0	0.0	29.2
Office Personnel	229.7	0.0	0.0	0.0	5.7	5.7	0.0	114.9	11.5	11.5	28.9	0.0	0.0	51.5
Operations Manager	57.7	0.0	0.0	0.0	54.1	(2.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2
Line Maint.	49.7	0.0	0.0	0.0	52.2	(2.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Maintenance	49.7	0.0	0.0	0.0	51.1	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Meter Reading	133.1	0.0	0.0	0.0	0.0	0.0	0.0	133.1	0.0	0.0	0.0	0.0	0.0	0.0
Service & Install.	154.3	0.0	0.0	0.0	0.0	80.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.1
Sales	81.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.7	0.0	0.0	0.0	0.0	44.0
Benefits	158.9	0.0	0.0	0.0	28.5	16.3	5.0	38.3	10.8	4.2	26.2	0.0	0.0	29.7
Total (F7)	1,260.9	0.0	0.0	0.0	226.2	129.4	39.6	303.5	85.9	32.9	207.6	0.0	0.0	235.7
Total Excl Ancillary (F4)	1,025.2	0.0	0.0	0.0	226.2	129.4	39.6	303.5	85.9	32.9	207.6	0.0	0.0	

SHEET 1.6A

FUNCTIONALIZATION OF AUTOMOTIVE EXPENSES
$ 000

				Distribution		Customer Service		Administrative					
	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Measrmnt	Mains	Services	Meters	Billing/ Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment	Other Assignment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)
All Autos	32.0	0.0	0.0	0.0	42.2	(10.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel/Oil	39.0	0.0	0.0	0.0	51.4	(12.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Expenses (F12)	71.0	0.0	0.0	0.0	93.5	(22.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SHEET 1.6B

FUNCTIONALIZATION OF AUTOMOTIVE RATE BASE
$ 000

				Distribution		Customer Service		Administrative					
	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Measrmnt	Mains	Services	Meters	Billing/ Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment	Other Assignment
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)
All Autos	117.8	0.0	0.0	0.0	155.2	(37.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Rate Base (F6)	117.8	0.0	0.0	0.0	155.2	(37.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SHEET 1.7

FUNCTIONALIZATION OF REPAIRS & MAINTENANCE EXPENSES

$ 000

					Distribution		Customer Service		Administrative						
		Total	Gas Supply	Union Transportation/ Load Bal/Storage	Measrmnt	Mains	Services	Meters	Billing/ Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment	Other Assignment	Ancillary Services
9		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
11	General	213.1	0.0	0.0	0.0	253.8	(61.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5
12	Trencher	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Computer	37.4	0.0	0.0	0.0	0.0	0.0	0.0	17.1	0.0	0.0	17.1	0.0	0.0	3.2
14	Meters		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Building	18.7	0.0	0.0	0.0	3.4	1.9	0.6	4.6	1.3	0.5	3.1	0.0	0.0	3.2
16	Compressor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Other Equipment	6.9	0.0	0.0	0.0	5.3	(1.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9
18	Regulators		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Small Tools	7.0	0.0	0.0	0.0	2.8	2.8	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.7
20	Equipment Rental	6.0	0.0	0.0	0.0	7.3	(1.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
21	Line Compressors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Total (F9)	289.1	0.0	0.0	0.0	272.5	(59.4)	1.2	21.7	1.3	0.5	20.3	0.0	0.0	31.0

1 **SHEET 2.1** **CLASSIFICATION OF RATE BASE**

2 $ 000

Line	FUNCTION	Total	Gas Supply	Union Demand	Union Commodity	Delivery Commodity	Delivery Demand	Weighted Customer Services	Weighted Customer Meters	Weighted Customer Billing	Unweighted Customer	Bad Debt/ Collection	A&G	Direct Assignment	Other Assign	Ancillary Services
8		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
11	Gas Supply	(86.0)	(86.0)													
12	Union Trans/Load Bal/Storage	(2.4)		(1.8)	(0.5)											
13	Dist'n Measurement	310.7				155.4	155.4									
14	Mains	9,081.5					6,041.9				3,039.6					
15	Services	1,437.2						1,437.2								
16	Meters	923.8							923.8							
17	Accounting/Billing	191.8								192.0	(0.1)					
18	Promotion	45.2									45.2					
19	Bad Debt/Collection	17.1										17.1				
20	A&G	258.0											258.0			
	Direct Assignment	0.0												0.0		
21	Other Assignment	(270.8)													(270.8)	
22	Ancillary Services	1,712.4														1,712.4
24	TOTAL RATE BASE	13,618.7	(86.0)	(1.8)	(0.5)	155.4	6,197.3	1,437.2	923.8	192.0	3,084.7	17.1	258.0	0.0	(270.8)	1,712.4

1 **SHEET 2.2**

CLASSIFICATION OF REVENUE REQUIREMENT

2 $ 000

Line		Total	Gas Supply	Union Demand	Union Commodity	Delivery Commodity	Delivery Demand	Weighted Customer Services	Weighted Customer Meters	Weighted Customer Billing	Unweighted Customer	Bad Debt/ Collection	A&G	Direct Assignment	Other Assign	Ancillary Services
8		(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
9	**FUNCTION**															
11	Gas Supply	6.1	6.1													
12	Union Trans/Load Bal/Storage	732.1		564.5	167.6											
13	Dist'n Measurement	55.8				27.9	27.9									
14	Mains	2,390.5					1,590.4				800.1					
15	Services	403.5						403.5								
16	Meters	203.7							203.7							
17	Accounting/Billing	869.7								869.7						
18	Promotion	180.6									180.6					
19	Bad Debt/Collection	124.3										124.3				
20	A&G	1,000.0											1,000.0			
	Direct Assignment	0.0												0.0		
21	Other Assignment	(21.6)				0.0									(21.6)	
22	Ancillary Services	662.4														662.4
24	TOTAL REVENUE REQUIREMENT	6,607.1	6.1	564.5	167.6	27.9	1,618.3	403.5	203.7	869.7	980.7	124.3	1,000.0	0.0	(21.6)	662.4
26	Classification of A&G		1.5	0.0	0.0	6.8	393.8	98.2	49.6	211.6	238.6	0.0	0.0	0.0	0.0	0.0
28	Total Revenue Requirement after															
29	Classification of A&G	6,607.1	7.6	564.5	167.6	34.7	2,012.1	501.7	253.3	1,081.3	1,219.3	124.3	0.0	0.0	(21.6)	662.4
31	Less: OTHER REVENUE															
33	Late Payment Fees	52.7										48.3				4.4
34	Transfer/Connection Charges	30.7									30.7					
36	REVENUE REQUIREMENT for Rates	6,523.7	7.6	564.5	167.6	34.7	2,012.1	501.7	253.3	1,081.3	1,188.7	76.0	0.0	0.0	(21.6)	657.9

SHEET 2.3

CLASSIFICATION FACTORS

	Total	Gas Supply	Union Demand	Union Commodity	Delivery Commodity	Delivery Demand	Weighted Customer Services	Weighted Customer Meters	Weighted Customer Billing	Unweighted Customer	Bad Debt/ Collection	A&G	Direct Assignment	Direct Assign	Ancillary Services
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
C1: Mains	100.00%	0.00%	0.00%	0.00%	0.00%	66.53%	0.00%	0.00%	0.00%	33.47%	0.00%	0.00%	0.00%	0.00%	0.00%
C2: Services	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C3: A&G	100.00%	0.15%	0.00%	0.00%	0.68%	39.38%	9.82%	4.96%	21.16%	23.86%	0.00%	0.00%	0.00%	0.00%	0.00%
C4: Union Demand/Com	100.00%	0.00%	77.11%	22.89%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C5: Dist. Measurement	100.00%	0.00%	0.00%	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

1 **SHEET 3.1** **ALLOCATION**

2 $ 000

Line			RATE 1			RATE 2	RATE 3		Rate 4	Rate 5		
5	**CLASSIFIED COSTS**	TOTAL	Residential	Commercial	Industrial	Seasonal	Firm	Interruptible	Int. Fall	Int. Fall	Ancillary	Factor
7	RATE BASE											
9	Gas Supply	(86.0)	(54.2)	(14.1)	(2.4)	(1.7)	(9.2)	0.0	(0.5)	(3.9)	0.0	E1
10	Union Demand	(1.8)	(0.8)	(0.2)	(0.1)	(0.0)	(0.8)	0.0	0.0	0.0	0.0	D1
11	Union Commodity	(0.5)	(0.1)	(0.0)	(0.0)	(0.0)	(0.3)	0.0	(0.0)	(0.0)	0.0	E2
12	Delivery Commodity	155.4	36.8	11.6	1.6	1.4	100.0	0.0	1.3	2.7	0.0	E2
13	Delivery Demand	6,197.3	2,047.4	610.2	148.7	216.9	2,853.5	0.0	50.2	270.4	0.0	D2
14	Weighted Customer - Services	1,437.2	1,162.7	73.4	26.0	114.1	11.4	0.0	36.0	11.4	0.0	CC1
15	Weighted Customer - Meters	923.8	568.9	35.9	33.3	163.3	33.0	0.0	49.9	33.0	0.0	CC2
16	Weighted Customer - Billing	192.0	174.7	11.0	0.7	1.9	1.3	0.0	0.6	1.3	0.0	CC3
17	Unweighted Customer	3,084.7	2,847.7	179.7	11.3	31.7	2.2	0.0	10.0	2.2	0.0	CC4
18	Bad Debt/Collection	17.1	13.5	3.2	0.5	0.0	0.0	0.0	0.0	0.0	0.0	CC5
19	A&G	258.0	165.7	18.3	3.7	8.9	48.0	0.0	2.5	5.4	0.0	
	Direct Assignment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
20	Security Deposits	(270.8)	(253.8)	(16.0)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	R1
21	Ancillary Services	1,712.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,712.4	DA
23	Total Rate Base	13,618.7	6,708.5	913.0	222.3	536.5	3,039.1	0.0	149.9	322.5	1,712.4	
25	REVENUE REQUIREMENT											
27	Gas Supply	7.6	4.8	1.2	0.2	0.2	0.8	0.0	0.0	0.3	0.0	E1
28	Union Demand	564.5	239.2	71.6	17.4	0.5	235.7	0.0	0.0	0.0	0.0	D1
29	Union Commodity	167.6	39.7	12.5	1.8	1.5	107.9	0.0	1.4	2.9	0.0	E2
30	Delivery Commodity	34.7	8.2	2.6	0.4	0.3	22.3	0.0	0.3	0.6	0.0	E2
31	Delivery Demand	2,012.1	664.7	198.1	48.3	70.4	926.4	0.0	16.3	87.8	0.0	D2
32	Weighted Customer - Services	501.7	405.9	25.6	9.1	39.8	4.0	0.0	12.6	4.0	0.0	CC1
33	Weighted Customer - Meters	253.3	156.0	9.8	9.1	44.8	9.0	0.0	13.7	9.0	0.0	CC2
34	Weighted Customer - Billing	1,081.3	984.3	62.1	3.9	11.0	7.5	0.0	3.5	7.5	0.0	CC3
35	Unweighted Customer	1,188.7	1,097.2	69.2	4.3	12.2	0.8	0.0	3.8	0.8	0.0	CC4
36	Bad Debt/Collection	76.0	59.8	14.0	2.2	0.0	0.0	0.0	0.0	0.0	0.0	CC5
	Direct Assignment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
37	Security Deposits	(21.6)	(20.2)	(1.3)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	R1
38	Ancillary Services	657.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	657.9	DA
40	Total Revenue Requirement	6,523.7	3,639.6	465.6	96.6	180.7	1,314.5	0.0	51.5	113.0	657.9	
41	Rev Rqmnt excl Ancillary Services	5,861.5	3,639.6	465.6	96.6	180.7	1,314.5	0.0	51.5	113.0		
43	CAPITAL COSTS											
45	Income Taxes	163.1	92.0	12.5	3.0	7.4	41.7	0.0	2.1	4.4	0.0	
46	Return on Rate Base	1245.2	613.4	83.5	20.3	49.1	277.9	0.0	13.7	29.5	156.6	
48	Total Capital Costs	1408.3	705.4	96.0	23.4	56.4	319.5	0.0	15.8	33.9	156.6	
51	Allocated A&G	1,021.6	656.1	72.6	14.8	35.1	190.0	0.0	9.9	21.6	0.0	
52	A&G per m^3	$0.0185	$0.0501	$0.0176	$0.0254	$0.0698	$0.0053	$0.0000	$0.0217	$0.0228		

1 **SHEET 3.2** **ALLOCATION FACTORS**

Line	FACTOR	DESCRIPTION	TOTAL	RATE 1 Residential	RATE 1 Commercial	RATE 1 Industrial	RATE 2 Seasonal	RATE 3 Firm	RATE 3 Interruptible	RATE 4 Int. Fall	Rate 5 Int. Fall
2											
3											
4											
7											
8											
9		Sales Volumes (m^3)	20,646,638	13,008,204	3,379,039	577,627	410,741	2,204,921	0	118,945	947,162
10	E1	% OF TOTAL	100.00%	63.00%	16.37%	2.80%	1.99%	10.68%	0.00%	0.58%	4.59%
12		Delivery/Transp Volumes (m^3)	55,332,726	13,103,581	4,131,750	580,997	502,859	35,612,115	0	454,263	947,162
13	E2	% OF TOTAL	100.00%	23.68%	7.47%	1.05%	0.91%	64.36%	0.00%	0.82%	1.71%
15											
16		Coincident Peak (m^3/day)	308,688	130,816	39,154	9,529	271	128,918	0	0	0
17		Peak Day Use/Cust/HDD (3 yr avg)		0.52318	2.50347	7.21926	0.13525				
18		# of customers @ Peak Day		6251	391	33	50	5	0	24	5
19	D1	% OF TOTAL	100.00%	42.38%	12.68%	3.09%	0.09%	41.76%	0.00%	0.00%	0.00%
21		Non-Coincident Peak(m^3/day)	477,492	113,143	33,470	8,171	33,005	240,293	0	7,742	41,668
22		Peak day Use/Cust (3 yr avg)		18.1	85.6	247.6	660.1	26,435.0	5,080.5	322.6	8,333.6
23		% OF TOTAL	100.00%	23.70%	7.01%	1.71%	6.91%	50.32%	0.00%	1.62%	8.73%
24			100.0%	19.32%	5.72%	1.40%	5.64%	41.03%	0.00%	1.32%	7.12%
25		Weighted CP/NCP Allocator	393,090	129,864	38,707	9,431	13,758	180,993	0	3,187	17,151
26	D2	% OF TOTAL	100.00%	33.04%	9.85%	2.40%	3.50%	46.04%	0.00%	0.81%	4.36%
28		Wtd Customers Services	8,096	6,560	414	147	644	64	0	203	64
29		Weighting Factor		1.00	1.00	5.64	8.82	12.86	12.86	8.82	12.86
30	CC1	% OF TOTAL	100.00%	81.03%	5.11%	1.81%	7.95%	0.79%	0.00%	2.51%	0.79%
32		Wtd Customers Meters	10,577	6,560	414	384	1,883	381	0	575	381
33		Weighting Factor		1.00	1.00	14.76	25.79	76.11	76.11	25.01	76.11
34	CC2	% OF TOTAL	100.00%	62.02%	3.91%	3.63%	17.80%	3.60%	0.00%	5.44%	3.60%
36		Wtd Customers Billing	7,196	6,560	414	26	73	50	0	23	50
37		Weighting Factor		1	1	1	1	10	10	1	10
38	CC3	% OF TOTAL	100.00%	91.16%	5.75%	0.36%	1.01%	0.69%	0.00%	0.32%	0.69%
40		Customers (average)	7,106	6,560	414	26	73	5		23	5
41	CC4	% OF TOTAL	100.00%	92.32%	5.83%	0.37%	1.03%	0.07%	0.00%	0.32%	0.07%
43		m^3 per Customer		1,997	9,980	22,346	6,888	7,122,423	0	19,751	189,432
44											
45		Rate 1 Revenues	8,648	6,808	1,595	245					
46	CC5	% OF TOTAL	100.00%	78.72%	18.45%	2.83%					
48											
49		Security Deposit & DSM									
50	R1	% OF TOTAL	100.00%	93.71%	5.91%	0.37%	0.00%	0.00%	0.00%	0.00%	0.00%
52											

SHEET 3.3

ANALYSIS OF ALLOCATED COSTS

	Total	RATE 1 Residential	RATE 1 Commercial	RATE 1 Industrial	RATE 2 Seasonal	RATE 3 Firm	RATE 3 Interruptible	RATE 4 Int. Fall	RATE 5 Int. Fall	Ancillary Services
REVENUES										
Current Rates	6,061.4	2,898.0	579.5	71.3	68.4	1,739.0	0.0	61.5	62.9	580.8
Gas Supply	21.4	15.1	3.9	0.7	0.5	0.0	0.0	0.1	1.1	
Transportation & Distribution	5,459.2	2,882.9	575.6	70.7	67.9	1,739.0	0.0	61.4	61.8	
Ancillary Services	580.8									580.8
Cost based rates	6,519.5	3,639.6	465.6	96.6	180.7	1,314.5	0.0	51.5	113.0	657.9
Gas Supply	7.6	4.8	1.2	0.2	0.2	0.8	0.0	0.0	0.3	
Transportation & Distribution	5,853.9	3,634.8	464.4	96.3	180.5	1,313.7	0.0	51.5	112.6	
Ancillary Services	657.9									657.9
(Deficiency)/Sufficiency	(458.1)	(741.6)	113.8	(25.2)	(112.3)	424.4	0.0	10.0	(50.1)	(77.1)
Gas Supply	13.8	10.3	2.7	0.5	0.3	(0.8)	0.0	0.1	0.7	0.0
Transportation & Distribution	(394.7)	(751.9)	111.2	(25.7)	(112.6)	425.2	0.0	9.9	(50.8)	0.0
Ancillary Services	(77.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(77.1)
R/C @ current rates - total	92.97%	79.62%	124.45%	73.89%	37.85%	132.29%	NA	119.40%	55.67%	88.28%
R/C @ current rates - gas supply	281.45%	315.10%	315.10%	315.10%	315.10%	0.00%	NA	315.10%	315.10%	
R/C @ current rates - distribution	93.26%	79.31%	123.94%	73.36%	37.61%	132.37%	NA	119.24%	54.87%	
R/C @ current rates - ancillary	88.28%	NA	NA	NA	NA	NA	NA	NA	NA	88.28%
SUMMARY OF COSTS										
Total	5,865.8	3,639.6	465.6	96.6	180.7	1,314.5	0.0	51.5	113.0	
Supply	209.9	52.7	16.3	2.3	2.0	131.0	0.0	1.7	3.8	
Demand	2,576.5	903.9	269.7	65.7	70.9	1,162.2	0.0	16.3	87.8	
Customer	3,079.4	2,683.0	179.6	28.5	107.8	21.4	0.0	33.5	21.4	
Costs by Function										
Gas Supply	7.6	4.8	1.2	0.2	0.2	0.8	0.0	0.0	0.3	
Union Transportation										
Commodity	167.6	39.7	12.5	1.8	1.5	107.9	0.0	1.4	2.9	
Demand	564.5	239.2	71.6	17.4	0.5	235.7	0.0	0.0	0.0	
Distribution										
Commodity	34.7	8.2	2.6	0.4	0.3	22.3	0.0	0.3	0.6	
Demand	2,012.1	664.7	198.1	48.3	70.4	926.4	0.0	16.3	87.8	
Customer	3,079.4	2,683.0	179.6	28.5	107.8	21.4	0.0	33.5	21.4	
SUMMARY OF UNIT COSTS										
Total - $/m^3	0.106240	0.277761	0.112765	0.166191	0.359351	0.037258	0.000000	0.113738	0.119269	
Supply - $/m^3	0.004024	0.004024	0.004024	0.004024	0.004024	0.004024	0.000000	0.004024	0.004024	
Demand - $/m^3	0.046565	0.068984	0.065281	0.113078	0.141023	0.032634	0.000000	0.035910	0.092688	
Cust - $/m^3	0.055652	0.204753	0.043461	0.049089	0.214305	0.000600	0.000000	0.073805	0.022558	
UNIT COSTS BY FUNCTION										
Gas Supply -$/m^3	0.000368	0.000368	0.000368	0.000368	0.000368	0.000368	0.000000	0.000368	0.000368	
Total Union Transportation	0.013231	0.021285	0.020358	0.033022	0.004013	0.009649	0.000000	0.003029	0.003029	
Transport Commodity - $/m^3	0.003029	0.003029	0.003029	0.003029	0.003029	0.003029	0.000000	0.003029	0.003029	
Transport Demand - $/m^3	0.010202	0.018256	0.017329	0.029994	0.000984	0.006620	0.000000	0.000000	0.000000	
Distribution-$/m^3	0.092642	0.256108	0.092039	0.132801	0.354971	0.027241	0.000000	0.110342	0.115872	
Commodity - $/m^3	0.000627	0.000627	0.000627	0.000627	0.000627	0.000627	0.000000	0.000627	0.000627	
Demand - $/m^3	0.036363	0.050728	0.047951	0.083085	0.140039	0.026014	0.000000	0.035910	0.092688	
Customer - $/m^3	0.055652	0.204753	0.043461	0.049089	0.214305	0.000600	0.000000	0.073805	0.022558	
Cust - $/customer/mth	$36.11	$34.08	$36.14	$91.41	$123.02	$356.10	$0.00	$121.47	$356.10	

SHEET 1.1

FUNCTIONALIZATION OF RATE BASE
$ 000

	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Distribution Measrmnt	Distribution Mains	Customer Service Services	Customer Service Meters	Administrative Billing/Accounting	Administrative Promotion	Administrative Bad Debt/ Collection	Administrative A&G	Direct Assignment to IGPC	Other Assignment	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
DISTRIBUTION PLANT														
Meters	1,174.4	0.0	0.0	271.4	0.0	0.0	903.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulators	438.6	0.0	0.0	39.3	0.0	399.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Plastic	4,415.8	0.0	0.0	0.0	4,415.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Steel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Services - Plastic	986.3	0.0	0.0	0.0	0.0	986.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Line Compressors		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Steel Mains	4,428.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,428.3	0.0	0.0
Total Distribution Plant	11,443.3	0.0	0.0	310.7	4,415.8	1,385.5	903.0	0.0	0.0	0.0	0.0	4,428.3	0.0	0.0
GENERAL PLANT														
Land	71.7	0.0	0.0	0.0	13.1	7.5	2.3	17.5	5.0	1.9	12.0		0.0	12.5
Buildings & Imprs.	546.2	0.0	0.0	0.0	99.5	56.9	17.4	133.6	37.8	14.5	91.4		0.0	95.0
Furniture & Fixtures	23.7	0.0	0.0	0.0	4.3	2.5	0.8	5.8	1.6	0.6	4.0		0.0	4.1
Computer Equipmt.	18.9	0.0	0.0	0.0	0.0	0.0	0.0	8.7	0.0	0.0	8.7		0.0	1.6
Computer Software	51.5	0.0	0.0	0.0	0.0	0.0	0.0	23.6	0.0	0.0	23.6		0.0	4.3
Mach. & Equipmt	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Communication Equip.	108.5	0.0	0.0	0.0	24.8	24.8	0.0	0.0	0.0	0.0	49.6		0.0	9.2
Rental Equipmt	1,357.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	1,357.9
Automotive	117.8	0.0	0.0	0.0	124.2	(29.9)	0.0	0.0	0.0	0.0	0.0		0.0	23.6
Total General Plant	2,296.2	0.0	0.0	0.0	266.0	61.8	20.5	189.1	44.4	17.0	189.2		0.0	1,508.2
OTHER ITEMS														
Franchises	103.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.5		0.0	0.0
Appraisal Surplus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Total Other	103.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.5		0.0	0.0
WORKING CAPITAL														
Inv - Construction	(35.2)	0.0	0.0	0.0	(31.7)	(11.0)	0.0	0.0	0.0	0.0	0.0		0.0	7.5
Inv - Anc. Svces.	180.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	180.3
PPE - Insurance	17.4	0.0	0.0	0.0	1.1	(0.2)	0.0	0.1	0.0	0.0	15.9		0.0	0.5
PPE - Rent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Cash - Ancillary Programs	13.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	13.7
Cash - Transfer/connect	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0	0.0	0.0		0.0	0.0
Cash - Delayed Payment	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)	0.0		0.0	(0.0)
Cash - Gas Commodity	(86.0)	(86.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Cash - Wages	11.5	0.0	0.0	0.0	2.1	1.2	0.4	2.8	0.8	0.3	1.9		0.0	2.2
Cash - Transportation	(2.4)	0.0	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Cash - Other	(52.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(52.5)		0.0	0.0
Security Deposits	(270.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		(270.8)	0.0
Total Working Capital	(224.3)	(86.0)	(2.4)	0.0	(28.5)	(10.1)	0.4	2.7	0.8	0.1	(34.7)		(270.8)	204.2
TOTAL RATE BASE	13,618.7	(86.0)	(2.4)	310.7	4,653.2	1,437.2	923.8	191.8	45.2	17.1	258.0	4,428.3	(270.8)	1,712.4

SHEET 1.2

FUNCTIONALIZATION OF DEPRECIATION EXPENSE

$ 000

	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Distribution Measrmnt	Distribution Mains	Customer Service Services	Customer Service Meters	Administrative Billing/Accounting	Administrative Promotion	Administrative Bad Debt/ Collection	Administrative A&G	Direct Assignment to IGPC	Other/Direct Assignment	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
DISTRIBUTION PLANT														
Meters	84.4	0.0	0.0	19.5	0.0	0.0	64.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulators	46.3	0.0	0.0	4.2	0.0	42.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Plastic	249.9	0.0	0.0	0.0	249.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mains - Steel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Services - Plastic	95.5	0.0	0.0	0.0	0.0	95.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Line Compressors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Steel Mains	253.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	253.7	0.0	0.0
Total Distribution Plant	729.8	0.0	0.0	23.7	249.9	137.6	64.9	0.0	0.0	0.0	0.0	253.7	0.0	0.0
GENERAL PLANT														
Buildings & Imprs.	16.0	0.0	0.0	0.0	2.9	1.7	0.5	3.9	1.1	0.4	2.7	0.0	0.0	2.8
Furniture & Fixtures	4.9	0.0	0.0	0.0	0.9	0.5	0.2	1.2	0.3	0.1	0.8	0.0	0.0	0.8
Computer Equipmt.	6.5	0.0	0.0	0.0	0.0	0.0	0.0	3.0	0.0	0.0	3.0	0.0	0.0	0.5
Computer Software	9.0	0.0	0.0	0.0	0.0	0.0	0.0	4.1	0.0	0.0	4.1	0.0	0.0	0.8
Mach. & Equipmt	44.6	0.0	0.0	0.0	55.9	-13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
Communication Equip.	13.9	0.0	0.0	0.0	3.2	3.2	0.0	0.0	0.0	0.0	6.4	0.0	0.0	1.2
Rental Equipmt	187.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	187.7
Automotive	103.2	0.0	0.0	0.0	108.7	-26.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.6
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total General Plant	385.9	0.0	0.0	0.0	171.6	-34.3	0.7	12.2	1.4	0.6	17.0	0.0	0.0	216.7
Franchises	97.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	97.5		0.0	0.0
Capitalized Dep'n	-6.6	0.0	0.0	0.0	-6.6	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
NET DEPRECIATION	1,206.5	0.0	0.0	23.7	414.9	103.4	65.5	12.2	1.4	0.6	114.5	253.7	0.0	216.7

SHEET 1.3

FUNCTIONALIZATION OF REVENUE REQUIREMENT

$ 000

				Distribution		Customer Service		Administrative						
	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Measrmnt	Mains	Services	Meters	Billing/Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment to IGPC	Other/Direct Assignment	Ancillary Services
GAS SUPPLY & TRANSPORTATION	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
Firm Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Union Gas Delivery	167.7	0.0	58.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	109.3	0.0	0.0
Union Gas Demand	564.7	0.0	343.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	221.2	0.0	0.0
Local Production - A	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Local Production - B	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unaccted For Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Gas Supply	732.3	0.0	401.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	330.5	0.0	0.0
O&M EXPENSES														
Wages and Benefits	1,260.9	0.0	0.0	0.0	226.2	129.4	39.6	303.5	85.9	32.9	207.6	0.0	0.0	235.7
Insurance	284.9	0.0	0.0	0.0	5.3	(1.1)	0.0	0.3	0.1	0.0	74.2	198.0	0.0	8.1
Utilities	18.1	0.0	0.0	0.0	3.1	1.8	0.5	4.2	1.2	0.5	2.9	0.7	0.0	3.1
Marketing/Promotion	98.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	83.3	0.0	0.0	0.0	0.0	14.7
Telephone	65.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.6	0.0	0.0	2.5
Office/Postage	127.9	0.0	0.0	0.0	0.0	0.0	0.0	117.1	0.0	0.0	0.0	0.0	0.0	10.8
R&M General	289.1	0.0	0.0	0.0	65.5	(9.5)	1.2	21.7	1.3	0.5	20.3	157.2	0.0	31.0
Automotive	71.0	0.0	0.0	0.0	74.8	(18.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.2
Dues & Fees	41.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.6	0.0	0.0	2.1
Mapping Exps	0.9	0.0	0.0	0.0	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory	146.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	121.7	0.0	0.0	12.3
Bad Debts	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.7	0.0	0.0	0.0	6.3
Office Rent	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sec Dep Interest	6.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0
Bank Charges	17.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3	0.0	0.0	1.5
Collection Exps	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.3	0.0	0.0	0.0	1.7
Travel & Ent.	4.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	0.0	0.4
Legal	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.4	0.0	0.0	0.0
Audit	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.3	0.0	0.0	1.7
Consulting	64.6	3.0	0.0	0.0	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Management Fees	457.0	0.0	0.0	0.0	0.0	0.0	0.0	381.4	0.0	0.0	45.0	0.0	0.0	30.6
Demand Side Management		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous	(221.8)	0.0	0.0	0.0	(138.1)	33.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(117.0)
Total O&M Costs	2,901.1	15.0	0.0	0.0	297.6	136.2	41.4	828.1	171.8	120.9	666.7	355.9	6.4	261.0

SHEET 1.3 continued

FUNCTIONALIZATION OF REVENUE REQUIREMENT

				Distribution		Customer Service		Administrative						
	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Measrmnt	Mains	Services	Meters	Billing/Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment	Other/Direct Assignment	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
CAPITALIZED EXPENSES														
Wages	(30.3)	0.0	0.0	0.0	(31.8)	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Equipment	(11.5)	0.0	0.0	0.0	(15.2)	3.7	0.0	0.0	0.0	0.0	0.0	0	0.0	0.0
Total Capitalized Expens	(41.8)	0.0	0.0	0.0	(47.0)	5.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net O&M Costs	3,591.6	15.0	401.9	0.0	250.7	141.4	41.4	828.1	171.8	120.9	666.7	686.3	6.4	261.0
Capital Taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Property Taxes	400.8	0.0	0.0	0.0	264.1	53.1	0.9	7.2	2.0	0.8	5.0	60	0.0	7.6
Net Depreciation Expens	1,206.5	0.0	0.0	23.7	414.9	103.4	65.5	12.2	1.4	0.6	114.5	253.7	0.0	216.7
Total Expenses	5,198.9	15.0	401.9	23.7	929.7	297.9	107.9	847.6	175.3	122.3	786.1	1,000.0	6.4	485.3
Net Def Acct Disp.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
Return on Rate Base	1,245.2	(7.9)	(0.2)	28.4	425.5	131.4	84.5	17.5	4.1	1.6	23.6	404.9	(24.8)	156.6
Income Taxes	163.1	(1.0)	(0.0)	3.7	55.7	17.2	11.1	2.3	0.5	0.2	3.1	53.0	(3.2)	20.5
REVENUE REQUIREME	6,607.2	6.1	401.6	55.8	1,410.8	446.5	203.4	867.4	180.0	124.0	812.8	1,457.9	(21.6)	662.4

SHEET 1.4

FUNCTIONALIZATION FACTORS

				Distribution		Customer Service		Administrative						
	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Measrmnt	Mains	Services	Meters	Billing/Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment to IGPC	Other/Direct Assignment	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
F1: Meters	100.00%	0.00%	0.00%	23.11%	0.00%	0.00%	76.89%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F2: Regulators	100.00%	0.00%	0.00%	8.97%	0.00%	91.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F3: Computers	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	50.00%	0.00%	0.00%	50.00%	0.00%	0.00%	0.00%
F4: Bldgs & Impr.	100.00%	0.00%	0.00%	0.00%	22.06%	12.62%	3.86%	29.60%	8.38%	3.21%	20.25%	0.00%	0.00%	0.00%
F5: Mains/Svces - C. E.	100.00%	0.00%	0.00%	0.00%	131.73%	-31.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F6: Auto Rate Base	100.00%	0.00%	0.00%	0.00%	131.73%	-31.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F7: Wages/Benefits	100.00%	0.00%	0.00%	0.00%	17.94%	10.26%	3.14%	24.07%	6.82%	2.61%	16.47%	0.00%	0.00%	18.69%
F8: Marketing	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F9: R&M General	100.00%	0.00%	0.00%	0.00%	49.66%	-7.20%	0.93%	16.44%	0.98%	0.38%	15.35%	0.00%	0.00%	23.47%
F10: Mains/Svces - C. L.	100.00%	0.00%	0.00%	0.00%	105.04%	-5.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F11: Mapping	100.00%	0.00%	0.00%	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F12: Auto Expenses	100.00%	0.00%	0.00%	0.00%	131.73%	-31.73%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F13: Communications	100.00%	0.00%	0.00%	0.00%	25.00%	25.00%	0.00%	0.00%	0.00%	0.00%	50.00%	0.00%	0.00%	0.00%
F14: Travel & Ent.	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%
F15: Mains/Svces - M.	100.00%	0.00%	0.00%	0.00%	74.21%	25.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F16: Small Tools	100.00%	0.00%	0.00%	0.00%	45.00%	45.00%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F17: Mains/Svces - C.D.	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
F18: Insurance	100.00%	0.00%	0.00%	0.00%	6.73%	-1.40%	0.05%	0.37%	0.10%	0.04%	94.11%	0.00%	0.00%	0.00%
F19: Property Taxes	100.00%	0.00%	0.00%	0.00%	79.27%	15.94%	0.28%	2.17%	0.62%	0.24%	1.49%	0.00%	0.00%	0.00%
F20: Management Fees	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	89.44%	0.00%	0.00%	10.56%	0.00%	0.00%	0.00%

SHEET 1.5

FUNCTIONALIZATION OF EMPLOYMENT COSTS
$ 000

Total Wages	1,101.9
Total Benefits	158.9

				Distribution		Customer Service		Administrative						
	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Measrmnt	Mains	Services	Meters	Billing/Accounting	Promotion	Bad Debt/ Collection	A&G	Direct Assignment to IGPC	Other/Direct Assignment	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
Management	100.00%	0.00%	0.00%	0.00%	10.00%	10.00%	10.00%	5.00%	7.50%	5.00%	44.06%	0.00%	0.00%	8.44%
Office Personnel	100.00%	0.00%	0.00%	0.00%	2.50%	2.50%	0.00%	50.00%	5.00%	5.00%	12.60%	0.00%	0.00%	22.40%
Operations Manager	100.00%	0.00%	0.00%	0.00%	93.80%	-4.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.70%
Line Maint.	100.00%	0.00%	0.00%	0.00%	105.04%	-5.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
System Maintenance	100.00%	0.00%	0.00%	0.00%	102.83%	-4.93%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.10%
Meter Reading	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Service & Install.	100.00%	0.00%	0.00%	0.00%	0.00%	52.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	48.00%
Sales	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	46.10%	0.00%	0.00%	0.00%	0.00%	53.90%
Management	346.2	0.0	0.0	0.0	34.6	34.6	34.6	17.3	26.0	17.3	152.5	0.0	0.0	29.2
Office Personnel	229.7	0.0	0.0	0.0	5.7	5.7	0.0	114.9	11.5	11.5	28.9	0.0	0.0	51.5
Operations Manager	57.7	0.0	0.0	0.0	54.1	(2.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2
Line Maint.	49.7	0.0	0.0	0.0	52.2	(2.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Maintenance	49.7	0.0	0.0	0.0	51.1	(2.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Meter Reading	133.1	0.0	0.0	0.0	0.0	0.0	0.0	133.1	0.0	0.0	0.0	0.0	0.0	0.0
Service & Install.	154.3	0.0	0.0	0.0	0.0	80.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.1
Sales	81.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.7	0.0	0.0	0.0	0.0	44.0
Benefits	158.9	0.0	0.0	0.0	28.5	16.3	5.0	38.3	10.8	4.2	26.2	0.0	0.0	29.7
Total (F7)	1,260.9	0.0	0.0	0.0	226.2	129.4	39.6	303.5	85.9	32.9	207.6	0.0	0.0	235.7
Total Excl Ancillary (F4)	1,025.2	0.0	0.0	0.0	226.2	129.4	39.6	303.5	85.9	32.9	207.6	0.0	0.0	

SHEET 1.6A

FUNCTIONALIZATION OF AUTOMOTIVE EXPENSES

$ 000

	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Distribution		Customer Service		Administrative				Direct Assignment to IGPC	Other Assignment
				Measrmnt	Mains	Services	Meters	Billing/Accounting	Promotion	Bad Debt/ Collection	A&G		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)
All Autos	32.0	0.0	0.0	0.0	42.2	(10.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel/Oil	39.0	0.0	0.0	0.0	51.4	(12.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Expenses (F12)	71.0	0.0	0.0	0.0	93.5	(22.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SHEET 1.6B

FUNCTIONALIZATION OF AUTOMOTIVE RATE BASE

$ 000

	Total	Gas Supply	Union Transportation/ Load Bal/Storage	Distribution		Customer Service		Administrative				Direct Assignment to IGPC	Other Assignment
				Measrmnt	Mains	Services	Meters	Billing/Accounting	Promotion	Bad Debt/ Collection	A&G		
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)		(11)
All Autos	117.8	0.0	0.0	0.0	155.2	(37.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Rate Base (F6)	117.8	0.0	0.0	0.0	155.2	(37.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0

1 **SHEET 1.7**

FUNCTIONALIZATION OF REPAIRS & MAINTENANCE EXPENSES

2 $ 000

Line		Total	Gas Supply	Union Transportation/ Load Bal/Storage	Distribution		Customer Service		Administrative				Direct Assignment to IGPC	Other/Direct Assignment	Ancillary Services
8					Measrmnt	Mains	Services	Meters	Billing/Accounting	Promotion	Bad Debt/ Collection	A&G			
9		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
10															
11	General	213.1	0.0	0.0	0.0	46.7	(11.3)	0.0	0.0	0.0	0.0	0.0	157.2	0.0	20.5
12	Trencher	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Computer	37.4	0.0	0.0	0.0	0.0	0.0	0.0	17.1	0.0	0.0	17.1	0.0	0.0	3.2
14	Meters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	Building	18.7	0.0	0.0	0.0	3.4	1.9	0.6	4.6	1.3	0.5	3.1	0.0	0.0	3.2
16	Compressor	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Other Equipment	6.9	0.0	0.0	0.0	5.3	(1.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9
18	Regulators	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Small Tools	7.0	0.0	0.0	0.0	2.8	2.8	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.7
20	Equipment Rental	6.0	0.0	0.0	0.0	7.3	(1.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
21	Line Compressors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	Total (F9)	289.1	0.0	0.0	0.0	65.5	(9.5)	1.2	21.7	1.3	0.5	20.3	157.2	0.0	31.0

SHEET 2.1

CLASSIFICATION OF RATE BASE

$ 000

FUNCTION	Total	Gas Supply	Union Demand	Union Commodity	Delivery Commodity	Delivery Demand	Weighted Customer Services	Weighted Customer Meters	Weighted Customer Billing	Unweighted Customer	Bad Debt/ Collection	A&G	Direct Assignment to IGPC	Other Assign	Ancillary Services
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
Gas Supply	(86.0)	(86.0)													
Union Trans/Load Bal/Storage	(2.4)		(2.0)	(0.3)											
Dist'n Measurement	310.7				155.4	155.4									
Mains	4,653.2					3,095.8				1,557.4					
Services	1,437.2						1,437.2								
Meters	923.8							923.8							
Accounting/Billing	191.8								192.0	(0.1)					
Promotion	45.2									45.2					
Bad Debt/Collection	17.1										17.1				
A&G	258.0											258.0			
Direct Assignment to IGPC	4,428.3												4,428.3		
Other Assignment	(270.8)													(270.8)	
Ancillary Services	1,712.4														1,712.4
TOTAL RATE BASE	13,618.7	(86.0)	(2.0)	(0.3)	155.4	3,251.1	1,437.2	923.8	192.0	1,602.5	17.1	258.0	4,428.3	(270.8)	1,712.4

SHEET 2.2

CLASSIFICATION OF REVENUE REQUIREMENT
$ 000

FUNCTION	Total	Gas Supply	Union Demand	Union Commodity	Delivery Commodity	Delivery Demand	Weighted Customer Services	Weighted Customer Meters	Weighted Customer Billing	Unweighted Customer	Bad Debt/ Collection	A&G	Direct Assignment to IGPC	Direct Assign	Ancillary Services
	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
Gas Supply	6.1	6.1													
Union Trans/Load Bal/Storage	401.6		343.3	58.4											
Dist'n Measurement	55.8				27.9	27.9									
Mains	1,410.8					938.6				472.2					
Services	446.5						446.5								
Meters	203.4							203.4							
Accounting/Billing	867.4								867.4						
Promotion	180.0									180.0					
Bad Debt/Collection	124.0										124.0				
A&G	812.8											812.8			
Direct Assignment	1,457.9												1,457.9		
Other Assignment	(21.6)				0.0									(21.6)	
Ancillary Services	662.4														662.4
TOTAL REVENUE REQUIREMENT	6,607.2	6.1	343.3	58.4	27.9	966.5	446.5	203.4	867.4	652.2	124.0	812.8	1,457.9	(21.6)	662.4
Classification of A&G		1.1	0.0	0.0	4.9	169.7	78.4	35.7	152.3	114.5	0.0	0.0	256.0	0.0	0.0
Total Revenue Requirement after Classification of A&G	6,607.2	7.2	343.3	58.4	32.8	1,136.3	524.9	239.2	1,019.7	766.7	124.0	0.0	1,714.0	(21.6)	662.4
Less: OTHER REVENUE															
Late Payment Fees	52.7										48.3				4.4
Transfer/Connection Charges	30.7									30.7					
REVENUE REQUIREMENT for Rates	6,523.8	7.2	343.3	58.4	32.8	1,136.3	524.9	239.2	1,019.7	736.1	75.8	0.0	1,714.0	(21.6)	657.9

SHEET 2.3 **CLASSIFICATION FACTORS**

Line		Total	Gas Supply	Union Demand	Union Commodity	Delivery Commodity	Delivery Demand	Weighted Customer Services	Weighted Customer Meters	Weighted Customer Billing	Unweighted Customer	Bad Debt/ Collection	A&G	Direct Assignment to IGPC	Direct Assign	Ancillary Services
6		(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)		(12)	(13)
8	C1: Mains	100.00%	0.00%	0.00%	0.00%	0.00%	66.53%	0.00%	0.00%	0.00%	33.47%	0.00%	0.00%	0.00%	0.00%	0.00%
9	C2: Services	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10	C3: A&G	100.00%	0.13%	0.00%	0.00%	0.60%	20.88%	9.65%	4.40%	18.74%	14.09%	0.00%	0.00%	31.50%	0.00%	0.00%
11	C4: Union Demand/Com	100.00%	0.00%	85.47%	14.53%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12	C5: Dist. Measurement	100.00%	0.00%	0.00%	0.00%	50.00%	50.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

1 **SHEET 3.1** **ALLOCATION**
2 $ 000

#			RATE 1			RATE 2	RATE 3		Rate 4	Rate 5	Rate 6			
5	**CLASSIFIED COSTS**	TOTAL	Residential	Commercial	Industrial	Seasonal	Firm	Interruptible	Int. Fall	Int. Fall	Allocated	Direct Allocation	Ancillary	Factor
7	<u>RATE BASE</u>													
9	Gas Supply	(86.0)	(54.2)	(14.1)	(2.4)	(1.7)	(9.2)	0.0	(0.5)	(3.9)	0.0	0.0	0.0	E1
10	Union Demand	(2.0)	(1.3)	(0.4)	(0.1)	(0.0)	(0.2)	0.0	0.0	0.0	0.0	0.0	0.0	D1
11	Union Commodity	(0.3)	(0.2)	(0.1)	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0	E2
12	Delivery Commodity	155.4	92.9	29.3	4.1	3.6	15.6	0.0	3.2	6.7	0.0	0.0	0.0	E2
13	Delivery Demand	3,251.1	1,748.4	520.9	126.9	202.9	351.5	0.0	47.1	253.4	0.0	0.0	0.0	D2
14	Weighted Customer - Services	1,437.2	1,164.6	73.5	26.0	114.3	9.1	0.0	36.0	11.4	2.3	0.0	0.0	CC1
15	Weighted Customer - Meters	923.8	573.0	36.2	33.5	164.4	26.6	0.0	50.2	33.2	6.6	0.0	0.0	CC2
16	Weighted Customer - Billing	192.0	175.0	11.0	0.7	1.9	1.1	0.0	0.6	1.3	0.3	0.0	0.0	CC3
17	Unweighted Customer	1,602.5	1,479.6	93.4	5.9	16.5	0.9	0.0	5.2	1.1	0.0	0.0	0.0	CC4
18	Bad Debt/Collection	17.1	13.5	3.2	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	CC5
19	A&G	258.0	132.4	15.3	3.3	8.1	6.7	0.0	2.3	5.1	5.1	0.0	0.0	
	Direct Assignment	4,428.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,428.3	0.0	
20	Security Deposits	(270.8)	(253.8)	(16.0)	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0	R1
21	Ancillary Services	1,712.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	1,712.4	DA
23	Total Rate Base	13,618.7	5,069.8	752.2	197.4	510.1	402.0	0.0	144.2	308.4	14.3	4,428.3	1,712.4	
25	REVENUE REQUIREMENT													
27	Gas Supply	7.2	4.5	1.2	0.2	0.1	0.8	0.0	0.0	0.3	0.0	0.0	0.0	E1
28	Union Demand	343.3	223.9	67.0	16.3	0.5	35.6	0.0	0.0	0.0	0.0	0.0	0.0	D1
29	Union Commodity	58.4	34.9	11.0	1.5	1.3	5.8	0.0	1.2	2.5	0.0	0.0	0.0	E2
30	Delivery Commodity	32.8	19.6	6.2	0.9	0.8	3.3	0.0	0.7	1.4	0.0	0.0	0.0	E2
31	Delivery Demand	1,136.3	611.1	182.1	44.4	70.9	122.8	0.0	16.5	88.6	0.0	0.0	0.0	D2
32	Weighted Customer - Services	524.9	425.3	26.8	9.5	41.7	3.3	0.0	13.2	4.2	0.8	0.0	0.0	CC1
33	Weighted Customer - Meters	239.2	148.3	9.4	8.7	42.6	6.9	0.0	13.0	8.6	1.7	0.0	0.0	CC2
34	Weighted Customer - Billing	1,019.7	929.6	58.7	3.7	10.3	5.7	0.0	3.3	7.1	1.4	0.0	0.0	CC3
35	Unweighted Customer	736.1	679.5	42.9	2.7	7.6	0.4	0.0	2.4	0.5	0.1	0.0	0.0	CC4
36	Bad Debt/Collection	75.8	59.7	14.0	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	CC5
	Direct Assignment	1,714.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,714.0		
37	Security Deposits	(21.6)	(20.2)	(1.3)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	R1
38	Ancillary Services	657.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	657.9	DA
40	Total Revenue Requirement	6,523.8	3,116.2	417.9	89.9	175.8	184.6	0.0	50.2	113.2	4.1	1,714.0	657.9	
41	Rev Rqmnt excl Ancillary Services	5,865.9	3,116.2	417.9	89.9	175.8	184.6	0.0	50.2	113.2	4.1	1,714.0		
43	CAPITAL COSTS													
45	Income Taxes	163.1	75.4	11.2	2.9	7.6	6.0	0.0	2.1	4.6	0.2	53.0	0.0	
46	Return on Rate Base	1245.2	463.6	68.8	18.0	46.6	36.8	0.0	13.2	28.2	1.3	404.9	156.6	
48	Total Capital Costs	1408.3	539.0	80.0	21.0	54.2	42.7	0.0	15.3	32.8	1.5	457.9	156.6	
51	Allocated A&G	829.3	425.7	49.2	10.5	26.1	21.4	0.0	7.3	16.6	16.6	256.0	0.0	
52	A&G per m^3	$0.0378	$0.0325	$0.0119	$0.0180	$0.0519	$0.0098	$0.0000	$0.0162	$0.0175	$0.0175	$0.0077		
51	Allocated A&G	775.3	383.7	42.6	9.0	22.8	17.8	1.9	6.5	13.8	13.8	263.4	0.0	

Row	FACTOR	DESCRIPTION	TOTAL	RATE 1 Residential	RATE 1 Commercial	RATE 1 Industrial	RATE 2 Seasonal	RATE 3 Firm	RATE 3 Interruptible	RATE 4 Int. Fall	Rate 5 Int. Fall	RATE 6 Firm	
1	**SHEET 3.2**	**ALLOCATION FACTORS**											
2													
3													
4													
5					RATE 1		RATE 2	RATE 3		RATE 4	Rate 5	RATE 6	
6	FACTOR	DESCRIPTION	TOTAL	Residential	Commercial	Industrial	Seasonal	Firm	Interruptible	Int. Fall	Int. Fall	Firm	
7													
8													
9		Sales Volumes (m^3)	20,646,638	13,008,204	3,379,039	577,627	410,741	2,204,921	0	118,945	947,162		
10	E1	% OF TOTAL	100.00%	63.00%	16.37%	2.80%	1.99%	10.68%	0.00%	0.58%	4.59%		
11	E1:1-6		100.00%	63.00%	16.37%	2.80%	1.99%	10.68%	0.00%	0.58%	4.59%	0.00%	
12		Delivery/Transp Volumes (m^3)	21,915,910	13,103,581	4,131,750	580,997	502,859	2,195,299	0	454,263	947,162	33,416,816	
13	E2	% OF TOTAL	100.00%	59.79%	18.85%	2.65%	2.29%	10.02%	0.00%	2.07%	4.32%		
14	E2:1-6		100.00%	23.68%	7.47%	1.05%	0.91%	3.97%	0.00%	0.82%	1.71%	60.39%	
15													
16		Coincident Peak (m^3/day)	200,570	130,816	39,154	9,529	271	20,800	0	0	0	108,118	
17		Peak Day Use/Cust/HDD (3 yr avg)		0.52318	2.50347	7.21926	0.13525					2702.95	
18		# of customers @ Peak Day		6251	391	33	50	5	0	24	5	1	
19	D1	% OF TOTAL	100.00%	65.22%	19.52%	4.75%	0.13%	10.37%	0.00%	0.00%	0.00%		
20	D1:1-6		100.00%	42.38%	12.68%	3.09%	0.09%	6.74%	0.00%	0.00%	0.00%	35.02%	
21		Non-Coincident Peak(m^3/day)	267,275	113,143	33,470	8,171	33,005	30,076	0	7,742	41,668	108,118	
22		Peak day Use/Cust (3 yr avg)		18.1	85.6	247.6	660.1	6,015.2	0.0	322.6	8,333.6	108,118.0	
23		% OF TOTAL	100.00%	42.33%	12.52%	3.06%	12.35%	11.25%	0.00%	2.90%	15.59%		
24			100.0%	30.14%	8.92%	2.18%	8.79%	8.01%	0.00%	2.06%	11.10%	28.80%	
25		Weighted CP/NCP Allocator	233,923	125,797	37,479	9,133	14,601	25,291	0	3,388	18,234		
26	D2	% OF TOTAL	100.00%	53.78%	16.02%	3.90%	6.24%	10.81%	0.00%	1.45%	7.79%		
27	D2:1-6		100.00%	53.78%	16.02%	3.90%	6.24%	10.81%	0.00%	1.45%	7.79%	0.00%	
28		Wtd Customers Services	8,083	6,560	414	147	644	51	0	203	64	13	
29		Weighting Factor		1.00	1.00	5.64	8.82	12.86	12.86	8.82	12.86	12.86	
30	CC1	% OF TOTAL	100.00%	81.16%	5.12%	1.81%	7.97%	0.64%	0.00%	2.51%	0.80%		
31	CC1:1-6		100.00%	81.03%	5.11%	1.81%	7.95%	0.64%	0.00%	2.51%	0.79%	0.16%	
32		Wtd Customers Meters	10,501	6,560	414	384	1,883	304	0	575	381	76	
33		Weighting Factor		1.00	1.00	14.76	25.79	76.11	76.11	25.01	76.11	76.11	
34	CC2	% OF TOTAL	100.00%	62.47%	3.94%	3.65%	17.93%	2.90%	0.00%	5.48%	3.62%		
35	CC2:1-6		100.00%	62.02%	3.91%	3.63%	17.80%	2.88%	0.00%	5.44%	3.60%	0.72%	
36		Wtd Customers Billing	7,186	6,560	414	26	73	40	0	23	50	10	
37		Weighting Factor		1	1	1	1	10	10	1	10	10	
38	CC3	% OF TOTAL	100.00%	91.29%	5.76%	0.36%	1.02%	0.56%	0.00%	0.32%	0.70%		
39	CC3:1-6		100.00%	91.16%	5.75%	0.36%	1.01%	0.56%	0.00%	0.32%	0.69%	0.14%	
40		Customers (average)	7,105	6,560	414	26	73	4	0	23	5	1	
41	CC4	% OF TOTAL	100.00%	92.33%	5.83%	0.37%	1.03%	0.06%	0.00%	0.32%	0.07%		
42	DD4:1-6		100.00%	92.32%	5.83%	0.37%	1.03%	0.06%	0.00%	0.32%	0.07%	0.01%	
43		m^3 per Customer		1,997	9,980	22,346	6,888	548,825	0	19,751	189,432		
44													
45		Rate 1 Revenues	8,648	6,808	1,595	245							
46	CC5	% OF TOTAL	100.00%	78.72%	18.45%	2.83%							
47	CC5:1-6		100.00%	78.72%	18.45%	2.83%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
48													
49		Security Deposit & DSM											
50	R1	% OF TOTAL	100.00%	93.71%	5.91%	0.37%	0.00%	0.00%	0.00%	0.00%	0.00%		
51	R1:1-6		100.00%	93.71%	5.91%	0.37%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
52													

SHEET 3.3 **ANALYSIS OF ALLOCATED COSTS**

		RATE 1			RATE 2	RATE 3		RATE 4	RATE 5	RATE 6		Ancillary
	Total	Residential	Commercial	Industrial	Seasonal	Firm	Interruptible	Int. Fall	Int. Fall	Firm		Services
REVENUES												
Current Rates	6,061.4	2,898.0	579.5	71.3	68.4	157.9	0.5	61.5	62.9	1,580.6		580.8
Gas Supply	1,541.6	15.1	3.9	0.7	0.5	2.6	0.0	0.1	1.1	1,517.7		
Transportation & Distribution	3,939.0	2,882.9	575.6	70.7	67.9	155.3	0.5	61.4	61.8	62.9		
Ancillary Services	580.8											580.8
Cost based rates	6,523.8	3,116.2	417.9	89.9	175.8	184.6	0.0	50.2	113.2	1,718.0		657.9
Gas Supply	7.2	4.5	1.2	0.2	0.1	0.8	0.0	0.0	0.3	0.0		
Transportation & Distribution	5,858.7	3,111.7	416.7	89.7	175.7	183.9	0.0	50.1	112.9	1,718.0		
Ancillary Services	657.9											657.9
(Deficiency)/Sufficiency	(462.4)	(218.2)	161.6	(18.6)	(107.5)	(26.8)	0.5	11.4	(50.3)	(137.4)		(77.1)
Gas Supply	1,534.4	10.6	2.7	0.5	0.3	1.8	0.0	0.1	0.8	1,517.7		0.0
Transportation & Distribution	(1,919.7)	(228.7)	158.9	(19.0)	(107.8)	(28.6)	0.5	11.3	(51.1)	(1,655.1)		0.0
Ancillary Services	(77.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		(77.1)
R/C @ current rates - total	92.91%	93.00%	138.67%	79.35%	38.88%	85.50%	NA	122.62%	55.55%	92.00%		88.28%
R/C @ current rates - gas supply	21468.64%	333.24%	333.24%	333.24%	333.24%	333.24%	NA	333.24%	333.24%	-		
R/C @ current rates - distribution	67.23%	92.65%	138.12%	78.78%	38.65%	84.47%	NA	122.45%	54.74%	3.66%		
R/C @ current rates - ancillary	88.28%	NA	NA	NA	NA	NA	NA	NA	NA	NA		88.28%
SUMMARY OF COSTS												
Total	5,865.9	3,116.2	417.9	89.9	175.8	184.6	0.0	50.2	113.2	4.1	1,379.4	
Supply	98.3	59.0	18.4	2.6	2.2	9.9	0.0	1.9	4.3	0.0	0.0	
Demand	1,479.5	834.9	249.1	60.7	71.4	158.4	0.0	16.5	88.6	0.0	0.0	
Customer	4,288.0	2,222.2	150.5	26.6	102.2	16.3	0.0	31.8	20.4	4.1	1,379.4	
Costs by Function												
Gas Supply	7.2	4.5	1.2	0.2	0.1	0.8	0.0	0.0	0.3	0.0	0.0	
Union Transportation												
Commodity	167.6	34.9	11.0	1.5	1.3	5.8	0.0	1.2	2.5	0.0	109.3	
Demand	564.5	223.9	67.0	16.3	0.5	35.6	0.0	0.0	0.0	0.0	221.2	
Distribution												
Commodity	32.8	19.6	6.2	0.9	0.8	3.3	0.0	0.7	1.4	0.0	0.0	
Demand	1,136.3	611.1	182.1	44.4	70.9	122.8	0.0	16.5	88.6	0.0	0.0	
Customer	4,288.0	2,222.2	150.5	26.6	102.2	16.3	0.0	31.8	20.4	4.1	1,375.3	
SUMMARY OF UNIT COSTS												
Total - $/m^3	0.282754	0.237814	0.101202	0.154765	0.349753	0.084108	0.000000	0.110744	0.119534	0.000122	0.051168	
Supply - $/m^3	0.009492	0.004507	0.004507	0.004507	0.004507	0.004507	0.000000	0.004507	0.004507	0.000000	0.003270	
Demand - $/m^3	0.077603	0.063718	0.060280	0.104424	0.141961	0.072176	0.000000	0.036229	0.093513	0.000000	0.006620	
Cust - $/m^3	0.195659	0.169589	0.036414	0.045834	0.203284	0.007426	0.000000	0.070007	0.021514	0.000122	0.041279	
UNIT COSTS BY FUNCTION												
Gas Supply -$/m^3	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000000	0.000348	0.000348	0.000000	0.000000	
Total Union Transportation	0.033404	0.019748	0.018881	0.030733	0.003584	0.018878	0.000000	0.002663	0.002663	0.000000	0.009889	
Transport Commodity - $/m^3	0.007648	0.002663	0.002663	0.002663	0.002663	0.002663	0.000000	0.002663	0.002663	0.000000	0.003270	
Transport Demand - $/m^3	0.025756	0.017085	0.016218	0.028070	0.000921	0.016215	0.000000	0.000000	0.000000	0.000000	0.006620	
Distribution-$/m^3	0.249002	0.217718	0.081973	0.123684	0.345821	0.064882	0.000000	0.107733	0.116524	0.000122	0.041279	
Commodity - $/m^3	0.001496	0.001496	0.001496	0.001496	0.001496	0.001496	0.000000	0.001496	0.001496	0.000000	0.000000	
Demand - $/m^3	0.051847	0.046633	0.044062	0.076354	0.141041	0.055960	0.000000	0.036229	0.093513	0.000000	0.000000	
Customer - $/m^3	0.195659	0.169589	0.036414	0.045834	0.203284	0.007426	0.000000	0.070007	0.021514	0.000122	0.041279	
Cust - $/customer/mth	$50.29	$28.23	$30.28	$85.35	$116.69	$339.63	$0.00	$115.22	$339.63	$339.63	$114,950.82	

NATURAL RESOURCE GAS LIMITED

SUMMARY OF RECOMMENDATIONS & CHANGES

The following is a summary of the proposed changes to NRG's rate design based on the forecast for the 2011 Test Year. Further details are available on each of the rates can be found in Exhibit H2, Tab 1, Schedule 1.

Fiscal 2011 Test Year

NRG does not propose its existing rate design.

NRG is proposing to increase the monthly fixed charge from $11.50 per month for Rate 1 customers to $13.50. The monthly fixed charge for Rate 2 and Rate 4 customers are proposed to increase from $12.75 to $15.00. The monthly customer charge for Rate 3 and Rate 5 customers remain at $150.00. The proposed monthly charge for Rate 6 customers will be set at the same level as is the fixed monthly charge for Rate 3. These changes reflect a movement to recover a higher proportion of fixed costs through fixed charges.

NRG proposes to adjust the currently authorized variable rates so that the 2011 Test Year revenue requirement is recovered without causing undue cross subsidization among customer classes. Initially NRG examined the impact to rates if each class was to achieve a Revenue:Cost ratio of 1.00. The impact to Rate classes 2 and 5 was unacceptably large.

NRG then examined an alternative scenario. First, Rate 1 – Residential variable rates were set to achieve a Revenue:Cost ratio of unity for the Residential customers only. The second block variable rates were set at a level that recovered the remaining allocated costs from the Rate 1 – Commercial and Rate 1 – Industrial customers. This combination of fixed and variable rates achieves a class Revenue:Cost ratio of unity. NRG then altered the variable rates of its other customer classes to avoid rate shock and to ensure that the revenue requirement was recovered.

Finally, NRG estimated distribution rates that recovered the revenue requirement associated with amortizing its distribution assets over the remaining life of the Aylmer franchise agreement.

NRG quantified the rates that would be charged to each customer class to achieve a Revenue:Cost ratio of unity.

NATURAL RESOURCE GAS LIMITED

5-YEAR INCENTIVE REGULATION PLAN

Given its limited resources and small customer base, NRG has proposed a 5-Year Incentive Regulation Plan ("the IRP) building on the plans developed by Union Gas and Enbridge Gas Distribution. The components of both of these plans have been thoroughly reviewed by a broad range of representative parties and the resulting plans have been approved by the Board. NRG's main objective in proposing a simplified IRP is to provide its customers with the same incentive regulation benefits that are available to other natural gas consumers in Ontario without having to expend all of the resources that went into the Union and Enbridge settlement agreements.

The practical implementation of NRG's approach was made possible by selecting a simple incentive method and corresponding planning components that have already been carefully designed by utilities with significant resources; vetted diligently by experienced intervenors; and, approved by the Board as being appropriate to protect the interests of natural gas consumers. This approach promises to be significantly more cost effective than the alternative of developing and negotiating a distinct NRG plan. Following a review of the key components of the Union and Enbridge plans, NRG selected the price cap model as the simplest and most appropriate model for its utility.

Since there was no apparent reason why the approved plans could not be applied cost effectively to NRG, the company retained Elenchus Research Associates to review the details of the approved IR plans for Union and Enbridge and to recommend a simplified IRP that could be applied to NRG. The attached comparison table provides a summary of the IRP proposal that NRG is submitting for Board approval. The company's proposed 5-Year IRP is based on the simplified approach recommended by John Todd in Exhibit H2, Tab 1, Schedule 1.

NRG's proposed IRP meets the objectives outlined in the Board's Natural Gas Forum Report and guarantees that future rate increases will be significantly below the 2% maximum expected for residential customers under the Union and Enbridge plans. In addition, NRG provides the same commitment to earnings sharing as Union and uses a similar incentive approach, but with a simpler price cap formula based on a fixed rate adjustment and limited use of Y and Z factors. There is no change in weather risk, no costs associated with negotiating inflation or productivity factors and no need for average use adjustments as the consumption of NRG's residential customers has remained relatively constant. The off-ramp and earnings-sharing thresholds are the same as Union's. The reporting, annual rate adjustments and rebasing information is the same as NRG's normal filing requirements to minimize costs. The proposed changes to rate design are limited to graduated annual increases in the monthly fixed charges matching the approach taken by Union and Enbridge. All other rate design changes and any new services during the IRP term will require Board approval. There is no need for base year revenue adjustments since the base year revenue requirement will be determined by the Board in the current proceeding.

Comparison of Incentive Regulation Plans for Ontario's Natural Gas Distributors

Factor	Enbridge Gas	Union Gas	NRG
Case No.	**EB-2007-0615**	**EB-2007-0606**	**EB-2010-0018**
Type	revenue per customer cap	price cap index	simplified price cap
Term	5 years 2008 to 2012, option to extend to 2014	5 years 2008 to 2012	5 years 2011 to 2015
Objectives	lower rates, shared benefits, investment stability	lower rates, shared benefits, investment stability	lower rates, shared benefits, investment stability
Rate Impact	annual increase for residential class < 2%	annual increase for residential class < 2%	annual increase for residential class set at 1.5%
Weather Risk	retained by utility	retained by utility	retained by utility
ROE	fixed at 8.39 subject to OEB formula change	fixed at 8.54 subject to OEB formula change	fixed at level approved by Board; 10.25 proposed
Open Issues	customer additions	commodity risk, customer adds, tax changes	no open issues; base rates set by Board
Rate Formula	multi-year, customer based, productivity 0.82-1.12	single year with fixed productivity factor 1.82%	single year with fixed annual increase
Average Use	recorded in variance account	average use adjustment factor	no adjustment required
Inflation Rate	GDP Implicit Price Index Final Domestic Demand	GDP Implicit Price Index Final Domestic Demand	incorporated in fixed annual increase
Z-Factors	ROE formula, NGEIR, Tax changes	ROE Formula, NGEIR, LPP, municipal permit fees	ROE formula, IGPC decommissioning
Y-Factors	DSM, CIS, upstream costs, generator capex	DSM, CIS, upstream costs, storage margin	Upstream costs
Off Ramps	300 bp variance from normalized earnings	300 bp variance from normalized earnings	300 bp variance from normalized earnings
Shared Earnings	earnings 100 bp > ROE formula shared 50/50	earnings 200 bp > ROE formula shared 50/50	earnings 200 bp > ROE formula shared 50/50
Reporting	detailed annual reporting requirements	detailed annual reporting requirements	standard annual reporting
Adjustments	detailed annual reporting requirements	detailed annual reporting requirements	standard annual reporting
New Services	separate approval required	separate approval required	separate approval required
Rate Design	fixed charges increased annually for R1 & R6	separate approval beyond $1/mo/yr for R01 & M1	fixed charges increases for R1, R2, R4 & R5
Rebasing	cost of service filing, plus 5 yrs plant continuity	cost of service filing, plus 5 yrs plant continuity	cost of service filing, plus 5 yrs plant continuity
Base Year	costs lowered by $18M, $125 CIS spread over 5 yrs	parties agreed to adjustments totaling $8.8M	base year = 2011 test year approved by the Board

NATURAL RESOURCE GAS LIMITED

DIRECT PURCHASE ADMINISTRATION FEE

NRG's direct purchase administration fee is as follows:

New customer processing fee per customer	$ 5.54
Monthly fee per Bundled T contract	$60.00
Monthly per customer fee	$ 0.23.

NRG is not proposing any changes in the direct purchase administration fee in the fiscal 2011 test year. At the current time NRG has a total of 6 direct purchase contracts and approximately 60 direct purchase customers.

The ABC (Agency, Billing and Collection) fee for those customers who opt to use this service is $0.23 per customer per month. This fee is also unchanged from the current charge.

PROPOSED RATE DESIGN

		RATE 1			RATE 2		RATE 3		RATE 4		RATE 5	RATE 6
	TOTAL	Residential	Commercial	Industrial	Apr - Oct	Nov - Mar	Firm	Interruptible	Apr - Dec	Jan - Mar	Interruptible	Firm
BLOCK STRUCTURE												
		m^3/mth	m^3/mth	m^3/mth	m^3/mth	m^3/mth			m^3/mth	m^3/mth		
Block 1 <=		1,000	1,000	1,000	1,000	1,000			1,000	1,000		
Block 2 >		1,000	1,000	1,000	1,000	1,000			1,000	1,000		
Block 2 <=					24,000	24,000						
Block 3					25,000	25,000						
% of volume in 1st block		98.2%	45.7%	25.6%	11.0%	9.8%	100.0%	100.0%	51.3%	3.8%	100.0%	100.0%
% of volume in 2nd block		1.8%	54.3%	74.4%	79.2%	0.0%			44.9%	0.0%		
% of volume in 3rd block					0.0%	0.0%						
		100.0%	100.0%	100.0%	90.2%	9.8%			96.2%	3.8%		
VOLUMES	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3
Block 1	14,903,422	12,867,716	1,886,970	148,735	55,314	49,460	2,195,299	0	232,954	17,338	947,162	33,416,816
Block 2	2,912,906	235,864	2,244,780	432,262	398,085	0			203,970	0		
Block 3	0	0	0	0	0	0			0	0		
TOTAL	17,816,328	13,103,581	4,131,750	580,997	453,399	49,460			436,924	17,338		
Firm CD m^3/day							22,650					108,118
RATES - DISTRIBUTION												
CUSTOMER CHARGE $/cust/mth		$13.50	$13.50	$13.50	$15.00	$15.00	$150.00	$175.00	$15.00	$15.00	$150.00	$150.00
BLOCK RATES	$ /m^3				$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3
Block 1	0.155753				0.143470	0.183687	0.037310	0.092249	0.144482	0.185629	0.065963	0.037310
Block 2	0.111874				0.099370	0.164498			0.103477	0.166237		
Block 3					0.064726	0.160241						
DIFFERENTIAL	0.043879											
Demand Rate ($/DCQ)							0.269947					0.361848
RATES - GAS SUPPLY												
Gas Commodity	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
System Gas Fee	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348
Total Gas Supply	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348	0.000348
REVENUE												
		$ 000	$ 000	$0	$ 000	$ 000	$ 000	$ 000	$ 000	$ 000	$ 000	$ 000
DISTRIBUTION												
Customer Charge	1,134.0	1,062.7	67.1	4.2	7.7	5.5	7.0	0.0	3.1	1.0	9.0	1.8
Commodity Block 1	2,321.3	2,004.2	293.9	23.2	7.9	9.1	81.9	0.0	33.7	3.2	62.5	1,246.8
Block 2	325.9	26.4	251.1	48.4	39.6	0.0			21.1	0.0		
Block 3					0.0	0.0						

		TOTAL	RATE 1 Residential	RATE 1 Commercial	RATE 1 Industrial	RATE 2 Apr - Oct	RATE 2 Nov - Mar	RATE 3 Firm	RATE 3 Interruptible	RATE 4 Apr - Dec	RATE 4 Jan - Mar	RATE 5 Interruptible	RATE 6 Firm
54	Demand Charge							73.4					469.5
55	Balancing Adjustment	(0.5)	(0.4)	(0.0)	(0.0)	(0.9)		(0.0)	0.0	(0.0)		(0.0)	(0.0)
58	GAS SUPPLY	5.9	4.5	1.2	0.2	0.1		0.8	0.0	0.0		0.3	0.0
60	TOTAL REVENUE	3,786.5	3,097.4	613.3	75.9	54.4	14.6	163.0	0.0	57.9	4.3	71.8	1,718.0
62	**R/C RATIOS**												
63	**GAS SUPPLY**	100.0%	100.0%	100.0%	100.0%	100.0%		100.0%	100.0%	100.0%		100.0%	0.0%
65	**DISTRIBUTION**	104.5%	99.4%	146.9%	84.4%	39.2%		88.2%	0.0%	123.8%		63.3%	934.3%
67	**TOTAL**	**104.5%**	**99.4%**	**146.8%**	**84.4%**	**39.2%**		**88.3%**	**0.0%**	**123.8%**		**63.4%**	**930.5%**
69	**TOTAL INCL GAS**	**101.8%**	**99.7%**	**111.8%**	**94.7%**	**67.3%**		**97.4%**	**0.0%**	**106.4%**		**89.6%**	**115.0%**
70	**COMMODITY**												
72	**IMPLIED REVENUE INCREASE**		**6.9%**	**5.8%**	**6.4%**	**0.9%**		**3.3%**	**0.0%**	**1.0%**		**14.2%**	**988.2%**
74	**% RETURN ON RATE BASE**	**11.8%**	**8.8%**	**35.1%**	**2.0%**	**-11.8%**		**3.8%**	**0.0%**	**18.0%**		**-4.3%**	**390.6%**

1 **ANALYSIS OF FIXED COSTS**

		TOTAL	RATE 1 Residential	RATE 1 Commercial	RATE 1 Industrial	RATE 2 Apr - Oct	RATE 2 Nov - Mar	RATE 3 Firm	RATE 3 Interruptible	RATE 4 Apr - Dec	RATE 4 Jan - Mar	RATE 5 Interruptible	RATE 6 Firm
7	Customer Charge Revenue	1,134.0	1,062.7	67.1	4.2	7.7	5.5	7.0	0.0	3.1	1.0	9.0	1.8
8	Total Customer costs	2,399.3	2,222.2	150.5	26.6	102.2		16.3	0.0	31.8		20.4	16.3
9	% Customer Costs recovered	47.3%	47.8%	44.6%	15.8%	12.9%		42.8%	0.0%	13.0%		44.2%	11.0%
11	Demand Charge							73.4					469.5
12	Demand Costs	1,144.7	834.9	249.1	60.7	71.4		158.4	0.0	16.5		88.6	158.4
13	% Demand Costs recovered							46.3%					296.3%
15	Total Fixed Charges	1,134.0	1,062.7	67.1	4.2	7.7	5.5	80.3	0.0	3.1	1.0	9.0	471.3
16	Total Fixed Costs	3,544.0	3,057.2	399.5	87.3	173.6		174.7	0.0	48.3		108.9	174.7
17	% Total Fixed Costs recovered	32.0%	34.8%	16.8%	4.8%	7.6%		46.0%	0.0%	8.6%		8.3%	269.7%
19	through block 1	65.5%	65.6%	73.6%	26.5%	9.8%		46.9%	0.0%	76.4%		57.3%	713.5%
20	through block 2	9.2%	0.9%	62.9%	55.4%	22.8%				43.7%			
21	through block 3	0.0%	0.0%	0.0%	0.0%	0.0%				0.0%			
22	Total FIXED COST RECOVERY	106.7%	101.2%	153.2%	86.8%	40.2%		92.8%	0.0%	128.7%		65.6%	983.2%

			TOTAL	RATE 1 Residential	RATE 1 Commercial	RATE 1 Industrial	RATE 2 Apr - Oct	RATE 2 Nov - Mar	RATE 3 Firm	RATE 3 Interruptible	RATE 4 Apr - Dec	RATE 4 Jan - Mar	RATE 5 Interruptible	RATE 6 Firm
	Estimated Deficiency													
60	TOTAL REVENUE	5,865.5	3,781.1	3,093.3	612.1	75.7	55.2	14.6	163.0	0.0	57.9	4.3	71.5	1,718.0
	Allocated Costs	5,865.9	3,624.0	3,116.2	417.9	89.9	175.8		184.6	0.0	50.2		113.2	1,718.0
	R:C		104.34%	99.27%	146.48%	84.23%	39.65%		88.29%	-	115.30%		63.13%	100.00%

PROPOSED RATE DESIGN - ILLUSTRATIVE RATES

		RATE 1			RATE 2		RATE 3		RATE 4		RATE 5	RATE 6
	TOTAL	Residential	Commercial	Industrial	Apr - Oct	Nov - Mar	Firm	Interruptible	Apr - Dec	Jan - Mar	Interruptible	Firm
BLOCK STRUCTURE												
		m^3/mth	m^3/mth	m^3/mth	m^3/mth	m^3/mth			m^3/mth	m^3/mth		
Block 1 <=		1,000	1,000	1,000	1,000	1,000			1,000	1,000		
Block 2 >		1,000	1,000	1,000	1,000	1,000			1,000	1,000		
Block 2 <=					24,000	24,000						
Block 3					25,000	25,000						
% of volume in 1st block		98.2%	45.7%	25.6%	11.0%	9.8%	100.0%	100.0%	51.3%	3.8%	100.0%	100.0%
% of volume in 2nd block		1.8%	54.3%	74.4%	79.2%	0.0%			44.9%	0.0%		
% of volume in 3rd block					0.0%	0.0%						
		100.0%	100.0%	100.0%	90.2%	9.8%			96.2%	3.8%		
VOLUMES	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3	m^3
Block 1	14,904,661	12,867,716	1,888,210	148,735	55,314	49,460	2,195,299	0	232,954	17,338	947,162	33,416,816
Block 2	2,911,667	235,864	2,243,540	432,262	398,085	0			203,970	0		
Block 3	0	0	0	0	0	0			0	0		
TOTAL	17,816,328	13,103,581	4,131,750	580,997	453,399	49,460			436,924	17,338		
Firm CD m^3/day							22,461					108,118
RATES - DISTRIBUTION												
CUSTOMER CHARGE $/cust/mth		$13.50	$13.50	$13.50	$15.00	$15.00	$150.00	$150.00	$15.00	$15.00	$150.00	$150.00
BLOCK RATES	$ /m^3				$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3	$ /m^3
Block 1	0.602675				2.230535	2.855823	0.167522	0.092249	0.628579	0.807569	0.512976	0.116967
Block 2	0.527205				1.544930	2.557485			0.450125	0.723205		
Block 3					1.006310	2.491308						
DIFFERENTIAL	0.075470											
Demand Rate ($/DCQ)							1.149009					0.802259
RATES - GAS SUPPLY												
Gas Commodity	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
System Gas Fee	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297
Total Gas Supply	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297	0.000297
REVENUE												
		$ 000	$ 000	$0	$ 000	$ 000	$ 000	$ 000	$ 000	$ 000	$ 000	$ 000
DISTRIBUTION												
Customer Charge	1,134.0	1,062.7	67.1	4.2	7.7	5.5	7.0	0.0	3.1	1.0	9.0	1.8
Commodity Block 1	8,982.7	7,755.0	1,138.0	89.6	123.4	141.2	367.8	0.0	146.4	14.0	485.9	3,908.7
Block 2	1,535.0	124.3	1,182.8	227.9	615.0	0.0			91.8	0.0		
Block 3					0.0	0.0						
Demand Charge							309.7					1040.9
Balancing Adjustment	(0.5)	(0.4)	(0.0)	(0.0)	(0.9)		(0.0)	0.0	(0.0)		(0.0)	(0.0)

GAS SUPPLY	5.0	3.9	1.0	0.2	0.1		0.7	0.0	0.0		0.3	0.0
TOTAL REVENUE	11,656.2	8,945.5	2,388.8	321.9	745.3	146.7	685.1	0.0	241.4	15.0	495.2	4,951.3
R/C RATIOS												
GAS SUPPLY	100.0%	100.0%	100.0%	100.0%	100.0%		100.0%	100.0%	100.0%		100.0%	0.0%
DISTRIBUTION	100.0%	90.1%	173.8%	91.6%	100.0%		100.1%	0.0%	100.0%		99.9%	724.1%
TOTAL	**100.0%**	**90.1%**	**173.8%**	**91.6%**	**100.0%**		**100.1%**	**0.0%**	**100.0%**		**99.9%**	**723.5%**
TOTAL INCL GAS COMMODITY	**100.0%**	**92.9%**	**138.8%**	**94.4%**	**100.0%**		**100.1%**	**0.0%**	**100.0%**		**100.0%**	**139.8%**
IMPLIED REVENUE INCREASE		**208.7%**	**312.2%**	**351.1%**	**1204.6%**		**333.9%**	**0.0%**	**316.6%**		**687.3%**	**3036.2%**
% RETURN ON RATE BASE	**8.7%**	**-7.4%**	**128.1%**	**-4.0%**	**8.7%**		**8.8%**	**0.0%**	**9.1%**		**8.6%**	**977.2%**

ANALYSIS OF FIXED COSTS

		RATE 1			RATE 2		RATE 3		RATE 4		RATE 5	RATE 6
	TOTAL	Residential	Commercial	Industrial	Apr - Oct	Nov - Mar	Firm	Interruptible	Apr - Dec	Jan - Mar	Interruptible	Firm
Customer Charge Revenue	1,134.0	1,062.7	67.1	4.2	7.7	5.5	7.0	0.0	3.1	1.0	9.0	1.8
Total Customer costs	7,359.7	6,792.5	437.7	129.4	568.9		70.5	0.0	176.7		88.2	70.5
% Customer Costs recovered	15.4%	15.6%	15.3%	3.3%	2.3%		9.9%	0.0%	2.3%		10.2%	2.6%
Demand Charge							309.7					1,040.9
Demand Costs	4,023.1	2,935.1	874.8	213.1	315.1		580.7	0.0	73.0		393.0	580.7
% Demand Costs recovered							53.3%					179.2%
Total Fixed Charges	1,134.0	1,062.7	67.1	4.2	7.7	5.5	316.7	0.0	3.1	1.0	9.0	1,042.7
Total Fixed Costs	11,382.7	9,727.6	1,312.5	342.6	884.1		651.2	0.0	249.7		481.2	651.2
% Total Fixed Costs recovered	10.0%	10.9%	5.1%	1.2%	1.5%		48.6%	0.0%	1.7%		1.9%	160.1%
through block 1	78.9%	79.7%	86.7%	26.2%	29.9%		56.5%	0.0%	64.2%		101.0%	600.2%
through block 2	13.5%	1.3%	90.1%	66.5%	69.6%				36.8%			
through block 3	0.0%	0.0%	0.0%	0.0%	0.0%				0.0%			
Total FIXED COST RECOVERY	102.4%	91.9%	181.9%	93.9%	101.0%		105.1%	0.0%	102.7%		102.9%	760.3%

Estimated Deficiency													
TOTAL REVENUE	18,932.1	11651.7	8942.1	2387.8	321.7	746.1	146.7	685.1	0.0	241.3	15.0	494.9	4951.3
Allocated Costs	18,931.1	11651.7	9925.6	1374.7	351.3	891.6		684.4	0.0	256.5		495.5	4951.4
R:C		100.00%	90.09%	173.70%	91.57%	100.13%		100.10%	-	99.96%		99.88%	100.00%

A Proposed Incentive Regulation Mechanism for Natural Resource Gas Limited

A Report Prepared by
John Todd, President
Elenchus Research Associates Inc.

On Behalf of
Natural Resource Gas Limited

January 2010

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1 INTRODUCTION

Natural Resource Gas Limited ("NRG") has asked Elenchus Research Associates Inc.[1] (ERA) to assist it in developing a multi-year incentive regulation mechanism ("IRM") that would be appropriate for NRG to adopt commencing in 2011.

The primary basis of the proposed IRM for NRG is the OEB's report on the Natural Gas Forum entitled "Natural Gas Regulation in Ontario: A Renewed Policy Framework" which is dated on March 30, 2005 ("NGF Report"). Although the Natural Gas Forum focussed on the two largest distributors of natural gas in Ontario, Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("Enbridge"), the general principles contained in the rate regulation section of the NGF Report appear to be as relevant to NRG as they are to Union and Enbridge. In particular, the identified concern "about perceived inefficiencies in the current ratemaking framework, such as a resource-intensive hearing process and weak incentives for utilities to perform efficiently" is at least equally relevant to NRG given its small customer and revenue base.

1.1 THE OEB'S NATURAL GAS FORUM

The Message from the Chair that introduces the NGF Report states:

> *This report outlines our vision for a regulatory framework for the sector and lays the groundwork for improved efficiency and effectiveness in the regulation of natural gas.*
>
> *The Board has regulated the natural gas sector for many years and has overseen the development of the competitive market. Although the gas market is functioning well in Ontario, there are improvements to the regulatory framework that are in the public interest.*
>
> *First, we believe that all stakeholders will benefit from a more predictable and longer-term treatment of rates. Utilities will benefit because they can make longer-term decisions and customers will benefit through downward pressure on rates. The Board's report identifies the specific components of the incentive regulation plan that the Board believes will lead to these results.*

Since the NGF Report was issued in 2005, both Union and Enbridge have operated under incentive regulation regimes that advance the principles approved by the OEB. As a result, NRG is able to draw not only on the guidance provided in the NGF Report but also on the negotiated settlements and OEB Decisions that developed regimes that were tailored to the specific circumstances of each utility in proposing an incentive regulation regime that is appropriate for the specific circumstance of NRG.

The OEB's vision of the rate regulation regime for natural gas utilities is set out at pages 14 through 36 of the NGF Report. A key conclusion of the Board on the regulatory framework appears at page 22.

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[1] The evidence was prepared by John Todd, President of ERA, whose curriculum vitae is available at www.era-inc.ca.

The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet its criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities – to the benefit of customers and shareholders. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario. The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan.

The NGF Report then identifies nine "key parameters of the ratemaking framework":

- *annual adjustment mechanism*
- *rebasing*
- *earnings sharing mechanism*
- *the term of the plan*
- *off-ramps, z-factors and deferral or variance accounts*
- *service quality monitoring*
- *financial reporting*
- *filing guidelines*
- *the role of alternative dispute resolutions*

Each of these key parameters is addressed in the NGF Report with Board Conclusions provided on each parameter. The NGF Report serves as the foundation for the proposed NRG IRM and this evidence parallels that report by addressing the way each key parameter is addressed in the NRGIRM.

The specifics of the annual adjustment mechanisms for Union and Enbridge were subsequently addressed through proceedings EB-2007-0606 (Union) and EB-2007-0615 (Enbridge), both of which resulted in settlement agreements that were approved by the Board. These settlement agreements have supplemented the NGF Report in forming the basis for the NRG IRM. By doing so, controversy related to the proposed the IRM should be minimized therefore controlling regulatory costs. The deviations from the schemes approved by the Board for Union and Enbridge are intended to simplify the IRM so as to avoid the need for expensive supporting studies (e.g., on productivity potential) and to streamline the annual reporting and rate adjustment processes.

1.2 UNIQUE CHARACTERISTICS OF NRG

In order to achieve the objectives of introducing an incentive regulation mechanism that were identified in the Message from the Chair in the NGF Report (quoted in part above), it is necessary to take into account certain unique characteristics of NRG, in the context of Ontario's three natural gas utilities that are actively regulated by the Ontario Energy Board. In particular, NRG operating scale is comparatively small, as can be seen from

Table 1, below. As a result, NRG revenue risk associated with the loss of customers is comparatively high and the value of minimizing regulatory costs is increased since the per-customer cost of similar regulatory activities is significantly higher.

Table1: Scale of Ontario Natural Gas Distributors

	NRG (2009)	Union (2008)	Enbridge (2008)
Customers	6,870	1,309,430	1,865,020
Rate Base ($ million)	14	3,348	3,779
Throughput ($10^6 m^3$)	53	13,843	11,908

1.3 RECOMMENDATION

The primary recommendation of this evidence is introduce a simplified version of the Union price cap index based IRM that relies on a fixed annual escalator rather than the price cap index being used by Union.

Adopting Union version of a price cap index without simplification would require an NRG-appropriate productivity factor to be determined. Based on the effort involved in conducting the analysis of appropriate productivity factors for Union and Enbridge it is reasonable to expect that conducting a similar exercise for NRG would not be a cost-effective way to establish a price cap index, in terms of the costs of the associated regulatory process.

2 THE PROPOSED NRG INCENTIVE REGULATION MECHANISM

This section outlines the proposed NRG IRM using a structure that parallels the nine key parameters identified in the NGF Report.

2.1 ANNUAL ADJUSTMENT MECHANISM

As the Board states in its conclusions pertaining to the annual adjustment mechanism,

> *In a multi-year IR plan, the annual adjustment mechanism embodies the combined assessment of cost changes and productivity improvements. Various methods can be used to evaluate these trends (inflation factors, industry productivity factors, and so on), and the resulting adjustment mechanism could be a complex formula or it could be a single factor, taking the form of an increase, a decrease or a rate freeze.*

In the subsequent implementation proceedings the parties agreed to a price cap index for Union (Union IRM Settlement Agreement, s. 1.2) and a Distribution Revenue Requirement per Customer Formula for Enbridge (Enbridge IRM Settlement Agreement, s. 1.2). The differences between the two approved approaches to establishing the annual adjustment mechanism presumably reflect the different circumstances and cost pressures facing the two companies.

In the case of NRG, the price cap approach would appear to be more straightforward and less controversial. Setting new rates based on the Distribution Revenue Requirement per Customer Formula is dependent on a forecast of the number of customers (to calculate the revenue requirement per customer) and volume throughput (to calculate the volumetric charge). Furthermore, a price cap offers greater price certainty for customers.

Perhaps the greatest challenge in adopting Union's price cap index design for NRG would be the determination of the appropriate productivity factor. The Union IRM Settlement Agreement set the X factor (productivity inclusive of any stretch factor) at 1.82% for the IR term, exclusive of the impact of changes in average use per customer in the general service rate class (Union IRM Settlement Agreement, s. 3.1). It is simply not practical to undertake a battle of the experts on the issue of reasonable productivity expectations for a distributor the size of NRG. For this reason, there is substantial merit in adopting a fixed price cap for NRG for the term of the IR that implicitly includes inflation, productivity, and the impact of declining use.

The Board Decisions pertaining to both the Union and Enbridge IRM Settlement Agreements indicated that the annual increase for the residential class was not expected to exceed 2% (Union, EB-2007-0606 Decision, p. 2; Enbridge, EB-2007-0615 Decision, p. 2). A simple and balanced approach to establishing a fixed annual adjustment rate would be to adopt an escalator that is below this 2% level. Establishing an "all-in" price cap escalator of 1.5% would provide reasonable price protection for customers while accommodating inflation, productivity and the impact of declining volumes. In adopting an all-in fixed escalator, NRG's rate increases will not reflect actual inflation rates or declining volume; hence, it will be exposed to higher risk than it would if these factors were determined annually and the price cap adjusted accordingly.

The parties to both the Union and Enbridge Settlement Agreements agreed that weather risk would remain with the distributor (s. 1.3 of the respective agreements). It would be appropriate for NRG to be consistent with those agreements that specified that there would be no change in the attribution of weather risk during the IR period.

2.2 REBASING

The Board's Conclusion in the NGF Report on this issue stated:

> *Each IR plan must begin with a robust set of cost-based rates, based on a thorough and transparent review. The Board's view is that a thorough cost-of-service rebasing must occur at the end of each IR plan's term before a new plan is put in place. Rebasing is an important consumer protection feature. Through robust rebasing, efficiency improvements will be revealed and their benefits passed on to customers through base rates for the next period. The Board will determine the base rates through a hearing for each utility.*

NRG's current application for the 2011 test year should serve as the rebasing that the Board expects to be undertaken to establish base rates for an IR period.

2.3 EARNINGS SHARING MECHANISM

The Board's Conclusion in the NGF Report on this issue stated:

> *The Board does not intend for earnings sharing mechanisms to form part of IR plans.*

Despite the view of the Board expressed in the NGF Report, the parties agreed to earnings sharing mechanisms in both the Union and Enbridge IRMs (s. 10 of each Settlement Agreement).

Given that regulatory costs are a far more significant concern for NRG than they are for either Union or Enbridge, the justification for including an earnings sharing mechanism in the design of the IRM is weaker in the case of NRG. Any earning sharing mechanism runs the risk of increasing controversy in relation to the annual IR rate adjustments; hence, the regulatory costs associated with a review of any earnings sharing calculation could encroach significantly on the earnings to be shared.

Nevertheless, it may be appropriate to include an earnings sharing mechanism that is consistent with the earnings sharing mechanism that was included in section 10 of the Union IRM Settlement Agreement (i.e., "50/50 sharing for earnings that exceed the ROE as determined by the Board's formula plus 200 basis points") in order to maintain consistency with the Union IRM, given that the proposed off-ramp relies on the same threshold (300 basis points) as the Union IRM and both adjust rates using a price cap variant.

2.4 THE TERM OF THE PLAN

The Board's Conclusion in the NGF Report on this issue stated:

> *The Board expects that the term of IR plans will be between three and five years. The Board's view is that three years represents the minimum term that may be expected to give rise to productivity incentives, and its preference is for a plan of five years. The Board is reluctant to approve a term greater than five years at this time, given the importance of ensuring that productivity gains are passed on to customers in subsequent periods. The term of the plan will be determined in the generic hearing on the annual adjustment mechanism.*

The parties to both the Union and Enbridge Settlement Agreements agreed that terms of the plans would be five years (s. 8 of the respective agreements). It would be appropriate for NRG to be consistent with those agreements that five years is an appropriate term for the IRM, possibly with the ability to extend the term by 2 years, a term that is included in section 8 of the Enbridge IRM Settlement Agreement.

2.5 OFF-RAMPS, Z-FACTORS AND DEFERRAL OR VARIANCE ACCOUNTS

The Board's Conclusion in the NGF Report on this issue stated:

> *In the Board's view, an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variance accounts, and reliance on off-ramps or Z-factors in limited, well-defined and well-justified cases only.*

This section addresses Y-factors as well as off-ramps and Z-factors.

2.5.1 OFF-RAMPS

The parties to both the Union and Enbridge Settlement Agreements agreed that "if there is a 300 basis point or greater variance in weather normalized utility earnings above or below the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, [the LDC} will file an application to the Board, with appropriate supporting evidence, for a review of the price cap mechanism."[2]

It would be appropriate for NRG to be consistent with those agreements and adopt a 300 basis point variance in weather normalized utility earnings above or below the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan as the off-ramp criterion. If the criterion is met during any year of the IR term NRG would file an application for a review of the price adjustment mechanism the following year.

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[2] The quote is from the Union IRM Settlement Agreement. The wording in the Enbridge IRM Settlement Agreement was slightly different:"The Parties agree that if, in any year of the IR Plan, there is a 300 basis point or greater variance in weather normalized utility earnings, above or below the amount calculated annually by the application of the ROE Formula, Enbridge shall file an application with the Board, with appropriate supporting evidence, for a review of the Adjustment Formula."

2.5.2 Z-FACTORS

The parties to both the Union and Enbridge Settlement Agreements agreed that certain Z-factors, consistent with the OEB's NGF Report would be recognized. Section 6 of each Settlement Agreement defined Z-factors as follows.

The Parties agree that Z factors generally have to meet the following criteria:

(i) the event must be causally related to an increase/decrease in cost;

(ii) the cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps;

(iii) the cost increase/decrease must not otherwise [be] reflected in the per customer revenue cap;

(iv) any cost increase must be prudently incurred; and

(v) the cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event).[3]

In addition, the agreements with respect to the Z-factor for each company included certain company-specific issues that would have required a deferral/variance account in the absence of a Z-factor.

It would be appropriate for NRG to define the Z-factor in a way that is consistent with the Union and Enbridge IRM Settlement Agreements, subject to an adjustment to the materiality threshold that reflects NRG's scale of operations.

As Table 1 above shows, NRG's operations are less than 1/2 of 1% of the scale of operations of Enbridge, based on a variety of measures. It therefore appears reasonable for NRG to adopt a materiality threshold of $50,000, which is 3.3% of the materiality threshold adopted by Enbridge and Union. Relative to their scale of operations, this threshold is 7 times the materiality of the Enbridge materiality threshold.

A factor that is unique to NRG that would be appropriate to identify explicitly as a Z-factor is the possible decommissioning costs associated with the IGPC ethanol plant, should it be shut down due to economic conditions. This factor is unique to NRG and is consistent with the general Z-factor criteria.

2.5.3 Y-FACTORS

The parties to both the Union and Enbridge Settlement Agreements agreed that upstream gas and transportation costs, among other factors, would be treated as Y-factors (section 5 of the respective agreements). The Enbridge IRM Settlement Agreement provides the clearest identification of the relevant costs that are relevant in the context of NRG's operations:

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[3] The quoted wording is from the Enbridge IRM Settlement Agreement. The wording in the Union IRM Settlement Agreement is not identical; however, the criteria are the same.

- upstream gas costs;
- upstream transportation, storage and supply mix costs; and
- changes in the embedded carrying cost of gas in storage and working cash related to changes to upstream gas, transportation and storage costs.

It would be appropriate for NRG to be consistent with those agreements by treating the identified upstream gas, transportation and storage costs as Y-factors.

2.6 SERVICE QUALITY MONITORING

The Board's Conclusion in the NGF Report on this issue stated:

> *The Board will develop the service quality framework, and will undertake a consultation to finalize the measures, standards and reporting mechanism. The Board expects to use its rule making tools to implement this framework.*

Service quality monitoring has been addressed outside of the IRM framework that was part of the Union and Enbridge IRM Settlement Agreements. This issue is therefore not addressed as part of the NRG IRM proposal on the expectation that service quality monitoring will be addressed in a similar fashion at NRG.

2.7 FINANCIAL REPORTING

The Board's Conclusion in the NGF Report on this issue stated:

> *The Board will consult with stakeholders and modify the Gas Reporting and Record Keeping Requirements (RRRs) as necessary to meet the requirements for financial reporting in the new ratemaking framework. While the Board intends to conduct this consultation and modify the RRRs before the development of the first IR plan, it expects that the RRRs may be further refined in the context of specific IR plan development.*

Both Union and Enbridge agreed to make their RRR filings available to intervenors (section 11 of the respective IRM Settlement Agreements). It is appropriate for NRG to make the same commitment. Given the importance of minimizing NRG's regulatory costs given its small scale, it would be appropriate to avoid any additional filing requirements.

2.8 FILING GUIDELINES

The Board's Conclusion in the NGF Report on this issue stated:

> *The Board will undertake a review of the gas utility data filing guidelines for rate hearing processes, and then develop a set of draft filing guidelines, which it will distribute for consultation. Wherever possible, the Board will seek to develop consistent guidelines for Union and Enbridge, and will consider issues such as electronic filings.*

Filing guidelines relate to both the annual rate adjustments under IRM and the end-of-term rebasing.

2.8.1 END-OF-TERM REBASING

The issue of filing guidelines was addressed in section 13 of the Union and Enbridge IRM Settlement Agreements in the context of the rebasing applications to be filed at the end of the IR term (or earlier in the event that the off-ramp is triggered, or later should there be an agreement to extend the term). The parties agreed that both Union and Enbridge would provide full historical plant continuity information from the previous rebasing application as well as three years of financial information (historic year actual, bridge year estimate and test year forecast).

It is appropriate for NRG to make the same commitment and that the rebasing evidence be similar to the cost-of-service application filed in this proceeding.

2.8.2 ANNUAL RATE ADJUSTMENTS

Section 12 of the Union and Enbridge IRM Settlement Agreements addressed issues related to the annual rate setting process during the IRM term. The Union IRM Settlement Agreement is the most appropriate model for NRG since Union's price cap index is similar to the fixed price escalator proposed for NRG. The Union IRM Settlement Agreement states in section 12.1.1

> *The parties agree that annual rate adjustments will be made in accordance with the following process:*
>
> 1. *Union will make application for Z factor adjustments, any structural rate design changes or the pricing of new regulated services in a time frame that will enable these issues to be resolved in sufficient time to be reflected prospectively in the next year's rates;*
> 2. *Union will file a draft rate order with supporting documentation by October 31 which reflects the impact of the PCI pricing formula, Y factors, Z factors, fixed monthly charge changes, and AU factor;*
> 3. *A final rate order will be issued by December 15 for implementation by January 1; and*
> 4. *As soon as reasonably possible following the public release of Union's annual audited financial statements, Union will make application (as it does now) for disposition of actual year end deferral account balances. (This would coincide with the filing of an annual earnings sharing calculation as described in section 11.1). It would be Union's intent to implement all rate adjustments associated with deferral account disposition at the time of its July 1 QRAM.*

Adapting this process to be consistent with NRG's rate year and proposed IRM, it would be appropriate for NRG's annual rate adjustments to be made in accordance with the following process:

1. NRG will make application for Z factor adjustments, any structural rate design changes or the pricing of new regulated services in a time frame that will enable these issues to be resolved in sufficient time to be reflected prospectively in the next year's rates;

2. NRG will file a draft rate order with supporting documentation by July 31 which reflects the impact of the fixed price escalator, Y factors, Z factors, and fixed monthly charge changes;
3. A final rate order will be issued by September 15 for implementation by October 1; and
4. As soon as reasonably possible following completion of NRG's annual audited financial statements, NRG will make application for disposition of actual year end deferral account balances.

Furthermore, consistent with the Union and Enbridge agreements, it would be appropriate for NRG to obtain OEB approval for any charges that are introduced for new services. In addition, it would be consistent for modest rate design changes to be permitted, such as the proposed increases to the fixed monthly charge that are similar to the increases implemented by Union and Enbridge, provided that there is no impact on the forecast revenue as a result of the rate design adjustments.

2.9 THE ROLE OF ALTERNATIVE DISPUTE RESOLUTIONS

The Board's Conclusion in the NGF Report on this issue stated:

> *The Board is mindful of the concerns stakeholders have expressed and the efforts they have made to propose improvements to the ADR process. The Board will not decide at this time the precise structure of the ADR process for the utility-specific IR plans. The Board has already undertaken a review of the ADR process, and it will consider the submissions made through the Natural Gas Forum before releasing its conclusions in the ADR review. The Board expects that the ADR process will evolve further in the process leading to the first IR applications.*

Given that the proposed NRG IRM is a simplified version of the Union and Enbridge IRMs detailed in their respective settlement agreements, it should be reasonable to expect the proposed NRG IRM to raise few, if any concerns, among stakeholders. It may therefore be realistic to review the proposed IRM without adding to the streamlined hearing process that is normally adopted for NRG applications. It is clearly desirable to avoid any unnecessary regulatory costs and that is a consideration in seeking to adopt a simplified version of the Union IRM that has been agreed to through a settlement process and approved by the OEB.

NATURAL RESOURCE GAS LIMITED

PROPOSED RATE SCHEDULE – 2011 TEST YEAR

RATE 1 - General Service Rate

Rate Availability
The entire service area of the Company.

Eligibility
All customers.

Rate

a)	Monthly Fixed Charge	$13.50
b)	Delivery Charge	
	First 1,000 m^3 per month	15.5753 cents per m^3
	All over 1,000 m^3 per month	11.1874 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A

Meter Readings
Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty
When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery
Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 2 - Seasonal Service

Rate Availability

The entire service area of the company.

Eligibility

All customers.

Rate

For all gas consumed from:		April 1 through October 31:	November 1 through March 31:
a)	Monthly Fixed Charge	\$15.00	\$15.00
b)	Delivery Charge		
	First 1,000 m^3 per month	14.3470 cents per m^3	18.3687 cents per m^3
	Next 24,000 m^3 per month	9.9370 cents per m^3	16.4498 cents per m^3
	All over 25,000 m^3 per month	6.4726 cents per m^3	16.0241 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar (\$1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 3 - Special Large Volume Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 113,000 m^3.

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00 for firm or interruptible customers; or
A Monthly Customer Charge of $175.00 for combined (firm and interruptible) customers.

b) A Monthly Demand Charge:

A Monthly Demand Charge of 26.9947 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 3.7310 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 10.9612 cents per m^3 and not to be less than 7.9412 per m^3.

d) Gas Supply Charge (if applicable)

See Schedule A.

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 3 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company=s suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;
b) The load factor of the customer's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.1530 cents per m^3 for firm gas and 5.4412 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the customer during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 5.7163 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 4 - General Service Peaking

Rate Availability

The entire service area of the company.

Eligibility

All customers whose operations, in the judgment of Natural Resource Gas Limited, can readily accept interruption and restoration of gas service with 24 hours notice.

Rate

For all gas consumed from:		April 1 through December 31:	January 1 through March 31:
a)	Monthly Fixed Charge	$15.00	$15.00
b)	Delivery Charge		
	First 1,000 m^3 per month	14.4482 cents per m^3	18.5629 cents per m^3
	All over 1,000 m^3 per month	10.3477 cents per m^3	16.6237 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 5 - Interruptible Peaking Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a daily contracted demand for interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 50,000 m^3 .

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00.

b) A Monthly Delivery Charge:

A Monthly Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 8.4612 cents per m^3 and not to be less than 5.4612 per m^3.

c) Gas Supply Charge (if applicable)

See Schedule A.

d) Overrun Gas Charge:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any applicable Gas Supply Charge.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company=s suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;

b) The load factor of the customer's anticipated gas consumption and the pattern of annual use and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;

c) Interruptible or curtailment provisions;

d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas of 50,000 m^3. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this annual minimum shall be 5.6702 cents per m^3 for interruptible gas.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 6 – Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility

Rate Availability
Entire service area of the company.

Eligibility
Integrated Grain Processors Co-Operative's ("IGPC") ethanol production facility located in the Town of Aylmer

Rate
1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00 for firm services

b) A Monthly Demand Charge:

A Monthly Demand Charge of 36.1848 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 3.7310 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and IGPC not to exceed 10.9612 cents per m^3 and not to be less than 7.9412 per m^3.

d) Gas Supply Charge (if applicable)

See Schedule A.

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, IGPC should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to IGPC on such day, or if, on any day, IGPC fails to comply with any curtailment notice reducing IGPC's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 6 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, IGPC shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company's suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which IGPC is willing to contract;
b) The load factor of IGPC's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which IGPC is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, IGPC shall take delivery from the company, or in any event pay for it if available and not accepted by the IGPC, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.1530 cents per m^3 for firm gas and 5.4412 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the IGPC during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 5.7163 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where IGPC elects under this rate schedule to directly purchase its gas from a supplier other than NRG, IGPC or its agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to IGPC if it elects said Bundled T transportation service.

Unless otherwise authorized by NRG, IGPC, when delivering gas to NRG under direct purchase arrangements, must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010
RP-2004-0167 / EB-2006-0037

NATURAL RESOURCE GAS LIMITED

SCHEDULE A – Gas Supply Charges

Rate Availability
Entire service area of the company.

Eligibility
All customers served under Rates 1, 2, 3, 4 and 5.

Rate
The Gas Supply Charge applicable to all sales customers shall be made up of the following charges:

PGCVA Reference Price	(EB-2009-0407)	29.4915 cents per m3
GPRA Recovery Rate	(EB-2009-0407)	(0.0332) cents per m3
System Gas Fee	(RP-2005-0544)	0.0348 cents per m3
Total Gas Supply Charge		29.4931 cents per m3

Note:
PGCVA means Purchased Gas Commodity Variance Account
GPRA means Gas Purchase Rebalancing Account

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE BT1 – Bundled Direct Purchase Contract Rate

Availability

Rate BT1 is available to all customers or their agent, who enter into a Receipt Contract for delivery of gas to NRG. The availability of this option is subject to NRG obtaining a satisfactory agreement or arrangement with Union Gas and NRG's gas supplier for direct purchase volume and DCQ offsets.

Eligibility

All customers electing to purchase gas directly from a supplier other than NRG must enter into a Bundled T-Service Receipt Contract with NRG either directly or through their agent, for delivery of gas to NRG at a mutually acceptable delivery point.

Rate

For gas delivered to NRG at any point other than the Ontario Point of Delivery, NRG will charge a customer or their agent, all approved tolls and charges incurred by NRG to transport the gas to the Ontario Point of Delivery.

Note:

Ontario Point of Delivery means Dawn or Parkway on the Union Gas System as agreed to by NRG and NRG's customer or their agent.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

ILLUSTRATIVE RATE SCHEDULE (SHORTER DEPRECIATION)

RATE 1 - General Service Rate

Rate Availability

The entire service area of the Company.

Eligibility

All customers.

Rate

a)	Monthly Fixed Charge	\$13.50
b)	Delivery Charge	
	First 1,000 m^3 per month	59.3013 cents per m^3
	All over 1,000 m^3 per month	50.5076 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar (\$1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 2 - Seasonal Service

Rate Availability

The entire service area of the company.

Eligibility

All customers.

Rate

For all gas consumed from:		April 1 through October 31:	November 1 through March 31:
a)	Monthly Fixed Charge	$15.00	$15.00
b)	Delivery Charge		
	First 1,000 m^3 per month	199.3750 cents per m^3	255.2660 cents per m^3
	Next 24,000 m^3 per month	138.0926 cents per m^3	228.5993 cents per m^3
	All over 25,000 m^3 per month	89.9484 cents per m^3	222.6840 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 3 - Special Large Volume Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 113,000 m^3.

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00 for firm or interruptible customers; or
A Monthly Customer Charge of $175.00 for combined (firm and interruptible) customers.

b) A Monthly Demand Charge:

A Monthly Demand Charge of 115.1568 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 16.7895 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 10.9612 cents per m^3 and not to be less than 7.9412 per m^3.

d) Gas Supply Charge (if applicable)

See Schedule A.

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 3 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company=s suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;
b) The load factor of the customer's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.1530 cents per m^3 for firm gas and 5.4412 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the customer during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 5.7163 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 4 - General Service Peaking

Rate Availability

The entire service area of the company.

Eligibility

All customers whose operations, in the judgment of Natural Resource Gas Limited, can readily accept interruption and restoration of gas service with 24 hours notice.

Rate

	For all gas consumed from:	April 1 through December 31:	January 1 through March 31:
a)	Monthly Fixed Charge	$15.00	$15.00
b)	Delivery Charge		
	First 1,000 m^3 per month	68.6380 cents per m^3	88.1828 cents per m^3
	All over 1,000 m^3 per month	49.1516 cents per m^3	78.9707 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 5 - Interruptible Peaking Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a daily contracted demand for interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 50,000 m^3 .

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00.

b) A Monthly Delivery Charge:

A Monthly Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 84.6120 cents per m^3 and not to be less than 45.4612 per m^3.

c) Gas Supply Charge (if applicable)

See Schedule A.

d) Overrun Gas Charge:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any applicable Gas Supply Charge.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company=s suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;

b) The load factor of the customer's anticipated gas consumption and the pattern of annual use and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;

c) Interruptible or curtailment provisions;

d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas of 50,000 m^3. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this annual minimum shall be 5.6702 cents per m^3 for interruptible gas.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE 6 – Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility

Rate Availability

Entire service area of the company.

Eligibility

Integrated Grain Processors Co-Operative's ("IGPC") ethanol production facility located in the Town of Aylmer

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00 for firm services

b) A Monthly Demand Charge:

A Monthly Demand Charge of 80.3539 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 11.7153 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and IGPC not to exceed 10.9612 cents per m^3 and not to be less than 7.9412 per m^3.

d) Gas Supply Charge (if applicable)

See Schedule A.

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, IGPC should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to IGPC on such day, or if, on any day, IGPC fails to comply with any curtailment notice reducing IGPC's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 6 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, IGPC shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company's suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which IGPC is willing to contract;
b) The load factor of IGPC's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which IGPC is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, IGPC shall take delivery from the company, or in any event pay for it if available and not accepted by the IGPC, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.1530 cents per m^3 for firm gas and 5.4412 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the IGPC during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 5.7163 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where IGPC elects under this rate schedule to directly purchase its gas from a supplier other than NRG, IGPC or its agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to IGPC if it elects said Bundled T transportation service.

Unless otherwise authorized by NRG, IGPC, when delivering gas to NRG under direct purchase arrangements, must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010
RP-2004-0167 / EB-2006-0037

NATURAL RESOURCE GAS LIMITED

SCHEDULE A – Gas Supply Charges

Rate Availability

Entire service area of the company.

Eligibility

All customers served under Rates 1, 2, 3, 4 and 5.

Rate

The Gas Supply Charge applicable to all sales customers shall be made up of the following charges:

PGCVA Reference Price	(EB-2009-0407)	29.4915 cents per m3
GPRA Recovery Rate	(EB-2009-0407)	(0.0332) cents per m3
System Gas Fee	(RP-2005-0544)	0.1828 cents per m3
Total Gas Supply Charge		29.6411 cents per m3

Note:
PGCVA means Purchased Gas Commodity Variance Account
GPRA means Gas Purchase Rebalancing Account

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

RATE BT1 – Bundled Direct Purchase Contract Rate

Availability

Rate BT1 is available to all customers or their agent, who enter into a Receipt Contract for delivery of gas to NRG. The availability of this option is subject to NRG obtaining a satisfactory agreement or arrangement with Union Gas and NRG's gas supplier for direct purchase volume and DCQ offsets.

Eligibility

All customers electing to purchase gas directly from a supplier other than NRG must enter into a Bundled T-Service Receipt Contract with NRG either directly or through their agent, for delivery of gas to NRG at a mutually acceptable delivery point.

Rate

For gas delivered to NRG at any point other than the Ontario Point of Delivery, NRG will charge a customer or their agent, all approved tolls and charges incurred by NRG to transport the gas to the Ontario Point of Delivery.

Note:

Ontario Point of Delivery means Dawn or Parkway on the Union Gas System as agreed to by NRG and NRG's customer or their agent.

Effective: October 01, 2010
Implementation: All bills rendered on or after October 01, 2010

NATURAL RESOURCE GAS LIMITED

Revenue Deficiency Recovery by Rate Class
2011 Test Year

Revenue Requirement		Current Revenues	Proposed Revenues	Change	Percent Change
Rate 1	Residential	2,898,012	3,097,379	199,368	6.9%
	Commercial	579,473	613,250	33,777	5.8%
	Industrial	71,348	75,904	4,556	6.4%
Rate 1	Total	3,548,834	3,786,534	237,700	6.7%
Rate 2		68,376	68,973	597	0.9%
Rate 3	Firm	157,877	163,016	5,139	3.3%
	Interruptible	503	0	-503	-100.0%
Rate 3	Total	158,380	163,016	4,636	2.9%
Rate 4		61,544	62,143	598	1.0%
Rate 5		62,891	71,806	8,916	14.2%
Rate 6		1,580,588	1,718,045	137,457	8.7%
Total		5,480,613	5,870,517	389,904	7.1%

NATURAL RESOURCE GAS LIMITED

Class Revenue Calculation - Rate 1
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Gas Throughput Volumes by Block - 10*3 m*3													
Residential													
Block 1	680.6	1,379.0	2,115.9	2,301.6	2,048.4	1,727.8	999.6	515.9	281.3	244.7	231.9	340.9	12,867.7
Block 2	12.5	25.3	38.8	42.2	37.5	31.7	18.3	9.5	5.2	4.5	4.3	6.2	235.9
Total	693.1	1,404.3	2,154.7	2,343.8	2,085.9	1,759.5	1,017.9	525.3	286.5	249.2	236.2	347.1	13,103.6
Commercial													
Block 1	101.4	199.8	310.4	345.2	306.4	253.4	135.7	70.8	39.8	38.5	34.7	50.9	1,887.0
Block 2	120.7	237.6	369.2	410.6	364.5	301.5	161.4	84.2	47.4	45.8	41.2	60.6	2,244.8
Total	222.1	437.4	679.6	755.8	670.9	554.9	297.1	155.0	87.2	84.3	75.9	111.5	4,131.8
Industrial													
Block 1	20.5	34.9	19.8	16.0	14.9	16.1	10.2	4.9	3.0	2.3	2.0	4.1	148.7
Block 2	59.6	101.3	57.6	46.4	43.4	46.7	29.6	14.4	8.6	6.7	6.0	12.1	432.3
Total	80.1	136.2	77.4	62.4	58.3	62.8	39.8	19.3	11.6	9.0	8.0	16.2	581.0
Customers													
Residential	6,489	6,513	6,518	6,544	6,550	6,563	6,577	6,581	6,594	6,595	6,596	6,599	
Commercial	414	414	414	414	414	414	414	414	414	414	414	414	
Industrial	26	26	26	26	26	26	26	26	26	26	26	26	
Revenues ('000's)													
Residential													
Current	180.0	288.5	402.6	431.7	392.5	343.1	230.4	155.6	119.4	113.7	111.8	128.7	2,898.0
Proposed	195.3	305.5	421.9	451.6	411.7	361.3	246.5	170.3	133.4	127.6	125.7	142.9	3,093.5
% Change													6.7%
Commercial													
Current	32.8	60.1	90.7	100.3	89.6	74.9	42.3	24.4	15.8	15.4	14.4	18.9	579.5
Proposed	35.0	63.5	95.5	105.6	94.3	79.0	44.9	26.1	17.1	16.7	15.6	20.3	613.6
% Change													5.9%
Industrial													
Current	9.6	16.2	9.3	7.6	7.1	7.6	4.9	2.5	1.6	1.3	1.2	2.2	71.3
Proposed	10.2	17.2	9.9	8.1	7.6	8.1	5.3	2.7	1.8	1.5	1.3	2.4	76.0
% Change													6.4%
Total Rate 1													
Current	222.5	364.7	502.6	539.6	489.2	425.6	277.7	182.5	136.8	130.5	127.4	149.7	3,548.8
Proposed	240.5	386.2	527.3	565.2	513.5	448.3	296.7	199.1	152.3	145.8	142.6	165.6	3,783.0
% Change													6.6%

Rates	Current Rates		Proposed Rates	
Customer Charge	$11.50	per month	$13.50	per month
Block 1	$0.152999	per m*3 first 1,000 m*3	$0.155753	per m*3 first 1,000 m*3
Block 2	$0.104073	per m*3 over 1,000 m*3	$0.111874	per m*3 over 1,000 m*3
Gas Commodity	$0.001828	per m*3	0.000348	per m*3

NATURAL RESOURCE GAS LIMITED

Class Revenue Calculation - Rate 2
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Gas Throughput Volumes by Block - 10*3 m*3													
Block 1	5.2	26.2	7.6	6.8	3.3	5.5	1.6	0.5	0.1	0.1	16.1	31.8	104.8
Block 2	37.1	0.0	0.0	0.0	0.0	0.0	11.2	3.5	0.7	0.8	115.9	228.9	398.1
Block 3	0.0	0.0	(0.0)	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0	(0.0)	0.0	0.0
Total	42.3	26.2	7.6	6.8	3.3	5.5	12.7	3.9	0.8	0.9	132.0	260.8	502.9
Customers	73	73	73	73	73	73	73	73	73	73	73	73	
Revenues ('000's)													
Current	5.5	5.5	2.3	2.1	1.5	1.9	2.3	1.4	1.0	1.0	15.1	28.9	68.4
Proposed	$5.50	$5.90	$2.50	$2.35	$1.70	$2.11	$2.43	$1.51	$1.18	$1.19	$14.97	$28.50	69.8
% Change													2.1%

Rates	Current Rates			Proposed Rates		
	Off Peak	Peak		Off Peak	Peak	
Customer Charge	$12.75	$12.75	per month	$15.00	$15.00	per month
Block 1	$0.145000	$0.185648	per m*3 first 1,000 m*3	$0.143470	$0.183687	per m*3 first 1,000 m*3
Block 2	$0.100431	$0.166254	per m*3 next 24,000 m*3	$0.099370	$0.164498	per m*3 next 24,000 m*3
Block 3	$0.065417	$0.161952	per m*3 over 25,000 m*3	$0.064726	$0.160241	per m*3 over 25,000 m*3
Gas Commodity	$0.001828	$0.001828	per m*3	$0.000348	$0.000348	per m*3

NATURAL RESOURCE GAS LIMITED

Class Revenue Calculation - Rate 3
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Gas Throughput Volumes - 10*3 m*3													
Firm	128.4	218.3	283.8	307.7	278.9	289.0	177.9	127.8	112.6	117.3	98.5	55.2	2,195.3
Interruptible	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	128.4	218.3	283.8	307.7	278.9	289.0	177.9	127.8	112.6	117.3	98.5	55.2	2,195.3
Firm Demand (m*3 per month)													
	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	22,650.0	
Customers	4	4	4	4	4	4	4	4	4	4	4	4	
Revenues ('000's)													
Current	11.2	14.5	17.0	17.9	16.8	17.2	13.0	11.1	10.6	10.7	10.0	8.4	158.4
Proposed	11.6	14.9	17.4	18.3	17.2	17.6	13.4	11.5	11.0	11.1	10.4	8.8	163.2
% Change													3.1%

Rates	Current Rates	Proposed Rates
Customer Charge	$150.00 per month	$150.00 per month
Demand Charge	$0.255904 per m*3 per month	$0.269947 per m*3 per month
Firm Delivery	$0.037310 per m*3	$0.037310 per m*3
Interruptible Delivery	$0.060992 per m*3	$0.092249 per m*3
Gas Commodity	$0.001828 per m*3	$0.000348 per m*3

NATURAL RESOURCE GAS LIMITED

Class Revenue Calculation - Rate 4
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Gas Throughput Volumes by Block - 10*3 m*3													
Block 1	72.6	80.0	20.0	8.0	5.2	4.1	1.6	0.7	0.2	5.9	11.0	41.1	250.3
Block 2	63.5	70.0	17.5	(0.0)	0.0	0.0	1.4	0.6	0.2	5.1	9.6	36.0	204.0
Total	136.1	150.0	37.5	8.0	5.2	4.1	3.1	1.3	0.4	11.0	20.6	77.0	454.3
Customers	23	23	23	23	23	23	23	23	23	23	23	23	
Revenues ('000's)													
Current	15.7	21.1	5.6	1.9	1.2	1.0	0.6	0.4	0.3	1.8	2.8	9.2	61.5
Proposed	17.5	19.2	5.1	1.8	1.3	1.1	0.7	0.5	0.4	1.7	2.9	10.0	62.3
% Change													1.2%

Rates	Current Rates			Proposed Rates		
	Off Peak	Peak		Off Peak	Peak	
Customer Charge	$12.75	$12.75	per month	$15.00	$15.00	per month
Block 1	$0.144501	$0.185648	per m*3 first 1,000 m*3	$0.144482	$0.185629	per m*3 first 1,000 m*3
Block 2	$0.103477	$0.166254	per m*3 all over 1,000 m*3	$0.103477	$0.166237	per m*3 all over 1,000 m*3
Gas Commodity	$0.001828	$0.001828	per m*3	$0.000348	$0.000348	per m*3

NATURAL RESOURCE GAS LIMITED

Class Revenue Calculation - Rate 5
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Gas Throughput Volumes - 10*3 m*3													
Total	300.2	530.3	68.4	7.6	5.1	1.8	0.4	0.1	0.0	20.7	11.3	1.4	947.2
Customers	5	5	5	5	5	5	5	5	5	5	5	5	
Revenues ('000's)													
Current	19.5	30.4	4.0	1.0	1.1	0.9	0.8	0.8	0.8	1.8	1.2	0.8	62.9
Proposed	20.7	35.9	5.3	1.3	1.1	0.9	0.8	0.8	0.8	2.1	1.5	0.8	71.8
% Change													14.2%

Rates	Current Rates		Proposed Rates	
Customer Charge	$150.00	per month	$150.00	per month
Delivery Commodity	$0.064122	per m*3	$0.065963	per m*3
Gas Commodity	$0.001828	per m*3	$0.000348	per m*3

NATURAL RESOURCE GAS LIMITED

Class Revenue Calculation - Rate 6
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total
Gas Throughput Volumes - 10*3 m*3													
Total	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	2,784.7	1,331,672.8
Firm Demand (m*3 per month)	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	108,188.0	
Customers	1	1	1	1	1	1	1	1	1	1	1	1	
Revenues ('000's)													
Current	131.7	131.7	131.7	131.7	131.7	131.7	131.7	131.7	131.7	131.7	131.7	131.7	1,580.6
Proposed	143.2	143.2	143.2	143.2	143.2	143.2	143.2	143.2	143.2	143.2	143.2	143.2	1,718.4
% Change													8.7%

Rates	Current Rates		Proposed Rates	
Customer Charge	$150.00	per month	$150.00	per month
Demand Charge	$0.255904	per m*3 per month	$0.361848	per m*3 per month
Delivery Commodity	$0.037310	per m*3	$0.037310	per m*3
Gas Commodity	$0.001828	per m*3	$0.000348	per m*3

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 1 Residential
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total	
M*3 per Customer - Current Block Structure														
Block 1	106.8	215.6	330.6	358.2	318.5	268.1	154.8	79.8	43.4	37.8	35.8	52.6	2,002.0	
Block 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Total	106.8	215.6	330.6	358.2	318.5	268.1	154.8	79.8	43.4	37.8	35.8	52.6	2,002.0	
EB-2005-0544 - October 2006														Charge
Customer	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	138.00	$11.50
Block 1	16.34	32.99	50.58	54.80	48.73	41.02	23.68	12.21	6.64	5.78	5.48	8.05	306.30	$0.152999
Block 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$0.104073
System Gas Charge	0.20	0.39	0.60	0.65	0.58	0.49	0.28	0.15	0.08	0.07	0.07	0.10	3.66	$0.001828
Total Bill	28.04	44.88	62.69	66.96	60.81	53.01	35.47	23.86	18.22	17.35	17.04	19.64	447.96	
EB-2010-0018 - October 2010 (Proposed)														Charge
Customer	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	162.00	$13.50
Block 1	16.63	33.58	51.49	55.79	49.61	41.76	24.11	12.43	6.76	5.89	5.58	8.19	311.82	$0.155753
Block 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$0.111874
System Gas Charge	0.04	0.07	0.11	0.12	0.11	0.09	0.05	0.03	0.02	0.01	0.01	0.02	0.70	$0.000348
Total Bill	30.17	47.16	65.11	69.42	63.22	55.35	37.66	25.96	20.27	19.40	19.09	21.71	474.51	
Percent Change													5.9%	

Note: System Gas Charge does not apply to direct purchase customers.

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 1 Commercial
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total	
M*3 per Customer - Current Block Structure														
Block 1	536.4	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	717.6	374.5	210.7	203.6	183.3	269.2	7,495.3	
Block 2	0.0	56.6	641.6	825.5	620.6	340.4	0.0	0.0	0.0	0.0	0.0	0.0	2,484.7	
Total	536.4	1,056.6	1,641.6	1,825.5	1,620.6	1,340.4	717.6	374.5	210.7	203.6	183.3	269.2	9,980.0	
EB-2005-0544 - October 2006														Charge
Customer	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	138.00	$11.50
Block 1	82.07	153.00	153.00	153.00	153.00	153.00	109.79	57.30	32.24	31.15	28.04	41.19	1,146.77	$0.152999
Block 2	0.00	5.89	66.77	85.91	64.59	35.43	0.00	0.00	0.00	0.00	0.00	0.00	258.59	$0.104073
System Gas Charge	0.98	1.93	3.00	3.34	2.96	2.45	1.31	0.68	0.39	0.37	0.34	0.49	18.24	$0.001828
Total Bill	94.55	172.32	234.27	253.75	232.05	202.38	122.60	69.48	44.12	43.02	39.88	53.18	1,561.60	
EB-2010-0018 - October 2010 (Proposed)														Charge
Customer	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	162.00	$13.50
Block 1	83.55	155.75	155.75	155.75	155.75	155.75	111.77	58.33	32.82	31.71	28.55	41.93	1,167.42	$0.155753
Block 2	0.00	6.33	71.78	92.35	69.43	38.08	0.00	0.00	0.00	0.00	0.00	0.00	277.97	$0.111874
System Gas Charge	0.19	0.37	0.57	0.63	0.56	0.47	0.25	0.13	0.07	0.07	0.06	0.09	3.47	$0.000348
Total Bill	97.23	175.95	241.60	262.24	239.25	207.80	125.52	71.96	46.39	45.28	42.11	55.52	1,610.86	
Percent Change													3.2%	

Note: System Gas Charge does not apply to direct purchase customers.

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 1 Industrial
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total	
M*3 per Customer - Current Block Structure														
Block 1	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	741.1	445.1	345.7	307.7	623.2	9,462.9	
Block 2	2,080.4	4,238.7	1,978.0	1,401.1	1,241.5	1,414.4	529.1	0.0	0.0	0.0	0.0	0.0	12,883.2	
Total	3,080.4	5,238.7	2,978.0	2,401.1	2,241.5	2,414.4	1,529.1	741.1	445.1	345.7	307.7	623.2	22,346.1	
EB-2005-0544 - October 2006														Charge
Customer	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	138.00	$11.50
Block 1	153.00	153.00	153.00	153.00	153.00	153.00	153.00	113.39	68.10	52.89	47.08	95.36	1,447.81	$0.152999
Block 2	216.52	441.13	205.86	145.81	129.21	147.20	55.07	0.00	0.00	0.00	0.00	0.00	1,340.79	$0.104073
System Gas Charge	5.63	9.57	5.44	4.39	4.10	4.41	2.79	1.35	0.81	0.63	0.56	1.14	40.84	$0.001828
Total Bill	386.64	615.21	375.80	314.70	297.81	316.11	222.36	126.24	80.41	65.02	59.14	107.99	2,967.44	
EB-2010-0018 - October 2010 (Proposed)														Charge
Customer	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	162.00	$13.50
Block 1	155.75	155.75	155.75	155.75	155.75	155.75	155.75	115.43	69.32	53.84	47.93	97.07	1,473.87	$0.155753
Block 2	232.75	474.20	221.29	156.74	138.90	158.23	59.20	0.00	0.00	0.00	0.00	0.00	1,441.30	$0.111874
System Gas Charge	1.07	1.82	1.04	0.84	0.78	0.84	0.53	0.26	0.15	0.12	0.11	0.22	7.77	$0.000348
Total Bill	403.07	645.28	391.57	326.83	308.93	328.32	228.98	129.19	82.98	67.46	61.54	110.79	3,084.94	
Percent Change													4.0%	

Note: System Gas Charge does not apply to direct purchase customers.

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 2 Seasonal
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total		
M*3 per Customer - Current Block Structure															
Block 1	579.4	358.6	104.7	93.4	45.2	75.7	174.5	53.9	11.1	12.3	1,000.0	1,000.0	3,508.8		
Block 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	807.9	2,571.9	3,379.8		
Block 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Total	579.4	358.6	104.7	93.4	45.2	75.7	174.5	53.9	11.1	12.3	1,807.9	3,571.9	6,888.6		
EB-2005-0544 - October 2006														Summer	Winter
Customer	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	153.00	$12.75	$12.75
Block 1	84.01	66.57	19.44	17.34	8.39	14.05	25.30	7.82	1.61	1.78	145.00	145.00	536.32	$0.145000	$0.185648
Block 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	81.14	258.30	339.44	$0.100431	$0.166254
Block 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$0.065417	$0.161952
System Gas Charge	1.06	0.66	0.19	0.17	0.08	0.14	0.32	0.10	0.02	0.02	3.30	6.53	12.59	$0.001828	$0.001828
Total Bill	97.82	79.98	32.38	30.26	21.22	26.94	38.37	20.66	14.38	14.56	242.19	422.58	1,041.35		
EB-2010-0018 - October 2010 (Proposed)														Summer	Winter
Customer	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	180.00	$15.00	$15.00
Block 1	83.13	65.87	19.23	17.16	8.30	13.91	25.04	7.73	1.59	1.76	143.47	143.47	530.66	$0.143470	$0.183687
Block 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.28	255.57	335.85	$0.099370	$0.164498
Block 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$0.064726	$0.160241
System Gas Charge	0.20	0.12	0.04	0.03	0.02	0.03	0.06	0.02	0.00	0.00	0.63	1.24	2.40	$0.000348	$0.000348
Total Bill	98.33	80.99	34.27	32.19	23.32	28.93	40.10	22.75	16.60	16.77	239.38	415.28	1,048.91		
Percent Change													0.7%		

Note: System Gas Charge does not apply to direct purchase customers.

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 3 Firm
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total	
M*3 per Customer														
Total	32,087.6	54,577.1	70,954.2	76,923.1	69,720.6	72,247.3	44,466.8	31,940.2	28,147.6	29,318.5	24,631.3	13,810.5	548,824.8	
Firm CD	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5	5,662.5		
EB-2005-0544 - October 2006														Charge
Customer	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	$150.00
Demand	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	1,449.06	17,388.68	$0.255904
Delivery	1,197.18	2,036.25	2,647.27	2,869.97	2,601.25	2,695.51	1,659.04	1,191.67	1,050.18	1,093.86	918.98	515.26	20,476.41	$0.037310
System Gas Charge	58.65	99.75	129.68	140.59	127.43	132.04	81.27	58.38	51.44	53.58	45.02	25.24	1,003.08	$0.001828
Total Bill	2,854.88	3,735.05	4,376.01	4,609.61	4,327.73	4,426.61	3,339.36	2,849.11	2,700.68	2,746.50	2,563.06	2,139.56	40,668.16	
EB-2010-0018 - October 2010 (Proposed)														Charge
Customer	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	$150.00
Demand	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	1,528.57	18,342.88	$0.269947
Delivery	1,197.19	2,036.27	2,647.30	2,870.00	2,601.28	2,695.55	1,659.06	1,191.69	1,050.19	1,093.87	918.99	515.27	20,476.65	$0.037310
System Gas Charge	11.16	18.98	24.68	26.75	24.25	25.13	15.47	11.11	9.79	10.20	8.57	4.80	190.88	$0.000348
Total Bill	2,886.92	3,733.83	4,350.55	4,575.33	4,304.10	4,399.25	3,353.09	2,881.37	2,738.55	2,782.64	2,606.13	2,198.65	40,810.41	
Percent Change													0.3%	

Note: System Gas Charge does not apply to direct purchase customers.

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 4
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total		
M*3 per Customer - Current Block Structure															
Block 1	1,000.0	1,000.0	1,000.0	349.8	225.1	179.0	133.3	55.0	17.6	479.2	894.7	1,000.0	6,333.6		
Block 2	4,917.9	5,520.8	629.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,348.7	13,417.0		
Total	5,917.9	6,520.8	1,629.7	349.8	225.1	179.0	133.3	55.0	17.6	479.2	894.7	3,348.7	19,750.6		
EB-2005-0544 - October 2006														Summer	Winter
Customer	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	12.75	153.00	$12.75	$12.75
Block 1	144.50	144.50	144.50	64.93	41.78	33.23	19.26	7.95	2.54	69.24	129.28	144.50	946.23	$0.144501	$0.185648
Block 2	508.89	571.27	65.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	243.04	1,388.35	$0.103477	$0.166254
System Gas Charge	10.82	11.92	2.98	0.64	0.41	0.33	0.24	0.10	0.03	0.88	1.64	6.12	36.10	$0.001828	$0.001828
Total Bill	676.95	740.44	225.38	78.32	54.94	46.31	32.26	20.80	15.32	82.86	143.67	406.41	2,523.67		
EB-2010-0018 - October 2010 (Proposed)														Summer	Winter
Customer	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	180.00	$15.00	$15.00
Block 1	144.48	144.48	144.48	64.93	41.78	33.23	19.26	7.95	2.54	69.23	129.27	144.48	946.11	$0.144482	$0.185629
Block 2	508.89	571.27	65.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	243.04	1,388.35	$0.103477	$0.166237
System Gas Charge	2.06	2.27	0.57	0.12	0.08	0.06	0.05	0.02	0.01	0.17	0.31	1.16	6.87	$0.000348	$0.000348
Total Bill	670.43	733.02	225.20	80.05	56.86	48.29	34.31	22.96	17.55	84.40	144.58	403.68	2,521.33		
Percent Change													-0.1%		

Note: System Gas Charge does not apply to direct purchase customers.

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 5
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total	
M*3 per Customer														
Total	60,042.0	106,051.8	13,676.3	1,510.8	1,010.6	361.6	74.4	25.6	2.2	4,143.7	2,256.4	276.9	189,432.3	
EB-2005-0544 - October 2006														Charge
Customer	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	$150.00
Delivery	3,786.33	6,687.78	862.45	95.27	63.73	22.80	4.69	1.61	0.14	261.31	142.29	17.46	11,945.87	$0.063061
System Gas Charge	109.74	193.83	25.00	2.76	1.85	0.66	0.14	0.05	0.00	7.57	4.12	0.51	346.22	$0.001828
Total Bill	4,046.07	7,031.60	1,037.44	248.03	215.58	173.46	154.83	151.66	150.15	418.88	296.41	167.97	14,092.09	
EB-2010-0018 - October 2010 (Proposed)														Charge
Customer	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	$150.00
Delivery	3,960.55	6,995.49	902.13	99.65	66.66	23.85	4.91	1.69	0.15	273.33	148.84	18.27	12,495.51	$0.065963
System Gas Charge	20.88	36.88	4.76	0.53	0.35	0.13	0.03	0.01	0.00	1.44	0.78	0.10	65.88	$0.000348
Total Bill	4,131.43	7,182.38	1,056.89	250.18	217.02	173.98	154.93	151.69	150.15	424.77	299.62	168.36	14,361.40	
Percent Change													1.9%	

Note: System Gas Charge does not apply to direct purchase customers.

NATURAL RESOURCE GAS LIMITED

Typical Bill Comparisons - Rate 6
2011 Test Year

	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Total	
M*3 per Customer														
Total	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	2,784,734.7	33,416,816.0	
Firm CD	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0	108,118.0		
EB-2005-0544 - October 2006														Charge
Customer	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	$150.00
Demand	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	27,667.83	332,013.94	$0.255904
Delivery	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	1,246,766.37	$0.037310
System Gas Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$0.000000
Total Bill	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	131,715.03	1,580,580.31	
EB-2010-0018 - October 2010 (Proposed)														Charge
Customer	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	$150.00
Demand	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	39,122.31	469,467.72	$0.361848
Delivery	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	103,897.20	1,246,766.37	$0.037310
System Gas Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	$0.000000
Total Bill	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	143,169.51	1,718,034.08	
Percent Change													8.7%	

Note: System Gas Charge does not apply to direct purchase customers.

APPENDIX "A" TO

DECISION AND ORDER

BOARD FILE NO. EB-2010-0049

DATED March 16, 2010

NATURAL RESOURCE GAS LIMITED

RATE 1 - General Service Rate

Rate Availability

The entire service area of the Company.

Eligibility

All customers.

Rate

a)	Monthly Fixed Charge	$11.50
b)	Delivery Charge First 1,000 m^3 per month All over 1,000 m^3 per month	 15.2999 cents per m^3 10.4073 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: April 01, 2010
Implementation: All bills rendered on or after April 01, 2010
EB-2010-0049

NATURAL RESOURCE GAS LIMITED

RATE 2 - Seasonal Service

Rate Availability
The entire service area of the company.

Eligibility
All customers.

Rate

For all gas consumed from:		April 1 through October 31:	November 1 through March 31:
a)	Monthly Fixed Charge	$12.75	$12.75
b)	Delivery Charge		
	First 1,000 m^3 per month	14.5000 cents per m^3	18.5648 cents per m^3
	Next 24,000 m^3 per month	10.0431 cents per m^3	16.6254 cents per m^3
	All over 25,000 m^3 per month	6.5417 cents per m^3	16.1952 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A	Schedule A

Meter Readings
Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty
When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery
Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: April 01, 2010
Implementation: All bills rendered on or after April 01, 2010
EB-2010-0049

NATURAL RESOURCE GAS LIMITED

RATE 3 - Special Large Volume Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 113,000 m^3.

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00 for firm or interruptible customers; or
A Monthly Customer Charge of $175.00 for combined (firm and interruptible) customers.

b) A Monthly Demand Charge:

A Monthly Demand Charge of 25.5904 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 3.7310 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 9.2249 cents per m^3 and not to be less than 6.0992 per m^3.

d) Gas Supply Charge (if applicable)

See Schedule A.

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 3 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company's suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;
b) The load factor of the customer's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.3853 cents per m^3 for firm gas and 5.7536 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the customer during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 6.3515 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: April 01, 2010
Implementation: All bills rendered on or after April 01, 2010
EB-2010-0049

NATURAL RESOURCE GAS LIMITED

RATE 4 - General Service Peaking

Rate Availability

The entire service area of the company.

Eligibility

All customers whose operations, in the judgment of Natural Resource Gas Limited, can readily accept interruption and restoration of gas service with 24 hours notice.

Rate

For all gas consumed from:		April 1 through December 31:	January 1 through March 31:
a)	Monthly Fixed Charge	$12.75	$12.75
b)	Delivery Charge		
	First 1,000 m^3 per month	14.4501 cents per m^3	18.5648 cents per m^3
	All over 1,000 m^3 per month	10.3477 cents per m^3	16.6254 cents per m^3
c)	Gas Supply Charge (if applicable)	Schedule A	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: April 01, 2010
Implementation: All bills rendered on or after April 01, 2010
EB-2010-0049

NATURAL RESOURCE GAS LIMITED

RATE 5 - Interruptible Peaking Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a daily contracted demand for interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 50,000 m^3 .

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00.

b) A Monthly Delivery Charge:

A Monthly Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 8.8345 cents per m^3 and not to be less than 5.7192 per m^3.

c) Gas Supply Charge (if applicable)

See Schedule A.

d) Overrun Gas Charge:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any applicable Gas Supply Charge.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company=s suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;

b) The load factor of the customer's anticipated gas consumption and the pattern of annual use and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;

c) Interruptible or curtailment provisions;

d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas of 50,000 m^3. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this annual minimum shall be 5.9604 cents per m^3 for interruptible gas.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

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NATURAL RESOURCE GAS LIMITED

SCHEDULE A – Gas Supply Charges

Rate Availability

Entire service area of the company.

Eligibility

All customers served under Rates 1, 2, 3, 4 and 5.

Rate

The Gas Supply Charge applicable to all sales customers shall be made up of the following charges:

PGCVA Reference Price	(EB-2010-0049)	30.7476 cents per m3
GPRA Recovery Rate	(EB-2010-0049)	0.3407 cents per m3
System Gas Fee	(EB-2005-0544)	0.1828 cents per m3
Total Gas Supply Charge		31.2711 cents per m3

Note:
PGCVA means Purchased Gas Commodity Variance Account
GPRA means Gas Purchase Rebalancing Account

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NATURAL RESOURCE GAS LIMITED

RATE BT1 – Bundled Direct Purchase Contract Rate

Availability

Rate BT1 is available to all customers or their agent, who enter into a Receipt Contract for delivery of gas to NRG. The availability of this option is subject to NRG obtaining a satisfactory agreement or arrangement with Union Gas and NRG's gas supplier for direct purchase volume and DCQ offsets.

Eligibility

All customers electing to purchase gas directly from a supplier other than NRG must enter into a Bundled T-Service Receipt Contract with NRG either directly or through their agent, for delivery of gas to NRG at a mutually acceptable delivery point.

Rate

For gas delivered to NRG at any point other than the Ontario Point of Delivery, NRG will charge a customer or their agent, all approved tolls and charges incurred by NRG to transport the gas to the Ontario Point of Delivery.

Note:

Ontario Point of Delivery means Dawn or Parkway on the Union Gas System as agreed to by NRG and NRG's customer or their agent.

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