CAR-NGTL-001(a)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1.5 – Commercial and Regulatory, Customer Service pg. 14 of 27

Preamble:

Lines 23 – 26 NGTL states "Costs are also increasing as a result of new, complex and manually intensive services plus increased workload to determine risk exposure with respect to customer credit worthiness, in relation to recent high profile bankruptcies in the energy sector."

Request:

Please describe in detail the new, complex and manually intensive services.

Response:

FT-P service was implemented in 2003 on the Alberta System. The service has unique characteristics, such as daily balancing and month-end tolling provisions, that are not wholly compatible with NGTL's existing transportation systems and processes.

The following tasks require increased effort to administer FT-P contracts:

- review financial assurances and creditworthiness
  - obtain additional financial assurances, if necessary
- generate contract
- store contract information in spreadsheet
  - customer name, contacts, address
  - receipt stations
  - pricing
  - contractual quantities
- set up FT-P account in GSAM
- nominations
  - uses existing NrG and GSAM systems

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- inventory balancing
  - manual process to zero each FT-P account each day by transferring imbalance to parent (guarantor) account using NITS process
- FT-P allocations
  - using existing allocation procedures and systems
- Generate invoice
  - enter allocation information into contract spreadsheet
  - use spreadsheet to determine invoice amount
  - manually enter amount into invoice system
  - review/verify

CAR-NGTL-001(b)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1.5 – Commercial and Regulatory, Customer Service pg. 14 of 27

Preamble:

Lines 23 – 26 NGTL states "Costs are also increasing as a result of new, complex and manually intensive services plus increased workload to determine risk exposure with respect to customer credit worthiness, in relation to recent high profile bankruptcies in the energy sector."

Request:

Please describe in detail the increased workload to NGTL.

Response:

There are three main factors that influence workload in the risk exposure area. The first factor is the number of contract transactions, such as assignments and transfers of existing contracts, which could increase financial exposure with a particular customer. In the first ten months of 2003, NGTL processed an average of 482 assignments per month. That represents a 41% increase over 2002 levels. NGTL also processed an average of 1127 transfers per month over the same period in 2003, an increase of 16% over 2002 levels.

The second factor is the number of new contracts and new types of contracts. As noted in NGTL's response to CAR-NGTL-001 (a), FT-P service was recently introduced on the Alberta System. This has resulted in additional contracts which require determination of financial exposure. Implementation of FT-A tolls for intra-Alberta deliveries has also resulted in additional exposures for certain shippers and the requirement for NGTL to update shipper exposure calculations.

The third factor is the overall financial health of individual shippers on the Alberta System. NGTL gathers information from credit rating agencies and other sources in order

CAR-NGTL-001(b)

to keep abreast of any risk concerns. As concerns arise, NGTL will perform a thorough review of exposures under Alberta System contracts. The bankruptcy of a single major shipper, can negatively impact other shippers due to gas purchase and sales arrangements. This could increase risk concerns and necessitate further reviews of risk exposures.

CAR-NGTL-002(a)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1.8 – General Expenses, Incentive Compensation, pg 23 of 27

Preamble:

Lines 21 – 25 Discussion of increasing IC costs, NGTL states "This increase is partially due to market alignment on one employee group's compensation and due to incomplete data gathering for the IC accrual process in 2002, resulting in an under-accrual."

Request:

Please identify which employee group requires the market alignment.

Response:

A review of total compensation was completed for the Fixed Rate (Field) employee group in 2001. This review resulted in the market alignment of this group in 2002 and is already reflected in the 2003 IC forecast costs.

TCPL continually monitors all components of Total Direct Compensation (TDC) for all employee groups and adjusts the compensation of any group that is out of alignment with the defined competitive compensation market, the comparator group. TCPL's TDC programs are in place to attract, motivate, and retain employees with the knowledge and experience required to operate its business in a safe, reliable, and efficient manner. In order to compete for these employees, TCPL must provide a market competitive TDC package.

CAR-NGTL-002(b)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1.8 – General Expenses, Incentive Compensation, pg 23 of 27

Preamble:

Lines 21 – 25 Discussion of increasing IC costs, NGTL states "This increase is partially due to market alignment on one employee group's compensation and due to incomplete data gathering for the IC accrual process in 2002, resulting in an under-accrual."

Request:

Please identify what portion of the $3.4 million increase is due to the under-accrual.

Response:

The 2002 under accrual applicable to NGTL was approximately $0.9 million.

CAR-NGTL-003(a)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1.8 – General Expenses, Long Term Incentive Compensation, pg. 24 of 27

Preamble:

Lines 14 – 16 NGTL states "Approximately $1.2 million of this increase is due to the continued implementation of the share unit program for management and executives."

Request:

Please explain how the share unit program works.

Response:

Please refer to the response to CAPP-NGTL-008(a).

CAR-NGTL-003(b)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1.8 – General Expenses, Long Term Incentive Compensation, pg. 24 of 27

Preamble:

Lines 14 – 16 NGTL states "Approximately $1.2 million of this increase is due to the continued implementation of the share unit program for management and executives."

Request:

Please explain how the continued implementation of this program causes the $1.2 million cost increase.

Response:

Under the TransCanada ESU Plan, certain individuals are eligible for an annual grant of a certain number of units, which will vest over a three year cycle. The first annual grant under this program was made in February 2003.

The $1.2 million increase is due to the second annual grant that is anticipated in February 2004.

CAR-NGTL-004(a)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1, Long Term Incentive Compensation, pg. 24 of 27

Preamble:

Lines 14 - 20 NGTL states that there was a $2.4 million increase to Long Term Incentive Compensation in 2003 attributable to the implementation of a share unit program for management and executive, and an increase in PUP expenses attributable to an increase in the total number of vested units and related dividends. NGTL then discusses the Long Term Incentive Compensation costs for 2004, and breaks out the $2.4 million increase into various categories (i.e. continued implementation of the share unit program, PUP expense increases in RSUs and stock option expense).

Request:

Please provide the split for ‘implementation of share unit program’ and PUP expense for 2003.

Response:

Please refer to the response to CAR-NGTL-007(a).

CAR-NGTL-004(b)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1, Long Term Incentive Compensation, pg. 24 of 27

Preamble:

Lines 14 - 20 NGTL states that there was a $2.4 million increase to Long Term Incentive Compensation in 2003 attributable to the implementation of a share unit program for management and executive, and an increase in PUP expenses attributable to an increase in the total number of vested units and related dividends. NGTL then discusses the Long Term Incentive Compensation costs for 2004, and breaks out the $2.4 million increase into various categories (i.e. continued implementation of the share unit program, PUP expense increases in RSUs and stock option expense).

Request:

Please provide the total cost for 2003 and 2004 for the 'implementation of the share unit program'.

Response:

Please refer to the response to CAR-NGTL-007(a).

CAR-NGTL-004(c)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1, Long Term Incentive Compensation, pg. 24 of 27

Preamble:

Lines 14 - 20 NGTL states that there was a $2.4 million increase to Long Term Incentive Compensation in 2003 attributable to the implementation of a share unit program for management and executive, and an increase in PUP expenses attributable to an increase in the total number of vested units and related dividends. NGTL then discusses the Long Term Incentive Compensation costs for 2004, and breaks out the $2.4 million increase into various categories (i.e. continued implementation of the share unit program, PUP expense increases in RSUs and stock option expense).

Request:

What is the forecasted share price and how is it factored into the PUP expense?

Response:

Forecasted share price is not a factor in determining the PUP expense.

CAR-NGTL-004(d)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1, Long Term Incentive Compensation, pg. 24 of 27

Preamble:

Lines 14 - 20 NGTL states that there was a $2.4 million increase to Long Term Incentive Compensation in 2003 attributable to the implementation of a share unit program for management and executive, and an increase in PUP expenses attributable to an increase in the total number of vested units and related dividends. NGTL then discusses the Long Term Incentive Compensation costs for 2004, and breaks out the $2.4 million increase into various categories (i.e. continued implementation of the share unit program, PUP expense increases in RSUs and stock option expense).

Request:

With respect to the stock option expense, to which employee group are additional units being granted and what is the valuation applied?

Response:

Stock options are granted to executive officers, as well as certain key employees. The company uses the Black-Scholes model for valuation purposes.

CAR-NGTL-005(a)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1, Pension and Benefit Adjustment, pg. 27 of 27

Preamble:

Line 1 – 3 NGTL states that the increase of $7.5 million in 2003 is due to higher pension expense and the consolidation of all employees into the defined benefit pension plan.

Request:

Please clarify the cost associated with the consolidation of all employees into the defined benefit pension plan.

Response:

Please refer to the response to CAPP-NGTL-030(a).

CAR-NGTL-005(b)

Issue:

Revenue Requirement, Operating Costs

Reference:

Section 2.3.1, Pension and Benefit Adjustment, pg. 27 of 27

Preamble:

Line 1 – 3 NGTL states that the increase of $7.5 million in 2003 is due to higher pension expense and the consolidation of all employees into the defined benefit pension plan.

Request:

Please clarify whether or not any costs associated with the consolidation have been carrired [sic] forward into 2004. If yes, please specify the costs.

Response:

The 2004 Pension and Benefit Adjustment account includes $1.2 million of past service cost amortization related to the consolidation of all employees into the Defined Benefit (DB) pension plan. This amount is calculated based on the funding deficiency transferred from the Defined Contribution (DC) Plan to the DB Plan as at January 1, 2003, which has been amortized over the employees' expected remaining service lives.

TCPL made a decision to consolidate the DC Plan into the DB Plan effective January 1, 2003. The decision was based on considerations such as adequate retirement income for long term employees, employee retention of its skilled and experienced workforce, and attraction of new employees. Further, continuation of the DC plan would have become more expensive for toll payers as the contribution rates for the DC plan would likely have been increased to make the plan competitive. NGTL believes that these actions were reasonable and prudent and, as such, its share of the resulting costs should be recoverable through its rates.

CAR-NGTL-006(a)

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs pg. 11 of 15

Preamble:

Line 14 – 15 NGTL states that TCPL's long-term incentive plans have evolved to remain competitive with the market, to meet changing business conditions, and to align with and support business strategies.

Request:

Please provide all studies and work papers that specifies changing business conditions that has caused TCPL's Long Term Incentive Plan to evolve?

Response:

Business conditions that have contributed to and caused change to all of the current TDC components include, but are not limited to:

- Ability to compete with other organizations to attract and retain employees with the skills necessary to operate in a safe, reliable, and efficient manner.
- Harmonizing to one set of total direct compensation programs after the merger of NOVA Corporation and TCPL.
- Change in business strategy.
- Integration of functional services into one company maximizes operational efficiencies and eliminates duplication of costs; long-term incentive compensation focuses employees on sustaining these operational efficiencies.
- Focus on long-term success for TCPL's core businesses necessitates the ability to reward sustained performance over a longer period of time.
- Senior management desire to focus employee attention on longer-term company results and for employees to become shareholders in the company.

CAR-NGTL-006(a)

As described above, the company has changed dramatically since the 1995 GRA. The company had to align its Total Direct Compensation (TDC) to remain competitive with the defined competitive compensation market and to provide balanced rewards to its employees for achieving both short-term business objective and sustaining long-term business objectives.

TCPL will not provide working papers related to compensation programs. They are often either draft or otherwise incomplete documents, which seldom indicate the context and purpose for which they were prepared, and as a result can be misleading. They often do not reflect TCPL's considered view, are typically voluminous in nature, and in many cases contain confidential and proprietary information. The evidentiary value of the requested information would be in any event far outweighed by the time and effort required to locate, compile, review and determine the produceability of the material.

CAR-NGTL-006(b)

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs pg. 11 of 15

Preamble:

Line 14 – 15 NGTL states that TCPL's long-term incentive plans have evolved to remain competitive with the market, to meet changing business conditions, and to align with and support business strategies.

Request:

Please provide all work papers and studies that specifies the NGTL business strategies supported by Long Term Incentive Compensation Plan.

Response:

TCPL's Total Direct Compensation (TDC) programs are in place to attract, motivate, and retain employees with the knowledge and experience required to operate its business in a safe, reliable, and efficient manner.

TransCanada's corporate strategy (available on www.transcanada.com), which also encompasses the Alberta System, includes these three key strategies:

- Relentlessly pursue our commitment to an operational excellence business model that provides low-cost, reliable and responsive service to our customers.
- Sustain, grow and optimize the gas transmission business, including capture of the northern opportunities and extensions into U.S. markets.
- Work with customers to establish a new regulated business model with the flexibility to successfully compete in the North American market.

As described in CAR-NGTL-006(a), the company has changed dramatically since the 1995 GRA. The company had to align its Total Direct Compensation (TDC) to remain competitive with the defined competitive compensation market and to provide balanced

CAR-NGTL-006(b)

rewards to its employees for achieving both short-term business objectives and sustaining long-term business objectives.

TCPL will not provide working papers related to compensation programs. They are often either draft or otherwise incomplete documents, which seldom indicate the context and purpose for which they were prepared, and as a result can be misleading. They often do not reflect TCPL's considered view, are typically voluminous in nature, and in many cases contain confidential and proprietary information. The evidentiary value of the requested information would be in any event far outweighed by the time and effort required to locate, compile, review and determine the produceability of the material.

CAR-NGTL-007(a) **REVISED February 2004**

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs pg. 11 - 13 of 15

Request:

Please provide for 2002, 2003 and 2004 a breakdown of the costs for the KESIP Employee Stock Incentive Plan by category (i.e. PUP, RSU and ESU).

Response:

As per the February 2004 Update, ~~T~~the breakdown of the costs of Long Term Incentive Programs ~~are~~ is as follows:

(in $millions)	2002	2003	2004
PUP	1.1	~~2.6~~ 2.5	~~3.1~~ 3.2
RSU	7.0	~~6.7~~ 8.7	~~7.0~~ 8.4
ESU	-	~~1.2~~ 1.3	~~2.4~~ 2.6
Stock Options	0.8	~~0.8~~ 0.7	1.1
Total	8.9	~~11.3~~ 13.2	~~13.6~~ 15.3

CAR-NGTL-007(b) **REVISED February 2004**

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs pg. 11 - 13 of 15

Request:

What is the full cost of the Long Term Incentive Compensation Plan that is included in the 2004 Revenue Requirement?

Response:

~~As per Line 6, Schedule 2.3.1.8~~As per the February 2004 Update, the amount of Long Term Incentive Compensation included in the 2004 Revenue Requirement is $~~13.6~~ 15.3 million (Refer to Line 6, Revised Schedule 2.3.1.8).

CAR-NGTL-008(a)

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs, Appropriateness of TDC for NGTL, pg. 1 – 15 of 15

Request:

Within the Towers Perrin Data – TCPL's Comparator Group, please specify how many of participants in the study have Total Direct Compensation for executives and management including Long Term Incentive Compensation paid for by rate payers?

Response:

This information is not provided in the Towers Perrin data.

CAR-NGTL-008(b)

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs, Appropriateness of TDC for NGTL, pg. 1 – 15 of 15

Request:

Within the Towers Perrin Data – TCPL's Comparator Group, please specify how many of participants in the study have Total Direct Compensation for non-management employees including Long Term Incentive Compensation paid for by rate payers?

Response:

This information is not provided in the Towers Perrin data.

CAR-NGTL-009(a)

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs pg. 12 of 15

Preamble:

NGTL lists six items that reflect prudent business management and are tied to long-term incentives. They include financial measures (1), corporate governance (2), health and safety targets (3), cost containment (4), and both regulated (5) and non-regulated business growth (6).

Request:

Please specify the general performance levels and pay-out targets under the long-term incentives program required in order to receive such compensation.

Response:

Please refer to the response to CAPP-NGTL-008(a).

CAR-NGTL-009(b)

Issue:

Revenue Requirement, Total Direct Compensation and Benefits

Reference:

Section 2.3.2, Long-Term Incentive Programs pg. 12 of 15

Preamble:

NGTL lists six items that reflect prudent business management and are tied to long-term incentives. They include financial measures (1), corporate governance (2), health and safety targets (3), cost containment (4), and both regulated (5) and non-regulated business growth (6).

Request:

Please provide the specific performance levels and pay-out targets under the long-term incentives program required in order to receive such compensation which are specific to each of the six items listed.

Response:

It is not possible to link specific performance levels and pay-out targets to each of the six items listed.

As NGTL stated in the Application, Sub-section 2.3.2, page 12, lines 9 to 18, long-term incentives are tied to measures that, in aggregate, reflect sustained, prudent business management, including financial measures, corporate governance, health and safety targets, cost containment, and both regulated and non-regulated business growth. These measures are ultimately reflected in such aggregate measures as Total Shareholder Return (TSR) and stock price.

CAR-NGTL-010(a)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, pg. 15 and 19

Request:

Has NGTL considered using the Average Service Life (ASL) depreciation procedure for depreciable facilities? If not, why not?

Response:

Yes, but NGTL does not believe the use of the Average Service Life (ASL) procedure to be appropriate for NGTL. The Equal Life Group (ELG) procedure results in a superior matching of depreciation expense to the consumption of service value than does the ASL method.

The Board has a long-standing practice of accepting the use of the ELG procedure for Alberta utilities. Within the recent past, the Board has reviewed and approved depreciation expenses resulting from depreciation rates based on the ELG procedure in a number of proceedings, including:

- 1999/2000 Electric Tariff Applications - EPCOR Generation Inc. / EPCOR Transmission Inc. - Decision U99099
- 1999/2000 Electric Tariff Application - ATCO Electric Ltd. (Negotiated Settlement) – Decision – U99099
- 2000/2001/2002 General Rate Application - AltaGas Utilities Inc. (Negotiated Settlement) – Decision 2002-027
- ATCO Gas South (CWNG) – 2000/2001 General Rate Application - Decision 2001-096
- Aquila Networks Canada (Alberta) Ltd. – 2002/2003 Distribution Tariff Application – Decision 2003-019
- AltaLink Management Limited – May 2002 – April 2004 General Transmission Tariff Application – Decision 2003-061
- ATCO Gas – 2003/2004 General Rate Application – Decision 2003-072

CAR-NGTL-010(a)

- ATCO Electric Ltd. – 2003/2004 General Tariff Application – Decision 2003-071
- ATCO Gas and Pipelines Limited, Pipeline Division – 2003/2004 General Rate Application (Negotiated Depreciation Component) – Decision 2003-100.

In addition to the above decisions, virtually all depreciation studies submitted to the Board since the 1980’s have been prepared using the ELG procedure. In all circumstances, the Board has approved the depreciation expenses resulting from those studies.

CAR-NGTL-010(b)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, pg. 15 and 19

Request:

Please identify which depreciation procedure, ELG or ASL, is utilized by the pipeline industry participants identified by NGTL on page 15.

Response:

The use and acceptance of the ELG procedure varies between regulatory jurisdictions. As indicated in CAR-NGTL-010(a), all utilities regulated by the EUB have depreciation rates based on the ELG procedure. The pipelines listed at page 15 of Section 4.0 are all regulated by the National Energy Board (NEB), which historically has accepted depreciation studies using the ASL procedure. The depreciation rates of Enbridge Pipelines, Terasen Pipelines, and the TransCanada Mainline all currently are calculated using the ASL procedure. The depreciation rates for Alliance Pipeline were calculated in accordance with a 25-year amortization method.

CAR-NGTL-010(c)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, pg. 15 and 19

Request:

Please provide the overall composite depreciation rate for NGTL based on the ASL depreciation methodology.

Response:

NGTL does not propose the use of the ASL procedure. Further, the requested information cannot be provided with reasonable effort.

CAR-NGTL-010(d)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, pg. 15 and 19

Request:

Please provide a forecast of depreciation expenses over the 22 year economic planning horizon based on both ELG and ASL depreciation methodologies.

Response:

NGTL declines to provide the requested information. A 22-year forecast of depreciation expenses would require a forecast of facilities additions and retirements by asset account over the economic planning horizon. NGTL does not have such a forecast and believes that any such forecast would be valueless because of the number and magnitude of assumptions that would be required to complete it and could not be provided with reasonable effort.

CAR-NGTL-011(a)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 - 3

Request:

Please provide NGTL's assessment of future natural gas demand for North America, including data and studies that NGTL is relying on.

Response:

Please refer to CAR-NGTL-11(a) attachment.

Western Canada Supply/Demand Balance (Bcf/d) - Base Case

	WCSB Conventional & Unconventional Supply	WCSB Net Storage	Northern Supply - Makenzie Delta	Northern Supply - Alaska Gas	Total Supply	Western Canadian Demand	Fuel on Northern Pipelines	Western Canadian Capacity	Foothills SK Northern Border	GTN Capacity	Alliance Capacity	NWP at Sumas Capacity	New Capacity	Mainline Capacity	Western Canadian Exports	Foothills SK Norther Border	GTN Flows	Alliance Flows	NWP at Sumas Flows	Flow on New Capacity	Mainline Flows	Western Canadian Pipeline Utilization	Foothills SK Northern Border	GTN Utilization	Alliance Utilization	NWP at Sumas Utilization	Utilization on New Capacity	Mainline Utilization
2002/03	16.6	0.2			16.7	4.3		15.1	2.2	2.8	1.6	1.3		7.2	12.4	2.1	1.7	1.6	0.9		6.1	82%	97%	63%	100%	68%		84%
2003/04	16.8	-0.1			16.8	4.6		15.2	2.2	2.8	1.6	1.4		7.2	12.2	1.9	2.0	1.6	1.0		5.7	80%	88%	72%	99%	68%		79%
2004/05	17.0	-0.1			17.0	4.9		15.2	2.2	2.8	1.6	1.4		7.2	12.0	2.0	2.3	1.6	1.0		5.2	79%	90%	82%	99%	70%		72%
2005/06	17.2	0.0			17.2	5.1		15.2	2.2	2.8	1.6	1.4		7.2	12.1	2.1	2.4	1.6	1.0		5.0	79%	95%	86%	99%	70%		69%
2006/07	17.4	0.0			17.3	5.3		15.6	2.2	2.8	1.6	1.4	0.4	7.2	12.0	2.1	2.2	1.6	0.9	0.3	5.0	77%	95%	79%	99%	65%	73%	69%
2007/08	17.6	0.0			17.6	5.6		15.6	2.2	2.8	1.6	1.4	0.4	7.2	12.0	2.1	2.4	1.6	0.9	0.3	4.8	77%	95%	85%	99%	63%	73%	67%
2008/09	17.8	0.0	1.0		18.8	5.9	0.0	15.6	2.2	2.8	1.6	1.4	0.4	7.2	12.9	2.1	2.5	1.6	0.9	0.3	5.5	83%	95%	90%	99%	65%	73%	76%
2009/10	17.9	0.0	1.1		19.0	6.1	0.0	15.6	2.2	2.8	1.6	1.4	0.4	7.2	12.9	2.1	2.5	1.6	0.9	0.3	5.5	83%	95%	90%	99%	64%	74%	77%
2010/11	18.1	0.0	1.3		19.3	6.3	0.0	15.6	2.2	2.8	1.6	1.4	0.4	7.2	13.0	2.1	2.5	1.6	0.9	0.3	5.7	84%	95%	90%	99%	61%	74%	79%
2011/12	18.5	-0.1	1.4		19.8	6.5	0.1	15.6	2.2	2.8	1.6	1.4	0.4	7.2	13.3	2.1	2.5	1.6	0.9	0.3	5.8	85%	96%	92%	99%	62%	74%	81%
2012/13	18.9	0.0	1.5		20.4	6.6	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	13.8	2.1	2.6	1.6	0.8	0.5	6.2	87%	97%	92%	99%	57%	82%	86%
2013/14	18.8	0.0	1.5		20.3	6.7	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	13.5	2.1	2.5	1.6	0.8	0.5	6.1	86%	95%	90%	99%	55%	82%	85%
2014/15	18.6	0.0	1.5		20.0	6.8	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	13.2	2.0	2.4	1.6	0.8	0.5	5.9	84%	92%	88%	99%	54%	82%	82%
2015/16	18.3	0.0	1.5		19.8	6.9	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	12.9	2.0	2.4	1.6	0.7	0.5	5.7	82%	89%	85%	99%	52%	82%	80%
2016/17	17.9	0.0	1.5		19.4	6.9	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	12.4	1.9	2.3	1.6	0.7	0.5	5.5	79%	85%	82%	99%	50%	82%	76%
2017/18	17.2	0.0	1.5		18.7	7.0	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	11.7	1.7	2.1	1.6	0.7	0.5	5.1	74%	79%	76%	99%	46%	82%	71%
2018/19	16.4	0.0	1.5		17.9	7.1	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	10.7	1.6	1.9	1.6	0.6	0.5	4.6	68%	72%	68%	99%	42%	82%	64%
2019/20	15.3	0.0	1.5		16.8	7.1	0.1	15.8	2.2	2.8	1.6	1.4	0.6	7.2	9.6	1.4	1.6	1.6	0.5	0.5	4.0	61%	62%	59%	99%	37%	82%	56%

U.S. DEMAND CONSUMPTION
(bcf/d - calendar year basis)
Base Case

New England	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Commercial	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Industrial	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Electric Generation	0.8	0.9	1.0	1.0	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5
Other (Including P/L Fuel)	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	0.0	0.0	0.0	0.0	0.0
Total	2.1	2.2	2.3	2.4	2.4	2.5	2.6	2.6	2.7	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.0	3.1	3.2
Middle-Atlantic	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	2.3	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.7
Commercial	1.7	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3
Industrial	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4
Electric Generation	1.1	1.1	1.2	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.7	2.8
Other (Including P/L Fuel)	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	6.5	6.7	6.9	7.1	7.3	7.5	7.6	7.8	7.9	8.0	8.1	8.3	8.4	8.6	8.8	8.9	9.1	9.3	9.5
South Atlantic	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	1.2	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8
Commercial	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4
Industrial	1.6	1.6	1.6	1.7	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0
Electric Generation	1.5	1.7	1.9	2.0	2.2	2.5	2.7	2.8	2.8	2.9	3.0	3.2	3.3	3.4	3.6	3.8	4.0	4.1	4.3
Other (Including P/L Fuel)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	5.5	5.9	6.1	6.3	6.7	7.1	7.4	7.6	7.7	7.8	8.0	8.2	8.4	8.6	8.9	9.1	9.4	9.6	9.9
East North Central	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	3.9	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6
Commercial	2.1	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Industrial	3.3	3.3	3.3	3.4	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.6	3.6	3.6
Electric Generation	0.7	0.8	0.9	1.0	1.1	1.1	1.3	1.4	1.5	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4
Other (Including P/L Fuel)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Total	10.3	10.6	10.9	11.1	11.4	11.5	11.7	11.9	12.0	12.0	12.1	12.3	12.4	12.6	12.7	12.9	13.0	13.2	13.4
West North Central	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Commercial	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Industrial	1.1	1.1	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Electric Generation	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Other (Including P/L Fuel)	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.3	4.4	4.4	4.4	4.5	4.6	4.6	4.7	4.7	4.8	4.9	4.9
East South Central	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Commercial	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
Industrial	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5
Electric Generation	0.7	0.7	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.6	1.7	1.8	1.9	2.0	2.1	2.1	2.2
Other (Including P/L Fuel)	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	3.2	3.3	3.3	3.4	3.6	3.7	3.8	4.0	4.1	4.2	4.3	4.4	4.6	4.7	4.9	5.0	5.1	5.1	5.3
West South Central	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Commercial	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Industrial	7.8	7.2	7.0	7.1	7.5	7.6	7.7	7.7	7.6	7.6	7.6	7.6	7.7	7.7	7.8	7.8	7.9	8.0	8.0
Electric Generation	4.8	4.5	4.5	4.6	4.9	5.1	5.2	5.3	5.3	5.3	5.3	5.3	5.4	5.4	5.5	5.5	5.6	5.7	5.7
Other (Including P/L Fuel)	2.0	2.0	1.9	2.0	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3
Total	16.4	15.6	15.3	15.6	16.5	16.9	17.1	17.2	17.2	17.2	17.2	17.3	17.4	17.5	17.7	17.8	18.0	18.2	18.3
Mountain	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3
Commercial	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Industrial	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Electric Generation	1.0	1.2	1.3	1.4	1.5	1.4	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.8
Other (Including P/L Fuel)	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2
Total	4.0	4.3	4.6	4.7	4.9	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.6	5.7	5.8	5.8	5.9	6.1
Pacific (Excluding Alaska)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	1.7	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1
Commercial	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2
Industrial	2.5	2.3	2.3	2.4	2.6	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	3.0	3.0
Electric Generation	2.0	1.9	2.2	2.4	2.6	2.7	2.9	3.1	3.1	3.2	3.2	3.3	3.4	3.4	3.6	3.7	3.8	3.9	4.0
Other (Including P/L Fuel)	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	7.4	7.2	7.6	7.9	8.4	8.7	8.9	9.2	9.3	9.3	9.4	9.5	9.7	9.8	10.0	10.2	10.4	10.5	10.7

Total L48 Demand	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	13.4	13.9	14.2	14.4	14.6	14.8	15.0	15.1	15.2	15.3	15.4	15.5	15.6	15.7	15.9	16.0	16.2	16.3	16.5
Commercial	8.7	9.2	9.4	9.5	9.6	9.8	9.9	10.0	10.1	10.2	10.2	10.3	10.5	10.6	10.7	10.8	10.9	11.1	11.2
Industrial	19.9	19.1	18.9	19.3	20.2	20.6	20.8	21.0	21.0	20.9	20.9	21.1	21.2	21.3	21.5	21.6	21.8	22.0	22.1
Electric Generation	12.9	13.1	14.1	14.8	16.0	16.9	17.8	18.7	19.0	19.4	19.8	20.6	21.2	21.8	22.7	23.3	24.0	24.7	25.5
Other (Including P/L Fuel)	4.4	4.5	4.5	4.6	4.8	4.9	5.0	5.0	5.1	5.2	5.3	5.4	5.4	5.5	5.5	5.6	5.6	5.7	5.8
Total	59.3	59.8	61.1	62.6	65.1	67.0	68.5	69.7	70.3	70.9	71.6	72.8	73.9	74.9	76.3	77.4	78.6	79.8	81.1
Alaskan Demand	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Electric Generation	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Other (Including P/L Fuel)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Total	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.6	1.7	1.7	1.7
Total US Demand (L48 & Alaska)	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	13.4	14.0	14.3	14.5	14.7	14.8	15.0	15.1	15.2	15.3	15.4	15.5	15.7	15.8	16.0	16.1	16.3	16.4	16.6
Commercial	8.8	9.2	9.4	9.6	9.7	9.9	10.0	10.1	10.2	10.3	10.3	10.4	10.5	10.7	10.8	10.9	11.0	11.2	11.3
Industrial	20.1	19.3	19.1	19.5	20.4	20.8	21.0	21.2	21.2	21.1	21.1	21.3	21.4	21.5	21.7	21.8	22.0	22.2	22.3
Electric Generation	13.0	13.2	14.2	15.0	16.1	17.1	18.0	18.9	19.3	19.6	20.1	20.9	21.6	22.2	23.0	23.7	24.4	25.1	25.9
Other (Including P/L Fuel)	5.1	5.3	5.3	5.4	5.6	5.7	5.8	5.9	5.9	6.0	6.1	6.2	6.3	6.3	6.4	6.5	6.5	6.6	6.7
Total	60.5	61.0	62.3	63.9	66.5	68.3	69.8	71.1	71.8	72.3	73.1	74.4	75.5	76.5	78.0	79.0	80.3	81.5	82.8

Canadian Demand Consumption
(bcf/d - Gas year basis)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Maritimes																			
Residential	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	0.0	0.0	0.0	0.0	0.0
Commercial	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	0.0	0.0	0.0	0.0	0.0
Industrial/ Elect. Gen. / Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Quebec	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Industrial/ Elect. Gen. / Other	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Ontario	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Commercial	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Industrial/ Elect. Gen. / Other	1.3	1.3	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.1	2.1	2.2	2.3	2.3	2.4
Total	2.6	2.7	2.8	2.9	3.0	3.0	3.1	3.2	3.3	3.3	3.4	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1
Manitoba	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial/ Elect. Gen. / Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Total	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Saskatchewan	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Industrial/ Elect. Gen. / Other	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Alberta	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Commercial	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Industrial/ Elect. Gen. / Other	2.5	2.7	3.0	3.2	3.3	3.5	3.7	3.9	4.0	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.6	4.7	4.7
Total	3.1	3.3	3.6	3.9	4.0	4.1	4.4	4.6	4.7	4.9	5.0	5.0	5.1	5.2	5.2	5.3	5.3	5.4	5.4
BC	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Commercial	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Industrial/ Elect. Gen. / Other	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9
Total	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3
Total Canadian	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0
Commercial	1.3	1.2	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.6
Industrial/ Elect. Gen. / Other	5.0	5.3	5.8	6.1	6.4	6.7	7.0	7.4	7.6	7.9	8.1	8.2	8.4	8.7	8.8	8.9	9.0	9.2	9.3
Total	7.9	8.2	8.8	9.2	9.4	9.8	10.1	10.6	10.8	11.1	11.3	11.5	11.8	12.0	12.2	12.4	12.5	12.7	12.9

US Exports

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Mexico																			
Net Exports	0.7	0.7	0.8	0.9	0.1	-0.2	-0.1	0.0	0.1	0.2	0.1	0.0	0.1	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
LNG	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Exports from Alaska	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

Total North American Demand Consumption

Total North American Demand Consumption	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential	15.1	15.6	16.0	16.2	16.4	16.6	16.8	16.9	17.0	17.2	17.3	17.4	17.6	17.7	17.9	18.1	18.2	18.4	18.6
Commercial	10.0	10.5	10.7	10.9	11.0	11.2	11.3	11.5	11.6	11.6	11.7	11.9	12.0	12.1	12.3	12.4	12.6	12.7	12.9
Industrial 1	25.1	24.7	24.8	25.6	26.7	27.5	28.0	28.6	28.8	29.0	29.1	29.5	29.8	30.2	30.5	30.8	31.1	31.4	31.6
Electric Generation 2	13.0	13.2	14.2	15.0	16.1	17.1	18.0	18.9	19.3	19.6	20.1	20.9	21.6	22.2	23.0	23.7	24.4	25.1	25.9
Other (Including P/L Fuel)	5.1	5.3	5.3	5.4	5.6	5.7	5.8	5.9	5.9	6.0	6.1	6.2	6.3	6.3	6.4	6.5	6.5	6.6	6.7
Mexico	0.7	0.7	0.8	0.9	0.1	-0.2	-0.1	0.0	0.1	0.2	0.1	0.0	0.1	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Exports from Alaska	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	69.2	70.2	72.1	74.2	76.2	78.1	80.0	81.8	82.9	83.8	84.7	86.1	87.5	88.5	90.2	91.4	92.8	94.2	95.6

1 Industrial demand consumption in Canada includes these sectors: Electric Generation, Transportation, Plant & Lease Fuel, Pipeline Fuel
2 Includes Electric Generation in US L48 only. Canadian Electric Generation demand is included in the Industrial sector.

NORTH AMERICAN SUPPLY
Base Case

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
WCSB	**Total WCSB Supply**	16.8	16.6	16.8	17.0	17.2	17.4	17.6	17.8	17.9	18.1	18.5	18.9	18.8	18.6	18.3	17.9	17.2	16.4	15.3
Other	**Other Northern Supply**					0.0	0.0	0.0	1.0	1.1	1.3	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
	Eastern Offshore (Sable)	0.5	0.5	0.6	0.6	0.6	0.6	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Total Cdn & Northern Supply	17.4	17.1	17.4	17.6	17.8	17.9	18.5	19.6	20.0	20.3	20.8	21.4	21.2	21.0	20.7	20.4	19.7	18.8	17.7

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
US	**Lower 48**																			
	GOM Offshore	12.3	12.0	12.6	13.2	13.7	14.3	14.7	15.0	15.4	15.8	16.1	16.3	16.4	16.6	16.8	16.9	17.0	17.0	16.9
	GOM Onshore	13.7	13.4	13.6	13.8	13.9	13.9	13.9	13.9	13.9	13.9	13.8	13.8	13.7	13.6	13.5	13.4	13.2	13.1	13.0
	Mid-Continent	6.5	6.2	6.1	6.0	5.9	5.8	5.7	5.6	5.5	5.4	5.3	5.2	5.2	5.1	5.1	5.0	5.0	4.9	4.9
	Permian Basin	4.4	4.4	4.3	4.3	4.3	4.2	4.2	4.2	4.1	4.1	4.0	3.9	3.9	3.8	3.8	3.7	3.7	3.6	3.6
	San Juan Basin	3.5	3.5	3.4	3.4	3.3	3.3	3.2	3.2	3.1	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.7	2.7	2.6
	Rockies Basins	6.1	6.3	6.6	6.8	7.2	7.5	7.7	7.9	8.1	8.5	8.7	8.9	9.1	9.2	9.4	9.5	9.6	9.7	9.7
	Appalachia	1.1	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.9	1.9	1.9	1.9
	Mid-Atlantic	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Northern California	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Southern California	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	Michigan	0.8	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3
	Ventura	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Florida	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	0.0	0.0	0.0	0.0	0.0
	N. Dakota	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Lower 48 Subtotal	49.9	49.2	50.2	51.3	52.3	53.3	53.9	54.2	54.8	55.3	55.6	55.8	56.0	56.1	56.2	56.2	56.1	55.9	55.6
	Supplemental Gas	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	US LNG	0.6	1.5	2.2	3.5	4.6	5.1	5.5	5.9	6.0	6.1	6.1	6.7	8.2	9.1	9.6	10.5	11.3	11.8	11.9
	Existing Alaska Production	1.4	1.4	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.9	1.9
	Other Southern Supplies 1	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	1.6	2.1	3.6	5.5	8.3
	Total US Supply	52.2	52.4	54.2	56.6	58.7	60.3	61.3	62.0	62.7	63.3	63.7	64.5	66.2	67.3	69.4	70.9	73.1	75.4	77.9

Total North American Supply	69.6	69.6	71.5	74.2	76.5	78.2	79.7	81.7	82.7	83.6	84.5	85.9	87.4	88.3	90.2	91.2	92.7	94.2	95.7

1 Other Southern Supplies, which could include additional LNG, Mexican imports, a pipeline from Trinidad or Venezuela, or Potential Production from unconventional gas in the Gulf of Mexico, may be greater in the later years if North American demand is sufficient.

	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total North American Supply	69.6	69.6	71.5	74.2	76.5	78.2	79.7	81.7	82.7	83.6	84.5	85.9	87.4	88.3	90.2	91.2	92.7	94.2	95.7
Total North American Demand	69.2	70.2	72.1	74.2	76.2	78.1	80.0	81.8	82.9	83.8	84.7	86.1	87.5	88.5	90.2	91.4	92.8	94.2	95.6
Storage/Balancing Item	0.3	-0.6	-0.6	0.0	0.2	0.1	-0.3	-0.2	-0.1	-0.2	-0.2	-0.1	0.0	-0.2	0.0	-0.1	0.0	0.0	0.0

CAR-NGTL-011(b)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 – 3

Request:

Please provide NGTL's assessment of what supply sources will be utilized to meet the demand scenario identified in a). If NGTL's assessment does not include Alaskan gas, please explain in detail why not? Please include all internal and external studies and workpapers.

Response:

For NGTL's assessment of supply sources, please refer to the response to CAR-NGTL-011(a). Please also refer to the Application, Section 4.0, Appendix A – Supply Study, page 2, lines 14-28, and page 3, line 1, for the reasons NGTL has not included Alaskan gas. Also refer to the response to CAR-NGTL-011(f).

CAR-NGTL-011(c)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 – 3

Request:

Please explain in detail why NGTL states that the later the development of Alaskan resource, the more likely it is that the development will take the form of gas-to-liquids or liquefied natural gas development? Please provide all internal and external studies and workpapers.

Response:

NGTL has relied on several sources to reach the above conclusion.

The State of Alaska and the US Department of Energy have actively investigated the viability of commercializing Alaskan North Slope natural gas. The State of Alaska in particular has been supporting gas commercialization efforts such as Liquefied Natural Gas (LNG) and Gas-To-Liquids (GTL).

<u>GTL</u>
BP has built a small scale test GTL plant in Nikiski where the technology to develop GTL can be transferred to the North Slope. The small scale test facility is suited to a long term learning curve strategy where costs can be driven down with time. While the current state of technical feasibility for GTL is still being developed, future research in this area will lead to lower costs and hence, greater viability. Also, there is a strong incentive to develop GTL in later years as North Slope oil production continues to decline. At low oil production, the economics of a GTL operation are significantly enhanced when the production from a GTL plant can be used to lower the tariffs on the Trans Alaska Pipeline System (TAPS). In particular, the Oil & Gas Journal December 6, 1999, “GTL Technology Augments Gas Production Options”, page 45-46 discusses a “window of opportunity” for GTL that when taken into consideration with the State of Alaska revised forecasts from its 2002 report would be after 2022.

CAR-NGTL-011(c)

LNG

There has been a small scale LNG operation in Alaska for over 30 years and efforts to expand this operation to include the North Slope are regularly reviewed. At this time, a pipeline is seen as the most economic of the three options. In the future, circumstances are not assured to remain this way. Thus in a relative sense, the LNG option has a higher likelihood to be realized if the resource is developed later.

These and other insights have been obtained by NGTL through reviewing the following studies:

(a) Options for Gas-to-Liquids Technology in Alaska, E.P. Robertson, Idaho National Engineering and Environmental Laboratory INEEL/EXT-99-01023, December 1999
(b) Alaska Oil and Gas Energy Wealth or Vanishing Opportunity? US Department of Energy (in cooperation with the State of Alaska) DOE/ID/01570-H1 January 1991
(c) Juneau Report Alaska Gas… what's the next move? BP Spring 1991
(d) Critical Evaluation of Options for Utilizing Alaska North Slope Natural Gas, D.A. Lannon et al University of Alaska Fairbanks, SPE paper 35701
(e) CERA White Paper Alaskan Natural Gas October 1999
(f) State of Alaska 2002 Report.
(g) Oil & Gas Journal December 6, 1999, Volume 49, GTL Technology augments gas production options page 45-46

CAR-NGTL-011(d)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 - 3

Request:

Please explain in detail why NGTL's parent TCPL would invest additional dollars in Foothills Pipelines in light of the "too speculative to consider" nature of the Alaskan pipeline development?

Response:

TCPL's purchase of an additional interest in the Foothills pipeline was driven, in part, by TCPL's desire to be as well-positioned as possible to participate in an Alaska project, should it occur. The magnitude of the potential impact of an Alaskan project on TCPL and NGTL, either positive or negative, made the acquisition important, even if the probability of an Alaskan pipeline project is low or if the timing is not certain.

In other words, the implications of an Alaskan project are so large for NGTL and TCPL that TCPL could not afford <u>not</u> to make the investment in Foothills if that investment in any way increased the probability of participation in an Alaskan project. The magnitude of the benefit of attracting incremental supply and preventing further off-loading of existing infrastructure is simply too large to ignore regardless of the uncertainties of the project.

CAR-NGTL-011(e)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 – 3

Request:

What are TCPL's expected short-term and long-term returns from its recent incremental investment in Foothills Pipelines? What are TCPL's expected short-term and long-term returns from its ownership in NGTL? Please provide detailed calculations and supporting data.

Response:

NGTL declines to answer this question because the requested information is confidential and not relevant to this proceeding. Furthermore, a response would violate disclosure rules.

CAR-NGTL-011(f)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 – 3

Request:

Please explain in detail why NGTL's parent TCPL, in its 2003 Rate Case, included Alaskan gas in its determination of an economic planning horizon for the mainline, but NGTL chose to exclude Alaskan gas? Please provide all internal and external studies and workpapers relied on by TCPL and NGTL.

Response:

NGTL considers Alaska gas to be too speculative to include. Not only is there uncertainty with respect to whether the project is economic or not, the timing of the project is not certain. In addition, if and when there is a project to develop Alaska gas, there is uncertainty with respect to whether or not it will be a gas pipeline project. Finally, if and when a gas pipeline project is completed to move Alaska gas to market, there is uncertainty with respect to whether the project will be integrated with the existing WCSB infrastructure.

The following factors influenced NGTL's decision to exclude Alaskan gas for purposes of the Supply Study provided. Almost three years have passed since gas prices peaked at $10.00/Mcf (NYMEX) and more than two years have passed since the events of September 11/01 heightened concerns for energy security. The lack of progress for the project during this time has made NGTL less optimistic about the project. NGTL also notes that the focus on LNG has increased markedly over the past year.

Over the same time frame, NGTL has recognized the progress made with respect to the Mackenzie Delta project and has, accordingly, included Delta gas.

NGTL continues to recognize the possibility of an Alaska gas pipeline project, but does not believe it should be included in an assessment of reasonably likely future flows on the Alberta System.

CAR-NGTL-011(g) **REVISED February 2004**

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 - 3

Request:

Please provide NGTL's assessment of the economic planning horizon with Alaskan resource included as a supply source for NGTL.

Response:

~~Please refer to the response to CAPP-NGTL-5(b).~~
NGTL has completed the assessment of an economic planning horizon for the "with Alaska" supply case and has determined that it would fall in the 2050 to 2055 interval. Gannett Fleming has informed NGTL that such a planning horizon is equivalent to no truncation date case.

CAR-NGTL-011(h) **REVISED February 2004**

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 – 3

Request:

Please provide the overall composite depreciation rate for NGTL based on the economic planning horizon determined in g).

Response:

~~Please refer to the response to CAPP-NGTL-005(b).~~
Please refer to the response to CG-NGTL-012(g), which provides the overall composite depreciation rate if no truncation date is used.

NGTL does not believe that the composite depreciation rate under a no truncation date case (under either the base supply case or the "with Alaska" supply case) is an appropriate depreciation rate for Alberta System facilities. Further, NGTL believes that it would be misleading to give any consideration to one extreme case, a high alternative supply case such as "with Alaska" without considering the low supply case. NGTL is, therefore, including the results of the low supply case in this response.

Under NGTL's low supply case, the truncation date is 2015 and the overall composite depreciation rate, when applied to 2004 account balances, is 5.68%.

CAR-NGTL-011(i)

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix A – Supply Study, pg. 2 - 3

Request:

Should Alaskan gas be developed in the 2010 – 2015 timeframe, will NGTL have underutilized capacity to transport Alaskan gas through Alberta?

Response:

Yes, as per NGTL's current expectations.

CAR-NGTL-012

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix C – Depreciation Study, pg. I-10

Preamble:

Gannett Fleming states that the net salvage estimates for depreciable and amortizable property were based on judgement that incorporated analyses of historical data, a review of policies and outlook with NGTL management, a general knowledge of the gas pipeline industry, and comparisons of the net salvage estimates from studies of other gas pipelines.

Request:

(a) Please provide copies of the studies of other gas pipelines utilized for comparisons of the net salvage estimates.

(b) Please explain in detail how these studies were utilized in estimation of the net salvage percentages for NGTL.

(c) Please provide justification and rationale for any differences in net salvage percentages between NGTL and the studies of other gas pipelines.

Response:

(a) The referenced quote was made to point to the experience of Gannett Fleming in the preparation of hundreds of depreciation studies over many decades. Attachment CAR-NGTL-012 is a listing of over 100 cases of Gannett Fleming testimony since 1992. While Gannett Fleming has testified and assembled an extensive library of depreciation testimony for many decades prior to 1992, the most recent 11-year period is considered to be the most relevant to this study. As these testimonies are on the public record, copies have not been provided.

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(b) The knowledge gained from the participation of Gannett Fleming in the development of depreciation studies provides Gannett Fleming with a background upon which to develop an expert opinion on the appropriateness of the net salvage percentages. It is with this knowledge and background that Gannett Fleming was able to interpret the data provided, conduct meaningful staff interviews, and make the determination that certain transactions with regard to the divesture activities should be excluded from the analysis of net salvage in order to develop appropriate net salvage percentages for the current asset base.

(c) Every utility has a number of unique circumstances that result in differences in the net salvage percentages. While comparisons to the net salvage percentages of peer companies provide a basis to test the reasonableness of the selected net salvage percentage, it would be unusual for a number of gas pipelines to have identical net salvage percentages. As such, it is virtually impossible to develop a list of reasons that would provide any type of meaningful analysis as to the reasons that the net salvage percentages in each of the amount of depreciation studies conducted by Gannett Fleming for gas pipelines are different from the specific net salvage percentages selected by Gannett Fleming in this proceeding.

LIST OF GANNETT FLEMING DEPRECIATION RELATED TESTIMONY SINCE 1992

LIST OF CASES IN WHICH WILLIAM M. STOUT, P. E. TESTIFIED

	Year	Jurisdiction	Docket No.	Client/ Utility	Subject
1.	1992	Pa. PUC	R- 912164	Equitable Gas Company	Depreciation
2.	1992	Pa. PUC	R- 922180	The Peoples Natural Gas Company	Depreciation
3.	1992	Pa. PUC	R- 922168	The York Water Company	Depreciation, Cost Allocation and Rate Design
4.	1992	Pa. PUC	C- 913749	North Penn Gas Company	Main Extension Policy
5.	1992	Pa. PUC	R- 922195	UGI Utilities, Inc. - Electric Utility Division	Depreciation
6.	1992	Pa. PUC	R- 922254	Apollo Gas Company	Depreciation, Cost Allocation and Rate Design
7.	1992	Pa. PUC	R- 922428	Pennsylvania- American Water Company	Cost Allocation and Rate Design
8.	1992	National Energy Board	RH- 2- 92	TransCanada PipeLines Limited	Depreciation
9.	1992	Pa. PUC	R- 922378	West Penn Power Company	Depreciation
10.	1992	Pa. PUC	R- 922420	Shenango Valley Water Company	Depreciation
11.	1993	Pa. PUC	R- 922476	Philadelphia Suburban Water Company	Customer Demand Study
12.	1993	Pa. PUC	R- 932548	National Fuel Gas Distribution Corporation - PA Division	Depreciation
13.	1993	Pa. PUC	R- 932665	Roaring Creek Water Company	Depreciation
14.	1993	Pa. PUC	C- 935103	Shenango Valley Water Company	Valuation of Mercer Water Company
15.	1993	Pa. PUC	R- 932798	Shenango Valley Water Company	Depreciation
16.	1994	Pa. PUC	R- 932886	The Peoples Natural Gas Company	Depreciation
17.	1994	Pa. PUC	R- 932862	UGI Utilities, Inc. - Electric Division	Depreciation
18.	1994	Pa. PUC	R- 932670	Pennsylvania- American Water Company	Cost Allocation and Rate Design
19.	1994	Pa. PUC	R- 932868	Philadelphia Suburban Water Company	Cost Allocation and Rate
20.	1994	Pa. PUC	R- 932952	Penn Fuel Gas, Inc.	Depreciation, Cost Allocation and Original Cost

LIST OF GANNETT FLEMING DEPRECIATION RELATED TESTIMONY SINCE 1992
LIST OF CASES IN WHICH WILLIAM M. STOUT, P. E. TESTIFIED (cont'd)

	Year	Jurisdiction	Docket No.	Client/ Utility	Subject
21.	1994	Pa. PUC	R- 942991	National Fuel Gas Distribution Corporation - PA Division	Depreciation
22.	1994	Pa. PUC	R- 942986	West Penn Power Company	Depreciation
23.	1994	Pa. PUC	R- 943124	City of Bethlehem – Bureau of Water	Depreciation and Original Cost
24.	1994	Pa. PUC	R- 943157	Pennsylvania- American Water Company	Wholesale Rates of the Newtown Artesian Water Company
25.	1995	PUC of Texas	12065	Houston Lighting & Power Company	Depreciation
26.	1995	Pa. PUC	R- 943231	Pennsylvania- American Water Company	Depreciation, Cost Allocation and Rate Design
27.	1995	Pa. PUC	R- 943252	The Peoples Natural Gas Company	Depreciation
28.	1995	Pa. PUC	R- 953299	National Fuel Gas Distribution Corporation - PA Division	Depreciation
29.	1995	Pa. PUC	R- 943245	North Penn Gas Company	Depreciation, Cost Allocation and Rate Design
30.	1995	Pa. PUC	R- 953297	UGI Utilities, Inc. - Gas Division	Depreciation
31.	1995	Ill. Commerce Commission	95- 0076	Illinois- American Water Company	Single Tariff Pricing, Cost Allocation and Rate Design
32.	1995	Pa. PUC	R- 953343	Philadelphia Suburban Water Company	Depreciation, Cost Allocation and Rate Design
33.	1995	Alberta Energy & Util. Board		Centra Gas of Alberta, Inc.	Depreciation
34.	1995	NJ BPU	WR95040165	New Jersey- American Water Company	Cost Allocation and Rate Design
35.	1995	Pa. PUC	R- 953406	T. W. Phillips Gas and Oil Co.	Depreciation, Cost Allocation and Rate Design
36.	1996	Ct. DPUC	95- 10- 13	Connecticut- American Water Company Re Stamford Water Company	Cost Allocation and Rate Design
37.	1996	NJ PBU	WR95110557	New Jersey- American Water Company Re Elizabethtown Water Company	Cost Allocation and Rate Design
38.	1996	Pa. PUC	R- 953534	UGI Utilities, Inc. - Electric Division	Depreciation
39.	1996	Pa. PUC	R- 953524 PFG	Gas, Inc. and North Penn Gas	Depreciation, Cost Allocation and Company Rate Design

LIST OF GANNETT FLEMING DEPRECIATION RELATED TESTIMONY SINCE 1992

LIST OF CASES IN WHICH WILLIAM M. STOUT, P. E. TESTIFIED (cont'd)

	Year	Jurisdiction	Docket No.	Client/ Utility	Subject
40.	1996	Can. Radio- TV & Telecom Com.	GRA96& 97	AGT Limited	Depreciation
41.	1996	The Bd of Commissioners of Public Utilities	1996 General Rate Proceeding	Newfoundland Light & Power Co. Limited	Depreciation
42.	1996	Arizona Corp. Commission	E- 1032- 95- 417	Citizens Utilities Company - Maricopa Water/ Wastewater Operations	Cost Allocation and Rate Design
43.	1997	Ct. DPUC	95- 06- 33	Connecticut- American Water Company Re Bridgeport Hydraulic Company	Cost Allocation and Rate Design
44.	1997	Pa. PUC	R- 00973869	Consumers Pennsylvania Water Company - Roaring Creek Division	Depreciation, Cash Working Capital and Distribution System Improvement Charge
45.	1997	Pa. PUC	R- 00963858	Equitable Gas Company	Depreciation
46.	1997	Ind. URC	Cause No. 40703	Indiana- American Water Company, Inc.	Depreciation
47.	1997	Ill. Commerce Commission	97- 0102	Illinois- American Water Company	Cost Allocation and Rate Design
48	1997	FERC	RP97- 126- 000	Iroquois Gas Transmission System	Depreciation
49.	1997	Pa. PUC	R- 00973972	Consumers Pennsylvania Water Company - Shenango Valley Division	Depreciation
50.	1997	Alaska	PUC U- 97- 107	Chugach Electric Association, Inc.	Depreciation
51.	1997	Pa. PUC	R- 00973975	UGI Utilities, Inc. - Electric Division	Depreciation
52.	1998	NJ BPU	WR98010015	New Jersey- American Water Company	Cost Allocation and Rate Design
53.	1998	MO PSC	WO- 98- 204	Missouri- American Water Company	Cost Allocation and Rate Design
54.	1999	Alberta Energy & Util. Board	Application No. 980550	Enmax Corporation Re Edmonton Power Generation, Inc.	Depreciation
55.	1999	Pa. PUC	R- 00994638	Pennsylvania- American Water Company	Depreciation, Cost Allocation and Rate Design
56.	1999	NH PUC	DW 99- 057	Hampton Water Works Company	Depreciation, Cost Allocation and Rate Design
57.	2000	MO PSC	WR- 2000- 281	Missouri- American Water Company	Cost Allocation and Rate Design

LIST OF GANNETT FLEMING DEPRECIATION RELATED TESTIMONY SINCE 1992

LIST OF CASES IN WHICH WILLIAM M. STOUT, P. E. TESTIFIED (cont'd)

	Year	Jurisdiction	Docket No.	Client/ Utility	Subject
58.	2001	PUC of TX	22355	Reliant Energy	Depreciation
59.	2001	PUC of CO	00S- 422G	Public Service Company of Colorado	Depreciation
60.	2001	MO PSC	WR- 2000- 844	St. Louis County Water Company	Depreciation, Cost Allocation and Rate Design
61.	2001	County of Ulster	99- 2096	City of New York	Valuation
62.	2002	MO PSC	EC- 2002- 1	Union Electric Company, d/ b/ a AmerenUE	Depreciation
63.	2002	Reg. Com. of AK	U- 01- 108	Chugach Electric Association, Inc.	Depreciation
64.	2003	National Energy Bd. Of Canada	RH-1-2002	TransCanada Pipelines Limited	Depreciation
65.	2003	Cal.PUC		Pacific Gas and Electric	Depreciation

LIST OF GANNETT FLEMING DEPRECIATION RELATED TESTIMONY SINCE 1992
LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client/ Utility	Subject
1.	1998	Pa. PUC	R- 00984375	City of Bethlehem- Bureau of Water	Original Cost and Depreciation
2.	1998	Pa. PUC	R- 00984567	City of Lancaster	Original Cost and Depreciation
3.	1999	Pa. PUC	R- 00994605	The York Water Company	Depreciation
4.	2000	D. T.& E.	DTE 00- 105	Massachusetts- American Water Company	Depreciation
5.	2001	Pa. PUC	R- 00016114	City of Lancaster	Original Cost and Depreciation
6.	2001	Pa. PUC	R- 00016236	The York Water Company	Depreciation
7.	2001	Pa. PUC	R- 00016339	Pennsylvania- American Water Company	Depreciation
8.	2001	PUC of Ohio	01- 1228-	GA- AIR Cinergy Corp. - Cincinnati Gas and Electric Company	Depreciation
9.	2001	Ky. PSC	2001- 092	Cinergy Corp. - Union Light, Heat and Power Company	Depreciation
10.	2002	Pa. PUC	R- 00016750	Philadelphia Suburban Water Co.	Depreciation
11.	2002	Ky. PSC	2002- 00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GR02040245	NUI Corporation/ Elizabethtown Gas Co.	Depreciation
13.	2002	Id. PUC	IPC- E- 03- 7	Idaho Power Company	Depreciation
14.	2003	Pa. PUC	R- 0027975	The York Water Company	Depreciation
15.	2003	Ind. URC	Cause 42359	Cinergy Corp. - PSI Energy, Inc.	Depreciation
16.	2003	Pa. PUC	R- 00038304	Pennsylvania- American Water Co.	Depreciation
17.	2003	Mo. PSC	WR- 2003- 0500	Missouri- American Water Co.	Depreciation
18.	2003	FERC		NSTAR - Boston Edison Company	Depreciation

LIST OF GANNETT FLEMING DEPRECIATION RELATED TESTIMONY SINCE 1992
LIST OF CASES IN WHICH LARRY E. KENNEDY SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client/ Utility	Subject
1.	1999	Alberta EUB	980550	ENMAX Corporation. RE: Edmonton Power Corp.	Depreciation
2.	2000	Alberta EUB	Negotiated Settlement	AltaGas Utilities Inc.	Depreciation
3.	2001	Alberta DOE	(Note 1)	ENMAX Power Corporation -Electric Transmission Assets	Depreciation
4.	2001	Alberta EUB	2000-365	City of Calgary RE: ATCO PipeLines South	Depreciation
5.	2001	Alberta EUB	2000-350	City of Calgary RE: ATCO Gas South	Depreciation
6.	2001	Alberta EUB	1237673	City of Calgary RE: ATCO Affiliate Hearing	Cost Allocation
7.	2002	British Columbia Utilities Commission	(Note 1)	Centra Gas British Columbia	Depreciation
8	2002	Alberta DOE	(Note 1)	ENMAX Power Corporation -Electric Transmission Assets	Depreciation- Technical Update
9.	2003	Manitoba PUC	(Note 1)	Manitoba Hydro	Depreciation
10	2003	Alberta EUB	1279345	AltaLink L.P.	Depreciation
11.	2003	National Energy Bd. Of Canada	RH-1-2002	TransCanada PipeLines Limited	Depreciation
12.	2003	Alberta EUB	1275466	City of Calgary RE: ATCO Gas	Depreciation
13.	2003	Alberta EUB	1275494	City of Calgary RE: ATCO Electric	Depreciation
14.	2003	Manitoba PUC	(Note 2)	Centra Gas Manitoba	Depreciation
15.	2003	Alberta EUB	1275494	City of Calgary RE: ATCO Pipelines	Depreciation

Note 1: Depreciation reports were submitted for review. Public hearings were not held.
Note 2: Evidence was filed. An Appearance in the public hearing was not required.

LIST OF GANNETT FLEMING DEPRECIATION RELATED TESTIMONY SINCE 1992
LIST OF CASES IN WHICH JOHN F. WIEDMAYER SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client/ Utility	Subject
1.	2000	Kentucky Public Service Commission	2000-373	Jackson electric Cooperative	Depreciation
2.	2002-03	Newfoundland and Labrador Bd. Of Commissioners Of Public Utilities		Newfoundland Power, Inc.	Depreciation
3.	2003	Nova Scotia Utiltiy and Review Board	P-879	Nova Scotia Power	Depreciation

CAR-NGTL-013

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix C – Depreciation Study, pg. II-11

Preamble:

Gannett Fleming states that in future years, the market value of various segments will be reduced as the gas supply becomes more limited. Gannett Fleming also states that booked costs of plant retired, the costs of removal and gross salvage proceeds resulting from these divestiture transactions were removed from the database of net salvage transactions analyzed.

Request:

(a) Please identify each segment which will have reduced market value, the amount of market value reduction, and the timing of expected reduction.

(b) What type of industry participants have purchased facilities from NGTL, ex. producers, pipeline companies, gas processing companies, etc?

(c) Please provide NGTL's views on the rationale for the facility purchases made by these participants from NGTL.

(d) Please provide analysis of net salvage transactions which include data from divestiture transactions.

Response:

(a) Gannett Fleming's comments regarding the future market value of various segments were general in nature and based on the company interviews. The notes resulting from the company interviews are attached to the response to ATCO-NGTL-012(b).

Gannett Fleming does not view it as necessary to complete a detailed segment-by-segment analysis of the future marketability of the pipeline system to understand that

CAR-NGTL-013

a segment of a gas pipeline will likely have lower market value in the circumstance that all of the gas supply underpinning the pipeline is exhausted. While some alternative uses may exist in certain circumstances, it is the view of Gannett Fleming, based on the staff interviews, that as gas supply becomes more limited, the future divesture opportunities for pipeline segments will also become more limited.

(b) Producers, pipeline companies and gas processing companies have purchased facilities from NGTL.

(c) The purchase of NGTL facilities was more orderly and economic than the participants' alternatives.

(d) Attachment CAR-NGTL-013(d) provides the net salvage detail including the divestiture transactions, summarized in the same manner as the net salvage analysis provided in the Depreciation Study from pages III-54 to III-74.

The purpose of completing a study of appropriate net salvage percentages is to estimate future costs of retirements, and gross salvage proceeds for the assets remaining currently in service. To the extent that historical transactions can be considered indicative of the future, an analysis of the past transactions is appropriate and meaningful. However, a review of the historical trends is only useful if the historical events that are not considered likely to repeat at the same pace into the future are eliminated from the analysis. To include historical events that are not expected to continue into the future render the historical analysis less useful. As indicated in the filed depreciation study, these divestiture transactions were considered to be "outlier transactions" and were removed from the historical analysis.

PROGRAM OPTIONS IN EFFECT:

EXPERIENCE BAND	1993-2002
NET SALVAGE ANALYSIS	YES
NUMBER OF YEARS IN MOVING AVERAGE	3
TRAN CODES INCLUDED AS RETIREMENTS	0,2,0,0
COMBINE REUSE AND FINAL SALVAGE	YES

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4610 PIPELINES - LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1996	35,853-	18	0	46,646	130-	46,628	130-
1997	231,241	3,700	2	406,867	176	403,167	174
1998	112,766	7,227	6	24,132	21	16,905	15
1999	128,351	118,457-	92-	137,747	107	256,204	200
2000	217,448	517	0	3-	0	520-	0
2001	162,001		0		0		0
2002	136,706	6,034-	4-		0	6,034	4
TOTAL	952,660	113,029-	12-	615,389	65	728,418	76
THREE-YEAR MOVING AVERAGES							
96-98	102,718	3,648	4	159,215	155	155,567	151
97-99	157,453	35,843-	23-	189,582	120	225,425	143
98-00	152,855	36,904-	24-	53,959	35	90,863	59
99-01	169,267	39,313-	23-	45,915	27	85,228	50
00-02	172,052	1,839-	1-	1-	0	1,838	1
FIVE-YEAR AVERAGE							
98-02	151,454	23,349-	15-	32,375	21	55,724	37

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4611 METER STATION - LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1993							
1994	129		0	821	636	821	636
1995	2,191		0		0		0
1996	12,024	618	5		0	618-	5-
1997		509				509-	
1998	11,383	513	5		0	513-	5-
1999	361	209	58		0	209-	58-
2000	5,002	48	1		0	48-	1-
2001		15,750				15,750-	
2002	5,195	903-	17-		0	903	17
TOTAL	36,285	16,744	46	821	2	15,923-	44-

THREE-YEAR MOVING AVERAGES

93-95	773		0	274	35	274	35
94-96	4,781	206	4	274	6	68	1
95-97	4,738	376	8		0	376-	8-
96-98	7,802	547	7		0	547-	7-
97-99	3,915	410	10		0	410-	10-
98-00	5,582	257	5		0	257-	5-
99-01	1,788	5,336	298		0	5,336-	298-
00-02	3,399	4,965	146		0	4,965-	146-

FIVE-YEAR AVERAGE

98-02	4,388	3,123	71		0	3,123-	71-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4612 COMPRESSOR STATION - LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1996	1,677		0		0		0
1997							
1998							
1999							
2000							
2001							

2002	494	0	0	0
TOTAL	2,171	0	0	0

THREE-YEAR MOVING AVERAGES

96-98	559	0	0	0
97-99				
98-00				
99-01				
00-02	165	0	0	0

FIVE-YEAR AVERAGE

98-02	99	0	0	0

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4620 COMPRESSOR STATION - BUILDINGS

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	1,059,774	239,725	23	14,424	1	225,301-	21-
1994	3,887,085	434,512	11	54,283	1	380,229-	10-
1995	1,262,975	1,400,134	111	1,704	0	1,398,430-	111-
1996	527,201	118,809	23		0	118,809-	23-
1997	52,463	484,265	923		0	484,265-	923-
1998	29,972	16,610	55	3,554	12	13,056-	44-
1999	663,566	15,810	2		0	15,810-	2-
2000	2,447,218		0	37-	0	37-	0
2001	602,919		0		0		0
2002	714,904	13,113	2		0	13,113-	2-
TOTAL	11,248,077	2,722,978	24	73,928	1	2,649,050-	24-

THREE-YEAR MOVING AVERAGES

93-95	2,069,945	691,457	33	23,470	1	667,987-	32-
94-96	1,892,421	651,152	34	18,662	1	632,490-	33-
95-97	614,213	667,736	109	568	0	667,168-	109-
96-98	203,212	206,561	102	1,185	1	205,376-	101-
97-99	248,667	172,228	69	1,185	0	171,043-	69-
98-00	1,046,919	10,807	1	1,172	0	9,635-	1-
99-01	1,237,901	5,270	0	12-	0	5,282-	0
00-02	1,255,014	4,371	0	12-	0	4,383-	0

FIVE-YEAR AVERAGE

98-02	891,716	9,107	1	703	0	8,404-	1-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4621 COMPRESSOR STATION - SITE

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1993	361,429	1,343,638	372		0	1,343,638-	372-
1994	1,140,860	1,202,958	105		0	1,202,958-	105-
1995	420,481		0		0		0
1996	186,228	465,093	250		0	465,093-	250-
1997	1,012	13,900			0	13,900-	
1998	654	151	23		0	151-	23-
1999	47,540	192,909	406		0	192,909-	406-
2000	631,873	471,408	75	10-	0	471,418-	75-
2001	289,147	2,432-	1-		0	2,432	1
2002	327,670	43,369	13		0	43,369-	13-
TOTAL	3,406,894	3,730,994	110	10-	0	3,731,004-	110-
THREE-YEAR MOVING AVERAGES							
93-95	640,923	848,865	132		0	848,865-	132-
94-96	582,523	556,017	95		0	556,017-	95-
95-97	202,574	159,664	79		0	159,664-	79-
96-98	62,631	159,715	255		0	159,715-	255-
97-99	16,402	68,987	421		0	68,987-	421-
98-00	226,689	221,489	98	3-	0	221,492-	98-
99-01	322,853	220,628	68	3-	0	220,631-	68-
00-02	416,230	170,781	41	3-	0	170,784-	41-
FIVE-YEAR AVERAGE							
98-02	259,377	141,081	54	2-	0	141,083-	54-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4630 METER STATION - BUILDINGS

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1993	309,352	34,919	11	11,612	4	23,307-	8-
1994	801,722	37,644	5	114,338	14	76,694	10
1995	741,513	6,174	1	129	0	6,045-	1-

1996	699,375	33,080	5	67,275	10	34,195	5
1997	178,231	59,001	33	27,808	16	31,193-	18-
1998	922,243	235,559	26	4,571	0	230,988-	25-
1999	1,005,218	313,597	31	32,341	3	281,256-	28-
2000	1,860,858	531,955	29	128,890	7	403,065-	22-
2001	1,162,012	130,060	11	412,141	35	282,081	24
2002	1,060,643	99,205	9	309,493	29	210,288	20
TOTAL	8,741,167	1,481,194	17	1,108,598	13	372,596-	4-

THREE-YEAR MOVING AVERAGES

93-95	617,529	26,246	4	42,026	7	15,780	3
94-96	747,537	25,633	3	60,581	8	34,948	5
95-97	539,706	32,752	6	31,737	6	1,015-	0
96-98	599,950	109,213	18	33,218	6	75,995-	13-
97-99	701,897	202,719	29	21,573	3	181,146-	26-
98-00	1,262,773	360,370	29	55,267	4	305,103-	24-
99-01	1,342,696	325,204	24	191,124	14	134,080-	10-
00-02	1,361,171	253,740	19	283,508	21	29,768	2

FIVE-YEAR AVERAGE

98-02	1,202,195	262,075	22	177,487	15	84,588-	7-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4631 METER STATION - SITE

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	43,202	5,362	12		0	5,362-	12-
1994	161,278	16,360	10	38,010	24	21,650	13
1995	50,224		0		0		0
1996	141,445	5,747	4		0	5,747-	4-
1997	42,938	18,160	42	4,883	11	13,277-	31-
1998	193,718	47,440	24		0	47,440-	24-
1999	119,882	10,344	9		0	10,344-	9-
2000	496,104	759,286	153	2,550	1	756,736-	153-
2001	723,255	8,887	1	7,860	1	1,027-	0
2002	250,660	609,258	243		0	609,258-	243-
TOTAL	2,222,706	1,480,844	67	53,303	2	1,427,541-	64-

THREE-YEAR MOVING AVERAGES

93-95	84,902	7,241	9	12,670	15	5,429	6
94-96	117,649	7,369	6	12,670	11	5,301	5
95-97	78,202	7,969	10	1,628	2	6,341-	8-
96-98	126,034	23,782	19	1,628	1	22,154-	18-
97-99	118,846	25,315	21	1,628	1	23,687-	20-

98-00	269,902	272,357	101	850	0	271,507-	101-
99-01	446,414	259,506	58	3,470	1	256,036-	57-
00-02	490,006	459,144	94	3,470	1	455,674-	93-

FIVE-YEAR AVERAGE

98-02	356,724	287,043	80	2,082	1	284,961-	80-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4661 COMPRESSOR STATION - COMPRESSOR UNIT

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	5,630,675	1,033,226	18	27,118	0	1,006,108-	18-
1994	21,253,183	1,182,737	6	1,409,954	7	227,217	1
1995	10,401,314	180,651	2	28,213	0	152,438-	1-
1996	6,578,713	199,070	3	5,864,591	89	5,665,521	86
1997	3,581,755	231,498-	6-	979,578	27	1,211,076	34
1998	817,834	140,999	17	2,167,997	265	2,026,998	248
1999	7,220,312	88,572	1	4,409,939	61	4,321,367	60
2000	14,497,158	158,819	1	1,285,652	9	1,126,833	8
2001	3,644,735	8,144	0		0	8,144-	0
2002	11,395,274	603,318	5	3,415,121	30	2,811,803	25
TOTAL	85,020,953	3,364,038	4	19,588,163	23	16,224,125	19

THREE-YEAR MOVING AVERAGES

93-95	12,428,391	798,871	6	488,428	4	310,443-	2-
94-96	12,744,403	520,820	4	2,434,252	19	1,913,432	15
95-97	6,853,927	49,408	1	2,290,794	33	2,241,386	33
96-98	3,659,434	36,190	1	3,004,055	82	2,967,865	81
97-99	3,873,300	643-	0	2,519,171	65	2,519,814	65
98-00	7,511,768	129,463	2	2,621,196	35	2,491,733	33
99-01	8,454,068	85,178	1	1,898,530	22	1,813,352	21
00-02	9,845,722	256,760	3	1,566,924	16	1,310,164	13

FIVE-YEAR AVERAGE

98-02	7,515,063	199,970	3	2,255,742	30	2,055,772	27

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4662 COMPRESSOR STATION - PIPING

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	2,578,012	436,910	17	63,017	2	373,893-	15-
1994	8,945,284	1,015,498	11	188,273	2	827,225-	9-
1995	5,142,602	1,202,170	23	37,763	1	1,164,407-	23-
1996	2,384,473	343,560	14	38,286	2	305,274-	13-
1997	1,311,224	247,230	19		0	247,230-	19-
1998	760,478	25,655	3	109,239	14	83,584	11
1999	5,144,781	259,574	5		0	259,574-	5-
2000	5,547,196	558,150	10	121-	0	558,271-	10-
2001	2,740,051	56,930	2		0	56,930-	2-
2002	2,407,333	1,300,400	54	27,135	1	1,273,265-	53-
TOTAL	36,961,434	5,446,077	15	463,592	1	4,982,485-	13-

THREE-YEAR MOVING AVERAGES

93-95	5,555,299	884,859	16	96,351	2	788,508-	14-
94-96	5,490,786	853,742	16	88,107	2	765,635-	14-
95-97	2,946,100	597,653	20	25,350	1	572,303-	19-
96-98	1,485,392	205,482	14	49,175	3	156,307-	11-
97-99	2,405,494	177,487	7	36,413	2	141,074-	6-
98-00	3,817,485	281,126	7	36,373	1	244,753-	6-
99-01	4,477,343	291,551	7	40-	0	291,591-	7-
00-02	3,564,860	638,493	18	9,005	0	629,488-	18-

FIVE-YEAR AVERAGE

98-02	3,319,968	440,142	13	27,251	1	412,891-	12-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4663 COMPRESSOR STATION - INSTRUMENTATION

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	276,757	42,824	15	17,867	6	24,957-	9-
1994	866,953	101,726	12	7,771	1	93,955-	11-
1995	257,456	600,573	233	380,126	148	220,447-	86-
1996	68,754	1,276	2		0	1,276-	2-
1997	211,395	13,911	7		0	13,911-	7-
1998	174,100	26,157	15		0	26,157-	15-
1999	355,670	199	0		0	199-	0
2000	388,718		0	15-	0	15-	0
2001	215,816		0		0		0
2002	40,873		0		0		0
TOTAL	2,856,492	786,666	28	405,749	14	380,917-	13-

THREE-YEAR MOVING AVERAGES

93-95	467,055	248,374	53	135,255	29	113,119-	24-
94-96	397,721	234,525	59	129,299	33	105,226-	26-
95-97	179,202	205,253	115	126,709	71	78,544-	44-
96-98	151,416	13,781	9		0	13,781-	9-
97-99	247,055	13,422	5		0	13,422-	5-
98-00	306,163	8,785	3	5-	0	8,790-	3-
99-01	320,068	66	0	5-	0	71-	0
00-02	215,136		0	5-	0	5-	0

FIVE-YEAR AVERAGE

98-02	235,035	5,271	2	3-	0	5,274-	2-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4664 COMPRESSOR STATION - ELECTRICAL SYSTEM

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	388,702	59,695	15	21,832	6	37,863-	10-
1994	2,930,517	312,244	11	58,489	2	253,755-	9-
1995	1,039,412	33,150	3	26,756	3	6,394-	1-
1996	578,386	79,367	14	500	0	78,867-	14-
1997	150,739	20,366	14		0	20,366-	14-
1998	12,239	15,085	123		0	15,085-	123-
1999	159,728	589	0		0	589-	0
2000	1,246,709		0	39-	0	39-	0
2001	330,965	26,283-	8-		0	26,283	8
2002	222,278	34,251	15		0	34,251-	15-
TOTAL	7,059,675	528,464	7	107,538	2	420,926-	6-

THREE-YEAR MOVING AVERAGES

93-95	1,452,877	135,029	9	35,692	2	99,337-	7-
94-96	1,516,105	141,587	9	28,581	2	113,006-	7-
95-97	589,512	44,294	8	9,085	2	35,209-	6-
96-98	247,121	38,273	15	167	0	38,106-	15-
97-99	107,569	12,013	11		0	12,013-	11-
98-00	472,892	5,225	1	13-	0	5,238-	1-
99-01	579,134	8,565-	1-	13-	0	8,552	1
00-02	599,984	2,656	0	13-	0	2,669-	0

FIVE-YEAR AVERAGE

98-02	394,384	4,728	1	8-	0	4,736-	1-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4665 COMPRESSOR STATION - CONTROL SYSTEM

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	773,558	103,772	13		0	103,772-	13-
1994	2,107,938	248,966	12	3,000	0	245,966-	12-
1995	2,178,334	65,941	3	4,760	0	61,181-	3-
1996	291,433	32,289	11		0	32,289-	11-
1997	319,979	19,137	6		0	19,137-	6-
1998	327,198	136	0		0	136-	0
1999	416,265	3,334	1		0	3,334-	1-
2000	1,055,660		0	27-	0	27-	0
2001	113,517	9,534	8		0	9,534-	8-
2002	437,701	12,900	3		0	12,900-	3-
TOTAL	8,021,583	496,009	6	7,733	0	488,276-	6-

THREE-YEAR MOVING AVERAGES

93-95	1,686,610	139,560	8	2,587	0	136,973-	8-
94-96	1,525,902	115,732	8	2,587	0	113,145-	7-
95-97	929,915	39,122	4	1,587	0	37,535-	4-
96-98	312,870	17,187	5		0	17,187-	5-
97-99	354,481	7,536	2		0	7,536-	2-
98-00	599,708	1,157	0	9-	0	1,166-	0
99-01	528,480	4,289	1	9-	0	4,298-	1-
00-02	535,626	7,478	1	9-	0	7,487-	1-

FIVE-YEAR AVERAGE

98-02	470,068	5,181	1	5-	0	5,186-	1-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4670 METER STATION - AUTOMATION

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	315,300	8,389	3	56,971-	18-	65,360-	21-
1994	959,513	30,088	3	100,816	11	70,728	7
1995	2,615,115	38,192	1	172	0	38,020-	1-

1996	999,410	16,462-	2-	21,507	2	37,969	4
1997	2,041,324	15,484	1	3,377	0	12,107-	1-
1998	1,452,211	33,760	2		0	33,760-	2-
1999	503,804	67,861	13	22,714	5	45,147-	9-
2000	1,387,335	43,641	3	74,199	5	30,558	2
2001	621,694	68,520	11	278,706	45	210,186	34
2002	653,159		0	24,475	4	24,475	4
TOTAL	11,548,865	289,473	3	468,995	4	179,522	2

THREE-YEAR MOVING AVERAGES

93-95	1,296,643	25,556	2	14,672	1	10,884-	1-
94-96	1,524,679	17,272	1	40,832	3	23,560	2
95-97	1,885,283	12,405	1	8,352	0	4,053-	0
96-98	1,497,648	10,927	1	8,295	1	2,632-	0
97-99	1,332,446	39,035	3	8,697	1	30,338-	2-
98-00	1,114,450	48,421	4	32,304	3	16,117-	1-
99-01	837,611	60,007	7	125,206	15	65,199	8
00-02	887,396	37,387	4	125,793	14	88,406	10

FIVE-YEAR AVERAGE

98-02	923,641	42,756	5	80,019	9	37,263	4

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4671 METER STATION - INSTRUMENTATION

SUMMARY OF BOOK SALVAGE

		COST OF REMOVAL		GROSS SALVAGE		NET SALVAGE	
YEAR	RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1993	1,685,460	75,580	4	126,196	7	50,616	3
1994	3,076,316	76,108	2	523,505	17	447,397	15
1995	5,205,077	217,147	4	109,734	2	107,413-	2-
1996	2,172,352	71,453	3	151,920	7	80,467	4
1997	909,736	83,703	9	106,170	12	22,467	2
1998	773,447	87,796	11		0	87,796-	11-
1999	516,061	91,902	18	59,866	12	32,036-	6-
2000	1,247,755	7,934	1	14,550	1	6,616	1
2001	1,308,457	77,087	6	100,283	8	23,196	2
2002	825,728	67,339	8	249,355	30	182,016	22
TOTAL	17,720,389	856,049	5	1,441,579	8	585,530	3

THREE-YEAR MOVING AVERAGES

93-95	3,322,284	122,945	4	253,145	8	130,200	4
94-96	3,484,581	121,570	3	261,720	8	140,150	4
95-97	2,762,388	124,101	4	122,608	4	1,493-	0
96-98	1,285,179	80,984	6	86,030	7	5,046	0
97-99	733,081	87,800	12	55,345	8	32,455-	4-

98-00	845,755	62,544	7	24,805	3	37,739-	4-
99-01	1,024,091	58,974	6	58,233	6	741-	0
00-02	1,127,313	50,787	5	121,396	11	70,609	6
FIVE-YEAR AVERAGE							
98-02	934,290	66,412	7	84,811	9	18,399	2

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4672 METER STATION - PIPING

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	2,895,730	224,613	8	63,886	2	160,727-	6-
1994	4,494,916	232,270	5	1,198,035	27	965,765	21
1995	2,375,844	36,843	2	34,837	1	2,006-	0
1996	1,535,520	33,715	2		0	33,715-	2-
1997	1,981,066	2,284,199	115	11,006	1	2,273,193-	115-
1998	2,343,592	462,335	20	27,975	1	434,360-	19-
1999	1,573,532	188,383	12	47,466	3	140,917-	9-
2000	5,075,545	880,794	17	66,070	1	814,724-	16-
2001		381,868		667,486		285,618	
2002	3,163,715	1,040,949	33	730,609	23	310,340-	10-
TOTAL	25,439,460	5,765,969	23	2,847,370	11	2,918,599-	11-
THREE-YEAR MOVING AVERAGES							
93-95	3,255,497	164,575	5	432,253	13	267,678	8
94-96	2,802,094	100,942	4	410,957	15	310,015	11
95-97	1,964,144	784,919	40	15,281	1	769,638-	39-
96-98	1,953,393	926,750	47	12,993	1	913,757-	47-
97-99	1,966,064	978,306	50	28,815	1	949,491-	48-
98-00	2,997,556	510,504	17	47,170	2	463,334-	15-
99-01	2,216,359	483,682	22	260,341	12	223,341-	10-
00-02	2,746,420	767,870	28	488,055	18	279,815-	10-
FIVE-YEAR AVERAGE							
98-02	2,431,277	590,866	24	307,921	13	282,945-	12-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4673 METER STATION - ELECTRICAL SYSTEM

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	166,772	9,941	6		0	9,941-	6-
1994	473,096	8,459	2	132,177	28	123,718	26
1995	659,577	166,065	25	596,655	90	430,590	65
1996	446,742	14,651	3		0	14,651-	3-
1997	350,891	14,531	4	18,861	5	4,330	1
1998	648,935	38,270	6		0	38,270-	6-
1999	445,334	72,240	16	19,349	4	52,891-	12-
2000	1,272,109	172,310	14	52,464	4	119,846-	9-
2001	1,007,877	33,337-	3-	127,104	13	160,441	16
2002	634,429	2,844	0	63,929	10	61,085	10
TOTAL	6,105,762	465,974	8	1,010,539	17	544,565	9

THREE-YEAR MOVING AVERAGES

93-95	433,148	61,488	14	242,944	56	181,456	42
94-96	526,472	63,058	12	242,944	46	179,886	34
95-97	485,737	65,082	13	205,172	42	140,090	29
96-98	482,189	22,484	5	6,287	1	16,197-	3-
97-99	481,720	41,680	9	12,736	3	28,944-	6-
98-00	788,793	94,273	12	23,938	3	70,335-	9-
99-01	908,440	70,404	8	66,306	7	4,098-	0
00-02	971,472	47,272	5	81,166	8	33,894	3

FIVE-YEAR AVERAGE

98-02	801,737	50,465	6	52,569	7	2,104	0

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4821 GENERAL PLANT - OFFICE BUILDINGS

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1994	217,531	69,110	32	54,818	25	14,292-	7-
1995	4,523,206		0		0		0
1996	167,653	32,672	19	113,668	68	80,996	48
1997	20,870,103	68,753	0	6,165,110	30	6,096,357	29
1998	1,445,889	83,871	6	507,373	35	423,502	29
1999	711,184	14,280	2		0	14,280-	2-
2000	888,081	321,301	36	21-	0	321,322-	36-
2001	38,649,282	1,451,579	4	13,691,313	35	12,239,734	32
2002	2,312,611	380,305	16	604,847	26	224,542	10
TOTAL	69,785,540	2,421,871	3	21,137,108	30	18,715,237	27

THREE-YEAR MOVING AVERAGES

94-96	1,636,130	33,927	2	56,162	3	22,235	1
95-97	8,520,321	33,808	0	2,092,926	25	2,059,118	24
96-98	7,494,548	61,765	1	2,262,050	30	2,200,285	29
97-99	7,675,725	55,635	1	2,224,161	29	2,168,526	28
98-00	1,015,051	139,817	14	169,117	17	29,300	3
99-01	13,416,182	595,720	4	4,563,764	34	3,968,044	30
00-02	13,949,991	717,728	5	4,765,380	34	4,047,652	29

FIVE-YEAR AVERAGE

98-02	8,801,409	450,267	5	2,960,702	34	2,510,435	29

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4841 GENERAL PLANT - VEHICLES & TRAILERS

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	2,211,582	12,795	1	556,433	25	543,638	25
1994	4,918,694	731	0	1,728,562	35	1,727,831	35
1995	4,632,912	210,004	5	75	0	209,929-	5-
1996	6,969,079	12,310	0	2,004,976	29	1,992,666	29
1997	1,945,044	522,551	27	2,454,302	126	1,931,751	99
1998	5,425,129	64,037	1	1,676,653	31	1,612,616	30
1999		45,525		1,332,112		1,286,587	
2000	2,591,344	146,817	6		0	146,817-	6-
2001							
2002	1,240,169	698	0	883,706	71	883,008	71
TOTAL	29,933,953	1,015,468	3	10,636,819	36	9,621,351	32

THREE-YEAR MOVING AVERAGES

93-95	3,921,063	74,510	2	761,690	19	687,180	18
94-96	5,506,895	74,348	1	1,244,537	23	1,170,189	21
95-97	4,515,678	248,288	5	1,486,451	33	1,238,163	27
96-98	4,779,751	199,633	4	2,045,310	43	1,845,677	39
97-99	2,456,724	210,704	9	1,821,022	74	1,610,318	66
98-00	2,672,158	85,460	3	1,002,922	38	917,462	34
99-01	863,781	64,114	7	444,037	51	379,923	44
00-02	1,277,171	49,172	4	294,569	23	245,397	19

FIVE-YEAR AVERAGE

98-02	1,851,328	51,415	3	778,494	42	727,079	39

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4850 GENERAL PLANT - HEAVY WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	12,664		0	7,870	62	7,870	62
1994	597,096		0	108,450	18	108,450	18
1995	682,690	935	0	1,816,404	266	1,815,469	266
1996	3,297,288		0	2,321,006	70	2,321,006	70
1997	518,683	60,495-	12-	149,798	29	210,293	41
1998	2,022,071	62,356	3	80,877	4	18,521	1
1999		11,381		231,707		220,326	
2000	5,307		0		0		0
2001							
2002	28,282		0		0		0
TOTAL	7,164,081	14,177	0	4,716,112	66	4,701,935	66

THREE-YEAR MOVING AVERAGES

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
93-95	430,816	312	0	644,241	150	643,929	149
94-96	1,525,691	312	0	1,415,287	93	1,414,975	93
95-97	1,499,553	19,853-	1-	1,429,069	95	1,448,922	97
96-98	1,946,014	621	0	850,560	44	849,939	44
97-99	846,918	4,414	1	154,127	18	149,713	18
98-00	675,793	24,579	4	104,194	15	79,615	12
99-01	1,769	3,794	214	77,236		73,442	
00-02	11,196		0		0		0

FIVE-YEAR AVERAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
98-02	411,132	14,747	4	62,517	15	47,770	12

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT PIP.E0

SUMMARY OF BOOK SALVAGE

YEAR	RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	1,204,650	748,834	62	55,974	5	692,860-	58-
1994	4,135,451	502,950	12	411,612	10	91,338-	2-
1995	21,374,246	319,956	1	3,860	0	316,096-	1-
1996	3,240,951	277,522	9	2,658,354	82	2,380,832	73
1997	6,357,628	188,248	3	11,972,220	188	11,783,972	185

1998	4,653,634	550,467	12	1,224,140	26	673,673	14
1999	3,083,679	883,660	29	2,876,992	93	1,993,332	65
2000	20,081,123	262-	0	11,162,350	56	11,162,612	56
2001	6,538,091	136,897	2		0	136,897-	2-
2002	3,159,299	1,237,917	39		0	1,237,917-	39-
TOTAL	73,828,752	4,846,189	7	30,365,502	41	25,519,313	35

THREE-YEAR MOVING AVERAGES

93-95	8,904,782	523,914	6	157,149	2	366,765-	4-
94-96	9,583,549	366,810	4	1,024,609	11	657,799	7
95-97	10,324,275	261,909	3	4,878,145	47	4,616,236	45
96-98	4,750,738	338,746	7	5,284,905	111	4,946,159	104
97-99	4,698,313	540,792	12	5,357,784	114	4,816,992	103
98-00	9,272,812	477,955	5	5,087,827	55	4,609,872	50
99-01	9,900,964	340,098	3	4,679,781	47	4,339,683	44
00-02	9,926,171	458,184	5	3,720,783	37	3,262,599	33

FIVE-YEAR AVERAGE

98-02	7,503,165	561,736	7	3,052,696	41	2,490,960	33

CAR-NGTL-014

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix C – Depreciation Study, pg. II-12

Preamble:

Gannett Fleming states that a number of the compressor units, as they have been removed from service, have been sold into a seller's marketplace for this type of equipment, resulting in high level of gross salvage transactions in Account 4661 – Compressor Units. Gannett Fleming also states that the Company has indicated that this circumstance will not continue at the same pace into the future; and, as such, Gannett Fleming is recommending an increase in the net salvage percentage from 0 percent to +5 percent.

Request:

(a) Please provide all internal and external studies and workpapers that support the Company's view that this circumstance will not continue.

(b) Please provide detailed information regarding at what pace will "this circumstance" continue into the future.

(c) Please provide detailed information related to the sales of individual compressor units in a format similar to the salvage analysis table on pg. III-62.

Response:

(a) and (b)

Gannett Fleming's comments regarding the sale and future marketability of the compression units were general in nature and based on the company interviews. The notes resulting from the company interviews are attached to the response to ATCO-NGTL-012(b).

CAR-NGTL-014

Gannett Fleming does not view it as necessary to complete a detailed company-by-company analysis of all gas pipelines to understand the general trends of net salvage percentage recommendations within the pipeline industry.

Gannett Fleming, when reviewing the compression unit account, considered three factors in making a recommendation of a positive salvage value of 5%:

i. There is a not a current match of cost of removal expenditures to the retirement of plant, as a number of units that have been retired, have not yet been physically removed. The expenditures to remove these units will be made in future years. As such, historic percentages of cost of removal expenditures to original cost retired are too low.
ii. It is anticipated by NGTL that the ability to sell used compression equipment into the marketplace will diminish significantly in the future. As such the historic trends of gross salvage proceeds are overstated when compared to the future expectations.
iii. The ability to re-use compression units has been limited in the past. However, it is anticipated by the company that the pace of re-use for compression units will slow in the future as overall gas supply declines.

In consideration of the above three factors, the historic indications of net salvage are not an accurate representation of the future expectations. As historic data were not entered in the plant accounting systems on a unit-by-unit basis, as the unit-by-unit information is not required under Alberta Regulation 546/63,[1] elimination from the databases of the outlier transactions was not possible. However, Gannett Fleming did not want to completely discard the historic indications of some positive salvage entirely. As such, Gannett Fleming recommended an increase in the level of positive salvage from 0% to +5%, and will continue to monitor this account closely in future studies.

(c) The source retirement and cost of retirement data were not recorded into the plant accounting systems on a unit-by-unit basis, as the unit-by-unit information is not required by the Board.[2] As such, this request would involve the detailed manual review of all compression retirement orders, in order to specifically identify the original cost, cost of removal and gross salvage proceeds specific to the units that were sold. The requested information cannot be provided with reasonable effort.

[1, 2] Alberta Regulation 546/63, Uniform Classification of Accounts for Natural Gas Utilities.

CAR-NGTL-015

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix C – Depreciation Study, pg. II-12

Preamble:

Gannett Fleming states that the Company has also, in recent years, undertaken an optimization program of metering facilities. Gannett Fleming also states that while it is not expected that the pace of reuse of metering facilities will continue into the future, it is anticipated that some level of this activity will continue to occur.

Request:

(a) Please provide all internal and external studies and workpapers which support the Company's view that this circumstance will not continue.

(b) Please provide detailed information regarding what pace will "this circumstance" continue into the future.

(c) Please provide detailed information related to reuse transactions on an annual basis in a format similar to the salvage analysis tables on pg. III-55 to III-74.

Response:

(a) and (b)
Gannett Fleming's comments regarding the reuse of the meter stations were general in nature and based on the company interviews. The notes resulting from the company interviews are attached to the response to ATCO-NGTL-012(b).

(c) NGTL does not segregate the salvage entries through the accumulated depreciation account between final and reuse salvage. As such, the requested analysis cannot be prepared without an extensive manual review of all of the salvage entries from 1993 through 2002. Please refer to the response to ATCO-NGTL-027(b) for a description of the analysis undertaken in the development of the net salvage percentages for the meter station accounts.

CAR-NGTL-016

Issue:

Depreciation

Reference:

Section 4.0 – Depreciation, Appendix C – Depreciation Study, pg. III-55 to III-74

Preamble:

Gannett Fleming provides Salvage Analysis tables for individual accounts for the years 1993 to 2002.

Request:

(a) Please provide Salvage Analysis tables for Account 4651 – Pipe and Account 4652 – Valve Assemblies. If unable to provide, please explain in detail why?

(b) Please provide Salvage Analysis tables for individual accounts with all historical salvage data included for all years prior to 1993. In unable to provide, please explain in detail why?

Response:

(a) Attachment CAR-NGTL-016(a) provides the requested analysis.

(b) Detailed transaction files from prior depreciation analyses were used for this study. The totals from such data files were balanced to the plant accounting system. In the view of Gannett Fleming, the most recent 10-year band of salvage analysis provides the most appropriate period as well as a sufficient period of analysis from which net salvage percentages can be developed.

The net salvage data prior to 1993 cannot be easily verified. The evidentiary value of the requested information would be in any event far outweighed by the time and effort required to locate, compile and review the material.

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4651 PIPELINES - PIPE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	886,658	672,363	76	55,028	6	617,335-	70-
1994	2,883,656	485,649	17	411,612	14	74,037-	3-
1995	20,722,657	265,332	1	3,587	0	261,745-	1-
1996	546,327	271,255	50	47,757	9	223,498-	41-
1997							
1998							
1999	1,499,007		0		0		0
2000							
2001	3,465,920	7,770-	0		0	7,770	0
2002	2,835,141	1,191,120	42		0	1,191,120-	42-
TOTAL	32,839,366	2,877,949	9	517,984	2	2,359,965-	7-

THREE-YEAR MOVING AVERAGES

93-95	8,164,323	474,448	6	156,743	2	317,705-	4-
94-96	8,050,880	340,745	4	154,319	2	186,426-	2-
95-97	7,089,661	178,862	3	17,115	0	161,747-	2-
96-98	182,109	90,418	50	15,919	9	74,499-	41-
97-99	499,669		0		0		0
98-00	499,669		0		0		0
99-01	1,654,976	2,590-	0		0	2,590	0
00-02	2,100,353	394,450	19		0	394,450-	19-

FIVE-YEAR AVERAGE

98-02	1,560,014	236,670	15		0	236,670-	15-

NOVA GAS TRANSMISSION LTD.

SALVAGE ANALYSIS 1993 - 2002 TRANSACTIONS

ACCOUNT 4652 PIPELINES - VALVE ASSEMBLIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1993	317,992	76,471	24	946	0	75,525-	24-
1994	1,251,795	17,301	1		0	17,301-	1-
1995	651,590	54,624	8	273	0	54,351-	8-
1996	294,624	6,267	2		0	6,267-	2-
1997							
1998							
1999	355,649	150,876	42	136,943	39	13,933-	4-
2000	1,089,723	7,393-	1-	34-	0	7,359	1
2001							
2002							
TOTAL	3,961,373	298,146	8	138,128	3	160,018-	4-

THREE-YEAR MOVING AVERAGES

93-95	740,459	49,466	7	406	0	49,060-	7-
94-96	732,669	26,064	4	91	0	25,973-	4-
95-97	315,404	20,297	6	91	0	20,206-	6-
96-98	98,208	2,089	2		0	2,089-	2-
97-99	118,550	50,292	42	45,648	39	4,644-	4-
98-00	481,791	47,828	10	45,636	9	2,192-	0
99-01	481,791	47,828	10	45,636	9	2,192-	0
00-02	363,241	2,464-	1-	11-	0	2,453	1

FIVE-YEAR AVERAGE

98-02	289,075	28,697	10	27,382	9	1,315-	0

CAR-NGTL-017

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.2 – The Fort McMurray Area

Request:

(a) Does NGTL have an obligation to serve customers in the Fort McMurray area?

(b) If yes, please explain why, and provide all supporting documents and information.

Response:

(a) and (b)

While NGTL does not have an obligation to serve as that term is commonly used in utility regulation, it is in the business of providing gas transmission service in Alberta. NGTL has executed FCS Agreements with customers requesting delivery service to the Fort McMurray area. NGTL will under those agreements make reasonable efforts to obtain necessary regulatory approvals to provide the requested service.

CAR-NGTL-018(a)

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.8 – The TransCanada Pipeline Ventures Limited Partnership Arrangement

Request:

What was the original cost of Ventures Oil Sands Pipeline?

Response:

NGTL understands from the Ventures Oil Sands Pipeline's hearing transcripts dated November 13, 1998 that Jim McPherson, Vice-President, in his opening remarks indicated the estimated construction cost of the pipeline to be $50 million. Additional facilities have since been added to the Oil Sands Pipeline.

CAR-NGTL-018(b)

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.8 – The TransCanada Pipeline Ventures Limited Partnership Arrangement

Request:

On an annual basis since date of first flow to the present, please provide the net book value of Ventures Oil Sands Pipeline.

Response:

NGTL does not have the requested information.

CAR-NGTL-018(c) and (d)

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.8 – The TransCanada Pipeline Ventures Limited Partnership Arrangement

Request:

(c) On an annual basis from the April 1st, 2004 to April 1st, 2029, please provide forecasted replacement cost for Ventures Oil Sands Pipeline.

(d) Please specify the source of the data with respect to replacement cost.

Response:

(c) The estimated aggregate replacement cost of the Ventures Oil Sands pipeline, Oil Sands Extension, Buffalo compressor station, and meter stations owned by Ventures in the Fort McMurray area is shown in the table below. The replacement costs do not include the Moosa Lateral. The replacement cost of the Ventures facilities is assumed to increase at a rate of 2% per year.

Year	Cost ($millions)	Year	Cost ($millions)
2003	93.74	2017	123.69
2004	95.61	2018	126.16
2005	97.53	2019	128.68
2006	99.48	2020	131.26
2007	101.47	2021	133.88
2008	103.50	2022	136.56
2009	105.57	2023	139.29
2010	107.68	2024	142.08
2011	109.83	2025	144.92
2012	112.03	2026	147.82
2013	114.27	2027	150.77
2014	116.55	2028	153.79
2015	118.88	2029	156.87
2016	121.26		

(d) The forecasted replacement costs are based on internal NGTL cost estimates.

CAR-NGTL-018(e)

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.8 – The TransCanada Pipeline Ventures Limited Partnership Arrangement

Request:

Please explain why net book value would not be an acceptable purchase price for Ventures Oil Sands Pipeline.

Response:

Please refer to the response to BR-NGTL-30(b).

CAR-NGTL-018(f)

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.8 – The TransCanada Pipeline Ventures Limited Partnership Arrangement

Request:

If a premium or discount to net book value is appropriate, what is the value of the premium or discount and why is it considered appropriate?

Response:

The question is not relevant to the Application. NGTL is not applying to acquire the Ventures assets at this point in time.

CAR-NGTL-018(g)

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.8 – The TransCanada Pipeline Ventures Limited Partnership Arrangement

Request:

Who on behalf of NGTL and Ventures participated in negotiations for the TBO or purchase price of Ventures Oil Sands Pipeline?

Response:

The primary business representatives included:

For NGTL:
- Steve Clark - VP, Gas Development and Director, Sales & Marketing,
- Don Bell – Manager, Western End Users and Interconnects
- Dan Ronsky – Senior Customer Account Representative

For Ventures:
- Jeff Rush – President
- Francis MacMullin – Manager, Western Business Development

CAR-NGTL-018(h)

Issue:

Fort McMurray Area Delivery Service

Reference:

Sub-Section 8.8 – The TransCanada Pipeline Ventures Limited Partnership Arrangement

Request:

Please provide detailed role descriptions of the individuals who participated in the negotiations for the TBO or purchase price of Ventures Oil Sands Pipeline, including duties and reporting structure.

Response:

Please refer to the response to CAR-NGTL-018(g).