# 2.1 REVENUE REQUIREMENT SUMMARY

## 2.1.1 2002 - 2004 Revenue Requirement

Schedule 2.1.1 provides a summary, by component, of the revenue requirements for the 2002 base year, the 2003 ~~forecast~~actual year, and the 2004 test year. Both the 2002 and 2003 revenue requirements were determined through negotiated settlements and represent compromise positions that were acceptable to the negotiating parties.

The total revenue requirement requested for 2004 is $~~1,349~~ 1,356 million, compared to $1,286 million in 2003 and $1,290 million in 2002. The change from the 2003 revenue requirement to the amount requested for 2004 is primarily due to the increase in Non-Routine Adjustments. The final Non-Routine Adjustments amount related to 2003 that ~~will be~~is included in the 2004 revenue requirement ~~will not be known until the end of 2003~~is $33 million. ~~However, NGTL expects that~~This primarily relates to lower volumes being transported in 2003 than forecast, ~~will~~ resulting in significant balances in the 2003 Throughput Volume Revenue and Firm Service Demand Revenue deferral accounts, which are included in the Non-Routine Adjustments amount.

Smaller increases also occur in Operating Costs, Depreciation and Amortization, Income and Large Corporation Taxes~~ and~~, TBO and Pipeline Integrity Expense. These increases are partially offset by a decrease in the Annual Foreign Exchange Amortization Amount.

Operating Costs are increasing in 2004 primarily due to the inclusion of severance costs in 2004, along with increases in total direct compensation and benefits. Depreciation and Amortization costs for 2004 are based on the evidence filed in Section 4.0 of this Application. NGTL seeks, based on the filed depreciation study, rates that result in a composite depreciation rate of 4.13% in 2004 as compared to the negotiated composite rate of 4.0% used in both 2002 and 2003. The increase in income taxes is due to the increase in Depreciation and Amortization plus the impact of lower Capital Cost Allowance (CCA) deductions available and higher return related to equity, partially offset by a lower expected tax rate in 2004. The increase in TBO costs is due to a new arrangement with

TransCanada Pipeline Ventures Limited Partnership, which is described in Section 8, and a forecast increase in Foothills' costs. Pipeline Integrity Expenses are increasing primarily as a result of two line breaks that occurred in December 2003, after which the Alberta System's corrosion program was re-analyzed and additional projects were identified. These increases are partially offset by a decrease in the Annual Foreign Exchange Amortization Amount that is the result of the recent strengthening in the Canadian dollar against the U.S. dollar.

### 2.1.2 Revenue Requirement History

Schedule 2.1.2 shows average rate base and total revenue requirement broken down by major cost categories for the years 1995 to 2004. The last general rate application filed by NGTL was in 1995. From 1996 to 2003, the Alberta System's revenue requirement was determined under various negotiated settlements, specifically:

- From 1996 to 2000, revenue requirement was determined under the provisions of the Cost Efficiency Incentive Settlement (CEIS).
- In 2001 and 2002, revenue requirement was based on the provisions of the Alberta System Rate Settlement (ASRS).
- In 2003, the revenue requirement was based on the provisions of the Alberta System Revenue Requirement Settlement (ASRRS).

The 1995 revenue requirement approved by the Board was $1,065 million as determined in Decision U96001, amended by Decision U96020. Revenue requirement increased in the following years until 2000 largely due to an increasing rate base and the related increase in capital-related costs and gradually increasing composite depreciation rates (2.96% to 3.5%). These increases were partially offset by lower TBO and Operating Costs.

From 2000 to 2002, capital expenditures levels were lower with a corresponding decrease in rate base and capital-related costs. Operating Costs have continued to decrease even with the addition of approximately $44 million of indirect costs that were previously capitalized. These decreases were partially offset by an increase in the composite depreciation rate to 4.0% in 2001.

Income and Large Corporation Taxes have also increased significantly since 1995. The income tax amount included in the Alberta System's revenue requirement is calculated on a flow-through basis and, therefore, is impacted by timing differences created due to differences between the depreciation and amortization expense calculated for accounting purposes and the CCA deduction allowed for tax purposes. As a result of lower capital expenditures and higher depreciation rates, the relationship between depreciation and amortization and CCA has reversed, resulting in a large increase in the income tax amount included in revenue requirement. This increase would be even larger had income tax rates not decreased from 44.57% to 34.62% since 1995.

While capital-related costs have increased since 1995, Operating Costs have decreased significantly. Allowed Operating Costs in 1995 were approximately $271 million. In addition, approximately $58 million of Operating Costs indirectly related to the capital program were capitalized in 1995, for a total of $329 million. Such costs are no longer capitalized and are now included in the Operating Cost amount recovered through revenue requirement. By comparison, NGTL is requesting an Operating Cost amount of $~~205~~ 208 million in 2004. This significant reduction has been achieved through initiatives undertaken to achieve operational excellence and by efficiencies gained through functional integration following the merger with TCPL. NGTL is continuing its efforts to maintain these efficiencies in light of ongoing pressures to increase compensation levels in order to remain market competitive and inflationary pressures on other costs. NGTL believes that the requested 2004 amount represents a level of costs that will allow it to operate its pipeline system safely, reliably, and cost effectively.

REVENUE REQUIREMENT SUMMARY

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | Operating Return | 2.2.1 | 476,634 | 440,799 | 437,123 |
| 2 | Operating Costs | 2.3 | 199,762 | 197,896 | 208,327 |
| 3 | Depreciation and Amortization | 2.4 | 292,882 | 293,791 | 302,203 |
| 4 | Income and Large Corporation Taxes | 2.5.1 | 177,611 | 161,147 | 168,494 |
| 5 | Property Taxes | 2.6 | 65,439 | 68,832 | 72,300 |
| 6 | Transportation by Others | 2.7 | 79,597 | 76,780 | 83,886 |
| 7 | Foreign Exchange on Interest Payments | 2.8.1 | 16,760 | 5,809 | 3,420 |
| 8 | Regulatory Hearing Costs | 2.9 | 1,741 | 5,381 | 5,834 |
| 9 | Uninsured Losses | 2.10 | 4,141 | 3,422 | 4,000 |
| 10 | Pipeline Integrity Expense | 2.11 | 5,276 | 10,846 | 19,565 |
| 11 | $CO_2$ Management Service Costs | 2.12 | N/A | 4,458 | 2,852 |
| 12 | Amortization of Severance Costs | 2.13.3 | 5,657 | 8,899 | 11,855 |
| 13 | Revenue Requirement Adjustments | 2.13.1 | 21,500 | (1,060) | N/A |
| 14 | Negotiated Revenue Requirement Per ASRS and ASRRS | | 1,347,000 | 1,277,000 | N/A |
| 15 | Annual Foreign Exchange Amortization Amount | 2.8.2 | 21,431 | 18,704 | 3,378 |
| 16 | Non-Routine Adjustments | 2.13.2 | (78,125) | (21,980) | 32,590 |
| 17 | $CO_2$ Management Service Costs Estimate | | N/A | 12,000 | N/A |
| 18 | **Total Revenue Requirement** | | 1,290,306 | 1,285,724 | 1,355,827 |

**NOVA** GAS TRANSMISSION LTD.

RATE BASE AND REVENUE REQUIREMENT HISTORY

FOR THE YEARS ENDED DECEMBER 31
($Thousands)

| LINE NO. | DESCRIPTION | 1995 (1) | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Average Rate Base** | 4,451,994 | 4,750,286 | 4,808,131 | 4,941,016 | 5,224,961 | 5,220,115 | 5,156,045 | 5,042,082 | 4,871,658 | 4,661,460 |
| | **Revenue Requirement** | | | | | | | | | | |
| 2 | Operating Return | 442,805 | 465,375 | 467,551 | 485,246 | 506,485 | 513,210 | 513,556 | 476,634 | 440,799 | 437,123 |
| 3 | Operating Costs | 270,544 | 249,122 | 252,118 | 231,374 | 230,268 | 233,185 | 175,525 | 199,762 | 197,896 | 208,327 |
| 4 | Depreciation and Amortization | 166,012 | 182,812 | 193,918 | 208,539 | 230,199 | 250,660 | 289,302 | 292,882 | 293,791 | 302,203 |
| 5 | Income and Capital Taxes | 10,278 | 74,755 | 98,463 | 109,093 | 137,457 | 167,804 | 196,412 | 177,611 | 161,147 | 168,494 |
| 6 | Property Taxes | 68,479 | 70,682 | 75,470 | 75,457 | 75,352 | 72,318 | 65,212 | 65,439 | 68,832 | 72,300 |
| 7 | Transportation by Others | 96,862 | 88,888 | 82,604 | 82,593 | 77,522 | 77,372 | 86,518 | 79,597 | 76,780 | 83,886 |
| 8 | Other Costs | 9,858 | 18,366 | 65,236 | 69,930 | 58,650 | 105,659 | 66,514 | (1,619) | 46,479 | 83,494 |
| 10 | | 1,064,838 | 1,150,000 | 1,235,360 | 1,262,232 | 1,315,933 | 1,420,209 | 1,393,040 | 1,290,306 | 1,285,724 | 1,355,827 |
| 11 | **Indirect Capitalization** | 57,959 | 57,000 | 45,500 | 44,400 | 43,600 | 43,600 | 22,000 | - | - | - |

(1) 1995 revenue requirement as approved in Decisions U96001 and U96020.

## 2.2 OPERATING RETURN

Schedule 2.2.1 shows the operating return amount included in the revenue requirement for the 2004 test year. In 2002 and 2003, operating return was determined based on the provisions of the ASRS and ASRRS. Capital structure and rate of return on equity were not prescribed under these agreements and, therefore, are not provided for 2002 and 2003 in Schedule 2.2.1.

Operating return for the 2004 test year reflects NGTL's application in the Generic Cost of Capital Proceeding No. 1271597. NGTL has requested in that proceeding that the Board approve a rate of return of 11% on a deemed common equity of 40%. This approach is consistent with the Board's direction in its letter dated May 28, 2003, that a "placeholder be determined and applied until the outcome of the Generic Cost of Capital Proceeding is known and can be applied in lieu of the placeholder" in all general rate applications for the test periods including 2004 and later years submitted to the Board subsequent to May 28, 2003.

The calculation of operating return for the 2004 test year begins with the forecast thirteen-month weighted average capital outstanding, which includes rate base and gas plant under construction. The capital structure applied to this amount is based on the deemed 40% equity ratio, discussed above. A forecast of NGTL's average long-term debt outstanding is used to calculate the ratio of long-term debt in the capital structure. The remaining portion of the capital structure is unfunded debt. The unfunded debt ratio is calculated as total capital structure less the equity ratio and the long-term debt ratio. These capital ratios are then applied to the average rate base.

Cost factors are then applied to each component of the capital structure. The cost factor for equity is 11%, as applied for in the Generic Cost of Capital Proceeding. The cost factor for long-term debt is 8.63%, as calculated in Schedule 2.2.2, Sheet 3 of 3. The cost factor for unfunded debt is 3.90%, which is NGTL's forecast of its average short-term borrowing rate for 2004. All of NGTL's actual short-term financing requirements are currently, and will continue to be, met by TCPL.

**Weighted Average Cost of Long-Term Debt Outstanding**

Schedule 2.2.2 details the weighted average cost of long-term debt outstanding for the base year 2002, ~~forecast~~ actual year 2003 and test year 2004. These costs consist of the interest expense on long-term debt and the amortization of issue costs related to that debt.

The annual interest expense for each debt issue is based on the number of days that debt issue is outstanding during the year. For U.S. dollar denominated debt issues, the annual interest expense is calculated based on the historic exchange rate for each debt issue. The total interest expense plus the amortization of debt issue costs is then divided by the average long-term debt outstanding to determine the weighted average interest rate.

The effective interest rates on NGTL's Series 19, 20, and 21 debentures have been reduced in accordance with Order E92086, in which the Alberta Public Utilities Board (PUB) disallowed a portion of NGTL's long-term debt interest costs. These amounts are indicated on Schedule 2.2.2.

As per Order U99053 and NGTL's June 7, 1999 Application in that regard, the cost of long-term debt provided to NGTL by TCPL is based on the market cost of debt to TCPL for the relevant term as of the issue date. If TCPL raises long-term third party debt for NGTL, it passes on the cost of that debt. If long-term debt has not been raised from a third party, TCPL prices such debt using market rates provided by investment dealers.

**Weighted Average Long-Term Debt Outstanding**

Schedule 2.2.3 details the weighted average amount of long-term debt outstanding for the base year 2002, ~~forecast~~ actual year 2003 and test year 2004. Long-term debt includes bonds and medium term notes issued publicly by NGTL, as well as notes payable to TCPL.

As per Order U99053 and NGTL's June 7, 1999 Application, which led to the issuance of this order, NGTL intends to obtain from TCPL all future financial requirements that cannot be met with cash flow from NGTL's operations. Such borrowings will be on terms and conditions no less favourable than NGTL would obtain directly in the marketplace and on terms consistent with and no more onerous than those obtained by TCPL from third parties.

The weighted average long-term debt outstanding is determined by totaling the monthly balances, including the balance at the beginning of the year, and dividing the sum by thirteen.

**Amortization of Long-Term Debt Issue Expense**

Schedule 2.2.4 details the amortization of the issue costs related to the long-term debt outstanding for the base year 2002, ~~forecast~~ actual year 2003 and test year 2004. Issue costs are amortized over the term of the related debt.

OPERATING RETURN

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | AVERAGE CAPITAL OUTSTANDING | CAPITAL RATIO % [1] | AVERAGE RATE BASE | COST FACTOR % [1] | WEIGHTED COST % [1] | OPERATING RETURN |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 1 | Common Equity | 1,867,806 | 40.00% | 1,864,584 | 11.00% | 4.40% | 205,104 |
| 2 | Long Term Debt | 2,603,729 | 55.76% | 2,599,238 | 8.63% | 4.81% | 224,311 |
| 3 | Unfunded Debt | 197,980 | 4.24% | 197,638 | 3.90% | 0.17% | 7,708 |
| 4 | | 4,669,514 | 100.00% | 4,661,460 | | 9.38% | 437,123 |

[1] Rounded to 2 decimal places for presentation purposes only.

WEIGHTED AVERAGE COST OF LONG TERM DEBT OUTSTANDING

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
($Thousands)

| LINE NO. | DESCRIPTION | INTEREST RATE % | PRINCIPAL OUTSTANDING | DAYS OUTSTANDING | TOTAL NGTL INTEREST | DISALLOWED INTEREST [1] % | DISALLOWED INTEREST [1] | ADJUSTED INTEREST |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| | **Debentures** | | | | | | | |
| 1 | 11.95% Series 13 | 11.95% | 71,870 | 273 | 6,424 | | | 6,424 |
| 2 | 11.95% Series 13 | 11.95% | 66,557 | 92 | 2,005 | | | 2,005 |
| 3 | 11.70% Series 15 | 11.70% | 91,500 | 288 | 8,447 | | | 8,447 |
| 4 | 11.70% Series 15 | 11.70% | 85,000 | 77 | 2,098 | | | 2,098 |
| 5 | 11.2% Series 18 | 11.20% | 111,000 | 151 | 5,143 | | | 5,143 |
| 6 | 11.2% Series 18 | 11.20% | 106,125 | 214 | 6,969 | | | 6,969 |
| 7 | 12 5/8% Series 19 | 12.63% | 69,669 | 105 | 2,530 | 0.44% | 84 | 2,446 |
| 8 | 12 5/8% Series 19 | 12.63% | 65,336 | 260 | 5,876 | 0.44% | 208 | 5,668 |
| 9 | 12.20 % Series 20 | 12.20% | 100,000 | 365 | 12,200 | 0.88% | 880 | 11,320 |
| 10 | 12.20 % Series 21 | 12.20% | 125,000 | 365 | 15,250 | 0.88% | 1,100 | 14,150 |
| 11 | 8.30% Series 22 | 8.30% | 150,000 | 365 | 12,450 | | | 12,450 |
| 12 | 9.9% Series 23 | 9.90% | 100,000 | 365 | 9,900 | | | 9,900 |
| 13 | 8 1/2% U.S. $175MM | 8.50% | 223,046 | 365 | 18,959 | | | 18,959 |
| 14 | 7 7/8% U.S. $200MM | 7.88% | 248,544 | 360 | 19,573 | | | 19,573 |
| 15 | 8 1/2% U.S. $125MM | 8.50% | 163,024 | 365 | 13,857 | | | 13,857 |
| 16 | 7.7% U.S. $200 MM | 7.70% | 257,207 | 360 | 19,805 | | | 19,805 |
| 17 | 7.875% U.S. $125 MM | 5.61% | 159,319 | 349 | 8,589 | | | 8,589 |
| | **Medium Term Notes - Cdn** | | | | | | | |
| 18 | 9.4% MTN #2 | 2.24% | 6,000 | 90 | 33 | | | 33 |
| 19 | 8.90% MTN #7 | 8.90% | 33,000 | 365 | 2,937 | | | 2,937 |
| 20 | 8.90% MTN #8 | 8.90% | 39,000 | 365 | 3,471 | | | 3,471 |
| 21 | 8 7/8% MTN #9 | 8.88% | 30,000 | 365 | 2,663 | | | 2,663 |
| 22 | 8.50% MTN #10 | 8.50% | 102,900 | 365 | 8,747 | | | 8,747 |
| 23 | 8.46% MTN #11 | 8.46% | 45,000 | 365 | 3,807 | | | 3,807 |
| 24 | 8.90% MTN #12 | 8.90% | 15,000 | 365 | 1,335 | | | 1,335 |
| 25 | 8 7/8% MTN #13 | 8.88% | 15,000 | 365 | 1,331 | | | 1,331 |
| 26 | 8.50% MTN #14 | 8.50% | 20,000 | 365 | 1,700 | | | 1,700 |
| 27 | 8.50% MTN #15 | 8.50% | 35,000 | 365 | 2,975 | | | 2,975 |
| 28 | 7.00% $100MM MTN #17 | 7.00% | 100,000 | 365 | 7,000 | | | 7,000 |
| 29 | 6.05% $50MM MTN #18 | 6.05% | 50,000 | 365 | 3,025 | | | 3,025 |
| 30 | 6.00% $22MM MTN #19 | 6.00% | 22,000 | 365 | 1,320 | | | 1,320 |
| 31 | 6.59% $20MM MTN #20 | 6.59% | 20,000 | 365 | 1,318 | | | 1,318 |
| 32 | 6.59% $2.5MM MTN #21 | 6.59% | 2,500 | 365 | 165 | | | 165 |
| 33 | 6.59% $10MM MTN #22 | 6.59% | 10,000 | 365 | 659 | | | 659 |
| 34 | 6.59% $20MM MTN #23 | 6.59% | 20,000 | 365 | 1,318 | | | 1,318 |
| 35 | 6.00% $5MM MTN #24 | 6.00% | 5,000 | 365 | 300 | | | 300 |
| 36 | 6.00% $53MM MTN #25 | 6.00% | 53,000 | 365 | 3,180 | | | 3,180 |
| 37 | 6.59% $25MM MTN #29 | 6.59% | 25,000 | 365 | 1,648 | | | 1,648 |
| 38 | 6.00% $25MM MTN #30 | 6.00% | 25,000 | 365 | 1,500 | | | 1,500 |
| 39 | 6.30% $100MM MTN#31 | 6.30% | 100,000 | 365 | 6,300 | | | 6,300 |
| 40 | 7.52% $300MM Note Payable to TransCanada | 7.52% | 300,000 | 365 | 22,560 | | | 22,560 |
| 41 | 5.87% $300MM Note Payable to TransCanada | 5.87% | 300,000 | 90 | 4,342 | | | 4,342 |
| | **Medium Term Notes - U.S.** | | | | | | | |
| 42 | 7.50% U.S. $32.5MM | 7.50% | 38,400 | 365 | 2,880 | | | 2,880 |
| 43 | 5.18% U.S. Credit Suisse/Citibank - rollover | 2.15% | 38,402 | 365 | 825 | | | 825 |
| | **Unsecured Loans** | | | | | | | |
| 44 | 8.95% U.S. Credit Suisse/Citibank | 8.29% | 86,628 | 365 | 7,183 | | | 7,183 |
| 45 | **Total Interest** | | | | 264,594 | | 2,272 | 262,321 |
| 46 | Weighted Average (Schedule 2.2.3) | | 3,151,495 | | | | | |
| 47 | Amortization of Issue Costs (Schedule 2.2.4) | | | | | | | 2,090 |
| 48 | **Total Cost of Long Term Debt Outstanding** | | | | | | | 264,412 |
| 49 | **Financing Cost Rate** | | | | | | | 8.39% |

(1) The effective interest rate on Series 19, Series 20 and Series 21 debentures has been reduced by 44 basis points (bp), 88 bp and 88 bp respectively, in accordance with PUB order E92086.

WEIGHTED AVERAGE COST OF LONG TERM DEBT OUTSTANDING

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | INTEREST RATE % | PRINCIPAL OUTSTANDING | DAYS OUTSTANDING | TOTAL NGTL INTEREST | DISALLOWED INTEREST (1) % | DISALLOWED INTEREST (1) | ADJUSTED INTEREST |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| | **Debentures** | | | | | | | |
| 1 | 11.95% Series 13 | 11.95% | 66,557 | 273 | 5,949 | | | 5,949 |
| 2 | 11.95% Series 13 | 11.95% | 61,244 | 92 | 1,845 | | | 1,845 |
| 3 | 11.70% Series 15 | 11.70% | 85,000 | 288 | 7,847 | | | 7,847 |
| 4 | 11.70% Series 15 | 11.70% | 78,500 | 77 | 1,938 | | | 1,938 |
| 5 | 11.2% Series 18 | 11.20% | 106,125 | 151 | 4,917 | | | 4,917 |
| 6 | 11.2% Series 18 | 11.20% | 101,250 | 214 | 6,649 | | | 6,649 |
| 7 | 12 5/8% Series 19 | 12.63% | 65,336 | 105 | 2,373 | 0.44% | 79 | 2,294 |
| 8 | 12 5/8% Series 19 | 12.63% | 61,003 | 260 | 5,486 | 0.44% | 195 | 5,292 |
| 9 | 12.20 % Series 20 | 12.20% | 100,000 | 365 | 12,200 | 0.88% | 880 | 11,320 |
| 10 | 12.20 % Series 21 | 12.20% | 125,000 | 365 | 15,250 | 0.88% | 1,100 | 14,150 |
| 11 | 8.30% Series 22 | 8.30% | 150,000 | 195 | 6,651 | | | 6,651 |
| 12 | 9.9% Series 23 | 9.90% | 100,000 | 365 | 9,900 | | | 9,900 |
| 13 | 8 1/2% U.S. $175MM | 8.50% | 223,046 | 365 | 18,959 | | | 18,959 |
| 14 | 7 7/8% U.S. $200MM | 7.88% | 248,544 | 360 | 19,573 | | | 19,573 |
| 15 | 8 1/2% U.S. $125MM | 8.50% | 163,024 | 365 | 13,857 | | | 13,857 |
| 16 | 7.7% US $200MM | 7.70% | 257,207 | 360 | 19,805 | | | 19,805 |
| | **Medium Term Notes - Cdn** | | | | | | | |
| 17 | 8.90% MTN #7 | 8.90% | 33,000 | 365 | 2,937 | | | 2,937 |
| 18 | 8.90% MTN #8 | 8.90% | 39,000 | 365 | 3,471 | | | 3,471 |
| 19 | 8 7/8% MTN #9 | 8.88% | 30,000 | 365 | 2,663 | | | 2,663 |
| 20 | 8.50% MTN #10 | 8.50% | 102,900 | 365 | 8,747 | | | 8,747 |
| 21 | 8.46% MTN #11 | 8.46% | 45,000 | 365 | 3,807 | | | 3,807 |
| 22 | 8.90% MTN #12 | 8.90% | 15,000 | 365 | 1,335 | | | 1,335 |
| 23 | 8 7/8% MTN #13 | 8.88% | 15,000 | 365 | 1,331 | | | 1,331 |
| 24 | 8.50% MTN #14 | 8.50% | 20,000 | 365 | 1,700 | | | 1,700 |
| 25 | 8.50% MTN #15 | 8.50% | 35,000 | 365 | 2,975 | | | 2,975 |
| 26 | 7.00% $100MM MTN #17 | 7.00% | 100,000 | 365 | 7,000 | | | 7,000 |
| 27 | 6.05% $50MM MTN #18 | 6.05% | 50,000 | 365 | 3,025 | | | 3,025 |
| 28 | 6.00% $22MM MTN #19 | 6.00% | 22,000 | 365 | 1,320 | | | 1,320 |
| 29 | 6.59% $20MM MTN #20 | 6.59% | 20,000 | 365 | 1,318 | | | 1,318 |
| 30 | 6.59% $2.5MM MTN #21 | 6.59% | 2,500 | 365 | 165 | | | 165 |
| 31 | 6.59% $10MM MTN #22 | 6.59% | 10,000 | 365 | 659 | | | 659 |
| 32 | 6.59% $20MM MTN #23 | 6.59% | 20,000 | 365 | 1,318 | | | 1,318 |
| 33 | 6.00% $5MM MTN #24 | 6.00% | 5,000 | 365 | 300 | | | 300 |
| 34 | 6.00% $53MM MTN #25 | 6.00% | 53,000 | 365 | 3,180 | | | 3,180 |
| 35 | 6.59% $25MM MTN #29 | 6.59% | 25,000 | 365 | 1,648 | | | 1,648 |
| 36 | 6.00% $25MM MTN #30 | 6.00% | 25,000 | 365 | 1,500 | | | 1,500 |
| 37 | 6.30% $100MM MTN#31 | 6.30% | 100,000 | 365 | 6,300 | | | 6,300 |
| 38 | 7.52% $300MM Note Payable to TransCanada | 7.52% | 300,000 | 365 | 22,560 | | | 22,560 |
| | **Medium Term Notes - U.S.** | | | | | | | |
| 39 | 7.50% US $32.5MM | 7.50% | 38,402 | 365 | 2,880 | | | 2,880 |
| 40 | $32.5 MM Floating Term Note | | 38,402 | 318 | 562 | | | 562 |
| | **Unsecured Loans** | | | | | | | |
| 41 | 8.95% US Credit Suisse/Citibank | | 86,630 | 318 | 6,326 | | | 6,326 |
| 42 | **Total Interest** | | | | 242,224 | | 2,253 | 239,971 |
| 43 | Weighted Average (Schedule 2.2.3) | | 2,823,853 | | | | | |
| 44 | Amortization of Issue Costs (Schedule 2.2.4) | | | | | | | 1,871 |
| 45 | **Total Cost of Long Term Debt Outstanding** | | | | | | | 241,841 |
| 46 | **Financing Cost Rate** | | | | | | | 8.56% |

(1) The effective interest rate on Series 19, Series 20 and Series 21 debentures has been reduced by 44 basis points (bp), 88 bp and 88 bp respectively, in accordance with PUB order E92086.

WEIGHTED AVERAGE COST OF LONG TERM DEBT OUTSTANDING

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | INTEREST RATE % | PRINCIPAL OUTSTANDING | DAYS OUTSTANDING | TOTAL NGTL INTEREST | DISALLOWED INTEREST (1) % | DISALLOWED INTEREST (1) | ADJUSTED INTEREST |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| | **Debentures** | | | | | | | |
| 1 | 11.95% Series 13 | 11.95% | 61,244 | 273 | 5,459 | | | 5,459 |
| 2 | 11.95% Series 13 | 11.95% | 55,931 | 93 | 1,698 | | | 1,698 |
| 3 | 11.70% Series 15 | 11.70% | 78,500 | 288 | 7,227 | | | 7,227 |
| 4 | 11.70% Series 15 | 11.70% | 72,000 | 78 | 1,795 | | | 1,795 |
| 5 | 11.2% Series 18 | 11.20% | 101,250 | 151 | 4,679 | | | 4,679 |
| 6 | 11.2% Series 18 | 11.20% | 96,375 | 215 | 6,341 | | | 6,341 |
| 7 | 12 5/8% Series 19 | 12.63% | 61,003 | 106 | 2,231 | 0.44% | 74 | 2,157 |
| 8 | 12 5/8% Series 19 | 12.63% | 56,670 | 260 | 5,082 | 0.44% | 180 | 4,902 |
| 9 | 12.20 % Series 20 | 12.20% | 100,000 | 366 | 12,200 | 0.88% | 880 | 11,320 |
| 10 | 12.20 % Series 21 | 12.20% | 125,000 | 366 | 15,250 | 0.88% | 1,100 | 14,150 |
| 11 | 9.9% Series 23 | 9.90% | 100,000 | 366 | 9,900 | | | 9,900 |
| 12 | 8 1/2% U.S. $175MM | 8.50% | 223,046 | 366 | 18,959 | | | 18,959 |
| 13 | 7 7/8% U.S. $200MM | 7.88% | 248,544 | 360 | 19,573 | | | 19,573 |
| 14 | 8 1/2% U.S. $125MM | 8.50% | 163,000 | 341 | 12,909 | | | 12,909 |
| 15 | 7.7% U.S. $200MM | 7.70% | 257,207 | 360 | 19,805 | | | 19,805 |
| | **Medium Term Notes - Cdn** | | | | | | | |
| 16 | 8.90% MTN #7 | 8.90% | 33,000 | 366 | 2,937 | | | 2,937 |
| 17 | 8.90% MTN #8 | 8.90% | 39,000 | 366 | 3,471 | | | 3,471 |
| 18 | 8 7/8% MTN #9 | 8.88% | 30,000 | 366 | 2,663 | | | 2,663 |
| 19 | 8.50% MTN #10 | 8.50% | 102,900 | 366 | 8,747 | | | 8,747 |
| 20 | 8.46% MTN #11 | 8.46% | 45,000 | 366 | 3,807 | | | 3,807 |
| 21 | 8.90% MTN #12 | 8.90% | 15,000 | 366 | 1,335 | | | 1,335 |
| 22 | 8 7/8% MTN #13 | 8.88% | 15,000 | 366 | 1,331 | | | 1,331 |
| 23 | 8.50% MTN #14 | 8.50% | 20,000 | 366 | 1,700 | | | 1,700 |
| 24 | 8.50% MTN #15 | 8.50% | 35,000 | 366 | 2,975 | | | 2,975 |
| 25 | 7.00% $100MM MTN #17 | 7.00% | 100,000 | 366 | 7,000 | | | 7,000 |
| 26 | 6.05% $50MM MTN #18 | 6.05% | 50,000 | 366 | 3,025 | | | 3,025 |
| 27 | 6.00% $22MM MTN #19 | 6.00% | 22,000 | 366 | 1,320 | | | 1,320 |
| 28 | 6.59% $20MM MTN #20 | 6.59% | 20,000 | 366 | 1,318 | | | 1,318 |
| 29 | 6.59% $2.5MM MTN #21 | 6.59% | 2,500 | 366 | 165 | | | 165 |
| 30 | 6.59% $10MM MTN #22 | 6.59% | 10,000 | 366 | 659 | | | 659 |
| 31 | 6.59% $20MM MTN #23 | 6.59% | 20,000 | 366 | 1,318 | | | 1,318 |
| 32 | 6.00% $5MM MTN #24 | 6.00% | 5,000 | 366 | 300 | | | 300 |
| 33 | 6.00% $53MM MTN #25 | 6.00% | 53,000 | 366 | 3,180 | | | 3,180 |
| 34 | 6.59% $25MM MTN #29 | 6.59% | 25,000 | 366 | 1,648 | | | 1,648 |
| 35 | 6.00% $25MM MTN #30 | 6.00% | 25,000 | 366 | 1,500 | | | 1,500 |
| 36 | 6.30% $100MM MTN#31 | 6.30% | 100,000 | 366 | 6,300 | | | 6,300 |
| 37 | 7.52% $300MM Note Payable to TransCanada | 7.52% | 300,000 | 366 | 22,560 | | | 22,560 |
| | **Medium Term Notes - U.S.** | | | | | | | |
| 38 | 7.50% US$32.5MM | 7.50% | 38,402 | 366 | 2,880 | | | 2,880 |
| 39 | **Total Interest** | | | | 225,245 | | 2,234 | 223,011 |
| 40 | Weighted Average (Schedule 2.2.3) | | 2,603,729 | | | | | |
| 41 | Amortization of Issue Costs (Schedule 2.2.4) | | | | | | | 1,688 |
| 42 | **Total Cost of Long Term Debt Outstanding** | | | | | | | 224,698 |
| 43 | **Financing Cost Rate** | | | | | | | 8.63% |

(1) The effective interest rate on Series 19, Series 20 and Series 21 debentures has been reduced by 44 basis points (bp), 88 bp and 88 bp respectively, in accordance with PUB order E92086.

WEIGHTED AVERAGE LONG TERM DEBT OUTSTANDING

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
($Millions)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Debentures** | | | | | | | | | | | | | | |
| 1 | 11.95% Series 13 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 71.9 | 66.6 | 66.6 | 66.6 | 70.7 |
| 2 | 11.70% Series 15 | 91.5 | 91.5 | 91.5 | 91.5 | 91.5 | 91.5 | 91.5 | 91.5 | 91.5 | 91.5 | 85.0 | 85.0 | 85.0 | 90.0 |
| 3 | 11.2% Series 18 | 111.0 | 111.0 | 111.0 | 111.0 | 111.0 | 111.0 | 106.1 | 106.1 | 106.1 | 106.1 | 106.1 | 106.1 | 106.1 | 108.4 |
| 4 | 12 5/8% Series 19 | 69.7 | 69.7 | 69.7 | 69.7 | 65.4 | 65.4 | 65.4 | 65.4 | 65.4 | 65.4 | 65.4 | 65.4 | 65.4 | 66.7 |
| 5 | 12.20 % Series 20 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 6 | 12.20 % Series 21 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 |
| 7 | 8.30% Series 22 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 |
| 8 | 9.9% Series 23 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 9 | 8 1/2% U.S. $175MM | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 |
| 10 | 7 7/8% U.S. $200MM | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 |
| 11 | 8 1/2% U.S. $125MM | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 |
| 12 | 7.70% US$200MM | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 |
| 13 | 7.875% US$125MM | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | 159.3 | - | 147.1 |
| | **Medium Term Notes - Cdn** | | | | | | | | | | | | | | |
| 14 | 9.4% MTN #2 | 6.0 | 6.0 | 6.0 | 6.0 | - | - | - | - | - | - | - | - | - | 1.8 |
| 15 | 8.90% MTN #7 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 |
| 16 | 8.90% MTN #8 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 |
| 17 | 8 7/8% MTN #9 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 |
| 18 | 8.50% MTN #10 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 |
| 19 | 8.46% MTN #11 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 |
| 20 | 8.90% MTN #12 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 21 | 8 7/8% MTN #13 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 22 | 8.50% MTN #14 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 23 | 8.50% MTN #15 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 |
| 24 | 7.00% $100MM MTN #17 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 25 | 6.05% $50MM MTN #18 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| 26 | 6.00% $22MM MTN #19 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 |
| 27 | 6.59% $20MM MTN #20 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 28 | 6.59% $2.5MM MTN #21 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| 29 | 6.59% $10MM MTN #22 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| 30 | 6.59% $20MM MTN #23 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 31 | 6.00% $5MM MTN #24 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| 32 | 6.00% $53MM MTN #25 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 |
| 33 | 6.59% $25MM MTN #29 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 34 | 6.00% $25MM MTN #30 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 35 | 6.30% $100MM MTN#31 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 36 | 7.52% $300MM Note Payable to TransCanada | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 |
| 37 | 5.87% $300 MM Note Payable to TransCanada | - | - | - | - | - | - | - | - | 300.0 | 300.0 | 300.0 | - | - | 69.2 |
| | **Medium Term Notes - U.S.** | | | | | | | | | | | | | | |
| 38 | 7.50% US$32.5 MM | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| 39 | 5.18% U.S. Credit Suisse/Citibank - rollover | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| | **Unsecured Loans** | | | | | | | | | | | | | | |
| 40 | 8.95% U.S. Credit Suisse/Citibank | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 |
| 41 | **Total** | 3,107.0 | 3,107.0 | 3,107.0 | 3,107.0 | 3,096.7 | 3,096.7 | 3,091.8 | 3,091.8 | 3,391.8 | 3,391.8 | 3,380.1 | 3,080.1 | 2,920.7 | 3,151.5 |

WEIGHTED AVERAGE LONG TERM DEBT OUTSTANDING

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Millions)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Debentures** | | | | | | | | | | | | | | |
| 1 | 11.95% Series 13 | 66.6 | 66.6 | 66.6 | 66.6 | 66.6 | 66.6 | 66.6 | 66.6 | 66.6 | 66.6 | 61.2 | 61.2 | 61.2 | 65.3 |
| 2 | 11.70% Series 15 | 85.0 | 85.0 | 85.0 | 85.0 | 85.0 | 85.0 | 85.0 | 85.0 | 85.0 | 85.0 | 78.5 | 78.5 | 78.5 | 83.5 |
| 3 | 11.2% Series 18 | 106.1 | 106.1 | 106.1 | 106.1 | 106.1 | 106.1 | 101.3 | 101.3 | 101.3 | 101.3 | 101.3 | 101.3 | 101.3 | 103.5 |
| 4 | 12 5/8% Series 19 | 65.3 | 65.3 | 65.3 | 65.3 | 61.0 | 61.0 | 61.0 | 61.0 | 61.0 | 61.0 | 61.0 | 61.0 | 61.0 | 62.3 |
| 5 | 12.20 % Series 20 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 6 | 12.20 % Series 21 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 |
| 7 | 8.30% Series 22 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | 150.0 | - | - | - | - | - | - | 80.8 |
| 8 | 9.9% Series 23 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 9 | 8 1/2% U.S. $175MM | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 |
| 10 | 7 7/8% U.S. $200MM | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 |
| 11 | 8 1/2% U.S. $125MM | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 |
| 12 | 7.70% US$200 MM | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 |
| | **Medium Term Notes - Cdn** | | | | | | | | | | | | | | |
| 13 | 8.90% MTN #7 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 |
| 14 | 8.90% MTN #8 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 |
| 15 | 8 7/8% MTN #9 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 |
| 16 | 8.50% MTN #10 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 |
| 17 | 8.46% MTN #11 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 |
| 18 | 8.90% MTN #12 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 19 | 8 7/8% MTN #13 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 20 | 8.50% MTN #14 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 21 | 8.50% MTN #15 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 |
| 22 | 7.00% $100MM MTN #17 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 23 | 6.05% $50MM MTN #18 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| 24 | 6.00% $22MM MTN #19 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 |
| 25 | 6.59% $20MM MTN #20 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 26 | 6.59% $2.5MM MTN #21 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| 27 | 6.59% $10MM MTN #22 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| 28 | 6.59% $20MM MTN #23 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 29 | 6.00% $5MM MTN #24 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| 30 | 6.00% $53MM MTN #25 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 |
| 31 | 6.59% $25MM MTN #29 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 32 | 6.00% $25MM MTN #30 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 33 | 6.30% $100MM MTN#31 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 34 | 7.52% $300MM Note Payable to TransCanada | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 |
| | **Medium Term Notes - U.S.** | | | | | | | | | | | | | | |
| 35 | 7.50% US$32.5 MM | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| 36 | $32.5 MM Floating Term Note | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | - | - | 32.5 |
| | **Unsecured Loans** | | | | | | | | | | | | | | |
| 37 | 8.95% U.S. Credit Suisse/Citibank | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | 86.6 | - | - | 73.3 |
| 38 | **Total** | 2,920.7 | 2,920.7 | 2,920.7 | 2,920.7 | 2,916.3 | 2,916.3 | 2,911.5 | 2,761.5 | 2,761.5 | 2,761.5 | 2,749.7 | 2,624.6 | 2,624.6 | 2,823.9 |

WEIGHTED AVERAGE LONG TERM DEBT OUTSTANDING

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Millions)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Debentures** | | | | | | | | | | | | | | |
| 1 | 11.95% Series 13 | 61.2 | 61.2 | 61.2 | 61.2 | 61.2 | 61.2 | 61.2 | 61.2 | 61.2 | 61.2 | 55.9 | 55.9 | 55.9 | 60.0 |
| 2 | 11.70% Series 15 | 78.5 | 78.5 | 78.5 | 78.5 | 78.5 | 78.5 | 78.5 | 78.5 | 78.5 | 78.5 | 72.0 | 72.0 | 72.0 | 77.0 |
| 3 | 11.2% Series 18 | 101.3 | 101.3 | 101.3 | 101.3 | 101.3 | 101.3 | 96.4 | 96.4 | 96.4 | 96.4 | 96.4 | 96.4 | 96.4 | 98.6 |
| 4 | 12 5/8% Series 19 | 61.0 | 61.0 | 61.0 | 61.0 | 56.7 | 56.7 | 56.7 | 56.7 | 56.7 | 56.7 | 56.7 | 56.7 | 56.7 | 58.0 |
| 5 | 12.20 % Series 20 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 6 | 12.20 % Series 21 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 | 125.0 |
| 7 | 9.9% Series 23 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 8 | 8 1/2% U.S. $175 MM | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 | 223.0 |
| 9 | 7 7/8% U.S. $200 MM | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 | 248.5 |
| 10 | 8 1/2% U.S. $125 MM | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | 163.0 | - | 150.5 |
| 11 | 7.70% US$200 MM | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 | 257.2 |
| | **Medium Term Notes - Cdn** | | | | | | | | | | | | | | |
| 12 | 8.90% MTN #7 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 | 33.0 |
| 13 | 8.90% MTN #8 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 |
| 14 | 8 7/8% MTN #9 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 |
| 15 | 8.50% MTN #10 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 | 102.9 |
| 16 | 8.46% MTN #11 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 | 45.0 |
| 17 | 8.90% MTN #12 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 18 | 8 7/8% MTN #13 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| 19 | 8.50% MTN #14 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 20 | 8.50% MTN #15 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 | 35.0 |
| 21 | 7.00% $100MM MTN #17 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 22 | 6.05% $50MM MTN #18 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 | 50.0 |
| 23 | 6.00% $22MM MTN #19 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 | 22.0 |
| 24 | 6.59% $20MM MTN #20 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 25 | 6.59% $2.5MM MTN #21 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 |
| 26 | 6.59% $10MM MTN #22 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| 27 | 6.59% $20MM MTN #23 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 | 20.0 |
| 28 | 6.00% $5MM MTN #24 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| 29 | 6.00% $53MM MTN #25 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 | 53.0 |
| 30 | 6.59% $25MM MTN #29 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 31 | 6.00% $25MM MTN #30 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 | 25.0 |
| 32 | 6.30% $100MM MTN#31 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| 33 | 7.52% $300MM Note Payable to TransCanada | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 |
| | **Medium Term Notes - U.S.** | | | | | | | | | | | | | | |
| 34 | 7.50% US$32.5 MM | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 | 38.4 |
| 35 | **Total** | 2,624.6 | 2,624.6 | 2,624.6 | 2,624.6 | 2,620.3 | 2,620.3 | 2,615.4 | 2,615.4 | 2,615.4 | 2,615.4 | 2,603.6 | 2,603.6 | 2,440.6 | 2,603.7 |

AMORTIZATION OF LONG TERM DEBT ISSUE EXPENSE

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
($Thousands)

| LINE NO. | DESCRIPTION | TOTAL ISSUE COSTS | UNAMORTIZED BALANCE DEC. 31, 2001 | LESS: AMORTIZATION | UNAMORTIZED BALANCE DEC. 31, 2002 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **Debentures** | | | | |
| 1 | 11.95% Series 13 | 2,645 | 760 | 132 | 628 |
| 2 | 11.70% Series 15 | 1,804 | 612 | 90 | 522 |
| 3 | 11.20% Series 18 | 1,527 | 758 | 61 | 698 |
| 4 | 12.625% Series 19 | 1,243 | 515 | 62 | 453 |
| 5 | 12.20% Series 21 | 2,889 | 1,634 | 115 | 1,519 |
| 6 | 8.30% Series 22 | 1,681 | 258 | 168 | 90 |
| 7 | 9.90% Series 23 | 1,434 | 1,096 | 48 | 1,048 |
| 8 | 8.50% US$175MM | 3,685 | 2,023 | 185 | 1,839 |
| 9 | 7.875% US$125MM | 1,277 | 123 | 123 | - |
| 10 | 7.875% US$200MM | 4,013 | 2,842 | 134 | 2,708 |
| 11 | 8.50% US$125MM | 993 | 282 | 96 | 186 |
| 12 | 7.70% US$200MM | 2,749 | 2,516 | 92 | 2,425 |
| | **Medium Term Notes - Cdn** | | | | |
| 13 | CDN Medium Term Notes (1994) | 1,261 | 2 | 2 | - |
| 14 | CDN Medium Term Notes (1995) | 2,864 | 1,850 | 152 | 1,698 |
| 15 | 7.00% $100MM MTN #17 | 384 | 331 | 12 | 319 |
| 16 | 6.05% $50MM MTN #18 | 500 | 278 | 49 | 229 |
| 17 | 6.00% $22MM MTN #19 | 577 | 342 | 56 | 286 |
| 18 | 6.59% $20MM MTN #20 | 333 | 289 | 11 | 277 |
| 19 | 6.59% $2.5MM MTN #21 | 42 | 36 | 1 | 35 |
| 20 | 6.59% $10MM MTN #22 | 158 | 137 | 5 | 131 |
| 21 | 6.59% $20MM MTN #23 | 312 | 271 | 10 | 260 |
| 22 | 6.00% $5MM MTN #24 | 115 | 70 | 11 | 58 |
| 23 | 6.00% $53MM MTN #25 | 1,203 | 726 | 119 | 607 |
| 25 | 6.59% $25MM MTN #29 | 491 | 425 | 16 | 409 |
| 26 | 6.00% $25MM MTN #30 | 643 | 388 | 64 | 324 |
| 27 | 6.30% $100MM MTN#31 | 692 | 614 | 22 | 593 |
| 28 | 7.52% $300MM Note Payable to TransCanada | 1,200 | 970 | 120 | 850 |
| | **Medium Term Notes - US** | | | | |
| 29 | 7.50% US$32.5 MM | 883 | 727 | 29 | 697 |
| | **Unsecured Loans** | | | | |
| 30 | 8.95% U.S.Credit Suisse/Citibank | 1,529 | 192 | 104 | 87 |
| 31 | **Total** | 39,127 | 21,066 | 2,090 | 18,976 |

AMORTIZATION OF LONG TERM DEBT ISSUE EXPENSE

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | TOTAL ISSUE COSTS | UNAMORTIZED BALANCE DEC. 31, 2002 | LESS: AMORTIZATION | UNAMORTIZED BALANCE DEC. 31, 2003 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **Debentures** | | | | |
| 1 | 11.95% Series 13 | 2,645 | 628 | 132 | 497 |
| 2 | 11.70% Series 15 | 1,804 | 522 | 90 | 431 |
| 3 | 11.20% Series 18 | 1,527 | 698 | 61 | 637 |
| 4 | 12.625% Series 19 | 1,243 | 453 | 62 | 390 |
| 5 | 12.20% Series 21 | 2,889 | 1,519 | 115 | 1,403 |
| 6 | 8.30% Series 22 | 1,681 | 90 | 90 | - |
| 7 | 9.90% Series 23 | 1,434 | 1,048 | 48 | 1,001 |
| 8 | 8.50% US$175MM | 3,685 | 1,839 | 185 | 1,654 |
| 9 | 7.875% US$200MM | 4,013 | 2,708 | 134 | 2,575 |
| 10 | 8.50% US$125MM | 993 | 186 | 96 | 90 |
| 11 | 7.70% US$200MM | 2,749 | 2,425 | 92 | 2,333 |
| | **Medium Term Notes - Cdn** | | | | |
| 12 | CDN Medium Term Notes (1995) | 2,864 | 1,698 | 152 | 1,546 |
| 13 | 7.00% $100MM MTN #17 | 384 | 319 | 12 | 306 |
| 14 | 6.05% $50MM MTN #18 | 500 | 229 | 49 | 179 |
| 15 | 6.00% $22MM MTN #19 | 577 | 286 | 56 | 230 |
| 16 | 6.59% $20MM MTN #20 | 333 | 277 | 11 | 266 |
| 17 | 6.59% $2.5MM MTN #21 | 42 | 35 | 1 | 33 |
| 18 | 6.59% $10MM MTN #22 | 158 | 131 | 5 | 126 |
| 19 | 6.59% $20MM MTN #23 | 312 | 260 | 10 | 250 |
| 20 | 6.00% $5MM MTN #24 | 115 | 58 | 11 | 47 |
| 21 | 6.00% $53MM MTN #25 | 1,203 | 607 | 119 | 487 |
| 22 | 6.59% $25MM MTN #29 | 491 | 409 | 16 | 393 |
| 23 | 6.00% $25MM MTN #30 | 643 | 324 | 64 | 260 |
| 24 | 6.30% $100MM MTN#31 | 692 | 593 | 22 | 571 |
| 25 | 7.52% $300MM Note Payable to TransCanada | 1,200 | 850 | 120 | 730 |
| | **Medium Term Notes - US** | | | | |
| 26 | 7.50% US$32.5 MM | 883 | 697 | 29 | 668 |
| | **Unsecured Loans** | | | | |
| 27 | 8.95% U.S.Credit Suisse/Citibank | 1,529 | 87 | 87 | - |
| 28 | **Total** | 36,589 | 18,976 | 1,871 | 17,105 |

AMORTIZATION OF LONG TERM DEBT ISSUE EXPENSE

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | TOTAL ISSUE COSTS | UNAMORTIZED BALANCE DEC. 31, 2004 | LESS: AMORTIZATION | UNAMORTIZED BALANCE DEC. 31, 2004 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **Debentures** | | | | |
| 1 | 11.95% Series 13 | 2,645 | 497 | 132 | 365 |
| 2 | 11.70% Series 15 | 1,804 | 431 | 90 | 341 |
| 3 | 11.20% Series 18 | 1,527 | 637 | 61 | 576 |
| 4 | 12.625% Series 19 | 1,243 | 390 | 62 | 328 |
| 5 | 12.20% Series 21 | 2,889 | 1,403 | 115 | 1,288 |
| 6 | 9.90% Series 23 | 1,434 | 1,001 | 48 | 953 |
| 7 | 8.50% US$175MM | 3,685 | 1,654 | 185 | 1,470 |
| 8 | 7.875% US$200MM | 4,013 | 2,575 | 134 | 2,441 |
| 9 | 8.50% US$125MM | 993 | 90 | 90 | - |
| 10 | 7.70% US$200MM | 2,749 | 2,333 | 92 | 2,241 |
| | **Medium Term Notes - Cdn** | | | | |
| 11 | CDN Medium Term Notes (1995) | 2,864 | 1,546 | 152 | 1,395 |
| 12 | 7.00% $100MM MTN #17 | 384 | 306 | 12 | 294 |
| 13 | 6.05% $50MM MTN #18 | 500 | 179 | 49 | 130 |
| 14 | 6.00% $22MM MTN #19 | 577 | 230 | 56 | 174 |
| 15 | 6.59% $20MM MTN #20 | 333 | 266 | 11 | 255 |
| 16 | 6.59% $2.5MM MTN #21 | 42 | 33 | 1 | 32 |
| 17 | 6.59% $10MM MTN #22 | 158 | 126 | 5 | 121 |
| 18 | 6.59% $20MM MTN #23 | 312 | 250 | 10 | 239 |
| 19 | 6.00% $5MM MTN #24 | 115 | 47 | 11 | 35 |
| 20 | 6.00% $53MM MTN #25 | 1,203 | 487 | 119 | 368 |
| 21 | 6.59% $25MM MTN #29 | 491 | 393 | 16 | 376 |
| 22 | 6.00% $25MM MTN #30 | 643 | 260 | 64 | 197 |
| 23 | 6.30% $100MM MTN#31 | 692 | 571 | 22 | 550 |
| 24 | 7.52% $300MM Note Payable to TransCanada | 1,200 | 730 | 120 | 611 |
| | **Medium Term Notes - US** | | | | |
| 25 | 7.50% US$32.5 MM | 883 | 668 | 29 | 638 |
| 26 | **Total** | 33,379 | 17,105 | 1,688 | 15,417 |

## 2.3 OPERATING COSTS

**February Update**

This update replaces forecast 2003 cost data with actual results for the year ended December 31, 2003. In addition, the following changes have been made to the test year 2004 Operating Costs:

- Pension related costs have been updated to reflect the most recent actuarial assessment dated January, 2004 (Lines 15-16, Schedule 2.3.1.8). This represents an increase of $1.6 million in Operating Costs.

- Long term incentive compensation amounts were updated using valuations consistent with those applied in actual 2003 results (Line 6, Schedule 2.3.1.8). This represents an increase of $1.7 million in Operating Costs

- Errors affecting Plant Engineering ($0.5 million increase to Line 2, Schedule 2.3.1.2) and Customer Service ($0.4 million decrease to Line 3, Schedule 2.3.1.5), were corrected, resulting in a net increase in Operating Costs of $0.1 million. Correction of these errors has also resulted in minor changes to related support costs.

After incorporating the above-noted changes, Operating Costs for 2004 are now forecast to be $208.3 million, an increase of $3.5 million compared with $204.8 million included in the initial Application as filed September 30, 2003.

**Introduction**

Schedule 2.3.1 shows the Operating Costs amounts by functional area for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year. More detailed schedules and variance explanations for each functional area are provided in Section 2.3.1.

Operating Costs include employee-related costs (labour and expenses), contracted services, maintenance parts and other costs required for the safe, reliable operation and maintenance of the Alberta System. The largest cost type included in Operating Costs is total direct compensation and benefits. Section 2.3.2 discusses the basis for these costs.

TCPL's business operations are performed by integrated functional areas that provide services to its various lines of business. As a result, all costs, including employee costs, are accumulated at the TCPL level. This organizational structure eliminates duplication of costs and maximizes operational efficiencies. As a result of this integrated structure, a cost allocation process is necessary to ensure that individual business lines are ~~changed~~ charged an appropriate share of costs. Operating Costs are allocated to NGTL monthly on the basis of TCPL's Operating Costs Allocation Policy. This policy and an explanation of the cost allocation process are provided in Section 2.3.3.

TCPL's integrated services approach to operating its businesses coupled with an operational excellence focus has allowed management to drive efficiency and effectiveness into the overall business rather than purely at the department level. Though budgets are developed at the departmental level and program level each year, organizational streamlining on a functional basis tends to result in ~~material~~ cost transfers amongst departments that make year-over-year comparisons at the departmental level less effective. The information provided in Section 2.3.1 identifies material cost transfers but more importantly, lists some of the initiatives that have resulted in lower Operating Costs over the longer term to the benefit of NGTL shippers.

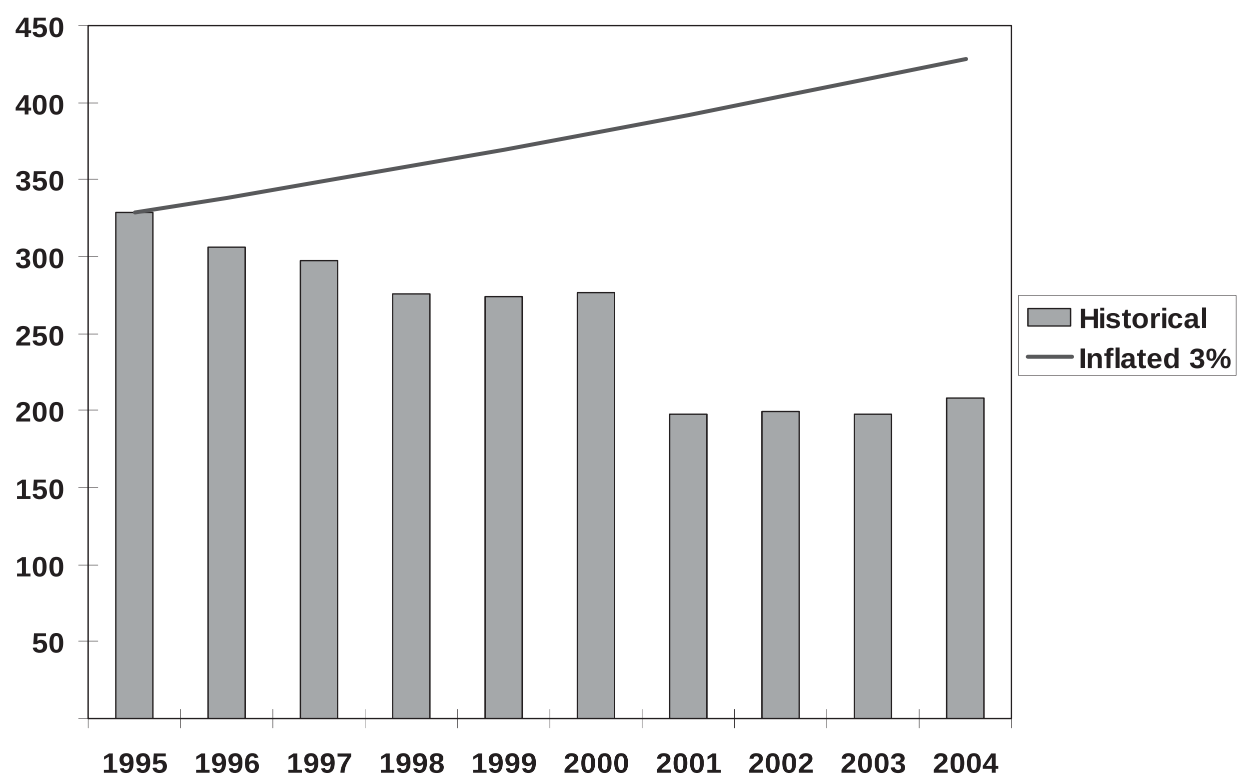
With the exception of the specific changes made in this February Update (as noted above), ~~The~~the 2004 test year Operating Costs amount was developed as part of the broader TCPL annual budget process, which is described in Sub-section 2.3.4.

**Operating Costs History**

NGTL's Operating Costs are significantly lower in 2004 than in 1995, when NGTL last filed a GRA. In Decision U96001, the Board approved the inclusion of $271 million in Operating Costs in NGTL's 1995 revenue requirement. In addition, approximately $58 million of Operating Costs indirectly related to the capital program were capitalized in

1995, for a total of $329 million. Such costs are no longer capitalized and are now recovered in Operating Costs. An equivalent level of Operating Costs in 2004, assuming an annual inflation rate of 3%, would be approximately $430 million. By comparison, NGTL is requesting an operating cost amount of $~~205~~208 million in 2004. This decrease in Operating Costs from 1995 to 2004 is illustrated in Figure 2.3-1.

**Revised Figure 2.3-1**
**Operating Cost History**
**($ millions)**




Since 1995, NGTL has operated under various incentive settlements that encouraged cost-efficient operations. Also during this time, the merger of NOVA Corporation and TCPL created opportunities for cost synergies and operational efficiencies. The Merger Costs and Benefits Agreement was negotiated with the objective of maximizing the sustainable benefits achievable as a result of the merger. The operating cost reductions that have been achieved since 1995 are reflective of widespread efforts throughout the organization to improve efficiency and maximize cost savings.

Programs and initiatives contributing to sustainable Operating Costs reductions include:

- Implementation of a reliability and risk-based approach to equipment maintenance has resulted in the optimization of maintenance plans and procedures based on management of known risk factors. This has enabled a reduction in maintenance costs, while maintaining reliability and safety.

- Implementation of a computerized maintenance management system, which has enabled more effective maintenance planning and deployment of staff.

- Implementation of technologies has reduced Operating Costs and maintenance effort in the field, such as the introduction of innovative techniques to refurbish equipment components as an alternative to replacement.

- Improvements to procurement processes that include a centralized order and dispatch system for supply of equipment, goods, services and consumables to the field organization. Additionally, national alliances have been established with third party providers of specialty services to enable bulk purchasing with associated cost savings.

- Ongoing organizational adjustments to achieve work process improvements.

- Integration of frontline functions in a single call centre for shippers on the Alberta System and TCPL's downstream pipelines, to improve service to customers doing their daily transactional business, at the least possible cost.

Relative to 1995, the pipeline network has increased in size by approximately 12%, to over 22,000 km. Compression and measurement facility numbers have remained relatively flat at over 100 compressor units and 1,000 metering stations. While the scope of Alberta System operations is substantially the same as it was in 1995, Operating Costs have been reduced significantly to the benefit of Alberta System customers.

## 2.3.1 2002 TO 2004 OPERATING COSTS

NGTL is requesting the inclusion of ~~$205~~$208 million of Operating Costs in the 2004 test year revenue requirement. This amount represents a ~~0.7~~5.3% increase over ~~the~~ 2003 ~~forecast year~~ actual results and a ~~2.5%~~ 4.3% increase over the 2002 base year amount. More than one-half of the increase in 2004 Operating Costs compared with 2003 is due to the inclusion of severance costs in 2004. In 2002 and 2003, severance costs were deferred and amortized under the provisions of the ASRS and ASRRS, respectively. Excluding this difference, 2004 Operating Costs are forecast to increase 2.3% over comparable 2003 costs. ~~The increases are primarily attributable~~ This increase is largely due to increases in total direct compensation and benefits. Increases in total direct compensation have been necessary to ensure employee compensation is market competitive and enable TCPL to attract and retain skilled experienced employees.

Benefit costs are forecast to increase ~~at a departmental level but not in total~~ in 2004. The standard benefit rate applied to base salaries has increased from 29% in 2003 to 34% in 2004. This increase ~~reflects an increase in~~is primarily due to higher pension costs ~~in 2003 and is offset by a decrease to the Pension/Benefit Adjustment included in General Expenses. The net impact is an increase in the standard benefit rate allocated to the departments but no net change in Operating Costs.~~ pursuant to an actuarial assessment obtained in January, 2003. An updated actuarial assessment was also obtained in January, 2004, resulting in a further increase in pension costs. The effect of this increase has been included in the Pension/Benefit adjustment line on Schedule 2.3.1.8 Revised February 2004.

The increases in total direct compensation and benefits have been largely offset by improved operational efficiencies that are forecast to reduce the number of average full-time equivalents (FTEs) allocated to the Alberta System. In addition, a decrease from 2002 and 2003 levels in Compressor Fleet Repair and Overhaul costs, which tend to be cyclical, is forecast for 2004.

### 2.3.1.1 Field Operations (Schedule 2.3.1.1)

Field Operations is organized geographically into three regions as shown in Schedule 2.3.1.1. Field Operations provides on-site operations and maintenance functions for NGTL's complex network of high pressure natural gas pipeline including valve sites and measurement and compression facilities.

Field Operations responsibilities include:

- Interaction with landowners, communities and customers on all aspects of pipeline facility operation and maintenance;
- Pipeline and right-of-way maintenance, including valve maintenance, brush control in forested areas, and maintenance of corrosion prevention systems;
- Gas handling, including pipeline isolation, depressurization and purge and pressure procedures for pipeline inspection, repair and new facility tie-ins;
- Maintenance and calibration of measurement and gas quality monitoring equipment;
- Maintenance of compression facilities, including all major components, electrical and control systems and auxiliary equipment; and
- The provision of 24x7 response capability for system alarms, upsets or operational emergencies.

Total Field Operations Operating Costs are forecast to remain relatively flat from 2002 to 2004, despite increases in salaries and benefits and work scope increases. Work scope increases have been absorbed including the transfer of generator set maintenance costs to Field Operations from the Compressor Fleet Repair and Overhaul program (approximately $0.3 million) and the acquisition of the Simmon’s pipeline system (approximately $0.4 million).

Year to year fluctuations in individual regional costs are the result of organizational changes implemented in mid-2003. This included the revision of regional boundaries to create operational efficiencies. The regional variances, therefore, largely reflect the shifting of costs from one region to another.

### 2.3.1.2 Engineering (Schedule 2.3.1.2)

Engineering is responsible for the design, planning and construction of compression, pipeline and measurement facilities including data acquisition and control systems. As well, Engineering develops integrity plans for all Alberta System facilities to ensure optimal system safety, reliability and efficiency at the lowest life-cycle cost.

Major categories of Engineering Operating Costs are outlined in Schedule 2.3.1.2. Plant Engineering includes the Operating Costs for all Engineering activities related to compressor stations and metering stations. Pipe Engineering includes the Operating Costs for all Engineering activities related to pipeline and associated facilities. Engineering Management and Project Controls provide project management and controls for major projects on the Alberta System.

Engineering's Operating Costs for ~~the~~ 2003 ~~forecast year are $8.6~~ were $8.2 million compared to $12.2 million for the 2002 base year, reflecting a decrease of ~~$3.6~~$4.0 million. The primary drivers of this cost reduction in Engineering are organizational re-alignment and efficiency gains, including:

- A 2003 mid-year organizational change, which resulted in the transfer of certain services from Plant Engineering to other parts of the organization of approximately ~~$1.1~~$1.0 million;

- A decline in the capital program on the Alberta System, resulting in a reduction of associated Operating Costs of approximately ~~$0.6~~$0.5 million dollars;

- The 2002 base year costs include a one time organizational efficiency study of approximately $0.8 million that was not incurred in ~~the~~ 2003~~. forecast year costs~~;

- Implementation of systems and processes to convert pipeline information from paper to a common software based geographic information system, which resulted in an approximate $0.4 million decrease in costs for ~~the~~ 2003 ~~forecast year~~; and

- Optimization of aerial patrol frequency and procedures resulting in a decrease of approximately $0.2 million as compared to the 2002 base year.

The 2004 test year Engineering Operating Costs are ~~$7.0~~$7.5 million as compared to ~~$8.6~~$8.2 million ~~for the~~ in 2003, ~~forecast year,~~ reflecting a further decrease of $~~1.6~~ $0.7 million. The 2004 test year reduction reflects the full-year impact of the 2003 organizational changes, partially offset by increases in salaries and benefits.

Normalizing for organizational changes and salary and benefits increases, ~~forecast~~ Engineering costs are relatively flat ~~for the forecast~~ in 2003 and the 2004 test year~~s~~, relative to the base year. Although costs are relatively flat, significant cost saving and cost avoidance benefits resulting from Engineering efforts are realized in other programs such as Compressor Fleet Repair and Overhaul, Pipeline Integrity, Capital expenditures and Field Operations maintenance plans.

### 2.3.1.3 Operations and Engineering Support Services (Schedule 2.3.1.3)

**Business Management Services**

Business Management Services provide the development, maintenance and support of business processes for Field Operations and Engineering. This includes the following functions: budgeting and forecasting; performance measurement and benchmarking; management and support of computerized maintenance and procurement systems; supplier analysis and qualification; technology management (research and development);

accounts payable; contracts administration; vehicle fleet management; and business records management.

The 2003 ~~forecast~~ Business Management Services Operating Costs ~~are~~ ~~$5.8~~ were $5.6 million compared to $5.3 million for the 2002 base year, reflecting an increase of ~~$0.5~~$0.3 million. The 2004 test year costs are $6.7 million compared to ~~$5.8~~$5.6 million ~~for the~~ in 2003 ~~forecast year~~, reflecting a further increase of ~~$0.9~~$1.1 million.

Prior to the mid-year 2003 organizational change, freight and courier charges were included in Field Services and Business Services. Subsequent to the organizational change, these costs are now included in Business Management Services and account for the variances noted. Freight and courier costs amounted to $1.6 million in the 2002 base year~~, and are forecast to be~~ ~~$1.6~~$1.4 million in ~~the~~ 2003, -and are forecast ~~year and~~ to be $1.5 million in the 2004 test year.

Normalizing for organizational changes and salary increases, ~~forecast~~ Business Management Services costs ~~are relatively flat for~~ ~~the~~ in 2003 ~~forecast~~ and the 2004 test year~~s, relative to~~ are relatively flat compared with the 2002 base year. Although costs are relatively flat, significant cost saving and cost avoidance have resulted from outsourcing specific activities and organizational efficiencies.

**Procurement Services**

Procurement Services sources materials and services for NGTL. Procurement Services utilizes its knowledge of supply chain management and the leverage potential of the larger TCPL organization to reduce the material and service costs for NGTL. Developing long term relationships and alliances with outside service providers for strategic procurement of materials and services ensures longer term value.

The 2003 ~~forecast~~ Operating Costs ~~are$3.4~~ were $3.6 million, compared to $3.5 million for the 2002 base year, reflecting an ~~decrease~~increase of $0.1 million. The 2004 test year costs are forecast at $2.7 million, a ~~further~~ reduction of ~~$0.8~~$0.9 million. The 2004 test year reduction is attributed to organizational adjustments and re-negotiation of contract management fees related to outsource providers. Additionally, implementation of large national contracts to provide a suite of goods and services at locations near Field Operations locations, and a reduction in the Alberta System capital program have resulted in a requirement for fewer employees for the procurement of materials and services. These staff reductions offset increases in salaries and benefits.

**Field Services**

Field Services provides laboratory analysis services, specialized construction services, warehousing, inventory management and equipment repairs.

Lab services provides analysis of gas samples to determine gas composition and quality and analysis of engine oil samples for input to the compressor fleet maintenance program. Construction services maintains a minimum core staff with multiple competencies to provide such activities as fabrication of piping assemblies, installation of pipeline branch connections, hydrostatic testing and pipeline dig activities. Warehousing and inventory management ensures the correct materials are available for NGTL when required and that inventory levels are appropriate given the requirements of the system. Equipment repairs provides specialized shop, field services and technical support for high-value critical compression equipment including gas turbines, aero assemblies, dry gas seals and ancillary equipment.

Construction services and equipment repairs provide NGTL with some leverage when negotiating external contracts for similar services and provide a degree of assurance that critical services are available when needed. However, NGTL regularly reviews the services provided to establish whether in-house services continue to add value relative to external providers. For example, NGTL recently ceased operation of its internal materials testing labs in favour of outsourced alternatives.

The 2003 ~~forecast~~ Operating Costs ~~remain flat at levels of $3.8 million.~~were $3.1 million, compared with $3.8 million for the 2002 base year reflecting a decrease of $0.7 million. The 2004 test year costs are forecast to increase by approximately ~~$0.6~~$1.3 million to $4.4 million.

The 2003 ~~forecast~~actual year costs include the impact of organizational adjustments resulting in a $0.9 million increase relative to the 2002 base year. This increase reflects a transfer of Lab Services and equipment repairs from Plant Engineering to Field Services. This increase along with salary and benefits increases are offset by a reduction in ~~inventory write down~~ freight and courier costs ($~~0.7~~1.1million) and a reduction in construction services work performed on the Alberta System ($0.2 million). Increases in the 2004 test year are reflective of full-year organizational changes ($0.9 million)~~offset by further decreases in~~, an increase in inventory write down (~~$0.2~~$0.5 million), offset by a decrease in ~~and~~ construction services work ($0.2 million).

**Community, Safety and Environment**

Community, Safety and Environment develops and implements policies and procedures used to promote the safe operation of the Alberta System, environmental due diligence and sustained community relationships. As well, Community, Safety and Environment works to ensure applicable safety and environment compliance requirements are understood and adhered to by all employees.

NGTL's community efforts are aimed at increasing awareness and understanding of existing facilities, which in turn positively contribute to the safety of the public, landowners, employees and facilities. Safety efforts focus on ensuring that employees have the right training to properly complete their tasks. Environmental efforts include the coordination and execution of environmental planning, environmental inspection, climate change initiatives, reclamation, remediation and vegetation/brush management.

Operating Costs in ~~the~~ 2003 ~~forecast year are~~were $3.6 million, compared to $4.3 million for the 2002 base year, reflecting a decrease of $0.7 million. Forecast costs for 2004 are $3.8 million, reflecting a $0.2 million increase relative to ~~the~~ 2003 ~~forecast year~~.

Decreases in ~~the~~ 2003 ~~forecast year~~ are attributed to organizational efficiencies and completion of certain work activities in 2002 related to the development of community and safety awareness programs. A slight increase in costs for the 2004 test year over actual ~~the~~ 2003 results~~forecast year~~ ($0.2 million) is attributed to increased effort to support multi-pollutant regulatory reporting requirements and an expected high level of pipeline crossings, line locates and salary and benefits increases, which is offset by certain staff reductions.

### 2.3.1.4 Operations and Engineering Programs (Schedule 2.3.1.4)

#### Compressor Fleet Repair and Overhaul

The Compressor Fleet Repair and Overhaul program includes Operating Costs associated with the maintenance of compressor units and associated systems. Maintenance programs are risk-based in order to optimize maintenance activities for major compression equipment. This approach utilizes detailed maintenance costs, wear rates, failure risk and failure consequence information to determine optimum maintenance intervals and activities.

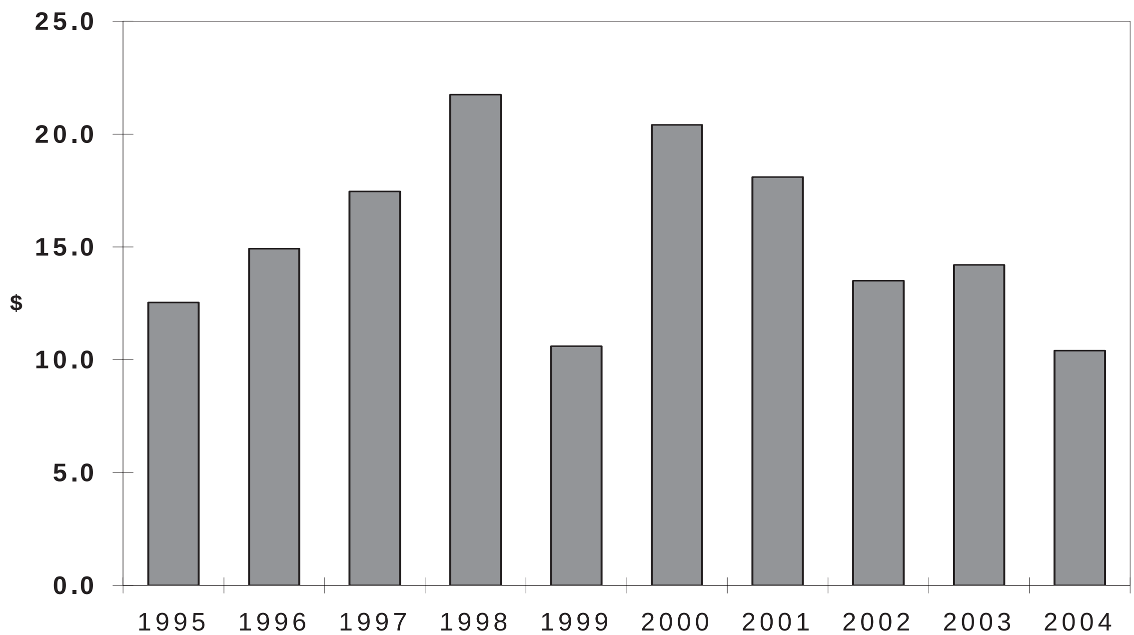
The typical maintenance cycle of a compressor unit includes on-site inspections, minor overhauls, and major overhauls. The overhaul of more specialized equipment, such as gas generators and some power turbines, is completed at specialized repair shops. Overhauls of reciprocating units, centrifugal compressors, and most of the large power turbines are typically carried out on-site, although some components are removed and taken to repair shops for refurbishment.

The Compressor Fleet Repair and Overhaul program includes an estimate of how many overhauls will be required in a given year, and the scope of work for each. The annual overhaul plan is based on a number of factors including: estimates of unit utilization based on flow forecasts; outage impact; operating time since installation, last overhaul, or repair; bundling of maintenance activities; manufacturer service bulletins; availability of spares to support equipment change-outs; and equipment condition. These factors contribute to the cyclical nature of the program costs shown in Figure 2.3.1.4-1.

**Revised Figure 2.3.1.4-1**

**NGTL Repair and Overhaul Historical Operating Costs**

($ millions)




Overhauls are triggered when one or more of the following conditions are met: the unit accumulates sufficient hours since the last overhaul or repair; equipment fails and it is economical to perform an upcoming overhaul during the repair; other scheduled maintenance is to be performed and it is economical to complete an upcoming overhaul during the same time window; the manufacturer issues a service bulletin that requires immediate action; or operating or integrity problems are identified.

Once an overhaul is triggered, the actual timing of the performance of the work may be advanced or delayed slightly by the following factors: bundling work to optimize down time and cost; operating conditions where downtime may impact system deliveries; repair shop constraints (loading, capacity, and spare parts); and availability of spare equipment.

The cost of performing overhauls depends on the complexity of the equipment. Lower-powered industrial gas generators are the least expensive to overhaul while the latest generation of high thermal efficiency, low emissions, aero-derivative gas generators are the most expensive. Low emission units are up to 41% more expensive to maintain than similar conventional gas generators.

The 2003 ~~forecast~~ Operating Costs ~~are $16.4~~were $14.2 million, as compared to $13.5 million for the 2002 base year, reflecting an increase of ~~$2.9~~$0.7 million. ~~from the 2002 base year due to:~~ This increase is primarily due to four refurbishments completed in 2003 compared with two completed in the 2002 base year.

- ~~Six minor overhauls will be completed compared to five in the 2002 base year;~~
- ~~Four refurbishments will be completed in the 2003 forecast year compared to two in the 2002 base year; and~~

The 2004 test year Operating Costs are forecast to be $10.4 million, reflecting a decrease of $~~6.0~~3.8 million relative to ~~the~~ 2003. This is ~~forecast year,~~ due to:

- Six major overhauls will be completed compared to 12 in the 2003 ~~forecast year~~;
- ~~Four~~Three minor overhauls will be completed compared to six minor overhauls completed in ~~the~~ 2003 ~~forecast year~~; and
- No refurbishments are planned for the 2004 test year compared to four in ~~the~~ 2003 ~~forecast year~~.

**Land Payments**

Land Payments consist of pipeline right-of-way costs, including lease and access payments for aboveground facilities, pipeline easement costs and road access costs.

The 2003 ~~forecast~~ Land Payments costs are $~~7.0~~6.2 million, compared to $6.1 million for the 2002 base year, reflecting an increase of $~~0.9~~0.1 million. The 2004 test year costs are forecast to be $8.6 million, reflecting an increase of $~~1.6~~2.4 million over 2003 costs.

Overall land values are increasing due to high levels of industry activity and increasing urban encroachments. In order to mitigate the potential impact of continuing increases in land payments, a pilot program has been introduced to determine appropriate amounts for one-time payments that would allow for the annual payment program to be discontinued. Costs of $1 million are included in ~~each of 2003 and~~ 2004 for this program.

Further contributing to the 2004 test year cost increase is the fact that one-third of the landowners who receive annual payments have their five-year agreements up for renewal in 2004. NGTL expects increased costs for those landowners remaining on the annual payment program as a result of inflationary pressures.

**Electrical Utilities**

Electrical Utilities costs consist of the supply and delivery of electricity to all Alberta System field facilities.

~~The 2003 forecast costs are expected to remain relatively flat compared to the 2002 base year. The 2004 test year costs are $0.8 million lower than the 2003 forecast year due primarily to~~ Operating costs for 2003 were $4.1 million compared with $4.4 million in the 2002 base year, a decrease of $0.3 million. Forecast costs for 2004 are $3.8 million, reflecting a $0.3 million decrease relative to 2003. The decrease in costs from the 2002 base year to the 2004 test year is primarily due to expected lower market prices, elimination of the 2000 pool price deferral recovery charge, and lower electricity distribution tariffs.

### 2.3.1.5 Commercial and Regulatory (Schedule 2.3.1.5)

**Sales, Market Development and Rates**

The Sales area customer account managers are responsible for individual customer relationships, in three key areas: identifying and evaluating opportunities to attach new supplies and markets; the development and execution of contracts; and customer service issue resolution. Associated with this function is a communications group, which is responsible for ongoing customer communications such as electronic newsletters, presentations at industry conferences, organization of special customer events and meetings, and the coordination of an annual customer survey.

Market Development is responsible for developing and obtaining stakeholder support for specific services that will allow both NGTL and its customers to be successful in the current and future competitive environment. This responsibility involves liaison between industry and NGTL through co-ordination of the Tolls, Tariff and Procedures Committee and the Facilities Liaison Committee.

The Rates department develops rate designs and rate forecasts. Other activities include analysis to support the resolution of customer and industry association concerns, provision of long-term rate forecasts for customers' business planning purposes, and support for regulatory initiatives and hearing requirements.

The 2003 costs for Sales, Market Development and Rates are ~~$4.8~~$4.5 million, up ~~$0.6~~$0.3 million from 2002. This increase is due to the transfer of the Rates department from Regulatory Services into this group. ~~($0.3 million) together with increased salaries and benefits~~. The 2004 costs are forecast to be $5.5 million, an increase of ~~$0.7~~$1.0 million from costs in 2003. The increase in 2004 is due primarily to an increase in salaries and benefits and also reflects the full-year impact of transferring the Rates group from Regulatory Services.

**System Design and Operations**

System Design and Operations includes departments responsible for gas quality, operations planning, and gas control. The System Design and Operations department is responsible for hydraulic analysis and system design and the safe and efficient operation the integrated gas transmission system. The key activities performed include receipt and delivery forecasting, facility planning, gas quality tariff management, daily operations planning and capacity management and the 24x7 control of the gas transmission system.

The facility planning process begins with a forecast of volumetric requirements for the Alberta System, incorporating specific customer requests for service, followed by the determination of requirements that provide the most economical and long-term orderly expansion of the system to meet those transportation requirements. This process focuses on future gas years.

The gas quality group maintains the specifications included in the tariff, and works with Field Operations and Engineering to resolve operational issues associated with the quality of gas received onto the Alberta System.

Operations planning deals with the current gas year, primarily day-to-day capacity planning and the selection of operating strategies that minimize fuel usage and operating costs.

Gas control executes a daily operational plan and anticipates and responds to system delivery problems resulting from scheduled and unscheduled outages. Gas control provides 24x7 control and monitoring, dispatching field technicians when SCADA alarms indicate a need, and managing system flows with operators of production, storage and extraction facilities and downstream pipelines.

The 2003 costs for System Design and Operations ~~are relatively flat compared to~~were slightly lower than 2002 at ~~$6.5~~$6.3 million. In 2004, costs are estimated to increase by ~~$0.6~~$0.8 million to $7.1 million. This increase is largely attributable to forecast salary and benefits increases. The variances from 2002 to 2003 and 2003 to 2004 also reflect the impact of organizational changes in mid-2003. ~~in which the Applications and Compliance, Facilities group moved from System Design and Operations to Regulatory Services.~~

**Customer Service**

The Customer Service area consists of two groups: contract and billing, and nominations and allocations.

The contract and billing group prepares and coordinates transportation contracts, economic evaluations, customer billing and all of the associated information systems support.

The nominations and allocations group facilitates the gas accounting processes and provides assistance to customers with their nomination and account balancing activities. This department is responsible for the daily and monthly transactions that facilitate the gas accounting process performed on all customer accounts. In order to complete this task, a series of nomination, allocation and inventory processes must be continually tracked and communicated to Alberta System shippers in order to enable them to conduct their business with NGTL.

The customer base that the nominations group serves includes shippers and operators at approximately 1,300 receipt, delivery, storage and extraction facilities within Alberta. The nomination group also deals directly with various interconnecting pipeline operators.

The 2003 costs for this function ~~are $3.2~~were $2.9 million, or ~~$1.2~~$1.4 million lower than actual 2002 costs. This decline results from overall efficiencies achieved from providing integrated service to TCPL's three regulated pipelines. The 2004 costs increase by $~~0.8~~0.7 million to $~~4.0~~3.6 million. This increase is largely due to increases in salaries and benefits. 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.

**Regulatory Services**

The Regulatory Services department is responsible for ensuring applications related to the Alberta System are filed in an effective and timely manner to provide essential information to both the regulator and customers. Activities associated with this function include:

- Preparation of submissions to the Board respecting transportation revenues, rates, terms, and conditions of service;
- Support for all key phases of a hearing process, including responding to information requests, preparing rebuttal evidence, preparing witnesses, and assisting with undertakings, argument, and reply argument;
- Preparation and filing of the Annual Plan, which provides an understanding of how specific facilities applications are consistent with and fit into the overall long-term development of the Alberta System;
- Submission of specific facilities applications that provide the final technical design, economics, routing/siting, land, environmental, and other relevant information;
- Monitoring and analyzing regulatory proceedings in Canada and the United States which relate to other pipelines that transport Canadian gas or could impact NGTL's interests or governing legislation; and

- Researching and analyzing issues of concern to NGTL which fall within the scope of regulation.

The increase in costs from $1.2 million in 2002 to $1.6 million in 2004 is due to the increasing number of regulatory proceedings related to the Alberta System. In 2002, NGTL was in the second year of the ASRS and had fewer regulatory requirements. In 2003, this level of activity has increased, primarily as a result of the 2004 Generic Cost of Capital proceeding currently underway and the submission of this Application. This level of activity is expected to continue to increase in 2004 when hearings on both Phase 1 and 2 of the 2004 GRA are expected to be held. The variances from 2002 to 2003 and 2003 to 2004 also reflect the impact of organizational changes in mid-2003 in which the Rates group moved from Regulatory Services to Sales, Market Developments and Rates and the Applications and Compliance, Facilities group moved to Regulatory Services from System Design and Operations.

### 2.3.1.6 Business Services (Schedule 2.3.1.6)

The 2003 costs for this function ~~are forecast to be~~ ~~$17.6~~were $16.9 million, or ~~$0.3~~$1.1 million lower than 2002 actual results. The 2004 costs are expected to ~~increase $0.4 million over the 2003 forecast to $18.0 million. The increase is due primarily to~~return to 2002 levels largely due to salary and benefit increases. ~~This~~ These increases ~~was~~ were partially offset by lower Building Services costs attributable to lower staff levels and the consolidation of courier costs with freight costs in Field Services.

**Human Resources**

The Human Resources department is responsible for providing services and programs, which are designed to attract, retain, and motivate quality employees.

Human Resources delivers to or assists the organization with day-to-day operational tasks including: employee recruiting and separation; payroll; compensation delivery; pension and benefits delivery; employee records management; performance management;

disability management; and employee/labour relations. Longer-term programs include: organizational design and effectiveness; succession planning and career development; leadership development; and resource planning and forecasting.

**Public Sector Relations**

The Public Sector Relations function encompasses the communications, community investment and government relations functions.

The communications group develops and manages communication materials and plans to ensure consistency in messages to internal and external stakeholders.

The community investment group develops partnerships with not-for-profit organizations in communities where the Alberta System conducts business. Community investment provides financial support, shares resources (such as contributions of employee time and expertise), and gives gifts in-kind.

The government relations group actively participates with all levels of government to acquire information and to constructively influence the development of policies, regulations and legislation. Government relations helps build relations with key decision makers in the federal, provincial, and local governments, working through a large variety of departments which include natural resources, energy, environment and economic development.

**Building Services**

Building Services provides building/tenant, printing and office services to the organization. These services include: coordination of moves and tenant services; space management, planning and design; construction and project management; reprographic services; office supplies; and internal mail services. These services are performed primarily in the TransCanada Tower and the Airdrie and Edmonton service centers.

**Finance**

The Finance functional area includes accounting, risk management, taxation, treasury, and investor relations. It also includes the strategy and planning department which is responsible for developing natural gas supply forecasts and economic forecasts used for system design and pipe project economics.

**Law and General Counsel**

This area includes legal services, internal audit and security.

The legal group provides timely support on legal issues. Dedicated in-house counsel are knowledgeable about the Alberta System. In providing these services, legal counsel are assigned to specific functional areas, and retain external counsel as required.

The internal audit department operates as an independent, objective, assurance function reporting to the Board of Directors through the audit and risk management committee. Internal audit reviews departments and functional areas at appropriate intervals to evaluate whether they are functioning effectively in accordance with laws, regulations, policies and procedures. It evaluates the adequacy and effectiveness of the internal control structure and promotes effective control at a reasonable cost. Internal audit also evaluates the appropriateness of risk mitigation.

Security services provides general protection to NGTL facilities and employees through physical security, development of policies, as well as communication of security issues to employees. Other services include crisis management and investigation of security-related matters.

**Other**

Costs in this area are primarily comprised of salary costs of the executive leadership team and the expenses of the president, as well as operating costs of the aviation department.

### 2.3.1.7 Information Systems (IS) (Schedule 2.3.1.7)

The IS departments enable NGTL's business processes through the provision of information systems solutions including: business applications (purchased or developed); infrastructure to support applications and other services (servers, databases, etc.); desktop computers and common productivity tools; voice and data networks and equipment; collaboration tools such as file-sharing, email and meeting scheduling; and information asset protection (security, backup and recovery, etc.).

A breakdown of IS costs can be found in Schedule 2.3.1.7. Overall, 2004 IS costs are forecast to be 19% lower than costs in 2002, and ~~14%~~ 9% lower than ~~forecast~~actual 2003 costs.

**Shared Services**

This functional area includes: desktop support, including provision of hardware upgrades, software and peripherals, maintenance agreements and licenses; server operation, support, software and peripherals, maintenance agreements and licensing; telecommunications support, upgrades, maintenance agreements and licensing; application development tools and environment, database support, maintenance agreements and licensing; security, architecture and technical planning; and IS management, planning and administration.

NGTL costs for IS shared services ~~are forecast to~~ declined from $12.7 million in 2002 to $~~9.5~~8.8 million in 2003 and ~~decline further to $8.8 million~~ are expected to remain at approximately that level in 2004. The primary cause of ~~this~~ the reduction ~~is~~ from 2002 to 2003 was a change in computing platform strategy that resulted in the elimination of mainframe computers in 2002 and a more than 50% reduction in mid-range servers. This has reduced overall operating, maintenance and support costs for the server infrastructure. Also contributing to the reduction is a transition to primarily in-house resources from an outsourced shared services model.

**Customer and Pipeline Systems Support**

This functional area provides computer applications and supporting services used specifically by the Alberta System's customer and pipeline business areas and customers. The work activities can be summarized as: requirements gathering, analysis and recommendations; operation of systems, monitoring and system administration; user training and support; "break-fix" and "sustain" activities ("bug" fixes, minor upgrades, version installs, etc.); and portfolio management and lifecycle planning.

The primary functional areas and applications supported by this group include: Customer systems supporting transportation contracting, nominations and billing, and gas control; Engineering and Operations systems such as measurement, design and operations functions supporting plant and pipeline facilities; and Regulatory and Engineering software applications supporting functions such as gas forecasting, engineering services, land, health, safety and environment.

Operating costs for this area have been reduced from $6.4 million in 2002 to ~~an estimated~~ ~~$5.3~~$5.1 million in 2003 and are forecast ~~of~~ to be $4.8 million in 2004. The reductions are primarily the result of reliability improvements resulting from enhanced operation monitoring, analysis, replacement and overhaul of servers supporting these applications.

~~The major system development project currently underway is the Dovetail project. The purpose of this project is to replace a number of legacy systems, which perform transportation contracting and a number of customer transactional functions. This project will incorporate a number of business process changes endorsed by customers, and result in lower long-term operating costs.~~

**Commercial Systems Support**

This functional area provides general business systems applications and supporting services used by employees. The work activities are the same as for the customer and pipeline Systems group, but involve a different set of software applications and required expertise. They include general business systems in areas such as human resources and procurement, as well as financial systems supporting accounting and treasury.

Operating Costs for this function have remained relatively stable from 2002 to 2004, as a result of salary and benefit increases, and inflationary increases in other costs being offset by productivity improvements.

**Telecommunication**

Telecommunication costs include equipment and circuit lease costs, tolls charges and maintenance and repair of all network and voice infrastructure for the purpose of remote monitoring and control of meter stations, compressor stations and mainline valves, as well as the provision of mobile radio and all voice services.

The costs in this area have decreased from $5.9 million in 2002 to a forecast of $4.0 million in 2004. This reduction is attributable mainly to changing technologies and operational efficiencies.

**Systems Development**

System Development costs includes the costs of development and enhancement of operating projects for Shared Services, Customer and Pipeline Systems and Commercial Systems. Included in these activities are: requirements gathering, analysis and recommendations; alternatives selection including acquisition of vendor-supplied solutions; customization or in-house development; acquisition or development activities; and implementation including data conversion, testing, training and integration with other systems.

This category is new in 2003 because of an increasing need to manage smaller development and enhancement projects within operating costs. This was driven by the need to enhance the new software applications delivered since 2000~~, the need to keep legacy applications current during Dovetail development~~ and an increased list of smaller new development projects required once the large applications were delivered. Prior to 2003, the majority of development work was on large system initiatives that were part of the capital program. Approximately $0.8 million was spent on expensed projects in 2002 but these costs were captured under Shared Services. The estimate for Systems Development expense is reduced from $3.3 million in 2003 to $2.3 million in 2004 as fewer projects impacting the Alberta System are currently planned.

### 2.3.1.8 General Expenses (Schedule 2.3.1.8)

General Expenses include third-party costs, as well as incentive compensation and certain benefit costs.

**Auditing**

Audit fees are amounts paid to external parties associated with the audit work performed on financial records, due diligence of the financial statements, and accounting advice. The increase in costs in ~~2004~~2003 compared with ~~2003~~2002 is attributable to additional corporate governance reviews driven by the Sarbanes-Oxley Act. Costs in 2004 are expected to remain relatively flat as compared to 2003.

**Legal**

Legal fees represent expenditures on third party legal fees attributable to the operation of the Alberta System, such as litigation and compliance. The increase in costs in 2004 compared to 2003 is attributable to anticipated litigation costs on existing files directly associated with NGTL and anticipated legal work associated with the change in the land administration program, and other general corporate matters relating to finance, corporate secretary and employment. External legal fees related to regulatory proceedings of NGTL have been included in the Regulatory Hearing Costs amount discussed in Section 2.9.

## Insurance

These costs include property and liability coverage for NGTL. Insurance costs for 2003 are $3.3 million, ~~$0.2~~$0.1 million higher than 2002. Insurance premiums paid in 2002 for 2002/2003 insurance coverage increased significantly due to market conditions. The impact in 2003 of these higher premiums is partially offset by the effect of lower insured property values as a result of compressor station retirements

Insurance costs in 2004 are forecast to be $4.0 million, an increase of ~~$0.6~~$0.7 million compared to 2003. This increase is due to tight market conditions for liability coverage that are expected to continue throughout the 2004 premium renewal period.

## Stock and Debt Administration

Stock and Debt Administration includes such costs as: transfer agent fees; trustee and rating agency fees; line of credit standby fees; annual report costs; and annual meeting costs.

Stock and Debt Administration costs increased from $1.7 million in 2002 to $2.1 million in 2003. This increase is due primarily to higher common stock expenses such as transfer agent and stock exchange fees, higher printing and mailing costs associated with the Annual General Meeting and the costs for establishment of a new credit facility. Costs in 2004 are expected to remain at 2003 levels.

## Incentive Compensation

This category represents broad-based annual incentive compensation (IC) payments to employees. A detailed description of IC is provided in Section 2.3.2, Compensation and Benefits. NGTL costs for IC ~~are forecast to increase $3.4 million to~~were $13.2 million in 2003 compared to $9.8 million in 2002. 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.

The 2004 costs are expected to decrease by $0.9 million to $12.3 million compared with $13.2 million in 2003. The decrease results from ~~a reduction in total and a lower allocation rate~~lower overall expense and a reduction in the amount applicable to NGTL.

**Long Term Incentive Compensation (LTIC)**

LTIC represents the costs for restricted share units (RSU), executive share units (ESU), performance unit payments (PUP) and stock options. A detailed description of the LTIC is provided in Section 2.3.2, Compensation and Benefits.

NGTL costs for LTIC increased by ~~$2.4~~$4.3 million to ~~$11.3~~$13.2 million in 2003 compared with $8.9 million in 2002. The increase is due primarily to the implementation of a share unit program for management and executives, a revised valuation for RSUs, and an increase in PUP expenses~~,~~ attributable to an increase in the total number of vested units and related dividends. ~~These factors are partially offset by a decrease in the cost of RSUs as a result of fewer FTEs being allocated to the Alberta System.~~

LTIC costs in 2004 increase by ~~$2.4~~$2.1 million to ~~$13.6~~$15.3 million. ~~Approximately $1.2 million of this increase is due to the~~ This increase is due primarily to continued implementation of the share unit program for management and executives ($1.3 million) and ~~. A further $0.5 million of the increase is due to~~ higher PUP expense resulting from an increase in the number of vested units and related dividends ($0.7 million~~. The balance of the increase is due to increases in RSUs ($0.3 million) as a result of an increased share price forecast and stock option expense ($0.4 million) due to additional units being granted and the valuation applied.~~).

**Dues and Subscriptions**

Dues and subscriptions consist primarily of memberships in natural gas pipeline industry associations. The $0.1 million increase in 2003 costs ~~to $0.6 million compared with $0.5 million in 2002~~ results from fee increases from these organizations. A similar increase is anticipated in ~~The~~ 2004~~. costs are expected to remain flat at 2003 levels.~~

**Directors' Fees and Expenses**

This account includes NGTL's allocation of the remuneration and expenses of TransCanada's Board of Directors. The ~~$0.1 million increase in~~ 2004 ~~to $0.6 million is primarily due to a 7% increase in director related costs~~costs are expected to remain relatively flat  at 2003 levels.

**Donations**

This account includes donations to support the communities in which the Alberta System operates. These donations assist in developing positive relations with the Alberta System's stakeholders. The largest donations go to support education, health and human services and the United Way. These costs ~~are expected to~~ declined by $0.2 million in 2003, to $1.0 million compared with 2002 costs of $1.2 million and are expected to remain at ~~that~~ the 2003 level in 2004.

**Other Regulatory**

In the original Application as filed September 30, 2003, this amount was included as part of Miscellaneous. It has now been shown separately to provide greater clarity and transparency. This account includes costs related to regulatory proceedings that are not part of Regulatory Hearing Costs, such as printing and translation costs and employee expenses.

**Relocation Expense**

Relocation costs represent the costs of moving employees between locations. The decline of ~~$0.3~~$0.3 million from $1.2 million in 2002 to $0.9 million in 2004 reflects an overall reduction in total relocation costs as well as a decline in the proportion attributable to the Alberta System.

**2004 Severance**

Severance costs of $5.9 million represent the Alberta System's share of anticipated severance expense in 2004. This amount has been determined based on the level of employment terminations expected in 2004. In 2002 and 2003, severance costs were deferred and amortized under the provisions of the ASRS and ASRRS, respectively. These amounts are included in Section 2.13, Revenue Requirements Adjustments and Non-routine Adjustments.

**Rent**

These costs include rent and operating costs for the company's Calgary office. These costs ~~are $9.0~~ were $9.3 million in 2003, a decrease of ~~$2.2~~$1.9 million compared with 2002. This decline is due to lower net rent and operating expenses and a reduction in the portion attributable to the Alberta System. The reduction in rent is primarily due to lower operating costs, including a credit relating to the prior year. Also contributing to the reduction in rent expense is additional sub-tenant revenue and further consolidation to the TransCanada Tower.

Rent costs in 2004 are ~~$9.7~~ forecast to be $9.8 million. This represents an increase of ~~$0.7~~$0.5 million from 2003. The increase is due to higher anticipated operating costs, partially offset by additional sub-tenant revenue.

**Other Post Employment Benefits (OPEBs)**

OPEBs represent the annual amortization of the transitional obligation created as a result of the implementation of the new accounting standard as at January 1, 2000, which effectively changed the accounting treatment of OPEBs from a cash basis to an accrual basis. The transitional obligation is amortized over the expected remaining service life and remains unchanged at $0.9 million each year.

**Pension and Benefit Adjustment**

The Pension and Benefit Adjustment represents the difference between benefits charged to departments at ~~a~~the standard benefit rate and actual benefit costs incurred. The standard benefit rate is determined during the budget process and is based on anticipated overall benefit costs as a percentage of salaries. ~~This account also includes the amortization of actuarial gains and losses on the defined benefit pension plan.~~ The increase in 2003 compared with 2002 is due primarily to the January, 2003 actuarial assessment that resulted in higher than expected pension expense in 2003. To adjust for this increase, the 2004 budgeted standard benefit rate was increased to 34% from the 29% rate applied in 2003. However, an updated actuarial assessment was received in January, 2004, indicating that pension expense would increase $2.8 million above the amount included in the standard benefit rate. As a result, the Pension/Benefit Adjustment of $2.8 million was created for 2004.

~~The cost increase of $7.5 million in 2003 to $9.4 million is mainly attributable to higher pension expense resulting from a January 2003 actuarial assessment and the consolidation of all employees into the defined benefit pension plan. Due to the timing of the actuarial assessment, the impact could not be accommodated in the standard benefit rate for the 2003 budget year.~~

~~In 2004, these costs are expected to decrease by $1.9 million to $7.5 million. For 2004, the impact of the January 2003 actuarial adjustments has been included in the standard benefit rate charged to all departments, resulting in a decrease of $4.3 million in the Pension and Benefits Adjustment amount. Partially offsetting this decline is an increase in the estimated actuarial pension loss amortizations of $2.7 million. This increase is largely due to a change in the discount rate applied in the actuarial assessment.~~

**Actuarial Gain/Loss Amortization**

In the original Application as filed September 30, 2003, this amount was included as part of the Pension/Benefit Adjustment. It has now been shown separately to provide greater clarity and transparency. This account includes the amortization of actuarial gains and losses, as well as amortization of past service costs related to the company's defined benefit pension plan. These amounts are based on the most recent actuarial assessment dated January 2004.

**Miscellaneous Costs**

Miscellaneous costs include advertising, public relations, overhead recoveries from third parties and non-regulated capital projects and other non-recurring expenditures.

OPERATING COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Reference | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 1 | Field Operations | Sched 2.3.1.1 | 39,214 | (669) | 38,545 | 86 | 38,631 |
| 2 | Engineering | Sched 2.3.1.2 | 12,214 | (4,060) | 8,154 | (674) | 7,480 |
| 3 | Operations and Engineering Support Services | Sched 2.3.1.3 | 16,913 | (1,008) | 15,905 | 1,607 | 17,512 |
| 4 | Operations & Engineering Programs | Sched 2.3.1.4 | 24,114 | 397 | 24,511 | (1,768) | 22,743 |
| 5 | Commercial and Regulatory | Sched 2.3.1.5 | 16,410 | (1,257) | 15,153 | 2,589 | 17,742 |
| 6 | Business Services | Sched 2.3.1.6 | 17,963 | (1,091) | 16,872 | 1,181 | 18,053 |
| 7 | Information Systems | Sched 2.3.1.7 | 27,863 | (2,810) | 25,053 | (2,354) | 22,699 |
| 8 | General Expenses | Sched 2.3.1.8 | 45,071 | 8,632 | 53,703 | 9,764 | 63,467 |
| 9 | TOTAL OPERATING COSTS | | 199,762 | (1,866) | 197,896 | 10,431 | 208,327 |

OPERATING COSTS
**FIELD OPERATIONS**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Central Region | 8,682 | (2,373) | 6,309 | (2,981) | 3,328 |
| 2 | Rocky Mountain Region | 12,888 | 378 | 13,266 | 581 | 13,847 |
| 3 | Wildrose Region | 17,644 | 1,326 | 18,970 | 2,486 | 21,456 |
| 4 | Total | 39,214 | (669) | 38,545 | 86 | 38,631 |

OPERATING COSTS
**ENGINEERING**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Pipe Engineering | 2,464 | (723) | 1,741 | 360 | 2,101 |
| 2 | Plant Engineering | 7,630 | (2,094) | 5,536 | (1,398) | 4,138 |
| 3 | Engineering Management & Project Controls | 2,120 | (1,243) | 877 | 364 | 1,241 |
| 4 | Total | 12,214 | (4,060) | 8,154 | (674) | 7,480 |

OPERATING COSTS
**OPERATIONS AND ENGINEERING SUPPORT SERVICES**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Business Management Services | 5,324 | 239 | 5,563 | 1,122 | 6,685 |
| 2 | Procurement Services | 3,457 | 153 | 3,610 | (952) | 2,658 |
| 3 | Field Services | 3,794 | (665) | 3,129 | 1,265 | 4,394 |
| 4 | Community, Safety & Environment | 4,338 | (735) | 3,603 | 172 | 3,775 |
| 5 | Total | 16,913 | (1,008) | 15,905 | 1,607 | 17,512 |

OPERATING COSTS
**OPERATIONS & ENGINEERING PROGRAMS**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Compressor Fleet Repair & Overhaul | 13,548 | 648 | 14,196 | (3,837) | 10,359 |
| 2 | Land Payments | 6,123 | 66 | 6,189 | 2,429 | 8,618 |
| 3 | Electric Utilities | 4,443 | (317) | 4,126 | (360) | 3,766 |
| 4 | Total | 24,114 | 397 | 24,511 | (1,768) | 22,743 |

OPERATING COSTS
**COMMERCIAL AND REGULATORY**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Sales, Market Development and Rates | 4,193 | 314 | 4,507 | 960 | 5,467 |
| 2 | System Design and Operations | 6,615 | (317) | 6,298 | 826 | 7,124 |
| 3 | Customer Service | 4,390 | (1,444) | 2,946 | 650 | 3,596 |
| 4 | Regulatory Services | 1,212 | 190 | 1,402 | 153 | 1,555 |
| 5 | Total | 16,410 | (1,257) | 15,153 | 2,589 | 17,742 |

OPERATING COSTS
**BUSINESS SERVICES**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Human Resources | 3,447 | (140) | 3,307 | 213 | 3,520 |
| 2 | Public Sector Relations | 1,191 | (51) | 1,140 | 305 | 1,445 |
| 3 | Building Services | 4,006 | (19) | 3,987 | (364) | 3,623 |
| 4 | Finance | 5,474 | (395) | 5,079 | 257 | 5,336 |
| 5 | Law and General Counsel | 1,977 | (87) | 1,890 | 198 | 2,088 |
| 6 | Other | 1,868 | (399) | 1,469 | 572 | 2,041 |
| 7 | Total | 17,963 | (1,091) | 16,872 | 1,181 | 18,053 |

OPERATING COSTS
**INFORMATION SYSTEMS**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Shared Services | 12,660 | (3,825) | 8,835 | 33 | 8,868 |
| 2 | Customer and Pipeline Systems Support | 6,352 | (1,221) | 5,131 | (311) | 4,820 |
| 3 | Commercial Systems Support | 2,951 | (466) | 2,485 | 285 | 2,770 |
| 4 | Telecommunication | 5,900 | (572) | 5,328 | (1,372) | 3,956 |
| 5 | Systems Development | - | 3,274 | 3,274 | (989) | 2,285 |
| 6 | Total | 27,863 | (2,810) | 25,053 | (2,354) | 22,699 |

OPERATING COSTS
**GENERAL EXPENSES**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| Line No. | Description | Base Year 2002 | Increase (Decrease) | Actual Year 2003 | Increase (Decrease) | Test Year 2004 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Auditing | 465 | 114 | 579 | (14) | 565 |
| 2 | Legal | 947 | (545) | 402 | 391 | 793 |
| 3 | Insurance | 3,131 | 127 | 3,258 | 729 | 3,987 |
| 4 | Stock and Debt Administration | 1,660 | 395 | 2,055 | (17) | 2,038 |
| 5 | Incentive Compensation (IC) | 9,755 | 3,446 | 13,201 | (934) | 12,267 |
| 6 | Long Term Incentive Compensation | 8,888 | 4,315 | 13,203 | 2,080 | 15,283 |
| 7 | Dues and Subscriptions | 458 | 68 | 526 | 83 | 609 |
| 8 | Director's Fees and Expenses | 505 | 56 | 561 | 32 | 593 |
| 9 | Donations | 1,222 | (205) | 1,017 | 10 | 1,027 |
| 10 | Other Regulatory | - | 268 | 268 | (221) | 47 |
| 11 | Relocation Expense | 1,170 | (240) | 930 | (59) | 871 |
| 12 | 2004 Severance (1) | - | - | - | 5,886 | 5,886 |
| 13 | Rent | 11,168 | (1,856) | 9,312 | 470 | 9,782 |
| 14 | Other Post Employment Benefits (OPEBS) | 887 | (1) | 886 | - | 886 |
| 15 | Pension / Benefit Adjustment | 1,130 | 3,654 | 4,784 | (2,028) | 2,756 |
| 16 | Actuarial Gain / Loss Amortization | 771 | 4,033 | 4,804 | 1,474 | 6,278 |
| 17 | Miscellaneous | 2,914 | (4,997) | (2,083) | 1,882 | (201) |
| 18 | Total General Expenses | 45,071 | 8,632 | 53,703 | 9,764 | 63,467 |

(1) Severance represents NGTL's share of anticipated severance expense in 2004. Severance relating to 2002 and 2003 was deferred and amortized under the provisions of the ASRS and the ASRRS, respectively. The resulting amounts are included in Section 2.13.

## 2.3.2 TOTAL DIRECT COMPENSATION AND BENEFITS

Schedule 2.3.2.1 shows the average Total Direct Compensation (TDC) and average benefits cost per full-time equivalent (FTE) for the Alberta System for the 2002 base year, 2003 ~~forecast~~ actual year, and 2004 test year. The annual increases reflected in TDC are the result of market movement of salaries, incentive compensation, and long-term incentive compensation. TCPL must compete with other employers in the marketplace to attract, retain, and motivate skilled employees and, as a result, follows a policy of providing market competitive TDC and benefits. This has resulted in increased costs as TCPL adjusts its TDC to remain competitive in the marketplace.

The year-over-year increases in average base salary are primarily the result of the aggregate average base salary increase shown in Table 2.3.2-5. The average base salary is also impacted slightly by the change in the mix of FTEs being allocated from the various functional areas, as shown in Schedule 2.3.2.2.

The increase in incentive compensation from 2002 to 2003 is partially due to market alignment of one employee group's compensation and due to incomplete data gathering for the Incentive Compensation accrual process in 2002, resulting in an under-accrual. Incentive compensation levels are expected to ~~remain flat~~ decrease slightly from 2003 to 2004.

The change in long term incentive compensation from 2002 to 2003 is the result of the implementation of a share unit program for management and executive in order to maintain a market competitive position and a revised valuation for RSUs. The expense related to performance unit payments (PUPs) also increased as a result of an increase in the total number of vested units and related dividends.

The increase in long term incentive compensation from 2003 to 2004 is the result of the continued implementation of the share unit program for management and executives~~, and an increase in the cost of RSUs as a result of an increased share price forecast~~. The cost related to stock options also increased as a result of additional units being granted and the valuation applied. In addition, the expense related to PUPs also increased as a result of an increase in the total number of vested units and related dividends.

The increase in benefit costs from 2002 to 2003 is the result of an adjustment to pension expense based on the effect of a January 2003 actuarial assessment. Benefit costs are expected to ~~remain flat~~increase slightly in 2004 compared to 2003, again as the result of an adjustment to pension expense based on the effect of a January 2004 actuarial assessment.

**Total Direct Compensation**

At the time of NGTL's last GRA in 1995, the TDC package consisted of base pay and a profit-sharing program for all employees, as well as short-term and long-term incentive programs for management level employees. Since that time, short-term and long-term incentives have become standard components of competitive compensation in the energy industry (short-term incentives ~~96~~99% prevalence, long-term incentives ~~84~~86% prevalence[1]). TCPL responds to market trends to remain competitive with companies in the energy industry. Consequently, TCPL has introduced both short-term and long-term incentive programs. Without these programs TCPL would be offering employees a TDC package that is less than that offered by other energy industry based companies. This would compromise TCPL's ability to attract, motivate and retain the skilled employees required to operate its business in a safe, reliable and efficient manner. These compensation components are appropriate in the current and foreseeable competitive marketplace but are subject to ongoing revision in order to maintain competitive compensation practices and programs in the future.

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 under current economic conditions in

[1] ~~Towers Perrin 2002 Energy Industry Report, October 29, 2002.~~ Towers Perrin 2003 Energy Industry Briefing, October 23, 2003.

Alberta, including the second lowest unemployment rate (2002 – 5.3%)[2] and the highest inflation rate (2002 CPI = 3.4% increase)[3] in Canada, TCPL must provide a competitive TDC package. TCPL's TDC expenditure levels and components are prudent when compared to industry norms and are necessary to remain competitive against industry compensation levels.

TCPL assesses the competitiveness of its TDC comparing it with compensation market survey data from a comparator group, which consists of companies in similar industries of similar size and scope. TCPL's objective in establishing its TDC target is to be competitive with the median of the comparator group. The median of the comparator group describes the point at which 50% of the sampled values are greater and 50% are lower. TDC for employees performing at sustained fully satisfactory performance levels are aligned with the median compensation level of the comparator group, while sustained performance that exceeds expectations provides the opportunity for employees to receive compensation that surpasses the median.

The table below demonstrates how TCPL's TDC compares to the median of the comparator group in ~~2002, the most recent year for which complete data are available~~2003.

**Revised Table 2.3.2-1**
**Comparison of TCPL Data to Towers Perrin Total Rewards Data Base (TRDB) ~~2002~~2003**

| | **1.1 TCPL ~~2002~~ 2003 data submitted to TRDB** | **1.2 Towers Perrin ~~2002~~ 2003 TCPL comparator group** | **1.3 Variance to Market** |
|---|---|---|---|
| **A) Target Total Direct Compensation** (for all positions matched to TRDB) | Average ~~$102,368~~$107,560 | Median ~~$109,565~~$116,288 | ~~-6.6%~~ -7.5% |
| **B) Actual Total Direct Compensation** (for all positions matched to TRDB) | Average ~~$104,301~~$111,566 | Median ~~$110,560~~$119,036 | ~~-5.7%~~ -6.3% |

[2] Conference Board of Canada, Provincial Outlook Summer 2003 – Economic Forecast.
[3] Conference Board of Canada, Provincial Outlook Summer 2003, Economic Forecast.

- Line A, Target Total Direct Compensation, represents the competitive position that TCPL wishes to target in the pay market. TCPL's target for Total Direct Compensation is the median of the market, provided that performance objectives are met or exceeded.

- Line B, Actual Total Direct Compensation, represents the actual ~~2002~~2003 base pay, actual incentive compensation paid in ~~2002~~2003 and the estimated future value of long-term incentives to be paid for the plan year ~~2002~~2003.

- Column 1.1 represents TCPL's Total Direct Compensation for approximately ~~1,715~~ 1,481 executive, management, professional and administrative employees.

- Column 1.2 represents all of the comparator group's target and actual compensation information for all positions that each company in the comparator group matched into the TRDB. This represents ~~16,643~~ 17,250 employees.

**Job Family Data**

The table below provides further detail on TCPL's TDC compared to the comparator group by summarizing TDC by job family. The job families selected are occupations that are reported on a sustainable basis year over year. These job families also have a sufficient number of incumbents both at TCPL and in the market surveys to allow for meaningful comparison. These data show that TCPL's TDC for the majority of these job families was within plus or minus 10% of the market median in ~~2002~~2003, a level TCPL considers competitive.

**Revised Table 2.3.2-2**

**Summary of TCPL TDC vs. Comparator Group TDC by Job Family[4]**

**~~2002~~2003**

| Job Family | Average TCPL Actual TDC ($) | Average Market 50th Actual TDC ($) | Variance to Market |
|---|---|---|---|
| Manager to CEO | ~~258,938~~256,203 | ~~251,979~~242,031 | ~~2.8%~~5.9% |
| Accounting | ~~81,648~~85,943 | ~~83,361~~86,722 | ~~2.1%~~-0.9% |
| Secretarial, Clerical, Administrative Assistants | ~~56,686~~53,538 | ~~55,861~~51,250 | ~~1.8%~~4.5% |
| Engineering | ~~94,772~~107,064 | ~~107,186~~105,103 | ~~11.6%~~1.9% |
| Human Resources | ~~84,300~~91,266 | ~~78,875~~82,928 | ~~6.9%~~10.1% |
| Information Systems | ~~82,346~~85,424 | ~~86,951~~83,313 | ~~-5.3%~~2.5% |
| Safety and Environment | ~~91,651~~94,271 | ~~88,273~~95,153 | ~~3.8%~~-0.9% |
| Procurement | ~~82,505~~85,235 | ~~77,478~~76,108 | ~~6.5%~~12.0% |

**Fixed Rate (Field) Positions**

Fixed rate (field) positions are positions held by employees who are engaged in the direct operation and maintenance of the pipeline system. They are paid according to a step progression (fixed rate) system based on compensation for similar trades and occupations. A step progression system specifies levels within a pay range. Employees may progress from step to step on the basis of performance, required education, practical application, proficiency in the role, and time-in-grade.

TRDB data for TDC are not available for these positions. The table below shows TCPL's actual average base salary for fully qualified and senior field positions as compared to aggregate median union rates for fully qualified field positions. The data on union rates

[4] Table reproduced from Towers Perrin report dated December 4, 2003.

are publicly available from the Human Resources Development Canada database. ~~and were compiled by Towers Perrin.~~

**Revised Table 2.3.2-3**

**Fixed Rate (Field) Positions**

**~~2002~~2003**

| | TCPL Actual Pay at Fully Qualified/ Senior Level | Aggregate Median Union Rates Fully Qualified Level Human Resources Development Canada and Towers Perrin | Variance to Market |
|---|---|---|---|
| **Base Pay** | $~~31.17~~ 32.30per hour | $~~30.54~~31.87-per hour | ~~2.1~~1.3% |

**Compensation Surveys and the Comparator Group**

TCPL determines the competitiveness of its TDC by comparing it to compensation market survey data. These surveys are developed, maintained and administered by external compensation consultants. In order to participate in and have access to the results of these surveys, TCPL agrees, through a signed confidentiality agreement, to maintain the survey data in a confidential manner and to use it only for the purposes of maintaining competitive compensation programs.

The surveys draw information from similar industries and from companies of similar size and scope to TCPL. Specifically, TCPL compares its compensation data with the data of a defined competitive compensation market, the comparator group, consisting of companies that are a source of skilled employees for TCPL or to whom TCPL may lose skilled employees. TCPL's comparator group consists of approximately 25 companies with the following attributes:

**Revised Table 2.3.2-4**

**Characteristics of TCPL's Compensation Comparator Group**

**~~2002~~2003**

| | TCPL Information | Towers Perrin Data – TCPL's Comparator Group |
|---|---|---|
| **Industry** | North American Pipelines, Power | Canadian Oil and Gas, Pipelines, Power |
| **Location** | Calgary | Principally Alberta |
| **Revenue** | $5.2 billion | ❑ Median is $~~3.8~~ 3.7billion<br>❑ 75th percentile is $~~7.0~~ 6.1billion |
| **Market Capitalization** | $~~10.6~~ 12.0 billion | ❑ Median is $~~9.6~~8.5 billion<br>❑ 75th percentile is $~~13.1~~14.4 billion |
| **Assets** | $19.9 billion | ❑ Median is $~~7.6~~9.2 billion<br>❑ 75th percentile is $~~10.6~~ 13.1billion |
| **Employees** | 2,350~~2,400~~ | ❑ Median is ~~2,406~~2,663<br>❑ 75th percentile is ~~4,045~~3,792 |

**Appropriateness of TDC for NGTL**

The 2004 test year Operating Costs amount includes costs related to each component of TDC: base salary, short-term incentive compensation, and long-term incentive compensation. It is appropriate to include these amounts in the revenue requirement because they are in their totality the prudent and legitimate fair market costs directly incurred for the purpose of operating the Alberta System. As such, NGTL should be provided with an opportunity to recover them in its rates.

TCPL has found it necessary to offer incentive-based compensation in order to compete effectively in the market for qualified employees. It has designed the specific incentive plans in use to enhance organizational performance towards specific objectives. In providing services required by its customers, NGTL has a responsibility to manage costs efficiently and economically. Its performance in this regard in the short and long term is due to the aggregate efforts of employees. Incentive payments to employees are determined on the basis of performance measured against multiple benchmarks at the individual and company level. The intended result is the existence of a healthy, sustainable pipeline operator that consistently provides safe, reliable service, which is to the benefit of customers and shareholders without distinction.

Recently, one of the performance benchmarks used by TCPL, namely, shareholder return, was singled out as a reason for disallowance of certain incentive costs notwithstanding that total compensation per employee was found to be in line with the compensation provided by companies of similar size and scope.[5] In NGTL's view, to elevate this benchmark to a reason for disallowance is to ignore what ought to be determinative of the question at hand: are the proposed total compensation costs prudent, legitimate and directly related to the provision of service and therefore recoverable in rates? To determine allowed incentive compensation on the basis of the acceptability of one of the benchmarks used to determined payment is perhaps ultimately pointless as the benchmark can be changed.

**Components of TDC**

The three components of TDC are base salary, short-term incentive compensation and long-term incentive compensation.

**Base Salary**

TCPL's base salary program is based on two fundamental principles: market competitiveness and individual performance.

TCPL competes with other organizations to attract and retain employees with the skills necessary to operate in a safe, reliable and efficient manner. To do so, TCPL offers salaries at competitive levels to the comparator group; TCPL monitors compensation levels in these markets and adjusts compensation levels as appropriate to remain competitive.

[5] National Energy Board, Reasons for Decision RH-1-2002, TransCanada PipeLines Limited Tolls and Tariff, July 2003, pp. 20-21.

The following table shows TCPL's aggregate annual pay base salary increases since 2000 compared to a broad oil and gas industry average over the same period of time.

**Revised Table 2.3.2-5**

**TCPL's Aggregate Annual Base Salary Increases Compared to Industry Average**

| Effective Date | TCPL | Towers Perrin Energy Industry Salary Management Survey |
|---|---|---|
| April 1, 2004 | Budget is based on estimates of 5.0% for salaried and 3.75% for fixed rate employees | Not available until Nov. 2004 |
| April 1, 2003 | 3.68% | ~~Not available until Nov. 2003~~5.1% |
| April 1, 2002 | 4.5% | 5.2% |
| April 1, 2001 | 5.5% | 5.6% |
| April 1, 2000 | 4.0% | 4.2% |

Preliminary projections for 2004 salary adjustments were required in June 2003 to satisfy budgeting requirements. The assumptions used for the annual budget process, and this Application, were based on an increase of 5% for salaried employees and a 3.75% increase for fixed rate employees over 2003 levels. Since market projections were not available at that time, these preliminary projections were largely based on past industry averages.

~~Market projections from credible compensation sources are expected to be released in the next few months, which will be used to determine TCPL's final 2004 base salary program in the first quarter of 2004.~~ Current projections from independent credible compensation sources for salary increases in the oil and gas industry range from 3.9% to 4.4%. These sources are used only as background information. TransCanada will make final decisions on salary increases based on all competitive compensation data available at the end of February 2004. Adjustments are implemented effective April 1.

An employee's base salary should also reflect the contribution of that individual to the success of the company. This is achieved by determining increases to base salary on the basis of individual performance. The actual increase to an employee's base salary for each job or position in the company may vary depending on the salary market data for that position and individual performance. The following table shows the distribution of employees across the performance ranges for base salary.

**Table 2.3.2-6**

**2003 Base Salary Performance Distribution**

**(% of total Employee Population as at April 1, 2003)**

| Employee Category | Developing or Newly Promoted | Fully Qualified, Fully Satisfactory | Key Contributors | Exceptional Performers | Total |
|---|---|---|---|---|---|
| Field | 0% | 25% | 0% | 0% | 25% |
| Non-Field | 12% | 53% | 8% | 2% | 75% |
| **Total** | 12% | 78% | 8% | 2% | 100% |
| | | | | | |
| Management [1] | 1% | 6% | 2% | 1% | 10% |
| Non-Mgmt | 11% | 72% | 6% | 1% | 90% |
| **Total** | 12% | 78% | 8% | 2% | 100% |

[1] Management is defined as the employment level at which there is clear responsibility for management tasks (supervising work, hiring, performance management, etc.), budgeting responsibilities, and decision-making impact on the business.

### Short-Term Incentive Compensation Program

The use of short-term incentive compensation allows TCPL to effectively manage costs in line with actual performance by putting a portion of compensation at risk unless certain objectives tied to individual performance are achieved.

Short-term incentive compensation is a common practice both in the energy industry and more broadly in the Canadian industry. According to a recent study[6] of Canadian energy companies:

- Short-term incentives are virtually universal: ~~96~~99% prevalence
- An overwhelming number of plans are broad based: 88%
  - Of the remaining plans, ~~half include Senior Professionals and above~~one third include professionals and above

According to a recent study by the Conference Board of Canada[7] the prevalence of annual variable pay in the private sector (in the reporting organizations) is ~~93~~92%.

TCPL's Short-Term Incentive Compensation program is based on individual performance results. Targets for all employees are set at the median of the defined competitive compensation market for the appropriate function, role and level of work. Individual incentive awards are based on performance against objectives, competencies, behaviors, and results, as well as market data reflecting bonus payments. If results are not achieved, the incentive award is reduced or not paid out; if results are outstanding, the incentive award is increased. This results-oriented assessment method ensures there is a value added in exchange for the incentive award. This value added benefits customers through improved efficiency, safety and reliability of the pipeline system.

[6] ~~Towers Perrin 2002 Energy Industry Report, October 29, 2002~~Towers Perrin 2003 Energy Industry Briefing, October 23, 2003.
[7] ~~Conference Board of Canada, Compensation Planning Outlook, November 4, 2002~~Conference Board of Canada, Compensation Planning Outlook, 2004.

**Long-Term Incentive Programs**

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.

Market Prevalence of Long-Term Incentive Programs

Long-term incentive programs are most prevalent in the oil and gas industry and well established in Canadian general industry. A study[8] of Canadian based energy companies noted the following:

- The vast majority of companies have long-term incentives: ~~84~~86%
- ~~Almost~~ More than half the plans are broad based: ~~42~~54%
- Of the remaining plans approximately half include professional~~s and above~~/senior technical level employees

In addition the Conference Board of Canada[9] disclosed that ~~44~~55% of organizations have long-term incentives for at least one employee group and that long-term incentive plans continue to be most common among firms that are publicly traded (~~74~~86%).

Customers benefit from long-term incentives being a component of a competitive TDC package because TCPL is able to attract and retain over the longer term skilled individuals required to sustain safe, reliable and efficient operation of the pipeline system. Long-term incentive programs focus employee attention in a way that is beneficial to the organization over a longer period of time by rewarding sustained results.

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

[8] ~~Towers Perrin 2002 Energy Industry Report, October 29, 2002~~Towers Perrin 2003 Energy Industry Briefing, October 23, 2003.

Return and stock price. Total Shareholder Return growth reflects the value of a company that has managed its affairs wisely, provides predictable return, and operates effectively, all factors that also benefit customers. It is a common business practice to tie long-term incentive plans to key corporate measures, such as TSR growth or stock price. Through this practice, long-term incentives are not paid out, nor further costs incurred, unless there is additional value generated.

The following information provides a description of TCPL's long-term incentive programs.

~~Key Employee Stock Incentive Plan (KESIP)~~TransCanada Stock Option Plan

TCPL utilizes a stock option program for executive officers, as well as other key employees. The size of the annual stock option award to individual executive officers is determined by considering individual performance results, level of responsibility, and the degree to which each executive officer's long-term potential and contribution will be key to the long-term success of TCPL.

Performance Unit Plan (PUP)

In July 2002, TCPL discontinued the use of PUPs in its compensation plan; however, accruals on existing units will continue in accordance with the terms of the former plan.

Executive Share Unit Plan (ESU)

The ESU Plan is part of TCPL's competitive compensation program for executives. It is a performance driven plan that aligns individual performance with the achievement of TCPL's objectives and is also intended to retain key executives.

[9] ~~Conference Board of Canada, Compensation Planning Outlook, November 4, 2002, pp. 5-7~~Conference Board of Canada, Compensation Planning Outlook 2004.

Restricted Share Unit Plan (RSU)

The RSU Plan is a broad-based employee program that is part of TCPL's competitive TDC package for employees who are Senior Managers and below. It is aimed at motivating and retaining skilled, experienced employees. The current RSU plan three-year cycle is in effect from January 1, 2002, through to December 31, 2004, with the first anticipated payments in the first quarter of 2005.

## BENEFITS

Employee benefits are offered to employees under a program TCPL refers to as the FlexComp Benefit Program. The FlexComp Benefit Program offers flexibility and choice in customizing benefits to meet employees' personal needs and lifestyle in a cost effective way. Employees receive FlexComp credits based on a formula applied against annual base pay. Employees receive core benefits and choose to purchase optional benefits with FlexComp credits to meet their individual needs. The various types of benefits offered and the use of the FlexComp Benefit Program have also been designed to be market competitive; therefore, contributing to NGTL's ability to attract and retain employees. Specific employee benefits offered are:

### Health and Dental Plans

The health and dental plans each have three options with varying coverages. Employees may also opt-out of the dental plan. The health and dental plans are self-insured and administered by a third party.

### Group Insurance Plans

Core employee life insurance coverage of $50,000 is company-paid. Employees may purchase optional employee, spousal and per child life insurance. Effective January 1, 2004, employee optional life insurance is limited to 7 times an employee's base pay or $1,500,000, reduced from $2,500,000. Spousal and per child life insurance have limits of $250,000 and $25,000 respectively.

Core employee accident insurance coverage of $50,000 is company-paid. Employees may purchase optional employee, spousal and per child accident insurance. Coverage is limited to $1,000,000, $250,000 and $25,000 respectively.

**Provincial Health Insurance**

In Alberta and British Columbia, the company pays 80% of the annual premium; employees pay 20%. In other provinces, the company pays the full cost according to provincial regulations (i.e., payroll/health tax).

**Short-Term Disability**

Coverage is company-paid and consists of 100% or 70% of base pay, based upon service, payable for up to 26 weeks.

**Long-Term Disability**

Coverage is company-paid and consists of 70% of base pay, payable to recovery or age 65. The benefit is taxable.

**Employee Stock Savings Plan**

Employees may purchase shares of TransCanada Corporation by directing optional contributions to an employee and/or spousal RRSP or a taxable account. For participating employees, TCPL will match the employee directed purchase in an amount equal to 25% of the employee amount to a maximum additional contribution of 1% of the employee’s base pay.

**Pension Plan**

TCPL provides its employees with a Registered Pension Plan. The plan is a defined benefit plan under which the annual pension plan benefits are integrated with Canada Pension Plan benefits and are based on: 1.25% of a person’s highest average pensionable earnings up to the Final Average Year’s Maximum Pensionable Earnings; plus 1.75% of a person's highest average pensionable earnings in excess of the Final Average Year's Maximum Pensionable Earnings; multiplied by the total number of years credited in the Registered Pension Plan ("Credited Pensionable Service").

Registered pension plan benefits are subject to a maximum annual benefit accrual provided for by the Income Tax Act (Canada), currently $1,722 for each year of Credited Pensionable Service, with the result that benefits cannot be earned in the Registered Pension Plan on salaries above approximately $110,000 per annum.

Under the Supplemental/Executive Supplemental Pension Plan, employees/executives of TCPL are entitled to supplementary pension benefits. The annual pension benefit is equal to the amount calculated using a formula of 1.75% multiplied by the employees/executives credited pensionable service under the plan multiplied by the amount by which such employees/executives highest average annual pensionable earnings exceeds such employees/executives highest average annual Registered Pension Plan earnings.

TOTAL DIRECT COMPENSATION & BENEFITS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| | | 2002 | | | 2003 | | | 2004 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Total | Average Full Time Equivalent | Average Salary | Total | Average Full Time Equivalent | Average Salary | Total | Average Full Time Equivalent | Average Salary |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| | TOTAL COMPANY BASE SALARIES:[1] | | | | | | | | | |
| 1 | Field Operations | 42,810 | 641 | 66.8 | 40,480 | 581 | 69.7 | 39,752 | 549 | 72.4 |
| 2 | Engineering | 18,422 | 230 | 80.1 | 17,644 | 209 | 84.4 | 17,105 | 197 | 86.8 |
| 3 | Operations & Engineering Support Services | 18,387 | 258 | 71.3 | 19,113 | 266 | 71.9 | 20,207 | 271 | 74.6 |
| 4 | Commercial & Regulatory | 20,951 | 264 | 79.4 | 21,729 | 262 | 82.9 | 23,461 | 269 | 87.2 |
| 5 | Business Services | 33,705 | 370 | 91.1 | 33,545 | 346 | 97.0 | 37,041 | 371 | 99.8 |
| 6 | Information Systems | 22,457 | 305 | 73.6 | 22,033 | 294 | 74.9 | 21,253 | 276 | 77.0 |
| 7 | Total Salaries | 156,732 | 2,068 | 75.8 | 154,544 | 1,958 | 78.9 | 158,819 | 1,933 | 82.2 |
| 8 | Allocated Alberta System Amounts[2] | | | | | | | | | |
| 9 | Base Salary | 67,278 | 905 | 74.3 | 63,506 | 827 | 76.8 | 63,304 | 795 | 79.6 |
| 10 | Incentive Compensation | 9,755 | 905 | 10.8 | 13,201 | 827 | 16.0 | 12,267 | 795 | 15.4 |
| 11 | Long Term Incentive Compensation | 8,888 | 905 | 9.8 | 13,203 | 827 | 16.0 | 15,283 | 795 | 19.2 |
| **12** | **Total Direct Compensation** | | | **94.9** | | | **108.8** | | | **114.2** |
| 13 | Benefits[3] | 19,978 | 905 | 22.1 | 23,212 | 827 | 28.1 | 24,299 | 795 | 30.6 |
| 14 | Total Direct Compensation and Benefits | | | 117.0 | | | 136.9 | | | 144.8 |

[1] Total Company operating costs include the costs of the Mainline, the Alberta System, the BC System, and corporate costs allocated to TCPL's other lines of business. It does not include operating costs directly incurred by other lines of business.

[2] Based on the Operating Cost Allocation Policy provided in Section 2.3.3

[3] Excludes amortization of actuarial gains and losses, as well as amortizations of past service costs.

STAFF ANALYSIS
**AVERAGE FULL TIME EQUIVALENT**
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| | | 2002 | | 2003 | | 2004 | |
|---|---|---|---|---|---|---|---|
| Line No. | Description | Total Company | Allocated Alberta | Total Company | Allocated Alberta | Total Company | Allocated Alberta |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 1 | Field Operations | 641 | 328 | 581 | 295 | 549 | 279 |
| 2 | Engineering | 230 | 124 | 209 | 89 | 197 | 72 |
| 3 | Operations and Engineering Support Services | 258 | 110 | 266 | 108 | 271 | 114 |
| 4 | Commercial & Regulatory | 264 | 136 | 262 | 136 | 269 | 143 |
| 5 | Business Services | 370 | 90 | 346 | 81 | 371 | 82 |
| 6 | Information Systems | 305 | 117 | 294 | 118 | 276 | 105 |
| 7 | TOTAL | 2,068 | 905 [1] | 1,958 | 827 | 1,933 | 795 |

| | |
|---|---|
| [1] Allocated Alberta FTEs for 2002 | 905 |
| Less: FTEs charged to construction and other | (187) |
| Average number of employees reported in Table 3-2 of the ASRS reporting package for the year ended December 31, 2002 | 718 |

## 2.3.3 COST ALLOCATION PROCESS

TCPL's business operations are performed by functional areas that provide integrated services to its various lines of business. This organizational structure eliminates duplication of costs and maximizes operational efficiencies. It has resulted in significant cost savings since the merger of NOVA Corporation and TCPL in 1998. As a result of this integrated structure, a cost allocation process is necessary to ensure that individual business lines receive a fair share of costs. TCPL's cost allocation process is based on the Operating Cost Allocation Policy that is attached as Appendix A to this section.

This allocation policy is an updated version of the policy previously presented to the Board as Schedule "C" to the Merger Costs and Benefits Agreement, which was accepted by the Board in Order U99076 on September 8, 1999. The basic principles of the policy remain the same but it has been updated periodically to reflect organizational changes. The allocation policy is based on the principle of direct charging costs to lines of business where possible and allocating the remaining costs using appropriate allocation drivers. Costs are allocated at a departmental level or general expense cost type based on the allocation driver most appropriate to that department or general expense. The allocation drivers used are time/activity analysis, permanent full-time equivalents, enterprise full-time equivalents, head office full-time equivalents, IS asset allocation, capital employed, profit contribution, and usage. The cost allocation process is applied to both actual and forecast/budget costs.

In order to provide additional information on how the NGTL Operating Costs amounts are calculated, Schedule 2.3.3.1 has been provided in this section to supplement the NGTL specific information provided in the schedules in Section 2.3.1. Schedule 2.3.3.1 shows the percentage of Total Company costs that are allocated to the Alberta System by functional area for each of the 2002 base year, the 2003 forecast year, and the 2004 test year. Total Company costs include the Operating Costs of the Mainline, Alberta System, B.C. System, and operating costs allocated to TCPL's other lines of business. It does not include Operating Costs directly incurred by TCPL's other lines of business. Over this three year period, total company costs have increased more rapidly than those attributable to NGTL due to growth in the size of other TCPL businesses. This results in a decrease in the overall percentage allocated to NGTL. As can also be seen from this schedule, the proportions allocated to NGTL by the various functional groups can vary from year to year. This occurs as the various departments update their allocations to reflect changes in the activities being undertaken for each line of business. This illustrates the efficiencies that are gained through an integrated organization by redeploying resources between lines of business as needs shift, resulting in greater total utilization of those resources and lower costs for each line of business.

Schedule 2.3.3.1 also provides a breakdown of the functional area Operating Costs by major cost type. This information has been provided to show the relative size of the various cost types. Actual and forecast/budget costs are recorded by cost type for each department. The allocation process is then applied to Operating Costs at the departmental level to determine the amount applicable to each line of business. As a result, the cost type information shown for the Alberta System is the mathematical result of applying the departments' allocation percentages to each cost type.

OPERATING COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($ Millions)

| | | Base Year 2002 | | | Actual Year 2003 | | | Test Year 2004 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Alberta | % | Total Company[1] | Alberta | % | Total Company[1] | Alberta | % | Total Company[1] |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 1 | **FIELD OPERATIONS** | | | | | | | | | |
| 2 | Salaries[2] | 19.7 | 26.2% | 37.5 | 18.2 | 26.5% | 33.7 | 18.6 | 26.0% | 34.8 |
| 3 | Benefits | 6.2 | 8.2% | 12.0 | 6.0 | 8.7% | 11.7 | 6.8 | 9.5% | 13.5 |
| 4 | Employee Expenses | 1.5 | 2.0% | 3.3 | 1.4 | 2.0% | 3.0 | 1.5 | 2.1% | 3.2 |
| 5 | Contracted Services / Consultant Fees | 5.6 | 7.4% | 11.2 | 5.6 | 8.1% | 10.6 | 4.4 | 6.1% | 8.4 |
| 6 | Maintenance Parts / Freight / Courier | 4.4 | 5.8% | 8.1 | 4.6 | 6.7% | 8.1 | 4.7 | 6.6% | 8.8 |
| 7 | Other Expenses | 2.1 | 2.8% | 4.4 | 3.8 | 5.5% | 5.7 | 3.1 | 4.3% | 4.8 |
| 8 | Amounts Charged to Other Accounts | (0.3) | -0.4% | (1.2) | (1.1) | -1.6% | (4.0) | (0.5) | -0.7% | (1.9) |
| | | 39.2 | 52.1% | 75.3 | 38.5 | 56.0% | 68.8 | 38.6 | 53.9% | 71.6 |
| 9 | **ENGINEERING** | | | | | | | | | |
| 10 | Salaries[2] | 4.6 | 17.2% | 8.8 | 3.5 | 17.9% | 7.2 | 3.6 | 16.1% | 10.2 |
| 11 | Benefits | 2.8 | 10.5% | 5.1 | 2.1 | 10.7% | 5.1 | 2.1 | 9.4% | 5.8 |
| 12 | Employee Expenses | 0.7 | 2.6% | 1.4 | 0.5 | 2.6% | 0.9 | 0.6 | 2.7% | 1.5 |
| 13 | Contracted Services / Consultant Fees | 3.5 | 13.1% | 10.3 | 1.7 | 8.7% | 4.1 | 0.8 | 3.6% | 2.8 |
| 14 | Maintenance Parts / Freight / Courier | 0.5 | 1.9% | 1.0 | 0.1 | 0.5% | 1.8 | 0.1 | 0.4% | 1.4 |
| 15 | Other Expenses | 0.1 | 0.4% | 0.2 | 0.3 | 1.5% | 0.5 | 0.3 | 1.3% | 0.7 |
| 16 | Amounts Charged to Other Accounts | - | 0.0% | (0.1) | - | 0.0% | - | - | 0.0% | - |
| | | 12.2 | 45.7% | 26.7 | 8.2 | 41.8% | 19.6 | 7.5 | 33.5% | 22.4 |
| 17 | **OPERATIONS & ENGINEERING SUPPORT SERVICES** | | | | | | | | | |
| 18 | Salaries[2] | 5.1 | 14.1% | 11.7 | 5.5 | 16.2% | 12.4 | 6.1 | 16.5% | 12.8 |
| 19 | Benefits | 2.2 | 6.1% | 5.1 | 2.3 | 6.8% | 5.5 | 2.9 | 7.8% | 6.9 |
| 20 | Employee Expenses | 0.8 | 2.2% | 1.7 | 0.7 | 2.1% | 1.6 | 1.0 | 2.7% | 2.1 |
| 21 | Contracted Services / Consultant Fees | 4.7 | 13.0% | 10.1 | 4.0 | 11.8% | 8.3 | 2.8 | 7.6% | 6.0 |
| 22 | Maintenance Parts / Freight / Courier | 2.5 | 6.9% | 4.2 | 2.5 | 7.4% | 3.8 | 3.0 | 8.1% | 5.4 |
| 23 | Other Expenses | 1.6 | 4.4% | 3.5 | 1.0 | 2.9% | 2.5 | 1.7 | 4.6% | 3.8 |
| 24 | Amounts Charged to Other Accounts | - | 0.0% | (0.1) | (0.1) | -0.3% | (0.1) | - | 0.0% | - |
| | | 16.9 | 46.7% | 36.2 | 15.9 | 46.8% | 34.0 | 17.5 | 47.3% | 37.0 |
| 25 | **OPERATIONS & ENGINEERING PROGRAMS** | | | | | | | | | |
| 26 | Salaries[2] | 0.1 | 0.2% | 0.1 | - | 0.0% | - | - | 0.0% | - |
| 27 | Benefits | - | 0.0% | - | - | 0.0% | - | - | 0.0% | - |
| 28 | Employee Expenses | - | 0.0% | - | - | 0.0% | - | - | 0.0% | - |
| 29 | Contracted Services / Consultant Fees | 10.9 | 17.9% | 36.1 | 6.3 | 9.6% | 22.2 | 3.5 | 6.6% | 11.0 |
| 30 | Maintenance Parts / Freight / Courier | 2.9 | 4.8% | 9.5 | 8.1 | 12.3% | 27.5 | 7.1 | 13.4% | 23.6 |
| 31 | Other Expenses | 10.4 | 17.0% | 15.9 | 10.3 | 15.7% | 16.6 | 12.1 | 22.8% | 18.4 |
| 32 | Amounts Charged to Other Accounts | (0.2) | -0.3% | (0.6) | (0.2) | -0.3% | (0.6) | - | 0.0% | - |
| | | 24.1 | 39.5% | 61.0 | 24.5 | 37.3% | 65.7 | 22.7 | 42.8% | 53.0 |

[1] Total Company operating costs include the costs of the Mainline, the Alberta System, the BC System, and operating costs allocated to TCPL's other lines of business. It does not include the operation costs directly incurred by other lines of business.

[2] Salaries includes overtime and ancillary, net of amounts charged to construction and other projects.

OPERATING COSTS
FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($ Millions)

| | | Base Year 2002 | | | Actual Year 2003 | | | Test Year 2004 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Alberta | % | Total Company[1] | Alberta | % | Total Company[1] | Alberta | % | Total Company[1] |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 33 | **COMMERCIAL AND REGULATORY** | | | | | | | | | |
| 34 | Salaries[2] | 10.4 | 32.3% | 20.5 | 10.8 | 36.6% | 20.8 | 12.0 | 34.5% | 22.7 |
| 35 | Benefits | 3.0 | 9.3% | 5.9 | 3.3 | 11.2% | 6.3 | 4.3 | 12.4% | 8.0 |
| 36 | Employee Expenses | 0.8 | 2.5% | 1.6 | 0.7 | 2.4% | 1.6 | 1.1 | 3.2% | 3.1 |
| 37 | Contracted Services / Consultant Fees | 0.8 | 2.5% | 1.6 | 0.7 | 2.4% | 1.5 | 0.7 | 2.0% | 1.6 |
| 38 | Maintenance Parts / Freight / Courier | - | 0.0% | - | - | 0.0% | - | - | 0.0% | - |
| 39 | Other Expenses | 1.6 | 5.0% | 3.1 | 0.2 | 0.7% | 0.4 | 0.3 | 0.9% | 0.8 |
| 40 | Amounts Charged to Other Accounts | (0.2) | -0.6% | (0.5) | (0.5) | -1.7% | (1.1) | (0.6) | -1.7% | (1.4) |
| | | 16.4 | 50.9% | 32.2 | 15.2 | 51.5% | 29.5 | 17.8 | 51.1% | 34.8 |
| 41 | **BUSINESS SERVICES** | | | | | | | | | |
| 42 | Salaries[2] | 8.1 | 11.8% | 34.6 | 7.7 | 11.8% | 33.7 | 8.0 | 10.9% | 37.1 |
| 43 | Benefits | 2.2 | 3.2% | 9.5 | 2.2 | 3.4% | 9.7 | 2.7 | 3.7% | 12.6 |
| 44 | Employee Expenses | 1.1 | 1.6% | 4.1 | 1.2 | 1.8% | 4.5 | 1.6 | 2.2% | 6.5 |
| 45 | Contracted Services / Consultant Fees | 3.3 | 4.8% | 10.5 | 3.2 | 4.9% | 8.8 | 3.0 | 4.1% | 8.8 |
| 46 | Maintenance Parts / Freight / Courier | 0.5 | 0.7% | 1.3 | 0.2 | 0.3% | 0.5 | 0.1 | 0.1% | 0.1 |
| 47 | Other Expenses | 2.8 | 4.1% | 9.2 | 2.5 | 3.8% | 8.5 | 2.7 | 3.7% | 8.9 |
| 48 | Amounts Charged to Other Accounts | - | 0.0% | (0.5) | (0.1) | -0.2% | (0.6) | (0.1) | -0.1% | (0.7) |
| | | 18.0 | 26.2% | 68.7 | 16.9 | 26.0% | 65.1 | 18.0 | 24.6% | 73.3 |
| 49 | **INFORMATION SYSTEMS** | | | | | | | | | |
| 50 | Salaries[2] | 5.9 | 8.8% | 14.8 | 7.6 | 12.5% | 20.0 | 6.4 | 11.1% | 17.8 |
| 51 | Benefits | 2.5 | 3.7% | 6.3 | 2.6 | 4.3% | 6.4 | 2.8 | 4.9% | 7.2 |
| 52 | Employee Expenses | 0.5 | 0.7% | 1.4 | 0.7 | 1.2% | 1.9 | 0.6 | 1.0% | 1.5 |
| 53 | Contracted Services / Consultant Fees | 9.4 | 13.9% | 23.4 | 5.9 | 9.7% | 13.9 | 5.2 | 9.0% | 12.7 |
| 54 | Maintenance Parts / Freight / Courier | - | 0.0% | - | - | 0.0% | 0.1 | - | 0.0% | - |
| 55 | Other Expenses | 9.6 | 14.2% | 21.6 | 8.2 | 13.5% | 18.5 | 7.7 | 13.4% | 18.4 |
| 56 | Amounts Charged to Other Accounts | - | 0.0% | (0.1) | - | 0.0% | - | - | 0.0% | - |
| | | 27.9 | 41.4% | 67.4 | 25.0 | 41.1% | 60.8 | 22.7 | 39.4% | 57.6 |
| 57 | **TOTAL FUNCTIONAL AREAS** | | | | | | | | | |
| 58 | Salaries[2] | 53.9 | 14.7% | 128.0 | 53.3 | 15.5% | 127.8 | 54.7 | 15.6% | 135.4 |
| 59 | Benefits | 18.9 | 5.1% | 43.9 | 18.5 | 5.4% | 44.7 | 21.6 | 6.2% | 54.0 |
| 60 | Employee Expenses | 5.4 | 1.5% | 13.5 | 5.2 | 1.5% | 13.5 | 6.4 | 1.8% | 17.9 |
| 61 | Contracted Services / Consultant Fees | 38.2 | 10.4% | 103.2 | 27.4 | 8.0% | 69.4 | 20.4 | 5.8% | 51.3 |
| 62 | Maintenance Parts / Freight / Courier | 10.8 | 2.9% | 24.1 | 15.5 | 4.5% | 41.8 | 15.0 | 4.3% | 39.3 |
| 63 | Other Expenses | 28.2 | 7.7% | 57.9 | 26.3 | 7.7% | 52.7 | 27.9 | 8.0% | 55.8 |
| 64 | Amounts Charged to Other Accounts | (0.7) | -0.2% | (3.1) | (2.0) | -0.6% | (6.4) | (1.2) | -0.3% | (4.0) |
| | | 154.7 | 42.1% | 367.5 | 144.2 | 42.0% | 343.5 | 144.8 | 41.4% | 349.7 |
| 65 | GENERAL EXPENSES | 45.1 | 37.6% | 120.1 | 53.7 | 31.5% | 170.6 | 63.5 | 32.9% | 193.1 |
| 66 | NET OPERATING EXPENSES | 199.8 | 41.0% | 487.6 | 197.9 | 38.5% | 514.1 | 208.3 | 38.4% | 542.8 |

[1] Total Company operating costs include the costs of the Mainline, the Alberta System, the BC System, and operating costs allocated to TCPL's other lines of business. It does not include the operation costs directly incurred by other lines of business.

[2] Salaries includes overtime and ancillary, net of amounts charged to construction and other projects.

# APPENDIX A: OPERATING COST ALLOCATION POLICY

# TRANSCANADA PIPELINES LIMITED

# OPERATING COST ALLOCATION POLICY

## 1.0 Purpose

The purpose of the “Operating Cost Allocation Policy” is to describe the methodology that TCPL will utilize for allocating departmental costs, general expenses, and certain other costs to TCPL’s lines of business including wholly-owned pipelines. This policy is consistent with and shall replace all related existing operating cost allocation policies and practices, including the policies and procedures used by TCPL and approved by the NEB in its RH-1-91 Reasons for Decision dated September 1991 and updated as schedule “C” to the Merger Costs and Benefits Agreement as approved by the EUB in Order U99076 on September 8, 1999 and by the NEB in AO-1-TG-7-91 on September 23, 1999.

## 2.0 Organizational Structure

TCPL is a leading North American energy company with operations in two principal business segments: gas transmission and services, and power generation and marketing. The business operations of TCPL are performed in functional areas that provide integrated services to various lines of business throughout the organization.

## 3.0 Allocation Principles

TCPL’s policy is to directly charge costs to lines of business where possible. When direct charge is not possible TCPL’s policy is to use appropriate allocation drivers to determine the charge by department or general expense to each line of business.

Employees also may periodically perform work for a specific project where a third party will be billed. In such cases, the cost of labour and overhead is billed to the third party. In addition, where employees are providing services in support of capital projects, the costs of those services are charged to capital. The effect of these charges is a reduction of departmental expenses prior to allocation to lines of business.

Also, departmental costs can either decrease or increase through cross-departmental project charges. Where applicable, the cross-departmental project charges provide an effective system to manage projects at the department level.

### 3.1 Cost Allocation Drivers

For those department costs and general expenses that are not directly charged, one or more of the methods detailed below are used as the basis for allocating costs. Management will periodically update the drivers for departmental and general expenses as the underlying business conditions and practices change.

(i) **Time/Activity Analyses** - The Time/Activity Analyses ("TAA") cost driver is dependent upon an estimate of employee and contracted (in-house contractors) labour hours in support of each of the various businesses. The activities of each employee in a department, excluding support staff, are analyzed to determine the proportion of each employee's time spent on each line of business, or on common activities that benefit TCPL as a whole.

The percentages that result from this analysis are then applied to the departmental costs to determine the allocation among the lines of business.

The costs of common activities and the support staff costs are allocated to the lines of business using the ratio established from the TAA for the department.

(ii) **Enterprise full-time equivalents** - The enterprise full-time equivalents ("enterprise FTEs") cost driver utilizes the number of full-time equivalent employees and contractors (in-house contractors) in the entire organization, including head office and field employees in all businesses. This calculation excluding contractors is referred to as "Permanent FTEs."

To allocate costs using enterprise FTEs the number of enterprise FTEs in any one of the lines of business is divided by the total number of enterprise FTEs and then multiplied by the department's costs to determine the allocation to the lines of business.

(iii) **Head office full-time equivalents** - The head office full-time equivalents ("head office FTEs") cost driver is calculated in the same manner as the enterprise full-time equivalents but excludes headcount for certain subsidiaries and field employees. This cost driver is used for certain general expenses and departments that provide administrative services to the Calgary offices only.

To allocate department costs using head office FTEs, the number of head office FTEs in any one of the lines of business is divided by the total number of head office FTEs and then multiplied by the department's costs to determine the allocation to the lines of business.

(iv) **IS Asset Allocation** - The Information Systems (IS) groups allocates its application support and design costs to the primary department users of applications. The costs of each primary user are subsequently allocated to each line on business based on the allocation methodology of the primary user. The IS uses the 'IS asset' list to determine the primary user of each asset or similar asset groups. Costs are recorded in functional system support groups to allow matching the supported asset.

(v) **Capital Employed** - Capital employed is used to allocate the costs of departments performing activities that benefit the enterprise as a whole and for which time cannot be easily determined and for which the use of other cost drivers would not be appropriate.

To allocate costs using this cost driver, the capital employed by any one of the lines of business is divided by the total capital employed by TCPL and then multiplied by the department's costs to determine the allocation for the lines of business.

Capital employed represents the sum of shareholders equity and any financing related liabilities.

(vi) **Profit Contribution** - Profit contribution is used to allocate corporate donations. Profit contribution represents the after tax net income of each line of business.

(vii) **Usage** - The costs of the aviation department are primarily allocated on the basis of flying time for direct usage by each line of business. Flying time that cannot be directly allocated to a line of business is allocated based on the executive TAA.

## 4.0 Categories

### 4.1 Departmental costs

Departmental costs include salaries, benefits, employee expenses, consulting and contracted services, and other expenses. Departmental costs that are not directly attributable to a line of business are allocated in the manner as described in Table A.

### 4.2 General expenses

General expenses includes external costs, such as auditing and accounting services, outside legal services, directors' fees and expenses, donations, stock and debt administration, insurance and rent. General expenses also includes the cost of total direct compensation and benefits that are not attributed to specific departments, such as incentive compensation, long term incentive compensation, and residual employee benefits. General expenses that are not directly attributable to a line of business are allocated in the manner as described in Table B.

## TABLE "A"

## SUMMARY OF ALLOCATION BASES

| Functional Area | Direct / Allocated | Allocated among the businesses based on: |
|---|---|---|
| Accounting | Allocated | TAA |
| Aviation | Allocated | Usage/Executive TAA |
| Corporate Strategy | Allocated | Capital Employed |
| Customer Service (Gas Transmission East, | Allocated | TAA |
| Engineering & Business Services | Allocated | TAA |
| Executive | Allocated | TAA |
| Field Operations (Transmission & Power) | Direct | - |
| Field Telecommunication | Direct | - |
| Finance | Allocated | TAA |
| Health, Safety and Environment | Allocated | TAA |
| Human Resources | Allocated | Enterprise FTEs/Permanent FTEs. |
| Internal Audit | Allocated | TAA |
| Investor Relations | Allocated | Capital Employed |
| IS Infrastructure/Shared Services | Allocated | Enterprise FTEs |
| IS Business Support (FST's) | | IS Asset Allocation and Enterprise FTEs |
| Law and General Counsel | Allocated | TAA/Capital Employed |
| Northern Development | Direct | - |
| Power Administration & Marketing | Direct | - |
| Public Sector Relations | Allocated | Capital Employed/TAA |
| Procurement | Allocated | TAA |
| Real Estate and Building Services | Allocated | Enterprise FTEs |
| Records Mgmt and Library | Allocated | Head Office FTEs |
| Regulatory Strategy | Allocated | TAA |
| Risk Management | Allocated | TAA |
| Strategy and Planning | Allocated | TAA/Capital Employed |
| Taxation | Allocated | TAA |
| Treasury | Allocated | TAA |

**Note:**
Functional / departmental areas are a representative list only and can change due to internal business or management requirements. Multiple allocation drivers are shown for functional areas where more than one department represents the functional area.

**TABLE "B"**

**SUMMARY OF ALLOCATION BASES FOR GENERAL EXPENSES**

| Functional Area | Direct / Allocated | Allocated among the businesses based on: |
|---|---|---|
| Auditing & accounting services: | | |
| Business area specific | Direct | - |
| General corporate | Allocated | Capital Employed |
| Calgary rent | Allocated | Head office FTEs |
| Directors' fees & expenses | Allocated | Executive TAA |
| Donations | Allocated | Profit contribution |
| Dues & subscriptions: | | |
| Business specific | Direct | - |
| General corporate | Allocated | Enterprise FTEs |
| Natural gas industry | Allocated | Capital Employed |
| Employee benefits (residual) | Allocated | Permanent FTEs |
| Insurance: | | |
| Corporate Jet | Allocated | Usage/Executive TAA |
| Directors' & Officers' Liability | Allocated | Executive TAA |
| Other | Allocated | Capital Employed |
| Outside legal services: | | |
| Business area specific | Direct | - |
| General corporate | Allocated | Capital Employed |
| Regulatory expenses | Direct | - |
| Incentive and Long Term Compensation | Allocated | Permanent FTEs |
| Stock & debt administration | Allocated | Capital Employed |

## 2.3.4 COST BUDGET PROCESS

### Overview

The 2004 test year operating and capital cost forecasts presented in this Application are the NGTL budget amounts that will be used to manage NGTL's operations throughout the upcoming test year. The budget amounts presented are reflective of a continuing internal focus on cost control. NGTL continues to reduce costs, where possible. However, the budget also reflects the fact that, in some instances, costs will increase as a result of market increases, inflationary pressures, periodic maintenance requirements, or changing levels of regulatory activity. New initiatives designed to improve overall safety, reliability, and efficiency may also increase certain costs.

### Budget Process

The annual budget for NGTL is prepared as part of the overall TCPL budget process. The annual budget process is initiated through the distribution of budget assumptions, timelines, and templates across the organization. Budget assumptions are provided to ensure consistency across the organization for such factors as inflation rates, foreign exchange rates, salary increase rates, and employee benefit rates used to develop the budget amounts.

Budgets are developed through a detailed build-up of costs based on specific projects, work activities or services that are planned for the coming year. This approach is coupled with comprehensive management reviews that challenge cost forecasts compared to current levels of spending. The resulting budget amounts are incorporated into the overall Financial Plan, which is presented to the Board of Directors for approval in December each year.

**Operating Cost Budgets**

Each department is responsible for identifying the key general day to day activities for which it will be responsible in the coming year. The labour costs and other expenses required to carry out all of the individual activities are estimated and rolled up to determine the departmental budget. Departments are also responsible for preparing budgets for any general expense items for which the department is responsible. A comparison is then made with the previous year's actual costs and the current year's most recent forecast costs. This analysis is used to highlight cost issues that may be evolving and may result in the need for prioritization of planned activities to control costs.

The Field Operations departmental budget, while following the same general principles, has some additional unique aspects. The operations and maintenance of the pipeline facilities are governed by comprehensive integrity plans developed by Engineering. These integrity plans are used to develop operating procedures that are the basis for generating a forecast of specific planned work activities for the upcoming year. These activities are then used to develop the field operations budget. Other components of the field operations budget, such as unplanned maintenance to repair equipment failures, are forecast using historical trends adjusted for any anticipated changes. In order to promote ongoing efficiency improvements, best practices developed in one regional group in the current year may be used to establish expectations for all regions in the budget year.

The budget costs for maintenance programs, including Compressor Fleet Repair and Overhauls, are developed using risk-based models that assist in developing efficient programs that allocate spending to the appropriate projects that minimize operating costs and maintain optimal levels of reliability and safety.

## 2.4 DEPRECIATION AND AMORTIZATION

Schedule 2.4 shows the depreciation and amortization expense included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year.

The amount of the expense for 2002 was based on the provisions of the ASRS, which specified a composite depreciation rate of 4.0%. The amount of the expense for 2003 was based on the provisions of the ASRRS, which specified a composite depreciation rate of 4.0%. The amount of the expense for 2004 reflects the depreciation and amortization rates proposed and discussed in Section 4 of this Application, which result in a composite depreciation rate of 4.13%.

DEPRECIATION AND AMORTIZATION

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| | | BASE YEAR 2002 | | ACTUAL YEAR 2003 | | TEST YEAR 2004 | |
|---|---|---|---|---|---|---|---|
| LINE NO. | DESCRIPTION | RATE | EXPENSE | RATE | EXPENSE | RATE | EXPENSE |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| 1 | Meter Stations | 3.55% | 17,080 | 3.60% | 17,303 | 4.14% | 20,060 |
| 2 | Compressor Stations | 5.40% | 80,495 | 5.40% | 81,740 | 5.70% | 85,632 |
| 3 | Pipelines | 2.97% | 145,996 | 3.11% | 153,103 | 2.96% | 146,918 |
| 4 | Structures and Improvements | 3.44% | 4,308 | 2.49% | 2,336 | 4.47% | 3,672 |
| 5 | Furniture and Office Equipment | 2.31% | 752 | 2.30% | 724 | 4.80% | 1,474 |
| 6 | Tools and Work Equipment | 4.60% | 1,540 | 4.60% | 1,557 | 1.98% | 669 |
| 7 | Aircraft | 2.77% | 72 | 2.42% | 39 | - | - |
| 8 | Transportation Equipment | 9.13% | 2,527 | 9.24% | 2,778 | 8.20% | 2,541 |
| 9 | Computer Equipment | 15.28% | 39,806 | 15.85% | 33,905 | 25.09% | 40,879 |
| 10 | Intangibles | 4.50% | 301 | 4.50% | 301 | 5.29% | 353 |
| 11 | Unallocated AFUDC | 3.82% | 5 | 5.07% | 7 | 4.31% | 6 |
| 12 | **Total Depreciation and Amortization** | | 292,882 | | 293,791 | | 302,203 |
| 13 | **Composite Depreciation Rate** | 4.00% | | 4.00% | | 4.13% | |

## 2.5 INCOME AND LARGE CORPORATION TAXES

### 2.5.1 Income Taxes

Schedule 2.5.1 shows the income tax and Large Corporation Tax amounts included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year.

NGTL's composite income tax rate is determined by combining federal and provincial income tax rates. The 2002 composite income tax rate was 39.245%, based on a federal income tax rate of 25%, a federal surtax of 1.12%, and a provincial income tax rate of 13.125%. The 2003 composite income tax rate decreased to 36.745%, based on a federal income tax rate of 23%, a federal surtax of 1.12%, and a provincial income tax rate of 12.625%. The 2004 composite income tax rate is expected to decrease further to 34.62%, based on the legislated federal income tax rate of 21%, a federal surtax of 1.12%, and the current provincial income tax rate of 12.5%.

NGTL's income tax requirement decreased in 2003 compared to 2002 as a result of the decrease in tax rates and a decrease in the return related to equity. These factors are partially offset by lower capital cost allowance deductions. NGTL's income tax requirement in 2004 is forecast to increase as a result of an increase in the return related to equity, an increase in depreciation expense, and lower capital cost allowance deductions. These factors are partially offset by lower tax rates.

NGTL seeks approval in this Application of a Future Legislative Tax Changes and Reassessments of Income and Large Corporation Taxes Deferral Account. This account would capture the impact of such changes to these taxes. Additional details on this deferral account are provided in Section 7, Deferral and Reserve Accounts.

### 2.5.2 Large Corporation Tax (LCT)

Schedule 2.5.2 shows the calculation of the LCT included in the revenue requirement for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year. The LCT is a federal capital tax levied on a large corporation's capital employed in Canada determined at its year end in excess of $10 million for 2002 and 2003, and $50 million for 2004. The LCT rate was 0.225% for 2002 and 2003, and is 0.200% for 2004. In determining the amount of the LCT, a reduction for the Federal Surtax Credit (1.12% of taxable income) has been applied in each year.

NGTL seeks approval in this Application of a Future Legislative Tax Changes and Reassessments of Income and Large Corporation Taxes Deferral Account. The account would capture the impact of such changes to this tax. Additional details on this deferral account are provided in Section 7, Deferral and Reserve Accounts.

INCOME AND LARGE CORPORATION TAXES

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | Return Related to Equity | 2.2.1 | 206,850 | 189,230 | 205,104 |
| | Add : | | | | |
| 2 | Large Corporation Taxes | 2.5.2 | 6,327 | 5,944 | 3,697 |
| 3 | Depreciation and Amortization | 2.4 | 292,882 | 293,791 | 302,203 |
| 4 | Amortization of Issue Costs | 2.2.4 | 2,090 | 1,871 | 1,688 |
| 5 | Non Allowable Expenses | | 200 | 215 | 215 |
| | (Deduct): | | | | |
| 6 | Capital Cost Allowance | 2.5.3 | (235,742) | (218,429) | (199,682) |
| 7 | Cumulative Eligible Capital | 2.5.3 | (1,118) | (1,092) | (1,030) |
| 8 | AFUDC Interest Component | | (1,408) | (394) | (335) |
| 9 | Debt Issue Costs | | (841) | (715) | (240) |
| 10 | Other | | (4,077) | (3,245) | (400) |
| 11 | | | 265,164 | 267,175 | 311,220 |
| 12 | Taxes thereon (Tax Rate/(1-Tax Rate)) (1) | | 64.60% | 58.09% | 52.95% |
| 13 | Income Taxes | | 171,284 | 155,203 | 164,797 |
| 14 | Large Corporation Taxes | 2.5.2 | 6,327 | 5,944 | 3,697 |
| 15 | **Total Income and Large Corporation Taxes** | | 177,611 | 161,147 | 168,494 |

(1) Income Taxes are calculated using the following rates:

| | | | |
|---|---|---|---|
| Federal | 25.000% | 23.000% | 21.000% |
| Federal Surcharge | 1.120% | 1.120% | 1.120% |
| Provincial | 13.125% | 12.625% | 12.500% |
| Total | 39.245% | 36.745% | 34.620% |

LARGE CORPORATION TAXES

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **Year End Capital:** | | | | |
| 1 | Rate Base | 3.1 | 4,995,569 | 4,741,037 | 4,562,017 |
| 2 | Gas Plant Under Construction | 3.3 | 4,529 | 13,379 | 1,952 |
| 3 | | | 5,000,098 | 4,754,417 | 4,563,969 |
| 4 | Base Deduction | | (10,000) | (10,000) | (50,000) |
| 5 | **Taxable Capital** | | 4,990,098 | 4,744,417 | 4,513,969 |
| 6 | Large Corporation Tax Rate | | 0.225% | 0.225% | 0.200% |
| 7 | Gross Large Corporation Tax | | 11,228 | 10,675 | 9,028 |
| 8 | Federal Surtax Deduction | | (4,901) | (4,731) | (5,331) |
| 9 | **Large Corporation Taxes** | | 6,327 | 5,944 | 3,697 |

CAPITAL COST ALLOWANCE AND CUMULATIVE ELIGIBLE CAPITAL

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
($Thousands)

**Capital Cost Allowance**

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2002 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2002 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | 2,712,241 | - | 116,237 | 7,213 | 2,821,265 | 109,025 | 54,512 | 2,766,753 | 4% | 110,670 | 2,710,595 |
| 2 | 02 | 270,641 | - | - | - | 270,641 | - | - | 270,641 | 6% | 16,238 | 254,402 |
| 3 | 03 | 41,626 | - | - | - | 41,626 | - | - | 41,626 | 5% | 2,081 | 39,545 |
| 4 | 06 | 3,971 | - | 53 | - | 4,024 | 53 | 27 | 3,997 | 10% | 400 | 3,624 |
| 5 | 08 | 326,767 | - | 54,065 | 4,511 | 376,320 | 49,553 | 24,777 | 351,544 | 20% | 70,309 | 306,012 |
| 6 | 10 | 50,068 | - | 10,130 | 884 | 59,315 | 9,247 | 4,623 | 54,692 | 30% | 16,407 | 42,908 |
| 7 | 12 | 7,850 | - | 14,436 | - | 22,286 | 14,436 | 7,218 | 15,068 | 100% | 15,068 | 7,218 |
| 8 | 13 | 9,359 | - | 102 | - | 9,461 | 102 | 51 | 9,410 | S/L | 1,750 | 7,711 |
| 9 | 17 | 34,186 | - | 2,090 | - | 36,276 | 2,090 | 1,045 | 35,231 | 8% | 2,818 | 33,458 |
| 10 | | 3,456,706 | - | 197,114 | 12,608 | 3,641,214 | 184,507 | 92,254 | 3,548,959 | | 235,742 | 3,405,471 |

| In-Service Additions | | |
|---|---|---|
| | Total | 196,792 |
| | AFUDC | (2,326) |
| | CEC | (24) |
| | Removal | 2,672 |
| | | 197,114 |

**Cumulative Eligible Capital**

| LINE NO. | OPENING BALANCE | COST OF ADDITIONS | EXCLUDE 25 % OF ADDITIONS | ELIGIBLE BALANCE | RATE | CEC DEDUCTION | CLOSING BALANCE |
|---|---|---|---|---|---|---|---|
| 11 | 15,959 | 24 | 6 | 15,977 | 7% | 1,118 | 14,859 |

CAPITAL COST ALLOWANCE AND CUMULATIVE ELIGIBLE CAPITAL

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

**Capital Cost Allowance**

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2003 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2003 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | 2,710,595 | - | 10,372 | (4,736) | 2,725,703 | 15,108 | 7,554 | 2,718,149 | 4% | 108,726 | 2,616,977 |
| 2 | 02 | 254,402 | - | (64) | - | 254,338 | - | - | 254,338 | 6% | 15,260 | 239,077 |
| 3 | 03 | 39,545 | - | 38 | - | 39,583 | 38 | 19 | 39,564 | 5% | 1,978 | 37,605 |
| 4 | 06 | 3,624 | - | 52 | - | 3,676 | 52 | 26 | 3,650 | 10% | 365 | 3,311 |
| 5 | 08 | 306,012 | - | 17,462 | (8,104) | 331,578 | 25,566 | 12,783 | 318,795 | 20% | 63,759 | 267,819 |
| 6 | 09 | - | - | - | - | - | - | - | - | 25% | - | - |
| 7 | 10 | 42,908 | - | 6,261 | (1,336) | 50,505 | 7,597 | 3,799 | 46,706 | 30% | 14,012 | 36,493 |
| 8 | 12 | 7,218 | - | 8,820 | - | 16,038 | 8,820 | 4,410 | 11,628 | 100% | 11,628 | 4,410 |
| 9 | 13 | 7,711 | 1,628 | 25 | - | 9,364 | 27 | 14 | 9,350 | S/L | - | 9,364 |
| 10 | 17 | 33,458 | - | 444 | (159) | 34,061 | 603 | 302 | 33,759 | 8% | 2,701 | 31,360 |
| 11 | | 3,405,471 | 1,628 | 43,410 | (14,336) | 3,464,845 | 57,812 | 28,906 | 3,435,939 | | 218,429 | 3,246,416 |

| | | |
|---|---|---|
| In-Service Additions | Total | 46,808 |
| | AFUDC | (421) |
| | CEC | (994) |
| | Land | 79 |
| | Removal | (2,062) |
| | | 43,410 |

**Cumulative Eligible Capital**

| LINE NO. | OPENING BALANCE | COST OF ADDITIONS | EXCLUDE 25 % OF ADDITIONS | ELIGIBLE BALANCE | RATE | CEC DEDUCTION | CLOSING BALANCE |
|---|---|---|---|---|---|---|---|
| 12 | 14,859 | 994 | 249 | 15,604 | 7% | 1,092 | 14,512 |

CAPITAL COST ALLOWANCE AND CUMULATIVE ELIGIBLE CAPITAL

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

**Capital Cost Allowance**

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2004 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2004 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | 2,616,977 | - | 49,132 | 570 | 2,665,136 | 48,562 | 24,281 | 2,640,854 | 4% | 105,633 | 2,559,503 |
| 2 | 02 | 239,077 | - | - | - | 239,077 | - | - | 239,077 | 6% | 14,345 | 224,733 |
| 3 | 03 | 37,605 | - | - | - | 37,605 | - | - | 37,605 | 5% | 1,880 | 35,724 |
| 4 | 06 | 3,311 | - | - | - | 3,311 | - | - | 3,311 | 10% | 331 | 2,980 |
| 5 | 08 | 267,819 | - | 33,154 | 2,985 | 297,987 | 30,168 | 15,084 | 282,903 | 20% | 56,581 | 241,407 |
| 6 | 09 | - | - | - | - | - | - | - | - | 25% | - | - |
| 7 | 10 | 36,493 | - | 6,557 | - | 43,050 | 6,557 | 3,279 | 39,771 | 30% | 11,931 | 31,118 |
| 8 | 12 | 4,410 | - | 4000 | - | 8,410 | 4,000 | 2,000 | 6,410 | 100% | 6,410 | 2,000 |
| 9 | 13 | 9,364 | - | 339 | - | 9,703 | 339 | 170 | 9,534 | S/L | - | 9,703 |
| 10 | 17 | 31,360 | - | 1,359 | 110 | 32,609 | 949 | 474 | 32,135 | 8% | 2,571 | 30,038 |
| 11 | | 3,246,416 | - | 94,541 | 3,665 | 3,336,888 | 90,576 | 45,288 | 3,291,600 | | 199,682 | 3,137,206 |

| | | |
|---|---|---|
| In-Service Additions | Total | 101,740 |
| | AFUDC | (3,067) |
| | Simmons Tax Basis Adjustment | (8,713) |
| | CEC | (280) |
| | Removal | 4,860 |
| | | 94,541 |

**Cumulative Eligible Capital**

| LINE NO. | OPENING BALANCE | COST OF ADDITIONS | EXCLUDE 25 % OF ADDITIONS | ELIGIBLE BALANCE | RATE | CEC DEDUCTION | CLOSING BALANCE |
|---|---|---|---|---|---|---|---|
| 12 | 14,512 | 280 | 70 | 14,722 | 7% | 1,030 | 13,692 |

## 2.6 PROPERTY TAXES

Schedule 2.6 shows the property tax amounts included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year.

The estimated increase in property taxes from 2002 to 2004 reflects a ~~6~~5% increase for the 2003 tax year and an estimated 5% increase for the 2004 tax year. The 5% increase is based on expected millrate increases.

Property taxes are levied by municipalities based on the assessed value of the Alberta System assets in service. The assessed values are updated annually. NGTL pays property taxes to 63 rural municipalities, 30 urban municipalities, four First Nations, and three Metis Settlements. Property tax payments also include education taxes collected by the municipalities on behalf of the Province of Alberta.

NGTL has no influence on tax rates as they are set by local municipalities and Alberta Learning (education taxes). However, NGTL is proactive in negotiating the assessed values of its facilities based on market value principles in direct discussions with municipal assessment officials. It also has discussions with Alberta Municipal Affairs with reference to municipal assessment standards and policies.

PROPERTY TAXES

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 1 | **Total Property Taxes** | 65,439 | 68,832 | 72,300 |

# 2.7 TRANSPORTATION BY OTHERS

## Introduction

Transportation By Others (TBO) costs are the costs NGTL incurs on behalf of its customers to transport gas on interconnected pipelines. These costs are invoiced to NGTL by the other pipeline companies and, in turn, collected from NGTL customers as one of the components of the revenue requirement.

## 2.7.1 History of Transportation By Others

In 1981 NGTL was first faced with the need to contract for capacity on another pipeline. In that year, NGTL had been asked to provide receipt service to customers with reserves located in the Liege area of the Alberta System. After examining system alternatives to connect these reserves, it became apparent that contracting for available capacity on the Simmons pipeline system was a cheaper alternative to constructing a receipt lateral the full distance required to interconnect with existing NGTL facilities since the Simmons pipeline system was already in place between NGTL's customers' reserves and the nearest point on the Alberta System. In subsequent years, similar opportunities have arisen and resulted in NGTL contracting for capacity on the Albersun pipeline system in 1987 and increasing its service entitlement on the Simmons pipeline system in 1988. In each of these instances the TBO was used to deliver gas to markets. As a condition of using the TBO to satisfy delivery markets, NGTL ensured the gas to be tied in was first transported on the Alberta System before entering the other pipeline system which ensured NGTL received a toll for providing this service.

Between 1981 and September of 1984, on a limited basis, NGTL contracted with the operators of certain other pipelines for transportation associated with gas that originated on the other pipeline systems. In September of 1984, NGTL discontinued this practice primarily due to the risks it perceived to NGTL’s customers and shareholders in continuing to roll-in third party pipeline charges. NGTL’s concern on behalf of its customers and shareholders was that any action on the part of NGTL was subject to complaint on the basis that the charges were neither just nor reasonable. NGTL was concerned that the service contracted for reflected an over-estimation of throughput volumes for which the customer was not directly accountable. The Public Utilities Board agreed with this position in Decision E86110.

During the period 1982 - 1989, NGTL’s customers requested increased deliveries to NGTL’s Empress Border delivery point which required additional capacity. NGTL contracted for capacity on the Foothills Pipe Lines Ltd. (Foothills) Zone 6 system and installed the crossover valves and pipes necessary to integrate the operation of the Alberta System and Foothills systems between James River (Caroline) and Empress. The rationale for the choice was obtaining the lowest cost means of providing required capacity to NGTL’s customers.

NGTL also contracted with Foothills for capacity provided by the Zone 7 facilities as part of the 1993 expansion at the Alberta/British Columbia border. This capacity contract was contested, and associated costs ultimately disallowed by the EUB for the period November 1, 1993 to December 31, 1994.

The restructuring of PanAlberta Gas (PAG) gas contracts in the late 1980’s and early 1990’s led to NGTL taking an assignment of PAG’s capacity on the Foothills Zone 6 and Zone 7 systems, effectively displacing PAG, which continued as a shipper on the Alberta System. This assignment from PAG, together with NGTL capacity contracts, effected a “roll-in” to the Alberta System’s revenue requirement of the full cost of service of the Foothills Alberta facilities. The Zone 6 roll-in was done in 1989 without shipper opposition. The Zone 7 roll-in was approved by the Board in Decision U96001.

In the NGTL 1995 GRA proceeding, Canadian Western Natural Gas Company Ltd. and Northwestern Utilities Ltd. (the Utilities) argued, among other things that certain of their transportation charges be rolled into the revenue requirement of NGTL. This would eliminate the dual toll faced by a shipper whose receipts were connected to the Utilities system and who sought access to markets via the Alberta System, thus encouraging gas development adjacent to the Utilities' system and ultimately resulting in more orderly, economic and efficient development of the province's natural gas resources. The Board did not approve the Utilities' proposal, but directed NGTL to re-evaluate its TBO policies with respect to Utilities TBO in consultation with interested parties and directed NGTL to report on this matter in its next GRA (Decision U96001, Page 157).

Following the Board's direction, NGTL and the Utilities entered into discussions related to TBO. The TBO matter was also adopted as an issue at the TTP in June 1996 and a TTP task force was formed to work the issues. The task force was unable to reach consensus and recommended to the TTP that no further actions be undertaken with respect of TBO. NGTL filed a TTP resolution with the Board in October 1996 indicating that the TBO issue had been addressed by the TTP and that no resolution had been reached.

In 1997, NGTL filed with the Board its Facility Acquisition Guidelines and Criteria (see Section 8, Appendix F) and established the principle that:

> When considering providing service into a new area, the decision to purchase existing facilities, build new facilities and where applicable, utilize capacity on an existing pipeline is based on the lowest cumulative present value cost of service (CPVCOS) and the lowest first year capital cost.

In 2001, NGTL received customer requests for delivery service into the Fort McMurray area. Please refer to Section 8 for a detailed discussion of the development of the Fort McMurray area delivery service and the resulting TBO arrangements.

Also in 2001, NGTL made application to construct the Fort Saskatchewan Extension. NGTL stated that while capacity was available on an other pipeline to meet current transportation requirements, new facilities would inevitably be required to serve forecast market demands. NGTL argued that existing shippers would benefit if NGTL was to construct the incremental capacity required, mitigating the risk of underutilization of Alberta System in the future. NGTL considered but dismissed the use of TBO as a viable option in this instance.

### 2.7.2 NGTL's TBO Policy

NGTL's policy in respect of TBO has evolved in response to changes in the competitive landscape. NGTL is not obligated to contract for service on other pipelines in order to provide service to its current or prospective shippers when NGTL could otherwise provide such service. However, in determining how best to fulfill its contractual transportation obligations and provide service to its customers, NGTL considers whether to construct new facilities or, if the opportunity is available, to purchase existing facilities or contract for capacity on facilities owned by other parties. NGTL assesses the relative merits of each of these alternatives based on the overall benefit each provides to its customers. Factors that are considered include:

**1. Long-term owning and operating cost of specific facilities**

NGTL will consider the "roll in" of third party transportation costs when such capacity can be purchased or contracted for more cost effectively than NGTL could construct alternative facilities. The least cost analysis is based on long term owning and operating costs; therefore, the certainty of market and flexibility of the TBO terms and conditions are incorporated into the analysis.

When considering providing service into a new area, the decision to purchase existing facilities, build new facilities and/or utilize capacity on an existing pipeline is based on the lowest long-term cumulative present value cost of service (CPVCOS) and lowest first year capital cost. If, for practical purposes, these alternatives are equal based on financial analysis, then a decision is made based on other relevant factors.

When capacity on an other pipeline is available and the pipeline is prepared to provide service to NGTL, NGTL typically applies the following methodology to evaluate that TBO option:

- determine whether the TBO option will meet NGTL's customers' over-all requirements for service;
- determine the cost of the TBO service option, either by applying posted tolls or requesting bids for provision of the required service; and,
- evaluate the CPVCOS of all service options, including TBO, to establish the lowest cost option. The evaluation of the lowest cost TBO is done in accordance with the principles outlined in NGTL's Guidelines for New Facilities that were filed with the Board in July 2000 through the Facilities Liaison Committee Resolution F2000-02 (see Section 8, Appendix G). The evaluation includes all costs associated with provision of gas to the final customer location, including NGTL and other party costs. In addition to the TBO price submitted by the bidder (i.e., the cost per unit transported), to determine the lowest total overall cost, NGTL considers the cost of pipeline extensions and metering facilities.

**2. Impact on overall system cost**

In addition to assessing the cost effectiveness of a particular facility, NGTL will consider the short-term and long-term impacts on NGTL shippers in aggregate. For example:

- NGTL will attempt to maintain the flexibility to adapt to evolving market conditions, by considering whether constructing facilities to fill current contract requirements rather than contracting for that capacity on a third party pipeline may better position NGTL to capture longer term market growth. The resulting potential for increased revenues could result in lower tolls for existing shippers.
- Where new facilities are required in addition to those already available via TBO, NGTL would consider whether the cost of a TBO arrangement plus the new facilities will be less than the cost of NGTL constructing capacity for the entire volume. NGTL will also consider whether there are administrative and operational efficiencies to be gained from this approach.
- NGTL will consider whether a particular decision to contract for capacity on a third party pipeline could ultimately result in an offloading of the Alberta System, leading to reduced revenues and increased tolls for existing shippers.

### 3. Collection of incremental revenue

NGTL will consider entering into a TBO arrangement only where gas volumes transported cannot avoid the payment of the appropriate NGTL tolls that would otherwise be paid as defined in the NGTL tariff. This requirement ensures that the appropriate contribution is made towards the collection of the Alberta System’s revenue requirement for those volumes transported on an other pipeline.

### 4. Contractual risks

NGTL will assess the risks of contracting with an other pipeline including customer accountability for estimation of throughput volumes and NGTL’s ability to control TBO costs.

The contractual risks of providing transportation on other pipelines become the contractual risk of NGTL and all of its customers. NGTL only contracts with other pipelines when NGTL requires transportation capacity on its system for NGTL customers. For NGTL to contract for transportation on other pipelines when NGTL does not require that capacity to meet the receipt or delivery obligations of NGTL customers, results in increased risk for NGTL and all of its customers.

**5. Other considerations**

Other factors that could affect the quality or ability of the service to meet the service needs of NGTL's customers could be relevant considerations for specific TBO evaluations. Among others, these considerations could include situation specific factors such as operability of the facilities, environmental consideration, land access, reliability, customer choice, or timing of the availability of service.

### 2.7.3 TBO Arrangements with Affiliates

In Decision 2003-051, the Board directed NGTL to address how its TBO policy relates to the use of affiliate owned capacity.

NGTL's policy does not differentiate between its affiliates and arm's-length parties when evaluating or contracting for TBO. Any TBO arrangements entered into with NGTL affiliates will be obtained as if the affiliate was an arm's-length party in accordance with the terms and conditions outlined in NGTL's Code of Conduct (see Section 9).

### 2.7.4 Current TBO Arrangements

Schedule 2.7 shows the TBO amounts included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~actual year, and the 2004 test year.

NGTL will have TBO arrangements in 2004 with three pipelines: Foothills Pipe Lines Ltd. (Foothills), TransCanada Pipeline Ventures Limited Partnership (Ventures), and Simmons Group Inc. (Simmons). These agreements are summarized in Table 2.7.1**.**

**Table 2.7.1**

**2004 NGTL TBO Arrangements**

| Pipeline | Receipt Point | Delivery Point | Start Date | Expiry Date | Contract Volume |
|---|---|---|---|---|---|
| **Foothills Zone 6** | Caroline East | Alberta / Sask Border | 01-Jul-2001 | 31-Oct-2006 | 58.77 $10^6m^3/d$ |
| **Foothills Zone 7** | Caroline West | Alberta / BC Border | 01-Jul-2001 | 31-Oct-2006 | 20.418 $10^6m^3/d$ |
| **Simmons** | Atmore or Conklin | House River | 01-Nov-2003 | 31-Mar-2004 | 4.085 $10^6m^3/d$ |
| **Ventures** | Buffalo Creek | Mildred Lake | 01-Mar-2002 | 31-Mar-2004 | 4.776 $10^6m^3/d$ |
| **Ventures** | Buffalo Creek | Oil Sands Sales | 01-Apr-2004 | 31-Mar-2029 | 9.466-15.017 $10^6m^3/d$ |

In response to the Board's directive in Appendix 4 to Decision 2003-051, the TBO arrangements with each of these parties and the associated costs are described below.

### 2.7.4.1 Foothills Pipe Lines Ltd.

Foothills, a transporter of natural gas to the United States, is 100% owned by TCPL effective August 15, 2003. Portions of the Foothills system, namely Zones 6 and 7, are designed and operated as integrated parts of the Alberta System. Zone 6 refers to the continuous portion of the Foothills system that extends from Caroline East to the Alberta/Saskatchewan border. Zone 7 refers to the three Foothills pipe sections integrated with the Alberta System's Western Alberta Mainline between Caroline West and the Alberta/BC border (refer to the map in Figure 2.7.1). Foothills is regulated by the National Energy Board (NEB).

NGTL is the sole shipper on Foothills' Zones 6 and 7 and as such has contracted for the entire capacity in Zones 6 and 7. This capacity has been required by NGTL to economically meet its contractual commitments with shippers at the Alberta/Saskatchewan and Alberta/BC borders. As indicated in Table 2.7.1, NGTL's current contractual commitments with Foothills expire on October 31, 2006.

Under the arrangement with Foothills, NGTL pays for transportation charges on a demand basis based on Foothills' cost of service~~ as approved by the~~ calculated in accordance with NEB Orders TG-1-79, TG-6-81, TG-4-82 and TG-2-2003. Per requirement 2(a) of NEB Order TG-6-81, on or before December 1 of each year, Foothills submits to the NEB for approval its proposed Operating and Maintenance expense budget for the next succeeding year. Foothills also provides a six-month forecast~~s~~ of its cost of service (January to June and July to December) to its shippers ~~six~~ two months in advance, ~~(January to June and July to December) and files with the NEB~~ on or before October 31 and April 30 each year. NGTL has based the 2004 test year Foothills TBO amount on a forecast provided by Foothills.

Foothills' TBO costs ~~are forecast to~~ decreased from 2002 to 2003 as a result of lower electrical rates, fewer engine and power turbine overhauls, and reduction in the Special Charge. Foothills' TBO costs are forecast to increase from 2003 to 2004 as a result of additional overhauls, higher land payments, higher pension costs, repairs to the cooling tower at the Decompression/Recompression facility, and higher financing charges. The 2004 TBO amount is also impacted by timing difference between when the expenses are incurred and included in the TBO amount charged to NGTL.

**Foothills Zone 6**

The TBO agreement with Foothills in Zone 6 was renewed July 1, 2001. At the time of renewal, the five-year summer forecast for contracts at the Empress and McNeill borders (collectively referred to as the "Eastern Gate") was in the range of 206-219 $10^6m^3/d$

(7.32-7.79 Bcf/d) (December 2000 Annual Plan, Figure 4.4.1.3 Eastern Alberta Mainline Design Sub Area Design Flows and Appendix 4 page 9). The summer 2001 delivery capability without the Zone 6 facilities would have been approximately 185.0 $10^6m^3/d$, resulting in a short fall of the capacity required at the Eastern Gate of approximately 21-34 $10^6m^3/d$ (0.75-1.20 Bcf/d) over the 2001/02 to 2004/05 timeframe. Beyond 2001, the contractual obligations at the Eastern Gate were forecast to increase, but the capability of the system was expected to decline, primarily as a result of decreasing supply flow from the North Lateral (Downstream Bens Lake Design Area). The requirement for Foothills capacity was expected to increase over the coming five-year period, and the loss of the Zone 6 Foothills facilities would have prevented NGTL from meeting its forecast Eastern Gate contractual commitments.

**Foothills Zone 7**

The TBO agreement with Foothills in Zone 7 was renewed July 1, 2001. At the time of renewal, the five-year summer forecast for delivery contracts at the Alberta/BC border (referred to as the “Western Gate”) was in the range of 64-65 $10^6m^3/d$ (2.29-2.32 Bcf/d) (December 2000 Annual Plan, Figure 4.4.1.4 Western Alberta Mainline Design Sub Area Design Flows, and Appendix 4 page 10). The summer 2001 delivery capability to the Alberta/BC border without the Zone 7 facilities would have been 52.4 $10^6m^3/d$, resulting in a shortfall of the capacity required at the Alberta/BC border of approximately 9.6-12.6 $10^6m^3/d$ (0.34-0.45 Bcf/d). Therefore, the loss of the Zone 7 Foothills facilities would have prevented NGTL from meeting its forecast Western Gate contractual commitments.

#### 2.7.4.2 Simmons Group Inc.

NGTL commences TBO service with Simmons on November 1, 2003. This service expires March 31, 2004. Simmons will receive gas from receipt points on the Alberta System at Atmore B Sales and Conklin West Sales Meter Stations, and deliver that gas back to the Alberta System at House River Meter Station. The alternative to contracting

for transportation service on the Simmons pipeline would have been to construct the North Central Corridor (Peerless Lake section). Simmons was the only pipeline in the region that had facilities and available capacity to offset the need for the incremental facilities. Further details of this arrangement are included in Section 8.
At the time this contract was entered into, the forecast demand in the region was 17.5 $10^6m^3/d$ (620 MMcf/d). Without the Simmons TBO capacity there would have been a shortfall of approximately 4.085 $10^6m^3/d$ (145 MMcf/d).

The rates consist of a demand payment of $95,000 per month and a commodity usage component of $0.7098/10^3m^3$. The contract demand volume for the 2004 test year is 4.085 $10^6m^3/d$ (145 MMcf/d). In forecasting the transportation costs for these contracts, NGTL multiplied the applicable commodity rate by the forecast volume and added this to the demand payment. This resulted in an expected cost of $0.546 million for January to March, 2004. NGTL has negotiated an agreement to acquire the Simmons pipeline system effective April 1, 2004, subject to regulatory approval. This agreement is discussed in detail in Section 8 of this Application.

#### 2.7.4.3 TransCanada Pipeline Ventures Limited Partnership (Oil Sands Pipeline)

**Existing (2002) Transportation Agreement**

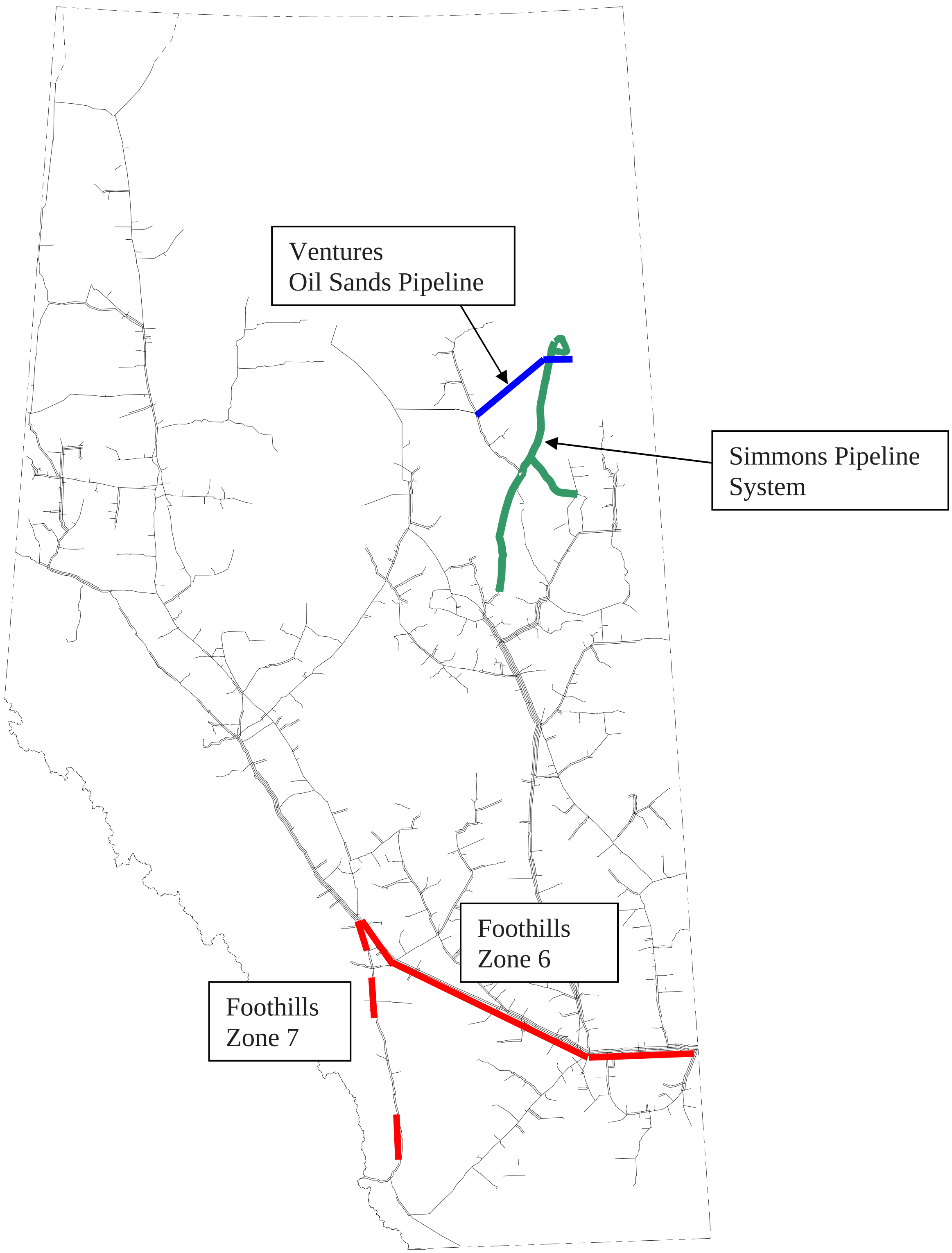
NGTL commenced TBO service with Ventures on March 1, 2002 to transport gas from the Buffalo Creek interconnect to the Alberta System meter stations at Mildred Lake Sales, Mildred Lake Sales #2, or the junction of the Ventures Oil Sands Pipeline and the Moosa Lateral. The existing TBO contract with Ventures will expire October 31, 2004. As a result of the new (2004) transportation agreement described in the following section, Ventures has agreed to terminate the existing contract effective April 1, 2004, or a date within 30 days following Board approval of the new agreement. For 2004, the contract demand volume is 4.776 $10^6m^3/d$ (170 MMcf/d) to accommodate current demand requirements. The toll associated with this service is $0.12 per Mcf resulting in a total forecast cost for January to March 2004 of $1.8 million.

**New (2004) Transportation Arrangement**

NGTL proposes to enter into a new TBO service with Ventures on the latter of April 1, 2004 or within 30 days of Board approval of this agreement to transport gas from the Buffalo Creek interconnect to the existing delivery points described above in the discussion of the Existing (2002) Transportation Agreement, as well as the Oil Sand Sales Meter Station located at 10-6-93-10W4M. The terms and conditions of this service, as well as the reasons for which it is required, are described in detail in Section 8 of this Application. NGTL's firm contract demand volume under this transportation agreement with Ventures is dependent on the delivery pressure provided by NGTL at the Buffalo interconnect, and will range from 9.466 to 15.017 $10^6m^3/d$ (336 to 533 MMcf/d), over a range in pressures from 900 to 1,200 psig. This firm service will have a fixed cost in 2004 of $6.1 million, assuming an April 1, 2004 commencement date. If the commencement date is delayed the fixed cost will be prorated depending on the remaining days in the 2004 calendar year. In addition to the fixed annual costs, NGTL will be charged operating and maintenance costs. These costs are estimated at $0.35 million per year. The resulting forecast cost is $0.26 million for April to December 2004. Further details on this arrangement are included in Section 8.

NGTL is seeking approval of a Transportation by Others deferral account commencing January 1, 2004 to capture differences between the forecast and actual 2004 amounts. Additional details on this deferral account are provided in Section 7, Deferral and Reserve Accounts.

**Figure 2.7.1 TBO Pipelines**



TRANSPORTATION BY OTHERS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 1 | Foothills Pipe Lines [1] | 75,155 | 70,334 | 75,149 |
| 2 | Simmons Pipeline | (4) | 190 | 546 |
| 3 | TransCanada Pipeline Ventures | 4,446 | 6,257 | 8,191 |
| 4 | **Total Transportation by Others** | 79,597 | 76,780 | 83,886 |

[1] 2003 Shippers Savings per Foothills' Settlement Agreement application dated January 31, 2003, and as approved per NEB Order TG-2-2003 will be included in Non-Routine Adjustments in the 2005 Revenue Requirement.

# 2.8 FOREIGN EXCHANGE

## 2.8.1 Foreign Exchange on Interest Payments

Schedule 2.8.1 shows the foreign exchange on interest payments included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year. These amounts represent the foreign exchange gains or losses that are incurred on interest payments for foreign currency denominated debt issues. The gains or losses are calculated as the difference between the historic exchange rates at which debt was issued and the actual exchange rates in effect when the interest payments are made multiplied by the interest payment amount.

NGTL seeks approval in this Application of the continuation of the Foreign Exchange Gain/Losses on Interest Payments deferral account effective January 1, 2004. Variances between the forecast and actual foreign exchange gains and losses on foreign debt interest payments will be captured in this deferral account. Additional details on this deferral account are provided in Section 7, Deferral and Reserve Accounts.

## 2.8.2 Annual Foreign Exchange Amortization Amount

Schedule 2.8.2 shows the Annual Foreign Exchange Amortization Amount included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year.

In Decision U96001, the Board stated at page 130:

> NGTL, in passing historical rates of exchange from one debt issue to the next, has not recovered any exchange gains or losses from customers. Whether NGTL's practice is realistic and achieves intergenerational equity was not fully explored in this proceeding. Nor was there any

> examination of alternative methods of incorporating exchange differences in respect of debt principal in customer rates. The Board wishes to consider this issue fully and, therefore, directs NGTL to address it in its next general rate application.

In response to the Board's direction, NGTL discussed various alternative methods of recovering foreign exchange gains and losses with its shippers during the negotiation process which lead to the ASRS. These discussions resulted in a Foreign Exchange Reserve Account being included in the ASRS, which was designed to facilitate the recovery of foreign exchange gains/losses over the life of the foreign currency debt issues. The Foreign Exchange Reserve Account was continued in 2003 in accordance with the terms of the ASRRS. This mechanism provides for intergenerational equity by ensuring that the customers who benefit from the financing provided by the foreign currency denominated debt bear an appropriate share of the foreign exchange gains or losses.

Each year, NGTL estimates the expected gain or loss for each foreign currency debt issue by calculating the difference between forecast and historic exchange rates and applying the difference to the principal amount of the issue. The revaluation process applies only to those foreign currency debt issues that do not have foreign currency swap arrangements in place which eliminate the risk of gains or losses occurring. These amounts are then added to or subtracted from the existing balance of the Foreign Exchange Reserve Account to determine the total gain or loss to be refunded or collected. The portion that applies to the current year is calculated by dividing the total by the number of years remaining before 2029, which is the year in which the last existing foreign currency debt issue matures. This amount is then included in the revenue requirement as the Annual Foreign Exchange Amortization Amount. Also included in the revenue requirement is the amount of income tax payable on the Annual Foreign Exchange Amortization Amount.

The Annual Foreign Exchange Amortization Amount collected is recorded in the Foreign Exchange Reserve Account. As foreign debt is repaid, the exchange gains or losses attributable to that debt will be applied to the balance in the reserve account. In the year following the year that all foreign debt has been repaid, any remaining balance in the reserve account will be disposed of subject to the approval of the Board

NGTL believes that the Foreign Exchange Reserve Account addresses the concerns expressed by the Board in Decision U96001. Accordingly, NGTL is seeking continuation of this reserve account commencing January 1, 2004. NGTL also requests that the balance of the reserve account be included in rate base effective January 1, 2004. Further information on this request is provided in Section 7, Deferral and Reserve Accounts.

FOREIGN EXCHANGE ON INTEREST PAYMENTS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
($Thousands)

| LINE NO. | DESCRIPTION | DEBT ISSUE (US$) | INTEREST RATE | DATE OF INTEREST PAYMENT | INTEREST PAYMENTS (US$) | HISTORICAL EXCHANGE RATE [1] | CURRENT EXCHANGE RATE | ACTUAL LOSS |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 1 | $32.5 MM Floating Term Note | 32,500 | Floating | Feb 14 | 192 | 1.18160 | 1.59200 | 79 |
| 2 | 7.50% MTN #5 | 32,500 | 7.5000% | Feb 20 | 1,219 | 1.18160 | 1.59050 | 498 |
| 3 | 7.875% U.S. $200 mm | 200,000 | 7.8750% | Apr 1 | 7,875 | 1.24272 | 1.59940 | 2,809 |
| 4 | 8.95% U.S. Credit Suisse/Citibank (8.2915% Fixed) | 75,000 | 8.2915% | May 14 | 3,109 | 1.15505 | 1.55860 | 1,255 |
| 5 | $32.5 MM Floating Term Note | 32,500 | Floating | May 14 | 176 | 1.18160 | 1.55860 | 66 |
| 6 | 7.70% U.S. $50 mm | 50,000 | 7.7000% | Jun 15 | 1,925 | 1.46170 | 1.54730 | 165 |
| 7 | 7.70% U.S. $150 mm | 150,000 | 7.7000% | Jun 15 | 5,775 | 1.22748 | 1.54730 | 1,847 |
| 8 | 8.50% U.S. $175 mm (Swap - 8.5% Fixed) [2] | 138,000 | 8.5000% | Jun 15 | 5,865 | 1.27455 | 1.54730 | 1,600 |
| 9 | $32.5 MM Floating Term Note | 32,500 | Floating | Aug 14 | 183 | 1.18160 | 1.56490 | 70 |
| 10 | 7.50% MTN #5 | 32,500 | 7.5000% | Aug 20 | 1,219 | 1.18160 | 1.57150 | 475 |
| 11 | 7.875% U.S. $200 mm | 200,000 | 7.8750% | Oct 1 | 7,875 | 1.24272 | 1.58600 | 2,703 |
| 12 | 8.95% U.S. Credit Suisse/Citibank (8.2915% Fixed) | 75,000 | 8.2915% | Nov 14 | 3,109 | 1.15505 | 1.57470 | 1,305 |
| 13 | $32.5 MM Floating Term Note | 32,500 | Floating | Nov 14 | 170 | 1.18160 | 1.57470 | 67 |
| 14 | 7.70% U.S. $50 mm | 50,000 | 7.7000% | Dec 15 | 1,925 | 1.46170 | 1.56250 | 194 |
| 15 | 7.70% U.S. $150 mm | 150,000 | 7.7000% | Dec 15 | 5,775 | 1.22748 | 1.56250 | 1,935 |
| 16 | 8.50% U.S. $175 mm (Swap - 8.5% Fixed) [2] | 138,000 | 8.5000% | Dec 15 | 5,874 | 1.27455 | 1.56250 | 1,691 |
| 17 | **Total foreign exchange loss on interest payments** | | | | | | | 16,760 |

(1) Historical exchange rates pertain to the original financing when a maturing issue(s) is rolled into a new issue.
(2) US $175 Million partially swapped to Cdn.

FOREIGN EXCHANGE ON INTEREST PAYMENTS

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | DEBT ISSUE (US$) | INTEREST RATE | DATE OF INTEREST PAYMENT | INTEREST PAYMENTS (US$) | HISTORICAL EXCHANGE RATE [1] | CURRENT EXCHANGE RATE | ACTUAL LOSS/(GAIN) |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 1 | $32.5 MM Floating Term Note | 32,500 | Floating | Feb 14 | 147 | 1.18160 | 1.51880 | 50 |
| 2 | 7.50% MTN #5 | 32,500 | 7.5000% | Feb 20 | 1,219 | 1.18160 | 1.50430 | 393 |
| 3 | 7.875% U.S. $200 mm | 200,000 | 7.8750% | Apr 1 | 7,875 | 1.24272 | 1.47260 | 1,810 |
| 4 | 8.95% U.S. Credit Suisse/Citibank (8.2915% Fixed) | 75,000 | 8.2915% | May 14 | 3,109 | 1.15505 | 1.37870 | 695 |
| 5 | $32.5 MM Floating Term Note | 32,500 | Floating | May 14 | 138 | 1.18160 | 1.37870 | 27 |
| 6 | 7.70% U.S. $50 mm | 50,000 | 7.7000% | Jun 15 | 1,925 | 1.46170 | 1.33920 | (236) |
| 7 | 7.70% U.S. $150 mm | 150,000 | 7.7000% | Jun 15 | 5,775 | 1.22748 | 1.33920 | 645 |
| 8 | 8.50% U.S. $175 mm (Swap - 8.5% Fixed) [2] | 138,000 | 8.5000% | Jun 15 | 5,865 | 1.27455 | 1.33920 | 379 |
| 9 | $32.5 MM Floating Term Note | 32,500 | Floating | Aug 14 | 138 | 1.18160 | 1.39340 | 29 |
| 10 | 7.50% MTN #5 | 32,500 | 7.5000% | Aug 20 | 1,219 | 1.18160 | 1.40240 | 269 |
| 11 | 7.875% U.S. $200 mm | 200,000 | 7.8750% | Oct 1 | 7,875 | 1.24272 | 1.34800 | 829 |
| 12 | 8.95% U.S. Credit Suisse/Citibank (8.2915% Fixed) | 75,000 | 8.2915% | Nov 14 | 3,109 | 1.15505 | 1.30380 | 463 |
| 13 | $32.5 MM Floating Term Note | 32,500 | Floating | Nov 14 | 125 | 1.18160 | 1.30380 | 15 |
| 14 | 7.70% U.S. $50 mm | 50,000 | 7.7000% | Dec 15 | 1,925 | 1.46170 | 1.31340 | (285) |
| 15 | 7.70% U.S. $150 mm | 150,000 | 7.7000% | Dec 15 | 5,775 | 1.22748 | 1.31340 | 497 |
| 16 | 8.50% U.S. $175 mm (Swap - 8.5% Fixed) [2] | 138,000 | 8.5000% | Dec 15 | 5,865 | 1.27455 | 1.31340 | 228 |
| 17 | **Total foreign exchange loss on interest payments** | | | | | | | 5,809 |

[1] Historical exchange rates pertain to the original financing when a maturing issue(s) is rolled into a new issue.
[2] US $175 Million partially swapped to Cdn.

FOREIGN EXCHANGE ON INTEREST PAYMENTS

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | DEBT ISSUE (US$) | INTEREST RATE | DATE OF INTEREST PAYMENT | INTEREST PAYMENTS (US$) | HISTORICAL EXCHANGE RATE[1] | CURRENT EXCHANGE RATE | ACTUAL LOSS/(GAIN) |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 1 | 7.50% MTN #5 | 32,500 | 7.5000% | Feb 20 | 1,219 | 1.18161 | 1.31580 | 164 |
| 2 | 7.875% U.S. $200 mm | 200,000 | 7.8750% | Apr 1 | 7,875 | 1.24272 | 1.31580 | 576 |
| 3 | 8.95% U.S. Credit Suisse/Citibank (8.2915% Fixed) | 75,000 | 8.2915% | May 14 | 3,109 | 1.15505 | 1.31580 | 500 |
| 4 | 7.70% U.S. $50 mm | 50,000 | 7.7000% | Jun 15 | 1,925 | 1.46170 | 1.31580 | (281) |
| 5 | 7.70% U.S. $150 mm | 150,000 | 7.7000% | Jun 15 | 5,775 | 1.22748 | 1.31580 | 510 |
| 6 | 8.50% U.S. $175 mm (Swap - 8.5% Fixed)[2] | 138,000 | 8.5000% | Jun 15 | 5,865 | 1.27455 | 1.31580 | 242 |
| 7 | 7.50% MTN #5 | 32,500 | 7.5000% | Aug 20 | 1,219 | 1.18161 | 1.31580 | 164 |
| 8 | 7.875% U.S. $200 mm | 200,000 | 7.8750% | Oct 1 | 7,875 | 1.24272 | 1.31580 | 576 |
| 9 | 8.95% U.S. Credit Suisse/Citibank (8.2915% Fixed) | 75,000 | 8.2915% | Nov 14 | 3,109 | 1.15505 | 1.31580 | 500 |
| 10 | 7.70% U.S. $50 mm | 50,000 | 7.7000% | Dec 15 | 1,925 | 1.46170 | 1.31580 | (281) |
| 11 | 7.70% U.S. $150 mm | 150,000 | 7.7000% | Dec 15 | 5,775 | 1.22748 | 1.31580 | 510 |
| 12 | 8.50% U.S. $175 mm (Swap - 8.5% Fixed)[2] | 138,000 | 8.5000% | Dec 15 | 5,865 | 1.27455 | 1.31580 | 242 |
| 13 | **Total Foreign exchange loss on interest payments** | | | | | | | 3,420 |

[1] Historical exchange rates pertain to the original financing when a maturing issue(s) is rolled into a new issue.
[2] US $175 Million partially swapped to Cdn.

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT

FOR THE BASE YEAR ENDING DECEMBER 31, 2002
($Thousands)

| LINE NO. | DESCRIPTION | MATURITY DATE | AMOUNT (US$) | HISTORICAL EXCHANGE RATE | DEC 31, 2001 EXCHANGE RATE | CURRENT YEAR LOSS |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | 8.50% US$175MM [1] | 2012 | 138,000 | 1.27455 | 1.5926 | 43,891 |
| 2 | 7.875% US$200MM | 2023 | 200,000 | 1.24272 | 1.5926 | 69,976 |
| 3 | 8.95% U.S. Credit Suisse/Citibank (8.2915% fixed) - US$75MM | 2003 | 75,000 | 1.15505 | 1.5926 | 32,816 |
| 4 | Floating Term Note - US$32.5MM | 2003 | 32,500 | 1.18160 | 1.5926 | 13,358 |
| 5 | 7.70% US$150MM Note Payable to TCPL | 2029 | 150,000 | 1.22748 | 1.5926 | 54,768 |
| 6 | 7.70% US$50MM Note Payable to TCPL | 2029 | 50,000 | 1.46170 | 1.5926 | 6,545 |
| 7 | 6.25% U.S. MTN #4 - US$32MM | 2025 | 32,000 | 1.28651 | 1.5926 | 9,795 |
| 8 | 7.50% Medium Term Note - US$32.5MM | 2026 | 32,500 | 1.18160 | 1.5926 | 13,358 |
| | | | | | | 244,506 |
| 9 | Foreign Exchange Reserve Account Balance at December 31, 2001 (Schedule 3.10) | | | | | 43,424 |
| 10 | **Total** | | 710,000 | | | 287,930 |
| 11 | Annual Foreign Exchange Amortization Amount (Line 10 divided by 27) | | | | | 10,664 |
| 12 | Income Tax Payable | | | | | 6,569 |
| 13 | | | | | | 17,233 |
| 14 | 2001 Carrying Charge adjustment | | | | | 619 |
| 15 | 2002 Carrying Charges | | | | | 3,579 |
| 16 | | | | | | 21,431 |

This table does not include USD debt issues that have been swapped to Canadian dollars.

[1] US$37 million of the 8.5% US$175 million debt instrument has been swapped to Canadian dollars.

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | MATURITY DATE | AMOUNT (US$) | HISTORICAL EXCHANGE RATE | DEC 31, 2002 EXCHANGE RATE | CURRENT YEAR LOSS |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | 8.50% US$175MM [1] | 2012 | 138,000 | 1.27455 | 1.5796 | 42,097 |
| 2 | 7.875% US$200MM | 2023 | 200,000 | 1.24272 | 1.5796 | 67,376 |
| 3 | 8.95% U.S. Credit Suisse/Citibank (8.2915% fixed) - US$75MM | 2003 | 75,000 | 1.15505 | 1.5796 | 31,841 |
| 4 | Floating Term Note - US$32.5MM | 2003 | 32,500 | 1.18160 | 1.5796 | 12,935 |
| 5 | 7.70% US$150MM Note Payable to TCPL | 2029 | 150,000 | 1.22748 | 1.5796 | 52,818 |
| 6 | 7.70% US$50MM Note Payable to TCPL | 2029 | 50,000 | 1.46170 | 1.5796 | 5,895 |
| 7 | 7.50% Medium Term Note - US$32.5MM | 2026 | 32,500 | 1.18160 | 1.5796 | 12,935 |
| | | | | | | 225,897 |
| 8 | Foreign Exchange Reserve Account Balance at December 31, 2002 (Schedule 3.10) | | | | | 32,759 |
| 9 | **Total** | | 678,000 | | | 258,656 |
| 10 | Annual Foreign Exchange Amortization Amount (Line 9 divided by 26) | | | | | 9,948 |
| 11 | Income Tax Payable | | | | | 5,780 |
| 12 | | | | | | 15,729 |
| 13 | 2003 Carrying Charges | | | | | 2,975 |
| 14 | | | | | | 18,704 |

This table does not include USD debt issues that have been swapped to Canadian dollars.

[1] US$37 million of the 8.5% US$175 million debt instrument has been swapped to Canadian dollars.

ANNUAL FOREIGN EXCHANGE AMORTIZATION AMOUNT

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | MATURITY DATE | AMOUNT (US$) | HISTORICAL EXCHANGE RATE | DEC 31, 2003 EXCHANGE RATE | CURRENT YEAR LOSS/(GAIN) |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | 8.50% US$175MM [1] | 2012 | 138,000 | 1.27455 | 1.2924 | 2,463 |
| 2 | 7.875% US$200MM | 2023 | 200,000 | 1.24272 | 1.2924 | 9,936 |
| 3 | 7.70% US$150MM Note Payable to TCPL | 2029 | 150,000 | 1.22748 | 1.2924 | 9,738 |
| 4 | 7.70% US$50MM Note Payable to TCPL | 2029 | 50,000 | 1.46170 | 1.2924 | (8,465) |
| 5 | 7.50% Medium Term Note - US$32.5MM | 2026 | 32,500 | 1.18160 | 1.2924 | 3,601 |
| | | | | | | 17,274 |
| 6 | Foreign Exchange Reserve Account Balance at December 31, 2003 (Schedule 3.10) | | | | | 37,938 |
| 7 | **Total** | | 570,500 | | | 55,212 |
| 8 | Annual Foreign Exchange Amortization Amount (Line 7 divided by 25) | | | | | 2,208 |
| 9 | Income Tax Payable | | | | | 1,169 |
| 10 | | | | | | 3,378 |

This table does not include USD debt issues that have been completely swapped to Canadian dollars.

[1] US$ 37 million of the 8.5% US$175 million debt instrument has been swapped to Canadian dollars.

REVISED February 2004

## 2.9 REGULATORY HEARING COSTS

Schedule 2.9 shows the regulatory hearing costs included in the revenue requirements for the 2002 base year, the 2003 forecast year, and the 2004 test year. Regulatory hearing costs include the following:

- the portion of the EUB's annual general assessment charged to NGTL;
- intervenor costs incurred in NGTL regulatory proceedings; and
- external costs, which include legal and consultants' fees, incurred by NGTL in regulatory proceedings.

Intervenor costs for 2002 have been approved by the Board and paid by NGTL. Under the terms of the ASRS approved by the Board in Decision 2001-44, NGTL's regulatory costs and approved intervenor costs incurred during the term of the ASRS were accommodated within the revenue requirement established under the ASRS. Regulatory hearing costs incurred in 2002 are in respect of the following proceedings:

- Application for Approval of Costs of Delivery Service to the Fort McMurray Area (Decision 2002-16); and
- Gas Transportation Tariff, Carbon Dioxide ($CO_2$) Gas Quality Requirements, Phase 1 ~~and 2~~ (Decision~~s~~ 2002-044~~ and 2002-084~~).

Under the terms of the ASRRS approved by the Board in Decision 2003-051, NGTL's regulatory costs and approved intervenor costs in 2003 are to be accommodated within the revenue requirement determined under the ASRRS.

Regulatory hearing costs incurred in 2003 are in respect of the following hearings:

- Gas Transportation Tariff, Carbon Dioxide ($CO_2$) Gas Quality Requirements, Phase~~s 1 and~~ 2 (Decision~~s 2002-044 and~~ 2002-084);

- Application to construct Fort Saskatchewan Extension and Scotford, Josephburg and Astotin Meter Stations (Decision 2002-58);
- 2004 Generic Cost of Capital Proceeding (Proceeding No. 1271597); and
- 2004 General Rate Application, Phase 1.

~~Of the $606,000~~For 2003, $617,000 in intervenor costs ~~for 2003, $563,000~~ have been approved by the Board and paid by NGTL. ~~The balance of intervenor costs are based on cost claims submitted to the Board for approval and may be adjusted once the claims are determined by the Board.~~

Projected 2004 costs are comprised of hearing costs associated with this Application, Phase 2 of NGTL's 2004 General Rate Application and the Generic Cost of Capital proceeding, with allowances made for other facilities or utilities proceedings that may arise in respect of the Alberta System and NGTL's participation in other proceedings.

NGTL is seeking approval of a Regulatory Hearing Costs Reserve Account commencing January 1, 2004, as described in Section 7 of this Application, Deferral and Reserve Accounts.

REGULATORY HEARING COSTS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 1 | EUB Levy | 938 | 1,404 | 1,404 |
| 2 | Intervenor Costs | 478 | 617 | 3,800 |
| 3 | External Hearing Costs | 325 | 3,360 | 630 |
| 4 | **Total Regulatory Hearing Costs** | 1,741 | 5,381 | 5,834 |

## 2.10 UNINSURED LOSSES

Schedule 2.10 shows the uninsured losses amount included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year.

NGTL uses a combination of insurance coverage and self-insurance to mitigate the financial impact of losses due to insurable incidents. The combination used is designed to minimize the total cost of such incidents to Alberta System customers. This is done by purchasing insurance coverage for losses that are potentially large in magnitude and for which economic coverage is available. NGTL also minimizes the overall premium cost of insurance by choosing appropriate deductible levels. Self-insurance is used for incidents for which it is uneconomic to purchase insurance given the level of potential exposure, e.g. collision damage to company vehicles.

When insurable incidents occur, the use of this combination of coverage methods results in NGTL incurring costs that are included in the uninsured losses component of the revenue requirement. These costs include:

- the deductible portion of insured losses under insurance policies;
- portions of insured claims not paid by the insurer, including expenses; and
- self-insured losses.

Actual uninsured losses in 2002 relate to four equipment failures, one station fire, one pipeline rupture and vehicle accidents. Actual uninsured losses in 2003 relate to four equipment failures, one break and enter, three pipeline ruptures and vehicle accidents. The ~~2003 forecast and~~ 2004 test year amount~~s~~ ~~are~~ is based on a long-term average of NGTL's historical experience for uninsured losses. The long-term annual average over ~~seven~~ eight years is just over $4 million. There are no material changes in coverage or risk levels that are expected to impact this amount in the test year.

UNINSURED LOSSES

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 1 | **Total Uninsured Losses** | 4,141 | 3,422 | 4,000 |

REVISED February 2004

## 2.11 PIPELINE INTEGRITY COSTS

Schedule 2.11 shows the Pipeline Integrity costs included in the revenue requirement for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year. Pipeline Integrity costs include both operating expenses and capital costs. The capital costs that are being recovered include the Alberta System's operating return, depreciation, and income and large corporation taxes. For 2002 and 2003, these costs are determined in accordance with the terms of the ASRS and the ASRRS, respectively. For 2004, operating return is calculated using the overall rate determined in Schedule 2.2.1. Depreciation expense for 2004 is based on the rates requested in Section 4 of this Application. Income and large corporation taxes for 2004 are calculated using the tax rates outlined in Section 2.5 of this Application.

Pipeline Integrity capital in service for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year is shown in Schedule 2.11.2. This schedule shows amounts ~~be~~ used in the calculation of the Pipeline Integrity capital cost recovery for each year. Pipeline Integrity capital is included in the Alberta System's total rate base, shown in Section 3.0 of this Application. As a result, the Pipeline Integrity capital costs being recovered are included in the amounts reported for Operating Return, Depreciation and Amortization, and Income and Large Corporation Taxes on Schedule 2.1.1. Thus, only the Pipeline Integrity expense indicated on Schedule 2.11 is separately identified on Schedule 2.1.1.

NGTL's achieved record of pipeline safety and service reliability is the direct result of a rigorous integrity management process. This process utilizes advanced inspection and mitigation technologies applied within the framework of a comprehensive risk-based methodology. Risk assessment is used to identify potential integrity threats and to initiate inspection/mitigation activities, while results from advanced inspections for known or suspected integrity threats are used to develop specific maintenance activities. The integrity management process provides the basis for developing the annual pipeline maintenance plan. Using this process, NGTL is able to achieve excellent levels of safety for all pipeline segments, regardless of pipeline vintage or method of construction. The integrity management process is similar to the International Standards Organization (ISO) model for quality assurance and is audited internally to ensure the program is followed and is effective.

NGTL's current pipeline maintenance plan benefits from knowledge gained through previous integrity programs. NGTL implemented a two year enhanced integrity program beginning in 1999 to act upon significant learnings from TCPL's experience with the Canadian Mainline. As information from these programs has been incorporated into the risk model, and confidence in the integrity of the Alberta System has increased, integrity programs have been adjusted to sustainable levels.

The pipeline integrity program consists of expense and capital spending required to maintain the physical integrity of the pipeline system, including the following programs:

> Cathodic Protection: The cathodic protection program addresses the risk of external corrosion on the pipeline. The program consists of annual monitoring of protection levels as well as associated mitigative actions when deficiencies are identified.

> Stress Corrosion Cracking (SCC): The SCC threat on the Alberta System is primarily addressed through the use of hydrotesting as well as investigative digs. Hydrotesting is necessary to ensure the integrity of specific pipeline sections. This technique will be complemented by the availability of an inline inspection tool to detect SCC. The primary focus of the investigative dig program is condition monitoring as well as model validation.

Valve Management: Valve management is focused on ensuring that pipeline isolation is possible in case of pipeline failure as well as during the course of pipeline integrity related work.

Corrosion (non-$CO_2$ service related): Activities, other than cathodic protection, undertaken to address the risk of external corrosion are included in this grouping. The primary activities in this grouping are inline inspection and corrosion excavations and repairs.

Geotechnical: The Geotechnical program has two primary components: monitoring and mitigation. Annual monitoring of high risk sites is conducted while in depth analysis of failed slopes is conducted to ensure that pipeline integrity is not compromised. The program also ensures that any pipe exposure issues are addressed.

Aerial Surveys: Aerial surveys of the Alberta System, in addition to the regular air patrol accounted for within operating costs, take place in order to supplement other programs. Additional surveys can allow for more immediate identification of integrity related concerns such as leaks, unauthorized crossings and geotechnical concerns resulting from weather and seasonal variations.

Mechanical Damage: This program has several components including maintaining up to date information regarding class locations across the pipeline system. Depths of cover, crossing and associated issues are also addressed through this program.

Research and Development (R&D): Numerous R&D projects directly associated with the pipeline integrity program are underway. The most notable in recent years has been the development of an inline inspection tool capable of detecting

SCC in gas pipelines. As this technology is implemented, savings are anticipated in the SCC component of the Pipeline Integrity program as more detailed information can be collected regarding the state of the pipeline. Further, there is the potential for replacing significant amounts of the hydrotesting program with this technology.

Other: Several smaller programs are included in this category, including the use of transfer compressors for work associated with pipeline integrity activities, maintenance of above ground crossings, and investigations of dents / sleeves if necessary.

The total 2004 Pipeline Integrity costs are forecast at ~~$11.6~~ $20.0 million, consisting of ~~$11.5~~$19.6 million in Pipeline Integrity expenses and ~~$0.2~~$0.4 million of Pipeline Integrity capital cost recovery related to a ~~$2.6~~ $5.5 million capital program. Pipeline Integrity costs in 2003 and 2002 were ~~$10.3~~$11.4 million and $12.4 million, respectively. 2002 costs included capital cost recovery related to the 2001 Pipeline Integrity capital program as provided for under the provisions of the ASRS.

Two line breaks occurred on the Western Alberta System Extension (WASE) in December 2003 resulting in an increase in Pipeline Integrity costs forecast for 2004. An increase in the number of repairs required for the WASE pipeline is forecast to cost an additional $1.6 million in Pipeline Integrity expense and an additional $1.2 million in Pipeline Integrity capital costs. Following the WASE line breaks, the corrosion program on the Alberta System was re-analyzed and additional work has been identified for 2004. The cost of this additional work is $6.5 million in Pipeline Integrity expense and $1.7 million in Pipeline Integrity capital costs.

~~The total~~Other significant components of the 2004 capital program consist~~s~~ ~~primarily~~ of cathodic-protection-related work~~, and~~ excavations and repairs based on inline inspection data, including the continuation of the Peace River Mainline Repair program. ~~The number of sites requiring capital repairs is expected to decrease in 2004 relative to 2003. The 2004 expense program is expected to increase relative to 2003.~~ Productivity gains in the cathodic protection program, planned reductions in SCC investigative digs and reduction in the number of sites requiring geotechnical remediation will be offset by an increase in corrosion-related spending. ~~Specifically, t~~ The Peace River Mainline program will continue in 2004 and will include ~~a~~ two hydrotests to confirm the pipeline integrity in specific locations. Further, ~~two~~ten inline inspections and the associated excavations are scheduled for 2004 compared to one in 2003. The cyclical nature of hydrostatic testing and inline inspection programs is the primary driver for variations in spending levels.

NGTL is seeking approval of a Pipeline Integrity deferral account commencing January 1, 2004 to capture differences between the forecast and actual 2004 amounts. Additional details on this deferral account are provided in Section 7 of this Application, Deferral and Reserve Accounts.

PIPELINE INTEGRITY COSTS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | Pipeline Integrity Expense | | 5,276 | 10,846 | 19,565 |
| 2 | Pipeline Integrity Capital Cost Recovery [1] | 2.11.1 | 7,146 | 538 | 414 |
| 3 | **Total Pipeline Integrity Costs** | | 12,422 | 11,384 | 19,979 |

[1] Costs have been included in the respective Revenue Requirement cost components (schedule 2.1.1).

PIPELINE INTEGRITY CAPITAL COST RECOVERY

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | BASE YEAR 2002 |
|---|---|---|---|
| | (a) | (b) | (c) |
| | **Pipeline Integrity Capital GPIS** | | |
| 1 | Pipeline Integrity Capital GPIS additions in year | 2.11.2 | 7,494 |
| 2 | Weighted Average Pipeline Integrity Capital GPIS | 2.11.2 | 49,781 |
| 3 | Weighted Average Pipeline Integrity Capital Net GPIS | 2.11.2 | 47,802 |
| | **Pipeline Integrity Capital Cost Recovery** | | |
| 4 | Operating Return (8.75% x Line 3) | | 4,184 |
| 5 | Depreciation (4.0% x Line 2) | 2.11.2 | 1,991 |
| 6 | Income and Large Corporation Taxes (Line 15) | | 971 |
| 7 | Pipeline Integrity Capital Cost Recovery | | 7,146 |
| | **Income and Large Corporation Taxes - Pipeline Integrity Capital** | | |
| 8 | Pipeline Integrity Capital Earnings | | 1,359 |
| 9 | Depreciation (Line 5 ) | | 1,991 |
| 10 | Capital cost allowance | 2.11.3 | (2,051) |
| 11 | Large corporation tax | | 80 |
| 12 | Taxable income | | 1,379 |
| 13 | Income taxes (Line 12 x 39.245%/(1-39.245%)) | | 891 |
| 14 | Large corporation tax | | 80 |
| 15 | Income and Large Corporation Taxes | | 971 |

PIPELINE INTEGRITY CAPITAL COST RECOVERY

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | ACTUAL YEAR 2003 |
|---|---|---|---|
| | (a) | (b) | (c) |
| | **Pipeline Integrity Capital GPIS** | | |
| 1 | Pipeline Integrity Capital GPIS additions in year | 2.11.2 | 4,596 |
| 2 | Weighted Average Pipeline Integrity Capital GPIS | 2.11.2 | 3,498 |
| 3 | Weighted Average Pipeline Integrity Capital Net GPIS | 2.11.2 | 3,440 |
| | **Pipeline Integrity Capital Cost Recovery** | | |
| 4 | Operating Return (8.65% x Line 3) | | 298 |
| 5 | Depreciation (4.0% x Line 2) | 2.11.2 | 140 |
| 6 | Income and Large Corporation Taxes (Line 15) | | 100 |
| 7 | Pipeline Integrity Capital Cost Recovery | | 538 |
| | **Income and Large Corporation Taxes - Pipeline Integrity Capital** | | |
| 8 | Pipeline Integrity Capital Earnings | | 108 |
| 9 | Depreciation (Line 5 ) | | 140 |
| 10 | Capital cost allowance | 2.11.3 | (95) |
| 11 | Large corporation tax | | 7 |
| 12 | Taxable income | | 160 |
| 13 | Income taxes (Line 12 x 36.745%/(1-36.745%)) | | 93 |
| 14 | Large corporation tax | | 7 |
| 15 | Income and Large Corporation Taxes | | 100 |

PIPELINE INTEGRITY CAPITAL COST RECOVERY

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | TEST YEAR 2004 |
|---|---|---|---|
| | (a) | (b) | (c) |
| | **Pipeline Integrity Capital GPIS** | | |
| 1 | Pipeline Integrity Capital GPIS additions in year | 2.11.2 | 5,520 |
| 2 | Weighted Average Pipeline Integrity Capital GPIS | 2.11.2 | 2,912 |
| 3 | Weighted Average Pipeline Integrity Capital Net GPIS | 2.11.2 | 2,885 |
| | **Pipeline Integrity Capital Cost Recovery** | | |
| 4 | Operating Return (9.38% x Line 3) | | 271 |
| 5 | Depreciation | 2.11.2 | 80 |
| 6 | Income and Large Corporation Taxes (Line 15) | | 64 |
| 7 | Pipeline Integrity Capital Cost Recovery | | 414 |
| | **Income and Large Corporation Taxes - Pipeline Integrity Capital** | | |
| 8 | Pipeline Integrity Capital Earnings | | 127 |
| 9 | Depreciation (Line 5 ) | | 80 |
| 10 | Capital cost allowance | 2.11.3 | (109) |
| 11 | Cumulative Eligible Capital | 2.11.3 | (3) |
| 12 | Large corporation tax | | 9 |
| 13 | Taxable income | | 103 |
| 14 | Income taxes (Line 12 x 34.62%/(1-34.62%)) | | 55 |
| 15 | Large corporation tax | | 9 |
| 16 | Income and Large Corporation Taxes | | 64 |

CAPITAL PIPELINE INTEGRITY RATE BASE SUMMARY[1]

FOR THE BASE YEAR ENDING DECEMBER 31, 2002
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) |
| 1 | Opening Gas Plant In Service | | 47,924 | 47,961 | 46,894 | 49,361 | 49,488 | 49,595 | 49,629 | 50,018 | 50,072 | 50,117 | 50,337 | 50,342 | | |
| 2 | Additions | | 37 | (1,067) | 2,467 | 127 | 107 | 34 | 388 | 55 | 45 | 220 | 5 | 5,076 | | 7,494 |
| 3 | Gas Plant In Service | 47,924 | 47,961 | 46,894 | 49,361 | 49,488 | 49,595 | 49,629 | 50,018 | 50,072 | 50,117 | 50,337 | 50,342 | 55,418 | 49,781 | |
| 4 | Opening Accumulated Depreciation | | 987 | 1,151 | 1,316 | 1,478 | 1,644 | 1,810 | 1,977 | 2,143 | 2,310 | 2,477 | 2,644 | 2,811 | | |
| 5 | Depreciation Expense | | 164 | 164 | 163 | 166 | 166 | 166 | 166 | 167 | 167 | 167 | 167 | 167 | | 1,991 |
| 6 | Accumulated Depreciation | 987 | 1,151 | 1,316 | 1,478 | 1,644 | 1,810 | 1,977 | 2,143 | 2,310 | 2,477 | 2,644 | 2,811 | 2,979 | 1,979 | |
| 7 | Net Gas Plant In Service | 46,937 | 46,810 | 45,578 | 47,883 | 47,844 | 47,785 | 47,653 | 47,874 | 47,762 | 47,640 | 47,693 | 47,531 | 52,440 | 47,802 | |

[1] Included in Rate Base Summary (Schedule 3.1)

CAPITAL PIPELINE INTEGRITY RATE BASE SUMMARY[1]

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) |
| 1 | Opening Gas Plant In Service | | - | 1,615 | 1,981 | 2,072 | 4,898 | 4,443 | 4,770 | 4,023 | 4,158 | 4,150 | 4,234 | 4,529 | | |
| 2 | Additions | | 1,615 | 366 | 92 | 2,826 | (455) | 327 | (747) | 135 | (8) | 84 | 295 | 68 | | 4,596 |
| 3 | Gas Plant In Service | - | 1,615 | 1,981 | 2,072 | 4,898 | 4,443 | 4,770 | 4,023 | 4,158 | 4,150 | 4,234 | 4,529 | 4,596 | 3,498 | |
| 4 | Opening Accumulated Depreciation | | - | - | 6 | 12 | 19 | 36 | 51 | 68 | 81 | 96 | 110 | 124 | | |
| 5 | Depreciation Expense | | - | 6 | 7 | 7 | 17 | 15 | 16 | 14 | 14 | 14 | 14 | 16 | | 140 |
| 6 | Accumulated Depreciation | - | - | 6 | 12 | 19 | 36 | 51 | 68 | 81 | 96 | 110 | 124 | 140 | 57 | |
| 7 | Net Gas Plant In Service | - | 1,615 | 1,975 | 2,060 | 4,879 | 4,407 | 4,718 | 3,956 | 4,077 | 4,055 | 4,124 | 4,404 | 4,457 | 3,440 | |

[1] Included in Rate Base Summary (Schedule 3.1)

CAPITAL PIPELINE INTEGRITY RATE BASE SUMMARY[1]

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) |
| 1 | Opening Gas Plant In Service | | - | 432 | 720 | 1,001 | 2,414 | 2,821 | 3,261 | 3,755 | 3,884 | 4,448 | 4,660 | 4,944 | | |
| 2 | Additions | | 432 | 288 | 281 | 1,413 | 407 | 440 | 494 | 129 | 564 | 212 | 284 | 576 | | 5,520 |
| 3 | Gas Plant In Service | - | 432 | 720 | 1,001 | 2,414 | 2,821 | 3,261 | 3,755 | 3,884 | 4,448 | 4,660 | 4,944 | 5,520 | 2,912 | |
| 4 | Opening Accumulated Depreciation | | - | - | 1 | 3 | 5 | 11 | 18 | 26 | 35 | 45 | 56 | 67 | | |
| 5 | Depreciation Expense | | - | 1 | 2 | 2 | 6 | 7 | 8 | 9 | 10 | 11 | 11 | 12 | | 80 |
| 6 | Accumulated Depreciation | - | - | 1 | 3 | 5 | 11 | 18 | 26 | 35 | 45 | 56 | 67 | 80 | 27 | |
| 7 | Net Gas Plant In Service | - | 432 | 719 | 998 | 2,409 | 2,810 | 3,243 | 3,729 | 3,849 | 4,403 | 4,604 | 4,877 | 5,440 | 2,885 | |

[1] Included in Rate Base Summary (Schedule 3.1)

CAPITAL PIPELINE INTEGRITY CAPITAL COST ALLOWANCE AND CUMULATIVE ELIGIBLE CAPITAL [1]

FOR THE BASE YEAR ENDING DECEMBER 31, 2002
($Thousands)

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2002 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2002 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | 42,811 | - | 9,184 | - | 51,995 | 9,184 | 4,592 | 47,403 | 4% | 1,896 | 50,099 |
| 2 | 02 | - | - | - | - | - | - | - | - | 6% | - | - |
| 3 | 03 | - | - | - | - | - | - | - | - | 5% | - | - |
| 4 | 06 | - | - | - | - | - | - | - | - | 10% | - | - |
| 5 | 08 | 2,771 | - | (2,012) | - | 758 | - | - | 758 | 20% | 152 | 606 |
| 6 | 09 | - | - | - | - | - | - | - | - | 25% | - | - |
| 7 | 10 | - | - | - | - | - | - | - | - | 30% | - | - |
| 8 | 12 | - | - | - | - | - | - | - | - | 100% | - | - |
| 9 | 13 | - | - | - | - | - | - | - | - | S/L | - | - |
| 10 | 17 | 39 | - | - | - | 39 | - | - | 39 | 8% | 3 | 36 |
| 11 | | 45,621 | - | 7,171 | - | 52,792 | 9,184 | 4,592 | 48,200 | | 2,051 | 50,741 |

| | | |
|---|---|---|
| In-Service Additions | Total | 7,494 |
| | AFUDC | (323) |
| | | 7,171 |

**Cumulative Eligible Capital**

| LINE NO. | OPENING BALANCE | COST OF ADDITIONS | EXCLUDE 25 % OF ADDITIONS | ELIGIBLE BALANCE | RATE | CEC DEDUCTION | CLOSING BALANCE |
|---|---|---|---|---|---|---|---|
| 12 | 4 | - | - | 4 | 7% | - | 4 |

[1] Included in CCA schedule 2.5.3

CAPITAL PIPELINE INTEGRITY CAPITAL COST ALLOWANCE AND CUMULATIVE ELIGIBLE CAPITAL [1]

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2003 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2003 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | - | - | 4,444 | - | 4,444 | 4,444 | 2,222 | 2,222 | 4% | 89 | 4,355 |
| 2 | 02 | - | - | - | - | - | - | - | - | 6% | - | - |
| 3 | 03 | - | - | - | - | - | - | - | - | 5% | - | - |
| 4 | 06 | - | - | - | - | - | - | - | - | 10% | - | - |
| 5 | 08 | - | - | 60 | - | 60 | 60 | 30 | 30 | 20% | 6 | 54 |
| 6 | 09 | - | - | - | - | - | - | - | - | 25% | - | - |
| 7 | 10 | - | - | - | - | - | - | - | - | 30% | - | - |
| 8 | 12 | - | - | - | - | - | - | - | - | 100% | - | - |
| 9 | 13 | - | - | - | - | - | - | - | - | S/L | - | - |
| 10 | 17 | - | - | - | - | - | - | - | - | 8% | - | - |
| 11 | | - | - | 4,504 | - | 4,504 | 4,504 | 2,252 | 2,252 | | 95 | 4,409 |

| | | |
|---|---|---|
| In-Service Additions | Total | 4,596 |
| | AFUDC | (92) |
| | | 4,504 |

**Cumulative Eligible Capital**

| LINE NO. | OPENING BALANCE | COST OF ADDITIONS | EXCLUDE 25 % OF ADDITIONS | ELIGIBLE BALANCE | RATE | CEC DEDUCTION | CLOSING BALANCE |
|---|---|---|---|---|---|---|---|
| 12 | - | - | - | - | 7% | - | - |

[1] Included in CCA schedule 2.5.3

CAPITAL PIPELINE INTEGRITY CAPITAL COST ALLOWANCE AND CUMULATIVE ELIGIBLE CAPITAL [1]

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2004 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2004 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | - | - | 5,254 | - | 5,254 | 5,254 | 2,627 | 2,627 | 4% | 105 | 5,149 |
| 2 | 02 | - | - | - | - | - | - | - | - | 6% | - | - |
| 3 | 03 | - | - | - | - | - | - | - | - | 5% | - | - |
| 4 | 06 | - | - | - | - | - | - | - | - | 10% | - | - |
| 5 | 08 | - | - | - | - | - | - | - | - | 20% | - | - |
| 6 | 09 | - | - | - | - | - | - | - | - | 25% | - | - |
| 7 | 10 | - | - | - | - | - | - | - | - | 30% | - | - |
| 8 | 12 | - | - | - | - | - | - | - | - | 100% | - | - |
| 9 | 13 | - | - | - | - | - | - | - | - | S/L | - | - |
| 10 | 17 | - | - | 108 | - | 108 | 108 | 54 | 54 | 8% | 4 | 104 |
| 11 | | - | - | 5,362 | - | 5,362 | 5,362 | 2,681 | 2,681 | | 109 | 5,253 |

| | | |
|---|---|---|
| In-Service Additions | Total | 5,520 |
| | AFUDC | (104) |
| | CEC | (54) |
| | | 5,362 |

**Cumulative Eligible Capital**

| LINE NO. | OPENING BALANCE | COST OF ADDITIONS | EXCLUDE 25 % OF ADDITIONS | ELIGIBLE BALANCE | RATE | CEC DEDUCTION | CLOSING BALANCE |
|---|---|---|---|---|---|---|---|
| 12 | - | 54 | 14 | 41 | 7% | 3 | 38 |

[1] Included in CCA schedule 2.5.3

## 2.12 $CO_2$ MANAGEMENT SERVICE COSTS

Schedule 2.12 summarizes the costs associated with providing the $CO_2$ Management Service ($CO_2$ Service) for the 2003 ~~forecast~~ actual year and the 2004 test year.

The Board approved the $CO_2$ Service and the related tariff amendments in Decision 2002-084, dated September 24, 2002, and provision of the $CO_2$ Service commenced in 2003. The terms of the $CO_2$ Service allow NGTL to recover the costs of providing this service from the parties that utilize it. In addition, NGTL is allowed to retain 10% of any excess revenue generated by providing the $CO_2$ Service, to a maximum of $500,000. The remaining excess revenue is credited against the Alberta System's general revenue requirement. The $CO_2$ Service costs include both expenses and capital costs, and explanations and details of each follow.

**$CO_2$ Service Expenses**

$CO_2$ Service expenses consist of the costs charged to NGTL by gas plant owners to remove $CO_2$, and NGTL's own expenses in providing the service, including expenses for management, invoicing, field maintenance, and overhead allocations.

As part of the $CO_2$ Service, NGTL has supplemented its current integrity management practices with additional measures to ensure the pipeline integrity of the Alberta System is not adversely affected by the acceptance of gas with $CO_2$ concentrations in excess of 2%. In 2004, the highest risk sections of pipeline will be monitored for corrosion using in-line inspection and ultrasonic testing, the latter requiring the excavation of pipeline.

The test year 2004 forecast of $CO_2$ Service expenses is $2.7 million, compared to ~~$5.1~~ $4.4 million for ~~the forecast year~~ 2003, a decrease of ~~$2.4~~$1.7 million. This decrease is predominantly due to an expected drop in the costs charged by gas plant owners to remove $CO_2$ to meet the requirements of the service in 2004.

**$CO_2$ Service Capital Cost Recovery**

Schedule 2.12.1, sheets 1-2, provides details of the $CO_2$ Service capital cost recovery for the 2003 ~~forecast~~ actual year and the 2004 test year. The capital costs to be recovered include the Alberta System's operating return, depreciation, and income and large corporation taxes. For 2003, these costs are determined in accordance with the terms of the ASRRS. For 2004, operating return is calculated using the overall rate determined in Schedule 2.2.1. Depreciation expense for 2004 is based on the rates requested in section 4 of this Application. Income and large corporation taxes for 2004 are calculated using the tax rates outlined in Section 2.5 of this Application.

The 2004 test year $CO_2$ Service capital cost recovery is ~~$139,000~~ $145,000, as compared to ~~$45,000~~$38,000 for ~~the~~ 2003.~~ forecast year.~~ These amounts are based on the $CO_2$ Service capital gas plant in service (GPIS) for each year. Schedule 2.12.2 shows the monthly $CO_2$ Service GPIS for the 2003 ~~forecast~~ actual year and the 2004 test year. In 2003, the $CO_2$ Service GPIS resulted from ~~$1.5~~ $1.6 million in spending for the installation of required water and $CO_2$ analysers. In 2004, $CO_2$ Service GPIS additions are forecast to be $0.4 million. This includes the installation of scraper traps on the Liege Lateral ($0.25 million) and the installation of water analysers where required.

NGTL seeks approval in this Application of a $CO_2$ Management Service deferral account, which would capture the difference between the revenue collected for this service and the costs associated with providing this service, including NGTL's share of excess revenue. Additional details on this deferral account are provided in Section 7, Deferral and Reserve Accounts.

$CO_2$ MANAGEMENT SERVICE COSTS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | $CO_2$ Management Service Expenses | | N/A | 4,420 | 2,707 |
| 2 | $CO_2$ Management Service Capital Cost Recovery | 2.12.1 | N/A | 38 | 145 |
| 3 | **Total $CO_2$ Management Service Costs** | | N/A | 4,458 | 2,852 |

$CO_2$ MANAGEMENT SERVICE CAPITAL COST RECOVERY

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | ACTUAL YEAR 2003 |
|---|---|---|---|
| | (a) | (b) | (c) |
| | **$CO_2$ Management Service Capital GPIS** | | |
| 1 | $CO_2$ Management Service GPIS additions in year | 2.12.2 | 1,574 |
| 2 | Weighted Average $CO_2$ Management Service Capital GPIS | 2.12.2 | 716 |
| 3 | Weighted Average $CO_2$ Management Service Capital Net GPIS | 2.12.2 | 708 |
| | **$CO_2$ Management Service Capital Cost Recovery** | | |
| 4 | Operating Return (8.65% x Line 3) | | 61 |
| 5 | Depreciation (4.0% x Line 2) | 2.12.2 | 29 |
| 6 | Income and Large Corporation Taxes (Line 15) | | (52) |
| 7 | $CO_2$ Management Service Capital Cost Recovery | | 38 |
| | **Income and Large Corporation Taxes - $CO_2$ Management Service Capital** | | |
| 8 | $CO_2$ Management Service Capital Earnings | | 22 |
| 9 | Depreciation (Line 5 ) | | 29 |
| 10 | Capital cost allowance | 2.12.3 | (155) |
| 11 | Large corporation tax | | 5 |
| 12 | Taxable income | | (99) |
| 13 | Income taxes (Line 12 x 36.745%/(1-36.745%) | | (57) |
| 14 | Large corporation tax | | 5 |
| 15 | Income and Large Corporation Taxes | | (52) |

$CO_2$ MANAGEMENT SERVICE CAPITAL COST RECOVERY

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | REF. SCHEDULE | TEST YEAR 2004 |
|---|---|---|---|
| | (a) | (b) | (c) |
| | **$CO_2$ Management Service Capital GPIS** | | |
| 1 | $CO_2$ Management Service GPIS additions in year | 2.12.2 | 380 |
| 2 | Weighted Average $CO_2$ Management Service Capital GPIS | 2.12.2 | 1,757 |
| 3 | Weighted Average $CO_2$ Management Service Capital Net GPIS | 2.12.2 | 1,695 |
| | **$CO_2$ Management Service Capital Cost Recovery** | | |
| 4 | Operating Return (9.38% x Line 3) | | 159 |
| 5 | Depreciation | 2.12.2 | 68 |
| 6 | Income and Large Corporation Taxes (Line 15) | | (81) |
| 7 | $CO_2$ Management Service Capital Cost Recovery | | 145 |
| | **Income and Large Corporation Taxes - $CO_2$ Management Service Capital** | | |
| 8 | $CO_2$ Management Service Capital Earnings | | 75 |
| 9 | Depreciation (Line 5 ) | | 68 |
| 10 | Capital cost allowance | 2.12.3 | (315) |
| 11 | Large corporation tax | | 7 |
| 12 | Taxable income | | (166) |
| 13 | Income taxes (Line 12 x 34.62%/(1-34.62%) | | (88) |
| 14 | Large corporation tax | | 7 |
| 15 | Income and Large Corporation Taxes | | (81) |

CO2 MANAGEMENT SERVICE RATE BASE SUMMARY

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) |
| 1 | Opening Gas Plant In Service | | - | - | - | - | - | 405 | 947 | 975 | 1,183 | 1,273 | 1,465 | 1,484 | | |
| 2 | Additions | | - | - | - | - | 405 | 542 | 28 | 209 | 89 | 192 | 20 | 90 | | 1,574 |
| 3 | Gas Plant In Service | - | - | - | - | - | 405 | 947 | 975 | 1,183 | 1,273 | 1,465 | 1,484 | 1,574 | 716 | |
| 4 | Opening Accumulated Depreciation | | - | - | - | - | - | - | 1 | 5 | 9 | 13 | 18 | 23 | | |
| 5 | Depreciation Expense | | - | - | - | - | - | 1 | 4 | 4 | 4 | 5 | 5 | 5 | | 29 |
| 6 | Accumulated Depreciation | - | - | - | - | - | - | 1 | 5 | 9 | 13 | 18 | 23 | 29 | 8 | |
| 7 | Net Gas Plant In Service | - | - | - | - | - | 405 | 945 | 970 | 1,175 | 1,260 | 1,447 | 1,461 | 1,546 | 708 | |

CO2 MANAGEMENT SERVICE RATE BASE SUMMARY

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | June 30 | July 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | 13 MONTH AVERAGE | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) |
| 1 | Opening Gas Plant In Service | | 1,574 | 1,631 | 1,673 | 1,714 | 1,718 | 1,730 | 1,746 | 1,766 | 1,786 | 1,816 | 1,846 | 1,885 | | |
| 2 | Additions | | 57 | 42 | 41 | 4 | 12 | 16 | 20 | 20 | 30 | 30 | 39 | 69 | | 380 |
| 3 | Gas Plant In Service | 1,574 | 1,631 | 1,673 | 1,714 | 1,718 | 1,730 | 1,746 | 1,766 | 1,786 | 1,816 | 1,846 | 1,885 | 1,954 | 1,757 | |
| 4 | Opening Accumulated Depreciation | | 29 | 34 | 40 | 45 | 51 | 56 | 62 | 67 | 73 | 79 | 85 | 91 | | |
| 5 | Depreciation Expense | | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 6 | | 68 |
| 6 | Accumulated Depreciation | 29 | 34 | 40 | 45 | 51 | 56 | 62 | 67 | 73 | 79 | 85 | 91 | 97 | 62 | |
| 7 | Net Gas Plant In Service | 1,546 | 1,597 | 1,634 | 1,669 | 1,668 | 1,674 | 1,685 | 1,699 | 1,713 | 1,737 | 1,761 | 1,794 | 1,858 | 1,695 | |

$CO_2$ MANAGEMENT CAPITAL COST ALLOWANCE

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

**Capital Cost Allowance**

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2003 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2003 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | - | - | 8 | - | 8 | 8 | 4 | 4 | 4% | - | 8 |
| 2 | 02 | - | - | - | - | - | - | - | - | 6% | - | - |
| 3 | 03 | - | - | - | - | - | - | - | - | 5% | - | - |
| 4 | 06 | - | - | - | - | - | - | - | - | 10% | - | - |
| 5 | 08 | - | - | 1,545 | - | 1,545 | 1,545 | 772 | 772 | 20% | 155 | 1,389 |
| 6 | 09 | - | - | - | - | - | - | - | - | 25% | - | - |
| 7 | 10 | - | - | - | - | - | - | - | - | 30% | - | - |
| 8 | 12 | - | - | - | - | - | - | - | - | 100% | - | - |
| 9 | 13 | - | - | - | - | - | - | - | - | S/L | - | - |
| 10 | 17 | - | - | - | - | - | - | - | - | 8% | - | - |
| 11 | | - | - | 1,552 | - | 1,552 | 1,552 | 776 | 776 | | 155 | 1,397 |

| | | |
|---|---|---|
| In-Service Additions | Total | 1,574 |
| | AFUDC | (22) |
| | | 1,552 |

$CO_2$ MANAGEMENT SERVICE CAPITAL COST ALLOWANCE

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

**Capital Cost Allowance**

| LINE NO. | CCA CLASS | UCC BALANCE JAN. 1, 2004 | ADJUSTMENTS TO OPENING BALANCE | COST OF ADDITIONS | NET SALVAGE | UCC BEFORE DEFERRED CAPITAL COST | EXCESS | CAPITAL COST DEFERRED | UCC BEFORE CCA | MAX RATE | CAPITAL COST ALLOWANCE | UCC BALANCE DEC. 31, 2004 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| 1 | 01 | 8 | - | - | - | 8 | - | - | 8 | 4% | 0 | 7 |
| 2 | 02 | - | - | - | - | - | - | - | - | 6% | - | - |
| 3 | 03 | - | - | - | - | - | - | - | - | 5% | - | - |
| 4 | 06 | - | - | - | - | - | - | - | - | 10% | - | - |
| 5 | 08 | 1,389 | - | 370 | - | 1,760 | 370 | 185 | 1,574 | 20% | 315 | 1,445 |
| 6 | 09 | - | - | - | - | - | - | - | - | 25% | - | - |
| 7 | 10 | - | - | - | - | - | - | - | - | 30% | - | - |
| 8 | 12 | - | - | - | - | - | - | - | - | 100% | - | - |
| 9 | 13 | - | - | - | - | - | - | - | - | S/L | - | - |
| 10 | 17 | - | - | - | - | - | - | - | - | 8% | - | - |
| 11 | | 1,397 | - | 370 | - | 1,767 | 370 | 185 | 1,582 | | 315 | 1,452 |

| | | |
|---|---|---|
| In-Service Additions | Total | 380 |
| | AFUDC | (10) |
| | | 370 |

# 2.13 REVENUE REQUIREMENT ADJUSTMENTS AND NON-ROUTINE ADJUSTMENTS

During the terms of the ASRS and the ASRRS, the majority of the Alberta System's revenue requirement each year was fixed at a negotiated amount. Generally, variances in costs under these fixed revenue requirements were to the account of NGTL's shareholder. There were, however, exceptions. The negotiated revenue requirements included estimates of costs that were not "at risk" and were subject to Non-Routine Adjustment in subsequent years' revenue requirements. In addition, there were estimates of costs included in Non-Routine Adjustments each year, which were combined with the negotiated revenue requirements to arrive at total revenue requirements.

The revenue requirement adjustments line on Schedule 2.1.1 represents, for the costs that are not "at risk," the difference between the forecast of these costs included in the negotiated revenue requirement and the actual costs reported in Schedule 2.1.1. In cases where a forecast of a cost is included in Non-Routine Adjustments for a given year (not in the negotiated revenue requirement), and an actual amount for that cost is reported in lines 1 through 12 of Schedule 2.1.1, the entire amount of that actual cost is offset by a credit in the revenue requirement adjustments line for that same year.

For a cost that is not "at risk" in a given year, any variance from the forecast that is included in the total revenue requirement for that year is generally included in Non-Routine Adjustments in the following year's total revenue requirement, along with the associated carrying charges.

## 2.13.1 Revenue Requirement Adjustments

Schedule 2.13.1 shows the revenue requirement adjustment amounts included in the revenue requirements for the 2002 base year and the 2003 ~~forecast~~ actual year. These are miscellaneous adjustment amounts that were included in arriving at the negotiated revenue requirements of $1,347 million and $1,277 million for 2002 and 2003, respectively. The following are brief descriptions of each of the items appearing on Schedule 2.13.1.

**Pipeline Integrity Variance:** The ASRS negotiated revenue requirement for 2002 included an estimate of $35 million for pipeline integrity costs, including expenses and capital-related costs. The variance from this estimated amount was deferred and included in the Non-Routine Adjustment to be disposed of in 2003. This variance is also included in the revenue requirement adjustments for 2002 to reconcile to the negotiated revenue requirement for that year.

Similarly, the ASRRS negotiated revenue requirement of $1,277 million includes an estimate of $11.3 million for pipeline integrity expenses and $258,000 for pipeline integrity capital-related costs. Variances from these estimated amounts ~~will be~~have been deferred and included in the Non-Routine Adjustment to be disposed of in 2004. This variance is also included in the ~~forecasted~~ revenue requirement adjustments for 2003 to reconcile to the negotiated revenue requirement for that year.

**Capital-Related Severance Costs:** Under the terms of the ASRS, severance costs associated with any individual whose time was directly charged to capital projects was to be amortized over the period commencing the first day of the month following the termination date for such employee and ending December 31, 2004. The amortization of these costs is treated as a Non-Routine Adjustment and added to the total revenue requirement. The 2002 amortization has been included in actual costs for 2002, and therefore a credit for the amortization amount must be included in the revenue requirement adjustment to reconcile to the negotiated revenue requirement for each year.

**Fort McMurray:** Under the ASRS, 2002 costs related to delivery service provided to the Fort McMurray area are treated as a Non-Routine Adjustment and added to the total revenue requirement. These costs are included in the actual costs for 2002. Therefore, a credit for the amount of these costs must be included in the revenue requirement adjustment to reconcile to the negotiated revenue requirement for 2002.

**Revenue requirement adjustment for 2000 actual O&M costs:** The ASRS negotiated revenue requirement of $1,347 million for 2002 was based on a forecast of 2000 operating costs. A provision was included to adjust the 2002 revenue requirement by the difference between the forecasted 2000 operating costs and the actual 2000 operating costs. This difference, which resulted in a reduction of $4,481,000 in the 2002 revenue requirement, is included in the revenue requirement adjustments for 2002 to reconcile to the negotiated revenue requirement for that year.

**Capacity Capital:** The ASRRS negotiated revenue requirement of $1,277 million included an estimate of $887,000 for costs related to capacity capital additions and retirements during 2003. The variance from this estimated amount ~~will be~~has been deferred and included in the Non-Routine Adjustment to be disposed of in 2004. As such, the variance between this estimate and the ~~current forecast of~~actual costs related to 2003 capacity capital additions and retirements is included in the revenue requirement adjustments.

**$CO_2$ Service costs:** The ASRRS negotiated revenue requirement of $1,277 million did not include any costs related to providing the $CO_2$ Service. Instead, an estimate of these costs was added to the negotiated revenue requirement in calculating the Total Revenue Requirement for 2003. However, ~~the forecasted costs included on Line 10 of Schedule 2.1.1 for 2003 include~~ ~~an updated forecast of the~~the actual costs of providing this service in 2003 are included on Line 11 of Schedule 2.1.1. The $CO_2$ Service costs are a flow-through item under the terms of the ASRRS, adjusted for NGTL's share of excess revenue generated by this service. Thus, a credit for the actual costs, net of NGTL's share of excess revenue, is included in the revenue requirement adjustments.

**Customer Share of O&M savings:** The ASRRS included a provision that, in the event actual 2003 Operating Costs were below $203 million, the difference between $203 million and the actual 2003 Operating Costs would be shared between NGTL and its customers. Actual 2003 Operating Costs were $197.896 million, so $5.104 million of savings is being shared equally between NGTL and its customers. The customers' share of the savings, $2.552 million, must be included in the revenue requirement adjustment to reconcile to the negotiated revenue requirement for 2003.

### 2.13.2 Non-Routine Adjustments

Schedule 2.13.2 shows the Non-Routine Adjustments included in the revenue requirements for the 2002 base year, the 2003 ~~forecast~~ actual year, and the 2004 test year.

These amounts reflect the refund or collection in the current year of Non-Routine Adjustments created in the prior year plus applicable carrying charges as defined in Article 4.1 of the 2001/2002 ASRS or in Article 5.1 of the 2003 ASRRS, as applicable. Further details supporting these amounts for 2002 and 2003 are provided in the ASRS reporting packages for 2001 and 2002, respectively.

~~NGTL is currently estimating a~~The 2003 Non-Routine Adjustment ~~of~~ is $33~~0~~ million, to be included in the 2004 revenue requirement. This primarily reflects ~~an anticipated~~a shortfall in revenue collected during 2003 due to lower than forecast contracted volumes. Details supporting the final amount~~s~~ of the Non-Routine Adjustment to be included in 2004 will be provided in the ASRRS reporting package.

### 2.13.3 Severance Costs

Schedule 2.13.3 shows the deferral and amortization of severance costs for the base year 2002, the ~~forecast~~ actual year 2003, and the test year 2004. The deferral and amortization of severance costs is calculated in accordance with Article 9.3 of the ASRS for those costs related to employees terminated during 2001 and 2002, and in accordance with Article 9 of the ASRRS for those costs related to employees terminated during 2003.

The severance amounts being amortized each month under the terms of the ASRS include amounts that terminated employees elected to contribute to their pension plan in lieu of a cash payment. However, the actual severance costs accumulated in these accounts only include cash payments made to terminated employees. Thus, the balance in the ASRS severance deferral accounts reaches zero prior to the time when the amortization is actually complete. Once the balance in each account reaches zero, the amortization of the severance costs, which is the amount that NGTL is collecting through its tolls, is credited to the Prefunded/(Unfunded) Pension and OPEB Liability account. See Section 3.11 for further details on this account.

REVENUE REQUIREMENT ADJUSTMENTS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
AND THE ACTUAL YEAR ENDED DECEMBER 31, 2003.
($Thousands)

| LINE NO. | DESCRIPTION | BASE YEAR 2002 | ACTUAL YEAR 2003 |
|---|---|---|---|
| | (a) | (b) | (c) |
| 1 | Pipeline Integrity Variance | 22,578 | 175 |
| 2 | Capital Related Severance Costs | (811) | - |
| 3 | Fort McMurray | (4,748) | - |
| 4 | Revenue Requirement adjustment for 2000 actual O&M costs | 4,481 | - |
| 5 | Capacity Capital | - | 671 |
| 6 | $CO_2$ Management Service Costs | - | (4,458) |
| 7 | Customer Share of O&M Savings | - | 2,552 |
| 8 | **Total Revenue Requirement Adjustments** | 21,500 | (1,060) |

NON-ROUTINE ADJUSTMENTS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002,
THE ACTUAL YEAR ENDED DECEMBER 31, 2003,
AND THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | BASE YEAR 2002 | ACTUAL YEAR 2003 | TEST YEAR 2004 |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| 1 | Firm Service Demand Revenue Deferral Account | (20,344) | 2,271 | 4,853 |
| 2 | Throughput volume Revenue Deferral Account | (32,516) | (5,120) | 31,304 |
| 3 | Merger Agreement Variance | (16,333) | - | - |
| 4 | Pipeline Integrity Deferral | (14,811) | (24,480) | (202) |
| 5 | Capacity Capital Deferral | - | - | (751) |
| 6 | Capital Related Severance Costs | 1,309 | - | - |
| 7 | Audit Costs | 164 | 17 | 73 |
| 8 | Fort McMurray Costs | 4,406 | 319 | - |
| 9 | Tax Rate Variance | - | 5,103 | - |
| 10 | Adjustment to Annual Foreign Exchange Amortization Amount | - | (90) | - |
| 11 | $CO_2$ Management Service | - | - | 103 |
| 12 | Customer Share of O&M Savings | - | - | (2,791) |
| 13 | **Total Non-Routine Adjustments** | (78,125) | (21,980) | 32,590 |

SEVERANCE COSTS

FOR THE BASE YEAR ENDED DECEMBER 31, 2002
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | Jun 30 | Jul 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| 1 | **OPERATING** | | | | | | | | | | | | | | |
| 2 | Opening Balance | | 4,827 | 7,618 | 8,553 | 8,632 | 8,577 | 8,627 | 9,065 | 9,190 | 9,060 | 8,672 | 8,297 | 8,361 | |
| 3 | Severance Costs - Actual | | 3,274 | 1,273 | 418 | 289 | 407 | 828 | 533 | 287 | 29 | 42 | 524 | 4 | 7,908 |
| 4 | Amortization | | (483) | (338) | (339) | (344) | (357) | (390) | (408) | (417) | (417) | (417) | (460) | (476) | (4,846) |
| 5 | Total Unamortized Severance Costs - Operating | 4,827 | 7,618 | 8,553 | 8,632 | 8,577 | 8,627 | 9,065 | 9,190 | 9,060 | 8,672 | 8,297 | 8,361 | 7,889 | |
| 6 | **CAPITAL** | | | | | | | | | | | | | | |
| 7 | Opening Balance | | 1,183 | 1,638 | 1,639 | 1,642 | 1,575 | 1,508 | 1,516 | 1,473 | 1,408 | 1,362 | 1,297 | 1,228 | |
| 8 | Severance Costs - Actual | | 522 | 68 | 70 | - | - | 75 | 24 | 3 | 22 | 3 | - | 2 | 789 |
| 9 | Amortization | | (67) | (67) | (67) | (67) | (67) | (67) | (68) | (68) | (68) | (69) | (69) | (69) | (811) |
| 10 | Total Unamortized Capital-related Severance Costs | 1,183 | 1,638 | 1,639 | 1,642 | 1,575 | 1,508 | 1,516 | 1,473 | 1,408 | 1,362 | 1,297 | 1,228 | 1,161 | |
| 11 | **TOTAL AMORTIZATION** | | | | | | | | | | | | | | **(5,657)** |

SEVERANCE COSTS

FOR THE ACTUAL YEAR ENDED DECEMBER 31, 2003
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | Jun 30 | Jul 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| 1 | **OPERATING (2001 and 2002 ASRS)** | | | | | | | | | | | | | | |
| 2 | Opening Balance | | 7,889 | 8,763 | 8,395 | 7,895 | 7,442 | 6,937 | 6,433 | 5,928 | 5,424 | 4,919 | 4,415 | 3,910 | |
| 3 | Severance Costs - Actual | | 1,381 | 138 | 7 | 53 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | - | 1,593 |
| 4 | Amortization | | (507) | (506) | (507) | (506) | (507) | (506) | (507) | (506) | (507) | (506) | (507) | (506) | (6,078) |
| 5 | Total Unamortized Severance Costs - Operating | 7,889 | 8,763 | 8,395 | 7,895 | 7,442 | 6,937 | 6,433 | 5,928 | 5,424 | 4,919 | 4,415 | 3,910 | 3,404 | |
| 6 | **CAPITAL (2001 and 2002 ASRS)** | | | | | | | | | | | | | | |
| 7 | Opening Balance | | 1,161 | 1,097 | 1,030 | 963 | 896 | 829 | 762 | 696 | 629 | 562 | 495 | 428 | |
| 8 | Severance Costs - Actual | | 2 | - | - | - | - | - | - | - | - | - | - | - | 2 |
| 9 | Amortization | | (66) | (67) | (67) | (67) | (67) | (67) | (66) | (67) | (67) | (67) | (67) | (67) | (802) |
| 10 | Total Unamortized Capital-related Severance Costs | 1,161 | 1,097 | 1,030 | 963 | 896 | 829 | 762 | 696 | 629 | 562 | 495 | 428 | 361 | |
| 11 | **2003 ASRRS** | | | | | | | | | | | | | | |
| 12 | Opening Balance | | - | 132 | 493 | 1,204 | 1,856 | 2,110 | 2,178 | 2,573 | 2,844 | 3,292 | 4,435 | 4,615 | |
| 13 | Severance Costs - Actual | | 132 | 380 | 780 | 738 | 353 | 194 | 554 | 450 | 635 | 1,450 | 561 | 477 | 6,704 |
| 14 | Amortization | | - | (19) | (69) | (86) | (99) | (126) | (159) | (179) | (187) | (307) | (381) | (407) | (2,019) |
| 15 | Total Unamortized Severance Costs - Operating | - | 132 | 493 | 1,204 | 1,856 | 2,110 | 2,178 | 2,573 | 2,844 | 3,292 | 4,435 | 4,615 | 4,685 | |
| 16 | **TOTAL AMORTIZATION** | | | | | | | | | | | | | | **(8,899)** |

SEVERANCE COSTS

FOR THE TEST YEAR ENDING DECEMBER 31, 2004
($Thousands)

| LINE NO. | DESCRIPTION | Jan 1 | Jan 31 | Feb 28 | Mar 31 | Apr 30 | May 31 | Jun 30 | Jul 31 | Aug 31 | Sep 30 | Oct 31 | Nov 30 | Dec 31 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| 1 | **OPERATING (2001 and 2002 ASRS)** | | | | | | | | | | | | | | |
| 2 | Opening Balance | | 3,404 | 2,901 | 2,397 | 1,893 | 1,389 | 886 | 382 | - | - | - | - | - | |
| 3 | Severance Costs - Actual | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Amortization | | (503) | (504) | (504) | (504) | (503) | (504) | (504) | (504) | (504) | (504) | (503) | (504) | (6,045) |
| 5 | Transfer to Pension Liability (Schedule 3.11)[1] | | - | - | - | - | - | - | 122 | 504 | 504 | 504 | 503 | 504 | |
| 6 | Total Unamortized Severance Costs - Operating | 3,404 | 2,901 | 2,397 | 1,893 | 1,389 | 886 | 382 | - | - | - | - | - | - | |
| 7 | **CAPITAL (2001 and 2002 ASRS)** | | | | | | | | | | | | | | |
| 8 | Opening Balance | | 361 | 295 | 229 | 162 | 95 | 29 | - | - | - | - | - | - | |
| 9 | Severance Costs - Actual | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | Amortization | | (66) | (66) | (67) | (67) | (66) | (67) | (67) | (66) | (67) | (66) | (67) | (67) | (799) |
| 11 | Transfer to Pension Liability (Schedule 3.11)[1] | | - | - | - | - | - | 38 | 67 | 66 | 67 | 66 | 67 | 67 | |
| 12 | Total Unamortized Capital-related Severance Costs | 361 | 295 | 229 | 162 | 95 | 29 | - | - | - | - | - | - | - | |
| 13 | **2003 ASRRS** | | | | | | | | | | | | | | |
| 14 | Opening Balance | | 4,685 | 5,928 | 7,169 | 6,752 | 6,334 | 5,917 | 5,499 | 5,082 | 4,664 | 4,247 | 3,829 | 3,411 | |
| 15 | Severance Costs - Forecast | | 1,660 | 1,659 | - | - | - | - | - | - | - | - | - | - | 3,319 |
| 16 | Amortization | | (417) | (418) | (417) | (418) | (417) | (418) | (417) | (418) | (417) | (418) | (418) | (418) | (5,011) |
| 17 | Total Unamortized Severance Costs - Operating | 4,685 | 5,928 | 7,169 | 6,752 | 6,334 | 5,917 | 5,499 | 5,082 | 4,664 | 4,247 | 3,829 | 3,411 | 2,993 | |
| 18 | **TOTAL AMORTIZATION** | | | | | | | | | | | | | | **(11,855)** [2] |

[1] Negative balances reflect amounts related to employees who elected to top-up their pension with a portion of their severance under the Qualified Downsizing Program (QDP). These negative amounts have been included in the prefunded/(unfunded) pension and other post employment benefits liability account (Schedule 3.11) in 2004.

[2] Treated as a Non-Routine Adjustment in 2004.