

1   **10.1 INTRODUCTION**

2           The purpose of this sub-section is to respond to Phase 1 and Phase 2 requirements set out  
3           in Appendices four and five of Decision 2003-051, which are not addressed elsewhere in  
4           the Application.

1 **10.2 DEFERRAL AND RESERVE ACCOUNTS – RECONCILIATION OF**  
2 **INSURANCE RESERVE**

3 The following section responds to the fourth directive in Schedule J as listed in  
4 Appendix 4 of Decision 2003-051. The Board directed NGTL to provide a reconciliation  
5 of the balances in the Insurance reserve account.

6 In accordance with the terms agreed to under the Cost Efficiency Incentive Settlement,  
7 the balance in the Insurance reserve account as of December 31, 1995 was refunded to  
8 Alberta System customers through tolls. There has been a zero balance in the Insurance  
9 reserve account since January 1, 1996. The Insurance reserve account has been held in  
10 abeyance since December 31, 1995, in accordance with the provisions of the CEIS,  
11 ASRS and ASRRS and the relevant Board approvals.

12 During the terms of the CEIS, ASRS and ASRRS, uninsured losses were recorded as an  
13 expense in the year in which they were incurred. For details regarding uninsured losses  
14 incurred during the base and forecast years 2002 and 2003, respectively, please see  
15 Section 2.10 of this Application.

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**10.3 EXISTING PROPERTY, PLANT AND EQUIPMENT**

A schedule in the 1980 Ernst & Whinney study, “A Study of Depreciation Concepts,” (Study) filed in the 1995 GRA proceeding indicated in error that year-end plant balances exceeded plant additions in 1972 by \$70 million.

In addressing the \$70 million discrepancy in 1972 rate base additions, the Board, at page 23 of Decision U96001, directed NGTL:

...to provide, in its next general rate application, evidence to support 1972 rate base additions and evidence to demonstrate that the amount of the addition is consistent with the opening and closing rate base balances for that year.

To provide evidence to support 1972 rate base additions, NGTL has relied upon its 1978 audited financial statements to verify the accuracy of the additions in question.

In the 1995 GRA proceeding, NGTL discussed the issue of the \$70 million discrepancy in response to CWNG/NUL Information Request No. 1, Item CWNG/NULR.N-88 wherein it was noted that the schedule in question (Attachment A) indicated a balance of account 465 - mains of \$248.5 million at December 31, 1971 and indicated additions of \$45.7 million which would have yielded a December 31, 1972 balance in the account of \$294.3 million. On the schedule, the balance at December 31, 1972 was shown as \$364.3 million, a difference of \$70 million.

NGTL has reviewed other information in the Study and notes that the total Property Plant & Equipment balance as of December 31, 1978, which appears on line 29 of column 1 (Attachment B), of \$893.4 million is in general agreement with the balance shown in the 1978 NOVA audited financial statements at that date (Attachment C).

On line 15 of Attachment B, the amount relating to account 465 - mains is correctly shown as \$640.6 million at December 31, 1978, which agrees with the year-end balance shown on Attachment A as at the same date.

1           The conclusion that can be drawn from this reconciliation is that, as of December 31,  
2           1978, the information contained in the Study agreed with the audited financial  
3           statements.

4           As such, it follows from this reconciliation that the discrepancy of \$70 million in the  
5           schedule is a transposition error and that the additions for 1972 were, in fact, \$70 million  
6           higher than that shown on the schedule.

TABLE 4.3.4.1

THE ALBERTA GAS TRUNK LINE COMPANY LIMITED  
 ACCOUNT 465 MAINS

Year	Year End Balance		Additions	Cumulative Additions	Retirements	Cumulative Retirements
1958	\$ 29,997,461	21	\$29,997,461	\$ 29,997,461	\$	\$ 0
1959	44,343,874	20	14,348,500	44,345,961	2,087	2,087
1960	55,220,646	19	10,877,644	55,223,603	872	2,959
1961	55,290,531	18	131,537	55,355,142	61,652	64,611
1962	129,826,545	17	74,566,422	129,921,564	30,408	95,019
1963	133,547,180	16	3,721,177	133,642,741	542	95,561
1964	138,032,039	15	4,484,859	138,127,600		95,561
1965	160,995,562	14	22,963,523	161,091,123		95,561
1966	183,088,314	13	22,092,752	183,183,875		95,561
1967	185,270,491	12	2,226,388	185,410,263	44,211*	139,772
1968	188,905,266	11	3,739,104	189,149,367	104,329	244,101
1969	195,515,817	10	6,682,685	195,832,052	72,133	316,234
1970	197,855,177	9	2,449,310	198,281,362	109,950	426,184
1971	248,546,519	8	50,701,194	248,982,556	9,851	436,035
1972	364,263,316	7	45,716,796	364,699,352		436,035
1973	387,611,108	6	24,210,549	388,909,901	862,757	1,298,792
1974	393,184,936	5	6,051,877	394,961,778	478,049	1,776,841
1975	403,821,415	4	10,636,479	405,598,257		1,776,841
1976	483,755,031	3	79,936,071	485,534,328	2,455	1,779,296
1977	560,371,991	2	76,618,967	562,153,295	2,007	1,781,303
1978	640,610,541	1	80,701,539	642,854,834	462,989	2,244,292

\* Actual retirements for the year was \$3,743,593. Of the total amount, \$3,699,382.04 was attributable to the Nevis lateral and Carstairs lateral which were both 1959 additions. Therefore, \$3,699,382 was omitted from the 1959 addition which actually totalled \$18,047,882.

RESERVE LIFE DEPRECIATION METHOD

Sub-Section 10.3 - Attachment B  
REPRODUCTION OF ORIGINAL

(Thousands of Dollars)			(1)	(2)	(3)	(4)	(5)	(6)
LINE NO.	ACCT. NO.	ACCOUNT DESCRIPTION	CROSS PLANT IN SERVICE	ACCUMULATED DEPRECIATION	NET PLANT IN SERVICE	RESERVE LIFE INDEX	REMAINING PHYSICAL LIFE	DEPRECIATION AMOUNT
1	402	INTANGIBLE PLANT - Other	\$ 820	\$ 254	\$ 566	24.1		\$ 24
2	403	GAS PRODUCTION - Lands	3	-	3	-		-
		GAS GATHERING:						
3	411	Land Rights	4	2	2	24.1		-
4	412	Compressor Structures	48	2	46	24.1		2
5	413	Measuring & Regulating Structures	7	1	6	24.1		-
6	414	Other Structures & Improvements	2	-	2	24.1		-
7	415	Gathering Lines	6,350	1,954	4,396	24.1		182
8	416	Compressor Equipment	127	5	122	24.1		5
9	417	Measuring & Regulating Equipment	3	1	2	24.1		-
		GAS TRANSMISSION:						
10	460	Land	963	-	963	-		-
11	461	Land Rights	5,986	1,442	4,544	24.1		189
12	462	Compressor Structures & Improvements	18,355	3,694	14,661	24.1		608
13	463	Measuring & Regulating Structures	7,819	1,583	6,236	24.1		259
14	464	Other Structures & Improvements	3,857	451	3,406		17.4	196
15	465	Mains	<b>640,611</b>	165,299	475,312	24.5		19,432
16	466	Compressors Equipment	109,208	23,445	85,763	22.5		3,818
17	467	Measuring & Regulating Structures	43,012	7,048	35,964	22.8		1,580
18	468	Communication Structures & Equipment	1,065	227	838		8.6	97
19	469	Other Transmission Equipment	318	20	298		13.0	23
		GENERAL PLANT:						
20	482	Structures & Improvements	5,121	554	4,567	24.1		190
21	483	Office Furniture & Equipment	10,767	1,290	9,477		*	1,581
22	484	Transportation Equipment	4,729	(2,132)	6,861		*	2,489
23	485	Heavy Work Equipment	3,828	867	2,961		*	256
24	486	Tools & Work Equipment	6,169	1,021	5,148		*	397
25	488	Communication Structure & Equipment	4	-	4		8.6	1
26	489	Other General Equipment	530	163	367	24.1		15
27	497	Undistributed Plant - AFUDC	23,740	6,699	17,041	24.1		707
28	498	Undistributed Plant - Overhead	1	-	1	24.1		-
29		TOTAL PROPERTY PLANT & EQUIPMENT	<b>\$893,447</b>	\$213,890	\$679,557			\$32,051
30		Less Land	966					
31		TOTAL DEPRECIABLE PROPERTY PLANT & EQUIPMENT	<b>\$892,481</b>					
32		COMPOSITE DEPRECIATION RATE (ANNUAL	3.59%					

\* ... Columns (1), (2) and (3): AGTL Accounting Dept.  
 Column (4): Lines 15, 16 & 17 from Tables 4.3.2.2; 4.3.2.3; 4.3.2.4. All other lines Pages 4-22 and 4-23.  
 Column (5): Pages 4-22 and 4-23.  
 Column (6) = Column (3) + Column (4) or (5). Lines 21 to 24 Pages 4-28 to 4-30.

4. Plant property and equipment

	December 31			
	1978		1977	
	(thousands of dollars)			
	Cost	Accumulated Depreciation and Depletion	Net	Net
Gas transmission plant (Note 1)				
In service.....	\$ 894,291	\$213,554	\$ 680,737	\$607,938
Under construction.....	16,784	-	16,784	62,336
Petrochemical facilities (Note 12)				
In service.....	89,063	919	88,144	-
Under construction.....	264,125	-	264,125	186,784
Petroleum and mineral resource properties.....	60,011	5,030	54,981	46,482
Manufacturing and other facilities.....	43,780	11,140	32,640	19,880
	<u>\$1,368,054</u>	<u>\$230,643</u>	<u>\$1,137,411</u>	<u>\$923,420</u>

5. Deferred charges

	December 31	
	1978	1977
	(thousands of dollars)	
Gas transmission - Northern projects.....	\$ 41,706	\$ 26,210
Artic Pilot Project.....	10,463	5,838
Q & M project.....	3,227	250
Unamortized debt discount and expense.....	3,968	4,441
License agreements and patents.....	1,459	1,706
Other.....	7,598	7,913
	<u>\$ 68,421</u>	<u>\$ 46,358</u>

Gas transmission – Northern projects –

The company is one of the principal sponsors of the Alaska Highway Gas Pipeline Project which has as its objective the transportation of natural gas from Alaska through Canada to the United States of America. The Company anticipates that its share of 1979 expenditures relating to this project will amount to approximately \$28,000,000. Upon commencement of construction the Company may incur or be responsible for large expenditures in respect of this project.

Arctic pilot project –

The Company and Petro-Canada have formed a joint venture (Arctic Pilot Project) for the purpose of determining the economic feasibility of producing, processing and transporting natural gas from the Arctic Islands. The costs of the project through the regulatory stage are estimated to be \$36,400,000 of which the Company's share would be \$12,200,000.

Q & M project –

In 1977 the Company initiated the Q & M project relating to the construction and operation of a major gas transmission system to transport Alberta natural gas to Quebec, New Brunswick and Nova Scotia. Costs associated with funding this through the regulatory stage are estimated to be \$7,800,000 of which the Company's share would be \$5,500,000

## 10.4 REPORTING REQUIREMENTS

In Decision U96001, the Board indicated that it was of the view that NGTL should begin to provide a periodic reporting package. However, given a lack of consensus between NGTL and intervenors regarding the nature of information that should be provided, a specific reporting package was not defined. The Board stated in the Decision that it “...encourages NGTL to consult its shippers and to provide recommendations in this regard to the Board in its next general rate application.”

In response to the Board’s comments in Decision U96001 regarding reporting requirements, NGTL has consulted with its customers on this matter. Through such consultations, reporting requirements were agreed to and included in the terms and conditions of the CEIS, ASRS, and ASRRS. Reporting packages were prepared annually that included information showing actual expenses, rate base, and throughput and contract demand levels. These reporting packages were filed with the Board in accordance with the terms and conditions of the CEIS and ASRS, and will be filed in accordance with the ASRRS in 2004.

The reporting packages provided under the settlement agreements evolved over time with NGTL expanding on the level of detail originally agreed to in the CEIS in order to better meet customers’ information needs. NGTL believes that providing a reporting package in respect of 2004 similar to that provided for the ASRS and ASRRS will continue to meet the needs of both the Board and customers. Therefore, NGTL proposes to continue with a similar annual reporting process for 2004. The reporting package would include the following schedules, along with explanations of material variances from what is approved by the Board:

- Actual Costs Summary,
- Operating Return,
- Average Cost of Long-Term Debt,

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- 1           • Long Term Debt Continuity Schedule,  
2           • Amortization of Long Term Debt Issue Costs,  
3           • Operating Costs by Functional Areas and General Expenses,  
4           • Foreign Exchange on Interest Payments,  
5           • Transportation by Others,  
6           • Regulatory Hearing Costs,  
7           • Uninsured Losses,  
8           • Pipeline Integrity Costs,  
9           • CO<sub>2</sub> Revenue and Costs Summary,  
10          • Income and Large Corporation Taxes Calculations,  
11          • Capital Cost Allowance,  
12          • Weighted Average Rate Base Summary,  
13          • Monthly Rate Base Details,  
14          • Monthly Gas Plant Under Construction,  
15          • Average Cash Working Capital,  
16          • Monthly Reserve Account Details; and,  
17          • Deferral Account Details.

18          The reporting package will be filed with the Board on or before May 15, 2005. NGTL  
19          does not believe that the additional information provided by preparing a quarterly  
20          reporting package would be sufficient to justify the additional effort and cost of  
21          generating such a package.

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1   **10.5   TECHNICAL AUDIT/OUTSOURCING**

2           In Decision U96001, the Board stated that:

3                   In general, the Board expects NGTL to take all reasonable efforts to  
4                   control its capital costs while maintaining the quality and reliability of its  
5                   pipeline system.<sup>1</sup>

6           The Board continued and stated that it was:

7                   ...not persuaded that NGTL has adequately addressed the question of  
8                   outsourcing. The Board believes that this question should be addressed  
9                   further by NGTL and discussed with shippers. It should be included as an  
10                  item for the Board's review in the progress report to be filed by NGTL.<sup>2</sup>

11          The Board also stated that:

12                  To assist the Board in evaluation of rate base additions, it is incumbent  
13                  upon NGTL to demonstrate to the Board that it has in place management  
14                  practices in the areas of facilities planning and construction which support  
15                  this objective.<sup>3</sup>

16          The issue of outsourcing was addressed under Articles 12.1 and 12.2 of the Cost  
17          Efficiency Incentive Settlement (CEIS) approved by the Board in Decision U96119.  
18          Article 12.1 set out the procedures for the handling of engineering, procurement and  
19          construction (EP&C) of receipt facilities connecting to the Alberta System. The  
20          procedures included requirements for customer consultation on particulars such as cost,  
21          timing and the option for customers to conduct EP&C. As well, the procedures included  
22          provisions for NGTL to competitively bid at least 25 percent of all EP&C services.  
23          Article 12.2 provided for Tolls, Tariff and Procedures Committee (TTP) review of the  
24          1997 receipt facilities construction program with the intent of extending or modifying the  
25          Receipt Facilities Incentive Mechanism for the remainder of the term of the CEIS.

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<sup>1</sup> EUB Decision U96001, Page 27

<sup>2</sup> EUB Decision U96001, Page 28

<sup>3</sup> EUB Decision U96001, Page 28

1 In accordance with the provisions of Article 12.1 of the CEIS, NGTL awarded twelve  
2 projects to four independent EP&C firms and one customer company, which completed  
3 its own EP&C, for capital facility additions during 1997.

4 NGTL measured the success of the 1997 EP&C outsource program based on the  
5 following criteria:

- 6 • customer in-service dates were met with no delays to the plant in-service date;
- 7 • cost management followed NGTL guidelines of +/- 10% of contracted amount;
- 8 and
- 9 • facilities constructed met industry and NGTL specifications.

10 In accordance with Article 12.2 of the CEIS, NGTL presented the results of the outsource  
11 program to the TTP on February 25, 1998. The results indicated that meter station  
12 installations performed by third party EP&C firms incurred higher final costs than  
13 NGTL's 1997 average. Outsourced lateral projects incurred similar final costs to  
14 NGTL's 1997 average based on a dollars-per-diameter-inch-kilometre metric.

15 NGTL concluded from the program that there were no direct cost benefits to NGTL and  
16 its customers to further pursue the outsource commitments of Article 12.1 of the CEIS.  
17 However, prudent use of third party EP&C contractors was recognized to provide some  
18 benefit in terms of enabling NGTL to manage its internal core manpower to sustainable  
19 levels required by the business. Based on these findings, the formal outsource program  
20 as prescribed in Article 12.1 of the CEIS was discontinued for 1998 and subsequent  
21 years.

22 With specific reference to control of capital costs, NGTL has made significant efforts to  
23 reduce capital costs since the last GRA was filed in 1995 while balancing this with safety  
24 and reliability of service. This is further explained in Section 3.4, Capital Expenditures,  
25 Sub-Section Capital Cost Management. NGTL's facilities planning practice is described  
26 in Section 3.4, Capital Expenditures, Sub-Section Capital Cost Budget Process.

1 **10.6 DEFINITION OF MAINLINE AND LATERAL FACILITIES**

2 **Q1. What is the purpose of this evidence?**

3 A1. This evidence reviews and provides the justification for the definition of mainline that is  
4 used to determine whether NGTL may construct (own/operate) new extension facilities  
5 on the Alberta System. Extension facilities are those facilities that connect new or  
6 incremental supply or markets to the Alberta System.

7 **Q2. Why is NGTL providing this evidence?**

8 A2. In decision 2003-051 the Board directed NGTL to address this issue. Specifically on page  
9 33 of the Decision, the Board stated:

10 The Board recognizes ATCO Pipelines' concern that the current  
11 definition of mainline and lateral, used to establish NGTL's  
12 eligibility to construct a pipeline to industrial customers, is not  
13 reasonable and has not recently been evaluated by the Board. ...  
14 However, the Board believes that this matter should be addressed  
15 as part of the 2004 GRA proceeding.

16 NGTL believes that the current definition was and still is appropriate for determining  
17 what mainline extension facilities NGTL may construct or conversely what lateral  
18 extension facilities NGTL cannot construct. In NGTL's view, this definition  
19 accomplishes the objectives for which it was intended and appropriately delineates  
20 mainline and lateral facilities on the Alberta System.

21 **Q3. What definition of mainline does NGTL use in deciding whether to construct new  
22 extension facilities?**

23 A3. NGTL may construct extension facilities that meet the majority of the following criteria:

- 24 1. Facilities to serve the aggregate forecast (more than one customer);  
25 2. Facilities greater than or equal to 12 inches in diameter;  
26 3. Facilities greater than 20 kilometres in length; and  
27 4. Associated volumes greater than 100 MMcf/d.

1 The corollary to this is that NGTL cannot construct extension facilities that do not meet  
2 the majority of these criteria. In this context, NGTL defines facilities that do not meet the  
3 majority of these criteria as laterals.

4 **Q4. What are the objectives associated with this definition of mainline?**

5 A4. This definition defines the business area in which NGTL operates. NGTL cannot  
6 construct new laterals that are designed to connect small levels of gas production or  
7 delivery for an individual customer. The objective in establishing the mainline and lateral  
8 definitions was to improve cost accountability by having shippers that require laterals be  
9 responsible for the cost of those laterals rather than having the costs rolled into the  
10 Alberta System rate base as well as to provide for additional choice and competition in  
11 constructing laterals. However, NGTL continues to construct larger facilities that would  
12 benefit multiple parties or the aggregate system. The economies of scale associated with  
13 pipe are significant and from an industry perspective it is less costly and more efficient to  
14 build one large extension than several small extensions.

15 **Q5. When was this definition of mainline established?**

16 A5. The original definition was established following Decision 2000-6, which was issued by  
17 the Board on February 4, 2000. Specifically at page 62 of the Decision the Board stated:

18 However the Board accepts as reasonable NGTL's submission that in  
19 general new connections of 12 inches or less in diameter distinctly  
20 associated with one or a few customers would normally be considered  
21 laterals, while facilities required to meet the aggregate forecast of more  
22 than one customer would normally be classified as mainlines.

23 This definition was modified to the current definition by NGTL's Facilities Liaison  
24 Committee (FLC). On July 11, 2000 the FLC approved the current definition as part of  
25 the Guidelines for New Facilities (Guidelines) through FLC Resolution F2000-01 that  
26 was filed with the Board on July 17, 2000. On February 11, 2003 the TTP approved

1 modifications to the Guidelines through Resolution T2003-01 that was filed with the  
2 Board on February 18, 2003. The definition of mainline remained the same.

3 **Q6. Has NGTL utilized the Guidelines to construct new facilities?**

4 A6. Yes, twice to date. On December 21, 2001, the Board approved a pipeline permit,  
5 approval number 19595, for the construction of a receipt mainline extension of  
6 approximately 40 kilometers of 16-inch pipe in the Narraway area. These facilities were  
7 placed into service in January 2002. In Decision 2002-16 the Board approved NGTL  
8 service to the Fort McMurray market with a delivery mainline extension via a TBO  
9 agreement utilizing 108 kilometres of TransCanada Pipeline Ventures Limited  
10 Partnership 24-inch Oil Sands Pipeline. Service commenced March 1, 2002.

11 **Q7. Why is this definition appropriate for determining what extension facilities NGTL**  
12 **may construct?**

13 A7. First and foremost, it reflects the agreement and support of NGTL's TTP and FLC  
14 through unopposed resolutions. Second, in the three years since this definition was  
15 adopted, NGTL has only constructed two mainline extensions and has thus exited the  
16 lateral construction business. Those parties requiring laterals to connect their gas to the  
17 Alberta System are required to pursue other options. This discourages uneconomic  
18 expansion and increases the accountability of those who have required lateral facilities.

19 Finally this definition appropriately delineates lateral and mainline facilities on the  
20 Alberta System.

1 **Q8. How and why does this definition appropriately delineate lateral and mainline**  
2 **facilities on the Alberta System?**

3 A8. As of December 31, 2002 NGTL had 937 receipt stations and 144 Alberta delivery  
4 stations. NGTL analyzed the connections to these stations against the criteria used to  
5 determine mainline extension facilities to determine whether these existing facilities  
6 would be classified as lateral or mainline facilities.

7 Criterion 1 - Facilities to serve the aggregate forecast (more than one customer)

8 As 24% of the receipt stations were interconnections to other pipeline systems such as  
9 ATCO Pipelines or had multiple producer tie-ins upstream of the station, they served  
10 more than one customer and thus the connections to these stations would be considered  
11 mainline. As a result the connections to the remaining 76% of receipt stations would be  
12 considered laterals. Similarly, 33% of the delivery stations were interconnections to other  
13 pipeline systems such as ATCO Pipelines or had multiple users downstream of the  
14 station. As a result the connections to the remaining 67% of delivery stations would be  
15 considered laterals.

16 Criterion 2 – Facilities greater than or equal to 12 inches in diameter

17 As 70% of the receipt stations and 51% of the delivery stations are connected via pipe  
18 with a diameter of less than 12 inches these pipes would be considered laterals.

19 Criterion 3 – Facilities greater than 20 kilometres in length

20 As 99% of all pipe with a diameter of less than 12 inches is located within 20 km of the  
21 upstream receipt station or downstream delivery station these pipes would be considered  
22 laterals.

1           Criterion 4 – Associated volumes greater than 100 MMcf/d

2           Based on annualized 2002 throughput, 98% of the receipt stations and 99% of the Alberta  
3           delivery stations had associated volumes less than 100 MMcf/d and thus the pipe  
4           connecting to these stations would be considered laterals.

5           Majority of criteria

6           Each criterion on its own would classify most of the connections to existing receipt and  
7           delivery stations as laterals. For new construction NGTL must meet the majority of the  
8           criteria which when applied to the existing system define 98% of the connections to  
9           receipt stations and 99% of the connections to delivery stations as laterals. Therefore this  
10          definition reflects the majority of existing lateral extensions on the Alberta System.

11   **Q9. Are any changes required to the definition?**

12   A9. No. NGTL believes that the current definition is appropriate for determining what  
13          mainline extension facilities NGTL may construct or conversely what lateral extension  
14          facilities NGTL cannot construct. No changes are required. This definition was  
15          developed by and is supported by the FLC and TTP which represent a broad cross-section  
16          of affected interests, including export shippers, intra-Alberta end-users, producers and  
17          industry associations. These parties are also responsible for the majority of revenue  
18          generated by NGTL's rates, tolls and charges for service. When applied to the Alberta  
19          System the current definition excludes the majority of lateral extensions, significantly  
20          constraining the opportunity for NGTL to construct extensions. In the three years since  
21          this definition was implemented NGTL has only constructed two mainline extensions and  
22          thus has exited the lateral construction business.

23   **Q10. Does this conclude the written evidence on the definition of mainline and lateral**  
24          **facilities?**

25   A10. Yes.

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1    **10.7    CUSTOMER ACCOUNTABILITY FOR STORAGE DELIVERY POINTS**

2    **Q1.    What is the purpose of this evidence?**

3    A1.    NGTL provides the information in this section as an update to the Board on the  
4           matter of appropriate customer accountability for facilities at Storage Delivery  
5           Points.

6    **Q2.    Why is NGTL providing this update?**

7    A2.    In Decision 2003-051 the Board accepted the commitment made by parties to the  
8           2003 Tariff Settlement to review and resolve, if necessary, prior to September 30,  
9           2003, the appropriate Customer accountability for facilities at a Storage Delivery  
10          Point.    The Board further directed NGTL to provide an update on such matters  
11          as part of its 2004 GRA Phase II submission requirements.

12   **Q3.    What is the status of this matter?**

13   A3.    This matter has been reviewed and resolved through a collaborative process open  
14          to all members of the TTP. The result of this process was the approval of TTP  
15          Resolution T2003-05 on September 9, 2003. On September 10, 2003, NGTL  
16          requested the Board approve the resulting amendments to Rate Schedule Facility  
17          Connection Service (FCS) of the Tariff. On September 18, 2003 the Board issued  
18          notice of this application and established September 25, 2003 as the deadline for  
19          the filing of objections.

20   **Q4.    Does this conclude the written evidence on customer accountability for**  
21          **Storage Delivery Points?**

22   A4.    Yes.

1 **10.8 FEDERATION OF ALBERTA GAS CO-OPS AND GAS ALBERTA LTD.**  
2 **(FGA) GAS QUALITY CONCERNS**

3 **Q1. What is the purpose of this evidence?**

4 A1. NGTL provides the information in this section as an update to the Board on the status of  
5 the FGA gas quality concern.

6 **Q2. Why is NGTL providing this update?**

7 A2. The Board directed NGTL to provide an update on such matters as part of its 2004 GRA  
8 Phase II submission requirements.

9 **Q3. What is the status of this matter?**

10 A3. This matter has been reviewed and resolved through a collaborative process open to all  
11 members of the TTP. The result of this process was the approval of TTP Resolution  
12 T2000-16 on June 10, 2003. On June 20, 2003, the FGA withdrew its request to raise  
13 this matter as part of the 2003 Tariff Settlement. The Board accepted the resolution as a  
14 filing for information in a letter dated July 14, 2003.

15 **Q4. Does this conclude the written evidence FGA gas quality concerns?**

16 A4. Yes.