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December 15, 2011

All Customers
Other Interested Parties

Re: 2011 Annual Plan

NOVA Gas Transmission Ltd. ("NGTL") has posted its 2011 Annual Plan on TransCanada PipeLines Limited's website at:

http://www.transcanada.com/customerexpress/5133.html

Customers and other interested parties are encouraged to communicate their suggestions and comments to NGTL regarding the development and operation of the Alberta System and other related issues to me at (403) 920-5574.

Yours truly,
NOVA Gas Transmission Ltd.
a wholly owned subsidiary of TransCanada PipeLines Limited

Dave Schultz
Director, System Design
System Design and Commercial Operations

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EXECUTIVE SUMMARY

The 2011 Annual Plan provides NOVA Gas Transmission Ltd.'s (NGTL's) Customers and other interested parties with an overview of the potential Alberta System facilities that are expected to be applied for in the 2012 calendar year. The plan describes NGTL's long-term outlook for receipts, deliveries, peak expected flows, design flow requirements and proposed facilities for the 2012/13 Gas Year. This Annual Plan is based on NGTL's July 2011 Design Forecast of receipts and deliveries.

Since the release of the 2010 Annual Plan, TransCanada PipeLines Limited (TransCanada) has identified 30 Alberta System facility additions. NGTL's Tolls, Tariff, Facility and Procedures (TTFP) taskforce has been notified of these facilities, and they are summarized in Appendix 2 – Facility Status Update. These projects have in-service dates between November 2011 and April 2014 and were initiated prior to the issuance of this Annual Plan to accommodate the lead time required to meet the on-stream requirements.

On October 1, 2011, ATCO Pipelines (AP) was commercially integrated with the NGTL Alberta System. The integrated systems are referred to as the Alberta System.

TransCanada follows facility planning processes to identify facilities required in both NGTL's and ATCO's footprints. An overview of these processes is contained in the Facilities Design Methodology Document. NGTL's design philosophy is the basis used to identify and scope any required Alberta System facilities. TransCanada is responsible for determining new facilities or system modifications to meet the requirements of the Alberta System, with the exception of Minor Modifications in the "ATCO Footprint" as defined in the Alberta System Integration Agreement. NGTL files facility applications with the National Energy Board (NEB) for facility additions on the Alberta System within the "NGTL Footprint." AP files facility applications with the Alberta Utilities

Commission (AUC) for facility additions on the Alberta System within the ATCO Footprint.

The facilities identified in this Annual Plan were presented to the Tolls, Tariff, Facilities and Procedures (TTFP) taskforce on November 22, 2011. New facilities proposed after the issuance of the 2011 Annual Plan will be shown in the 2012 Facility Status Update, which can be accessed at http://www.transcanada.com/customerexpress/5133.html.

Two facilities have been identified in the 2011 Annual Plan for the 2012/13 and 2013/14 Gas Years, as shown in Table E-1.

Table E-1: Proposed Facilities

Project Area	Proposed Facilities	Annual Plan Reference	Description	Required In-Service Date	Regulator	Capital Cost ($ Millions)
Mainline	Torrington Compressor Station Modifications	Chapter 2	Bi-directional flow	Nov 2012	NEB	7.1
Mainline	Northeast Calgary Connector	Chapter 2	17 km NPS 24	Nov 2013	AUC	50.5
					Total	**57.6**
Capital Costs are in 2011 dollars and include AFUDC						

The Torrington Compressor Station Modifications located in the Rimbey-Nevis Design Area are a new Alberta System facility proposed in this Annual Plan. These modifications are required to transport additional supply into central Alberta. In addition, the Northeast Calgary Connector in the Calgary transportation utility corridor (TUC) is proposed to allow the removal of high-pressure transmission from populated urban areas.

This 2011 Annual Plan includes the following sections:

- Executive Summary;
- Chapter 1 – Design Forecast;
- Chapter 2 – Design Flow and Mainline Facilities;
- Chapter 3 – Extensions, Lateral Loops and Meter Stations;
- Appendix 1 – Glossary of Terms;
- Appendix 2 – Facility Status Update; and
- Appendix 3 – System Map (available in February 2012).

An electronic version of the Annual Plan and the Facilities Design Methodology Document can be accessed at TransCanada's website, located at:

http://www.transcanada.com/customerexpress/5133.html

Customers and other interested parties are encouraged to communicate their suggestions, comments and questions to NGTL regarding this Annual Plan and other related issues. Please provide your comments to:

- Landen Stein, Manager, Customer Solutions (403) 920-5311;
- Gord Toews, Manager, Mainline Planning West (403) 920-5903;
- Roland Guebert, Manager, Receipt and Delivery Forecasting (403) 920-5386;
- Dave Schultz, Director, System Design (403) 920-5574; or
- Steve Emond, Vice President, System Design and Commercial Operations (403) 920-5979.

1.1 INTRODUCTION

This Annual Plan is based on the July 2011 Design Forecast of receipts and deliveries for the Alberta System. An overview of the July 2011 Design Forecast was presented at the November 22, 2011 TTFP meeting.

Information on forecasting methodology can be found in the Facilities Design Methodology Document Section 4.4 – Design Forecast Methodology which can be accessed online at:

http://www.transcanada.com/customerexpress/5133.html

In this section, NGTL describes the:

- economic assumptions used in developing the 2011 Design Forecast;
- receipts and deliveries for the Alberta System; and
- supply contribution, including winter withdrawal, from Storage Facilities used in the design process.

1.2 ECONOMIC ASSUMPTIONS

1.2.1 General Assumptions

The following assumptions, developed in January 2011, concern broader trends in the North American economy and energy markets, and underlie the forecast of receipts and deliveries:

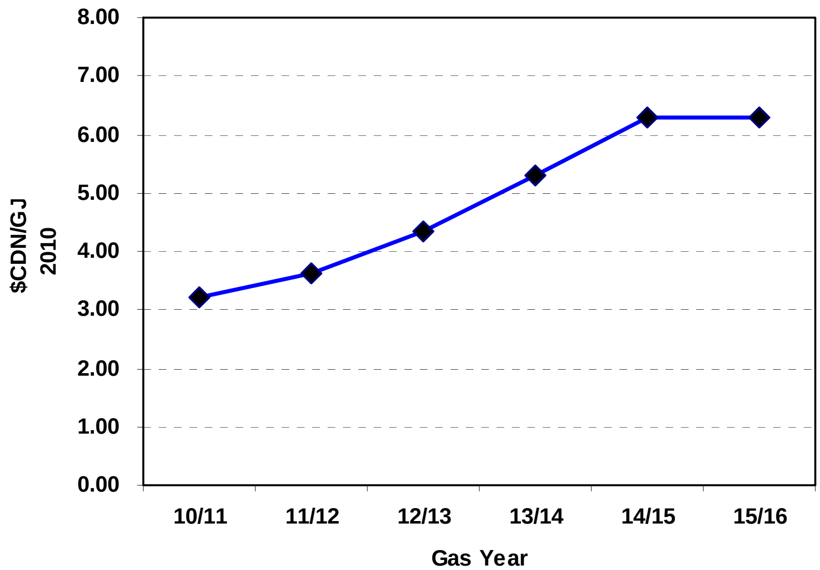
- North American natural gas demand will slowly increase in the short term as the U.S. and Canadian economies recover. In the longer term, gas demand is expected to increase with continued economic and population growth in both the U.S. and Canada. U.S. gas demand growth is predominantly associated with increased gas-fired electricity generation. Western Canadian industrial gas demand is expected to grow significantly, driven by the gas needs of the oil sands.

- The North American market will be well supplied with domestic natural gas because of the strength in unconventional gas production, primarily shale gas. This strong supply growth is now expected to be able to keep pace with the growth in gas demand, greatly reducing the volume of imported liquefied natural gas (LNG) required to balance the continental market.
- Because of weakness in natural gas demand from the slow pace of economic recovery, and the rapid expansion of shale gas supplies, short-term gas prices are expected to be soft. This is expected to be temporary as present prices are below the full cycle supply costs of most gas sources. Although a NYMEX gas price level of $6.75/MMBtu in Real 2010 $US by 2015 is more than sufficient to encourage development of unconventional shale gas resource, conventional gas is also required to meet increasing demand. NYMEX natural gas prices are forecast to recover over the next few years as the economy and gas demand improve. This higher price allows additional volumes of conventional gas to be produced, in conjunction with unconventional shale gas, to meet market demands. The gas price forecast rises from today's prices to reach an equilibrium price of $US 6.75/MMBtu in real 2010 $US by 2015.
- Currently, low gas prices are putting pressure on producers to be efficient and cost-effective. Recent drilling successes in many shale and tight gas plays have led to more fracture stages, higher initial production rates, and increases in the estimated ultimate recovery (EUR) per well, resulting in a lower cost per well for producers. These improvements have led to additional shale and tight gas resources being economic to produce in a low gas price environment, edging out higher cost conventional supply. However, even with strong growth in shale and tight gas production, there continues to be a need for a significant proportion of supply from conventional resources to meet North American gas demand requirements.

1.2.2 Alberta Average Field Price

TransCanada's NYMEX gas price forecast was used to develop the Alberta Average Field Price (Alberta Reference Price), which represents the estimated price of natural gas at a point just prior to receipt onto the Alberta System. The gas price forecast, shown in Figure 1-1, was developed in January 2011 and reflects the general assumptions from Section 1.2.1.

Figure 1-1: NGTL Gas Price Forecast, Alberta Average Field Price



The Alberta Average Field Price is forecast to rise from $3.22 Cdn/GJ to the long term equilibrium price of $6.30 Cdn/GJ (in real 2010 $) by 2015.

The gas price forecast affects the receipt and delivery forecast, and is used as input into the economic analysis for new facilities. The level of the gas price affects anticipated producer activity to support continuing production from connected supplies, connection of unconnected reserves, and the discovery and development of new reserves.

1.3 GAS DELIVERY FORECAST

Deliveries to markets within Alberta are forecast to rise, due primarily to industrial demand in the Oil Sands region. Gas demand from Oil Sands-related projects is influenced by factors such as the amount of oil produced, the price of oil and gas, the process used to produce oil, and the technological improvements employed over time. At major Border Points, contract demand and throughput have declined over the past few years, the result of changing market conditions and the ability of downstream markets to access alternative supply sources, all of which contribute to uncertainty in the gas delivery forecast.

Several sources of information were considered in developing the gas delivery forecast. First, operators of downstream facilities, such as connecting pipelines, local distribution companies (LDCs), and industrial plants, were requested to provide a forecast of their maximum, average, and minimum requirements for deliveries from the Alberta System over the next ten years. The forecasts were analyzed and compared to historical flow patterns at Alberta Delivery Points. In cases where NGTL's analysis differed substantially from the operator's forecast, NGTL contacted the operator and either the operator's forecast was revised or NGTL adjusted its analysis. In cases where the operator did not provide a forecast, NGTL based its forecast on historical flows and growth rates for specific demand sectors.

1.3.1 Average Annual Delivery Forecast

The Average Annual Delivery forecast is the forecast aggregate deliveries for the Alberta System for the 2011/12 through 2015/16 Gas Years. Forecast deliveries by

Gas Year are expressed as an average daily flow and are listed by Delivery Point in Table 1-1. Alberta deliveries are further detailed by Project Area in Table 1-2.

Table 1-1: System Average Annual Delivery Forecast by Delivery Point

Delivery Point	July 2011 Design Forecast ($10^6m^3/d$)				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Empress	90.0	100.6	108.5	116.4	121.2
McNeill	43.8	42.9	44.4	45.5	45.5
Alberta/B.C.	49.6	48.3	51.5	56.8	60.7
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	1.0	1.0	1.0	1.0	1.0
Cold Lake	0.8	0.8	0.8	0.8	0.8
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	0.7	0.7	0.7	0.7	0.7
Intra Alberta	112.2	118.5	123.9	131.6	138.2
Total System	**298.1**	**312.8**	**330.8**	**352.8**	**368.1**
Delivery Point	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Empress	3.18	3.55	3.83	4.11	4.28
McNeill	1.55	1.51	1.57	1.61	1.61
Alberta/B.C.	1.75	1.71	1.82	2.00	2.14
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.03	0.03	0.03	0.04	0.04
Cold Lake	0.03	0.03	0.03	0.03	0.03
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	0.02	0.02	0.02	0.02	0.02
Intra Alberta	3.96	4.18	4.37	4.65	4.88
Total System	**10.52**	**11.03**	**11.67**	**12.46**	**13.00**

Note:
Numbers may not add due to rounding.
Volumes expressed as an average daily flow for each Gas Year, at 101.325 kPa and 15°C.

Table 1-2: Alberta Deliveries – Average Annual Delivery Forecast by Project Area

Project Area	July 2011 Design Forecast ($10^6 m^3/d$)				
	2011/12	2012/13	2013/14	2014/15	2015/16
Peace River	2.1	2.1	2.1	2.4	2.7
North and East	75.5	81.3	86.8	93.5	98.7
Mainline	32.0	32.4	32.3	33.0	34.1
Gas Taps	2.6	2.6	2.7	2.7	2.7
Total Alberta	**112.2**	**118.5**	**123.9**	**131.6**	**138.2**
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	0.07	0.07	0.07	0.08	0.09
North and East	2.67	2.87	3.06	3.30	3.49
Mainline	1.13	1.15	1.14	1.17	1.20
Gas Taps	0.09	0.09	0.09	0.10	0.10
Total Alberta	**3.96**	**4.18**	**4.37**	**4.65**	**4.88**

Note:
Numbers may not add due to rounding.
Volumes expressed as an average daily flow for each Gas Year.
Gas taps are located in all areas of the province.

1.3.2 Maximum Day Delivery Forecast

Peak deliveries (Maximum Day Delivery) are also forecast for the Alberta Delivery Points and are based on customer input, market conditions, firm transportation contracts and historical flows.

A summary of the July 2011 Design Forecast Maximum Day Delivery by Project Area for Alberta Deliveries is provided in Table 1-3 for winter and Table 1-4 for summer.

Table 1-3: Winter Maximum Day Delivery Forecast

Project Area	July 2011 Design Forecast ($10^6m^3/d$)				
	2011/12	2012/13	2013/14	2014/15	2015/16
Peace River	6.3	6.3	6.4	6.8	7.3
North and East	122.6	131.8	138.6	146.9	155.1
Mainline	68.0	68.9	69.9	70.6	72.0
Gas Taps	5.1	5.2	5.3	5.3	5.3
Total Alberta	**202.0**	**212.3**	**220.1**	**229.6**	**239.7**
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	0.22	0.22	0.23	0.24	0.26
North and East	4.33	4.65	4.89	5.18	5.47
Mainline	2.40	2.43	2.47	2.49	2.54
Gas Taps	0.18	0.18	0.19	0.19	0.19
Total Alberta	**7.13**	**7.49**	**7.77**	**8.11**	**8.46**

Note:
Numbers may not add due to rounding.
Gas taps are located in all areas of the province.

Table 1-4: Summer Maximum Day Delivery Forecast

Project Area	July 2011 Design Forecast ($10^6m^3/d$)				
	2011/12	2012/13	2013/14	2014/15	2015/16
Peace River	6.0	6.1	6.1	6.5	7.0
North and East	122.4	131.5	138.2	146.4	154.4
Mainline	64.8	65.7	66.7	67.5	68.9
Gas Taps	2.4	2.4	2.5	2.5	2.5
Total Alberta	**195.6**	**205.7**	**213.5**	**222.9**	**232.9**
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2013/14**	**2014/15**	**2015/16**
Peace River	0.21	0.21	0.22	0.23	0.25
North and East	4.32	4.64	4.88	5.17	5.45
Mainline	2.29	2.32	2.36	2.38	2.43
Gas Taps	0.08	0.09	0.09	0.09	0.09
Total Alberta	**6.91**	**7.26**	**7.54**	**7.87**	**8.22**

Note:
Numbers may not add due to rounding.
Gas taps are located in all areas of the province.

1.4 RECEIPT FORECAST

NGTL develops its Receipt Forecast on an average annual basis and uses the following general approach:

- For conventional production, NGTL typically uses an internal pool-based forecasting model that incorporates established reserve estimates and actual production records from government sources. For discovered resources, the model uses current production rates and reservoir modelling, supplemented by internal analysis to estimate future production. In order to estimate the future supply from undiscovered resources, NGTL bases its assessment on play and pool-based resource estimates.
- For unconventional resources such as shale gas, NGTL typically uses well-based forecasting methods and models, supplemented with information gathered from customers, to generate forecasts of future production. Factors such as the total number of drilling locations available, well production profiles, and pace of development are considered along with material and equipment availability, potential capital requirements, and access constraints when developing a forecast of supply.

Exploration activity focused on unconventional gas has resulted in an expectation of significant incremental volumes of shale and tight gas entering the Alberta System in the Peace River Project Area in the near future. Incremental shale and tight gas supply is expected to offset declines in production from connected established reserves, resulting in an increase in overall production levels in the WCSB over the next five years.

Three major sources of gas supply used for the July 2011 Design Forecast included:

- Connected and Unconnected Reserves – supply from established conventional and unconventional reserves upstream of Receipt Points;

- Reserve Additions – supply from undiscovered resources, including conventional and unconventional resources; and
- Interconnections – supply from interconnections with other pipeline systems.

Gas supplied from storage facilities has not been included in the data presented in this section. Information pertaining to gas supply from Commercial Storage Facilities is contained in Section 1.6.

1.4.1 Average Receipt Forecast

The Average Receipt Forecast is the forecast aggregate receipts for the Alberta System for the 2011/12 through 2015/16 Gas Years. A summary of System Average Receipts by Gas Year and Project Area is expressed as an average daily flow and shown in Table 1-5.

Table 1-5: System Average Receipts

Project Area	July 2011 Design Forecast ($10^6m^3/d$)				
	2011/12	**2012/13**	**2011/12**	**2014/15**	**2011/12**
Peace River	138.9	155.5	172.2	193.3	212.1
North and East	27.7	26.2	26.4	28.2	27.8
Mainline	130.6	130.7	130.3	130.5	126.9
Total System	297.2	312.3	328.9	352.0	366.7
Project Area	**July 2011 Design Forecast (Bcf/d)**				
	2011/12	**2012/13**	**2011/12**	**2014/15**	**2011/12**
Peace River	4.90	5.48	6.08	6.82	7.49
North and East	0.98	0.92	0.93	1.00	0.98
Mainline	4.61	4.61	4.60	4.61	4.48
Total System	10.49	11.02	11.61	12.43	12.95
Note: Numbers may not add due to rounding.					

1.5 SUPPLY DEMAND BALANCE

Supply received on the Alberta System is balanced with System deliveries (net of gas in storage). System deliveries by destination are shown in Figure 1-2, while System receipts by Project Area are shown in Figure 1-3.

Figure 1-2: System Deliveries by Destination

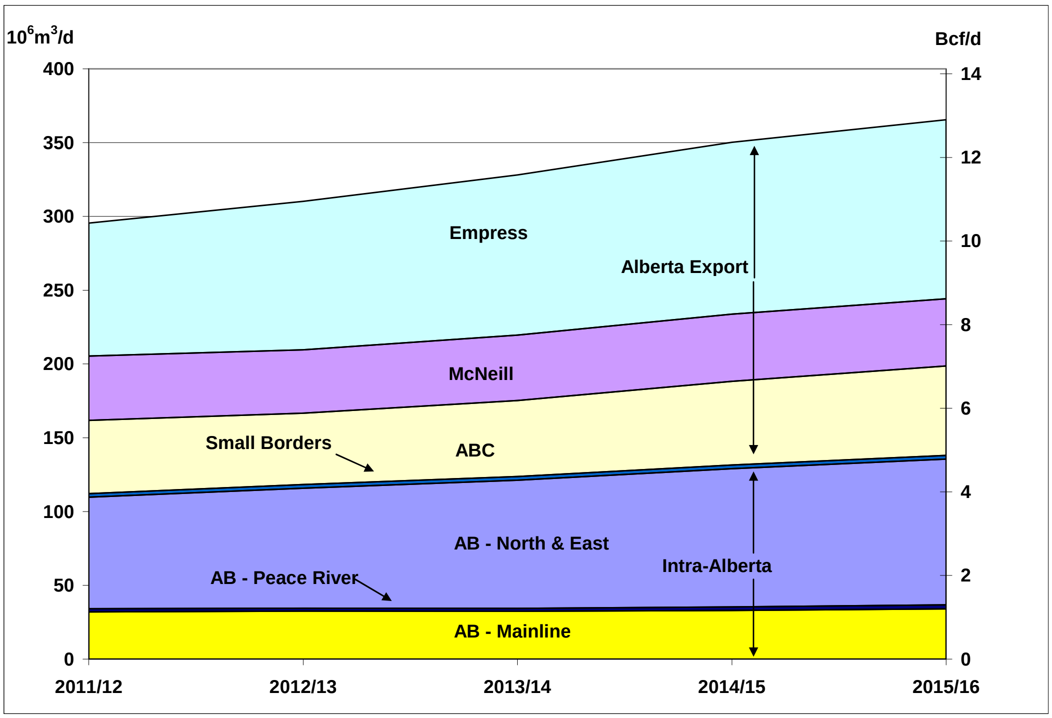
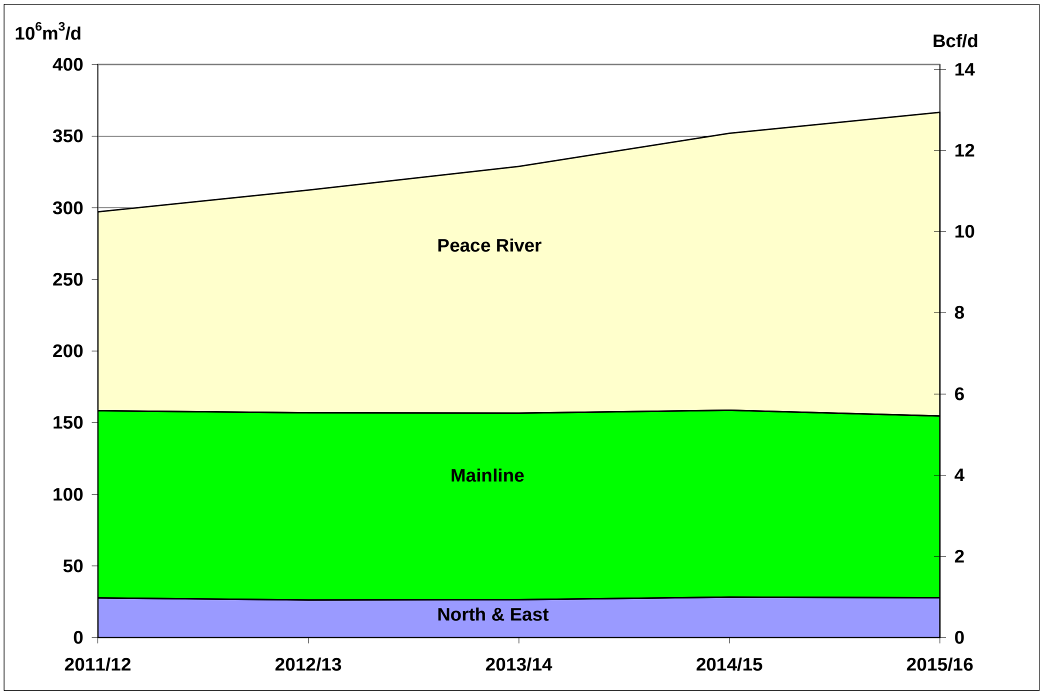


Figure 1-3: System Receipts by Project Area



1.6 STORAGE FACILITIES

1.6.1 Commercial Storage

There are eight commercial storage facilities connected to the Alberta System (AECO 'C', Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek, Severn Creek and Warwick Southeast Meter Stations). The total deliverability from Storage Facilities is significant, but actual maximum day receipts from storage are dependent upon a number of factors, including market conditions, the level of working gas in each storage facility, compression power at each Storage Facility, and Alberta System operations.

For design purposes, a supply contribution from Storage Facilities is used to meet peak day winter delivery requirements and provide for a better correlation between forecast design flow requirements and historical actual flows for the winter period. Historical withdrawals during recent winter periods at AECO 'C', Carbon, Crossfield East, Chancellor and Severn Creek were used to determine a reasonable expected rate of withdrawal for future winter seasons. The level of commercial storage withdrawal used in the design of the Alberta System for the winter season was 17.7 $10^6m^3/d$ (630 MMcf/d), which is similar to the average winter withdrawal rate from these facilities.

The receipt meter capacity for each of the connected Commercial Storage Facilities is shown in Table 1-6.

Table 1-6: Receipt Meter Capacity from Commercial Storage Facilities

Storage Facility	Receipt Meter Capacity from Commercial Storage Facilities – 2011/12	
	$10^6m^3/d$	Bcf/d
AECO C	50.7	1.79
Big Eddy	35.4	1.25
Carbon	13.8	0.49
Chancellor	35.2	1.24
Crossfield East #2	14.1	0.50
January Creek	14.1	0.50
Severn Creek	5.6	0.20
Warwick Southeast	6.1	0.22
Total	**175.0**	**6.18**

Note:
Storage is currently considered as an interruptible supply source.
Numbers may not add due to rounding.

1.6.2 Peak Shaving Storage

The Fort Saskatchewan Salt Caverns comprise a peak shaving Storage Facility in the Greater Edmonton Area within the North of Bens Lake Design Area of the Alberta System. Similar to Commercial Storage Facilities, the total deliverability from the peak shaving Storage Facility is significant, but the actual maximum day receipt from storage is dependent upon a number of factors, including market conditions, the level of working gas, compression power at the storage facility, and Alberta System operations.

For design purposes, a maximum withdrawal rate of 6,500 $10^3m^3/d$ was used to meet the peak expected winter season delivery requirements.

2.1 INTRODUCTION

This section presents an overview of the design flow requirement, as described in the Facilities Design Methodology Document, Section 3.5 – Mainline Facilities Flow Determination. The document can be accessed online at:
http://www.transcanada.com/customerexpress/5133.html

This section also presents the proposed natural gas transportation mainline facilities to be applied for on the Alberta System in the 2012 calendar year to transport the design flow requirements for the 2012/13 Gas Year. Included is information regarding size, routes, locations and cost estimates for the proposed facilities.

The design flow requirements are represented by peak expected flows and are presented for design areas where new mainline facilities are required. Peak expected flows are based on the July 2011 design forecast presented in Section 1.

This Section show a comparison of historical flow for the 2006/07 Gas Year through to the 2010/11 Gas Year as well as the projected winter and summer peak expected flow to the 2015/16 Gas Year. Additionally, the current design capability is shown for the Gas Year when facilities are required within each applicable design area. Where there is a shortfall between peak expected flow and the existing design capability, a facility solution has been proposed. A facility application to the regulator for construction and operation is triggered by Firm Transportation (FT) contracts and submitted to ensure the facility is in place in time to meet the FT requirements.

An overview of the design peak expected flows and proposed facilities resulting from the July 2011 design forecast was presented at the TTFP meeting on November 22, 2011.

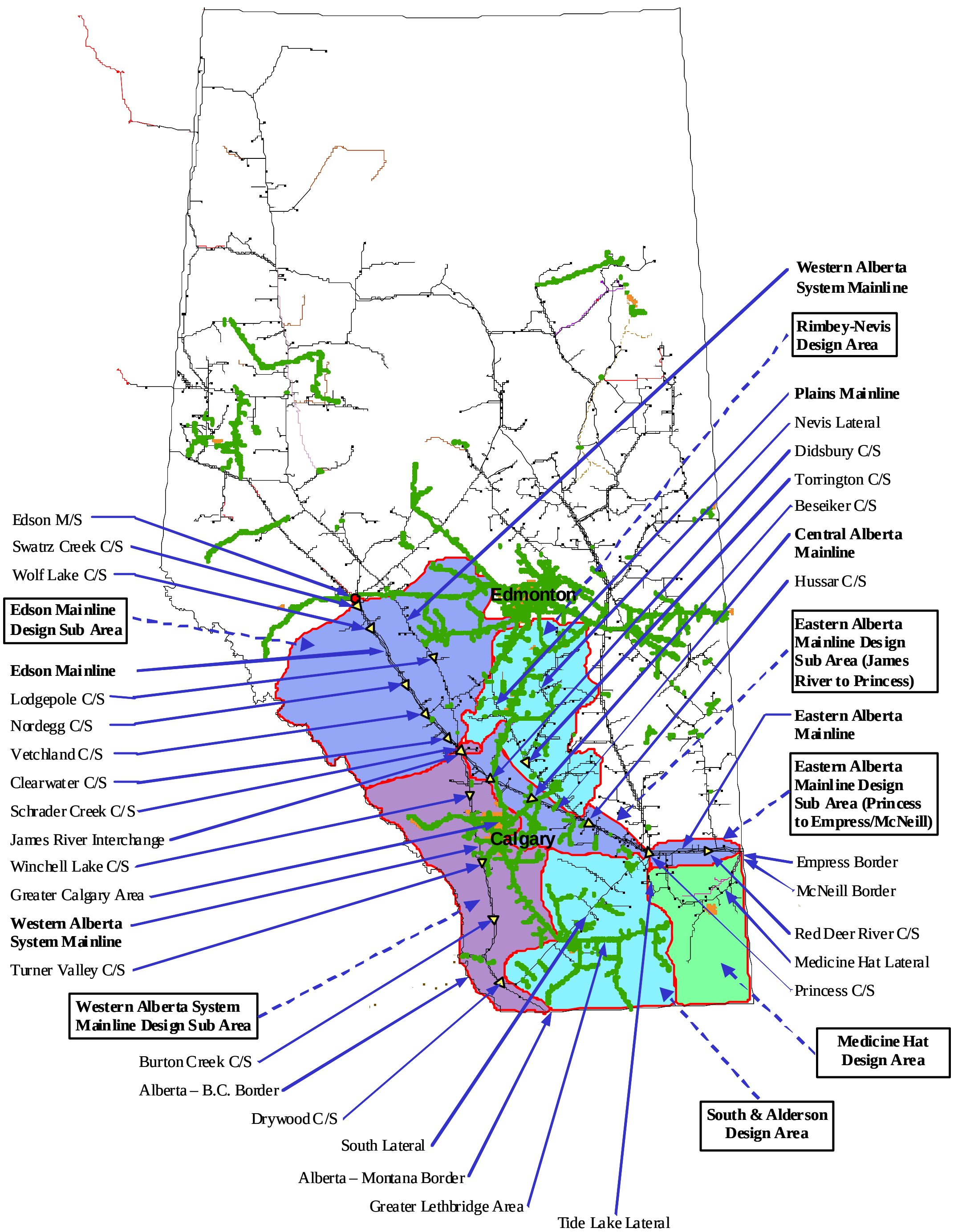
A summary of the status of mainline facilities that have been applied for or placed in-service since the December 2010 Annual Plan is included in Appendix 2 – Facility Status Update.

2.2 MAINLINE PROJECT AREA

The Mainline Project Area comprises the Mainline, Rimbey-Nevis, South and Alderson, and Medicine Hat Design Areas (see Figure 2-1).

In the Mainline Project Area, the proposed facility modification is required to meet the required gas deliveries in the Rimbey-Nevis Design Area. Additional information on design flow conditions can be found in the Facility Design Methodology Document Section 3.5 – Mainline Facilities Flow Determination.

Figure 2.1: Mainline Project Area



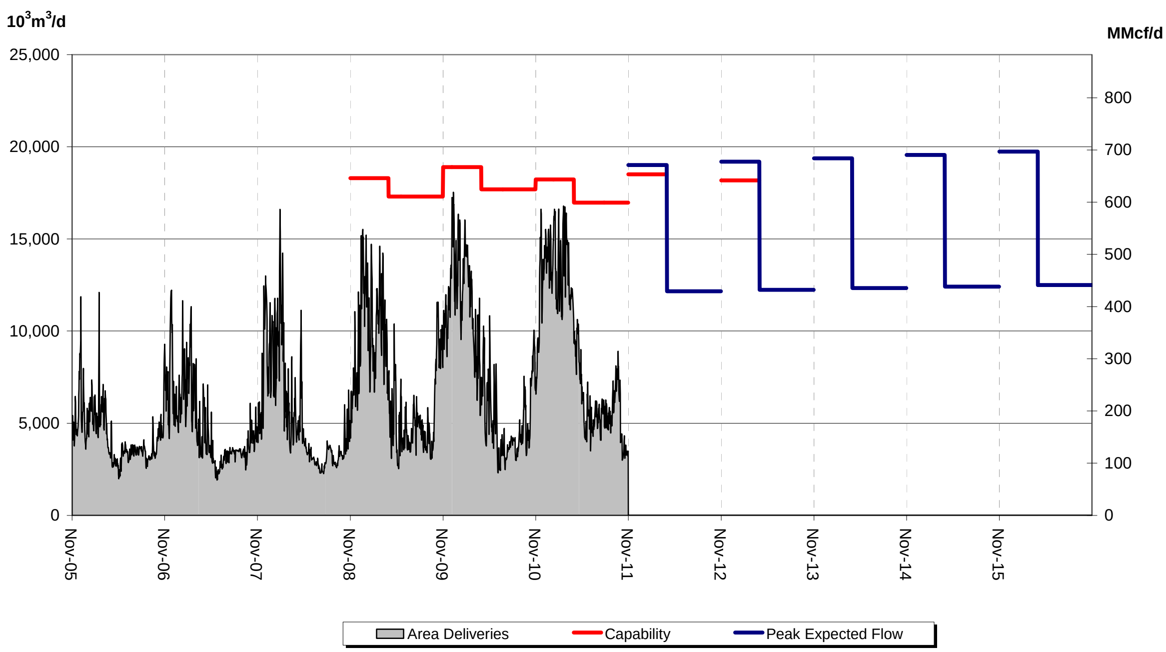
2.2.1 Rimbey-Nevis Design Area

2.2.1.1 Design Flows – Rimbey-Nevis Design Area

The peak expected flow for the flow within design condition in the Rimbey-Nevis Design Area is the net effect of maximum deliveries less the minimum available local supply within the area. Supply on the Nevis Lateral has been used to supplement the supply on the Rimbey Lateral to meet Rimbey Lateral demand. As the Nevis Lateral supply declines, the proposed Torrington Compressor Station modification will be required to transport additional supply from south of the Torrington Compressor Station to the Rimbey Lateral to meet the peak winter demand.

Figure 2-2 provides historical actual flow, the design capability for the area, and projected peak expected flow. The peak expected flow is anticipated to rise throughout this forecast period.

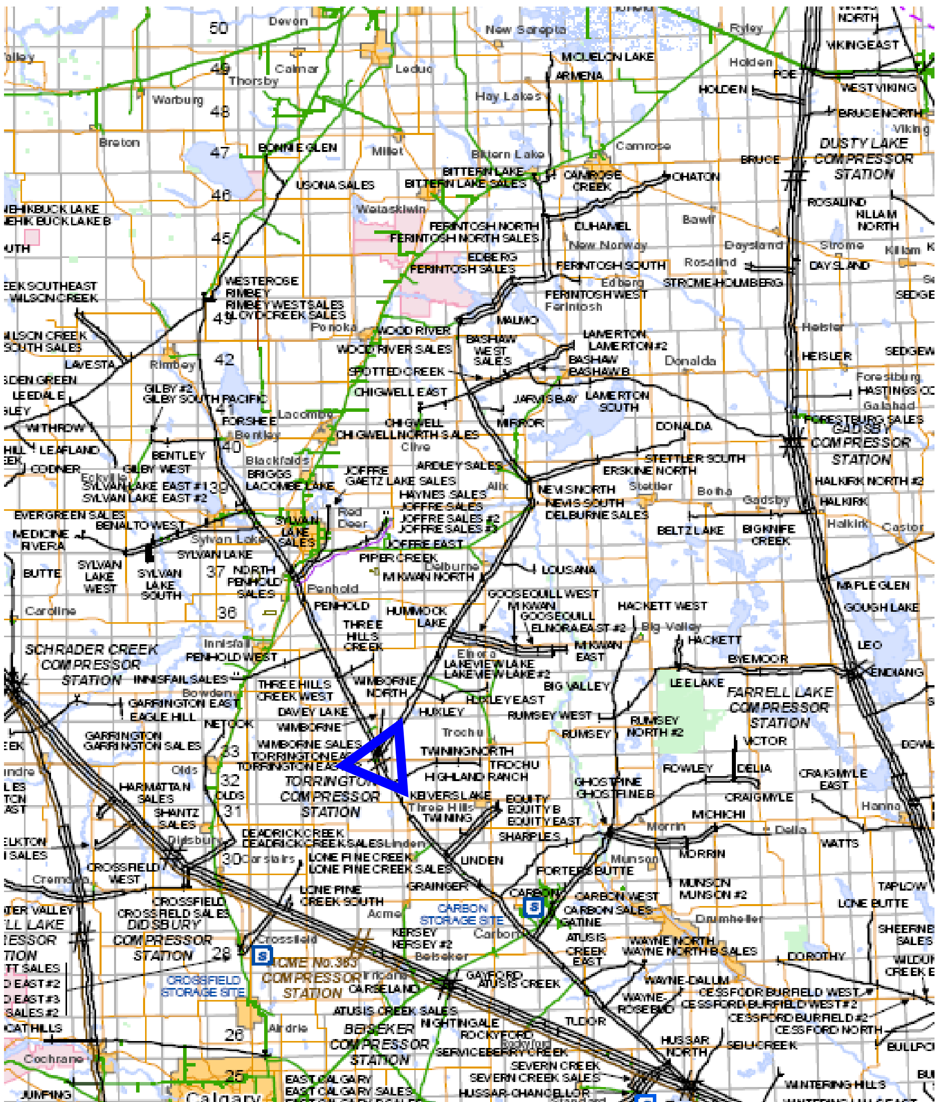
Figure 2-2: Deliveries / Design Capability / Peak Expected Flow for Rimbey-Nevis Design Area



2.2.1.2 Proposed Facilities – Rimbey-Nevis Design Area

Figure 2-3 shows the location of the proposed Torrington Compressor Station Modifications within the Rimbey-Nevis Design Area.

Figure 2-3: Location of Proposed Torrington Compressor Station Modifications



LEGEND:

Proposed Compressor Modification

The Torrington Compressor Station Modifications permit application will be applied for at the NEB in 2012 (see Table 2-1) and is proposed to be in-service in November 2012.

Table 2-1: Rimbey-Nevis Design Area Proposed Facilities

Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)
1	Torrington Compressor Station Modifications	Bi-directional flow	Nov 2012	7.1
Capital Costs are in 2011 dollars and include AFUDC.			**Total**	**7.1**

2.2.2 Western Alberta Mainline Design Sub Area

2.2.2.1 Urban Pipeline Project – Greater Calgary Area

The Northeast Calgary Connector is proposed by AP as a risk mitigation project, not a system expansion project, and therefore, the Design Flows are not presented.

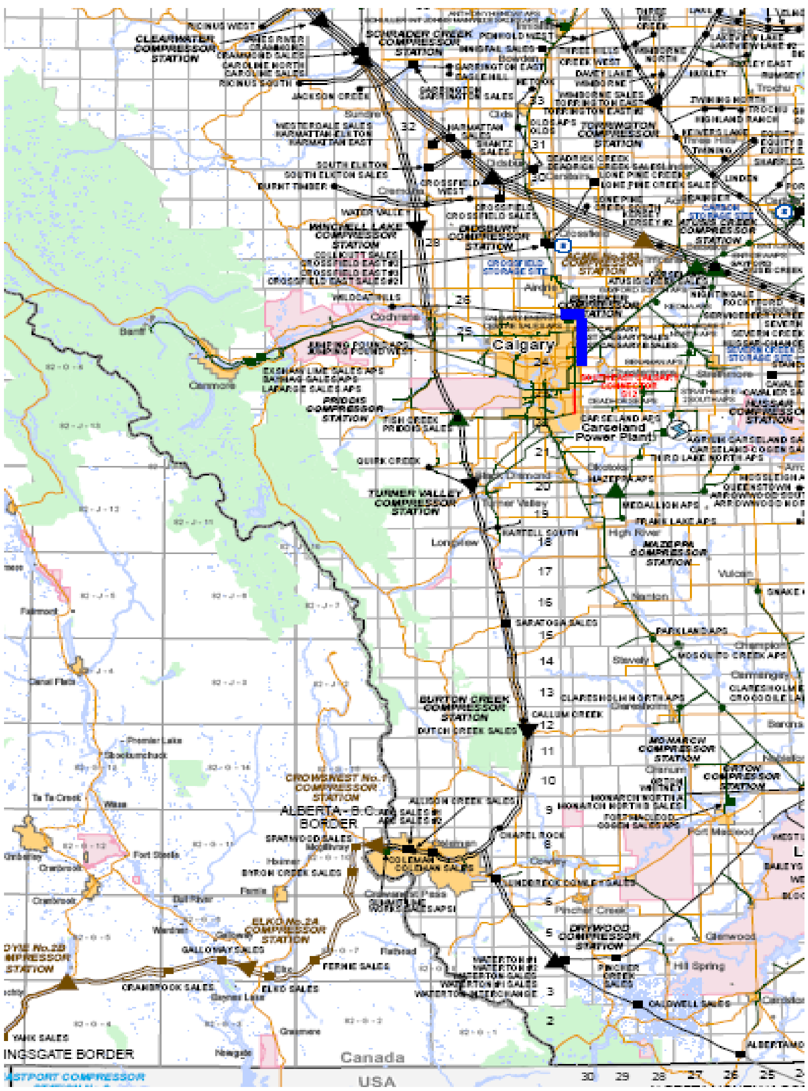
AP continues to relocate high-pressure transmission facilities to the transportation utility corridor (TUC) as part of a five-year plan to provide safe and reliable service within urban service areas. This initiative moves high-pressure transmission pipe to the TUC, away from developed and populated urban areas. Development opportunities within the TUC are restricted, which reduces the risk of a high consequence event as compared to existing pipelines.

The facility design for the Northeast Calgary Connector was proposed by AP. It was reviewed by TransCanada to confirm that the scope proposed is consistent with the Alberta System design requirements in the NGTL Facility Design Methodology Document.

2.2.2.2 Proposed Facilities - Western Alberta Mainline Design Sub Area

Figure 2-4 shows the location of the proposed Northeast Calgary Connector within the Western Alberta Mainline Design Sub Area.

Figure 2-4: Western Alberta Mainline Design Sub Area



LEGEND:

Proposed Pipeline

The Northeast Calgary Connector permit application will be applied for at the AUC in 2012 (see Table 2-2) and is proposed to be in-service in November 2013.

Table 2-2: Western Alberta Mainline Design Sub Area Proposed Facilities

Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)
1	Northeast Calgary Connector	17 km NPS 24	Nov 13	50.5
Capital Costs are in 2011 dollars and include AFUDC.			**Total**	**50.5**

3.1 SCOPE

This section generally presents an overview of the receipt and delivery meter stations, extension facilities and lateral loops that are required to meet customer requests for firm service. However, there are currently no proposed extensions, lateral loops or associated meter stations in this Annual Plan.

New extensions, lateral loops and associated meter stations proposed after the 2011 Annual Plan is issued will be shown as required, in the 2012 Facility Status Update. These facilities will be designed following the Transportation Design Process in Section 4 of the Facilities Design Methodology Document, which can be accessed online at:

http://www.transcanada.com/customerexpress/5133.html

If mainline facilities are required, transportation service may be provided to Customers on an interruptible basis until the required mainline facilities are in service. If a Customer's request for service results in the addition of new or modified receipt meter stations, the minimum term and minimum contractual obligation are determined in accordance with the economic criteria described in the *Criteria for Determining Primary Term* (Appendix E of the Alberta System Gas Transportation Tariff).

A summary of the status of the facilities that have been placed in-service or applied for since the issuance of the 2010 Annual Plan is included in Appendix 2 – Facility Status Update.

The following definitions are provided to help the reader understand the Annual Plan. The definitions are not intended to be precise or exhaustive and have been simplified for ease of reference. These definitions should not be relied upon in interpreting NGTL's Gas Transportation Tariff or any Service Agreement. Capitalized terms not otherwise defined here are defined in NGTL's Gas Transportation Tariff. The defined terms in this Glossary of Terms might not be capitalized in their use throughout the Annual Plan.

Alberta Average Field Price

Average estimated price of natural gas (post processing) prior to receipt into the Alberta System. The Alberta Average Field Price is equivalent to the Alberta Reference Price (ARP).

Allowance for Funds Used During Construction (AFUDC)

The capitalization of financing costs incurred during construction of new facilities before the facilities are included in rate base.

Annual Plan

A document outlining NGTL's planned facility additions and major modifications.

Average Annual Delivery

The average day delivery determined for the period of one Gas Year. All forecast years are assumed to have 365 days.

Average Day Delivery

The average day delivery over a given period of time, determined by summing the total volumes delivered divided by the number of days in that period. It is determined for either a Delivery Point or an aggregation of Delivery Points.

Average Receipt Forecast

The forecast of average flows expected to be received onto the Alberta System at each receipt point.

Coincidental

Occurring at the same time.

Delivery Meter Station

A facility which measures gas volumes leaving the Alberta System.

Delivery Point

The point where gas may be delivered to Customer by Company under a Schedule of Service, which shall include but not be limited to Export Delivery Point, Alberta Delivery Point, Extraction Delivery Point and Storage Delivery Point.

Delivery Design Area

The Alberta System is divided into five delivery design areas used to facilitate the transfer of delivery service within or between Delivery Design Areas. The Delivery Design Areas are:

- Northwest Alberta and Northeast BC Delivery Area;
- Northeast Delivery Area;
- Southwest Delivery Area;
- Southeast Delivery area and
- Edmonton and Area Delivery Area.

Demand Coincidence Factor

A factor applied to adjust the system maximum and minimum day deliveries for all of the Alberta Delivery Points within a design area to a value more indicative of the expected actual peak day deliveries.

Design Area

The Alberta System is divided into three project areas – Peace River Project Area, North and East Project Area, and the Mainline Project Area. These project areas are then divided into design and sub-design areas.

Dividing the system this way allows the system to be modelled in a way that best reflects the pattern of flows in each specific area of the system.

Design Capability

The maximum volume of gas that can be transported in a pipeline system considering design assumptions. Usually presented as a percentage of design flow requirements.

Design Flows

The forecast of Peak Expected Flow that is required to be transported in a pipeline system considering design assumptions.

Design Forecast

A forecast of the most current projection of receipts and deliveries over a five-year design horizon.

Expansion Facilities

Facilities that will expand the existing Alberta System to/from the point of Customer connection, including any pipeline loop of the existing system, metering and associated connection piping and system compression.

Extension Facilities

Facilities that connect new or incremental supply or markets to the Alberta System.

Firm Transportation

Service offered to Customers to receive gas onto the Alberta System at Receipt Points or deliver gas off of the Alberta System at Delivery Points with a high degree of reliability.

Gas Year

A period of time beginning at eight hundred hours (08:00) Mountain Standard Time on the first day of November in any year and ending at eight hundred hours (08:00) Mountain Standard Time on the first day of November of the next year.

Interruptible Transportation

Service offered to Customers to receive gas onto the Alberta System at Receipt Points or deliver gas off of the Alberta System at Delivery Points, provided capacity exists in the facilities, that is not required to provide firm transportation.

Lateral

A section of pipe that connects one or more Receipt or Delivery Points to the mainline.

Load / Capability Analysis

A statistical technique for comparing the available seasonal mainline capability in a design or design sub area with the expected range of seasonal loads or flows. The analysis provides a measure of both the probability of a service disruption, where load or flows exceed the available capability, and the expected magnitude of a service disruption.

Loop

The paralleling of an existing pipeline by another pipeline.

Mainline

A section of pipe, identified through application of the mainline system design assumptions, necessary to meet the aggregate requirements of all customers.

Maximum Day Delivery

The forecast maximum volume, included in the design, to be delivered to a Delivery Point.

Maximum Operating Pressure

The maximum operating pressure at which a pipeline is operated.

Minimum Day Delivery

The forecast minimum volume, included in the design, to be delivered to a Delivery Point.

NPS

Nominal pipe size, in inches.

Non-coincidental

Non-simultaneous occurrence.

Peak Expected Flow

The peak flow that is expected to occur at a point or points on the Alberta System. For a design area or sub design area, this is the coincidental peak of the aggregate flow. For a single receipt point, it is equivalent to field deliverability.

Project Area

For design purposes, the Alberta System is divided into three project areas – Peace River Project Area, North and East Project Area, and the Mainline Project Area.

Dividing the system this way allows the system to be modelled in a way that best reflects the pattern of flows in each specific area of the system. The Project Area may be amended from time to time by Company in consultation with the Tolls, Tariff, Facilities and Procedures (TTFP) Taskforce, provided Company has given six months notice of such amendment to its Customers.

Receipt Area

Areas where gas is received onto the Alberta System. The facilities in these areas include receipt meter stations and laterals**.**

Receipt Meter Station

A facility which measures gas volumes entering the Alberta System.

Receipt Point

The point in Alberta at which gas may be received from Customer by Company under a Schedule of Service.

Storage Facility

Any commercial facility where gas is stored, that is connected to the Alberta System, and that is available to all Customers.

Summer Season

The period commencing on April 1 and ending on October 31 of any calendar year.

System Annual Throughput

The total amount of gas that is transported or anticipated to be transported in one calendar year.

System Average Annual Throughput

The total amount of gas that is transported or anticipated to be transported in one gas year.

System Average Receipts

The forecast of aggregate average receipts at all Receipt Points.

System Maximum Day Deliveries

The forecast of aggregate maximum day deliveries at all Delivery Points.

Transportation Design Process

The process which includes the qualifying of Customer's applications for service, designing the additions to the system, sourcing all required facilities, and installing the facilities to meet firm transportation requests.

Two-way Flow Stations

A meter station on the Alberta System where gas can either be received onto the Alberta System or be delivered off of the Alberta System.

Winter Season

The period commencing on November 1 of any year and ending on March 31 of the following year.

This section describes the current status of facilities that were applied for, are under construction or have been placed on-stream since the 2010 Annual Plan was issued on December 20, 2010. Periodic updates are being provided based on the level of activity occurring with respect to facilities.

Applied-for Facilities	Description	Status	Previous Annual Plan Reference	Forecast Cost [1] ($Millions)
Alder Flats South Receipt Meter Station Upgrade	882 Orifice Meter	In-service	March 28, 2011 TTFP Notification	1.6
Bear River West Meter Station Upgrade	882 Orifice Meter	In-service	2010	1.4
Bear River Lateral Loop No. 2	10 km NPS 10	In-service	2010	7.7
Berland River C/S Unit Addition	28 MW	Under construction	April 12, 2011 TTFP	70.9
Cabin Meter Station	2 - 2012U-8 Ultrasonic Meter	Under construction	2009	4.7
Cheecham West #2 Sales Meter Station Modifications	2 - 1610U Ultrasonic Meter	Applied for	June 2, 2011 TTFP Notification	2.5
Cheecham West Crossover	14 km NPS 20	Applied for	April 12, 2011 TTFP	19.6
Chinchaga Lateral Loop No. 3	33 km NPS 48	Applied for	July 12/Sept 13, 2011 TTFP	103.4
Cutbank River Lateral Loop (Bald Mountain Section)	38 km NPS 24	In-service	July 13, 2010 TTFP	46.1
Cutbank River Lateral Loop (Red Rock Section)	10 km NPS 24	Under construction	May 10, 2011 TTFP	21.7
Drywood Control Valve	Control Valve	In-service	August 3, 2011 TTFP Notification	1.7
Foothills Tide Lake Control Valve	Control Valve	In-service	Sept. 21, 2011 TTFP Notification	1.9
Gilby Sales Meter Station	NPS 2 Low Volume Sales (LVS)	In-service	NA	0.5
Gold Creek C/S Unit Addition	28 MW	In-service	2010	60.3
Gordondale Lateral Loop No. 2	24 km NPS 42	Under construction	2010	65.3

[1] Forecast Cost is the applied for cost or the forecast cost to complete for facilities in-service.

Applied-for Facilities	Description	Status	Previous Annual Plan Reference	Forecast Cost [1]($Millions)
Gordondale East Meter Station	882 Orifice Meter	Applied for	October 27, 2011 TTFP Notification	1.5
GPML Loop (Karr North and Nosehill Creek Sections)	16 km NPS 42 (Karr N.) 3.5 km NPS 42 (Nosehill Ck.)	Under construction	2010	39.2 21.4
Groundbirch Mainline (Saturn Section) and Meter Station	24 km NPS 36	Under construction	2010	59.0
Groundbirch East Meter Station	1212-4U Ultrasonic Meter	Proposed	November 30, 2011 TTFP Notification	2.2
Harmattan Straddle Plant Connections	NPS 24 tie-in	Applied for	NA	CIAC
Hidden Lake North C/S	15 MW	Under construction	2010	53.0
Hidden Lake Streaming & Eastbound Pipe Modifications	Yard Piping Modifications	In-service	June 13, 2011 TTFP	3.0 3.4
Horn River Mainline (HRML) Loop (Kyklo Creek Section)	29.1 km NPS 42	Applied for	2010	81.2
Horn River Project (Ekwan & Cabin Sections)	85.2 km NPS 24 72 km NPS 36	Under construction	2009	253.2
HRML (Komie North Section) & Fortune Creek M.S.	100 km NPS 36	Applied for	July 12/Sept 13, 2011 TTFP	227.3 2.5
HRML Loop (Townsoitoi Section)	27 km NPS 42	Proposed	July 12/Sept 13, 2011 TTFP	77.5
Ipiatik Lake Sales Meter Station	2 - 860 Turbine Meter	In-service	February 4, 2011 TTFP Notification	1.4
Kearl Extension	4.2 km NPS 24 19.1 km NPS 20	In-service	2009	34.3
Kearl Meter Station	2 - 1612U Ultrasonic Meter	In-service	2009	2.5
Kettle River North Lateral Loop (Engstrom Section)	11.5 km NPS 24	Applied for	April 12, 2011 TTFP	20.2
Komie East Extension	2.2 km NPS 24	Under construction	2009	3.2
Komie East Meter Station	1010U-4 Ultrasonic Meter	Under construction	2009	2.6
Leismer to Kettle River Crossover	79 km NPS 30	Applied for	2010 and May 10, 2011 TTFP	156.8
Livock Meter Station	NPS 2 LVS	In-service	February 4, 2011 TTFP Notification	0.5

Applied-for Facilities	Description	Status	Previous Annual Plan Reference	Forecast Cost [1]($Millions)
Little Hay Creek Meter Station	442 Orifice Meter	Under construction	2009	1.7
Mayberne Receipt Meter Station Upgrade	880-2 Turbine Meter	In-service	May 10, 2011 TTFP Notification	1.0
Mayberne No. 2 Receipt Meter Station	880-2 Turbine Meter	In-service	January 28, 2011 TTFP Notification	1.2
Moody Creek C/S	15 MW	Under construction	2010	57.1
Musreau Lake Lateral Loop No. 2	16 km NPS 20	Under construction	May 10, 2011 TTFP	22.9
Musreau Lake Meter Station Modifications	2 - 1610U Ultrasonic Meter	Under construction	May 11, 2011 TTFP Notification	2.5
Musreau Lake No. 2 Meter Station	880U Ultrasonic Meter	In-service	August 16, 2011 TTFP Notification	1.1
Northwest Mainline Loop (Timberwolf Section)[2]	49.8 km NPS 48	Applied for	2010	153.6
NWML Loop (Pyramid Section	30 km NPS 48	Proposed	July 12/Sept 13, 2011 TTFP	92.5
Obed North Receipt Meter Station Upgrade	1010U Ultrasonic Meter	In-service	June 3, 2011 TTFP	1.8
Pelican Mainline Back-up Loop Relocation	1.4 km NPS 10	In-service	July 13, 2010 TTFP	CIAC
Rat Creek West Sales Meter Station	880U Ultrasonic Meter	In-service	January 7, 2011 TTFP Notification	0.5
Saamis Sales Meter Station	2 - 640T Turbine Meters	In-service	2010	1.2
Sand Creek Meter Station Upgrade	880U Ultrasonic Meter	In-service	June 17, 2011 TTFP Notification	1.4
Sierra Meter Station	880U-4 Ultrasonic Meter	Under construction	2009	3.3
Snuff Mountain North Receipt Meter Station	662 Orifice Meter	In-Service	April 7, 2011 TTFP Notification	1.3
Tanghe Creek Lateral Loop No. 2 (Cranberry Section)	32.3 km NPS 48	Applied for	2010	89.2
Tanghe Creek Lateral Loop No. 2 (Sloat Creek Section)	38 km NPS 48	Under construction	2010	115.0
Watino Crossover and Calais Extension	6.8 km NPS 4	In-service	2009	4.6

[2] The 2010 Annual Plan Chapter 2 included two sections of Northwest Mainline called Timberwolf and Sabbath sections. Since these were to be constructed together, both were combined under a single name – Timberwolf Section.

Applied-for Facilities	Description	Status	Previous Annual Plan Reference	Forecast Cost [1] ($Millions)
Whiskey Jack Lake Meter Station	2 - NPS 6 Turbine Meter	Under construction	June 13, 2011 TTFP Notification	1.4