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February 26, 2010

All Customers
Other Interested Parties

Re: 2009 Annual Plan

NOVA Gas Transmission Ltd. ("NGTL") has posted its 2009 Annual Plan on TransCanada PipeLines Limited's website at:

http://www.transcanada.com/Alberta/regulatory_info/facilities/index.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 Dave Schultz, Director, System Design, at (403) 920-5574, or Stephen Clark, Vice President, Commercial - West, Canadian and Eastern U.S. Pipelines at (403) 920-2018.

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

[Original Signed by]

Murray Sondergard
Director, Regulatory Services
Law and Regulatory Affairs

2009
ANNUAL PLAN

NOVA Gas Transmission Ltd.

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EXECUTIVE SUMMARY

The 2009 Annual Plan provides NOVA Gas Transmission Ltd.'s ("NGTL") Customers and other interested parties with an overview of the identified potential Alberta System facilities for the 2010/11 Gas Year. It also references the current status of facilities that were applied for, are pending regulatory approval, are under construction or are on-stream, following the issuance of the December 2008 Annual Plan.

Effective April 29, 2009, the Alberta System came under federal jurisdiction and is now subject to regulation by the National Energy Board. While NGTL is not required to prepare and file an Annual Plan, NGTL recognizes its customers and other interested parties value the information that is included in it. NGTL has therefore produced this Annual Plan.

This Annual Plan can be accessed at TransCanada PipeLines Limited's website located at:

http://www.transcanada.com/Alberta/regulatory_info/facilities/index.html

Definitions for terms commonly used in the Annual Plan are located in the Glossary in Appendix 1. Capitalized terms used in the Annual Plan are defined in NGTL's Gas Transportation Tariff, which can be accessed at the following website:

http://www.transcanada.com/Alberta/info_postings/tariff/index.html

The Annual Plan describes NGTL's design methodology, including assumptions and criteria, design forecast, its long term outlook for receipts, gas deliveries, peak expected flows, design flows and proposed facilities for the 2010/11 Gas Year. This Annual Plan is based on NGTL's June 2009 design forecast of gas receipts and deliveries. For the first time, the forecast includes significant future gas receipt volumes from unconventional shale gas plays. As technology for unlocking these resource plays continues to evolve, the potential for further increases to unconventional production exists.

The proposed facilities included in the 2009 Annual Plan for the 2010/2011 Gas Year are shown below in Table 1.

Table 1
Proposed Facilities

Project Area	Proposed Facilities	Annual Plan Reference	Description	Required In-Service Date	Capital Cost ($ millions)
Peace River	Doe Creek Lateral Loop	Chapter 6	8.5 km x NPS 16	November 2010	11.5
Peace River	Henderson Creek Lateral Loop #3	Chapter 6	9.2 km x NPS 16	November 2010	13.6
Peace River	Horn River Mainline (Cabin Section) & (Komie East Extension) & Meter Stations	Chapter 6	72 km x NPS 36 2.2 km x NPS 24	April 2012	245.3
Peace River	Horn River Mainline (Ekwan Section)	Chapter 6	83 km x NPS 24	April 2012	62.0
North & East	Bear River West Lateral Loop	Chapter 6	8.5 km x NPS 10	March 2011	7.4
North & East	Kearl Extension & Meter Station	Chapter 6	19.3 km x NPS 20 4 km x NPS 24	July 2011	55.1
Capital Costs are in 2009 dollars and include AFUDC			**Total**		**394.9**

NGTL is also proposing to decommission a 265 km section of the NPS 20 Peace River Mainline including the Valleyview Compressor Station. This work is described in further detail in Section 5.2.

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. Please provide your comments to:

- Landen Stein, Manager, Customer Solutions, at (403) 920-5311;
- Gord Toews, Manager, Mainline Planning West, at (403) 920-5903;
- Dave Schultz, Director, System Design, at (403) 920-5574;
- Steve Emond, Vice President, System Design and Commercial Operations, at (403) 920-5979; or
- Stephen Clark, Vice President, Commercial - West, Canadian and Eastern U.S Pipelines at (403) 920-2018.

CHAPTER 1 – THE ANNUAL PLAN PROCESS

1.1 Introduction

This chapter provides background information to the Annual Plan and gives an overview of how industry participates with NOVA Gas Transmission Ltd. ("NGTL") to understand and influence the development of the Alberta System.

1.2 Annual Plan Scope

The 2009 Annual Plan contains facilities requirements for the 2010/11 Gas Year commencing on November 1, 2010 and ending on October 31, 2011 ("Planning Period"). It also references the current status of facilities that were applied for, are pending regulatory approval, are under construction or are on-stream, following the issuance of the December 2008 Annual Plan.

In this Annual Plan there are no proposed Mainline Facilities. There is one section of the Peace River Mainline proposed to be decommissioned and proposed extension facilities and lateral loops are included in Chapter 6.

1.3 June 2009 Design Forecast

The June 2009 design forecast of receipts and deliveries was used in the preparation of this Annual Plan.

1.4 Industry Participation

To facilitate a participative and consultative role for industry participants in policy formation and system design, NGTL uses:

- committees;
- discussion papers or proposals which target specific issues;
- information circulars;
- industry presentations; and
- Internet-based applications, including Customer Express and NrG Highway.

The Tolls, Tariff, Facilities and Procedures Committee ("TTFP") is an important forum for reviewing Alberta System facilities plans with industry. Participation on the TTFP is open to any affected party that would directly experience implications of importance due to outcomes achieved by this committee, including facility-related decisions. The TTFP provides for the timely exchange of information among interested parties and provides a significant opportunity for parties to influence facility proposals and long-term planning. The design forecast, design flows and facility requirements were presented to the TTFP in November and December 2009, prior to the finalization of this Annual Plan.

Periodic updates on the Alberta System expansion plans and capital program, and the impact of the plans and program on the cost of transportation, are provided to all Customers. These updates provide opportunity for Customer input. NGTL also makes presentations to other industry committees and government agencies, and offers to meet with any association or Customer on system design inquiries or any other issue. Over the last year, NGTL has participated in meetings with various Customers and a broad range of consumers, marketers, and distributors in which Alberta System facilities requirements and capital programs were discussed.

CHAPTER 2 – FACILITIES DESIGN METHODOLOGY

2.1 Introduction

This chapter provides an overview of the facility planning processes employed to identify mainline facility requirements and new receipt and delivery meter stations and extension facilities. The overview will provide readers with the background to understand the purpose of and necessity for the facilities requirements for the Planning Period.

The Guidelines for New Facilities describe the new facilities that NGTL may construct. The Guidelines for New Facilities can be accessed on TransCanada's website at:
http://www.transcanada.com/Alberta/industry_committee/tolls_tariff_facilities_procedures/index.html

New facilities are divided into two categories:

- expansion facilities, which would include pipeline loop of the existing system, metering and associated connection piping and system compression; and
- extension facilities, which would include pipelines generally greater than 20 km in length, 12 inches or more in diameter, with volumes greater than 100 MMcf/d, that are expected to meet the aggregate forecast of two or more facilities (gas plants/industrials).

The transportation design process, described in Section 2.9, contains two distinct facility planning sub-processes. The first sub-process relates to the facilities planning, design and construction of mainline expansion facilities. The second sub-process relates to the facilities planning, design and construction of new receipt and Alberta delivery facilities and connecting extensions. NGTL has used these sub-processes to identify the necessary facility additions required to be placed in-service in the Planning Period.

An important element of the transportation design process is the filing of specific facility applications. Facilities applications are filed with the regulator to facilitate proposed construction schedules, which must account for summer or winter construction constraints and the long period of time required to procure major facility components such as pipe, compressors and valves.

The design flow determination as described in Section 2.6 is used to determine the mainline expansion facility requirements. The mainline system design includes a peak expected flow determination, as described in Section 2.6. The peak expected flow determination is used because of the increasing difference between levels of firm transportation contracts and actual flows and is used to identify potential transportation service constraints where the peak expected flow exceeds the system capability. Should a capability constraint be identified, any resulting facilities additions required to transport the peak expected flows are subjected to a risk of shortfall analysis prior to being recommended.

Receipt and Alberta delivery facilities, intended to meet Customers' firm transportation Service Agreements, are designed as part of the transportation design process but are constructed independently of the construction of mainline expansion facilities. If these facilities are in place prior to the completion of mainline expansion facilities, Customers may be offered interruptible transportation pending the availability of sufficient mainline transportation capability.

These two facility planning sub-processes form the basis for determining facilities requirements. An important element of the transportation design process is the timely planning of transportation capability requirements and the evaluation of facilities requirements in response to industry activity and Customer requirements for service.

NGTL monitors industry activity, thereby anticipating and responding to Customer requirements for service, by conducting periodic design reviews throughout each year. NGTL's most recent design review presented in this Annual Plan is based upon the June 2009 design forecast, which forms the basis for determining the facilities requirements in this Annual Plan.

2.2 The Alberta System

The physical characteristics of the Alberta System and the changing flow patterns on the system present significant design challenges. The Alberta System transports gas from many geographically diverse Receipt Points and moves it through pipelines that generally increase in size as they approach the three large Export Delivery Points at Empress, McNeill and Alberta/British Columbia. The approximately 1000 Receipt Points and 200 Delivery Points on the system have a significant impact on the sizing of extension and mainline facilities necessary to ensure that sufficient capacity to transport peak expected flows is available. Extension facilities are designed to peak expected flows for receipt facilities and maximum day delivery for delivery facilities in accordance with the meter station and extension facilities design assumptions (Section 2.4 and 2.5), whereas mainline facilities are designed in accordance with the mainline system facilities flow determination (Section 2.6).

The Alberta System is designed to meet the peak day design flow requirements of its Customers. NGTL's obligation under its firm transportation Service Agreements with each Customer is to:

- receive gas from the Customer at the Customer's Receipt Points including the transportation of gas; and/or
- deliver gas to the Customer at the Customer's Delivery Points including the transportation of gas.

NGTL's facility design must ensure prudently sized facilities in order to meet flow requirements. The system design methodology developed to achieve this objective is described in the remainder of this chapter.

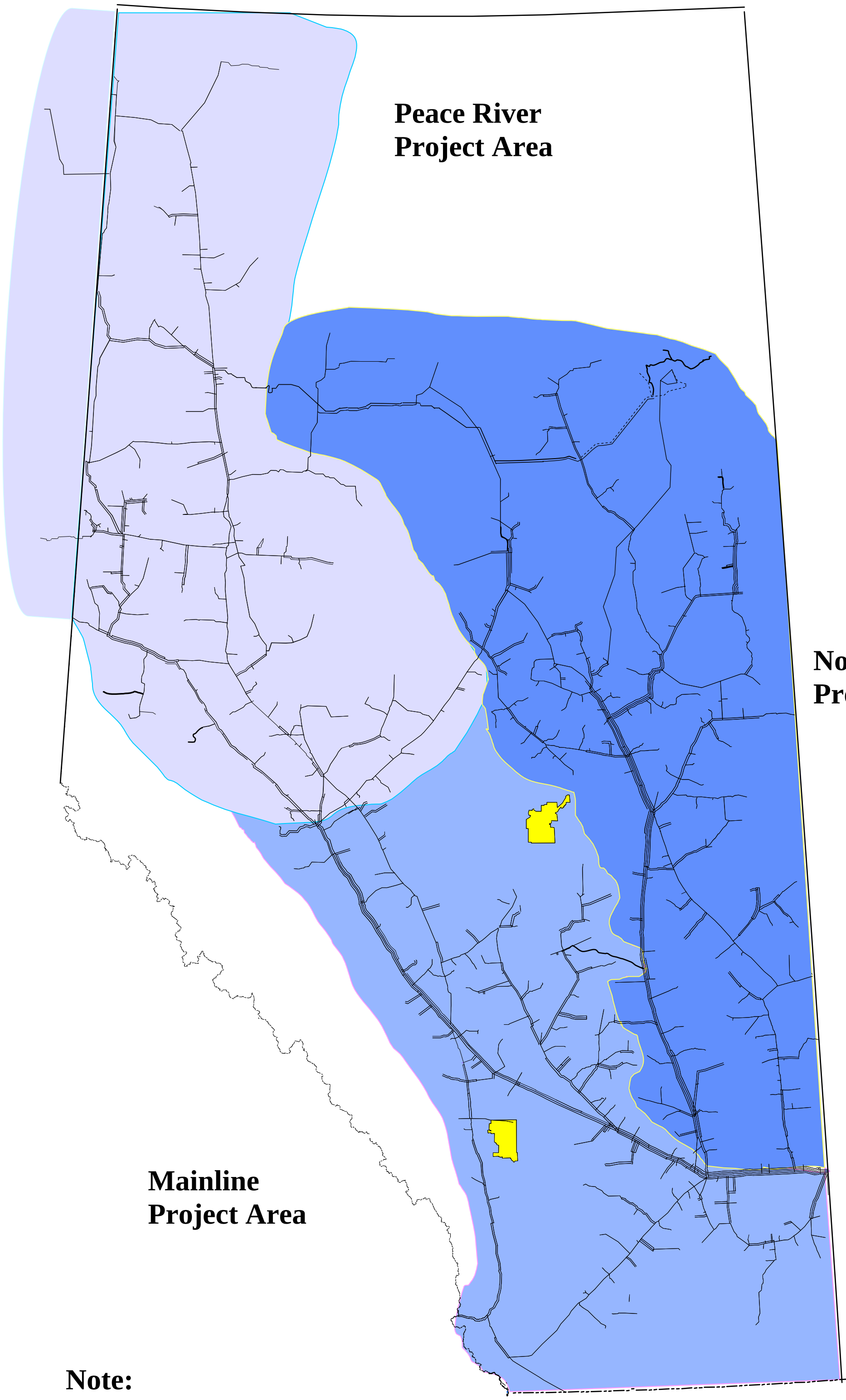
In the 2008/2009 Gas Year, approximately 75% of the gas transported on the Alberta System was delivered to Export Delivery Points. The remainder was delivered to the Alberta Delivery Points or used as fuel. The location of new Alberta Delivery Points and changing requirements at existing Alberta Delivery Points, particularly in the North of Bens Lake Design Area, may have a significant impact on the flow of gas in the system and, consequently, on system design. As well, the shift in the locations of new receipt volume additions to the system continues to be an important factor impacting gas flows and system design for the Planning Period.

Firm transportation capability may exist from time to time at certain Export Delivery Points for Short Term Firm Transportation-Delivery service ("STFT"). This capability availability is either ambient capability or capability created by unsubscribed Firm Transportation Delivery ("FT-D") transportation. Firm transportation capability may also exist in the winter season at certain Export Delivery Points for Firm Transportation-Delivery Winter service ("FT-DW") due to ambient capability. Interruptible transportation capability may exist from time to time on certain parts of the Alberta System.

2.3 NGTL Project and Design Areas

For design purposes, the Alberta System is divided into the three project areas shown in Figure 2.3, which are in turn divided into the design areas and design sub areas described in Sections 2.3.1 to 2.3.3. Dividing the pipeline system this way allows the system to be modeled in a way that best reflects the pattern of flows in each specific area of the system, as described in Section 2.6.

Figure 2.3
NGTL Project Areas



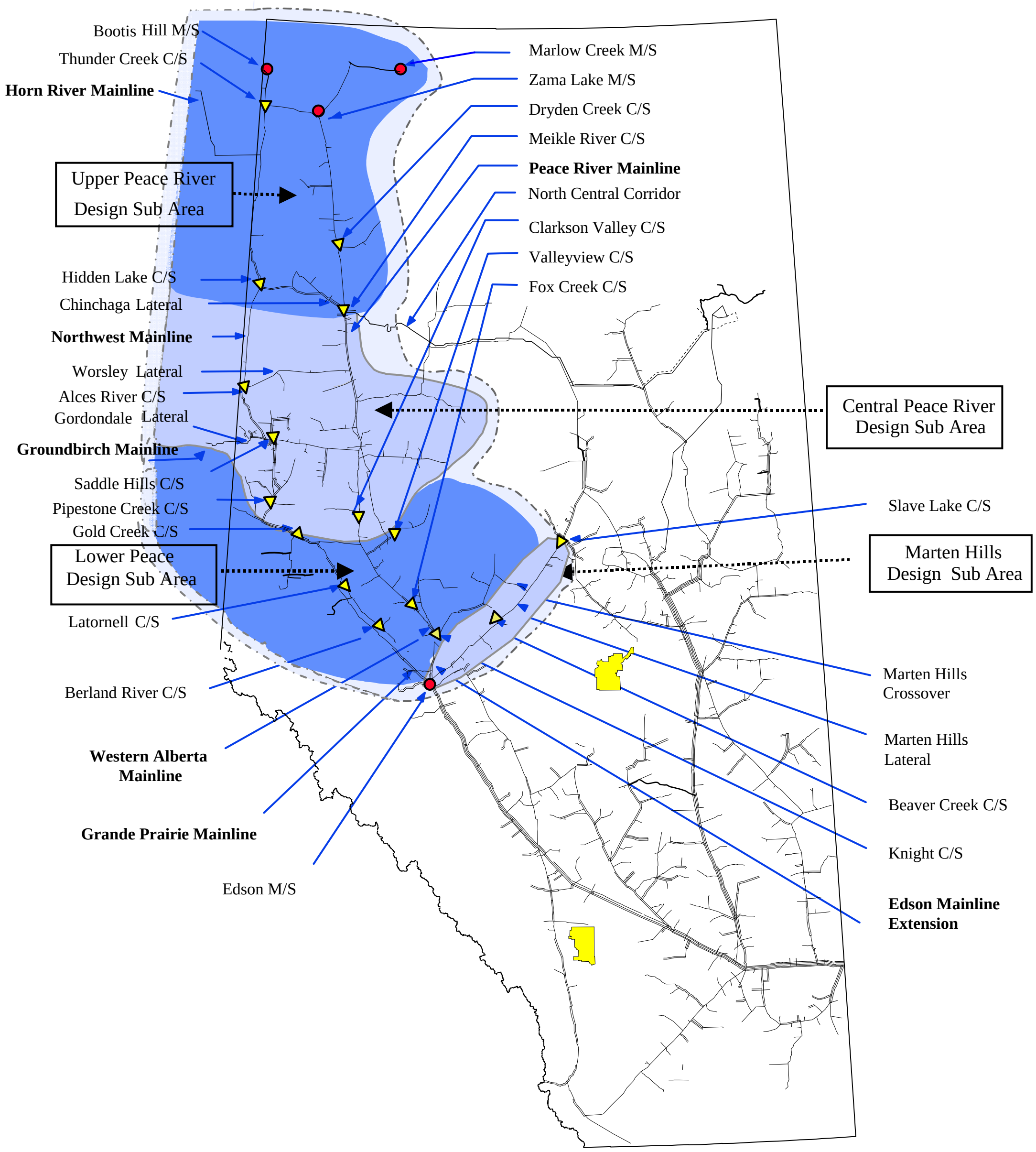
Note:

Includes facilities currently under construction or under development

2.3.1 Peace River Project Area

The Peace River Project Area comprises the Peace River and Marten Hills Design Areas (Figure 2.3.1).

Figure 2.3.1
Peace River Project Area



Note:
Includes facilities currently under construction

Peace River Design Area

The Peace River Design Area comprises three design sub areas: the Upper Peace River Design Sub Area; the Central Peace River Design Sub Area; and the Lower Peace River Design Sub Area. The Upper Peace River Design Sub Area comprises the proposed Horn River Mainline Project in Northeastern B.C., the Peace River Mainline from the Zama Lake Meter Station to the Meikle River Compressor Station and the Northwest Mainline from the Bootis Hill Meter Station and the Marlow Creek Meter Station to the Hidden Lake Compressor Station. The Central Peace River Design Sub Area comprises the Applied-for Groundbirch Extension in Northeastern B.C., the Western Alberta Mainline from the discharge of the Meikle River Compressor Station to the Clarkson Valley Compressor Station, as well as to the Valleyview Compressor Station on the Peace River Mainline plus the Northwest Mainline from the discharge of the Hidden Lake Compressor Station to the Saddle Hills Compressor Station on the Grande Prairie Mainline. The Lower Peace River Design Sub Area comprises the Grande Prairie Mainline from the discharge of the Saddle Hills Compressor Station to the Edson Meter Station as well as the Western Alberta Mainline from the discharge of the Clarkson Valley Compressor Station plus the Peace River Mainline from the discharge of the Valleyview Compressor Station to the Edson Meter Station. The North Central Corridor is located in the Peace River Design Area west of LSD 07-07-091-16 W5M.

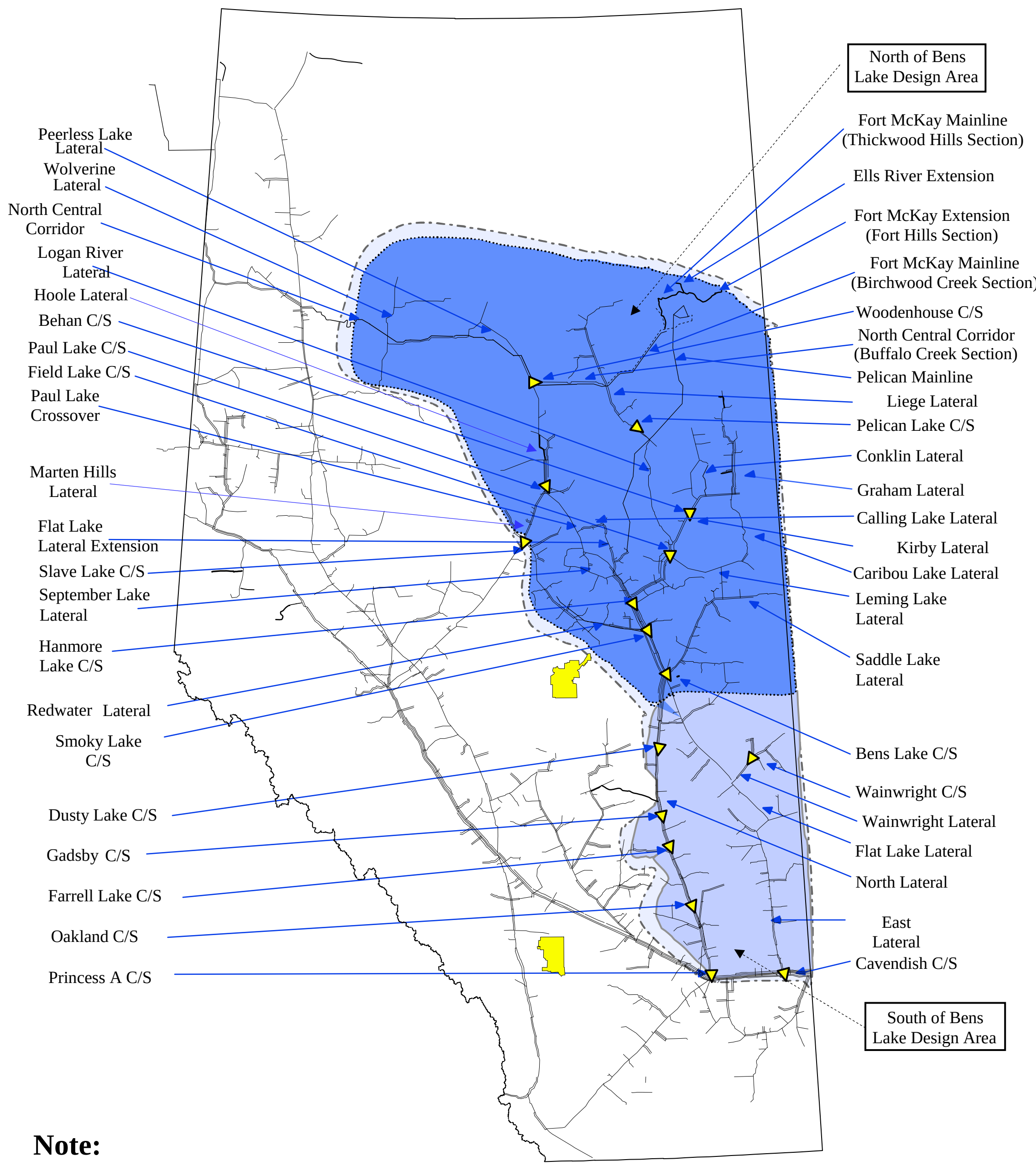
Marten Hills Design Area

The Marten Hills Design Area extends from the Slave Lake Compressor Station along the Marten Hills Lateral to the Edson Meter Station.

2.3.2 North and East Project Area

The North and East Project Area (Figure 2.3.2) comprises the North of Bens Lake and South of Bens Lake Design Areas.

Figure 2.3.2
North and East Project Area



Note:

Includes facilities currently under construction

North of Bens Lake Design Area

The North of Bens Lake Design Area comprises the Liege, Logan River, Kirby, Graham, Conklin, Calling Lake, September Lake, Caribou Lake, Leming Lake, Redwater, Pelican Mainline, Ells River Extension, Fort McKay Extension (Fort Hills Section), Fort McKay Mainline (Thickwood Hills Section), the Fort McKay Mainline (Birchwood Creek Section) and Saddle Lake Laterals, as well as the Flat Lake Lateral Extension, the Paul Lake Crossover, the Peerless Lake Lateral, the Wolverine Lateral, the Hoole Lateral and the Marten Hills Lateral north of the Slave Lake Compressor Station, which are all north of the Bens Lake Compressor Station. As capability on the Ventures Oil Sands Pipeline has been contracted under a Transportation by Others ("TBO") agreement, the Ventures Oil Sands Pipeline has been included in the North of Bens Lake Design Area. The North Central Corridor is located in the North of Bens Lake Design Area east of LSD 07-07-091-16 W5M.

South of Bens Lake Design Area

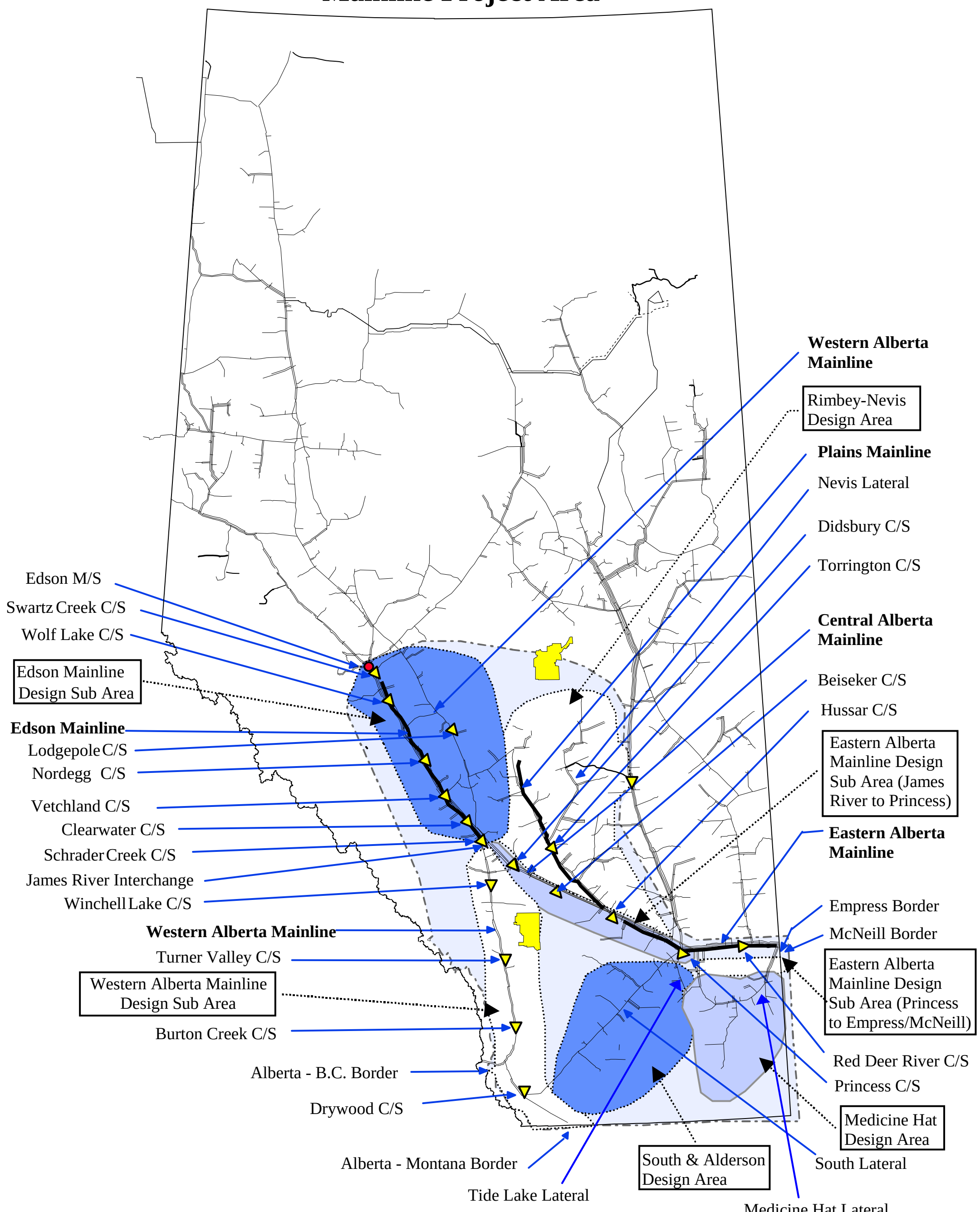
The South of Bens Lake Design Area comprises the Flat Lake Lateral, the Wainwright Lateral and the North and East Laterals which extend to the Princess "A" and Cavendish Compressor Stations, which are all south of the Bens Lake Compressor Station.

2.3.3 Mainline Project Area

The Mainline Project Area (Figure 2.3.3) comprises the Mainline Design Area, the Rimbey-Nevis Design Area, the South and Alderson Design Area and the Medicine Hat Design Area.

Figure 2.3.3

Mainline Project Area



Note:

Includes facilities currently under construction

Mainline Design Area

The Mainline Design Area comprises four design sub areas: the Edson Mainline Design Sub Area; the Eastern Alberta Mainline Design Sub Area (James River to Princess); the Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill); and the Western Alberta Mainline Design Sub Area.

The Edson Mainline Design Sub Area comprises the Edson Mainline from and including the Edson Meter Station to the Clearwater Compressor Station and the Western Alberta Mainline from the Knight Compressor Station to the Schrader Creek Compressor Station. The Eastern Alberta Mainline Design Sub Area (James River to Princess) comprises the Central Alberta Mainline from the Clearwater Compressor Station and the portion of the eastern leg of the Foothills Pipe Lines (Alberta) Ltd. from the Schrader Creek Compressor Station to the Princess Compressor Station. The Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill) comprises the Eastern Alberta Mainline and the portion of the eastern leg of the Foothills Pipe Lines (Alberta) Ltd. from the Princess Compressor Station to the Empress and McNeill Export Delivery Points. The Western Alberta Mainline Design Sub Area comprises the Western Alberta Mainline from the Schrader Creek Compressor Station to the Alberta/British Columbia and the Alberta/Montana Export Delivery Points as well as the pipeline sections on the western leg of the Foothills Pipe Lines (Alberta) Ltd. between Schrader Creek Compressor Station and the Alberta/British Columbia Export Delivery Point.

Rimbey-Nevis Design Area

The Rimbey-Nevis Design Area comprises the area upstream of the discharge of the Hussar “A” Compressor Station on the Plains Mainline as well as the Plains Mainline, the Nevis Lateral and the Nevis-Gadsby Crossover upstream of the Torrington Compressor Station.

South and Alderson Design Area

The South and Alderson Design Area comprises two laterals that connect to the Princess Compressor Station. The South Lateral extends from the Waterton area and the Alderson Lateral extends from the Alderson area.

Medicine Hat Design Area

The Medicine Hat Design Area comprises the Tide Lake Lateral upstream of the Tide Lake Control Valve and the Medicine Hat Lateral upstream of the Medicine Hat Control Valve.

2.4 Receipt Meter Station Design Assumption

The design of new receipt meter stations is based on the assumption that the highest possible flow through the receipt meter station will be the lesser of the aggregate Receipt Contract Demand under firm transportation Service Agreements for all Customers at the meter station or the capability of upstream producer facilities.

2.4.1 Receipt Extension Facilities Design Assumption

Extension facilities for receipts are designed to transport peak expected flow (Section 2.9.4.1), taking into consideration Receipt Contract Demand under firm transportation Service Agreements and the extension facilities criteria as described in the Guidelines for New Facilities shown in Table 2.4.1.

Table 2.4.1
Extension Facilities Criteria

NGTL Builds (Owns/Operates)
Facilities to serve aggregate forecast as per Annual Plan process
Facilities greater than or equal to 12 inches in diameter
Facilities greater than 20 kilometers in length
Volumes greater than 100 MMcf/d

Peak expected flow at specific receipt points (field deliverability) is based on an assessment of reserves, flow capability, future supply development and the capability of upstream gathering and processing facilities at each receipt meter station on the extension facility.

This design assumption recognizes and accommodates the potential for Customers to maximize peak expected flow from a small area of the Alberta System. In NGTL's assessment of facility alternatives to accommodate peak expected flow, a number of facility configurations are considered which may include future facilities. The assessment of facility alternatives includes both NGTL and third party costs to ensure the most orderly, economic and efficient construction of combined facilities. NGTL typically selects the proposed facilities and optimal tie-in point on the basis of overall (NGTL and third party) lowest cumulative present value cost of service ("CPVCOS").

2.5 Alberta Delivery Meter Station Design Assumption

The design of new Alberta delivery meter stations is based on the assumption that maximum day deliveries through such facilities will not exceed the capability of the facilities downstream of the delivery meter station. The capability of the downstream facilities is determined through ongoing dialogue with the operators of these facilities.

2.5.1 Delivery Extension Facilities Design Assumption

Delivery extension facilities are designed to transport maximum day delivery taking into consideration the extension facilities criteria as described in the Guidelines for New Facilities as shown in Table 2.4.1. In NGTL's assessment of facility alternatives to accommodate maximum day delivery, a number of facility configurations are considered which may include future facilities. NGTL's assessment of facility alternatives includes both NGTL and third party costs to ensure the most orderly, economic and efficient construction of combined facilities. NGTL typically selects the proposed facilities and optimal tie-in point on the basis of overall (NGTL and third party) lowest CPVCOS.

2.6 Mainline System Facilities Flow Determination

The Mainline system facilities flow determination is based on the peak expected flow determination as described in this section.

In order to predict peak expected flows a peaking factor is applied to the average receipt forecast to yield a more realistic design condition. The peaking factor is derived from an analysis of historical coincidental peak to average flow observed within the design areas over several gas years. When the peak expected flow determination identifies the potential need for facilities additions, a comparison of the level of existing and requested firm service contracts to the capacity available is made. If the level of existing and requested firm service contracts at the time of the design review is insufficient to support the expansion, a risk of shortfall analysis (load/capability analysis) is completed. The results of this analysis will be used by NGTL to determine if sufficient justification for proceeding with the expansion of capacity exists.

In each periodic design review, the facilities necessary to provide the capability to meet future peak expected flow requirements are identified. To ensure the facilities identified are the most economic, a minimum five-year forecast of facilities requirements is considered.

While the design of the Alberta System is affected by many interrelated factors, the following major design assumptions are currently included in determination of peak expected flow:

- equal proration assumption;
- design area delivery assumption;
- downstream capability assumption;
- storage assumption; and
- productive capability assumption.

These assumptions are briefly described in Sections 2.6.1 to 2.6.5.

2.6.1 Equal Proration Assumption

The Alberta System is designed to transport gas from many Receipt Points to multiple Delivery Points (Section 2.2). The pipeline system is designed to meet deliveries based on the general assumption that gas will be drawn on an equally prorated basis from each Receipt Point on the pipeline system. NGTL works with Customers to attempt to ensure that all delivery requirements are met. However, if gas is nominated in a manner that differs from the pattern assumed in the system design, delivery shortfalls may occur.

Application of the equal proration assumption results in a system design that will meet peak day delivery requirements by drawing on the peak expected flow from each meter station equally. Since the forecast supply is closely balanced to forecast peak day delivery requirements, the equal proration assumption did not apply to the facilities design within the Planning Period of this Annual Plan.

2.6.2 Design Area Delivery Assumption

In identifying facilities to transport gas within or through a design area, an assumption that the facilities must be capable of transporting the highest required flow into or out of that area is made. This is accomplished using the design area delivery assumption, which considers the following key factors:

- delivery requirements within the design area;
- delivery requirements outside the design area; and
- delivery requirements at the major Export Delivery Points.

This assumption is periodically reviewed to ensure load conditions that are likely to occur under system operations are reflected in the system design.

The design area delivery assumptions relied upon for the design review process for each design area are described in Table 2.6.2.1.

Table 2.6.2.1
Design Area Delivery Assumptions

Design Area	Prevailing Design Season	Winter[1]	Summer[1]
• Peace River (including Upper, Central & Lower Design Sub Areas)	Summer	Min u/s James[2]/Avg/Max	Min u/s James[2]/Max/Max
• Marten Hills	Summer	Min u/s James[2]/Avg/Max	Min u/s James[2]/Max/Max
• North and East Project Area (North and South of Bens Lake Design Areas)			
• Flow Through	Summer	Min[3]/Avg/Max	Min[3]/Max/Max
• Flow Within	Winter[4]	Max Area Delivery	Max Area Delivery
• Mainline	Summer	Min u/s James[2]/Avg/Max	Min u/s James[2]/Max/Max
• Rimbey Nevis	Summer	Min/Avg/Max	Min/Max/Max
• South and Alderson	Summer	Min/Avg/Max	Min/Max/Max
• Medicine Hat			
• Flow Through	Summer	Min/Avg/Max	Min/Max/Max
• Flow Within	Winter[5]	Max Area Delivery	Max Area Delivery

NOTES:
1 Within design area/outside design area and within Alberta/Export Delivery Points.
2 u/s James = upstream James River Interchange.
3 Total North and East Project Area.
4 Seasonally Adjusted Receipt Flow Conditions.
5 Average Receipt Flow Conditions.

Min = minimum Avg = average Max = maximum

For example, in the Peace River Design Area, a Min upstream James/Max/Max design flow assumption is applied to generate design flow requirements for summer conditions. The Min upstream James/Max/Max design flow condition assumes that the Alberta Delivery Points upstream of the James River Interchange and the Gordondale and Boundary Lake Export Delivery Points are at their minimum day delivery values, while the Alberta Delivery Points elsewhere on the system and the major Export Delivery Points are at their maximum day delivery values.

By contrast, a Min upstream James/Avg/Max design flow condition is applied for the same design area to generate design flow requirements for winter conditions. The Min upstream James/Avg/Max design area delivery assumption assumes that the Alberta Delivery Points within the area upstream of James River are at their minimum day delivery values while Alberta Delivery Points elsewhere on the system are at their average day delivery values and major Export Delivery Points are at their maximum day delivery values.

For the North and East Project Area and the Medicine Hat Design Area there are two distinct flow conditions that are examined in assessing facilities requirements. First, there is the “flow through” condition that is governed by the design flow requirements assumption. The “flow through” design condition occurs when the receipts are at the peak expected volume and the deliveries are at a seasonal minimum volume. Second, there is the “flow within” condition that is governed by the maximum day delivery and seasonal available supply within the area. The “flow within” design condition occurs when the receipts in the North and East Project Area are at a seasonal low volume and the deliveries are at a seasonal maximum volume. Currently, the “flow within” condition governs facilities requirements in the North and East Project Area.

For the North and East Project Area flow through condition, the following approach is used as a basis for generating the design flow requirements. First, the design focuses on optimizing the flow in the South of Bens Lake Design Area in order to maximize the utilization of existing facilities in this area. Second, if the design flow requirements in the South of Bens Lake Design Area have been maximized and there is a requirement to transport additional peak expected flow from the area, the design will focus on directing these volumes through the Marten Hills Design Area in order to maximize the utilization of existing facilities in the Marten Hills Design Area. Finally, if both the South of Bens Lake and the Marten Hills Design Areas are flowing at their existing capability and there is a requirement to transport additional peak expected flow then the design will focus on transporting these volumes through the Peace River Design Area.

In the North and East Project Area, seasonally adjusted receipt flows and maximum day delivery are the most appropriate conditions to describe the constraining design.

In the Medicine Hat Design Area, seasonal low receipt volume and maximum day delivery are the most appropriate conditions to describe the constraining design. NGTL reviews Alberta delivery patterns for each design area. These reviews show that while individual Alberta Delivery Points will require maximum day delivery, the probability that all Alberta Delivery Points will require maximum day delivery simultaneously is extremely low. To account for this, a factor, called the demand coincidence factor, was applied to decrease the forecast maximum day delivery for the aggregate of all the Alberta Delivery Points within each design area to a value more indicative of the forecast peak day deliveries. Similarly, demand coincidence factors were determined and applied to increase the aggregate minimum day delivery values at Alberta Delivery Points within each design area to be more indicative of the expected minimum day delivery.

2.6.3 Downstream Capability Assumption

The system design is based on the assumption that the maximum day delivery at the Delivery Points will not exceed the lesser of the capability of the downstream pipeline or the aggregate of the firm transportation Service Agreements associated with those Delivery Points. Downstream capability is determined through ongoing dialogue with downstream pipeline operators.

2.6.4 Storage Assumption

The Storage Facilities connected to the Alberta System at the AECO ‘C’, Carbon, Crossfield East, January Creek, Severn Creek, Chancellor, Big Eddy and the applied-for Warwick Southeast Storage Meter Stations are shown in Figure 2.6.4.1. Maximum receipt meter capabilities for Storage Facilities are presented in Section 3.6.

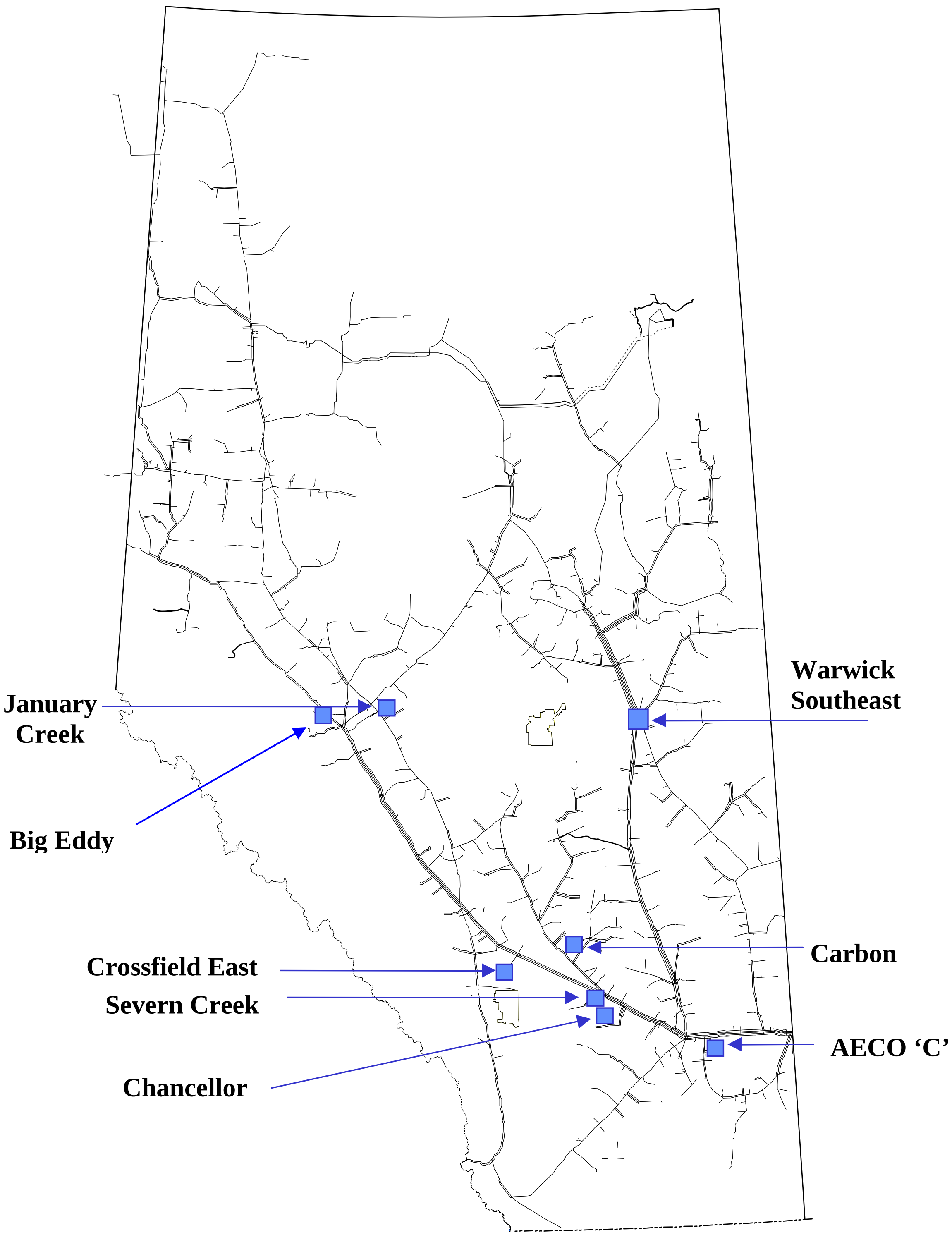
For the Planning Period it was assumed that:

- For the winter period, system design flow requirements will include receipt volumes from selected Storage Facilities onto the Alberta System at approximately average historical withdrawal levels.

  This assumption recognizes the supply contribution from Storage Facilities 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. The historical withdrawal flows were observed during recent winter periods at the AECO 'C', Carbon, Crossfield East, Chancellor and Severn Creek Meter Stations. The level of storage withdrawal used in the design of the Alberta System for the winter of the Planning Period was 17.7 $10^6m^3/d$ (630 MMcf/d). Volumes withdrawn from the Storage Facilities will be considered as interruptible flows, but will be incorporated into the flow analysis within all design areas where it may lead to a reduction in the design flow requirements and a potential reduction in additional mainline facilities.

- For the summer period, system design flow requirements will not include delivery volumes from the Alberta System into Storage Facilities. Consequently, for the purpose of calculating design flow requirements, volumes injected into the Storage Facilities will be considered to be interruptible flows and will therefore not be reflected in the design of mainline facilities.

Figure 2.6.4.1
Locations of Storage Facilities on the Alberta System



2.6.5 Productive Capability Assumption

In areas where gas is drawn from a small collection of Receipt Points, there is a greater likelihood that the peak expected flow will be required simultaneously from all such Receipt Points than is the case when gas is drawn from an area having a large number of Receipt Points. As a result, the system design for those areas with a small collection of Receipt Points, usually at the extremities of the system, is based on the assumption that the system must be capable of simultaneously receiving the aggregate of the peak expected flow from each Receipt Point. However, when the productive capability assumption is applied to any collection of Receipt Points, the flows from the other areas upstream of a common point are reduced such that the equal proration assumption (Section 2.6.1) is maintained through that common point. This results in the system upstream of the common point being designed to match the capability of the system downstream of the common point.

2.7 Maintaining Required Delivery Levels

Historically, the design of the Alberta System has been based on the assumption that facilities comprising the system are in-service and operating. However, compression facilities are not 100 percent reliable and are not always available for service. Even with stringent maintenance programs, compression facilities still experience unanticipated and unscheduled down-time, potentially impacting the ability to maintain required deliveries. Compression facilities generally require two to four weeks of scheduled maintenance per year.

Designing facilities to ensure that Customer delivery expectations and firm transportation requirements are met is an important consideration in the design of the Alberta System.

2.8 System Optimization

System optimization has been and will continue to be an integral part of the overall system design process to evaluate how the Alberta System can be optimized to reduce operating and maintenance costs, minimize fuel usage, greenhouse gas emissions and maintain flexibility without adversely affecting throughput. The intent is to maximize volumes on the system in order to minimize rates. Accordingly, cost reduction initiatives are not intended to reduce system volumes. The 2009 design review system optimization results are described in Section 5.2. The identification of compressor units and/or pipe that should be removed from service or replaced will continue to be an integral part of the overall system design.

2.9 Transportation Design Process

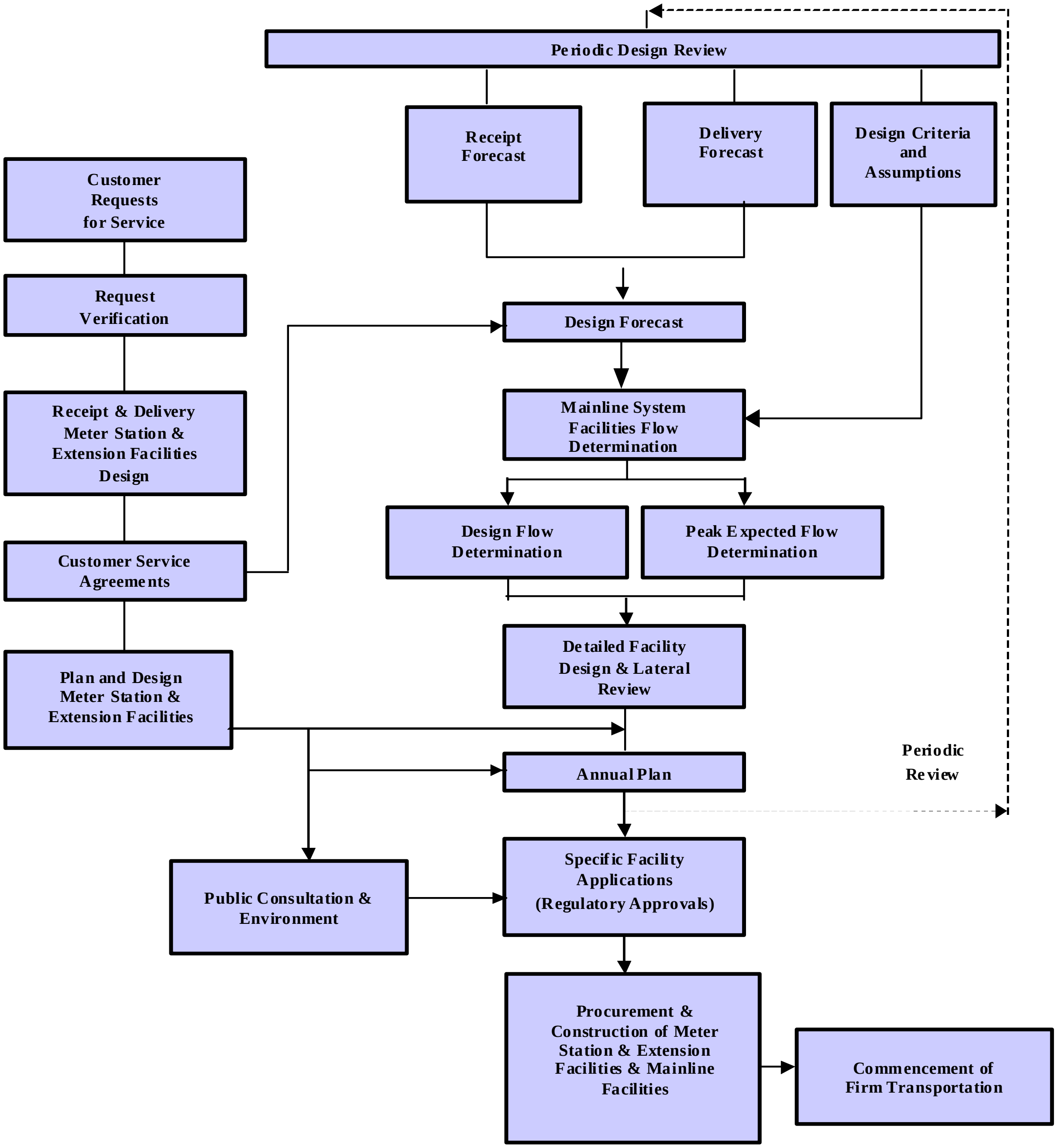
As stated in Section 2.1, periodic design reviews are conducted throughout the year to closely monitor industry activity and respond to Customer requirements for firm transportation on a timely basis.

The following is a brief overview of the significant activities involved in the transportation design process for the Planning Period. While Receipt Points, Alberta Delivery Points and extension facilities are designed as part of the transportation design process, the construction of these facilities takes place independently of the construction of mainline facilities.

The activities relating to the transportation design process are described below and are shown in the process flow chart included as Figure 2.9.1. Although activities have been grouped in distinct phases, some of the activities occur concurrently.

Figure 2.9.1

Transportation Design Process



2.9.1 Customer Request Phase

Requests for firm transportation for the Planning Period were received by NGTL and included in the transportation design process for the Planning Period.

Requests for firm transportation are reviewed through this process and categorized as requiring new facilities, requiring expansion of existing facilities, or not requiring either new facilities or expansion of existing facilities. Each category of receipt and delivery facility is treated somewhat differently in the following phases of the design process.

2.9.2 New Meter Station and Extension Facilities Design

NGTL proceeds with the design of new meter stations and extension facilities to meet Customers' requirements for those requests for firm transportation that remain after the initial review process and are consistent with the Guidelines for New Facilities.

NGTL, with significant input from Customers, has established economic criteria that must be met prior to receipt meter stations being constructed. The criteria are described in Appendix E of NGTL's Gas Transportation Tariff entitled *Criteria for Determining Primary Term*.

In the design of new extension facilities, the receipt or delivery volume and location of each new facility is identified. In the case of receipt facilities, a review is undertaken of the reserves that are identified as supporting each new extension facility to ensure the Receipt Point peak expected flow for the area can be accommodated. In the case of delivery facilities, a review is undertaken to establish the forecast demand levels that are identified for each new extension facility to ensure the maximum day delivery for the area can be accommodated. Hydraulic and economic analyses are also conducted, using the design assumptions for new meter station and extension facilities described in Section 2.4 and Section 2.5.

Once the design is completed and construction costs estimated, Project and Expenditure Authorizations for new receipt and delivery meter stations and related Service Agreements are prepared and forwarded to Customers for authorization.

2.9.3 Existing Meter Station Design

Concurrent with the design of new meter stations and extension facilities (Section 2.9.2), NGTL proceeds with the identification of new metering requirements and lateral restrictions associated with incremental firm transportation requests at existing Receipt and Delivery Points. If no new facilities are required, Customers requesting Service are asked to execute firm transportation Service Agreements. Where additional metering is identified as being required, construction costs are estimated, and Project and Expenditure Authorizations and related Service Agreements are prepared and forwarded to Customers for authorization. When a lateral restriction is identified, a review of the area peak expected flow is undertaken to determine potential looping requirements. Lateral loops are designed in conjunction with the design of mainline facilities.

2.9.4 Design Forecast Methodology

As shown in Figure 2.9.1, the transportation design process involves the preparation of a design forecast. The design forecast is a projection of anticipated peak expected flow, average receipts, and delivery requirements on the Alberta System, and plays an essential role in the determination of future facility requirements and planning capital expenditures.

The design forecast comprises the forecast of peak expected flow at each Receipt Point, the average receipt forecast and the gas delivery forecast. The following sections describe these forecasts and the methods by which they are developed.

2.9.4.1 Receipt Point Peak Expected Flow Forecast

The Receipt Point peak expected flow forecasts are the receipt component of the design forecast, and represent the forecast peak rate at which gas can be received onto the Alberta System at each Receipt Point. This section outlines the methodology used to determine a Receipt Point peak expected flow forecast. Receipt Point peak expected flow or “field deliverability” is the forecast peak rate at which gas can be received onto the Alberta System at each Receipt Point. NGTL forecasts peak expected flow through an assessment of reserves, flow capability and future supply development. NGTL determines this information based on data gathered from government sources, Canadian Gas Potential Committee studies, and through interaction with producers and Customers active in the area.

Section 2.4 describes how Receipt Point peak expected flow is used to identify facility requirements, while Section 3.5 presents the forecast of Receipt Point peak expected flow.

2.9.4.2 Average Receipt Forecast

Average receipt is the forecast of the annual average volume expected to be received onto the pipeline system at each Receipt Point. Section 3.5 presents the forecast of average receipts within the three main Project Areas on the Alberta System.

2.9.4.3 Gas Delivery Forecast

Delivery forecasts for each Alberta Delivery Point and each Export Delivery Point are developed. Each forecast includes average annual delivery as well as average, maximum and minimum delivery for both the winter and summer seasons. These seasonal conditions are used in the transportation design process to meet firm transportation delivery requirements over a broad range of operating conditions. The gas delivery forecast is reported in detail in Section 3.4.

The development of the gas delivery forecast draws upon historical data and a wide variety of information sources, including general economic indicators and growth trends. These gas forecasts are augmented by analysis of each regional domestic and U.S. end use market and other natural gas market fundamentals.

A consideration in developing the maximum day gas delivery forecast for Export Delivery Points is the forecast of new firm transportation Service Agreements. Firm transportation Service Agreements (new Service Agreements or renewals of expiring Service Agreements) are assumed to be authorized at each major Export Delivery Point (Empress, McNeill and Alberta/British Columbia) to a level based on the average annual delivery forecast and historical data. The average annual delivery forecast is developed through consideration of Customer requests for firm transportation and from NGTL's market analysis. NGTL's market analysis considers market growth, the competitiveness of Alberta gas within the various markets and a general assessment of the North American gas supply and demand outlook (Section 3.2).

The key component to the development of the Alberta delivery forecast is the assessment of economic development by market sectors within the province. The potential for additional electrical, industrial and petrochemical plants, oil sands, heavy oil exploitation, miscible flood projects, new natural gas liquids extraction facilities and residential/commercial space heating is evaluated. Each year, NGTL also surveys approximately forty Alberta based customers who receive gas from the Alberta System within the province regarding their forecast of gas requirements for the next several years.

2.9.5 Mainline Design Phase

The detailed mainline hydraulic design was completed using the Design Forecast and the mainline facilities design assumptions described in Section 2.6 as well as system optimization and compressor modernization described in Section 2.8. Computer simulations of the pipeline system are performed to identify the facilities that would be required to meet firm and peak transportation expectations for the Planning Period.

The following guidelines are used in assessing and determining the facilities requirements in this Annual Plan.

2.9.5.1 Maximum Operating Pressure

A higher maximum operating pressure ("MOP") results in a more efficient system. It is possible to consider more than one MOP when reviewing the long term expansion of the pipeline system. If the expansion is such that a complete looping of an existing pipeline is likely within a few years, then it may be appropriate to consider developing a high-pressure line that will eventually be isolated from the existing system.

2.9.5.2 Temperature Parameters

Pipeline design requires that reasonable estimates be made for ambient air and ground temperatures. These parameters influence the design in the following areas:

- power requirements for compressors;

- cooling requirements at compressor stations; and
- pressure drop calculations in pipes.

Winter and summer design ambient temperatures are determined using historical daily temperatures from Environment Canada at twenty locations throughout the province. An interpolation/extrapolation method was used to calculate the peak day ambient temperature for pipeline sections within each design area.

Ambient and ground temperatures based on historical information for each design area as described in Section 2.3 are shown in Tables 2.9.5.2.1 and 2.9.5.2.2.

Table 2.9.5.2.1
Ambient Air Temperature Parameters
(Degrees Celsius)

Design Area	Summer Design Temperature	Summer Average Temperature	Winter Design Temperature	Winter Average Temperature
Upper Peace River [1]	19	10	-1 to 0	-11
Central Peace River [1]	19	10	1 to 3	-11
Lower Peace River [1]	18 to 19	10	3	-11
Marten Hills	18	10	3	-9
North of Bens Lake	19 to 20	10	2 to 3	-11
South of Bens Lake	20 to 23	13	1 to 5	-8
Edson Mainline[2]	18	10	3 to 4	-8
Eastern Alberta Mainline[2] (James – Princess)	18 to 21	11	4 to 5	-7
Eastern Alberta Mainline[2] (Princess - Empress/McNeill)	22 to 23	13	6	-7
Western Alberta Mainline[2]	18 to 20	11	4 to 7	-4
Rimbey-Nevis	19 to 20	11	3 to 4	-7
South and Alderson	21 to 22	13	6 to 7	-7
Medicine Hat	23	13	7	-6

NOTES:
1 Design Sub Areas within the Peace River Design Area.
2 Design Sub Areas within the Mainline Design Area.

Table 2.9.5.2.2
Ground Temperature Parameters
(Degrees Celsius)

Design Area	Summer Design Temperature	Summer Average Temperature	Winter Design Temperature	Winter Average Temperature
Upper Peace River [1]	14	8	4	1
Central Peace River [1]	14	8	4	1
Lower Peace River [1]	14	8	4	1
Marten Hills	12	7	5	2
North of Bens Lake	11	6	5	2
South of Bens Lake	14	8	5	2
Edson Mainline[2]	12	8	5	2
Eastern Alberta Mainline[2] (James - Princess)	14	9	5	2
Eastern Alberta Mainline[2] (Princess-Empress/McNeill)	15	9	5	2
Western Alberta Mainline[2]	14	9	5	1
Rimbey-Nevis	14	10	5	2
South and Alderson	16	11	7	3
Medicine Hat	17	12	7	2

NOTES:
1 Design Sub Areas within the Peace River Design Area.
2 Design Sub Areas within the Mainline Design Area.

2.9.5.3 Pipe Size and Compression Requirements

A combination of pipe and compression facilities is reviewed to meet the design flow requirements. The possible combinations are almost unlimited so guidelines have been developed based upon experience and engineering judgment to assist in determining pipe size and compression requirements.

Experience has shown that the pressure drop along the mainline system should be within a range of approximately 15 to 35 kPa/km (3.5 to 8.0 psi/mile) of pipe. Above this range, compressor power requirements become excessive because of high friction losses, and pipeline loop usually becomes more economical than adding compression.

In addition, experience has also shown that generally it is advantageous to provide for a loop with a diameter at least as large as the largest existing line being looped. As a guide to selecting loop length, the loop should extend between two existing block valves where possible, thus minimizing system outages and impact from failures. In cases where design flow requirements are projected to increase, it is usually cost effective to add loop in a manner that will ensure that no additional loop will be required in the same area in the near future.

There is some flexibility in the location of compressor stations when new compression is required. Shifting the location changes the pressure at the inlet to the station and, hence, the compression ratio (i.e., the ratio of outlet pressure to inlet pressure). Capital costs, fuel costs, and environmental and public concerns are also key factors in selecting compressor station location.

2.9.5.4 Selection of Proposed and Alternative Facilities

Various alternatives are identified when combinations of the facility configurations and optimization parameters are considered. This process requires a careful evaluation of alternative designs to select those appropriate for further study.

Facilities that are most likely to meet future gas flows and minimize the long term cost of service are considered. As well, when appropriate, TBO or purchase of existing other party facilities, are considered as an alternative to constructing facilities.

The process to identify the potential for facilities requirements begins with the generation of design flow and peak expected flow requirements (Chapter 4). Then, design capabilities on the system are determined to identify where capability restrictions will occur. Pipe sizes, MOP and routings, as well as compressor station sizes and locations are evaluated as part of alternative solutions to eliminate these capability restrictions.

The capital cost of each reasonable alternative is then estimated. Rule of thumb costing guidelines are established at the beginning of the process. These guidelines take the form of cost per kilometer of pipeline and cost per unit type of compression and are based on the latest actual construction costs experienced by NGTL. Adjustments may be made for exceptions (i.e., winter/summer construction, location, and river crossings) that significantly impact these rule of thumb costing guidelines.

The results of the preliminary hydraulics and rule of thumb costs are compared and the best alternatives are given further study.

Simulations of gas flows on the Alberta System are performed for future years to determine when each new compressor station or section of loop should be installed and to establish the incremental power required at each station. Additional hydraulic flow simulations beyond the design period are performed for each remaining alternative to further define the location and size of compressor stations and loops.

Once the requirement for facilities in each year is determined, hydraulic flow simulations are performed based on seasonal average flows for each of the future years to determine compressor fuel usage, annual fuel, and operating and maintenance costs for each facility.

Next, detailed capital cost estimates for new facilities are determined to further improve upon the assessment of alternatives. Where appropriate, the alternatives include the use of standard compressor station designs which are incorporated into the cost estimates. These capital cost estimates reflect the best available information regarding the cost of labor and materials based on the preliminary project scope and also consider land and environmental constraints that may affect project timing and costs.

In reviewing capital, fuel, operating and maintenance costs, it is possible that some alternatives will have higher costs in all of these categories than other alternatives. The higher cost alternatives are eliminated from further consideration.

The annual cost of service, based on capital and operating cost estimates, is determined for each remaining alternative. This calculation includes annual fuel costs, capital costs escalated to the in-service date, annual operating costs, municipal and income taxes, return on investment and depreciation. The present value of each of the annual cost of service calculations are determined and then summed to calculate the CPVCOS for each alternative.

The proposed facilities are usually selected on the basis of lowest CPVCOS and lowest first year capital cost. However, a number of alternatives may be comparable when these costs are considered. For practical purposes, when these alternatives are essentially equal based on financial analyses, other relevant factors including operability of the facilities, environmental considerations and land access may more heavily influence alternative selections.

2.9.5.5 Preliminary Site and Route Selection Areas

Preliminary site and route selection areas are defined by hydraulic parameters. The downstream boundary of a compressor station is determined by locating the compressor station at a point where the maximum site-rated power available for the selected unit is fully used and the compressor station is discharging at the pipeline MOP while compressing the design flow requirements. The upstream boundary is determined by locating the selected unit at a location where any excess power available at the next downstream compressor station is consumed and the compressor station is discharging at the pipeline MOP while compressing the design flow requirements.

The preliminary route selection area for new pipelines is defined by the reasonable alternative routes between the end points of the new pipeline.

2.9.6 Final Site and Route Selection

Once preliminary site and route selection areas have been identified, efforts are directed at locating final sites for compression and metering facilities and routes for pipelines that meet operational, safety and environmental considerations and have minimal social impact.

2.9.6.1 Compressor Station Site Selection Process

The final site selection for a new compressor station is a two step process. The first step is a screening process where the preliminary site selection area is examined against relevant screening criteria with the objective of eliminating those locations determined to be inappropriate. This methodology is essentially one where geographical, physical, environmental and landowner impact constraints are used to eliminate unsuitable areas.

In the second step, a matrix is used to rank candidate sites against a number of engineering, operational, environmental, social and land use criteria. With appropriate weighting assigned to each of these criteria, based on input received from the public consultation process (Section 2.9.7), each candidate site is ranked relative to the others.

The criteria used to select compressor station sites include the following:

(1) Terrain:

Ideally, flat and well-drained locations are preferred, so that grading can be minimized and the surrounding landscape can be utilized to reduce visual impact to the surrounding residences.

(2) Access:

Compressor facilities are located as close as possible to existing roads and highways to minimize the cost and surface disturbance associated with new road construction.

(3) Land Use:

Compressor facilities are located, where possible, within areas cleared of vegetation and in areas where existing access routes can be utilized.

(4) Proximity to Residences:

Compressor facilities are designed to be in compliance with regulatory requirements and located as far away as possible from residences to minimize visual and noise impacts.

2.9.6.2 Meter Station Site Selection Process

Criteria similar to those applied to siting compressor stations are used to select meter station sites.

2.9.6.3 Pipeline Route Selection Process

The final pipeline route selection process consists of a review and an analysis of all available and relevant information, including: alignment sheets; aerial photographs; topographical maps; county maps; soil maps and historical data. Using this information, an aerial and/or ground reconnaissance of the preliminary route selection area is conducted to confirm the pipeline end points and to identify alternative pipeline routes between end points.

Input is sought from landowners and the public affected by the alternate pipeline routes (Section 2.9.7) through public consultation. The pipeline route that best satisfies a variety of route selection criteria, including: geographical; physical; environmental; engineering; and landowner and public concerns is selected.

The criteria used to select pipeline routes include the following:

(1) Terrain:

To minimize environmental and construction impacts, the driest and flattest route possessing both stable and non-sensitive soils is preferred. Other terrain features, such as side slopes, topsoil, rocky areas, wet areas and water crossings are also considered.

(2) Land Use:

To the extent possible, existing corridors are utilized while taking into consideration, the other current land use activities.

(3) Right-of-Way Corridors:

To the extent possible existing utility, seismic or pipeline right-of-way corridors within the route selection area are used. Utilizing existing corridors may reduce the amount of clearing and land disturbance and, in the case of shared right-of-way, allows for narrower new right-of-way width by overlapping existing pipeline corridors.

(4) Crossings:

On many occasions the pipeline route selected crosses both natural and man-made obstacles such as creeks, drainages, roads and other pipelines. Where practical, the pipeline is routed such that these crossings are avoided. However, when a crossing is necessary, the best possible location is selected considering terrain, land use, pipeline corridors, environmental considerations and the requirements of relevant regulatory authorities.

(5) Access:

The route which provides access during construction and that minimizes interference with surrounding land use is preferred. It is also preferable to locate the pipeline so that valves are easily accessible for day-to-day operations.

(6) Construction Time Frame:

The approximate timing of the construction phase, which is related to the required in-service date of the pipeline, is considered during pipeline route selection. The available construction time frame can be affected by terrain, land use, and the environment. Timing can also influence cost factors.

(7) Future System Expansion:

The possibility of future system expansion and any constraints that the proposed routing may have on future looping are considered.

2.9.7 Public Consultation Process

NGTL utilizes TransCanada's broad public consultation program that helps it establish and maintain positive relationships with people affected by the construction and operation of the Alberta system. The public consultation program ensures that landowners, communities, government, the general public, non-government organizations and Aboriginal communities have the opportunity to review and provide input for the siting of new facilities. NGTL uses an informative and consultative approach to ensure optimal stakeholder and public awareness of new projects, and identifies those stakeholders most likely to be affected by, or have a potential interest in, new projects in advance of consultation.

2.9.7.1 Purpose and Goals of the Consultation Program

The purpose and goals of TransCanada's consultation program are to:

- introduce projects to key stakeholders;
- actively seek and consider comments on:
  - pipeline routing and facility site selection;
  - potential environmental and socio-economic effects; and
  - mitigation measures where necessary to address potential project effects.
- identify and respond to stakeholder or public issues and concerns prior to the filing of applications;
- provide stakeholders with ongoing project updates;
- ensure, where practicable and reasonable, that stakeholder concerns or issues, if any, were incorporated into project planning; and

- initiate ongoing communications programs that carry on throughout the subsequent construction and operations phases of new projects to ensure future stakeholder concerns and issues, if any, are address appropriately and in a timely manner.

2.9.7.2 Design and Methodology of Consultation Program

The consultation program is designed and conducted in accordance with the principles of TransCanada's long-standing community relations practices. The program is designed to foster positive relationships with stakeholders and to provide stakeholders an opportunity to engage in the consultation process. The consultation program consists of identifying stakeholders and early notification of projects, stakeholder outreach information sharing, and continuing updates during construction.

While consultation is an integral and important component of the facility site and route selection process that precedes every facility application, the nature and scope of each consultation program depends on a number of factors, including the nature of the facility, the potential for significant adverse environmental effects, land or socio-economic effects, and the level of public or aboriginal interest. All contact with stakeholders throughout the consultation process is documented in a tracking form that is updated and reviewed regularly to ensure that all commitments are recorded and issues of concern are addressed.

Stakeholders are those who may be affected by or have a direct interest in the proposed facilities and may include: relevant federal and provincial government agencies, municipalities, local communities, landowners and occupants, trappers, aboriginal groups, special interest groups, and elected and appointed officials.

Once stakeholders are identified and potential issues and concerns are scoped, an appropriate consultation approach is selected. This approach may include mail-outs, one-on-one meetings, small group meetings, presentations, and open houses.

NGTL representatives meet with all directly impacted landowners and occupants to provide them with information about the project and provide an opportunity for input regarding routing and scheduling.

In addition, the Member of Parliament and Member of the Legislative Assembly for the affected area, as well as local elected officials and staff, civic organizations and other potentially interested and impacted stakeholders are identified and notified of the proposal.

Typical information packages sent out to stakeholders contain some or all of the following documents, as applicable:

- A project-specific fact sheet outlining information such as length of the project, the start and end points, proposed pipe size, maximum operating pressure, new right-of-way, existing corridors, the proposed construction timing, as well as environmental, safety and consultation commitments;
- A project map depicting the geographic location of the proposed pipeline route or facility site as well as company contact information;
- TransCanada brochures:

  Work Safely – Guidelines for Development near our Pipelines;

  Aboriginal Relations

  Your Safety, Our Integrity

  Connecting with Your Community

  Impacts in Alberta (or B.C.);
- TransCanada corporate profile;

- NEB brochure *Excavation and Construction Near Pipelines;*
- NEB pamphlet *A Proposed Pipeline or Powerline Project: What you need to know;*
- NEB pamphlet *Living and Working Near Pipelines: Landowner Guide;* and
- NEB booklet *Pipeline Regulation in Canada: A Guide for Landowners and the Public.*

Advertisements respecting proposed facilities are placed in local newspapers for a two week period. Any landowner or public concerns generated from the advertisement process are dealt with on a one-on-one basis.

A community meeting or open house is held, where appropriate, to provide information regarding specific proposed facilities and gain input from stakeholders and Aboriginal communities.

2.9.8 Aboriginal Policy

As a demonstration of TransCanada's respect for the diversity of aboriginal cultures and its commitment to work with aboriginal communities, an Aboriginal Policy was developed. All communications with aboriginal communities in areas of proposed facilities are guided by this policy. In developing its projects, NGTL strives to engage communities in dialogue to support an understanding of the potential impacts of proposed facilities, mitigate potential impacts on traditional land use and provide the opportunity to work closely with the communities to seek mutually acceptable solutions and benefits.

A copy of the Aboriginal Policy can be found on TransCanada's website at: http://www.transcanada.com/social/reports.html

2.9.9 Environmental Considerations

NGTL ensures all of its projects comply with the applicable legislative requirements. Depending on the scope of the project, an Order pursuant to section 52 or section 58 of the *National Energy Board Act* ("NEB Act") may be required to commence project construction on the Alberta System. The *Canadian Environmental Assessment Act* ("CEA Act") provides the process for environmental assessment of projects requiring a federal approval or authorization, such as NEB-regulated projects. Input from other federal agencies on proposed projects are included in the CEA Act process. The NEB also has an independent mandate to consult and assess environmental impacts associated with proposed projects.

2.9.9.1 Environmental and Socio-Economic Assessment

When a project triggers the assessment requirement of the CEA Act, an environmental assessment ("EA") must be completed before any action to enable a project to proceed can be taken under the NEB Act. Section 16 of the CEA Act specifies the items that must be considered in the EA:

- assessment of the environment;
- identification and assessment of any potential short and long-term effects from the proposed project;
- assessment of any environmental issues requiring individual attention, including; soil handling, weed control, clearing of timber, rare plants and species at risk, traditional use surveys, surface and groundwater considerations, wildlife resources, water crossings and aquatic resources, air emissions, historical and paleontological resources, noise issues;
- environmental protection, reclamation and mitigation procedures that indicate how the potential environmental effects will be addressed to eliminate or reduce potential project impacts; and,

- description of the programs that will be used to monitor the success of the environmental procedures.

As part of the NEB regulatory process, NGTL is also required to undertake a socio-economic assessment to define the area and existing socio-economic conditions that may be affected by the proposed project. General and specific mitigation measures are developed to promote positive project-related socio-economic effects that include local and group employment opportunities, demographic and health effects, and fiscal effects of government programs.

The level of detail in these assessments will depend in part on the magnitude and nature of the project.

CHAPTER 3 - DESIGN FORECAST

3.1 Introduction

This Annual Plan is based on the June 2009 design forecast of gas receipts and deliveries, which in turn is based on supply and market assessments completed in May 2009.

The June 2009 design forecast comprises two principal parts. The first part is the gas delivery forecast (Sections 2.9.4.3 and 3.4), which is a forecast of the natural gas volumes to be delivered at all Delivery Points on the Alberta System. The second part is the receipt forecast, comprised of peak expected flow and average receipts forecasts (Sections 2.9.4.1, 2.9.4.2 and 3.5) for all Receipt Points on the Alberta System.

From a receipt perspective, the forecasts of average receipts and peak expected flow used in this Annual Plan are subject to uncertainties. Producer success in developing new supply, actual levels of new firm transportation Service Agreements and changes in market demand may result in deviations from forecast values. In addition, significant exploration activity focused on unconventional gas has resulted in an expectation of incremental volumes of shale and tight gas entering the Alberta System in the Peace River Project Area in the near future.

From a delivery perspective, the forecast of maximum day delivery at the Export Delivery Points as shown in Section 3.4.2 is equal to the forecast of Firm Transportation-Delivery (“FT-D”) contracts at the Export Delivery Points and does not include Short Term Firm Transportation-Delivery (“STFT”) or Firm Transportation-Delivery Winter (“FT-DW”) contracts. Estimates of FT-D contracts at the Export Delivery Points have become difficult to forecast given the significant gap between these contracts and the actual gas flows at the major Export Delivery Points, due to increasing use of short-term contracts.

An overview of the June 2009 design forecast was presented at the November 17, 2009 TTFP meeting. This chapter presents a detailed description of the June 2009 design forecast.

The June 2009 design forecast includes winter and summer seasonal forecasts of maximum, average, and minimum day delivery for all Delivery Points and an annual forecast of peak expected flow, and average receipts for all Receipt Points on the Alberta System.

Gas from Storage Facilities remains a significant source of winter supply. Currently connected Storage Facilities have a maximum receipt meter capacity of approximately 168.9 $10^6m^3/d$ (5.96 Bcf/d). Actual maximum day receipts from storage will be dependent upon market conditions, storage working gas levels, storage compression power, and Alberta System operations. A discussion of the maximum day receipt meter capability associated with Storage Facilities is provided for information purposes in Section 3.6. Refer to Section 2.6.4 for further details on the treatment of storage in the system design.

3.2 Economic Assumptions

3.2.1 General Assumptions

Underlying the forecast of receipts and deliveries are assumptions concerning broader trends in the North American economy and energy markets. These assumptions, developed in January 2009 include:

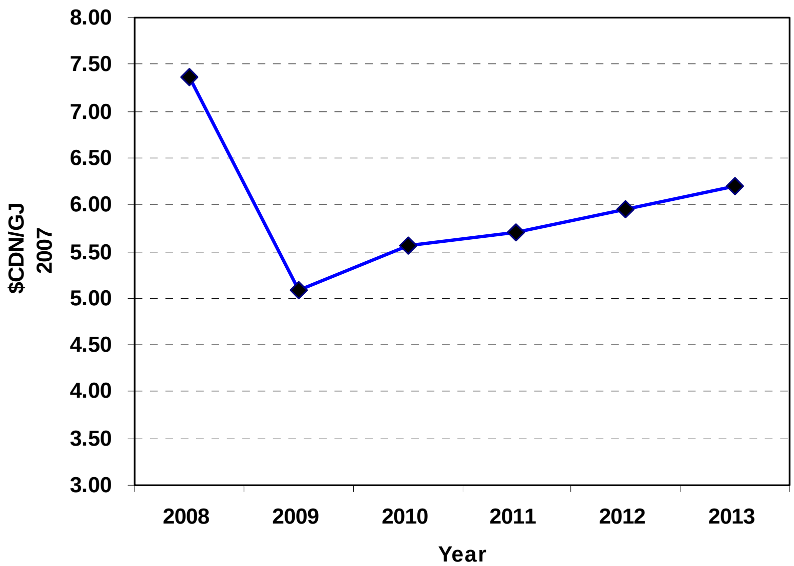
- North American natural gas demand will slowly recover in the short-term as the U.S. and Canadian economies recover. Longer term, gas demand is expected to increase with continued economic and population growth in both the U.S. and Canada. U.S. gas demand growth will be predominantly in the electricity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

- The North American market will be well supplied with natural gas sourced from North America due to the strength in unconventional gas production, primarily shale gas in the U.S. and Canada. This strong domestic supply growth is now expected to be able to keep pace with the growth in gas demand, leaving a greatly reduced volume of imported LNG required to balance the continental market.
- It is expected that a NYMEX gas price level of $7.00/MMBtu in Real 2007 $US over the forecast period will be sufficient to encourage the development of the extensive unconventional gas resource and to provide adequate returns for the production of the large volumes of conventional gas that will still be required. NYMEX natural gas prices recover over the next few years as the economy and gas demand improve. Prices rise from a 2009 average of $US 5.50/MMBtu or $US 5.32/MMBtu in terms of real 2007 $US to $US 8.10/MMBtu or $US 7.00/MMBtu in real 2007 $US by 2015. This is a long-term equilibrium price that is expected to balance the continental gas market.

3.2.2 Gas Price

A gas price forecast is used to help assess North American gas supply and demand. The gas price represents an Alberta average field price at a point just prior to receipt onto the Alberta System. The gas price forecast, shown in Figure 3.2.2, was developed in January 2009 and reflects the general assumptions from Section 3.2.1.

Figure 3.2.2
NGTL Gas Price Forecast
Alberta Average Field Price (Alberta Reference Price)



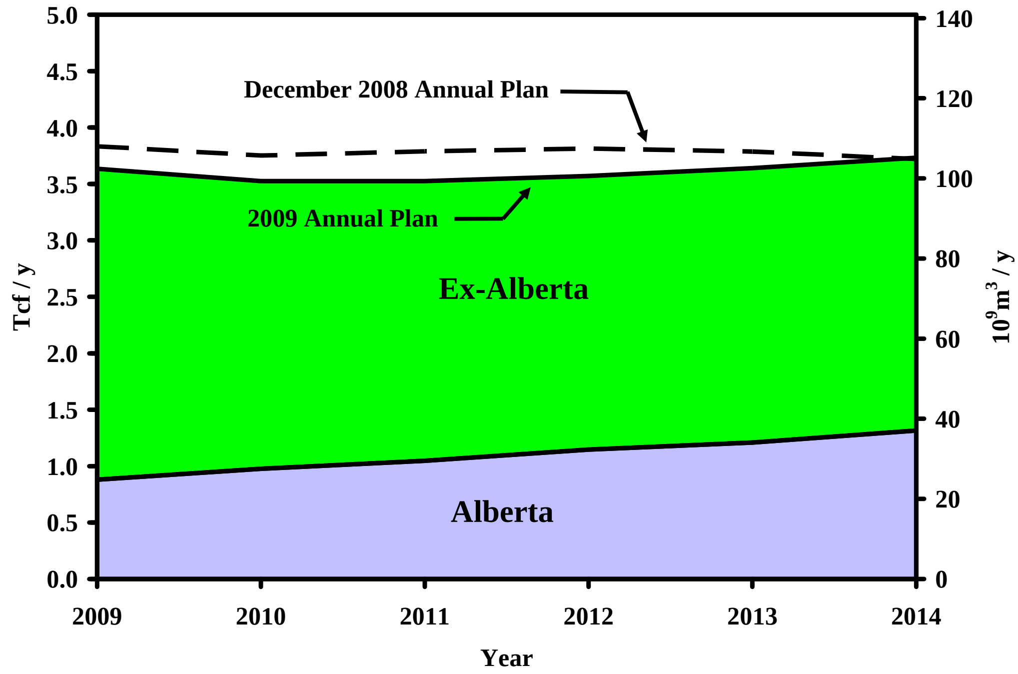
The Alberta average field price (in real 2007 $) is forecast to rise from $5.09 Cdn/GJ in 2009 to the long term equilibrium price of $6.55 Cdn/GJ by 2015.

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 activity required to discover and to develop new reserves.

3.3 System Annual Throughput

The forecast of system annual throughput is included for informational purposes. The system annual throughput forecast projects the total amount of gas to be transported on the Alberta System in future years and is shown in Figure 3.3.1.

Figure 3.3.1
System Annual Throughput



3.4 Gas Delivery Forecast

The gas delivery forecast describes one of the two principal components of the June 2009 design forecast. The second component, the receipt forecast, is described in Section 3.5. A breakdown of the system maximum day delivery forecast for both the winter and summer seasons of the Planning Period and by Export Delivery Point is provided in Tables 3.4.2.1 and 3.4.2.2.

3.4.1 System Maximum Day Delivery Forecast

The system maximum day delivery forecast projects aggregate maximum day delivery for the entire Alberta System in each of the winter and summer seasons for the 2009/10 through 2013/14 Gas Years. NGTL does not anticipate delivering the maximum day delivery at all Delivery Points simultaneously, although the maximum day delivery at individual Delivery Points may occur at some time during a season.

3.4.2 Export Delivery Points

The June 2009 design forecast of maximum day delivery at the Export Delivery Points is based on the assumption that it will not exceed the lesser of the capability of the downstream pipeline or the aggregate of firm transportation Service Agreements associated with those delivery points. For this Annual Plan, the forecasted aggregate level of firm transportation Service Agreements is the determining factor at every Export Delivery Point, which in some cases is zero.

Table 3.4.2.1
Winter System Maximum Day Delivery Forecast

	June 2009 Design Forecast				
Gas Year	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	37.3	30.0	30.0	35.1	34.8
McNeill	14.2	12.7	12.7	13.4	13.4
Alberta/B.C.	62.7	61.2	27.0	23.1	23.2
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.0	0.0	0.0	0.0	0.0
Cold Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	1.8	2.3	2.3	2.3	2.3
Alberta	140.6	148.4	156.9	167.3	177.6
TOTAL SYSTEM	**256.7**	**254.6**	**228.9**	**241.2**	**251.3**
(Volumes in Bcf/d at 14.73 psia and 60°F)					
Empress	1.32	1.06	1.06	1.24	1.23
McNeill	0.50	0.45	0.45	0.47	0.47
Alberta/B.C.	2.21	2.16	0.95	0.82	0.82
Boundary Lake	0.00	0.00	0.00	0.00	0.00
Unity	0.00	0.00	0.00	0.00	0.00
Cold Lake	0.00	0.00	0.00	0.00	0.00
Gordondale	0.00	0.00	0.00	0.00	0.00
Alberta/Montana	0.07	0.08	0.08	0.08	0.08
Alberta	4.96	5.24	5.54	5.91	6.27
TOTAL SYSTEM	**9.06**	**8.99**	**8.08**	**8.6**	**8.87**

NOTES:
- Delivery volumes shown are not anticipated to occur simultaneously but may occur at some time during the winter season.
- Numbers may not add due to rounding.

Table 3.4.2.2
Summer System Maximum Day Delivery Forecast

	June 2009 Design Forecast				
Gas Year	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	37.3	30.0	30.0	35.1	34.8
McNeill	12.7	12.7	12.7	13.4	13.4
Alberta/B.C.	62.2	61.2	27.0	23.1	23.2
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.0	0.0	0.0	0.0	0.0
Cold Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	1.4	2.3	2.3	2.3	2.3
Alberta	109.2	115.9	123.6	132.2	141.4
TOTAL SYSTEM	**222.9**	**222.1**	**195.7**	**206.1**	**215.1**
(Volumes in Bcf/d at 14.73 psia and 60°F)					
Empress	1.32	1.06	1.06	1.24	1.23
McNeill	0.45	0.45	0.45	0.47	0.47
Alberta/B.C.	2.20	2.16	0.95	0.82	0.82
Boundary Lake	0.00	0.00	0.00	0.00	0.00
Unity	0.00	0.00	0.00	0.00	0.00
Cold Lake	0.00	0.00	0.00	0.00	0.00
Gordondale	0.00	0.00	0.00	0.00	0.00
Alberta/Montana	0.05	0.08	0.08	0.08	0.08
Alberta	3.86	4.09	4.36	4.67	4.99
TOTAL SYSTEM	**7.87**	**7.84**	**6.91**	**7.28**	**7.59**

NOTES:
- Delivery volumes shown are not anticipated to occur simultaneously but may occur at some time during the summer season.
- Numbers may not add due to rounding.

3.4.3 Alberta Deliveries

Several sources of information were considered in developing the Alberta maximum day delivery forecast. First, operators of downstream facilities such as connecting pipelines and industrial plant operators 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 the Alberta Delivery Points. In cases where NGTL's analysis differed substantially with 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.

A summary of the June 2009 design forecast winter and summer maximum day delivery for Alberta Deliveries by project area is provided in Tables 3.4.3.1 and 3.4.3.2, respectively.

Table 3.4.3.1
Winter Maximum Day Delivery Forecast

Project Area	June 2009 Design Forecast ($10^6m^3/d$)	
	2009/10	**2010/11**
Peace River	6.7	6.8
North and East	75.4	81.2
Mainline	53.5	55.3
Gas taps	5.0	5.1
TOTAL ALBERTA	**140.6**	**148.4**
Project Area	**June 2009 Design Forecast (Bcf/d)**	
	2009/10	**2010/11**
Peace River	0.24	0.24
North and East	2.66	2.87
Mainline	1.89	1.95
Gas taps	0.18	0.18
TOTAL ALBERTA	**4.96**	**5.24**

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

Table 3.4.3.2

Summer Maximum Day Delivery Forecast

Project Area	June 2009 Design Forecast ($10^6m^3/d$)	
	2009/10	**2010/11**
Peace River	4.5	4.5
North and East	68.7	74.1
Mainline	33.6	35.0
Gas taps	2.3	2.4
TOTAL ALBERTA	**109.2**	**115.9**
Project Area	**June 2009 Design Forecast (Bcf/d)**	
	2009/10	**2010/11**
Peace River	0.16	0.16
North and East	2.43	2.61
Mainline	1.19	1.24
Gas taps	0.08	0.08
TOTAL ALBERTA	**3.86**	**4.09**

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

3.5 Receipt Forecast

The receipt forecast comprises the second principal part of the design forecast.

3.5.1 System Receipt Point Peak Expected Flow Forecast

In updating the Receipt Point peak expected flow for the June 2009 design forecast, three major sources of gas supply were 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 (coalbed methane, tight gas, shale gas); and
- Interconnections - supply from interconnections with other pipeline systems.

Incremental supply from reserve additions and from the unconnected component of discovered reserves are expected to become available to offset declines in Receipt Point peak expected flow from connected established reserves as economics permit.

In aggregate, the Western Canada Sedimentary Basin ("WCSB") peak expected flow is expected to decrease slightly, and then recover over the forecast period based on the June 2009 design forecast.

Gas supplied from Storage Facilities has not been included in the data presented in this section. Information pertaining to gas supply from Storage is contained in Section 3.6.

Supply from reserve additions was forecast on an area basis, based on resource potential estimates from the Canadian Gas Potential Committee Report "Natural Gas Potential in Canada – 2005", and from expected delivery requirements. The supply from reserve additions was then allocated to each Receipt Point within the forecast area. The allocated supply from reserve additions was combined with the established supply forecast from connected gas and existing economic unconnected gas to provide a forecast of future peak expected flow at each Receipt Point.

3.5.2 System Average Receipts

The system average receipt forecast from the June 2009 design forecast is 272.6 $10^6 m^3$/d (9.62 Bcf/d) in the 2010/11 Gas Year, which is a slight decrease from the previous year. A summary of system average receipts from the June 2009 design forecast by project area is shown in Table 3.5.2.

Table 3.5.2
System Average Receipts

	June 2009 Design Forecast ($10^6m^3/d$)				
Project Area	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**
Peace River	118.0	124.6	126.3	124.4	127.9
North and East	31.6	27.9	28.1	32.2	34.6
Mainline	124.1	120.0	119.3	122.0	124.0
TOTAL SYSTEM	273.7	272.6	273.7	278.5	286.5
	June 2009 Design Forecast (Bcf/d)				
Project Area	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**
Peace River	4.17	4.40	4.46	4.39	4.51
North and East	1.12	0.99	0.99	1.14	1.22
Mainline	4.38	4.24	4.21	4.30	4.38
TOTAL SYSTEM	9.66	9.62	9.66	9.83	10.11

NOTE:
- Numbers may not add due to rounding.

3.5.3 Established Natural Gas Reserves

Table 3.5.3.1 presents a summary of remaining established gas reserves in Alberta by project area as of October 2008, based on an assessment of available information. The Energy Resources Conservation Board ("ERCB") estimates 1093 10^9m^3 (38.6 Tcf) of CBM and conventional gas reserves at year end 2007. NGTL's estimate is based on the ERCB established reserves which existed at year end 2007 augmented by more recent data provided by customers and by additional reserves discovered as of October 2008. The reserves have been adjusted for production to October 2008.

NGTL's estimate of 1068 10^9m^3 (37.7 Tcf) remaining established gas reserves in Alberta is a decrease of about 23 10^9m^3 (0.8 Tcf), or 2.1 percent, from the 1091.1 10^9m^3 (38.5 Tcf) reported in the December 2008 Annual Plan.

Table 3.5.3.1
Remaining Established Alberta Gas Reserves by Project Area

Project Area	NGTL Estimate (10^9m^3)	NGTL Estimate (Tcf)
Peace River	234.8	8.3
North & East	156.0	5.5
Mainline	457.7	16.2
Other[1]	219.5	7.8
TOTAL[2]	**1068.0**	**37.7**

NOTES:
1 Reserves not directed to NGTL.
2 Numbers may not add due to rounding.

Table 3.5.3.2 presents the estimate of remaining established reserves. For British Columbia and the lower Northwest Territories, the estimate is limited to areas connected or likely to be connected to the Alberta System.

Table 3.5.3.2
Remaining Established Reserves

Reserve Basis	Alberta		B.C. and N.W.T.		Total	
	10^9m^3	Tcf	10^9m^3	Tcf	10^9m^3	Tcf
Remaining Established Reserves connected to the Alberta System [1,2]	848	30.0	141	5.0	989	34.9
Remaining Established Reserves not connected to the Alberta System [3,4,5]	220	7.8	-	-	220	7.8
TOTAL	**1068**	**37.7**	**141**	**5.0**	**1209**	**42.7**

NOTES:
1 The remaining established reserves are those connected and those expected to be connected to the Alberta System and include reserve estimates from NGTL initiated reserve studies.
2 Reserves not connected to the Alberta System are those which would be transported on other systems.
3 Only the estimates of B.C. reserves that are forecast to flow on the Alberta System are provided.
4 Numbers may not add due to rounding.
5 Does not include shale gas.

The history of supply growth in the WCSB is one of continually evolving drilling and completion technologies unlocking new sources of natural gas supply. Today this process is being applied to unconventional shale gas plays, primarily in north eastern British Columbia. It has been clearly demonstrated that the gas in place (“GIP”) resource associated with these plays is large. Technology is in the early stages of demonstrating economic recovery of these resources (reserves). As a result, NGTL has not included any reserves from shale gas plays in the above estimates, but recognizes the potential for these resources to make significant contributions to the WCSB deliverability in the future. Rapidly evolving technologies have the potential to significantly increase this contribution.

3.6 Storage Facilities

There are seven storage facilities presently connected to the Alberta System, as shown in Table 3.6.1, and one (Warwick Southeast Storage) currently under construction. They are located at the AECO ‘C’, Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek and Severn Creek Meter Stations (Figure 2.6.4.1). The total deliverability from Storage Facilities is significant when compared to the peak expected flow available from other Receipt Points on the Alberta System.

The receipt meter capacity for each of the connected Storage Facilities for the Planning Period is shown in Table 3.6.1.

Table 3.6.1
Receipt Capacity from Storage Facilities

	Receipt Meter Capacity from Storage Facilities 2010/11	
	$10^6 m^3/d$	**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**

NOTES:
- Storage is presently considered as an interruptible supply source. Refer to Section 2.6.4 for details on the treatment of storage in the system design.
- Numbers may not add due to rounding.
- Warwick Southeast under construction

CHAPTER 4 – DESIGN FLOWS

4.1 Introduction

This chapter is intended to provide an overview of the design flows and peak expected flows (as described in Section 2.6) that result in the need for mainline facilities. However, for this Annual Plan no new mainline facilities are being proposed for the Alberta System based on the June 2009 design forecast, and therefore, no design flow charts or tables are shown in this Chapter or in Appendix 2.

CHAPTER 5 – MAINLINE FACILITY REQUIREMENTS

5.1 Introduction

This chapter details the proposed natural gas transportation mainline facilities required to be in-service on the Alberta System to transport the design flow requirements and peak expected flows shown in Chapter 4 for the Planning Period.

An overview of the facilities requirements for the Planning Period was presented at the TTFP meeting on December 15, 2009. In addition, the current status of facilities that were applied for, are pending regulatory approval or are on-stream following the issuance of the December 2008 Annual Plan were also presented to the TTFP and are listed in Appendix 4.

There are no additional mainline facilities required based on the June 2009 design forecast for the Planning Period. There is one proposed pipeline decommissioning described in Section 5.2.

5.2 System Optimization Update

As described in Section 2.8 of this Annual Plan, system optimization continues to be an integral part of the regular facility design review and planning to meet the design flows.

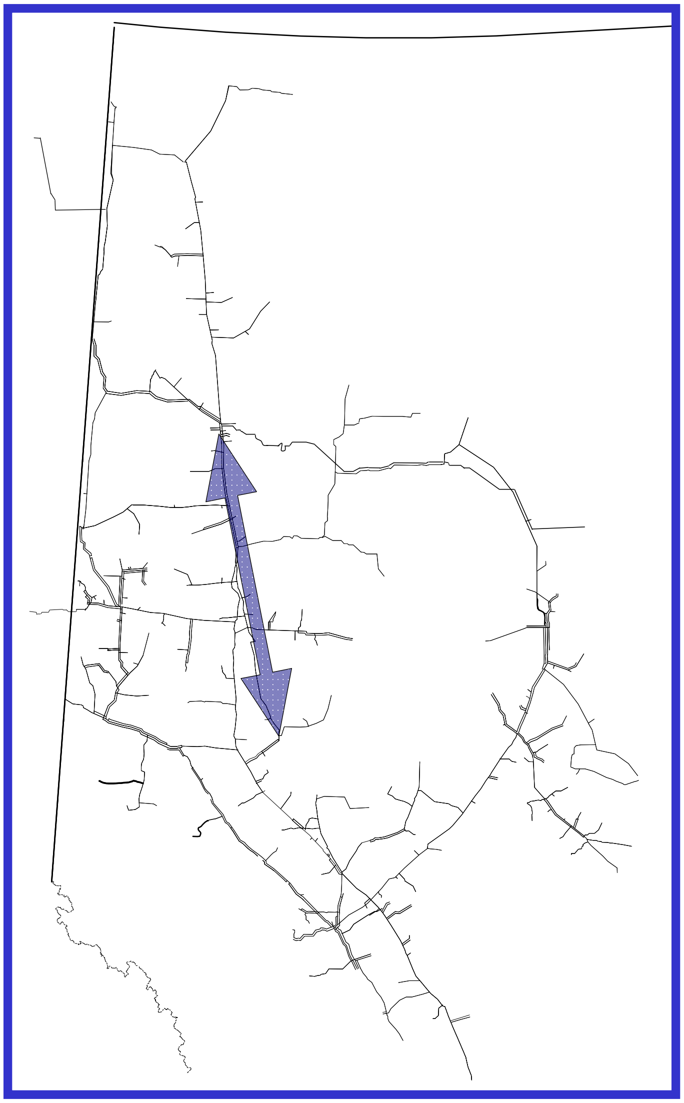
A 265 km section of the Peace River Mainline (“PRML”) NPS 20 from the discharge of NGTL’s existing Meikle River Compressor Station in LSD 15-26-094-02 W6M to the discharge of the Valleyview Compressor Station in LSD 09-09-069-22 W5M (‘PRML Meikle to Valleyview”) including the Valleyview Compressor site can be decommissioned without resulting in the requirement for additional mainline facilities in the Planning Period.

A number of factors resulted in the requirement for decommissioning:

- Pipeline integrity cost has surpassed the cost of decommissioning;
- There are few Receipt Stations and no Delivery Stations on this segment that are not already tied into the adjacent NPS 30 Peace River Mainline Loop;
- The North Central Corridor, located upstream of this segment and expected to be in-service April 2010, will unload this segment; and
- Removal of this segment will reduce fuel gas due to utilization of the more efficient NPS 30 PRML Loop.

Facilities required as a result of the decommissioning are re-connection of three receipt points and four sales taps. Overall, the cost saving for decommissioning is $9.8 million lower than the continued operation and maintenance of this segment, as indicated in the difference in CPVCOS in Table 5.2.1.

Figure 5.2
Peace River Mainline (Meikle to Valleyview) Proposed Decommissioning



The decommissioning of the PRML Meikle to Valleyview section including Valleyview Compressor Station will result in a requirement for the "Proposed Facilities" consisting of three reconnections at the existing Watino, Calais and Dixonville North Meter Stations, reconnections at four non-NGTL owned/operated sales taps, and the relocation or replacement of two pig traps.

Table 5.2.1
Peace River Project Area
Facility Comparison for the 2010/11 Gas Year

Proposed Facilities	Capital Cost ($ millions)		Total CPVCOS ($ millions)	Difference CPVCOS ($ millions)	km	NPS
	First Year	Long Term				
Watino M/S Reconnection	1.9				4.0	4
Calais M/S Reconnection	1.3				2.5	6
Dixonville N Reconnection	0.1					
Sales Tap Reconnections	0.6					
Pig Trap Relocation or Replacements	3.7					
PRML (Meikle to Valleyview Section) Abandonment	3.2					
TOTAL	**10.7**	**10.7**	**9.5**	**0.0**		
Alternative Facilities						
PRML (Meikle to Valleyview Section) Maintenance	0.5					
TOTAL	**0.5**	**3.6**	**19.3**	**+9.8**		

***Note: Valleyview Compressor Station decommissioning costs are not yet available and therefore not included in the cost comparison table above.**

CHAPTER 6 – EXTENSION FACILITIES AND LATERAL LOOPS

6.1 Introduction

As previously discussed (Section 2.1), receipt and delivery meter stations, extension facilities and lateral loops are designed and constructed independently of the construction of mainline facilities. Service may be provided to Customers on an interruptible basis until mainline facilities are in service. In those instances where responding to 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 all facilities application status following the issuance of the December 2008 Annual Plan is included under Appendix 4. Proposed extensions, lateral loops, and associated meter stations are listed in Table 6.1.

Table 6.1
Proposed Extensions and Lateral Loops

<table>
<tr><th>Proposed Facility</th><th>Description</th><th>Required In-Service Date</th><th>Estimated Cost (2009 $millions)</th></tr>
<tr><td>Doe Creek Lateral Loop</td><td>8.5 km NPS 16</td><td>November 2010</td><td>11.5</td></tr>
<tr><td>Henderson Creek Lateral Loop #3</td><td>9.2 km NPS 16</td><td>November 2010</td><td>13.6</td></tr>
<tr><td>Bear River West Lateral Loop</td><td>8.5 km NPS 10</td><td>March 2011</td><td>7.4</td></tr>
<tr><td>Kearl Extension & Meter Station</td><td>19.3 km NPS 20
4 km NPS 24</td><td>July 2011</td><td>55.1</td></tr>
<tr><td rowspan="4">Horn River Mainline Project</td><td>Cabin Section
72 km NPS 36</td><td rowspan="4">April 2012</td><td>229.0</td></tr>
<tr><td>Komie East Extension
2.2 km NPS 24</td><td>3.2</td></tr>
<tr><td>Ekwan Section (Acquisition)
83 km NPS 24</td><td>62.0</td></tr>
<tr><td>Meter stations (4)</td><td>13.1</td></tr>
<tr><td>TOTAL</td><td colspan="2"></td><td>394.9</td></tr>
</table>

6.2 Horn River Mainline

An application was filed with the Board on February 19, 2010 for authorization:

- to construct the Horn River Mainline (Cabin Section), consisting of 72 km of 914 mm (NPS 36) pipeline;
- to construct the Komie East Extension, consisting of 2.2 km of 610 mm (NPS 24) pipeline;
- to acquire the Horn River Mainline (Ekwan Section), consisting of 83 km of 610 mm (NPS 24) pipeline; and
- to construct four meter stations, including Cabin, Komie, Sierra and Little Hay Meter Stations.

The Horn River Mainline (Cabin Section and Ekwan Section) is required to transport gas from NE B.C. and will connect to the Alberta System at NGTL's existing Northwest Mainline (Zama Lake Section) in LSD 10-15-111-12 W6M. The Horn River Mainline and Komie East Extension are required for in-service April 2012 with construction expected to commence during Q4 2011.

6.3 Doe Creek Area

The Doe Creek Lateral Loop and the Henderson Creek Lateral Loop #3 facilities are required to transport incremental firm service contracts in the Doe Creek Area for the 2010/11 Gas Year and to meet the forecast supply growth in this area. Construction is expected to commence in Q3 2010 to meet the required in-service date of November 2010. It is anticipated that a facilities application will be filed with the Board in the first quarter of 2010.

6.4 Bear River West Lateral Loop

The Bear River West Lateral loop is required to transport incremental firm receipt service contracts for the 2010/11 Gas Year and to meet the forecast supply growth in the area. Construction is expected to commence in Q3 2010 to meet the required in-service date of November 2010. It is anticipated that an application will be filed with the Board in the first quarter of 2010.

6.5 Kearl Extension

The Kearl Extension is required to meet the aggregate delivery requirements for two oil sands projects in the Fort McMurray area. Construction is expected to commence in Q4 2010 to meet the required in-service date of July 2011. It is anticipated that an application will be filed with the Board in the first quarter of 2010.

APPENDIX 1

GLOSSARY OF TERMS

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 may 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")

AFUDC is 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 is 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 and shall include but not be limited to Export Delivery Point, Alberta Delivery Point, Extraction Delivery Point and Storage Delivery Point.

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

This is a forecast of the most current projection of field deliverability, average receipts and gas delivery over a five year design horizon.

Expansion Facilities

Expansion facilities are those facilities which 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

Extension facilities are those facilities which 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

Peak Expected Flow is 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 & 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 Facility Liaison Committee (or any replacement of it), provided Company has given six months notice of such amendment to it Customers.

Receipt Area

Receipt areas are 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 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.

APPENDIX 2

DESIGN FLOWS

This Appendix is intended to present both the winter and summer design flow requirements for design areas where additional mainline facilities are required for the Planning Period. As noted in Chapter 4, there are no mainline facility requirements identified for the Planning Period, therefore, no design flows are included in the 2009 Annual Plan.

APPENDIX 3

FLOW SCHEMATICS

This Appendix is intended to provide flow schematics for each of the design areas where additional mainline facilities are required for the Planning Period. As noted in Chapter 4, there are no additional mainline facility requirements for the Planning Period and therefore no flow schematics have been included for the 2009 Annual Plan.

APPENDIX 4

This Section describes the current status of facilities that were applied for, are pending regulatory approval or are constructed and on-stream since the last Annual Plan, the December 2008 Annual Plan, was issued.

Applied-for Facilities	Description	Status	Previous Annual Plan Reference	Forecast Cost as of December 31, 2009 ($Millions)
North Central Corridor (North Star Section)	140 km NPS 42	In-service	December 2006	383.4
North Central Corridor (Red Earth Section)	160 km NPS 42	Under construction	December 2006	383.7
Meikle River Compressor Station Units 4 & 5	2 x 15 MW	In-service	December 2006	65.5
North Central Corridor Loop (Buffalo Creek West Section)	54 km NPS 36	In-service	December 2007	125.9
Smoky River Expansion (Shady Oak Section)	9.6 km NPS 12	In-service	December 2007	8.7
Woodenhouse Compressor Station Unit B2	13 MW	In-service	December 2007	38.7
Doe Creek South Lateral Loop	5 km NPS12	In-service	December 2008	5.2
Smoky D and Gadsby Compressor Station Modifications	Piping and control modifications	In-service	December 2008	13.5
Sneddon Creek Lateral Loop #2	5 km NPS 16	In-service	December 2008	5.3
Albright North Crossover	18.9 km NPS 20	Under construction	N/A	15.7
Bonanza Meter Station	880 meter	Applied-for	N/A	1.3
Christina Lake North Sales Meter Station	2-1280 turbine meter	In-service	N/A	2.3
Collicutt Connection Pipeline	1.3 km NPS 8	In-service	N/A	0.0*
Collicutt Sales Meter Station	2-640 turbine meter	In-service	N/A	1.0
Crossfield East No.3 Meter Station	662 meter	In-service	N/A	0.0*
Demmitt Lateral Loop	6.1 km NPS 24	In-service	N/A	8.7
Doe Creek South No.2 Meter Station	1212 Ultrasonic meter	In-service	N/A	2.2
Egg Lake Sales Meter Station	2-860 turbine meter	In-service	N/A	1.2
Granor Sales Meter Station	NPS 2 LVS meter	Under construction	N/A	0.5
Groundbirch Pipeline Project	77 km NPS 36	Applied for	N/A	251.4
Hoole Sales No.3 Meter Station	NPS 2 LVS meter	In-service	N/A	0.4
Warwick Southeast Storage Meter Station	2 x NPS 8 Bi-directional Ultrasonic meters 0.8 km NPS 12	Applied-for	N/A	2.7
Whitesands Sales Meter Station	Type 420 2LV	In-service	N/A	0.5

*Estimated Capital Cost after a Contribution in Aid of Construction

APPENDIX 5

The Alberta System map is not included in this Annual Plan.

A copy can be mailed on request by calling the Customer Service Call Centre at (403) 920-PIPE (7473) and will be accessible on TransCanada's website at:
http://www.transcanada.com/Alberta/info_postings/system_map.html