NOVA Gas Transmission Ltd.

December 2006
Annual Plan

December
2006

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December 15, 2006

Alberta Energy and Utilities Board
640 - Fifth Avenue S.W.
Calgary, Alberta
T2P 3G4

Attention: Mr. Ken Sharp, P. Eng., Manager
Applications Branch, Facilities Applications

Re: December 2006 Annual Plan

Enclosed is a copy of the NOVA Gas Transmission Ltd. ("NGTL") December 2006 Annual Plan as required under Section "D" of Alberta Energy and Utilities Board (Board) Informational Letter IL90-8, and as revised by Board Informational Letter IL 98-5. The December 2006 Annual Plan can also be accessed on TransCanada PipeLines Limited's web site at:

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

All Customers and other interested parties are advised of the filing of the December 2006 Annual Plan with the Board. 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 Shelagh Ricketts, Vice President, System Design and Operations, at (403) 920-7655 or Stephen Clark, Vice President, Commercial – West, Canadian Pipelines at (403) 920-2018.

Should you have any questions or comments, please contact Darlene Maier at (403) 920-5108.

Yours truly,

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

Original Signed by

Dave Murray, P.Eng.
Manager,
Regulatory Services - Facilities

DECEMBER 2006
ANNUAL PLAN

NOVA Gas Transmission Ltd.

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EXECUTIVE SUMMARY

This Annual Plan has been prepared according to the requirements of the Alberta Energy and Utilities Board's (Board) IL 90-8 to provide the Board, NOVA Gas Transmission Ltd.'s ("NGTL") Customers and other interested parties with a comprehensive overview of the expected Alberta System facilities for the 2007/08 Gas Year.

IL 90-8 requires that NGTL follow a two stage process for facilities approvals. The first stage is the filing of an annual preliminary overall system plan ("Annual Plan") outlining planned facility additions and major system modifications. Section E of IL 90-8 requires that the Annual Plan contain information on the need, rationale, and justification for the proposed facility additions. The second stage is the filing of individual facility applications to the Board. NGTL understands that the Board assesses a number of factors in its application review process including the necessity and purpose of the facilities, economic and environmental considerations and available alternatives to the proposed facilities.

The December 2006 Annual Plan can be accessed on TransCanada PipeLines Limited's web site located at: http://www.transcanada.com/Alberta/regulatory_info/facilities/index.html

This is NGTL's seventeenth Annual Plan, and it follows a similar format to previous Annual Plans. Definitions are located in the Glossary in Appendix 1. Capitalized terms are defined in NGTL's Gas Transportation Tariff, which can be accessed at:

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

The Annual Plan contains NGTL's design methodology including assumptions and criteria, NGTL's design forecast including its long term outlook for system field deliverability, system FS productive capability, system average receipts, gas deliveries, NGTL's design flow requirements and proposed facilities for the 2007/08 Gas Year. Historical flow data are also included to illustrate the correlation between design flow requirements and actual flows. Capital expenditures, revenue requirements and firm transportation demand rates are limited to the years 2006 and 2007.

This Annual Plan is based on NGTL's June 2006 design forecast of gas receipt and delivery which in turn is based on supply and market assessments completed in May 2006.

From a receipt forecast perspective, the forecasts of field deliverability, average receipts and FS productive capability used in this Annual Plan are subject to numerous 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.

From a delivery forecast perspective, the 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 the preponderance of short term contracting. Although it is difficult to forecast maximum day delivery volumes (FT-D contracts) at the Export Delivery Points, there are no additional facilities requirements in this Annual Plan resulting from the forecast of maximum day delivery volumes at the Export Delivery Points.

NGTL will continue to closely monitor industry activity, contracting levels, and design implications throughout the year in order to anticipate and respond to Customer needs in a timely manner.

The mainline system facilities flow determination has been expanded in this years Annual Plan to include a peak expected flow determination, as described in Section 2.6.2. The peak expected flow determination is the result of the increasing difference between levels of firm transportation contracts and actual flows and is used to identify the potential of 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 (load/capability analysis) prior to being recommended.

There are no facilities additions identified in this Annual Plan resulting from the peak flow determination. Any future facilities additions identified using the peak expected flow determination will be presented to NGTL's Customers prior to the filing of any facility application.

The primary factors affecting NGTL's facilities requirements for the 2007/08 Gas Year are the increasing delivery requirements in the Fort McMurray area and the decreasing FS productive capability in the North of Bens Lake Design Area. The facilities additions proposed for the 2007/08 Gas Year are listed in Table 1. Costs associated with the proposed facilities will generally occur in the 2007 and 2008 calendar years.

Table 1
Proposed Facilities

Project Area	Proposed Facilities	Annual Plan Reference	Description	Required In-Service Date	Capital Cost ($ millions)
Peace River	No facilities required				
North & East	Fort McKay Mainline (Birchwood Section)	Chapter 5	85 km NPS 36	April 2008	149.9
	North Central Corridor Loop (Buffalo Creek East Section)	Chapter 5	28 km NPS 36	April 2008	51.7
	Marten Hills Lateral Loop #2 (McMullen Section)	Chapter 5	34 km NPS 30	April 2008	52.5
	Paul Lake Compressor Station – Unit #2	Chapter 5	15 MW	April 2008	27.7
Mainline	No facilities required				
Capital Costs are in 2006 dollars and include AFUDC			**Total**		**281.8**

The North Central Corridor ("NCC"), as described in the December 1999 Annual Plan, remains the preferred facilities to meet system-wide receipt and delivery requirements. The NCC meets all of the following needs:

- Addresses the growth in Alberta deliveries in the Fort McMurray area;
- Establishes a plan to ensure the long term utilization of existing facilities in the North and East Project Area which enhances NGTL's delivery capability at the Empress and McNeill Export Delivery Points and therefore maximizes the flexibility of the system to deliver to a variety of Alberta Delivery Points and Export Delivery Points; and
- Transports the future growth in FS productive capability from the Peace River Project Area to the North and East Project Area, reducing the requirement for facilities that would otherwise be necessary in and downstream of the Peace River Project Area.

When compared to the evaluated alternatives, the NCC will reduce the overall distance of gas transportation on the Alberta System, which significantly lowers fuel consumption.

The NCC is currently proposed to be on-stream April 2010, which is outside the scope of this Annual Plan. However, due to the lead time required for public involvement, land and environmental survey, route selection, and the long lead time required for materials procurement to enable an on-stream date of April 2010, it has been included in this Annual Plan in Section 5.6 as a future facility.

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:

- Shelagh Ricketts, Vice President, System Design and Operations, at (403) 920-7655; or
- Stephen Clark, Vice President, Commercial – West, Canadian Pipelines
  at (403) 920-2018.

Should you have any questions or comments regarding this Annual Plan, please contact Darlene Maier at (403) 920-5108.

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 buildup of the Alberta System.

1.2 Background to Annual Plan

NGTL seeks and receives authorization for construction and operation of pipeline and related facilities from the Alberta Energy and Utilities Board (“Board”) pursuant to the provisions of the *Pipeline Act*.

The Board has met periodically with NGTL and industry participants to review and revise the procedures and criteria used in assessing NGTL’s facility applications. The Board’s conclusions following such reviews have been set forth in Informational Letters. These letters function as directives respecting information that must be included in facility applications and as guidelines for NGTL, Customers, the Board, and other interested parties in the review and assessment of NGTL’s facility applications.

NGTL follows Board Informational Letter IL 90-8, a copy of which is provided in Appendix 2, in seeking authorization from the Board to construct and operate pipeline and related facilities. Section C of IL 90-8 requires that NGTL follow a two-stage application process:

The first stage is the filing with the Board of an annual preliminary overall system plan (“Annual Plan”) containing all planned facility additions and major modifications. The second stage is the filing of the final technical, cost, routing/siting, land, environmental and other information required to complete the application for each facility contained in the Annual Plan.

Section E of IL 90-8 requires that the Annual Plan contain information on the need, rationale, and justification for the proposed facility additions. The information must include, but is not limited to:

(a) system demand outlook;
(b) system reserves and deliverability on an area basis;
(c) assumptions, design criteria, and methodology;
(d) economic criteria;
(e) preliminary sizing of each facility;
(f) preliminary route/site for each facility;
(g) preliminary cost estimate and construction schedule for each facility;
(h) impact on NOVA's cost of service due to the implementation of the Annual Plan; and
(i) long-term plan and the impact resulting from the implementation of the Annual Plan on the long-term plan.

The Annual Plan provides the Board and industry participants with an understanding of how specific facility applications fit into the overall long term development of the Alberta System.

NGTL and those affected by the facility applications work together early in the planning process to exchange information and provide appropriate opportunity for input and comment. The Board ensures NGTL's applications meet the technical, environmental, economic, and safety criteria set out in the *Pipeline Act* and associated regulations. The Board also acts as a catalyst to ensure there is appropriate dialogue between NGTL and those interested in and affected by NGTL's facility applications. A major benefit of this dialogue has been the small number of facility hearings in recent years. In the event of a facility hearing, the Board makes a determination, based on the evidence presented to it, as to whether or not a permit for the facility will be granted.

1.3 Annual Plan Scope

The December 2006 Annual Plan contains facilities requirements for the 2007/08 Gas Year commencing on November 1, 2007 and ending on October 31, 2008.

1.4 Annual Plan Changes

This section describes changes that have been incorporated in this years' Annual Plan and are described in the following sub-sections: Design Area Name Changes, Peak Expected Flow Determination, Historical Peak Flow, and Glossary Additions.

1.4.1 Design Area Name Changes

The terms "upstream" and "downstream" are no longer clear in their description of the design areas within the North & East Project Area. Consequently, NGTL has renamed the design areas within the North & East Project Area as follows:

Current Name	**New Name**
Upstream Bens Lake Design Area	North of Bens Lake Design Area
Downstream Bens Lake Design Area	South of Bens Lake Design Area

1.4.2 Peak Expected Flow Determination

The mainline system facilities flow determination has been expanded in this years' Annual Plan to include a peak expected flow determination, as described in Section 2.6.2. The peak expected flow determination is the result of the increasing difference between levels of firm transportation contracts and actual flows and is used to identify the potential of 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 (load/capability analysis) prior to being recommended.

There are no facilities identified in this Annual Plan resulting from the peak expected flow determination. Any future facilities additions identified using the peak expected flow determination will be presented to NGTL's Customers prior to the filing of any facility application.

1.4.3 Historical Peak Flow

The historical peak flow has been added to the figures in Chapter 4 to illustrate the peak flow that has been observed in each design area of the Alberta System.

1.4.4 Glossary Additions

The following new definitions have been added to the Glossary in Appendix 1:

i) Average Receipt Forecast

ii) Load / Capability Analysis

iii) Peak Expected Flow

1.5 June 2006 Design Forecast

NGTL's June 2006 design forecast of gas delivery, FS productive capability, average receipts and field deliverability was used in the preparation of NGTL's December 2006 Annual Plan.

1.6 Industry Participation

It is clear from Board Informational Letter IL 90-8 that the Board intends that the concerns of interested parties related to NGTL facilities be addressed directly with NGTL or through the various industry committees and subcommittees that have been established for that purpose (IL 90-8, Paragraph H). The Board's objectives are to ensure an appropriate forum exists for input and comment prior to the finalization of specific facility applications and to ensure NGTL's facility applications are assessed in an informed, timely and cost effective manner.

To facilitate a more 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
- the internet, including Customer Express and NrG Highway.

The Facilities Liaison Committee ("FLC") was formally established in May 1990 and has been an important forum for reviewing NGTL's plans with industry. In 2004, the FLC became a standing task force, the Facilities Task Force ("FTF"), of a broader industry committee, the Tolls, Tariff, Facilities and Procedures Committee ("TTFP").

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 of NGTL. The TTFP provides for the timely exchange of information among interested parties and provides a significant opportunity for parties to influence NGTL's facility proposals and long-term planning. Since the filing of the December 2005 Annual Plan, NGTL has made presentations to the TTFP on a number of topics. The design forecast, design flows and facility requirements were presented to the TTFP on November 21, 2006, 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 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 the pipeline system facilities requirements and capital programs have been discussed.

The TTFP will be advised if additional facilities are identified to be placed in-service for the 2007/08 Gas Year after the filing of this Annual Plan and prior to the issuance of the next Annual Plan.

A copy of the December 2006 Annual Plan can also be accessed on TransCanada's Web site located at:
http://www.transcanada.com/Alberta/regulatory_info/facilities/index.html

CHAPTER 2 – FACILITIES DESIGN METHODOLOGY

2.1 Introduction

This chapter provides an overview of the facility planning processes employed by NGTL in identifying 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 2007/08 Gas Year.

The Guidelines for New Facilities, which were supported by the FLC and filed with the Board on July 17, 2000, describe the new facilities that NGTL may construct. The Guidelines for New Facilities can be accessed on TransCanada's Web site 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).

NGTL's 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 2007/08 Gas Year.

An important element of the transportation design process is the filing of specific facility applications connected with the requirement for facility additions. Facilities applications are filed with the Board to coincide with 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. Facilities applications are usually filed in conjunction with NGTL having firm transportation Service Agreements in place with Customers.

To determine the mainline/expansion facility requirements, NGTL uses the design flow determination as described in Section 2.6.1. The mainline system facilities flow determination has been expanded to include a peak expected flow determination, as described in Section 2.6.2. The peak expected flow determination is the result of the increasing difference between levels of firm transportation contracts and actual flows and is used to identify the potential of 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 firm transportation capability.

These two facility planning sub-processes form the basis for determining NGTL's 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 2006 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. A map of the Alberta System is provided in Appendix 7. The 976 Receipt Points and 173 Delivery Points on the system (year end 2005) have a significant impact on the sizing of extension and mainline facilities necessary to ensure that firm transportation obligations can be met. Extension facilities are designed to field deliverability 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 firm transportation Customers. NGTL's obligation under its firm transportation Service Agreement 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 meet two important objectives. One is to provide fair and equitable service to Customers requesting new firm transportation Service Agreements. The other is to prudently size facilities to meet peak day firm transportation delivery requirements. The system design methodology developed to achieve both of these objectives is described in the remainder of this chapter.

On average, approximately 84 percent of the gas transported on the Alberta System is delivered to Export Delivery Points, for removal from the province. The remainder is delivered to the Alberta Delivery Points. 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 2007/08 Gas Year.

Interruptible transportation capability may exist from time to time on certain parts of the Alberta System. However, Customers should not rely on interruptible transportation to meet their firm transportation requirements.

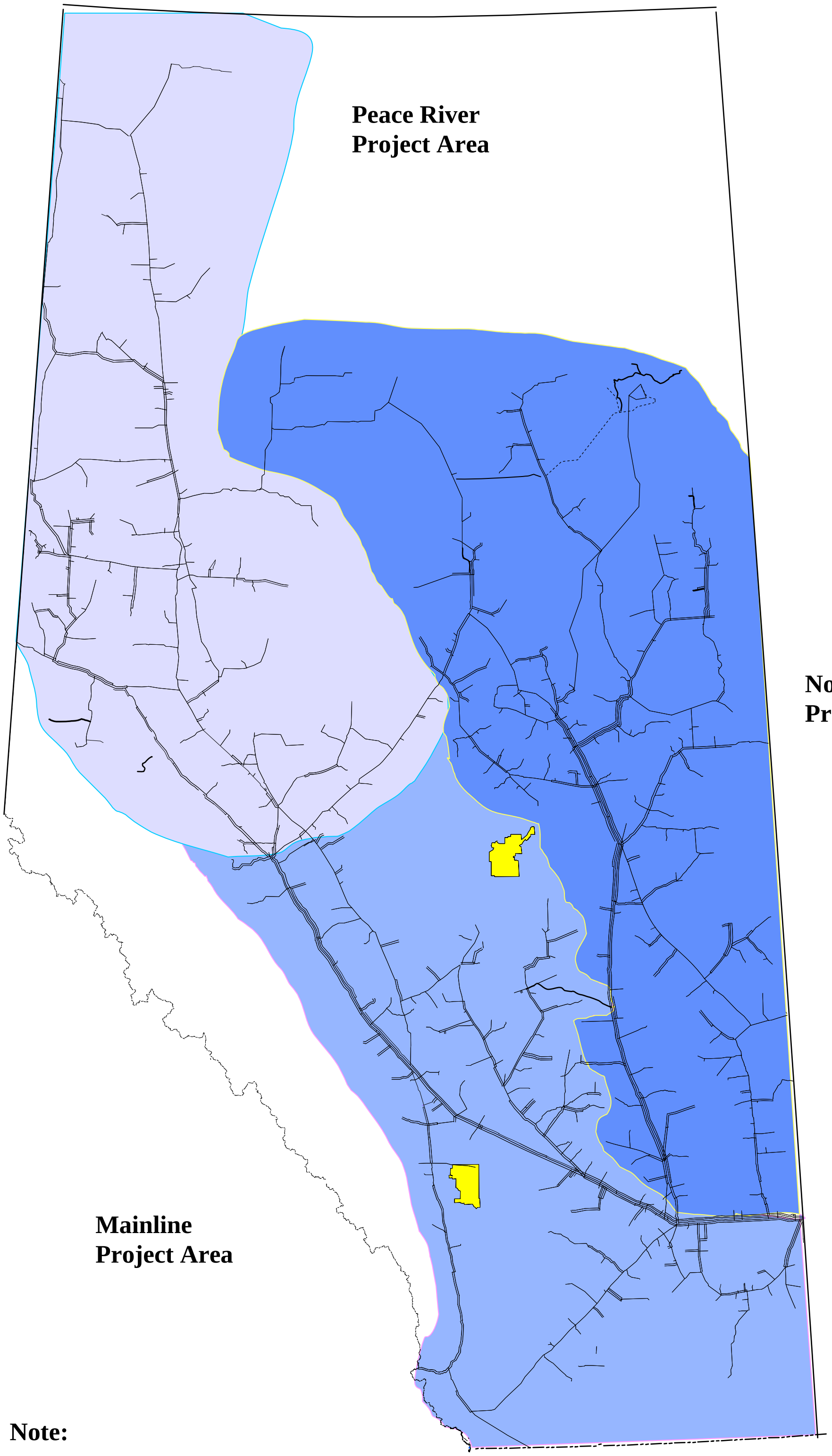
Firm transportation capability may exist from time to time at certain Export Delivery Points for Short Term Firm Transportation-Delivery service ("STFT"). This capability availability is either ambient capability or capability created by unsubscribed Firm Transportation Delivery ("FT-D") transportation. 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. NGTL will not construct facilities for STFT or FT-DW service.

Therefore volumes under these services are not included in the transportation design process described in Section 2.9.

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 NGTL to model the system 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



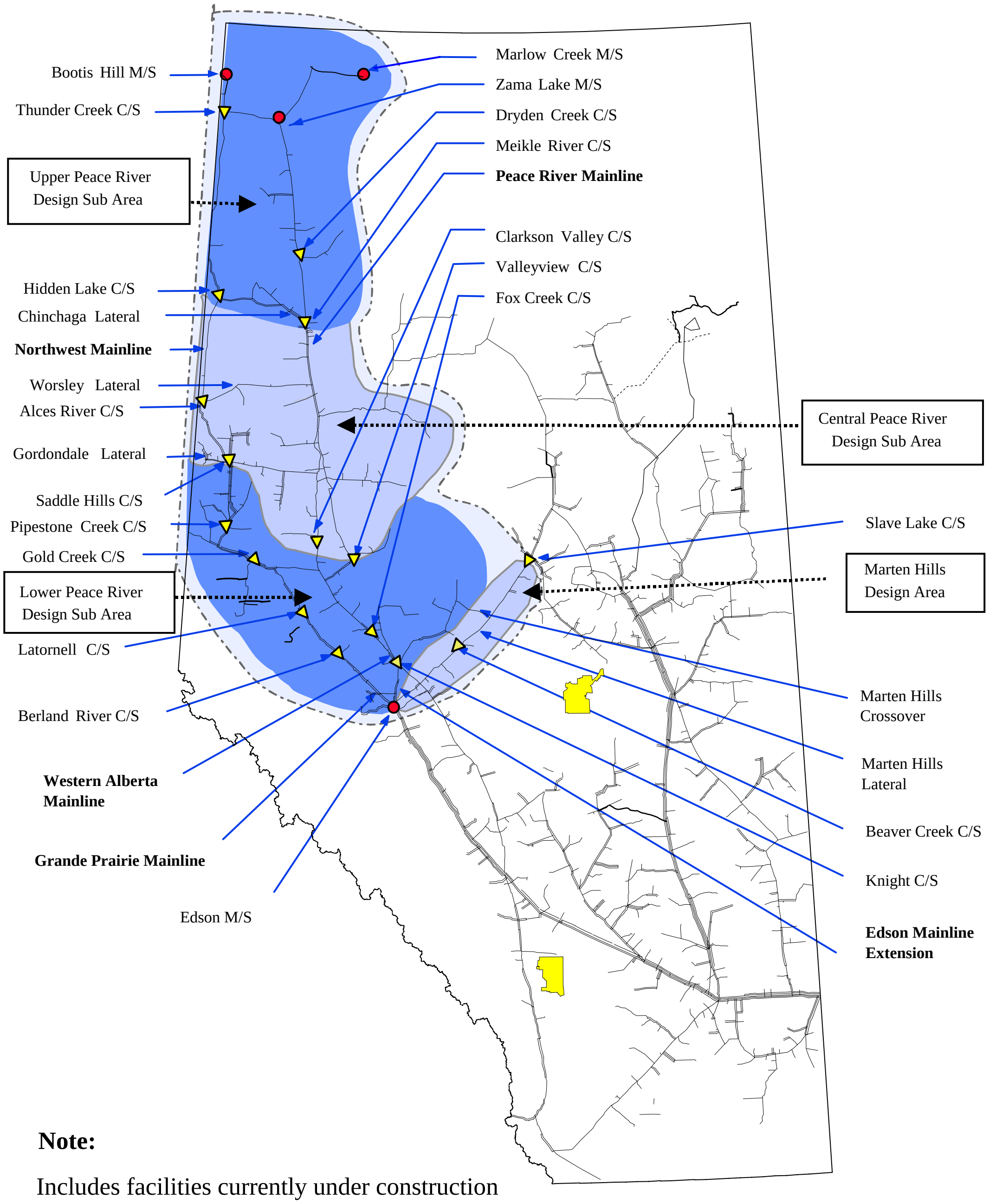
Note:

Includes facilities currently under construction

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 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 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.

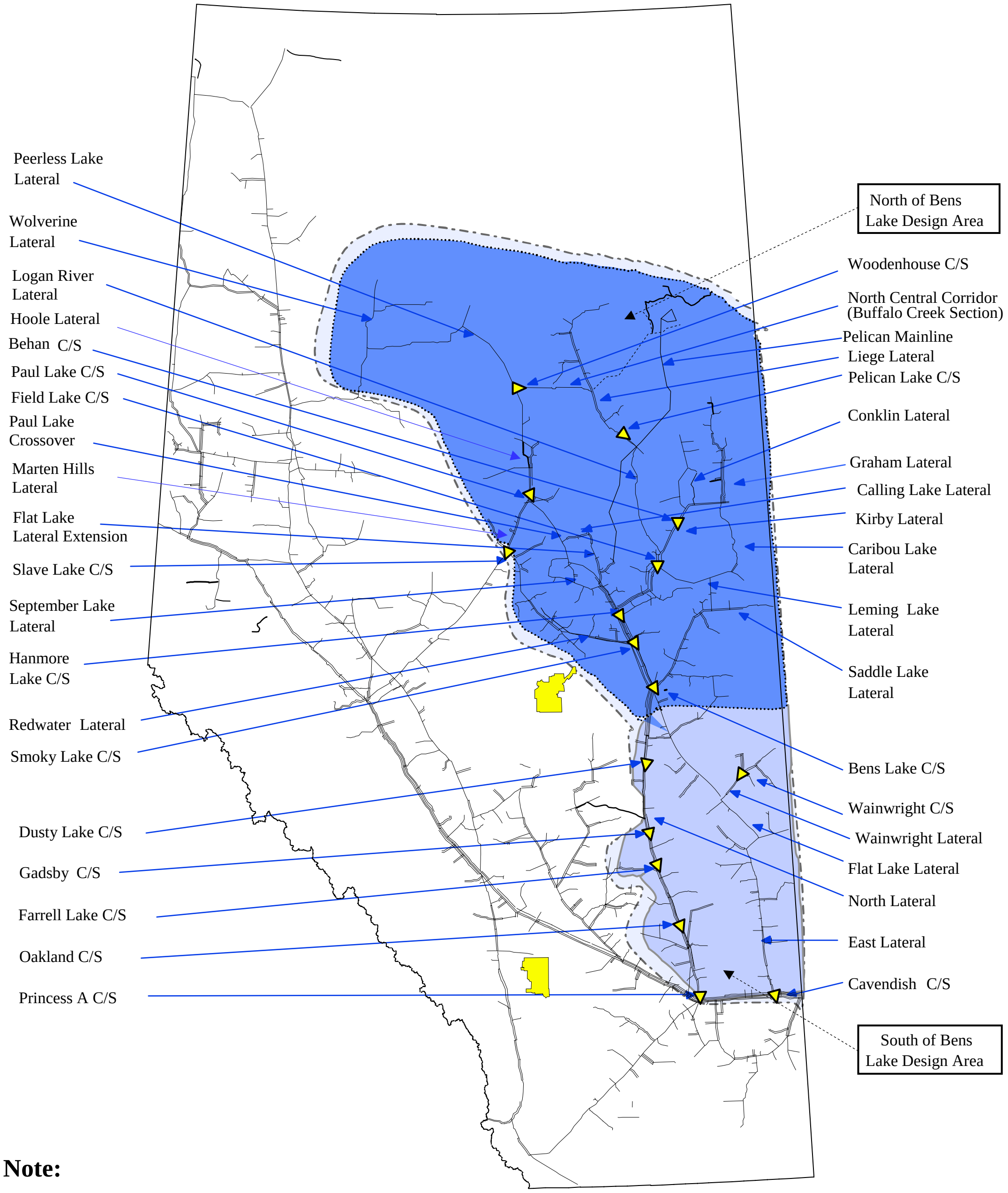
Marten Hills Design Area

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 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. The Ventures Oil Sands Pipeline is also included in the North of Bens Lake Design Area for the purposes of Transportation by Others ("TBO").

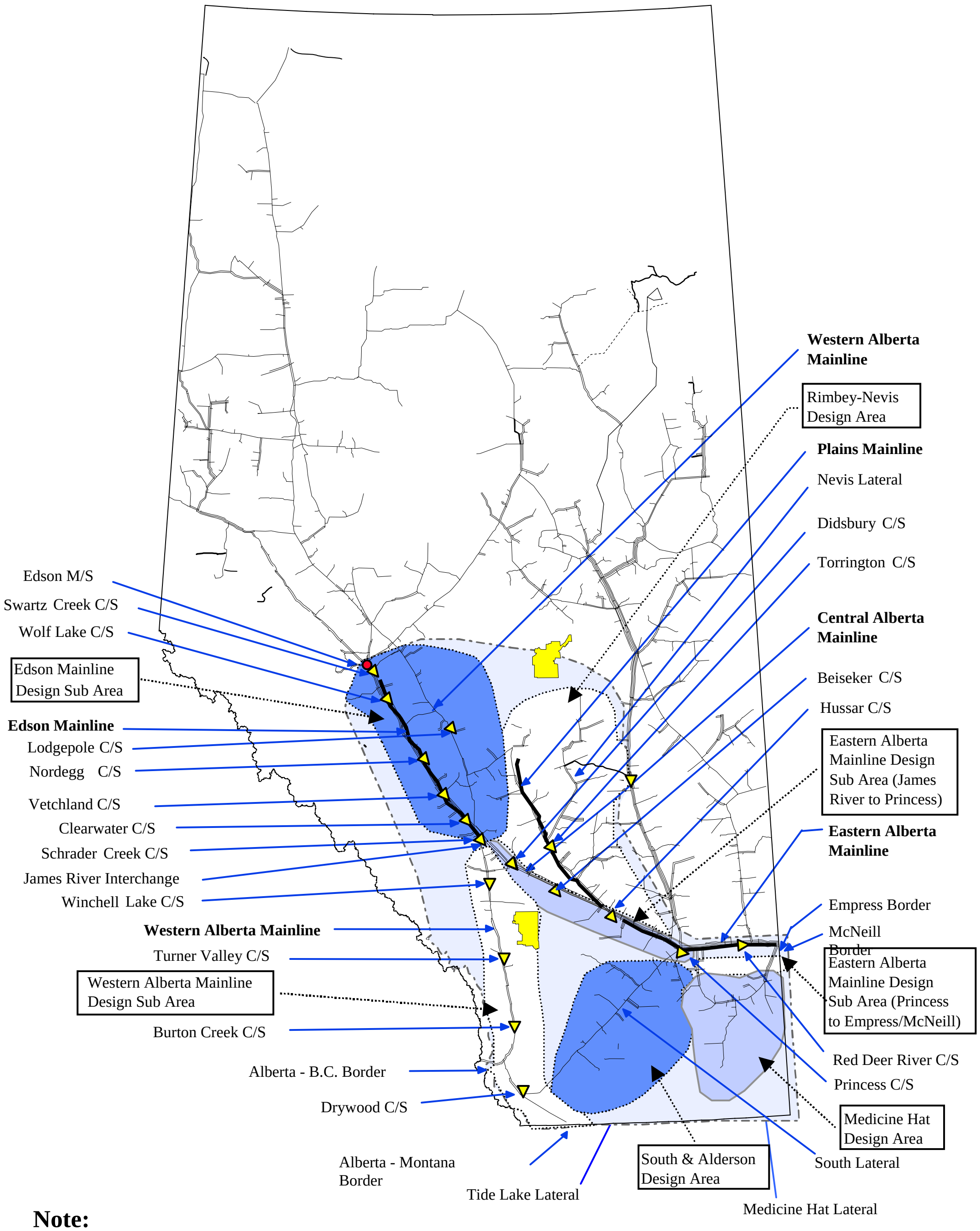
South of Bens Lake Design Area

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 and Extension Facilities 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.

Extension facilities for receipts are designed to transport field deliverability (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

Field deliverability is based on an assessment of reserves, flow capability, future supply development and the capability of 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 field deliverability from a small area of the Alberta System. In NGTL's assessment of facility alternatives to accommodate current and future field deliverability, 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 selects the proposed facilities and the 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 and Extension Facilities 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.

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 current and future 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 selects the proposed facilities and the 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 contains two processes: the design flow requirements determination as described in Section 2.6.1 and the peak expected flow determination as described in Section 2.6.2.

2.6.1 Design Flow Requirements Determination

In each periodic design review, the facilities necessary to provide the capability to meet future firm transportation requirements are identified. To ensure the facilities identified are the most economic, a 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 currently underlie the mainline system design:

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

These assumptions are briefly described in Sections 2.6.1.1 to 2.6.1.5.

2.6.1.1 Equal Proration Assumption

The Alberta System is designed primarily to transport gas from many Receipt Points to a limited number of large-volume 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 gas is drawn from each Receipt Point so that the system can meet each Customer’s firm transportation deliveries. However, if gas is nominated in a manner that differs from the pattern assumed in the system design, shortfalls in deliveries can occur.

Application of the equal proration assumption results in a system design that will meet peak day delivery requirements by drawing on FS productive capability equally from all Receipt Points on the system.

2.6.1.2 Design Area Delivery Assumption

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

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

NGTL periodically reviews this assumption 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 2.6.1.2.

Table 2.6.1.2
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 of Bens Lake	Summer	Min[3]/Avg/Max	Min[3]/Max/Max
• Fort McMurray area[5]	Winter	Max Area Delivery	Max Area Delivery
• South of Bens Lake	Summer	Min[3]/Avg/Max	Min[3]/Max/Max
• 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	Winter[4]	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] Average Receipt Flow Conditions.
[5] Additional design flow consideration applied to the deliveries to the Fort McMurray area in the North of Bens Lake Design Area.

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.

The Medicine Hat Design Area and the North of Bens Lake Design Area require additional consideration. In the Medicine Hat Design Area, average receipt flows and maximum day delivery are the most appropriate conditions to describe the constraining design. In the North of Bens Lake Design Area, seasonally adjusted receipt flows and maximum day delivery to the Fort McMurray area are the most appropriate conditions to describe the constraining design.

NGTL has reviewed Alberta delivery patterns for each design area. The review showed that while individual Alberta Delivery Points will require maximum day delivery as forecast by NGTL, 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.

2.6.1.3 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.

2.6.1.4 Storage Assumption

The Storage Facilities connected to the Alberta System at the AECO ‘C’, Carbon, Crossfield East, January Creek, Severn Creek, Chancellor and Big Eddy Meter Stations are shown in Figure 2.6.1.4. Maximum receipt meter capabilities for Storage Facilities are presented in Section 3.6. The Demmit #2 Storage Facility has been removed from the Storage Assumption because it is no longer used as a commercial storage facility.

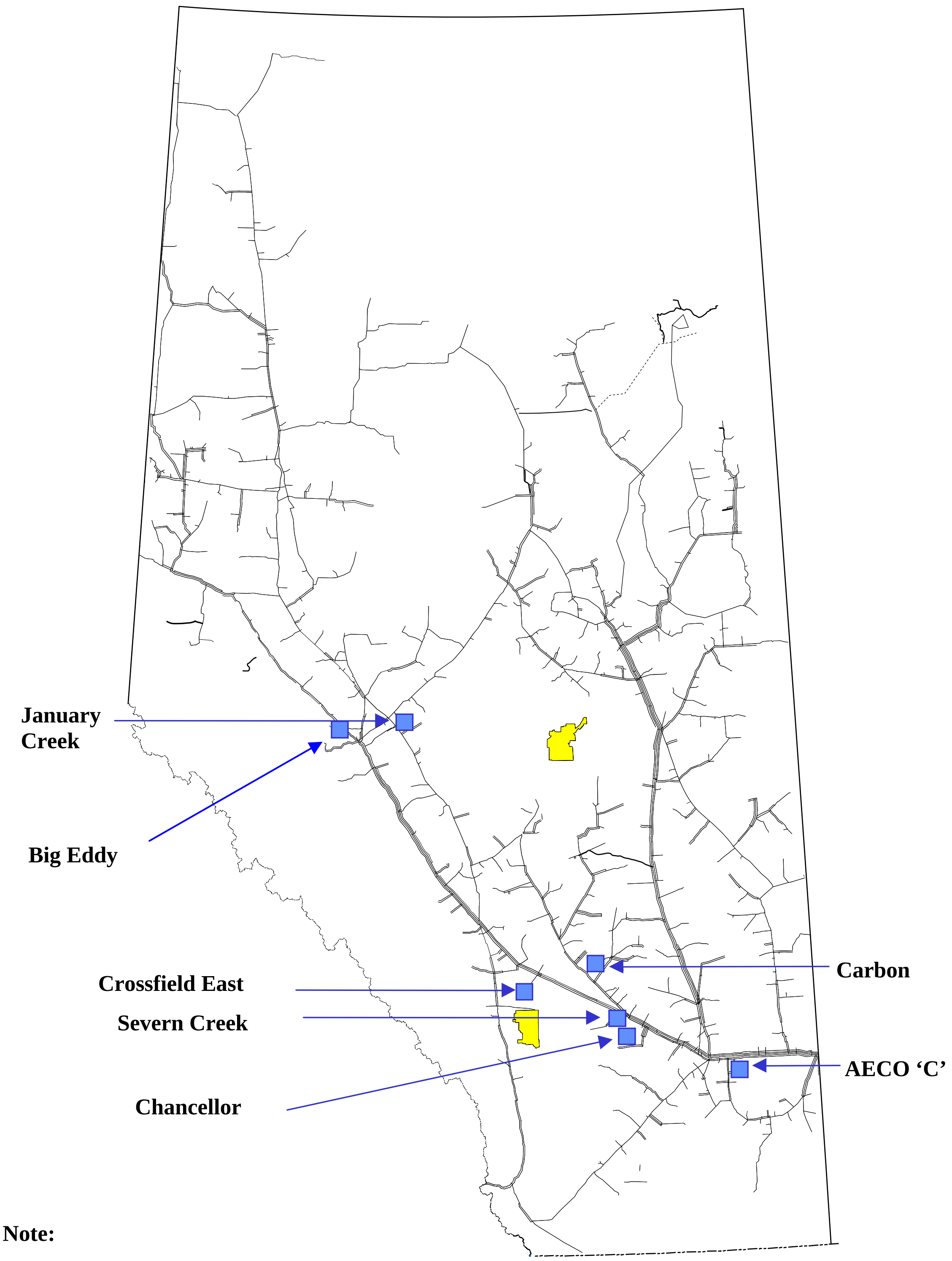
For the 2007/08 Gas Year it was assumed that:

- For the winter period, system design flow requirements will include receipt volumes from selected Storage Facilities onto the Alberta System at average historical withdrawal levels. The assumption is applicable to the Peace River, Marten Hills, North of Bens Lake and South of Bens Lake Design Areas and the Edson Mainline Design Sub Area (the “upstream design areas”). However, for the winter period, system design flow requirements will not include receipt volumes from the Storage Facilities for the Eastern Alberta Mainline (James River to Princess), Eastern Alberta Mainline (Princess to Empress/McNeill), Western Alberta Mainline Design Sub Areas, and the Rimbey-Nevis, South and Alderson and Medicine Hat Design Areas.

  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 upstream design areas for the winter of the 2007/08 Gas Year was 25.4 $10^6m^3/d$ (900 MMcf/d). The result of applying the storage assumption is a reduction in the design flow requirements in the upstream design areas. Volumes withdrawn from the Storage Facilities will be considered as interruptible flows, but will be incorporated into the flow analysis within all "upstream design areas" where it may lead to a reduction in the design flow requirements and a potential reduction in additional 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 2.6.1.4
Locations of Storage Facilities on the Alberta System



Note:

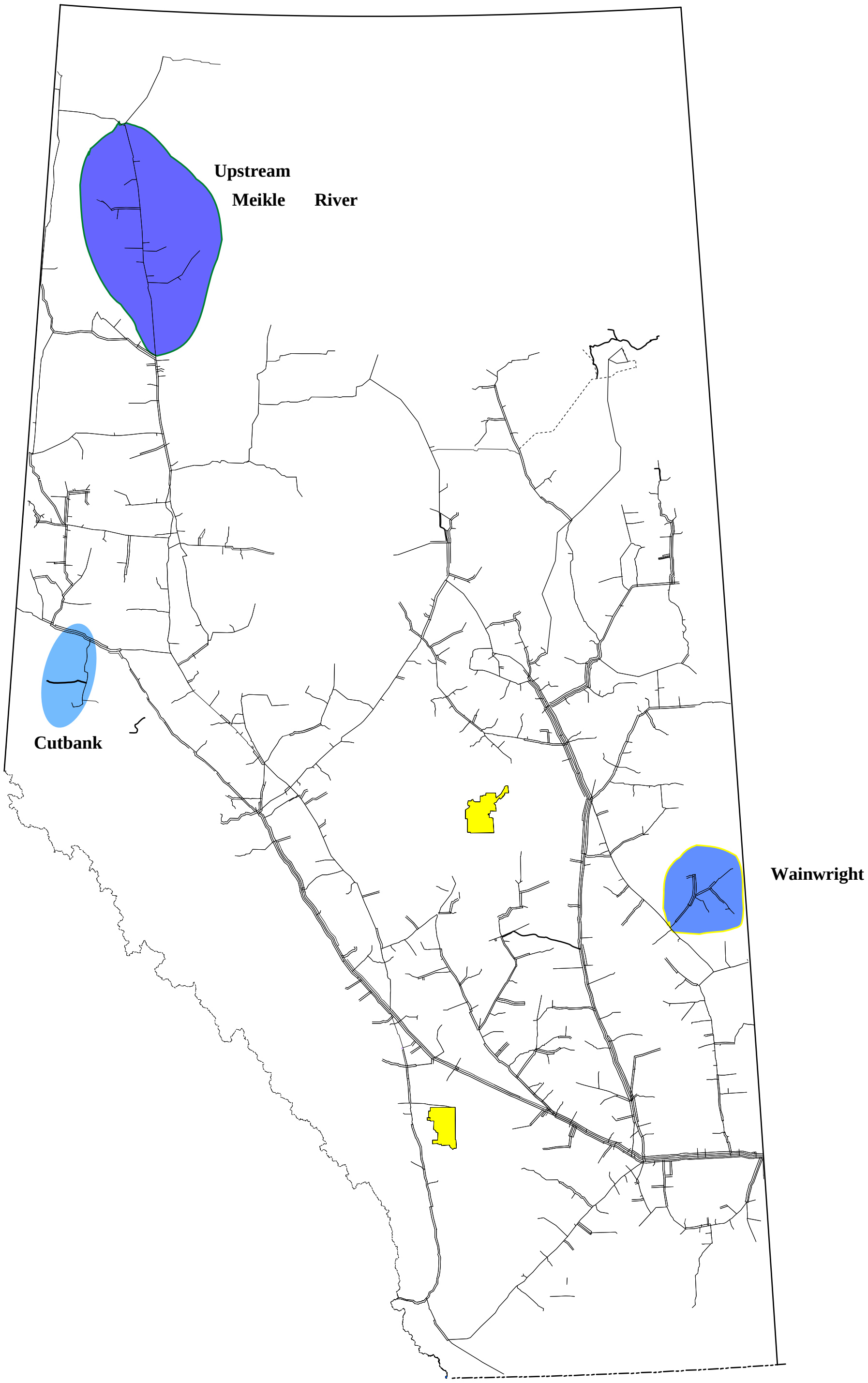
Includes facilities currently under construction

2.6.1.5 FS Productive Capability Assumption

In areas where gas is drawn from a small collection of Receipt Points, there is a greater likelihood that the FS productive capability will be drawn 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 these areas of 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 FS productive capability from each Receipt Point. However, when the FS 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 2.6.1.1) 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. With the addition of the Nevis-Gadsby Crossover to the Alberta System in 2006, the FS productive capability assumption is no longer applied to the Nevis Lateral.

The areas on the system where the FS productive capability assumption has been applied in the 2006 design review are shown in Figure 2.6.1.5.

Figure 2.6.1.5
FS Productive Capability Areas



Note:

Includes facilities currently under construction

2.6.2 Peak Expected Flow Determination

In order to predict peak expected flows a peaking factor is applied to the forecast of average receipts to yield a more realistic peak expected flow condition in the receipt dominated design areas. 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 analysis is applied to the facility design process, it will be used as a guide, not an absolute determinant, in assessing the requirement for facilities additions. When the peak expected flow determination identifies the potential need for facilities additions, a risk of shortfall analysis (load/capability analysis) will be completed prior to recommending the required facilities additions.

For this Annual Plan the assessment of peak expected flow will be confined to areas that are governed by receipt dominant flow conditions. Assessments of areas governed by delivery dominant flow conditions are still under development and will be addressed at a later date.

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 NGTL’s 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 and Compressor Modernization

Flow distribution on the Alberta System continues to change, such as declining FS productive capability and increasing Alberta deliveries in the North of Bens Lake Design Area and the proposed construction of the North Central Corridor in the winter of the 2009/10 Gas Year (Section 5.6.2). 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 and maintain flexibility without adversely affecting throughput. NGTL's interest is to maximize volumes on the system in order to minimize tolls. Accordingly, cost reduction initiatives are not intended to reduce system volumes. The 2006 design review system optimization results are described in Section 5.2. The identification of compressor units that should be removed from service or replaced will continue to be an integral part of the overall system design.

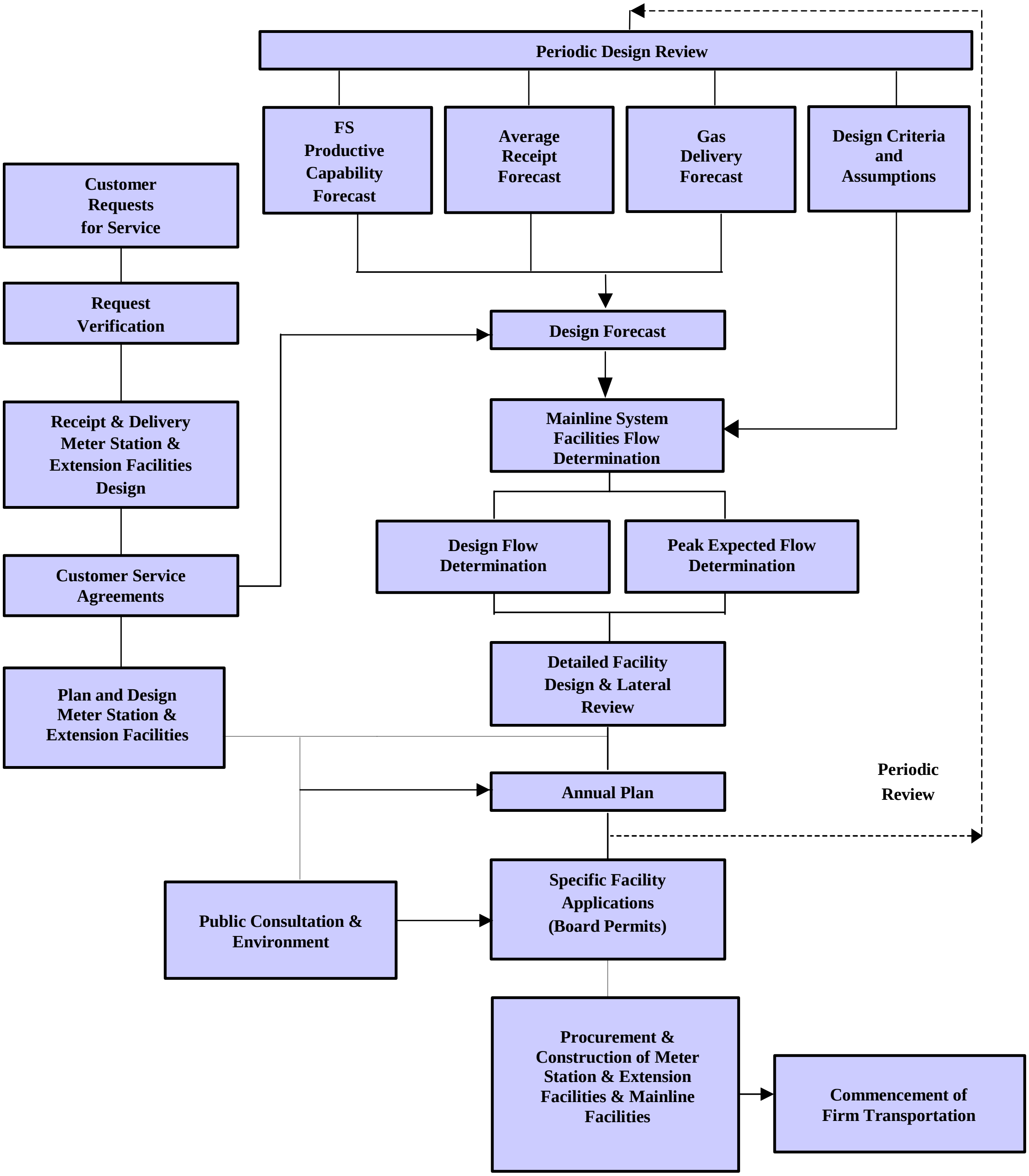
2.9 Transportation Design Process

As stated in Section 2.1, NGTL conducts periodic design reviews 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 2007/08 Gas Year. 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 2007/08 Gas Year were received by NGTL and included in the transportation design process for the 2007/08 Gas Year.

Requests for firm transportation, which are based on insufficient field deliverability, duplications, or over-contracting at a Receipt Point, are removed from the transportation design process.

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 and the Board, 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 field deliverability forecast for the area can be accommodated.

In the case of delivery facilities, a review is undertaken to establish the peak day demand levels that are identified as supporting 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 field deliverability 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 FS productive capability, average receipts and gas delivery requirements on the Alberta System, and plays an essential role in NGTL's determination of future facility requirements and planning capital expenditures.

The design forecast comprises the FS productive capability forecast, 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 FS Productive Capability Forecast

The FS productive capability 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 under firm transportation Service Agreements at each Receipt Point. This section describes NGTL's method for determining a FS productive capability forecast. The key forecasting terms are field deliverability, FS productive capability, and Receipt Contract Demand.

Field Deliverability

Field deliverability is the forecast peak rate at which gas can be received onto the Alberta System at each Receipt Point. NGTL forecasts field deliverability through an assessment of reserves, flow capability, future supply development and the capability of gathering and processing facilities at each Receipt Point. This information is gathered from Board sources, NGTL studies, and through interaction with producers and Customers active in the area. With this information, the field deliverability forecast is developed using NGTL's supply forecasting model.

Section 2.4 describes how field deliverability is used to identify facility requirements, while Section 3.5 presents the forecast of field deliverability.

FS Productive Capability

FS productive capability is the lesser of the field deliverability and the aggregate Receipt Contract Demand under firm transportation Service Agreements held at each Receipt Point.

Section 2.6.1 describes how FS productive capability is used to identify facility requirements, while Section 3.5 presents the forecast of FS productive capability.

Aggregate Receipt Contract Demand Under Firm Transportation Service Agreements

In order to prepare a forecast of FS productive capability, a method of forecasting the aggregate Receipt Contract Demand under firm transportation Service Agreements is required.

At each Receipt Point, the aggregate Receipt Contract Demand under firm transportation Service Agreements for the 2007/08 Gas Year consists of the sum of Receipt Contract Demand under:

- firm transportation Service Agreements with terms extending beyond the design period;
- firm transportation Service Agreements terminating before the end of the design period; and
- new requests for firm transportation to be authorized for commencement of service before the end of the design period.

To prepare a forecast of FS productive capability, NGTL forecasts the volume associated with firm transportation Service Agreements terminating before the end of the design period that will be renewed and the volume associated with new requests for firm transportation to be authorized for commencement of service before the end of the design period.

To forecast the volume associated with new requests for firm transportation Service Agreements that will be authorized and will commence service before the end of the design period, NGTL makes assumptions on the volumes associated with new requests for service based upon historical data, contract utilization and supply potential.

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 NGTL 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 June 2006 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. NGTL performed computer simulations of the pipeline system to identify the facilities that would be required for NGTL to meet its firm and peak transportation expectations for the 2007/08 Gas Year.

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

Many alternatives are identified when combinations of the facility configurations and optimization parameters are considered. This process requires NGTL to carefully evaluate a large number of alternative designs and 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, NGTL may consider when appropriate TBO or purchase of existing other party facilities 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 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, in this case the 2007/08 Gas Year, 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, the selection decision will consider other relevant factors including operability of the facilities, environmental considerations and land access.

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. Optimally, compressor stations are located in the immediate vicinity of existing pipelines to avoid additional pipeline that would otherwise be required to connect the new compressor stations.

The preliminary route selection area for new pipelines is defined by the reasonable alternative routes between the end points of the new pipeline. The location of loops of existing pipeline segments is often restricted, for practical purposes, to areas along existing pipeline corridors and between existing block valve sites.

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 Board Interim Directive ID 99-8 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, NGTL conducts an aerial and/or ground reconnaissance of the preliminary route selection area to confirm the pipeline end points and to identify alternative pipeline routes between end points.

Through public consultation input is sought from landowners and the public affected by the alternate pipeline routes (Section 2.9.7). 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:

Pipeline routes, which cause minimal disturbance to the surrounding area, are preferred.

(3) Right-of-Way Corridors:

In accordance with Board Informational Letter IL 80-11, NGTL attempts to make use of any existing utility, seismic or pipeline right-of-way corridors within the route selection area. Utilizing existing corridors reduces the amount of clearing and land disturbance and, in the case of shared right-of-way, allows for narrower 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. Timing 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 is involved in a variety of public consultation activities that help NGTL establish and maintain positive relationships with people affected by the construction and operation of the pipeline system. Part of the public consultation process involves information sharing on new projects and soliciting public input for the siting of new facilities.

The public consultation process enables NGTL to identify and address issues involving the public, share information on NGTL's plans and solicit input on decisions that may affect public stakeholders.

While public 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 public consultation program depends on a number of factors, including the nature of the facility, the potential for public impact, and the level of public interest. All contact with stakeholders throughout the consultation process is documented in a tracking form that is reviewed regularly to ensure that all commitments are recorded and issues of concern are addressed.

As part of the stakeholder identification process, NGTL conducts title searches of all lands directly impacted by or adjacent to each proposed facility to identify potentially impacted landowners and occupants. Public Land Standing Reports are obtained from Alberta Sustainable Resource Development to verify all Crown land disposition holders that would have an interest in the lands.

Lands potentially impacted may include:

- All lands crossed by the proposed pipeline route(s);
- All parcels of land lying within 0.2 km of the proposed pipeline route(s); and
- All lands lying within a 1.5 km radius of all proposed compressor station facilities.

NGTL meets in person with all directly impacted landowners and occupants to introduce them to NGTL's facility proposal and provide an opportunity for input regarding routing and scheduling.

In addition, the Member of Parliament and Member of the Legislative Assembly, the Board local area supervisor, as well as local elected officials and staff, civic organizations and other potential interested and impacted stakeholders are identified and notified of NGTL's proposal.

Standard information packages for all stakeholders contain:

- A fact sheet outlining project specific information such as length of the project, the start and end points, proposed pipe size, maximum operating pressure, new right-of-way, the proposed construction timing, as well as NGTL's environmental, safety and consultation commitments;
- A map depicting the geographic location of the proposed pipeline route/facility site;
- Letter from the Chairman of the EUB;
- EUB brochure *Understanding Oil and Gas Development in Alberta;*
- EUB public information document *EnerFAQs No. 8: Proposed Oil and Gas Development: A Landowners Guide;*
- EUB public information document *EnerFAQs No. 13: The EUB and You: Agreements, Commitments and Conditions;*
- EUB public information document *EnerFAQs No. 15: All About Appropriate Dispute Resolution (ADR);*
- Required EnerFAQs as outlined in EUB Directive 56: *Energy Development Application Guide;*
- EUB Guide 30: *Guidelines for Safe Construction Near Pipelines;*
- Alberta Agriculture, Food and Rural Development pamphlet: *Negotiating Surface Rights;* and
- Alberta Agriculture, Food and Rural Development pamphlet: *Pipelines in Alberta*.

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

Upon request or if deemed appropriate, specific interested individuals or groups, such as municipalities, civic organizations, or special interest groups, will receive a personal consultation in order for NGTL to provide further details of the proposed facilities and gain input from stakeholders.

A community meeting or open house is held, where appropriate, to provide information regarding specific proposed facilities and gain input from stakeholders. Community meetings provide a forum to review, discuss and resolve issues or concerns of interested parties. Invitations are extended to all potentially impacted landowners, occupants, government officials and general community members who may be impacted by or interested in the proposed facilities, as identified by NGTL. NGTL endeavors to answer any questions with regard to proposed facilities at these meetings. If NGTL is unable to respond to questions at that time, additional information is gathered and is provided following the meeting. Attendees are requested to sign into the open house and provide feedback on the effectiveness of the open house in addressing their issues or concerns with the proposed project. A summary of the information shared and the comments received, and any commitments made, is entered into the consultation tracking form.

In its respect for the diversity of aboriginal cultures and its commitment to work with aboriginal communities, NGTL has developed an Aboriginal Policy. 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 and provide the opportunity to work with the communities to seek mutually acceptable solutions and benefits.

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

2.9.8 Environmental Considerations

NGTL selects facility sites and pipeline routes that allow the facility to be constructed and operated in a cost effective manner with minimal environmental impact. The route and site selection processes consider the impact of proposed facilities on all aspects of the environment, including: surficial geology and landform; soils; timber; water resources; vegetation; fisheries; wildlife; land use; aesthetics; air quality and noise levels as outlined in Alberta Environment's ("AENV") *Guide for Pipelines, 1994* and *the NGTL Conservation and Reclamation Standard, 1999.* All identified potential environmental impacts are examined during the selection process and evaluated together with any mitigative measures that may be required to reduce the impacts of facility construction and operation. Measures appropriate to address hazardous materials, waste management, weed control and reclamation are designed to meet project specific conditions. Based on the consideration of potential environmental impacts and the design of mitigation measures, an Environmental Protection Plan is developed to communicate these mitigation measures.

2.9.8.1 Site Preparation

During the construction of meter stations and compressor stations, the topsoil in the White Area (arable lands) of the province and the surface organic and near surface mineral material in the Green Area (non-arable lands) are stripped from the entire graded area. The stripped material is stockpiled at an appropriate location to conserve the material for use during reclamation of the site upon decommissioning and abandonment. The stockpile is seeded with a mixture of species compatible with the surrounding area to prevent wind and water erosion.

2.9.8.2 Right-of-Way Preparation

During the construction of pipelines in the White Area of the province, NGTL conserves topsoil to maintain land capability following construction. Soil surveys are conducted in selected areas of the province to ensure that handling techniques are compatible with the soil conditions of the right-of-way.

In the Green Area of the province, surface materials are conserved through grubbing. Grubbing is the removal of woody debris (e.g. stumps, roots) from the right-of-way to allow for the safe passage of construction equipment. Timber is salvaged from the right-of-way when the trees meet merchantable criteria established in consultation with Alberta Sustainable Resource Development.

2.9.8.3 Vegetation Management

NGTL's vegetation management program is designed to assess and respond to weed problems on newly constructed and operating pipelines and facilities. NGTL takes all reasonable measures to prevent the proliferation of weeds and promote desirable, relatively stable plant communities that are compatible with existing land use. Certificates of Analysis are obtained for all grass and legume seed mixes used in NGTL's reclamation program to ensure that prohibited and noxious weeds are not introduced to an area through seed application. In addition, construction equipment is cleaned of mud and vegetative debris prior to entering the right-of-way.

Measures to prevent the proliferation of weeds include tilling, mowing, spraying, or in rare cases, hand pulling of weeds. The method of control is chosen to accommodate site conditions, landowner requirements and regulatory agency recommendations.

2.9.8.4 Surface and Groundwater Considerations

Surface water movements are taken into consideration during the facility site and pipeline route selection process. During construction, near surface groundwater flow may be encountered. In these situations, NGTL assesses the potential for impacting flow direction and, where necessary, installs below ground piping or takes other appropriate measures to ensure that groundwater moves across the facility.

2.9.8.5 Fisheries and Wildlife Resources

The identification and evaluation of fisheries and fisheries habitat is required for each watercourse crossing traversed by a pipeline route. This process enables NGTL personnel to: determine fisheries and fisheries habitat parameters and criteria at each watercourse crossing; evaluate and recommend appropriate crossing methodologies; identify construction mitigation measures; evaluate the need for specific reclamation measures at each crossing location; and meet provincial and federal legislative requirements.

Crossing evaluations and habitat assessment information establishes NGTL's recommended crossing methodology. This information provides documentation to meet the intent of the federal *Fisheries Act* and all other applicable legislation as well as the 'no net loss' principle. Information from the crossing evaluation (i.e., geotechnical assessment) and findings from the fisheries assessment are integrated to determine the most appropriate crossing methodology.

NGTL documents the evaluation and assessment to ensure and demonstrate due diligence in determining impacts associated with a crossing technique and/or proposed mitigation measures. NGTL attempts to install each crossing as quickly as possible to minimize potential environmental impacts during construction.

Identifying and evaluating wildlife and their habitats along the pipeline alignment and adjacent areas is part of NGTL's environmental planning process. NGTL reviews wildlife and habitat information to: ensure that pipeline activities have a minimal impact on these resources and their habitat; meet the requirements of the *Alberta Wildlife Act* and all other applicable legislation; and identify the status of critical key wildlife species and their habitat (i.e., endangered, threatened or vulnerable). NGTL then determines the most appropriate route alignment by and if possible, avoiding routing through critical and/or key habitat. If key and/or critical habitat cannot be avoided, NGTL identifies appropriate mitigative measures in consultation with local resource managers and documents these measures in the Environmental Protection Plan to be used during construction.

2.9.8.6 Historical and Paleontological Resources

Class I pipelines, as described in Section 2.9.9, are referred to Alberta Community Development to determine whether or not a Historical Resource Impact Assessment is required. The need for a historical resource assessment is based on the following principles: that crown owned archaeological and paleontological resources are held as a public trust; 'users pay' principle applies to all historical resource discoveries and therefore developers that create an impact on historical resources are responsible to undertake an impact assessment and implement mitigation measures to protect these resources; and the Minister responsible for historical resources management has discretionary powers to order an assessment and mitigation of historical resources impacts.

For Class II pipelines, NGTL reviews available provincial archaeological resources sensitivity maps and significant sites and area maps. In cases where this review suggests that a proposed project may have potential impact to an identified site, NGTL works with the appropriate Alberta Community Development representative to determine appropriate next steps.

If a significant historical site is discovered during the assessment of a proposed facility, NGTL employs the service of a qualified archaeologist to further delineate historical resources in relation to construction activities. If warranted, mitigative measures are employed during construction to conserve and preserve historical resources. Although the assessment is intensive, it is still possible to encounter new sites during construction. In accordance with Section 27 of the *Alberta Historical Resources Act*, should any cultural material be uncovered during construction, Alberta Community Development is contacted immediately to determine further requirements.

2.9.8.7 Land Surface Reclamation

The primary objective of surface land reclamation is to return lands to equivalent land capability. As a result, the focus is on the land capability of surface material and vegetation criteria. Surface land reclamation must be practical, feasible and cost-effective in meeting the objectives of equivalent land capability. Remedial efforts focus on reducing long-term risk and mitigating concerns.

Reclamation requirements are outlined in the Environmental Protection Plan. NGTL identifies reclamation criteria in the planning and preparation phase of a pipeline to ensure that any disturbed land is returned to an equivalent land capability. The reclamation criteria addresses: vegetation; drainage; moisture availability; erosion, contour or landscape pattern; and slope stability.

NGTL adheres to the following principles when developing and implementing a Reclamation Plan: salvage all surface materials/topsoil and store it separately from the subsoil and spoil material so it can be used for reclamation of the site; develop Reclamation Plans for all facilities; and obtain the appropriate regulatory approvals when abandoning a facility.

2.9.8.8 Air Emissions and Alberta Environmental Protection and Enhancement Act ("AEPEA") Approvals

NGTL complies with the AEPEA in the design and construction of compressor stations.

2.9.8.9 Noise Regulations

NGTL complies with Board Interim Directive ID 99-8 in the design and construction of facilities.

2.9.9 Facility Applications, Procurement and Construction Phase

Applications for facilities for the 2007/08 Gas Year will be submitted to the Board throughout 2007. Facilities not identified in this Annual Plan will be filed as a Section L application under the Board's IL 90-8. As facility applications are being prepared, discussions with industry representatives will continue and modifications to specific facility applications, if warranted, will be made to reflect industry feedback on the Annual Plan. If any significant changes are made to accommodate a concern, timing of the completion of the facilities may be affected and result in a delay in the provision of firm transportation. However, NGTL will take all reasonable steps to mitigate such delays.

Under the provisions of AEPEA and the *Activities Designation Regulation*, NGTL is required to submit Conservation and Reclamation ("C&R") applications to AENV for Class I pipelines with the exception of those located in the Green Area. Class I pipelines are those projects in which the pipe diameter (in millimeters) multiplied by the cumulative length (in kilometers) is equal to or greater than 2690. A C&R application contains details with respect to location of the pipeline, area description, environmental consultation activities, potential environmental impacts and an environmental protection plan. NGTL develops an environmental protection plan for all its pipeline construction projects, Class I and Class II. Class II pipelines are those projects in which the pipe diameter (in millimeters) multiplied by the cumulative length (in kilometers) is less than 2690. C&R applications are reviewed and approved by AENV prior to construction. During the review process, NGTL advertises the submission of the application, thereby allowing the public further opportunity to review and/or comment on the application. Statements of concern brought forth by the public to AENV are addressed by NGTL prior to a decision being made on the application. The application process typically parallels the Board facility application review process.

NGTL has developed and implemented the NGTL C&R Standard compiling all NGTL environmental policies and standard environment protection procedures. All project-specific C&R applications will refer to and incorporate the appropriate policies and procedures set out in NGTL's C&R Standard.

CHAPTER 3 - DESIGN FORECAST

3.1 Introduction

This Annual Plan is based on NGTL's June 2006 design forecast of gas receipts and deliveries, which in turn is based on supply and market assessments completed in May 2006.

From a receipt perspective, the forecasts of field deliverability, average receipts and FS productive capability used in this Annual Plan are subject to numerous 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.

From a delivery perspective, the maximum day delivery forecasts at the Export Delivery Points as shown in Chapter 3, Section 3.4.2 are equal to the forecasts of FT-D contracts at those Export Delivery Points and do not include STFT or 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 the preponderance of short term contracting.

NGTL will continue to closely monitor industry activity, contracting levels, and design implications throughout the year in order to anticipate and respond to Customer needs in a timely manner.

NGTL's June 2006 design forecast of gas receipt and delivery applies to the transportation design process for facilities to be in-service for the 2007/08 Gas Year. The June 2006 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 field deliverability, average receipts and FS productive capability forecasts (Sections 2.9.4.1, 2.9.4.2 and 3.5) for all Receipt Points on the Alberta System.

An overview of the June 2006 design forecast was presented at the November 21, 2006 TTFP meeting. This chapter presents a detailed description of the June 2006 design forecast.

The June 2006 design forecast includes winter and summer seasonal forecasts of maximum, average, and minimum day delivery for all Delivery Points and a forecast of field deliverability, average receipts and FS productive capability for all Receipt Points on the Alberta System. Refer to Section 2.9.4 for further details on the relationship between field deliverability, average receipts, FS productive capability and Receipt Contract Demand under firm transportation Service Agreements 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 154.0 $10^6m^3/d$ (5.47 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 May 2006, include:

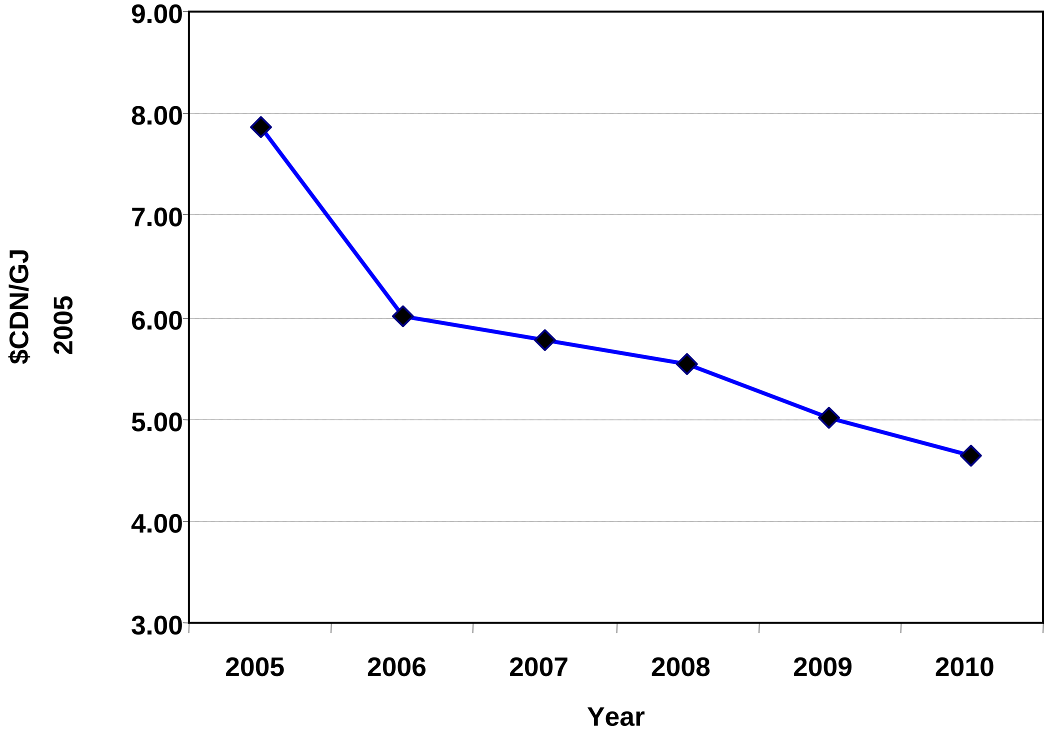
- World oil prices are forecasted to peak in 2006 at an average $U.S. 67.50/bbl for West Texas Intermediate ("WTI"), up from $U.S. 56.45/bbl in 2005. Going forward, world oil demand growth will remain strong, averaging around 2% per year. Non-OPEC oil supply is expected to grow significantly over the next several years, resulting in a slowly growing call on OPEC oil. OPEC has many projects underway to increase oil production capacity; as these come on-stream, OPEC's spare capacity will increase, removing the fear or security premium in prices. Shortfalls in refining capacity, especially to manufacture a higher proportion of light clean products and to upgrade heavy fuel oil are forecasted to be resolved over the next five years due to large investments in OPEC and in the rapidly industrializing countries of Asia. In addition, significant investment is occurring in North American refining to utilize the increasing volumes of heavy oil/bitumen from the Alberta oil sands. For these reasons, prices are expected to moderate going forward, declining to $U.S. 45.00/bbl or $U.S. 40.00 (real 2005) in 2010.
- A peak in U.S. gas prices was reached in 2005 with an average of $U.S. 8.62/MMBTU for NYMEX Henry Hub, while 2006 prices are forecasted to be lower, at $US 7.15/MMBTU. Prices will continue to slowly decline over the next five years due to the general decline in oil prices and the rising influx of liquefied natural gas ("LNG"). Prices reach $U.S. 5.80/MMBTU by 2010. This equates to $U.S. 5.16/MMBTU in real 2005 terms.

- 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 predominately in the electricity generation sector. Western Canadian industrial gas demand is expected to grow significantly, driven by oil sands and heavy oil activity.
- The U.S. is expected to be able to supply most of its natural gas needs by drawing from its extensive gas resource base, with production from basins in the Rocky Mountains showing significant growth. Much of the new supply will be from unconventional gas – coal bed methane and tight gas. However, U.S. domestic supply is expected to decline slowly in aggregate and will be unable to satisfy the growth in demand. Imported LNG will play a significant role in providing additional supply to U.S. markets. A large number of new projects have received Federal Energy Regulatory Commission or other necessary regulatory approvals and several are already under construction. Three of the four existing onshore U.S. receiving terminals have numerous expansions recently completed or underway. A wave of new LNG receiving capacity will become operational in the U.S. and Mexico from 2006/07 onward. By 2008/09, this additional LNG supply will help to moderate gas prices in the North American market.

3.2.2 Gas Price

A gas price forecast is used by NGTL to determine gas demand, to evaluate the viability of gas supply development for the June 2006 design forecast, and in the economic evaluation of facilities. The gas price forecast is based on an assessment of 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 May 2006 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 2006 (in real 2005 $) is forecasted at $6.02 Cdn/GJ, down from the peak of $7.87 Cdn/GJ in 2005. Alberta prices decline over the next five years in line with the drop in NYMEX gas prices, but the differential narrows. By 2010, Alberta prices have declined to $4.64/GJ in real 2005 terms.

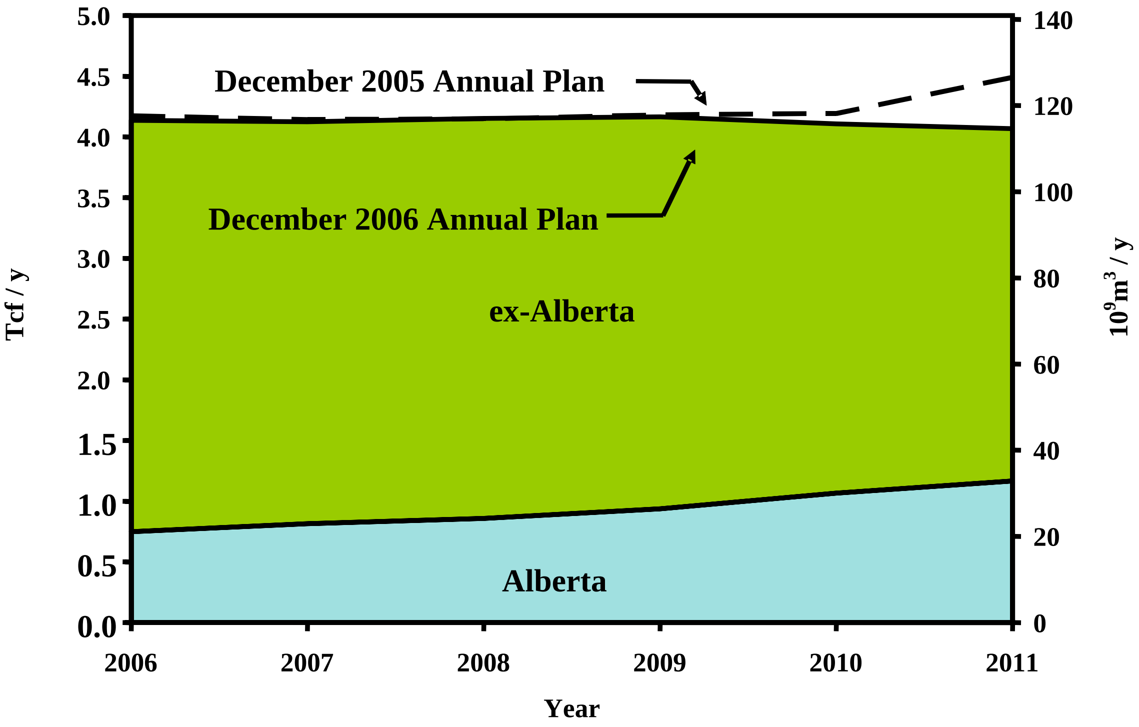
The gas price forecast affects NGTL’s receipt and delivery forecast, and is used as input into the economic analysis for new facilities. The level of the gas price affects anticipated producer activity to support continuing production from connected supplies, connection of unconnected reserves, and the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

3.3 System Annual Throughput

NGTL's forecast of system annual throughput is included for informational purposes. The system annual throughput forecast projects the total amount of gas to be transported by NGTL in future years and is the basis for the forecast of unit volume cost (Section 7.3).

System annual throughput (Figure 3.3.1) is expected to remain relatively flat at approximately 117 $10^9m^3/y$ (4.1 Tcf/y) over the design forecast period.

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 2006 design forecast. The second component, the receipt forecast, is described in Section 3.5.

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 2006/07 through 2010/11 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.

A breakdown of the system maximum day delivery forecast for both the winter and summer seasons of the 2007/08 Gas Year is provided in Tables 3.4.2.1 and 3.4.2.2. The June 2006 forecast indicates a winter system maximum day delivery of 316.6 $10^6m^3/d$ (11.25 Bcf/d) for the 2007/08 Gas Year. This represents an increase of 3.3 $10^6m^3/d$ (0.13 Bcf/d), or 1.1 percent from the winter system maximum day delivery in the June 2006 forecast for the 2006/07 Gas Year.

NGTL's June 2006 forecast of winter system maximum day delivery for the 2007/08 Gas Year includes deliveries to the major Export Delivery Points (Empress, McNeill, Alberta/British Columbia) of 184.3 $10^6m^3/d$ (6.55 Bcf/d), deliveries to other Export Delivery Points of 0.0 $10^6m^3/d$ (0.00 Bcf/d), and deliveries to Alberta Delivery Points of 132.3 $10^6m^3/d$ (4.70 Bcf/d.).

The June 2006 summer system maximum day delivery forecast for the 2007/08 Gas Year is 280.6 $10^6m^3/d$ (9.97 Bcf/d). This represents an increase of 7.6 $10^6m^3/d$ (0.27

Bcf/d), or 2.8 percent, from the summer system maximum day delivery forecast for the 2006/07 Gas Year.

NGTL’s June 2006 forecast of summer system maximum day delivery for the 2007/08 Gas Year includes deliveries to the major Export Delivery Points (Empress, McNeill, Alberta/British Columbia) of 179.3 $10^6m^3/d$ (6.37 Bcf/d), deliveries to other Export Delivery Points of 0.0 $10^6m^3/d$ (0.0 Bcf/d) and deliveries to Alberta Delivery Points of 101.3 $10^6m^3/d$ (3.60 Bcf/d).

3.4.2 Export Delivery Points

The June 2006 forecast of maximum day delivery at the Export Delivery Points is consistent with NGTL’s downstream capacity assumption (Section 2.6.1.3).

Table 3.4.2.2
Summer System Maximum Day Delivery Forecast

	June 2006 `Design Forecast				
Gas Year	**06/07**	**07/08**	**08/09**	**09/10**	**10/11**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	75.4	72.1	66.9	61.8	57.7
McNeill	37.6	37.4	37.2	36.2	36.2
Alberta/B.C.	70.4	69.8	57.0	52.6	51.3
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	0.0	0.0	0.0	0.0	0.0
Alberta	89.6	101.3	109.7	117.6	129.3
TOTAL SYSTEM	**273.0**	**280.6**	**270.8**	**268.2**	**274.5**
(Volumes in Bcf/d at 14.65 psia and 60°F)					
Empress	2.68	2.56	2.37	2.19	2.05
McNeill	1.34	1.33	1.32	1.29	1.28
Alberta/B.C.	2.50	2.48	2.02	1.87	1.82
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	0.00	0.00	0.00	0.00	0.00
Alberta	3.18	3.60	3.89	4.17	4.59
TOTAL SYSTEM	**9.70**	**9.97**	**9.60**	**9.52**	**9.74**

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.

3.4.2.1 Empress

The forecast of maximum day delivery at the Empress Export Delivery Point reflects the forecast level of firm transportation Service Agreements at the Empress Export Delivery Point.

3.4.2.3 Alberta/British Columbia

The forecast of maximum day delivery at the Alberta/British Columbia Export Delivery Point reflects the forecast level of firm transportation Service Agreements at the Alberta/British Columbia Export Delivery Point.

The June 2006 forecast winter maximum day delivery for the 2007/08 Gas Year at the Alberta/British Columbia Export Delivery Point is 71.3 $10^6m^3/d$ (2.53 Bcf/d). This represents an essentially flat forecast of winter season maximum day delivery in the June 2006 forecast when compared to the 2006/07 Gas Year.

The June 2006 forecast summer maximum day delivery for the 2007/08 Gas Year at the Alberta/British Columbia Export Delivery Point is 69.8 $10^6m^3/d$ (2.48 Bcf/d). This represents a decrease of 0.6 $10^6m^3/d$ (0.02 Bcf/d), or 0.9 percent, from the summer season maximum day delivery in the June 2006 forecast for the 2006/07 Gas Year.

3.4.2.4 Other Exports

Boundary Lake, Unity, Cold Lake, Gordondale and Alberta/Montana

The June 2006 forecast maximum day delivery for the 2007/08 Gas Year for each of the Boundary Lake, Unity, Cold Lake, Gordondale and Alberta/Montana Export Delivery Points is zero. This is unchanged from the maximum day delivery forecast for the 2006/07 Gas Year.

3.4.3 Alberta Deliveries

The June 2006 Alberta maximum day delivery forecast for the winter season of the 2007/08 Gas Year is 132.3 $10^6m^3/d$ (4.70 Bcf/d). This is an increase of 8.9 $10^6m^3/d$

(0.32 Bcf/d), or 7.2 percent, from the 2006/07 Gas Year winter season value in the June 2006 forecast. The June 2006 Alberta maximum day delivery forecast for the summer season of the 2007/08 Gas Year is 101.3 $10^6m^3/d$ (3.60 Bcf/d). This is an increase of 11.7 $10^6m^3/d$ (0.42 Bcf/d), or 13.1 percent, from the 2006/07 Gas Year summer season value in the June 2006 forecast.

NGTL considered several sources of information in developing its 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 NGTL over the next ten years. NGTL analyzed the forecasts and compared them 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 growth rates for specific demand sectors.

A summary of winter and summer maximum day delivery for Alberta Deliveries from the June 2006 design forecast by NGTL project area is shown 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 2006 Design Forecast ($10^6 m^3/d$)	
	2006/07	**2007/08**
Peace River	6.5	6.4
North and East	57.7	66.9
Mainline	54.4	54.1
Gas taps	4.8	4.9
TOTAL ALBERTA	**123.4**	**132.3**
Project Area	**June 2006 Design Forecast (Bcf/d)**	
	2006/07	**2007/08**
Peace River	0.23	0.23
North and East	2.05	2.37
Mainline	1.93	1.92
Gas taps	0.17	0.17
TOTAL ALBERTA	**4.38**	**4.70**

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 2006 Design Forecast ($10^6 m^3/d$)	
	2006/07	**2007/08**
Peace River	4.3	4.2
North and East	50.5	62.7
Mainline	32.6	32.2
Gas taps	2.2	2.3
TOTAL ALBERTA	**89.6**	**101.3**
Project Area	**June 2006 Design Forecast (Bcf/d)**	
	2006/07	**2007/08**
Peace River	0.15	0.15
North and East	1.79	2.22
Mainline	1.16	1.14
Gas taps	0.08	0.08
TOTAL ALBERTA	**3.18**	**3.60**

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

3.5 Receipt Forecast

The following receipt forecasts comprise the second principal part of the June 2006 design forecast.

3.5.1 System FS Productive Capability Forecast

The system FS productive capability forecast from the June 2006 design forecast is 281.4 $10^6m^3/d$ (9.99 Bcf/d) in the 2007/08 Gas Year. This is up slightly from the 2006/07 Gas Year forecast of 276.0 $10^6m^3/d$ (9.80 Bcf/d) in the June 2006 forecast.

A summary of system FS productive capability from the June 2006 design forecast by NGTL project area is shown in Table 3.5.1.

Table 3.5.1
System FS Productive Capability Forecast

Project Area	**June 2006 Design Forecast ($10^6m^3/d$)**				
	2006/07	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Peace River	113.4	117.4	115.6	110.0	110.5
North and East	38.2	37.4	34.0	32.7	31.7
Mainline	124.5	126.6	128.2	130.4	129.7
TOTAL SYSTEM	**276.0**	**281.4**	**277.7**	**273.1**	**271.9**
Project Area	**June 2006 Design Forecast (Bcf/d)**				
	2006/07	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Peace River	4.02	4.17	4.10	3.91	3.92
North and East	1.35	1.33	1.21	1.16	1.13
Mainline	4.42	4.49	4.55	4.63	4.61
TOTAL SYSTEM	**9.80**	**9.99**	**9.86**	**9.70**	**9.65**

NOTE:
- Numbers may not add due to rounding.

3.5.2 System Field Deliverability Forecast

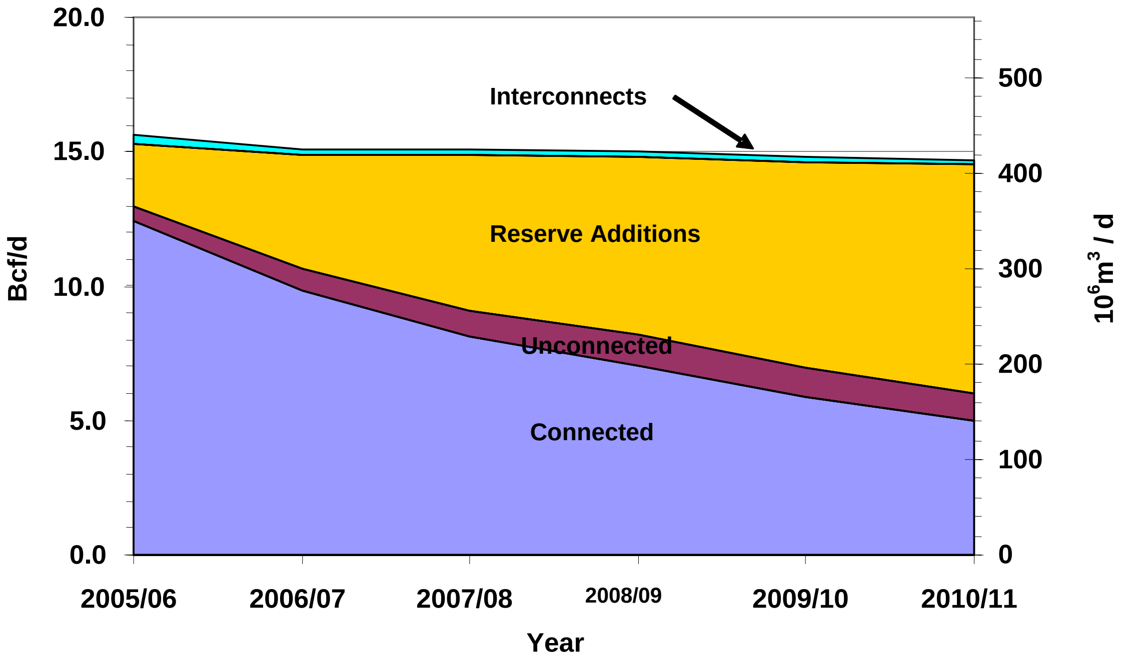
In updating the field deliverability for the June 2006 design forecast, three major sources of gas supply were included:

- Connected and Unconnected Reserves – supply from established reserves upstream of NGTL's Receipt Points.
- Reserve Additions - supply from undiscovered reserves, including unconventional coalbed methane and tight gas.
- 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 field deliverability from connected established reserves as economics permit.

Figure 3.5.2 shows the system field deliverability and its composition by supply source. In aggregate, NGTL expects the WCSB field deliverability to remain relatively flat over the forecast period.

Figure 3.5.2
System Field Deliverability by Component



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 economic potential estimates from the Canadian Gas Potential Committee Report – Natural Gas Potential in Canada – 2001, 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 supply at each Receipt Point.

A summary of system field deliverability from the June 2006 forecast by NGTL project area is shown in Table 3.5.2.

Table 3.5.2
System Field Deliverability Forecast

Project Area	**June 2006 Design Forecast ($10^6m^3/d$)**				
	2006/07	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Peace River	161.0	163.9	163.5	156.4	157.2
North and East	68.7	67.6	62.1	60.6	58.2
Mainline	194.9	193.8	197.1	199.5	198.1
TOTAL SYSTEM	**424.6**	**425.3**	**422.7**	**416.5**	**413.5**
Project Area	**June 2006 Design Forecast (Bcf/d)**				
	2006/07	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Peace River	5.7	5.8	5.8	5.6	5.6
North and East	2.4	2.4	2.2	2.1	2.1
Mainline	6.9	6.9	7.0	7.1	7.0
TOTAL SYSTEM	**15.1**	**15.1**	**15.0**	**14.8**	**14.7**

NOTES:
- Numbers may not add due to rounding.
- Includes unconventional gas.

3.5.3 Firm Transportation Service Agreements

The following is a summary of the aggregate Receipt Contract Demand forecast to be held under firm transportation Service Agreements on the Alberta System.

The June 2006 forecast of aggregate Receipt Contract Demand under firm transportation Service Agreements is 283.3 10^6m^3/d (10.06 Bcf/d) for the 2007/08 Gas Year, as shown in Table 3.5.3. This is an increase of 4.8 10^6m^3/d (0.18 Bcf/d), or 1.7 percent, from the 2006/07 Gas Year and reflects the net effect of both new and non-renewing firm transportation Service Agreements.

Table 3.5.3
Forecast of Receipt Contract Demand under Firm Transportation Service Agreements

Gas Year	June 2006 Design Forecast	
	(10^6m^3/d)	(Bcf/d)
2006/07	278.5	9.88
2007/08	283.3	10.06
2008/09	279.5	9.92
2009/10	274.8	9.75
2010/11	273.7	9.71

NOTE:
- Represents Alberta System peak values anticipated in Gas Year.

3.5.4 System Average Receipts

The system average receipt forecast from the June 2006 design forecast is 320.8 10^6m^3/d (11.39 Bcf/d) in the 2007/08 Gas Year. This is up slightly from the 2006/07 Gas Year forecast of 317.0 10^6m^3/d (11.25 Bcf/d) in the June 2006 forecast.

A summary of system average receipts from the June 2006 design forecast by NGTL project area is shown in Table 3.5.4.

Table 3.5.4
System Average Receipts

	June 2006 Design Forecast ($10^6m^3/d$)				
Project Area	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Peace River	122.3	125.8	126.4	121.2	121.6
North and East	49.0	49.2	45.5	44.4	42.9
Mainline	145.7	145.8	149.1	151.3	150.3
TOTAL SYSTEM	**317.0**	**320.8**	**321.1**	**316.9**	**314.8**
	June 2006 Design Forecast (Bcf/d)				
Project Area	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**
Peace River	4.34	4.47	4.49	4.30	4.32
North and East	1.74	1.75	1.62	1.57	1.52
Mainline	5.17	5.17	5.29	5.37	5.34
TOTAL SYSTEM	**11.25**	**11.39**	**11.40**	**11.25**	**11.17**

3.5.5 Established Natural Gas Reserves

Table 3.5.5.1 presents a summary of remaining established gas reserves in Alberta by NGTL project area as of October 2005. This summary is based on NGTL's assessment of available information. The Board estimates 1099.7 10^9m^3 (39.0 Tcf) of CBM and conventional gas reserves to year end 2004. NGTL's estimate is based on the Board's established reserves which existed at year end 2004 augmented by more recent data provided by NGTL customers and by additional reserves discovered as of October 2005. The reserves have been adjusted for production to October 2005.

NGTL's estimate of 1128.0 10^9m^3 (40.0 Tcf) remaining established gas reserves in Alberta is a decrease of about 3.0 10^9m^3 (0.1 Tcf), or 0.3 percent, from the 1131.0 10^9m^3 (40.1 Tcf) reported in the December 2005 Annual Plan.

Table 3.5.5.1
Remaining Established Alberta Gas Reserves by Project Area

Project Area	NGTL Estimate (10^9m^3)	NGTL Estimate (Tcf)
Peace River	182	6.5
North & East	200	7.1
Mainline	468	16.6
Other[1]	278	9.9
Total[2]	**1128**	**40.0**

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

Table 3.5.5.2 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 3.5.5.2
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 NGTL [1,2]	850	30.2	81	2.9	930	33.0
Remaining Established Reserves not connected to NGTL [3,4]	278	9.9	-	-	278	9.9
TOTAL	**1128**	**40.0**	**81**	**2.9**	**1209**	**42.9**

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 NGTL does not estimate B.C. reserves that are not forecasted to flow on its pipeline system.
4 Numbers may not add due to rounding.

3.6 Storage Facilities

There are seven storage facilities presently connected to the Alberta System, as shown in Table 3.6.1. They are located at the AECO 'C', Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek and Severn Creek Meter Stations (Figure 2.6.1.4). The total deliverability from Storage Facilities is significant when compared to the field deliverability available from other Receipt Points on the Alberta System.

The maximum receipt meter capacity for each of the connected Storage Facilities for the 2007/08 Gas Year is shown in Table 3.6.1.

Table 3.6.1
Receipt Capacity from Storage Facilities

	Maximum Receipt Meter Capacity from Storage Facilities 2007/08	
	$10^6m^3/d$	**Bcf/d**
AECO C	50.7	1.80
Big Eddy	20.5	0.73
Carbon	13.8	0.49
Chancellor	35.2	1.25
Crossfield East #2	14.1	0.50
January Creek	14.1	0.50
Severn Creek	5.6	0.21
TOTAL	**154.0**	**5.47**

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.

3.7 Receipt to Delivery Comparisons

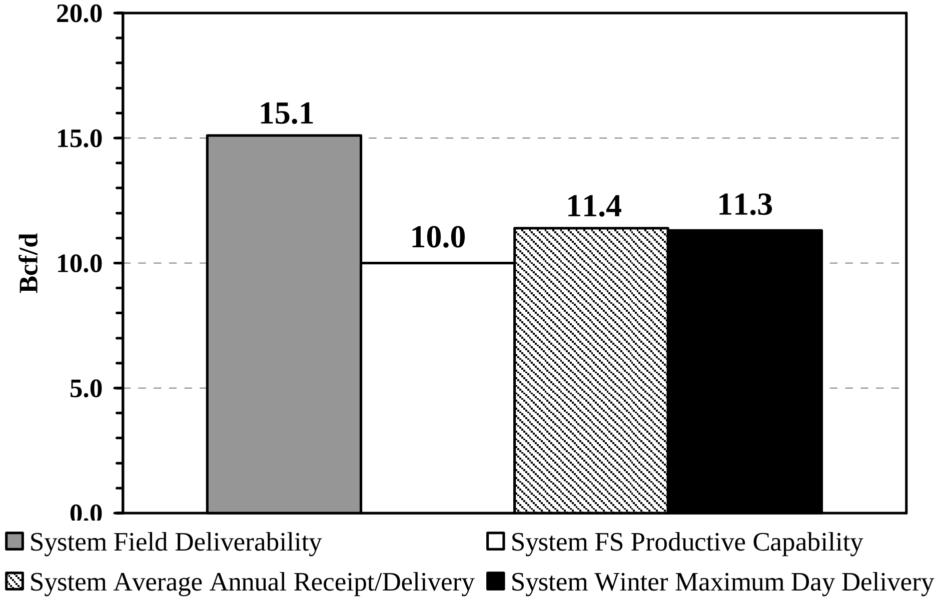
This section discusses the relative levels of gas receipt and delivery forecasts for the Alberta System, as were described in Sections 3.4 and 3.5, based on the June 2006 design forecast.

For illustrative purposes, Figure 3.7.1 also shows the forecast of the system FS productive capability, system field deliverability, the system average annual delivery and the system winter maximum day delivery for the 2007/08 Gas Year.

It should be noted that Storage Facilities are anticipated to contribute significant additional receipts to the pipeline system during peak demand conditions. As described in Section 2.6.1.4, gas deliverability from Storage Facilities is provided as an interruptible service on the Alberta System. The capability of the system to receive large withdrawals from Storage Facilities will be dependent upon the prevailing operating conditions and corresponding ability to move interruptible volumes at the time the withdrawals are requested. For this reason, the potential receipt contribution from Storage Facilities is not shown in Figure 3.7.1.

System field deliverability is projected to be 425.3 10^6m^3/d (15.1 Bcf/d) as shown in Figure 3.7.1. Based on the aggregate of each Receipt Point's FS productive capability forecast, the system FS productive capability is 281.4 10^6m^3/d (10.0 Bcf/d). Average annual receipt volumes are equal to the average annual delivery volumes and are projected to be 320.8 10^6m^3/d (11.4 Bcf/d). The winter maximum day delivery volume is projected to be 316.6 10^6m^3/d (11.3 Bcf/d).

Figure 3.7.1
Receipt/Delivery Comparison
2007/08 Gas Year



NOTE:
- Storage excluded.

CHAPTER 4 – DESIGN FLOW REQUIREMENTS AND PEAK EXPECTED FLOWS

4.1 Introduction

This chapter presents an overview of the design flow requirements and the peak expected flow, as described in Section 2.6. Design flow requirements, described in Section 2.6.1, for the 2007/08 Gas Year are presented for each of the design areas described in Section 2.3, and form the basis for the facilities requirements outlined in Chapter 5.

Design flow requirements for each design area are based on the June 2006 design forecast and the applicable design assumptions discussed in Section 2.6.1. The equal proration assumption, design area delivery assumption, storage assumption and downstream capacity assumption were applied in each design area. The FS productive capability assumption was applied to each of the areas shown in Figure 2.6.5.

The design flow requirements for each design area are presented in Appendix 4. Figures presented in this chapter illustrate both historical and forecast trends within each design area.

An overview of the design flow requirements resulting from the June 2006 design forecast was presented at the TTFP meeting on November 21, 2006.

The peak expected flow determination, is included in the facility design process, and is described Section 2.6.2. The peak expected flow line is shown along with the design flow requirement line on all charts having a receipt dominant flow condition to illustrate the difference between the two flow levels.

Historical data have been included in this chapter to illustrate the correlation between design flow requirements and actual flows. Historical actual flows and historical design flow requirements are shown for the 2001/02 Gas Year through the 2005/06 Gas Year. Historical design flow requirements represent the values that influenced the design for each Gas Year from 2001/02 to 2005/06. The period of time that the design flow figures cover no longer include the historical peak flow achieved in many of the Design Areas. The introduction of the historical peak flow on the design flow figures is to continue to provide this information.

The vertical scale in the figures for the Upper Peace River, Central Peace River, Marten Hills, North of Bens Lake, South of Bens Lake, Western Alberta Mainline, Rimbey-Nevis, South and Alderson and Medicine Hat Design Areas have been set over a consistent range of values between 0 and 100,000 $10^3m^3/d$ (0 and 3.5 Bcf/d). The Edson, Eastern Mainline and Lower Peace River Design Areas have been set over a consistent range of values between 0 and 300,000 $10^3m^3/d$ (0 and 10 Bcf/d). The figures are presented in this manner to enable easy comparison of the relative impact of the design flow requirements.

The figures in Sections 4.2 to 4.4 show a comparison between winter and summer historical design flow requirements and historical actual flows for the 2001/02 Gas Year through to the 2005/06 Gas Year. The historic peak flows have been added for comparison purposes. The figures also show the winter and summer design flow requirements from the June 2006 design forecast for the 2006/07 Gas Year through the 2010/11 Gas Year. The peak expected flow, as described in Section 2.6.2, is also shown on these figures out to the 2010/11 Gas Year for the design areas where receipt dominant flow conditions exist.

There are two distinct flow conditions that are examined in assessing facilities requirements in the North and East Project Area. First, there is the “flow through” condition that is governed by the North and East Project Area design flow requirements assumption as described in Section 2.6.1. Second, there is the "flow within" condition that is governed by the maximum day delivery to the Fort McMurray area also described in Section 2.6.1. Currently, the flow within condition governs facilities requirements in the North and East Project Area.

The following approach is used as a basis for generating the design flow requirements through the North and East Project Area. First, the design will focus on maximizing 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 FS productive capability 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 FS Productive Capability then the design will focus on transporting these volumes through the Peace River Design Area. Currently, with actual flows below the capability of existing facilities in the South of Bens Lake Design Area, the flow through condition has no impact on facilities requirements in the North and East Project Area for the 2007/08 Gas Year. The flow through design approach is consistent with the development of the North Central Corridor which is described in Section 5.6.2.

4.2 Peace River Project Area

4.2.1 Peace River Design Area

4.2.1.1 Upper Peace River Design Sub Area

The design flow requirements for the Upper Peace River Design Sub Area is the flow out of the area at the Hidden Lake and Meikle River Compressor Stations.

Figure 4.2.1.1 illustrates that historical actual flows declined slightly between the 2001/02 and 2003/04 Gas Years. The historical actual flows were steady during the 2003/04 and 2004/05 Gas Years then declined slightly during the 2005/06 Gas Year.

For the 2002/03, 2003/04, 2004/05 and 2005/06 Gas Years the historical design flow requirements decreased relative to the design flow requirements for the 2001/02 Gas Year due to FS productive capability declines in the area.

For the 2006/07 and 2007/08 Gas Years, the June 2006 design forecast shows winter and summer design flow requirements are slightly lower than the winter and summer design flow requirements in the 2005/06 Gas Year. Beyond the 2007/08 Gas Year the design flow requirements are expected to increase slightly out to the 2010/11 Gas Year. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

Figure 4.2.1.1
Upper Peace River Design Sub Area
Design Flow Requirements and Peak Expected Flows

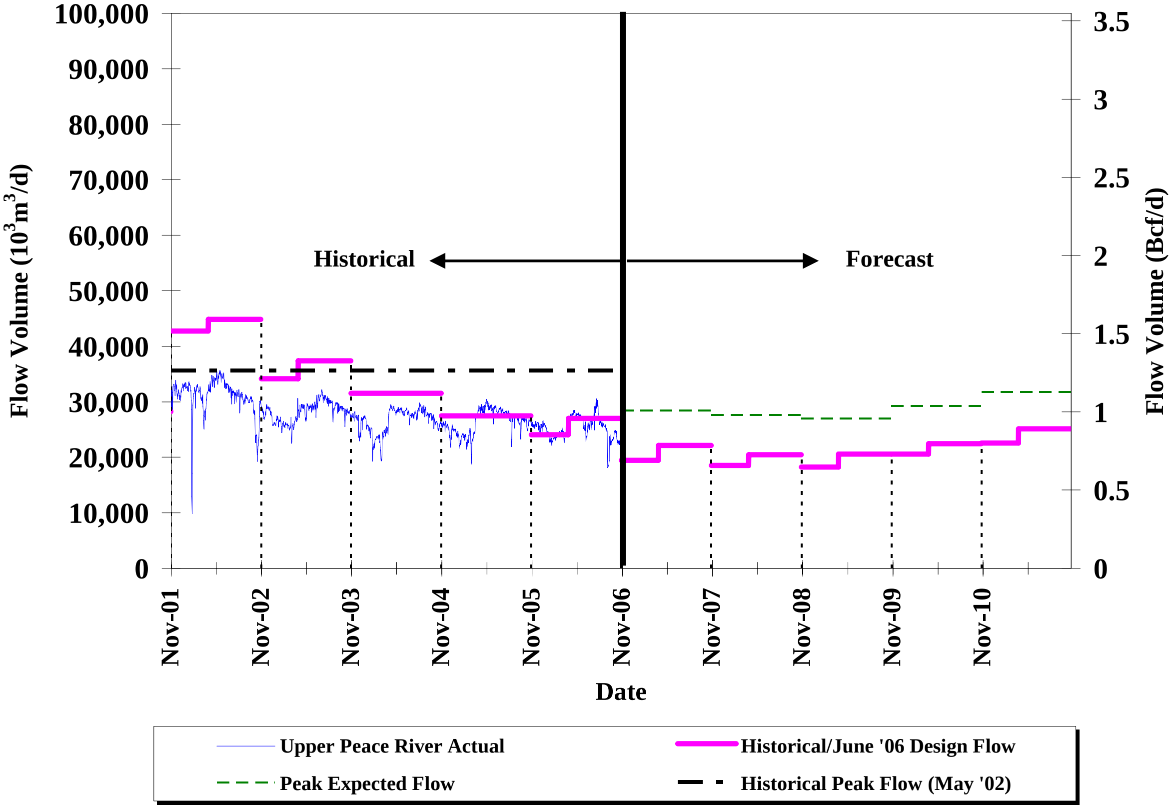


Table 4.2.1.1 shows winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.2.1.1
Upper Peace River Design Sub Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$
2007/08 Winter	0.66	18.5	0.98	27.6
2007/08 Summer	0.73	20.4	0.98	27.6

4.2.1.2 Central Peace River Design Sub Area

The design flow requirements for the Central Peace River Design Sub Area is the flow out of the area at the Saddle Hills, Clarkson Valley and Valleyview Compressor Stations. Flow into the area is the flow from the Upper Peace River Design Sub Area.

Figure 4.2.1.2 illustrates that both the historical design flow requirements and the historical actual flow for the 2002/03, 2003/04 and 2004/05 Gas Years decreased relative to the 2001/02 Gas Year due to FS productive capability declines in the area. The historical design flow requirements and the historical actual flow for the 2005/06 Gas Year are similar to those experienced in 2004/05.

The June 2006 design forecast shows a slight decline in winter and summer design flow requirements between the 2006/07 and 2008/09 Gas Years. Beyond 2008/09 the forecasted design flow requirements show slight increases out to the winter season of the 2009/10 Gas Year, then decreases during the summer season of the 2009/10 Gas Year and the 2010/11 Gas Year with the completion of the proposed North Central Corridor as described in Section 5.6.2. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

Figure 4.2.1.2
Central Peace River Design Sub Area
Design Flow Requirements and Peak Expected Flows

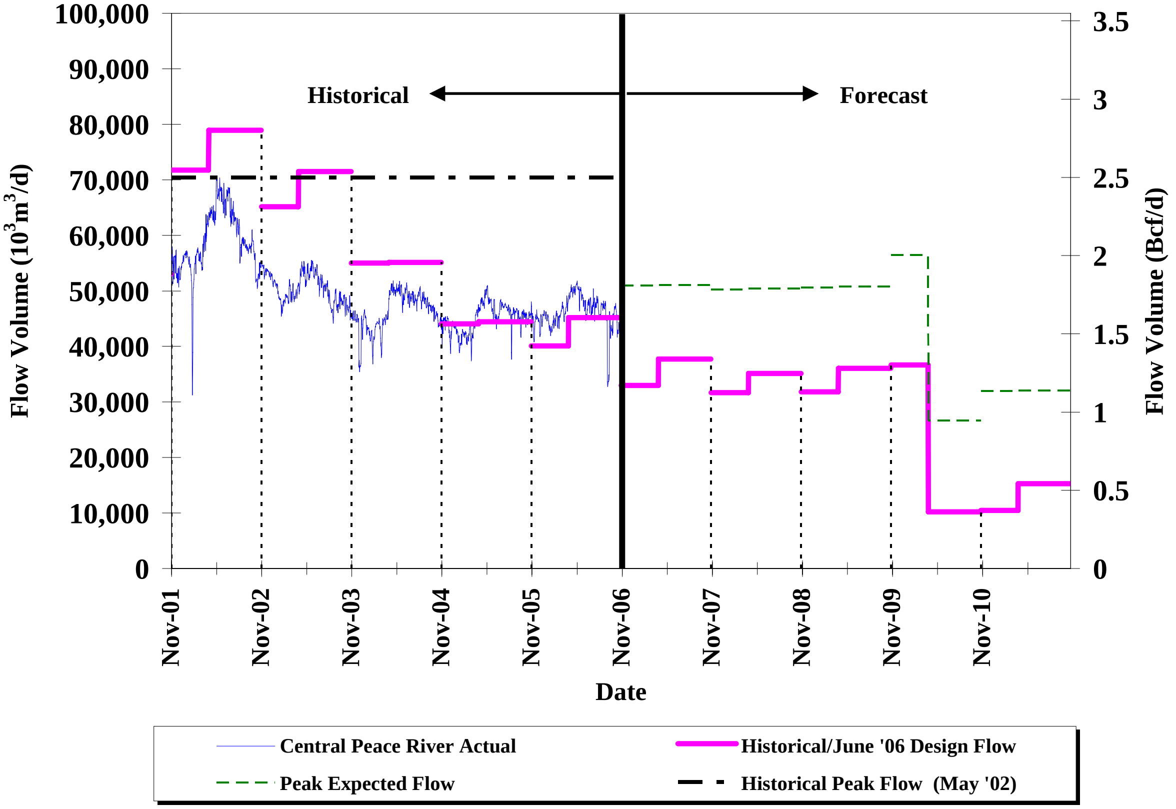


Table 4.2.1.2 shows winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.2.1.2
Central Peace River Design Sub Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$
2007/08 Winter	1.12	31.6	1.78	50.2
2007/08 Summer	1.25	35.1	1.79	50.4

4.2.1.3 Lower Peace River Design Sub Area

The design flow requirements for the Lower Peace River Design Sub Area is the flow out of the area from the Grande Prairie Mainline and the Edson Mainline Extension at the Edson Meter Station, excluding the Marten Hills Lateral flow. Flow into the area is the flow from the Central Peace River Design Sub Area.

Figure 4.2.1.3 illustrates that the historical actual and historical design flow requirements have followed similar trends during the 2001/02 and 2002/03 Gas Years. For the 2003/04 Gas Year the historical design flow requirements declined relative to 2002/03 while the historical actual flows increased in 2003/04 relative to 2002/03 due to increased FS productive capability being available from the Lower Peace River Design Sub Area. For the 2004/05 Gas Year both the historical actual flows and the historical design flow requirements were relatively flat. For the 2005/06 Gas Year the historical design flow requirements were down slightly in the winter and up slightly in the summer relative to the historical design flow requirements in 2004/05. The 2005/06 actual flows were up significantly over the 2004/05 actual flows due primarily to increased receipts coming onto the Alberta System within the Lower Peace River Design Area.

For the 2006/07 and 2007/08 Gas Years, the June 2006 design forecast shows a slight decrease in both winter and summer design flow requirements relative to the winter and summer design flow requirements in the 2005/06 Gas Year. For the 2008/09 Gas Year the winter and summer design flow requirements are similar to those projected for the 2007/08 Gas Year. The winter design flow requirements for 2009/10 decline slightly from the 2008/09 levels and decrease further during the summer season of the 2009/10 Gas Year as well as during the 2010/11 Gas Year with the completion of the proposed North Central Corridor as described in Section 5.6.2. The peak expected flows follow a similar trend as the design flow requirements but at somewhat higher flow levels.

Figure 4.2.1.3
Lower Peace River Design Sub Area
Design Flow Requirements and Peak Expected Flows

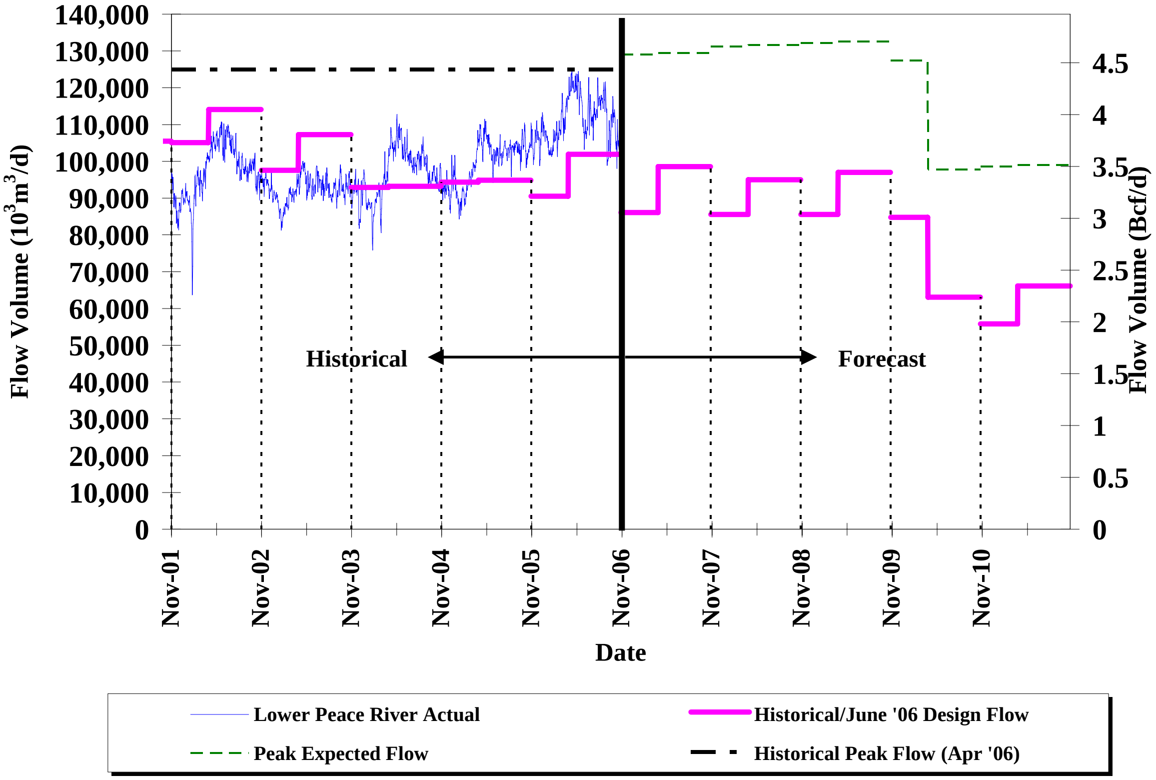


Table 4.2.1.3 shows winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.2.1.3
Lower Peace River Design Sub Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	Bcf/d	10^6m^3/d	10^6m^3/d
2007/08 Winter	3.04	85.5	4.66	131.3
2007/08 Summer	3.37	95.0	4.67	131.7

4.2.2 Marten Hills Design Area

The design flow requirements for the Marten Hills Design Area is the flow out of the area at the Edson Meter Station (excluding the Lower Peace River Design Sub Area flow), the flow across the Marten Hills Crossover and the northward flow, if any, through the Slave Lake Compressor. Design flow requirements in the Marten Hills Design Area will be determined as outlined in Section 4.1 and will be limited by the average winter and summer hydraulic capability of the existing facilities within the area. This is consistent with the long-range plans of maximizing the utilization of existing facilities and optimizing the use of the Marten Hills Design Area within the system. The flow into the area, if any, is the flow from the North of Bens Lake Design Area at the Slave Lake Compressor Station.

Figure 4.2.2.illustrates that historical design flow requirements were relatively flat between the 2001/02 Gas Year and the 2005/06 Gas Year.

The June 2006 design forecast shows the design flow requirements for the winter and summer seasons increase over the period 2006/07 to 2008/09 then remain steady out to 2010/11. This increase in design flow requirements results from increased FS Productive Capability in the area primarily associated with a coal bed methane development in the area. It is anticipated that a portion of these increased flow volumes will move toward the northeast into the North of Bens Lake design area and the remainder will move toward the southwest into the Edson Mainline design area. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

Figure 4.2.2
Marten Hills Design Area
Design Flow Requirements and Peak Expected Flows

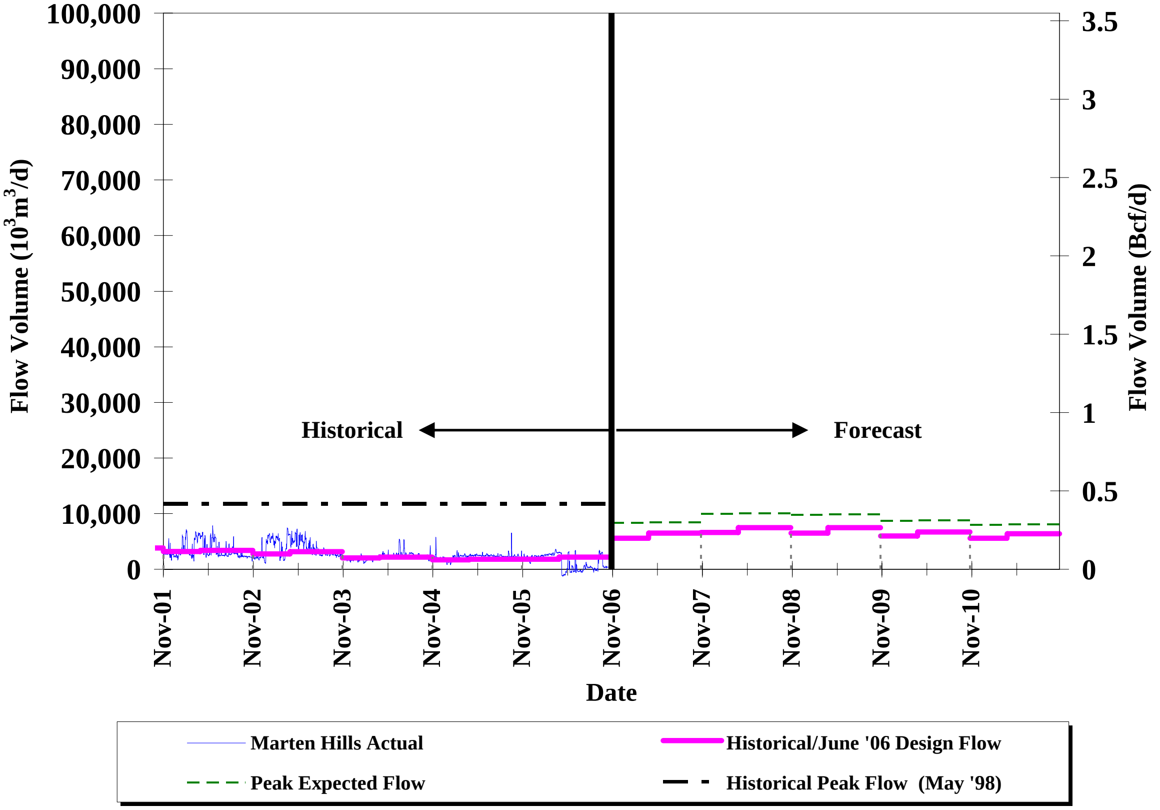


Table 4.2.2 shows the winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.2.2
Marten Hills Design Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	10^6m^3/d	Bcf/d	10^6m^3/d
2007/08 Winter	0.24	6.6	0.35	10.0
2007/08 Summer	0.27	7.5	0.36	10.1

4.3 North and East Project Area

4.3.1 North of Bens Lake Design Area

The design flow requirements for the North of Bens Lake Design Area is the flow out of the area at the Bens Lake Compressor Station. Design flow requirements for this area will be determined as outlined in Section 4.1. Flow into the area, if any, is the flow from the Peace River Design Area, via the Wolverine control valve, plus any flow passed from the Marten Hills Design Area at the Slave Lake Compressor Station.

Figure 4.3.1.1 illustrates that historical actual flows and historical design flow requirements follow a similar trend. In particular, historical design flow requirements and actual flows have exhibited a significant decline since the 2001/02 Gas Year.

For the 2006/07 Gas Year, the June 2006 design forecast shows a significant decrease in winter and summer design flow requirements relative to the winter and summer design flow requirements for the 2005/06 Gas Year. This decrease in design flow requirements is primarily due to a significant increase in the projected Alberta deliveries within the area, particularly to the Fort McMurray area, as well as the decrease in FS productive capability available within the design area.

The June 2006 design forecast projects the design flow requirements will continue to decline significantly for the 2007/08 Gas Year through to the winter season of the 2009/10 Gas Year resulting in negative design flow requirements. This signifies that the flow through design assumption will yield a flow condition that moves from south to north rather than the historical north to south flow pattern experienced in this area.

For the summer season of the 2009/10 Gas Year and the 2010/11 Gas Year, the design flow requirements increase with the completion of the proposed North Central

Corridor as described in Section 5.6.2. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

Figure 4.3.1.1
North of Bens Lake Design Area
Design Flow Requirements and Peak Expected Flows

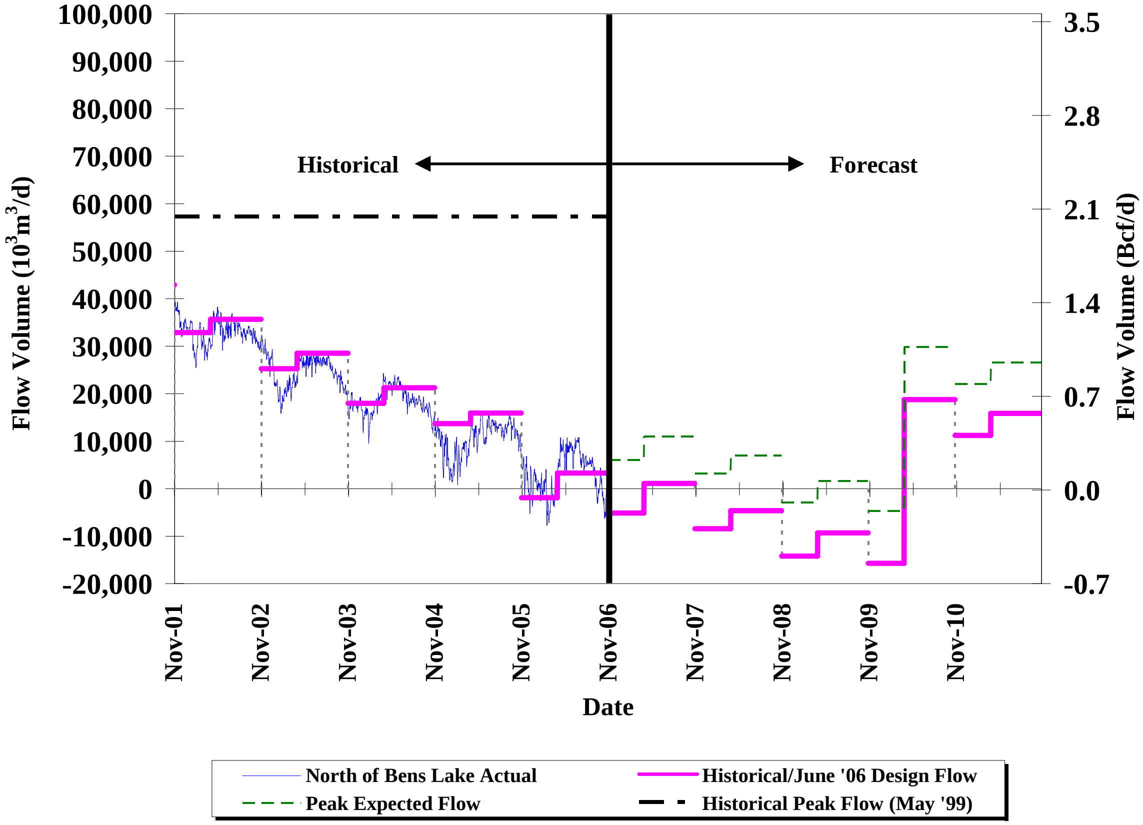


Table 4.3.1.1 shows the winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.3.1.1
North of Bens Lake Design Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$
2007/08 Winter	-0.30	-8.4	0.12	3.3
2007/08 Summer	-0.16	-4.6	0.25	7.0

A key consideration for the North of Bens Lake Design Area is the localized growth of Alberta deliveries within this area. As outlined in Chapter 3, Alberta deliveries to the Fort McMurray area are forecast to increase in the future. The FS productive capability required to meet the Fort McMurray maximum day delivery draws from available FS productive capability on the Liege, Logan, Conklin and Kirby Laterals plus the FS productive capability that is brought into the area from the Peerless Lake Lateral, via the North Central Corridor (Buffalo Creek Section).

For the 2007/08 Gas Year it is expected that additional FS productive capability will be transported northward along the Peerless Lake Lateral from the Marten Hills Lateral and the Paul Lake Crossover.

Figure 4.3.1.2 shows the June 2006 forecast winter and summer maximum day delivery to the Fort McMurray area for the 2006/07 Gas Year and the growth through to the 2010/11 Gas Year. The forecast for these area deliveries is a result of the growth in demand for oil sands and heavy oil production, and power generation in the area.

Figure 4.3.1.2
Maximum Day Delivery to the Fort McMurray Area

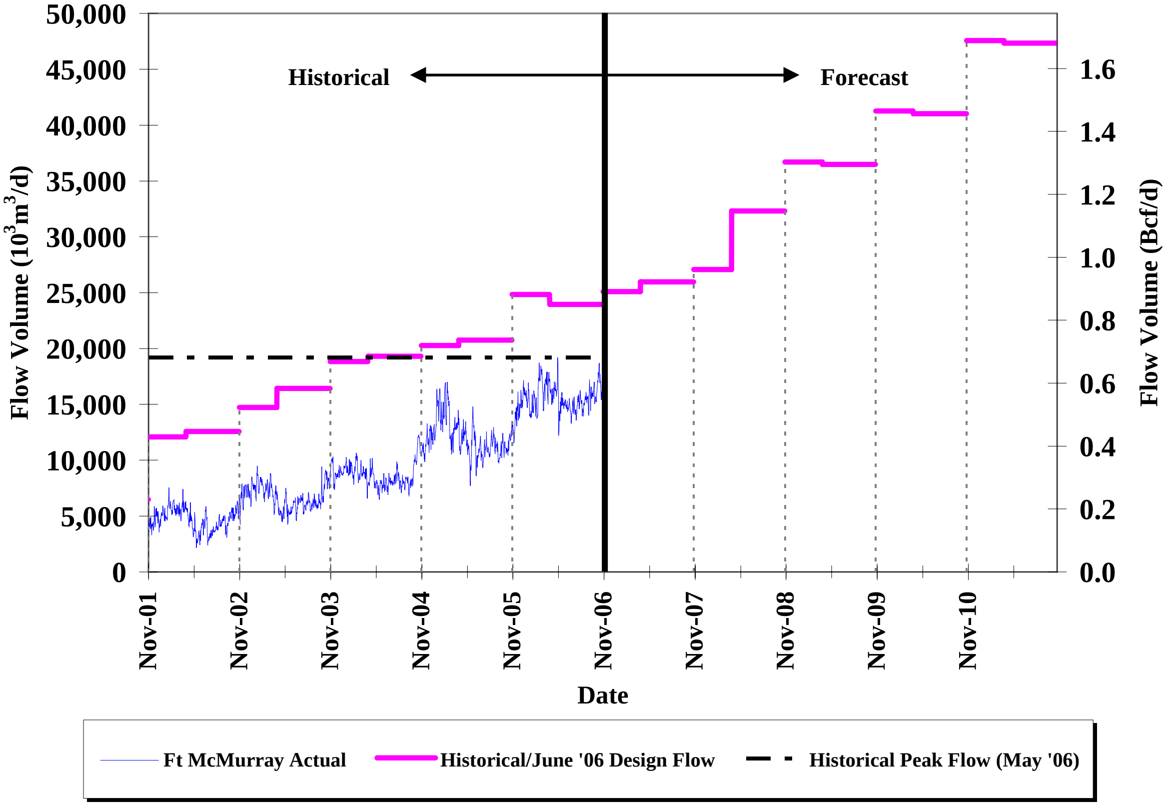


Table 4.3.1.2 shows the winter and summer design flow requirements for the 2007/08 Gas Year.

Table 4.3.1.2
Maximum Day Delivery to the Fort McMurray Area
June 2006 Design Forecast
Design Flow Requirements

Gas Year and Season	Design Flow Requirements	
	Bcf/d	$10^6m^3/d$
2007/08 Winter	0.96	27.1
2007/08 Summer	1.15	32.3

4.3.2 South of Bens Lake Design Area

The design flow requirements for the South of Bens Lake Design Area is the sum of the flow out of the area at the Princess “A” and Oakland Compressor Stations on the North Lateral and at the Cavendish Compressor Station on the East Lateral. Flow into the area is the flow from the North of Bens Lake Design Area as well as from the Rimbey Nevis Design Area via the Nevis-Gadsby Crossover.

Figure 4.3.2 illustrates the historical design flow requirements show a declining trend between the 2001/02 Gas Year and 2005/06 Gas Year. As shown in the figure, actual flows have exhibited steady declines between the 2001/02 and 2005/06 Gas Years.

The June 2006 design forecast shows a continued decrease in winter and summer design flow requirements out to the winter season of the 2009/10 Gas Year relative to the 2005/06 Gas Year. For the summer season of the 2009/10 Gas Year and the 2010/11 Gas Year the design flow requirements increase with the completion of the proposed North Central Corridor as described in Section 5.6.2. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

The decrease in design flow requirements and peak expected flows prior to the 2010/11 Gas Year, is primarily due to the decrease in flow from the North of Bens Lake Design Area. There is a slight incremental flow contribution to this area from the Rimbey-Nevis Design Area via the Nevis-Gadsby Crossover, however, this contribution is more than offset by the decrease in design flow requirements being experienced from the North of Bens Lake Design Area.

Figure 4.3.2
South of Bens Lake Design Area
Design Flow Requirements and Peak Expected Flows

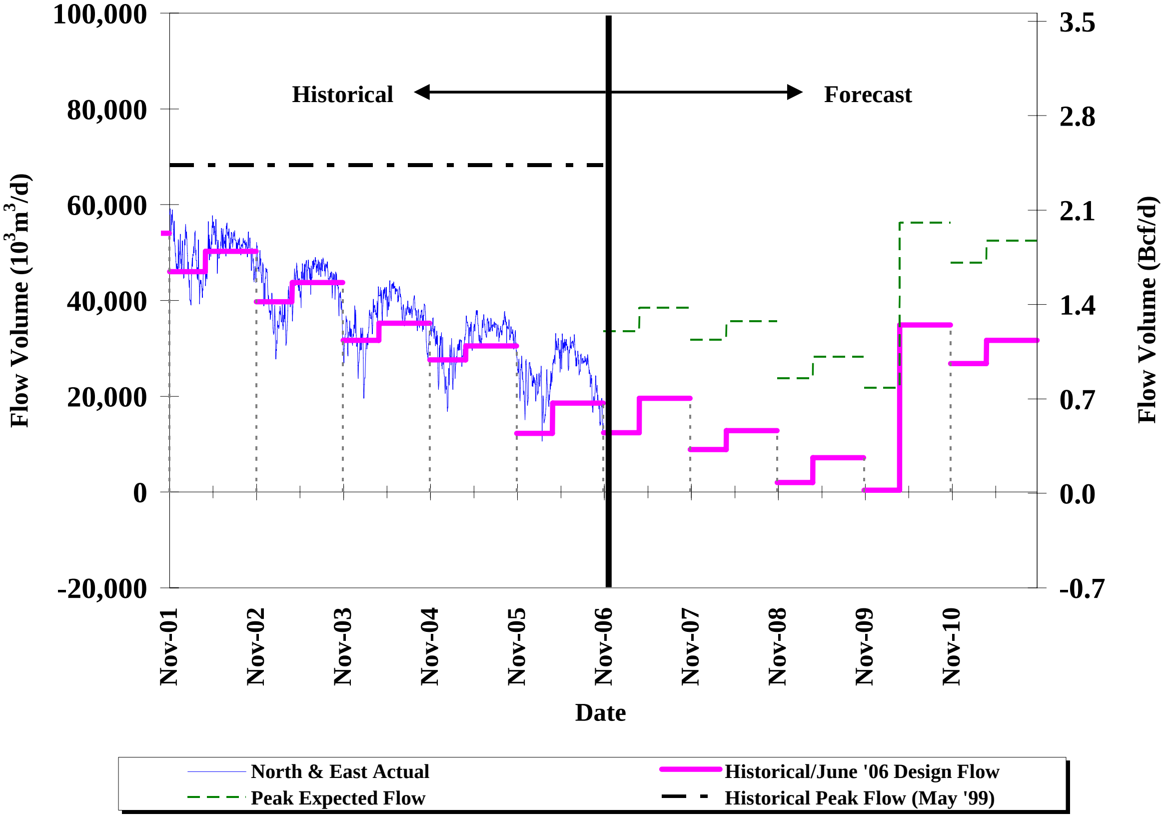


Table 4.3.2 shows winter and summer design flow requirements and the peak expected flows for the 2007/08 Gas Year.

Table 4.3.2
South of Bens Lake Design Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$
2007/08 Winter	0.32	8.9	1.13	31.9
2007/08 Summer	0.46	12.8	1.27	35.7

4.4 Mainline Project Area

4.4.1 Mainline Design Area

4.4.1.1 Edson Mainline Design Sub Area

The design flow requirements for the Edson Mainline Design Sub Area is the flow out of the area at the James River Interchange. Flow into the area is from the Peace River Design Area at the Knight Compressor Station and at the Edson Meter Station and from the Marten Hills Design Area at the Edson Meter Station.

Figure 4.4.1.1 illustrates that for the 2002/03 Gas Year, the historical design flow requirements declined slightly in both the winter and summer seasons relative to the design flow requirements for the 2001/02 Gas Year. The historical design flow requirements declined further in the 2003/04 Gas Year, remained steady for the 2004/05 Gas Year then increased slightly for the 2005/06 Gas Year. The historical actual flows declined during the 2002/03 Gas Year relative to the 2001/02 Gas Year then increased during the 2003/04, 2004/05 and 2005/06 Gas Years relative to the 2002/03 Gas Year due primarily to increased field receipts in the Lower Peace River design sub-area.

Beyond the 2005/06 Gas Year, design flow requirements are forecast to decrease slightly for the 2006/07 Gas Year, then remain steady out to the winter season of the 2009/10 Gas Year. For the summer season of the 2009/10 Gas Year and the 2010/11 Gas Year the design flow requirements decrease with the completion of the proposed North Central Corridor as described in Section 5.6.2. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

Figure 4.4.1.1
Edson Mainline Design Sub Area
Design Flow Requirements and Peak Expected Flows

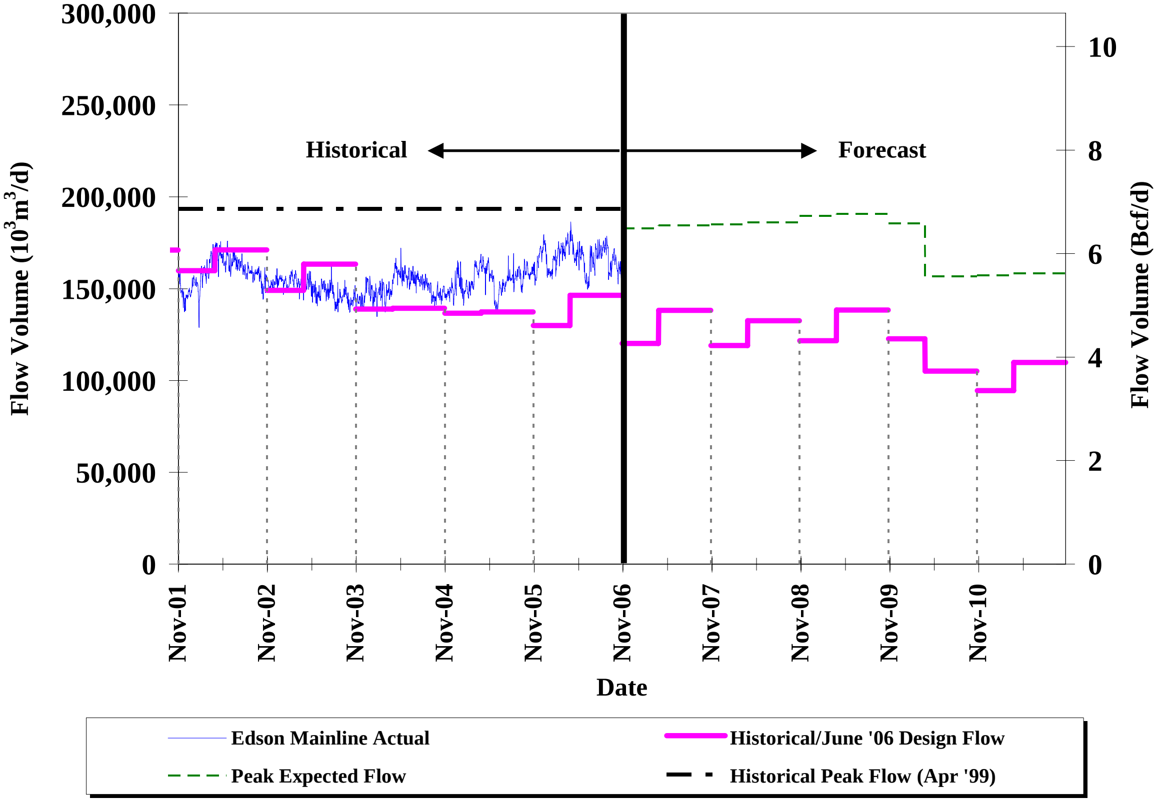


Table 4.4.1.1 shows the winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.4.1.1
Edson Mainline Design Sub Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$
2007/08 Winter	4.22	119.0	6.57	185.0
2007/08 Summer	4.70	132.5	6.61	186.3

4.4.1.2 Eastern Alberta Mainline Design Sub Area (James River to Princess)

The design flow requirements for the Eastern Alberta Mainline Design Sub Area (James River to Princess) is the flow out of the area at the Princess "B" Compressor Station and the flow on the Foothills Pipe Lines (Alberta) Ltd. eastern leg. Flow into the area is from the Edson Mainline Design Sub Area, the Rimbey-Nevis Design Area and the South and Alderson Design Area.

Figure 4.4.1.2 illustrates that for the 2002/03 and 2003/04 Gas Years, the historical design flow requirements declined significantly in both the winter and summer seasons. The decrease in design flow requirements was primarily due to a decrease in maximum day delivery expected at the Empress Export Delivery Point. For the 2004/05 and 2005/06 Gas Years the historical design flow requirements increased slightly relative to the 2003/04 Gas Year. The historical actual winter flows increased steadily between 2000/01 and 2002/03 and, decreased slightly in the winter of 2003/04 then increased again during the winters of 2004/05 and 2005/06. The historical actual summer flows decrease slightly in 2003 relative to the summer of 2002, and was about equal during the summer of 2004 relative to the summer of 2003. The actual summer flows increased significantly during 2005 and 2006 relative to 2004 due to strong market demands that were experienced in eastern North America. The difference between actual flows and design flow requirements over the past four gas years reflects shippers' significant dependence on interruptible transportation at the Eastern Alberta Export Delivery Points.

Design flow requirements are forecast to increase slightly between the 2006/07 and 2007/08 Gas Years as FS productive capability upstream of the Edson Mainline Design Sub Area continues to grow and as the design flow requirements for the South of Bens Lake Design Area continue to decline. Beyond the 2007/08 Gas Year, design flow requirements are forecast to remain steady out to the winter season of the 2009/10 Gas Year, then decline in the summer season of the 2009/10 Gas Year and the 2010/11 Gas Year with the completion of the proposed North Central Corridor as described in Section 5.6.2.

Figure 4.4.1.2
Eastern Alberta Mainline Design Sub Area
(James River to Princess)
Design Flow Requirements

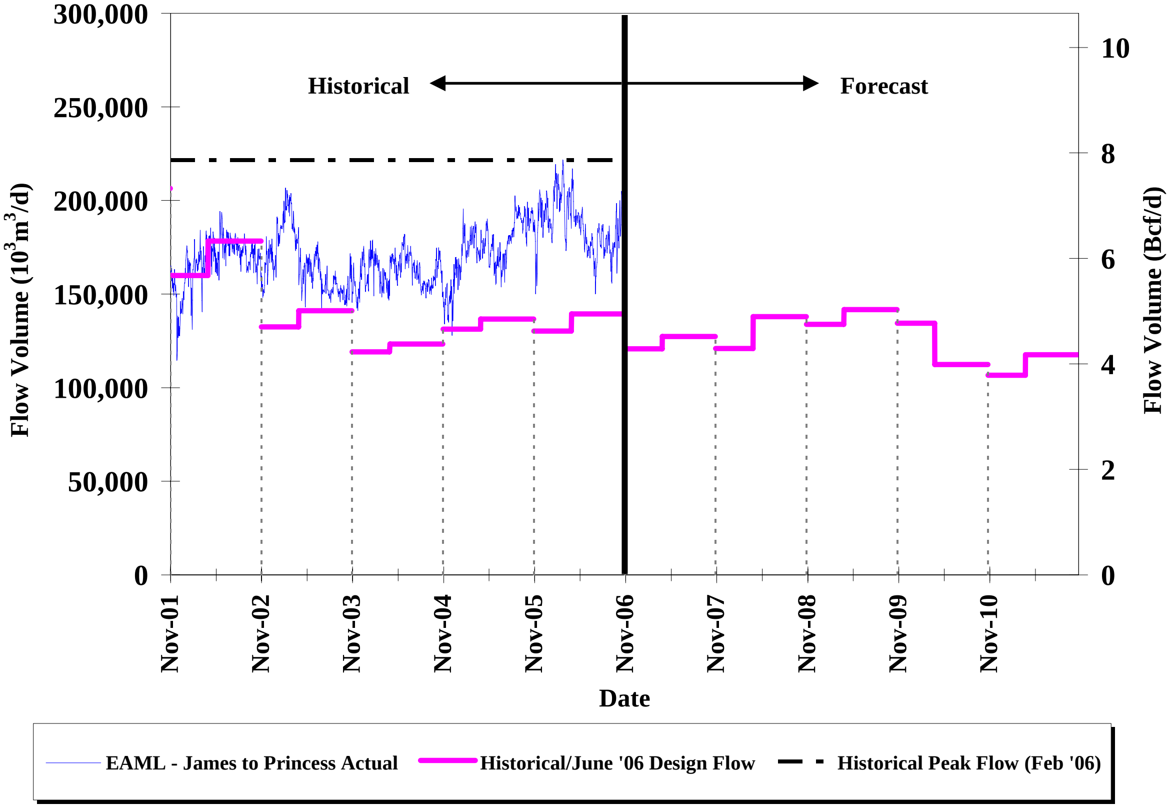


Table 4.4.1.2 shows the winter and summer design flow requirements for the 2007/08 Gas Year.

Table 4.4.1.2
Eastern Alberta Mainline Design Sub Area
(James River to Princess)
June 2006 Design Forecast
Design Flow Requirements

Gas Year and Season	Design Flow Requirements	
	Bcf/d	$10^6m^3/d$
2007/08 Winter	4.29	120.9
2007/08 Summer	4.90	137.9

4.4.1.3 Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill)

The design flow requirements for the Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill) is the flow out of the area at the Empress and McNeill Export Delivery Points. The flow into the area is from the North and East Project Area, the Eastern Alberta Mainline Design Sub Area (James River to Princess) and the Medicine Hat Design Area.

Figure 4.4.1.3 illustrates that for the 2002/03 and 2003/04 Gas Years the design flow requirements decreased significantly in both the winter and summer seasons. The decrease in design flow requirements is primarily due to a decrease in maximum day delivery expected at the Empress Delivery Point. For the 2004/05 winter and summer seasons the design flow requirements increased slightly relative to the 2003/04 winter and summer seasons. For the 2005/06 winter and summer seasons the design flow requirements decreased relative to the 2004/05 winter and summer seasons. The actual flows for 2002/03 were near historic peaks for a brief period in late February 2003 when demands in eastern North American markets were relatively high. Actual flows during the 2003 summer season, however, were well below those observed in the 2002 summer season. Actual flows during the 2003/04 winter season were slightly below those observed during the 2002/03 winter season while the 2004 summer flows were about the same as those observed during the 2003 summer season. Actual flows during the 2004/05 and 2005/06 Gas Years increased relative to the flows experienced during the 2003/04 Gas Year due to a return of strong demands in eastern North American markets. The difference between actual flows and design flow requirements over the past five gas years reflects shippers’ significant dependence on interruptible transportation at the Eastern Alberta Export Delivery Points.

The June 2006 design forecast shows that winter and summer design flow requirements will decrease in the 2006/07 Gas Year relative to the design flow requirements for the 2005/06 Gas Year. The design flow requirements decline slightly during the 2007/08 Gas Year and will continue to decline out to 2010/11. This behaviour corresponds with the forecast of maximum day delivery at the Empress and McNeill Export Delivery Points.

Figure 4.4.1.3
Eastern Alberta Mainline Design Sub Area
(Princess to Empress/McNeill)
Design Flow Requirements

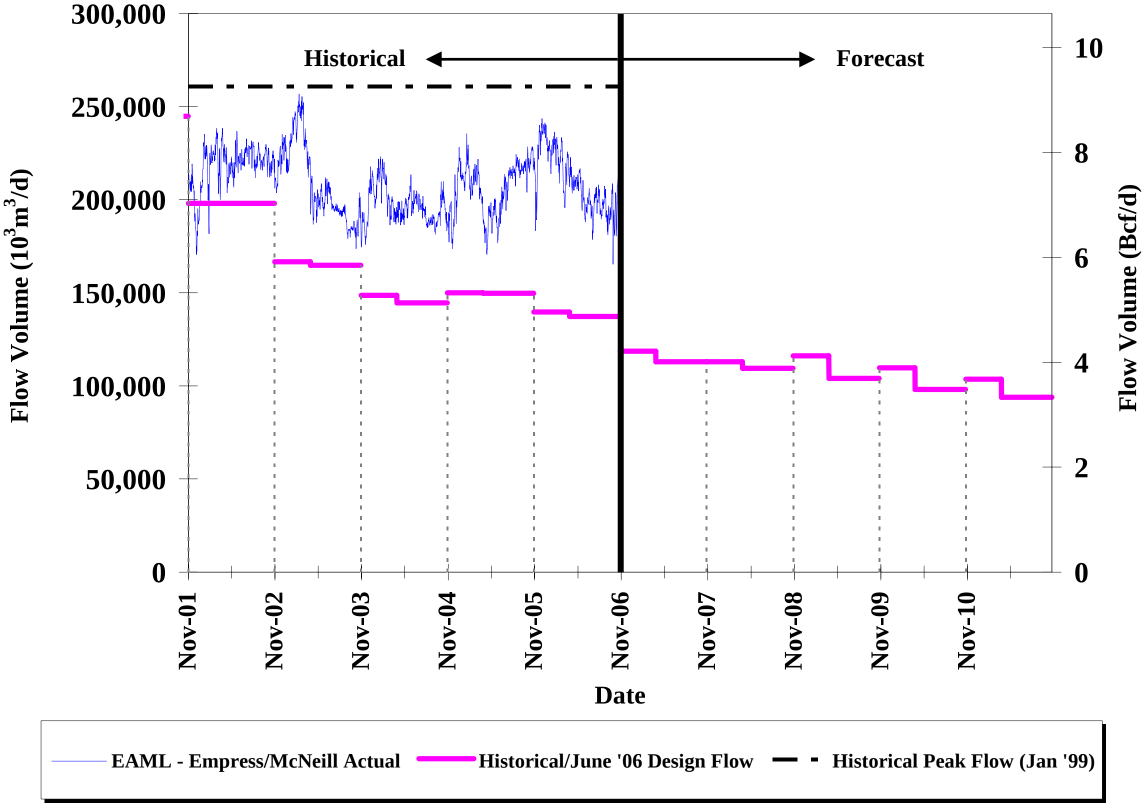


Table 4.4.1.3 shows the winter and summer design flow requirements for 2007/08 Gas Year.

Table 4.4.1.3
Eastern Alberta Mainline Design Sub Area
(Princess to Empress/McNeill)
June 2006 Design Forecast
Design Flow Requirements

Gas Year and Season	Design Flow Requirements	
	Bcf/d	$10^6 m^3/d$
2007/08 Winter	4.01	113.0
2007/08 Summer	3.89	109.5

4.4.1.4 Western Alberta Mainline Design Sub Area

The design flow requirements for the Western Alberta Mainline Design Sub Area is the flow out of the area at the Alberta/British Columbia Export Delivery Point as well as the flow out of the area at the Alberta/Montana Export Delivery Point. Flow into the area is from the Edson Mainline Design Sub Area and the South and Alderson Design Area.

Figure 4.4.1.4 illustrates that in the Gas Years from 2001/02 to 2005/06 inclusive, actual flows were quite low as a result of low demand from the Pacific Northwest and California markets, and increased flow to the Eastern Alberta Export Delivery Points.

For the 2006/07 Gas Year, the June 2006 design forecast shows the winter and summer design flow requirements decrease relative to the winter and summer design flow requirements for the 2005/06 Gas Year. The design flow requirements continue to decrease out to the 2010/11 Gas Year. This behaviour corresponds to the forecast of maximum day delivery at the Alberta/British Columbia and Alberta/Montana Export Delivery Points.

Figure 4.4.1.4
Western Alberta Mainline Design Sub Area
Design Flow Requirements

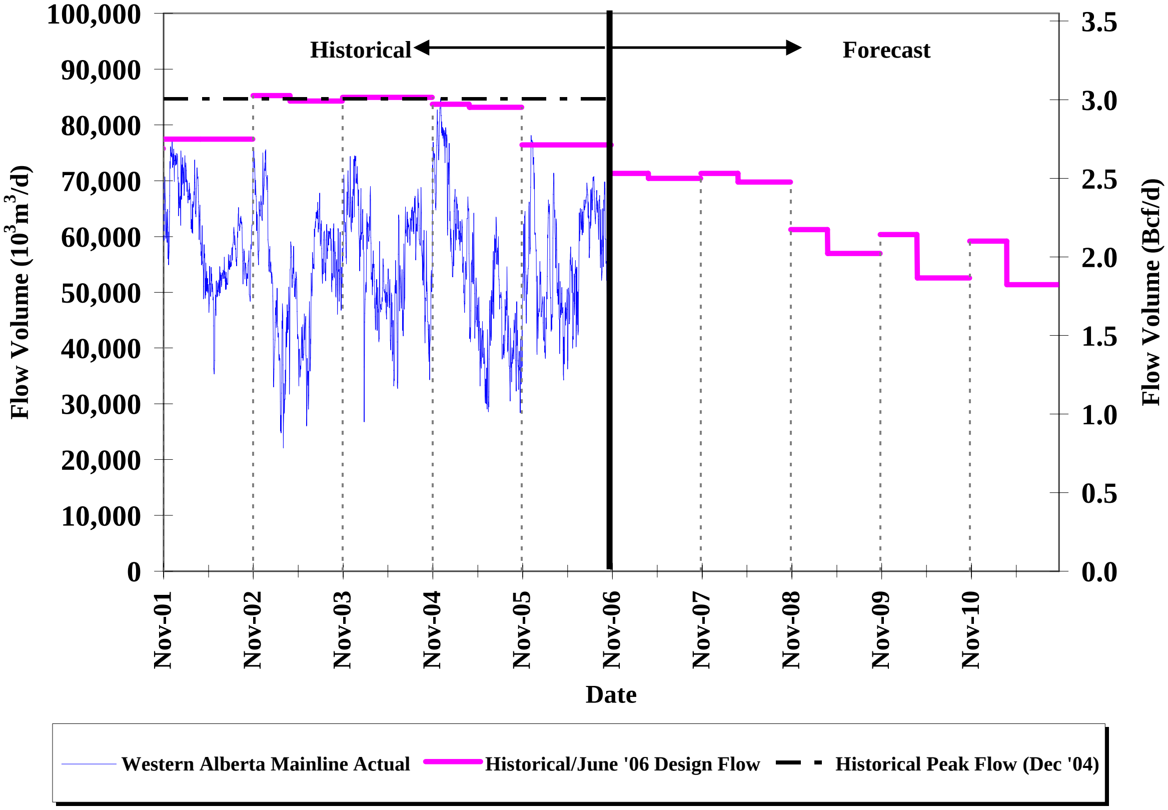


Table 4.4.1.4 shows the winter and summer design flow requirements for the 2007/08 Gas Year.

Table 4.4.1.4
Western Alberta Mainline Design Sub Area
June 2006 Design Forecast
Design Flow Requirements

Gas Year and Season	Flow	
	Bcf/d	$10^6m^3/d$
2007/08 Winter	2.53	71.3
2007/08 Summer	2.48	69.8

4.4.2 Rimbey-Nevis Design Area

The design flow requirements for the Rimbey-Nevis Design Area are the flow out of the area at the Hussar “A” Compressor Station and the Nevis-Gadsby Crossover.

Figure 4.4.2 illustrates that historical actual flows and historical design flow requirements follow a similar trend. The fluctuations between winter and summer actual flows are due to storage injections in the summer and storage withdrawals in the winter at the Carbon storage facility located within this design area.

The June 2006 design forecast shows an increase in winter and summer design flow requirements for the 2006/07 and 2007/08 Gas Years relative to the design flow requirements shown for the 2005/06 Gas Year. Beyond the 2007/08 Gas Year the design flow requirements decrease slightly each year to the 2010/11 Gas Year. This behaviour in design flow requirements is primarily due to the pattern of FS productive capability development expected to occur primarily on the Nevis lateral due to a number of existing and proposed coal bed methane projects. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

Figure 4.4.2
Rimbey-Nevis Design Area
Design Flow Requirements and Peak Expected Flows

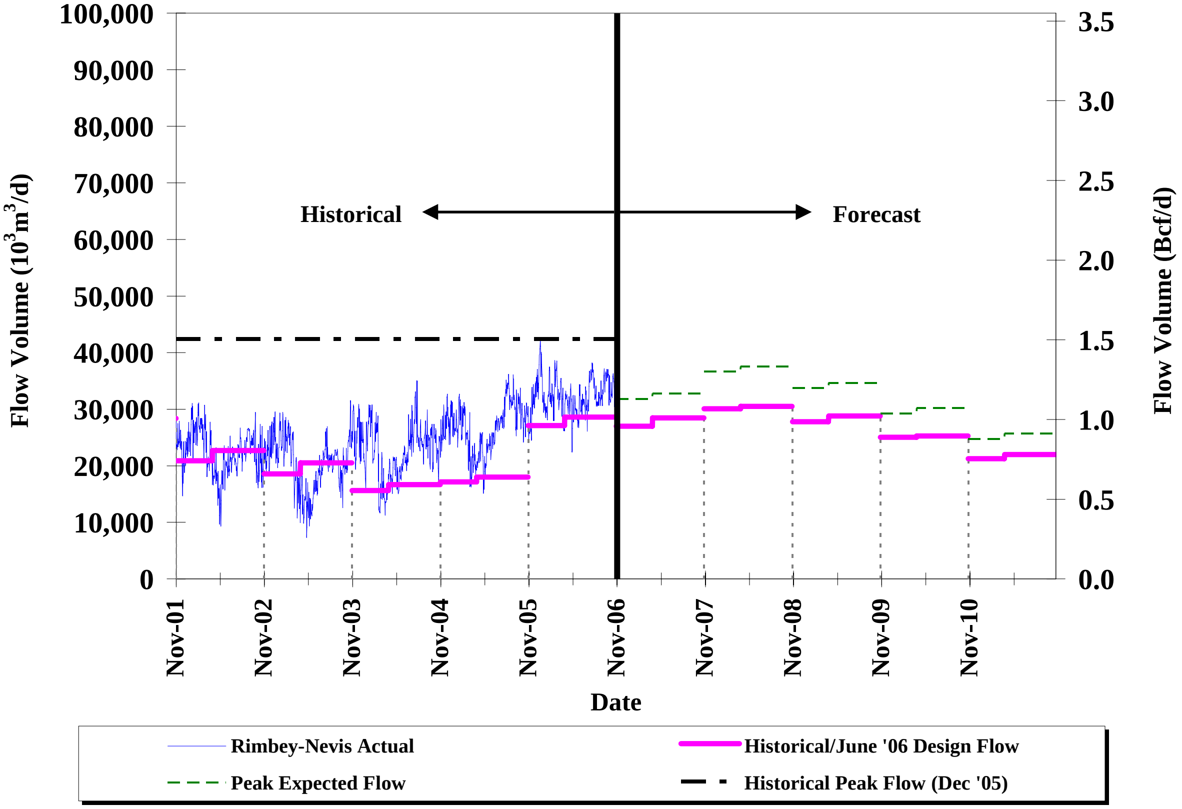


Table 4.4.2 shows the winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.4.2
Rimbey-Nevis Design Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flow	
	Bcf/d	$10^6 m^3/d$	Bcf/d	$10^6 m^3/d$
2007/08 Winter	1.07	30.1	1.30	36.6
2007/08 Summer	1.08	30.5	1.33	37.6

4.4.3 South and Alderson Design Area

The design flow requirements for the South and Alderson Design Areas are the flow out of the area to the Princess Compressor Station and the flow out of the area to the Drywood Compressor Station.

A greater quantity of gas from the South Lateral can be directed towards the Western Alberta Mainline Design Sub Area via the Drywood Compressor Station, located on the Waterton Montana Lateral. The ability also exists to flow gas from the South Lateral to the Princess Compressor Station.

Figure 4.4.3 illustrates that the historical design flow requirements declined slightly during the 2002/03 and 2003/04 Gas Years then remain flat during the 2004/05 and 2005/06 Gas Years. The historical actual flows remained steady out to the 2004/05 Gas Year then declined slightly during the 2005/06 Gas Year.

The June 2006 design forecast shows that winter and summer design flow requirements will decrease slightly during the 2006/07 and 2007/08 Gas Years, increase slightly out to the 2009/10 Gas Year, then remain steady for the 2010/11 Gas Year. The peak expected flows follow a similar trend as the design flow requirements but at higher flow levels.

Figure 4.4.3
South and Alderson Design Area
Design Flow Requirements and Peak Expected Flows

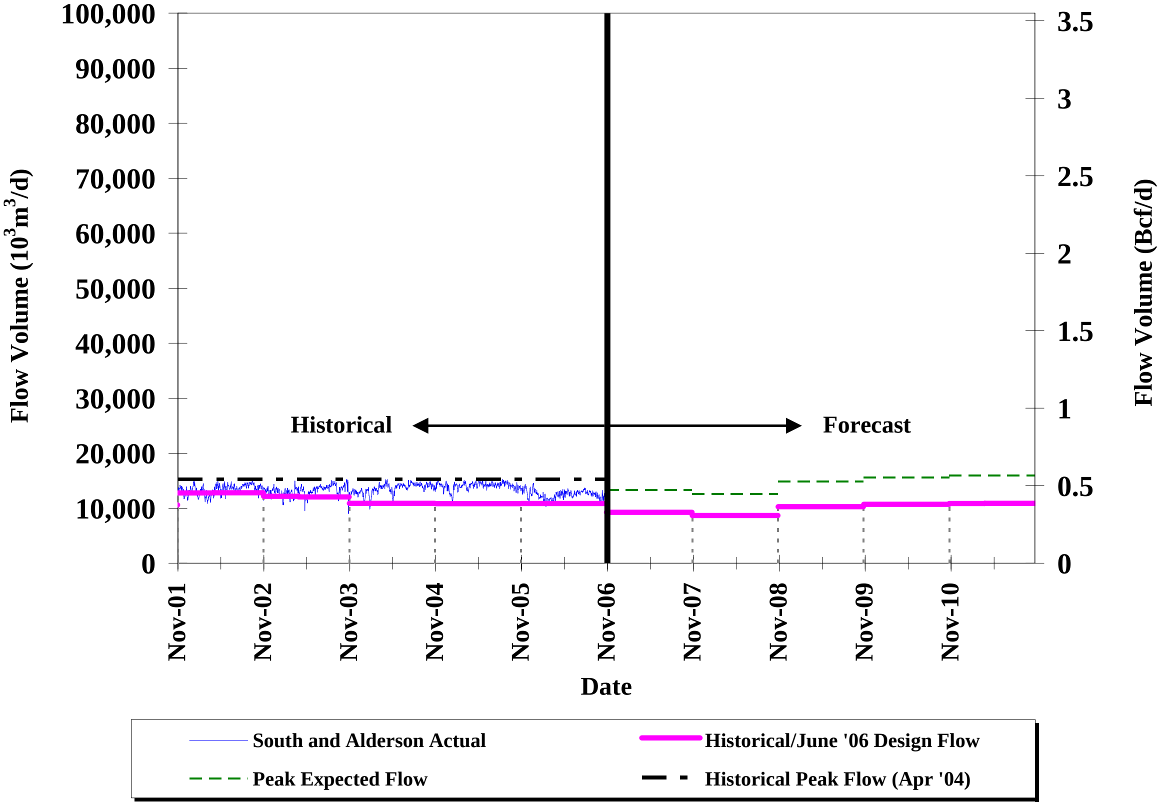


Table 4.4.3 shows the winter and summer design flow requirements and peak expected flows for the 2007/08 Gas Year.

Table 4.4.3
South and Alderson Design Area
June 2006 Design Forecast
Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Flow Requirements		Peak Expected Flows	
	Bcf/d	$10^6m^3/d$	Bcf/d	$10^6m^3/d$
2007/08 Winter	0.31	8.7	0.45	12.6
2007/08 Summer	0.31	8.7	0.45	12.6

4.4.4 Medicine Hat Design Area

The Medicine Hat Design Area is unique in that most of the gas produced within this area is required to meet maximum day delivery within the area.

Average receipt flows under conditions of maximum day delivery within the area best describe the design condition most likely to occur in the Medicine Hat Design Area and are therefore used to represent a reasonable constraining design condition. The design flow requirements for the Medicine Hat Design Area is the net flow to the Alberta deliveries within this area. The maximum day delivery forecast is critical to the design of facilities for the Medicine Hat Design Area (see Section 2.6.2).

Figure 4.4.4 illustrates that historical actual flows and historical design flow requirements follow a similar trend.

The June 2006 design forecast shows that winter and summer design flow requirements will increase slightly out to the 2010/11 Gas Year reflecting a moderate growth of deliveries within the area.

Figure 4.4.4
Medicine Hat Design Area
Maximum Day Delivery

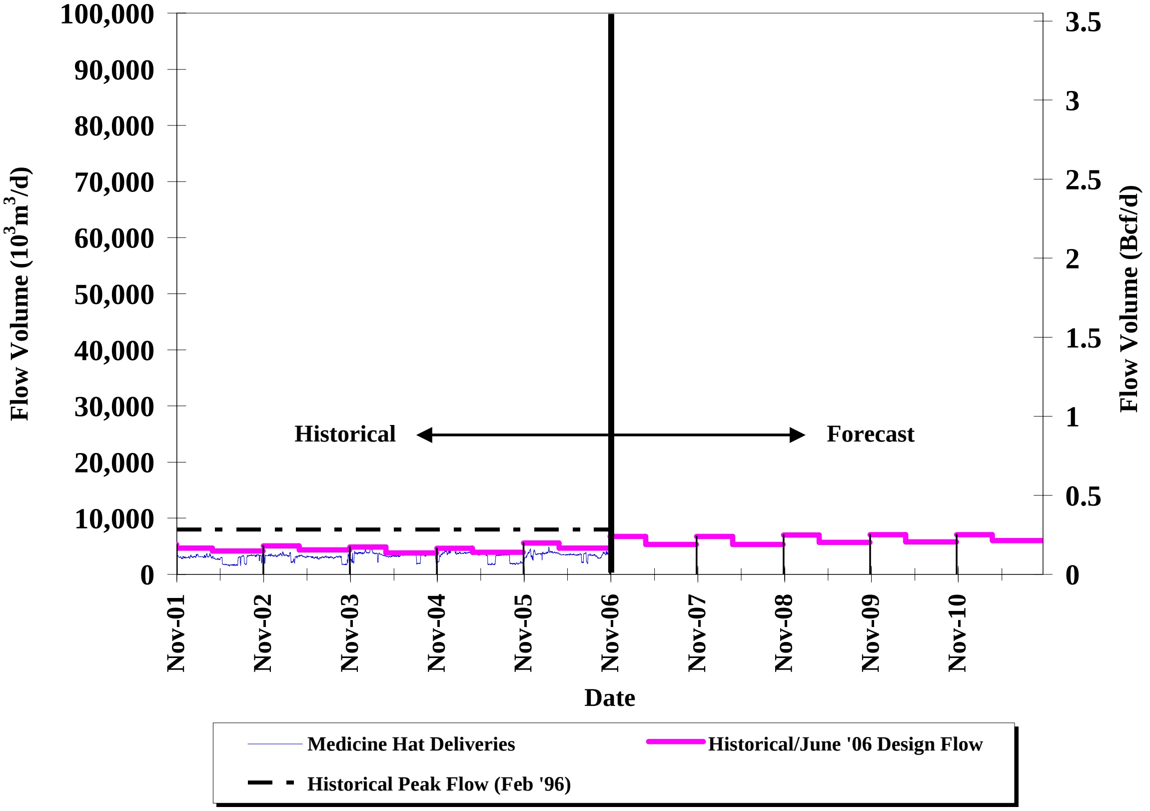


Table 4.4.4 shows the winter and summer maximum day delivery for the 2007/08 Gas Year.

Table 4.4.4
Medicine Hat Design Area
June 2006 Design Forecast
Maximum Day Delivery

Gas Year and Season	Flow	
	Bcf/d	$10^6m^3/d$
2007/08 Winter	0.24	6.7
2007/08 Summer	0.19	5.3

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 2007/08 Gas Year. Included is information regarding size, routes, locations and cost estimates for the proposed facilities together with descriptions of the next best alternative facilities.

An overview of the facilities requirements for the 2007/08 Gas Year was presented at the TTFP meeting on November 21, 2006.

For the purpose of discussing facilities requirements and next best alternative facilities, the material in this chapter is divided into the design areas described in Section 2.3.

For each project area, the design capability is shown as a percentage of design flow requirements and peak expected flows to a maximum of 100%. In project areas where facilities are required, design capability is shown for each design area within the project area. In this Annual Plan, design capability is determined using the design flow requirements and peak expected flows with facilities that are currently in-service and the facilities that are being constructed for the 2006/07 Gas Year. The design capability with proposed facilities is based on the June 2006 design forecast for the 2007/08 Gas Year.

Where new facilities are proposed, a table comparing proposed facilities and next best alternative facilities has been included. Flow schematics, based on design flow requirements for each of the design areas, with and without the proposed facilities, are provided in Appendix 5.

5.2 System Optimization Update

As described in Section 2.8.1 of this Annual Plan, system optimization continues to be an integral part of the regular facility design review and planning to meet the system design flow requirements.

There are no facilities identified for retirement for the 2007/08 Gas Year resulting from the 2006 design review.

5.3 Peace River Project Area

The Peace River Project Area comprises the Peace River Design Area and the Marten Hills Design Area as described in Section 2.3.1. There are no additional facilities required to be placed in-service based on the June 2006 design forecast to transport the 2007/08 design flow requirements and peak expected flows shown in Sections 4.2.1.1 through 4.2.1.3 and 4.2.2 for the Peace River Project Area. Future facilities required beyond the 2007/08 Gas Year for the Northwest Mainline in the Peace River Project Area are described in Section 5.6.

Table 5.3.1 shows the design capability of existing facilities as a percentage of design flow requirements and peak expected flows.

Table 5.3.1
Peace River Project Area
June 2006 Design Forecast
Design Capability vs. Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Capability (% of Design Flow Requirements)	Design Capability (% of Peak Expected Flows)
2007/08 Winter	100	100
2007/08 Summer	100	100

5.4 North and East Project Area

The North and East Project Area comprises the North of Bens Lake Design Area and the South of Bens Lake Design Area as described in Section 2.3.2. The proposed facilities for the North and East Project Area are identified in Figure 5.4.1.

Figure 5.4.1
North and East Project Area
Proposed Facilities

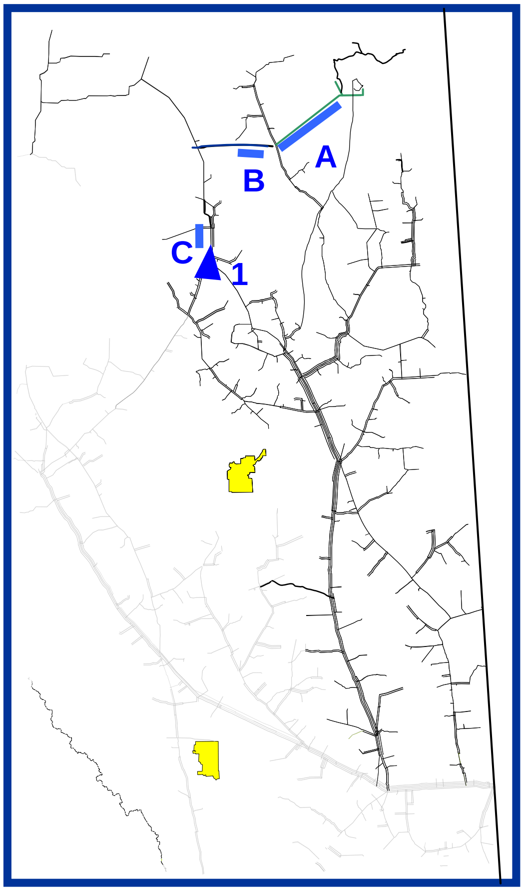


Table 5.4.1
North & East Project Area
Proposed Facilities

Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)	Facility Status
A	Fort McKay Mainline (Birchwood Section)	85 km NPS 36	April 2008	149.9	To Be Applied-for
B	North Central Corridor Loop (Buffalo Creek East Section)	28 km NPS 36	April 2008	51.7	To Be Applied-for
C	Marten Hills Lateral Loop #2 (McMullen Section)	34 km NPS 30	April 2008	52.5	To Be Applied-for
1	Paul Lake Compressor Station – Unit #2	15 MW	April 2008	27.7	To Be Applied-for
Capital Costs are in 2006 dollars and include AFUDC			**TOTAL**	**281.8**	

5.4.1 North of Bens Lake Design Area

In the North of Bens Lake Design Area, the facilities requirements are based on the flow through the area using the North of Bens Lake Design Area delivery assumption and the flow within the area using the North of Bens Lake maximum day delivery to the Fort McMurray area flow assumption as described in Section 2.6.1.2.

No additional facilities are required to be placed in-service based upon the June 2006 design forecast to transport the 2007/08 design flow requirements and peak expected flows, based on the flow through design area delivery assumption shown in Table 4.3.1.1 for the North of Bens Lake Design Area. Table 5.4.1.1 shows the design capability of existing facilities as a percentage of design flow requirements and peak expected flows.

Table 5.4.1.1
North of Bens Lake Design Area
June 2006 Design Forecast
Design Capability vs. Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Capability (% of Design Flow Requirements)	Design Capability (% of Peak Expected Flows)
2007/08 Winter	100	100
2007/08 Summer	100	100

Additional facilities are required to be placed in-service based upon the June 2006 design forecast to transport the 2007/08 design flow requirements, based on the flow within the area design flow assumption, shown in Table 4.3.1.2 for the North of Bens Lake Design Area, maximum day delivery to the Fort McMurray area.

The Fort McKay Mainline (Birchwood Section) consisting of 85 km of NPS 36 pipeline, the North Central Corridor Loop (Buffalo Creek East Section) consisting of 28 km of NPS 36 pipeline, the Marten Hills Lateral Loop #2 (McMullen Section) consisting of 34 km of NPS 30 pipeline and an additional 15 MW of compression at the Paul Lake Compressor Station are required to be placed in-service to meet the summer 2007/08 maximum day delivery to the Fort McMurray area. The summer 2007/08 in-service date is subject to the availability of the procurement of long lead time items and available labor required for construction in this heated market.

The next best alternative facilities are the Fort McKay Mainline (Birchwood Section) consisting of 85 km of NPS 30 pipeline, the North Central Corridor Loop (Buffalo Creek East Section) consisting of 28 km of NPS 30 pipeline, the Marten Hills Lateral Loop #2 (McMullen Section) consisting of 34 km of NPS 24 pipeline and an additional 15 MW of compression at the Paul Lake Compressor Station.

A comparison of the proposed facilities and the next best alternative facilities for the summer season of the 2007/08 Gas Year is shown in Table 5.4.1.2.

Table 5.4.1.2
North and East Project Area
Facility Comparison for the 2007/08 Gas Year

Proposed Facilities	**Capital Cost ($ millions)**		**CPVCOS (1)**	**km**	**NPS**	**MW**
	First Year	**Long Term**				
Fort McKay Mainline (Birchwood Section)	**149.9**			**85**	**36**	
North Central Corridor Loop (Buffalo Creek East Section)	**51.7**			**28**	**36**	
Marten Hills Lateral Loop #2 (McMullen Section)	**52.5**			**34**	**30**	
Paul Lake Compressor Station Unit #2	**27.7**					**15**
Total	**281.8**	**625.2**	**0.0**	**159**		**15**
Alternative Facilities						
Fort McKay Mainline (Birchwood Section)	**131.0**			**85**	**30**	
North Central Corridor Loop (Buffalo Creek East Section)	**43.8**			**28**	**30**	
Marten Hills Lateral Loop #2 (McMullen Section)	**41.2**			**34**	**24**	
Paul Lake Compressor Station Unit #2	**27.7**					**15**
Total	**243.7**	**638.4**	**+12.4**	**159**		**15**

Note:

1 CPVCOS is used as an economic tool for comparing design alternatives and is reported as a differential amount with zero being used as the reference point for the proposed facilities.

The proposed facilities were chosen over the next best alternative facilities because the cumulative present value cost of service is $12.4 million lower than the alternative.

The installation of the proposed facilities will provide the design capability to transport 100% of forecasted North & East Project Area design flow requirements for the 2007/08 Gas Year as shown in Table 5.4.1.3.

Table 5.4.1.3
North of Bens Lake Design Area
Maximum Day Delivery to the Fort McMurray Area June 2006 Design Forecast
Design Capability vs. Design Flow Requirements

Gas Year and Season	Design Capability (% of Maximum Day Delivery)	Design Capability with Proposed Facilities (% of Maximum Day Delivery)
2007/08 Winter	100	100
2007/08 Summer	84	100

5.4.2 South of Bens Lake Design Area

No additional facilities are required to be placed in-service based upon the June 2006 design forecast to transport the 2007/08 design flow requirements and peak expected flows, shown in Section 4.3.2, for the South of Bens Lake Design Area.

Table 5.4.2 shows the design capability of existing facilities as a percentage of design flow requirements and peak expected flows.

Table 5.4.2
South of Bens Lake Design Area
June 2006 Design Forecast
Design Capability vs. Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Capability (% of Design Flow Requirements)	Design Capability (% of Peak Expected Flows)
2007/08 Winter	100	100
2007/08 Summer	100	100

5.5 Mainline Project Area

The Mainline Project Area comprises the Mainline Design Area, the Rimbey-Nevis Design Area, the South and Alderson Design Area and the Medicine Hat Design Area as described in Section 2.3.3. 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.

There are no additional facilities required to be placed in-service based upon the June 2006 design forecast to transport the 2007/08 design flow requirements and peak expected flows shown in Sections 4.4.1.1, 4.4.2 and 4.4.3 for the Edson Mainline Design Sub Area, the Rimbey-Nevis Design Area and the South and Alderson Design Area.

Table 5.5.1.1 shows the design capability of existing facilities as a percentage of design flow requirements and peak expected flows in the Edson Mainline Design Sub Area, the Rimbey-Nevis Design Area, and the South and Alderson Design Area.

Table 5.5.1.1
Edson Mainline Design Sub Area,
Rimbey-Nevis Design Area, and
South and Alderson Design Area
June 2006 Design Forecast
Design Capability vs. Design Flow Requirements and Peak Expected Flows

Gas Year and Season	Design Capability (% of Design Flow Requirements)	Design Capability (% of Peak Expected Flows)
2007/08 Winter	100	100
2007/08 Summer	100	100

There are no additional facilities required to be placed in-service based upon the June 2006 design forecast to transport the 2007/08 design flow requirements shown in Sections 4.4.1.2, 4.4.1.3, 4.4.1.4 and 4.4.4 for the Eastern Alberta Mainline Design

Sub Area (James River to Princess), the Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill), the Western Alberta Mainline Design Sub Area and the Medicine Hat Design Area.

Table 5.5.1.2 shows the design capability of existing facilities as a percentage of design flow requirements for the Eastern Alberta Mainline Design Sub Area (James River to Princess), the Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill), the Western Alberta Mainline Design Sub Area and the Medicine Hat Design Area.

Table 5.5.1.2
June 2006 Design Forecast
Eastern Alberta Mainline Design Sub Area (James River to Princess),
Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill),
Western Alberta Mainline Design Sub Area
Medicine Hat Design Area
Design Capability vs. Design Flow Requirements

Gas Year and Season	Design Capability (% of Design Flow Requirements)
2007/08 Winter	100
2007/08 Summer	100

5.6 Future Facilities

The status of the proposed future facilities on the Northwest Mainline is described in Section 5.6.1.

The North Central Corridor (“NCC”) concept is described in Section 5.6.2.

5.6.1 Northwest Mainline

NGTL identified the future Northwest Mainline (Dickins Lake Section) and the Northwest Mainline Loop (Vardie River Section) facilities in the December 2004 and 2005 Annual Plans. These proposed facilities are required on the Alberta System to connect the proposed Mackenzie Valley pipeline. NGTL submitted a facilities application to the EUB in June 2006. The construction of the facilities, as filed, is proposed to begin in December 2010 with an on-stream date which aligns with the proposed completion of the Mackenzie Valley Pipeline in April 2011.

5.6.2 North Central Corridor

The NCC, as described in the December 1999 Annual Plan, remains the preferred facilities to meet system-wide receipt and delivery requirements. The NCC meets all of the following needs:

- Addresses the growth in Alberta deliveries in the North of Bens Lake Design Area;
- Establishes a plan to ensure the long term utilization of existing facilities in the North and East Project Area which enhances NGTL's delivery capability at the Empress and McNeill Export Delivery Points and therefore maximizes the flexibility of the system to deliver to a variety of Alberta Delivery Points and Export Delivery Points; and
- Transports the future growth in FS productive capability from the Peace River Project Area to the North and East Project Area, reducing the requirement for facilities that would otherwise be necessary in and downstream of the Peace River Project Area.

When compared to the evaluated alternatives, the NCC will reduce the overall distance of gas transportation in the Alberta System, which significantly lowers fuel consumption.

The NCC accommodates the growing maximum day delivery in the North of Bens Lake Design Area while accounting for declining FS productive capability in the

North & East Project Area. In 2006, NGTL executed long term transportation contracts with several of the oil sands and heavy oil developers in the North of Bens Lake Design Area including new projects in the Fort McMurray and the Kirby area. As the maximum day delivery continues to grow and FS productive capability continues to decline in the North of Bens Lake Design Area, significant additional facilities will be required for the summer season of the 2009/10 Gas Year. Since 2004, NGTL has made low cost modifications to existing compressor stations on the North Lateral to transport gas northward. By the summer season of the 2009/10 Gas Year, the low cost modifications to existing compressor stations will be completed, and pipeline looping projects would be required on the North Lateral to transport gas northward. The NCC is a more cost-effective alternative which replaces the need for the North Lateral pipeline looping projects.

The NCC ensures the long term utilization of existing facilities in the North and East Project Area which also enhances NGTL's delivery capability at the Empress and McNeill Export Delivery Points. The combination of increasing maximum day delivery and decreasing FS productive capability in the North & East Project Area has resulted in the decreased flow from the North & East Project Area at the Princess Compressor Station to the Eastern Alberta Mainline. The NCC will transport FS productive capability to the North & East Project Area which will directly enhance NGTL's delivery capability at the Empress and McNeill Export Delivery Points.

The NCC accommodates the future aggregate growth in FS productive capability in the Peace River Project Area which is forecast to increase beyond the capability of existing facilities. Additional pipeline loops will be required in the Peace River Project Area south of the Hidden Lake Compressor Station to transport incremental FS productive capability south to the Export Delivery Points. The NCC provides a more cost-effective alternative which eliminates the need for looping south of the Hidden Lake Compressor Station.

In the 2006 design review, NGTL evaluated several facility platforms to address the increasing maximum day delivery in the North of Bens Lake Design Area, maintaining/enhancing capability at the Empress and McNeill Export Delivery Points and the growth in FS productive capability in the Peace River Project Area. NGTL determined the NCC continues to be the most economic facility to accommodate all three integrated system requirements. The NCC eliminates the requirement for additional facilities in the South of Bens Lake Design Area and the Peace River Project Area, as well as reduces overall system fuel requirements by reducing the distance of haul to transport gas.

The NCC is currently proposed to be on-stream April 2010 and consists of 285 km of NPS 42 pipeline from the Meikle River Compressor Station located in the Upper Peace River Design Sub Area to the Woodenhouse Compressor Station located in the North of Bens Lake Design Area and two additional 15 MW compressor units at the Meikle River Compressor Station.

The NCC was chosen because the CPVCOS is $550 million lower than the next best alternative. The next best alternative (South Corridor) consists of 390 km of NPS 36 pipeline from the Latornell Compressor Station located in the Lower Peace River Design Sub Area to the Bens Lake Compressor Station located in the North & East Project Area and two additional 15 MW compressor units at the Latornell Compressor Station.

A comparison of the proposed facilities and the next best alternative facilities for the summer season of the 2009/10 Gas Year is shown in Table 5.6.2.1.

Table 5.6.2.1
North Central Corridor

Proposed Facilities	Capital Cost ($ millions)[2]		CPVCOS (1)	km	NPS	MW
	First Year	Long Term				
North Central Corridor	478.0			285	42	
Meikle River Compressor Station Units 4 & 5	46.0					30
Total	**524.0**	**674.0**	**0.0**	**285**		**30**
Alternative Facilities						
South Corridor	507.0			390	36	
Latornell Compressor Station Units 2 & 3	46.0					30
Total	**553.0**	**1346.0**	**+550.0**	**390**		**30**

Notes:

1 CPVCOS is used as an economic tool for comparing design alternatives and is reported as a differential amount with zero being used as the reference point for the proposed facilities.

2 Capital costs are in 2006 dollars.

The NCC is being presented in this Annual Plan due to the lead time required for public involvement, land and environmental survey, route selection, and the long lead time required for materials to enable an April 2010 on-stream date.

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, NGTL determines the term and contractual obligation in accordance with the economic criteria described in the Criteria for Determining Primary Term (Appendix E of NGTL's Gas Transportation Tariff).

In accordance with the Board's *Guide 56, Energy Development Applications and Schedules, October 2003* NGTL no longer submits permit applications to the Board to construct new meter stations. Consequently proposed meter stations are not included in this Chapter. As of December 2006, there are no new Customer authorized extension facilities or lateral loops that are required but have not been applied for.

A summary of all Section L facilities that were filed with the Board since the filing of the December 2005 Annual Plan is included under Appendix 6. In addition, a summary of all proposed meter stations from December 1, 2005 to November 30, 2006 is included under Appendix 6.

CHAPTER 7 – CAPITAL EXPENDITURE AND FINANCIAL FORECAST

7.1 Introduction

Capital expenditure and financial forecasts included in this Annual Plan are based upon the June 2006 design forecast and design assumptions outlined elsewhere in the Annual Plan. The forecasts are subject to revision and are dependent upon the approval and timing of construction projects and Customer applications for service.

This chapter includes data for the years 2006 and 2007. During 2006 NGTL operated under final rates that were approved by the Board in Decision U2006-83. The rates applied for were based on the revenue requirements established pursuant to the 2005-2007 Revenue Requirement Settlement approved by the Board in Decision 2005-057. For 2006, the data is based on the information contained in the 2006 final rate application. For 2007, the data is based on the 2007 Interim Rates, Tolls and Charges Application. A decision on the 2007 Interim Rates, Tolls and Charges Application is pending. This chapter does not include a forecast of capital expenditures for 2008 for the facilities contained in this Annual Plan or the impact on the revenue requirement and rates for 2008.

7.2 Capital Expenditure Forecast

NGTL's forecast of capital expenditures in 2007, including the facilities requirements identified in this Annual Plan, is provided in Table 7.2.1. This table also shows forecast capital expenditures for 2006. The table is segmented into capacity capital, including mainline expansion, receipt and delivery facilities, and retirements, and system maintenance and general plant. The figures are presented on a calendar year basis and are rounded to the nearest $5 million.

The firm transportation design process identifies facilities requirements for the 2007/08 Gas Year. The costs associated with the facilities requirements for the 2007/08 Gas Year will generally occur in the 2007 and 2008 calendar years.

Table 7.2.1
Capital Expenditure Forecast
($ millions)

	2006	2007
Capacity Capital		
Mainline Expansion	200	210
Receipt and Delivery	35	25
Retirements	0	0
System Maintenance and General Plant	20	25
Total	255	260

7.3 Financial Forecast

Financial information, including forecasts of NGTL's revenue requirements and firm transportation demand rates, associated with 2006 and 2007 is provided in Table 7.3.1. Also included are forecasts of system annual throughput and ex-Alberta firm transportation unit cost for the years 2006 and 2007. The amounts for investment base and for revenue requirement are rounded to the nearest $5 million.

Table 7.3.1
Financial Forecast
($ millions)

	2006	2007
Investment Base (December 31)	4,305	4,285
Revenue Requirement [1]	1,080	1,115
System Annual Throughput (tcf) [2]	4.12	4.08
Unit Volume Cost (¢/mcf)[3]	28.0	27.9
Monthly Average Firm Transportation Receipt Demand Rate ($/mcf) [4]	4.08	4.26
Monthly Firm Transportation Delivery Demand Rate ($/mcf)[5]	4.08	4.26
Ex-Alberta Average Firm Transportation Unit Cost (¢/mcf) [6]	26.8	28.0

NOTES:

1 The 2007 revenue requirement is based on the interim rate application for 2007. The 2006 revenue requirement is based on the 2005-2007 Revenue Requirement Settlement Application and information contained in the 2006 final rate application.

2 Throughput includes fuel gas.

3 Unit volume cost is lower in 2007 compared to 2006 because the revenue requirement (net of deferrals from the previous year) is lower in 2007 than 2006.

4 Based on a three year term.

5 The Monthly Firm Transportation Delivery Demand Rate for 2007 is $4.00/GJ. The rate has been provided on volumetric basis in the above table for comparative purposes.

6 The forecast of ex-Alberta firm transportation unit cost assumes a one to one receipt to delivery ratio at a 100% load factor and is based on the average three year firm transportation receipt rate and the firm transportation delivery rate, expressed on a volumetric basis.

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 NGTL 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 submitted annually to the Board 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 Receipt Forecast

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

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.

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

NGTL divides its pipeline system 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 NGTL to model the system in a way that best reflects the pattern of flows in each specific area of the system.

Design Flow Requirements

The forecast of Firm Requirements that is required to be transported in a pipeline system considering design assumptions.

Design Forecast

This is a forecast of NGTL's most current projection of FS productive capability and gas delivery over a five year design horizon.

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.

Expansion Facilities

Expansion facilities are those facilities which will expand NGTL's existing 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.

Field Deliverability

Field deliverability is the forecast peak rate at which gas can be received onto the pipeline system at each Receipt Point. NGTL forecasts field deliverability through an assessment of reserves, flow capability and the future supply development at each Receipt Point. This information is gathered from Board and industry sources, NGTL studies and through interaction with producers and Customers active in the area.

Firm Transportation

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

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.

FS Productive Capability

FS productive capability is the lesser of forecast field deliverability and the forecast of aggregate Receipt Contract Demand under Service Agreements for Rate Schedule FT-R, Rate Schedule LRS, Rate Schedule LRS-2, Rate Schedule LRS-3, Rate Schedule FT-P and Rate Schedule FT-RN held at each Receipt Point.

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.

Green Area

Defined by Alberta Environment as non-arable lands.

Interruptible Transportation

Service offered to Customers to receive gas onto the Alberta System at NGTL Receipt Points or deliver gas off of the Alberta System at NGTL 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 NGTL's customers.

Maximum Day Delivery

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

Maximum Operating Pressure

The maximum operating pressure at which a pipeline is operated.

Minimum Day Delivery

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

NPS

Nominal pipe size, in inches.

Non-coincidental

Non-simultaneous occurrence.

Peak Expected Flow

The peak flow that is expected to occur within a design area or design sub area on the Alberta System.

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 NGTL to model the system 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.

Rate Base

Rate base is the investment base on which NGTL earns its return and consists of the depreciated in-service physical pipeline system assets, the necessary working capital and linepack gas required to provide service and determine operating income. The rate base is determined monthly as new facilities are placed into service, facilities are retired and depreciation is recorded.

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.

Revenue Requirement

The total cost of providing service, including capital, operating and maintenance expenses, depreciation, taxes and return on rate base.

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.

Receipt Area

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

System Annual Throughput

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

System Average Annual Throughput

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

System Field Deliverability

System field deliverability is the sum of all individual Receipt Point field deliverability.

System FS Productive Capability

System FS productive capability is the sum of all individual Receipt Point FS productive capability.

System Maximum Day Deliveries

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

Two-way Flow Stations

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

White Area

Defined by Alberta Environment as arable lands.

Winter Season

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

EUB Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

Informational Letter

IL 98-5

28 May 1998

To: All Oil and Gas Well, Pipeline and Gas Plant Operators,
Gas Utility Companies and NOVA Customers

ADDENDUM TO ATTACHMENT TO INFORMATIONAL LETTER IL 90-8 PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

In accordance with Item D of Informational Letter IL 90-8, NOVA has historically filed an Annual Plan with the EUB in May or June of each year to ensure that facilities are completed in time to meet Firm Service requirements under the 27-month design cycle.

Since 1995, NOVA has been able to conduct quarterly design forecasts and shorten the design cycle. In February 1998, NOVA requested the Board to change the submission date of the Annual Plan from May of each year to 15 December of each year.

NOVA has reviewed the merit of this change with members of the Facilities Liaison Committee, the CAPP, and the Board staff. They have concluded that the change would increase the certainty of the Annual Plan, allow adequate time to complete all required facilities to meet the transportation services requested, and enable NOVA to more appropriately align its Annual Plan process with the Firm Service design process as well as other internal business and budgeting processes.

The Board has reviewed the matter, noting that no formal objection to the proposal remains, and has decided to grant this request. Therefore, this addendum strikes the word "May" in Item D in the Attachment to IL 90-8 and substitutes "15 December" effective immediately.

Should you have any questions, please contact Mr. Ken Sharp, Group Leader of the Board's Facilities Division - Applications Group at (403) 297-8133.

F. J. Mink
Board Member

ERCB

Energy Resources Conservation Board
640 Fifth Avenue SW
Calgary, Alberta
Canada T2P 3G4

Informational Letter

ADDENDUM TO
IL 90-8

To: All Oil and Gas Well, Pipeline
and Gas Plant Operators,
Gas Utility Companies and NOVA Customers

4 April 1994

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

In accordance with Item J of Informational Letter IL 90-8, a notice for objection has been issued by the ERCB for each NOVA pipeline application with a capital cost in excess of $10 million. Since the issuance of the IL in June 1990, approximately 30 such notices have been routinely published. To date only one objection, which related to the Pacific Gas Transmission Expansion Project, has been filed.

NOVA has reviewed the merit of this procedure and has consulted members of the Facilities Liaison Committee, the CAPP/NOVA Committee and the Board staff. They have concluded that the current practice of routine Publication of Notice provides little added value and its elimination would have no adverse impact on industry awareness of, and opportunity to object to, major NOVA facility applications. There would be the advantages of reducing application processing time and savings on costs of advertising. Consequently, NOVA has made a request to the Board to discontinue this practice.

The Board has reviewed the matter, noting the agreement of the affected parties, and has decided to grant this request. Therefore, the last sentence in Item J of the IL "The notice for objections would typically be issued for an application with a capital cost in excess of $10 million" is deleted effective immediately.

Should you have any questions, please contact the undersigned at 297-8133.

K. G. Sharp, P.Eng.
Manager
Pipeline Department

IL 90-8

TO: All Oil and Gas Well, Pipeline
and Gas Plant Operators,
Gas Utility Companies and NOVA Customers

22 June 1990

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

Since 1980 the handling by the ERCB of the NOVA Corporation of Alberta (NOVA) pipeline applications with respect to industry issues has been in accordance with the ERCB Informational Letter IL 80-10 "Procedures and Economic Criteria for the Assessment of Future Alberta Gas Trunk Line Applications". In view of the deregulation of the gas industry, NOVA's major system expansion program and its potential impact on the cost of service, the ERCB initiated a review to see if changes are required to IL 80-10. Board staff met with and received comments and inputs on the matter from representatives of NOVA, the Canadian Petroleum Association, the Independent Petroleum Association of Canada, the Small Explorers and Producers Association of Canada, the Alberta Petroleum Marketing Commission, and three major shippers. Considering the advice of the industry the Board concluded that the attached new procedures would be more relevant to the current situation and should replace those set out in IL 80-10. The attached procedure for review of NOVA facilities by industry will be adopted immediately.

It should be noted that these new procedures deal only with industry concerns related to the economic and orderly development of the NOVA system and the impact on its cost of service. Landowner/occupant, other public interest, or environmental concerns will be dealt with in accordance with normal ERCB procedure to ensure that any person whose rights may be directly and adversely affected would have the opportunity to comment on the matter.

Should you have any questions, please contact Mr. Ed Fox, Manager of the Board's Pipeline Department, at 297-8133.

This Information Letter supersedes and replaces IL 80-10.

F. J. Mink
Board Member

Attachment

Attachment to Informational Letter IL 90-8

PROCEDURES FOR THE ASSESSMENT OF NOVA PIPELINE APPLICATIONS - INDUSTRY REVIEW

The Board will use the following procedures for assessing NOVA pipeline applications.

A NOVA is required to establish a committee and appropriate sub-committees with representation from NOVA, industry associations such as the Canadian Petroleum Association, the Independent Petroleum Association of Canada, the Small Explorers and Producers Association of Canada, and other interested parties for the purposes of facilitating the effective, efficient, and timely exchange of information among involved parties and of addressing NOVA's long-term planning and policy issues. Board staff will participate as observers on matters that are within ERCB jurisdiction.

B NOVA is required to make industry aware on a regular basis of its upcoming facility additions and major modifications at an early stage in its design cycle time. Presently, each design cycle time is approximately 27 months from the deadline date for NOVA customers to sign their firm service requests through preliminary design, detailed design, regulatory approval, and construction to the in-service date of all resulting facility additions and major modifications to meet such service requests.

C NOVA will use a two-stage application process. The first stage is the filing with the ERCB of an annual preliminary overall system plan (Annual Plan) containing all planned facility additions and major modifications. The second stage is the filing of the final technical, cost, routing/siting, land, environmental, and other information required to complete the application for each facility contained in the Annual Plan.

D The Annual Plan will be filed as early as possible in the design cycle but not later than May of each year.

E The Annual Plan will contain sufficient information on the need, rationale, and justification for the proposed facility additions and major modifications, and will include but not be limited to

(a) system demand outlook,
(b) system reserves and deliverability on an areal basis,
(c) assumptions, design criteria, and methodology,

(d) economic criteria,
(e) preliminary sizing of each facility,
(f) preliminary route/site for each facility,
(g) preliminary cost estimate and construction schedule for each facility,
(h) impact on NOVA's cost of services due to the implementation of the Annual Plan, and
(i) long-term plan and the impact resulting from the implementation of the Annual Plan on the long-term plan.

F NOVA is required to publish a notice, soon after the Annual Plan is filed, in major newspapers advising industry that copies of the Annual Plan can be obtained from NOVA for review. The Board will also have a copy of the Annual Plan placed at its information centre for public viewing.

G The Board staff will review the Annual Plan and may request additional information. Such a review could include a technical review with industry participation.

H Any interested industry parties who have concerns or questions on any generic issues or on any individual facility or group of facilities in the Annual Plan must contact NOVA directly for resolution. If any of these concerns cannot be satisfactorily resolved, the parties may then submit them to the Board within a reasonable period. The Board will defer the consideration of concerns on individual facility or group of facilities to the second-stage application. With respect to the concerns on generic issues in the Annual Plan, the Board may call a meeting of interested parties to discuss them. All interested parties will be notified.

I NOVA will file the second-stage material required to complete each facility application referred to in item (C) as soon as that information is available.

J In assessing each facility application with respect to the need of notice, the Board will have regard for its review of the application and the Annual Plan, submissions received respecting the Annual Plan, concerns submitted regarding the facilities, and any significant changes in facts or circumstances between the filing of the Annual Plan and the application. If every aspect referred to above is deemed by the Board to be satisfactory, the application may be approved without a notice for objection, and if not, a notice will be issued. The notice for objections would typically be issued for an application with a capital cost in excess of $10 million.

K In certain instances where submissions have already been filed or the Board is aware that objections will likely be filed, it may go directly to public hearing. Additionally, where valid objections are filed as a result of notice, a hearing will be held.

L Any facility application filed for approval that is <u>not</u> contained in the Annual Plan must include, in addition to material referred to in item (C) for the second-stage application, information on

(a) the purpose and necessity for the proposed facility,
(b) the reasons why it was not included in the Annual Plan,
(c) the impact on the Annual Plan,
(d) the impact on NOVA's cost of service, and
(e) the impact on NOVA's long-term plan.

Any application of this nature will be assessed on its own merit and advertised if required.

APPENDIX 3

CRITERIA FOR DETERMINING PRIMARY TERM

Please refer to NGTL's Gas Transportation Tariff, Appendix E, for the Criteria for Determining Primary Term. NGTL's Gas Transportation Tariff can be accessed at: http://www.transcanada.com/Alberta/info_postings/tariff/index.html

APPENDIX 4.1

DESIGN FLOW REQUREMENTS

The following tables present both the winter and summer design flow requirements for each NGTL design area. The values are derived, as discussed in Chapters 2 and 4, through application of the mainline design assumptions to the June 2006 design forecast.

Design flow requirements, described as Area Design Flow Requirements in the tables, are calculated by subtracting the Area Minimum Deliveries and area fuel (not shown) from the Area Required Receipts. In some areas, Flow Into Area is added to the Area Required Receipts and represents the flow from other design areas. Area Minimum Deliveries are determined based on the design flow assumption discussed in Section 2.6.

Area FS Productive Capability represents the sum of the FS productive capability at each Receipt Point in the design area. The Area Required Receipts are determined through application of the design area delivery, equal prorationing and FS productive capability assumptions.

Area Peak Productive Capability represents the expected coincidental peak receipts received from all receipt points with the design area as described in Section 2.6.2. The Area Peak Receipts are determined through application of the design area delivery and equal prorationing assumptions against the assessed peak productive capability on the Alberta System.

The design flow requirements may differ from the flow schematics shown in Appendix 5. This is because the detailed flow schematic information is taken directly from the hydraulic simulations whereas design flow requirements are estimated for the entire design area.

Design Flow Requirements

Upper Peace River Design Sub Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	23792	23272	22638	24655	26987
Flow Into Area	0	0	0	0	0
Area Required Receipts	19746	18780	18505	20863	22883
Area Deliveries	-13	-13	-13	-13	-13
Area Design Flow Req'mts	19480	18526	18255	20583	22577

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	844	826	803	875	958
Flow Into Area	0	0	0	0	0
Area Required Receipts	701	667	657	741	812
Area Deliveries	0	0	0	0	0
Area Design Flow Req'mts	691	658	648	731	801

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	23792	23272	22638	24655	26987
Flow Into Area	0	0	0	0	0
Area Required Receipts	22450	20713	20842	22765	25485
Area Deliveries	-11	-11	-11	-11	-11
Area Design Flow Req'mts	22151	20436	20564	22462	25147

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	844	826	803	875	958
Flow Into Area	0	0	0	0	0
Area Required Receipts	797	735	740	808	905
Area Deliveries	0	0	0	0	0
Area Design Flow Req'mts	786	725	730	797	893

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Central Peace River Design Sub Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	16830	16824	17112	19575	21691
Flow Into Area	19480	18526	18255	20583	-7424
Area Required Receipts	13933	13553	14001	16565	18398
Area Deliveries	-257	-257	-260	-260	-260
Area Design Flow Req'mts	32976	31648	31816	36675	10478

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	597	597	607	695	770
Flow Into Area	691	658	648	731	-263
Area Required Receipts	495	481	497	588	653
Area Deliveries	-9	-9	-9	-9	-9
Area Design Flow Req'mts	1170	1123	1129	1302	372

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	16830	16824	17112	19575	21691
Flow Into Area	22151	20436	20563	-7538	-4853
Area Required Receipts	15869	14961	15760	18075	20485
Area Deliveries	-89	-90	-90	-90	-92
Area Design Flow Req'mts	37727	35115	36032	10214	15277

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	597	597	607	695	770
Flow Into Area	786	725	730	-268	-172
Area Required Receipts	563	531	559	642	727
Area Deliveries	-3	-3	-3	-3	-3
Area Design Flow Req'mts	1339	1246	1279	363	542

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Lower Peace River Design Sub Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	65693	68662	67471	58359	54863
Flow Into Area	32976	31648	31816	36675	10478
Area Required Receipts	54276	55101	54951	49260	46433
Area Deliveries	-493	-499	-505	-510	-518
Area Design Flow Req'mts	86063	85542	85556	84792	55797

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	2332	2437	2395	2071	1947
Flow Into Area	1170	1123	1129	1302	372
Area Required Receipts	1926	1956	1950	1748	1648
Area Deliveries	-18	-18	-18	-18	-18
Area Design Flow Req'mts	3055	3036	3037	3010	1980

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	65693	68662	67471	58359	54863
Flow Into Area	37727	35115	36032	10214	15277
Area Required Receipts	61906	60936	62030	53823	51776
Area Deliveries	-267	-268	-268	-268	-269
Area Design Flow Req'mts	98571	95002	96998	63078	66120

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	2332	2437	2395	2071	1947
Flow Into Area	1339	1246	1279	363	542
Area Required Receipts	2197	2163	2202	1910	1838
Area Deliveries	-9	-10	-10	-10	-10
Area Design Flow Req'mts	3499	3372	3443	2239	2347

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Marten Hills Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	7071	8607	8334	7435	6918
Flow Into Area	0	0	0	0	0
Area Required Receipts	5819	6874	6757	6253	5835
Area Deliveries	-176	-176	-177	-177	-183
Area Design Flow Req'mts	5569	6609	6494	5996	5577

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	251	305	296	264	246
Flow Into Area	0	0	0	0	0
Area Required Receipts	207	244	240	222	207
Area Deliveries	-6	-6	-6	-6	-6
Area Design Flow Req'mts	198	235	230	213	198

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	7071	8607	8334	7435	6918
Flow Into Area	0	0	0	0	0
Area Required Receipts	6656	7619	7648	6846	6521
Area Deliveries	-58	-58	-58	-58	-59
Area Design Flow Req'mts	6513	7464	7492	6699	6379

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	251	305	296	264	246
Flow Into Area	0	0	0	0	0
Area Required Receipts	236	270	271	243	231
Area Deliveries	-2	-2	-2	-2	-2
Area Design Flow Req'mts	231	265	266	238	226

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

North of Bens Lake Design Area

$10^3m^3/d$

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	21827	20755	18805	17739	17011
Flow Into Area	4000	4000	4000	4000	34000
Area Required Receipts	17600	16115	14616	13834	12968
Area Deliveries	-26500	-28336	-32645	-33378	-35563
Area Design Flow Req'mts	-5126	-8428	-14217	-15722	11239

mmcf/d

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	775	737	667	630	604
Flow Into Area	142	142	142	142	1207
Area Required Receipts	625	572	519	491	460
Area Deliveries	-941	-1006	-1159	-1185	-1262
Area Design Flow Req'mts	-182	-299	-505	-558	399

$10^3m^3/d$

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	21827	20755	18805	17739	17011
Flow Into Area	4000	4000	4000	34000	34000
Area Required Receipts	18859	16187	15018	13799	13129
Area Deliveries	-21533	-24578	-28160	-28841	-31073
Area Design Flow Req'mts	1084	-4598	-9334	18780	15887

mmcf/d

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	775	737	667	630	604
Flow Into Area	142	142	142	1207	1207
Area Required Receipts	669	575	533	490	466
Area Deliveries	-764	-872	-999	-1024	-1103
Area Design Flow Req'mts	38	-163	-331	667	564

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Fort McMurray Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability					
Flow Into Area					
Area Required Receipts					
Area Deliveries	-25091	-27063	-36709	-41263	-47572
Area Design Flow Req'mts	-25091	-27063	-36709	-41263	-47572

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability					
Flow Into Area					
Area Required Receipts					
Area Deliveries	-891	-961	-1303	-1465	-1688
Area Design Flow Req'mts	-891	-961	-1303	-1465	-1688

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability					
Flow Into Area					
Area Required Receipts					
Area Deliveries	-25977	-32309	-36480	-41033	-47342
Area Design Flow Req'mts	-25977	-32309	-36480	-41033	-47342

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability					
Flow Into Area					
Area Required Receipts					
Area Deliveries	-922	-1147	-1295	-1456	-1680
Area Design Flow Req'mts	-922	-1147	-1295	-1456	-1680

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

South of Bens Lake Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	16333	16650	15170	15006	14695
Flow Into Area	-626	-3928	-9717	-11222	15739
Area Required Receipts	13274	13049	11899	11818	11327
Area Deliveries	-66	-66	-71	-71	-71
Area Design Flow Req'mts	12412	8887	1958	373	26850

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	580	591	538	533	522
Flow Into Area	-22	-139	-345	-398	559
Area Required Receipts	471	463	422	419	402
Area Deliveries	-2	-2	-3	-3	-3
Area Design Flow Req'mts	441	315	70	13	953

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	16333	16650	15170	15006	14695
Flow Into Area	5584	-98	-4834	23280	20387
Area Required Receipts	14185	13105	12213	11789	11461
Area Deliveries	-16	-16	-21	-21	-21
Area Design Flow Req'mts	19571	12824	7202	34898	31681

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	580	591	538	533	522
Flow Into Area	198	-3	-172	826	724
Area Required Receipts	503	465	433	418	407
Area Deliveries	-1	-1	-1	-1	-1
Area Design Flow Req'mts	695	455	256	1239	1124

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Edson Mainline Design Sub Area

$10^3m^3/d$

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	39872	38853	41755	43083	44360
Flow Into Area	87631	88151	88050	86788	57375
Area Required Receipts	33003	31249	34050	36404	37579
Area Deliveries	-2	-2	-2	-2	-2
Area Design Flow Req'mts	120209	118998	121661	122723	94469

mmcf/d

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	1415	1379	1482	1529	1574
Flow Into Area	3110	3129	3125	3080	2036
Area Required Receipts	1171	1109	1209	1292	1334
Area Deliveries	0	0	0	0	0
Area Design Flow Req'mts	4267	4224	4318	4356	3353

$10^3m^3/d$

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	39872	38853	41755	43083	44360
Flow Into Area	101084	98466	100490	65777	68499
Area Required Receipts	37594	34521	38407	39753	41877
Area Deliveries	-2	-2	-2	-2	-2
Area Design Flow Req'mts	138193	132542	138402	105019	109836

mmcf/d

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	1415	1379	1482	1529	1574
Flow Into Area	3588	3495	3567	2335	2431
Area Required Receipts	1334	1225	1363	1411	1486
Area Deliveries	0	0	0	0	0
Area Design Flow Req'mts	4905	4704	4912	3728	3899

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Eastern Alberta Mainline Design Sub Area (James River to Princess)

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	18156	18102	16783	16060	15951
Flow Into Area	106984	107517	121940	124941	96673
Area Required Receipts	16692	16185	15224	15063	15002
Area Deliveries	-2667	-2606	-3106	-5342	-4867
Area Design Flow Req'mts	120795	120888	133863	134470	106615

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	644	642	596	570	566
Flow Into Area	3797	3816	4328	4435	3431
Area Required Receipts	592	574	540	535	532
Area Deliveries	-95	-93	-110	-190	-173
Area Design Flow Req'mts	4287	4291	4751	4773	3784

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	18156	18102	16783	16060	15951
Flow Into Area	112022	123588	128073	99392	104453
Area Required Receipts	17116	16078	15438	14818	15057
Area Deliveries	-1543	-1543	-1662	-1662	-1662
Area Design Flow Req'mts	127376	137916	141651	112357	117654

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	644	642	596	570	566
Flow Into Area	3976	4387	4546	3528	3707
Area Required Receipts	608	571	548	526	534
Area Deliveries	-55	-55	-59	-59	-59
Area Design Flow Req'mts	4521	4895	5028	3988	4176

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill)

$10^3m^3/d$

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	1718	1847	1863	1977	2024
Flow Into Area	125087	119100	122107	115102	108973
Area Required Receipts	1581	1654	1692	1856	1905
Area Deliveries	-8064	-7699	-7573	-7216	-7275
Area Design Flow Req'mts	118584	113034	116205	109719	103579

mmcf/d

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	61	66	66	70	72
Flow Into Area	4440	4227	4334	4085	3868
Area Required Receipts	56	59	60	66	68
Area Deliveries	-286	-273	-269	-256	-258
Area Design Flow Req'mts	4209	4012	4125	3894	3676

$10^3m^3/d$

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	1718	1847	1863	1977	2024
Flow Into Area	120190	116325	110894	104372	99928
Area Required Receipts	1621	1643	1716	1826	1912
Area Deliveries	-8756	-8429	-8536	-8125	-7945
Area Design Flow Req'mts	113034	109518	104051	98049	93870

mmcf/d

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	61	66	66	70	72
Flow Into Area	4266	4129	3936	3705	3547
Area Required Receipts	58	58	61	65	68
Area Deliveries	-311	-299	-303	-288	-282
Area Design Flow Req'mts	4012	3887	3693	3480	3332

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Western Alberta Mainline Design Sub Area

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	10888	10398	12498	17199	18182
Flow Into Area	65805	66285	54182	49139	46655
Area Required Receipts	9995	9279	11316	16112	17082
Area Deliveries	-4363	-4137	-4105	-4719	-4338
Area Design Flow Req'mts	71308	71308	61247	60325	59180

mmcf/d
PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	386	369	444	610	645
Flow Into Area	2336	2353	1923	1744	1656
Area Required Receipts	355	329	402	572	606
Area Deliveries	-155	-147	-146	-168	-154
Area Design Flow Req'mts	2531	2531	2174	2141	2101

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	10897	10408	12507	17207	18190
Flow Into Area	65036	64437	50043	41939	39006
Area Required Receipts	10262	9845	11486	15852	17154
Area Deliveries	-4730	-4402	-4402	-5021	-4591
Area Design Flow Req'mts	70435	69753	56980	52566	51348

mmcf/d
PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	387	369	444	611	646
Flow Into Area	2308	2287	1776	1489	1384
Area Required Receipts	364	349	408	563	609
Area Deliveries	-168	-156	-156	-178	-163
Area Design Flow Req'mts	2500	2476	2022	1866	1823

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Rimbey-Nevis Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	34088	38494	35328	31315	28103
Flow Into Area	0	0	0	0	0
Area Required Receipts	31277	34411	32086	29339	26541
Area Deliveries	-3887	-3894	-3894	-3900	-4949
Area Design Flow Req'mts	26988	30076	27780	25063	21251

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	1210	1366	1254	1111	997
Flow Into Area	0	0	0	0	0
Area Required Receipts	1110	1221	1139	1041	942
Area Deliveries	-138	-138	-138	-138	-176
Area Design Flow Req'mts	958	1067	986	890	754

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	34088	38494	35328	31315	28103
Flow Into Area	0	0	0	0	0
Area Required Receipts	31834	33880	32191	28630	26328
Area Deliveries	-2958	-2958	-2964	-2964	-3979
Area Design Flow Req'mts	28468	30486	28814	25298	22011

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	1210	1366	1254	1111	997
Flow Into Area	0	0	0	0	0
Area Required Receipts	1130	1203	1143	1016	934
Area Deliveries	-105	-105	-105	-105	-141
Area Design Flow Req'mts	1010	1082	1023	898	781

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

South and Alderson Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	9438	8844	10441	10874	11077
Flow Into Area	0	0	0	0	0
Area Required Receipts	9438	8844	10441	10874	11077
Area Deliveries	-48	-54	-54	-54	-62
Area Design Flow Req'mts	9269	8676	10253	10681	10873

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	335	314	371	386	393
Flow Into Area	0	0	0	0	0
Area Required Receipts	335	314	371	386	393
Area Deliveries	-2	-2	-2	-2	-2
Area Design Flow Req'mts	329	308	364	379	386

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	9438	8844	10441	10874	11077
Flow Into Area	0	0	0	0	0
Area Required Receipts	9438	8844	10441	10874	11077
Area Deliveries	-38	-44	-48	-48	-52
Area Design Flow Req'mts	9279	8686	10259	10687	10883

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	335	314	371	386	393
Flow Into Area	0	0	0	0	0
Area Required Receipts	335	314	371	386	393
Area Deliveries	-1	-2	-2	-2	-2
Area Design Flow Req'mts	329	308	364	379	386

PS = Peak Summer
PW = Peak Winter

Design Flow Requirements

Medicine Hat Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	7663	7362	7059	7563	7768
Flow Into Area	0	0	0	0	0
Area Required Receipts	7663	7362	7059	7563	7768
Area Deliveries	-6726	-6726	-7029	-7053	-7053
Area Design Flow Req'mts	839	542	-61	412	615

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	272	261	251	268	276
Flow Into Area	0	0	0	0	0
Area Required Receipts	272	261	251	268	276
Area Deliveries	-239	-239	-249	-250	-250
Area Design Flow Req'mts	30	19	-2	15	22

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	7663	7362	7059	7563	7768
Flow Into Area	0	0	0	0	0
Area Required Receipts	7663	7362	7059	7563	7768
Area Deliveries	-5343	-5343	-5690	-5762	-5993
Area Design Flow Req'mts	2222	1925	1278	1704	1675

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
FS Productive Capability	272	261	251	268	276
Flow Into Area	0	0	0	0	0
Area Required Receipts	272	261	251	268	276
Area Deliveries	-190	-190	-202	-205	-213
Area Design Flow Req'mts	79	68	45	60	59

PS = Peak Summer
PW = Peak Winter

APPENDIX 4.2

PEAK EXPECTED FLOWS

The following tables present both the winter and summer peak expected flows for areas governed by a receipt dominant flow condition.

The Peak Expected Flows, described as Area Peak Expected Flows in the tables, are calculated by subtracting the Area Minimum Deliveries and area fuel (not shown) from the Area Peak Receipts. In some areas, Flow Into Area is added to the Area Peak Receipts and represents the flow from other design areas.

Peak Expected Flows

Upper Peace River Design Sub Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	28819	28004	27303	29586	32231
Flow Into Area	0	0	0	0	0
Area Peak Receipts	28819	28004	27303	29586	32231
Area Deliveries	-13	-13	-13	-13	-13
Area Peak Expected Flow	28436	27632	26939	29194	31804

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1023	994	969	1050	1144
Flow Into Area	0	0	0	0	0
Area Peak Receipts	1023	994	969	1050	1144
Area Deliveries	0	0	0	0	0
Area Peak Expected Flow	1009	981	956	1036	1129

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	28819	28004	27303	29586	32231
Flow Into Area	0	0	0	0	0
Area Peak Receipts	28819	28004	27303	29586	32231
Area Deliveries	-11	-11	-11	-11	-11
Area Peak Expected Flow	28438	27634	26941	29196	31806

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1023	994	969	1050	1144
Flow Into Area	0	0	0	0	0
Area Peak Receipts	1023	994	969	1050	1144
Area Deliveries	0	0	0	0	0
Area Peak Expected Flow	1009	981	956	1036	1129

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

Central Peace River Design Sub Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	23044	23150	24279	27921	30789
Flow Into Area	28436	27632	26939	29194	1804
Area Peak Receipts	23044	23150	24279	27921	30789
Area Deliveries	-257	-257	-260	-260	-260
Area Peak Expected Flow	50927	50228	50647	56496	31938

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	818	822	862	991	1093
Flow Into Area	1009	981	956	1036	64
Area Peak Receipts	818	822	862	991	1093
Area Deliveries	-9	-9	-9	-9	-9
Area Peak Expected Flow	1808	1783	1798	2005	1134

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	23044	23150	24279	27921	30789
Flow Into Area	28438	27634	26941	-804	1806
Area Peak Receipts	23044	23150	24279	27921	30789
Area Deliveries	-89	-90	-90	-90	-92
Area Peak Expected Flow	51097	50397	50820	26668	32108

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	818	822	862	991	1093
Flow Into Area	1009	981	956	-29	64
Area Peak Receipts	818	822	862	991	1093
Area Deliveries	-3	-3	-3	-3	-3
Area Peak Expected Flow	1814	1789	1804	947	1140

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

Lower Peace River Design Sub Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	79610	82606	83056	72337	68054
Flow Into Area	50927	50228	50647	56496	31938
Area Peak Receipts	79610	82606	83056	72337	68054
Area Deliveries	-493	-499	-505	-510	-518
Area Peak Expected Flow	129022	131274	132132	127394	98600

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	2826	2932	2948	2568	2415
Flow Into Area	1808	1783	1798	2005	1134
Area Peak Receipts	2826	2932	2948	2568	2415
Area Deliveries	-18	-18	-18	-18	-18
Area Peak Expected Flow	4579	4659	4690	4522	3500

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	79610	82606	83056	72337	68054
Flow Into Area	51097	50397	50820	26668	32108
Area Peak Receipts	79610	82606	83056	72337	68054
Area Deliveries	-267	-268	-268	-268	-269
Area Peak Expected Flow	129418	131675	132541	97808	99019

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	2826	2932	2948	2568	2415
Flow Into Area	1814	1789	1804	947	1140
Area Peak Receipts	2826	2932	2948	2568	2415
Area Deliveries	-9	-10	-10	-10	-10
Area Peak Expected Flow	4594	4674	4704	3472	3515

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

Marten Hills Design Area

$10^3m^3/d$

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	8623	10267	10113	8956	8247
Flow Into Area	0	0	0	0	0
Area Peak Receipts	8623	10267	10113	8956	8247
Area Deliveries	-176	-176	-177	-177	-183
Area Peak Expected Flow	8337	9959	9807	8665	7958

mmcf/d

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	306	364	359	318	293
Flow Into Area	0	0	0	0	0
Area Peak Receipts	306	364	359	318	293
Area Deliveries	-6	-6	-6	-6	-6
Area Peak Expected Flow	296	353	348	308	282

$10^3m^3/d$

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	8623	10267	10113	8956	8247
Flow Into Area	0	0	0	0	0
Area Peak Receipts	8623	10267	10113	8956	8247
Area Deliveries	-58	-58	-58	-58	-59
Area Peak Expected Flow	8455	10078	9925	8783	8082

mmcf/d

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	306	364	359	318	293
Flow Into Area	0	0	0	0	0
Area Peak Receipts	306	364	359	318	293
Area Deliveries	-2	-2	-2	-2	-2
Area Peak Expected Flow	300	358	352	312	287

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

North of Bens Lake Design Area

$10^3m^3/d$

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	28884	27966	26098	24989	23894
Flow Into Area	4000	4000	4000	4000	34000
Area Peak Receipts	28884	27966	26098	24989	23894
Area Deliveries	-26500	-28336	-32645	-33378	-35563
Area Peak Expected Flow	6013	3271	-2883	-4710	22025

mmcf/d

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1025	993	926	887	848
Flow Into Area	142	142	142	142	1207
Area Peak Receipts	1025	993	926	887	848
Area Deliveries	-941	-1006	-1159	-1185	-1262
Area Peak Expected Flow	213	116	-102	-167	782

$10^3m^3/d$

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	28884	27966	26098	24989	23894
Flow Into Area	4000	4000	4000	34000	34000
Area Peak Receipts	28884	27966	26098	24989	23894
Area Deliveries	-21533	-24578	-28160	-28841	-31073
Area Peak Expected Flow	10980	7030	1603	29827	26515

mmcf/d

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1025	993	926	887	848
Flow Into Area	142	142	142	1207	1207
Area Peak Receipts	1025	993	926	887	848
Area Deliveries	-764	-872	-999	-1024	-1103
Area Peak Expected Flow	390	250	57	1059	941

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

South of Bens Lake Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	23393	24474	22453	22289	21781
Flow Into Area	10513	7771	1618	-210	26525
Area Peak Receipts	23393	24474	22453	22289	21781
Area Deliveries	-66	-66	-71	-71	-71
Area Peak Expected Flow	33540	31865	23711	21722	47955

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	830	869	797	791	773
Flow Into Area	373	276	57	-7	941
Area Peak Receipts	830	869	797	791	773
Area Deliveries	-2	-2	-3	-3	-3
Area Peak Expected Flow	1190	1131	842	771	1702

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	23393	24474	22453	22289	21781
Flow Into Area	15480	11530	6103	34327	31015
Area Peak Receipts	23393	24474	22453	22289	21781
Area Deliveries	-16	-16	-21	-21	-21
Area Peak Expected Flow	38558	35674	28247	56309	52496

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	830	869	797	791	773
Flow Into Area	549	409	217	1218	1101
Area Peak Receipts	830	869	797	791	773
Area Deliveries	-1	-1	-1	-1	-1
Area Peak Expected Flow	1369	1266	1003	1999	1863

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

Edson Mainline Design Sub Area

$10^3m^3/d$

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	50233	48340	52247	54118	55299
Flow Into Area	133359	137233	137939	132059	102559
Area Peak Receipts	50233	48340	52247	54118	55299
Area Deliveries	-2	-2	-2	-2	-2
Area Peak Expected Flow	182946	184952	189514	185481	157146

mmcf/d

PW					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1783	1716	1854	1921	1963
Flow Into Area	4733	4871	4896	4687	3640
Area Peak Receipts	1783	1716	1854	1921	1963
Area Deliveries	0	0	0	0	0
Area Peak Expected Flow	6493	6565	6727	6583	5578

$10^3m^3/d$

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	51091	49168	53024	54844	55974
Flow Into Area	133873	137753	138467	102592	103101
Area Peak Receipts	51091	49168	53024	54844	55974
Area Deliveries	-2	-2	-2	-2	-2
Area Peak Expected Flow	184307	186288	190808	156730	158356

mmcf/d

PS					
Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1813	1745	1882	1947	1987
Flow Into Area	4752	4889	4915	3641	3659
Area Peak Receipts	1813	1745	1882	1947	1987
Area Deliveries	0	0	0	0	0
Area Peak Expected Flow	6542	6612	6773	5563	5621

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

Rimbey-Nevis Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	36207	41063	38122	33568	30063
Flow Into Area	0	0	0	0	0
Area Peak Receipts	36207	41063	38122	33568	30063
Area Deliveries	-3887	-3894	-3894	-3900	-4949
Area Peak Expected Flow	31856	36643	33739	29238	24729

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1285	1457	1353	1191	1067
Flow Into Area	0	0	0	0	0
Area Peak Receipts	1285	1457	1353	1191	1067
Area Deliveries	-138	-138	-138	-138	-176
Area Peak Expected Flow	1131	1301	1198	1038	878

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	36207	41063	38122	33568	30063
Flow Into Area	0	0	0	0	0
Area Peak Receipts	36207	41063	38122	33568	30063
Area Deliveries	-2958	-2958	-2964	-2964	-3979
Area Peak Expected Flow	32785	37578	34668	30173	25699

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	1285	1457	1353	1191	1067
Flow Into Area	0	0	0	0	0
Area Peak Receipts	1285	1457	1353	1191	1067
Area Deliveries	-105	-105	-105	-105	-141
Area Peak Expected Flow	1164	1334	1231	1071	912

PS = Peak Summer
PW = Peak Winter

Peak Expected Flows

South and Alderson Design Area

$10^3m^3/d$

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	13508	12793	15099	15840	16162
Flow Into Area	0	0	0	0	0
Area Peak Receipts	13508	12793	15099	15840	16162
Area Deliveries	-48	-54	-54	-54	-62
Area Peak Expected Flow	13287	12575	14851	15583	15893

mmcf/d

PW

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	479	454	536	562	574
Flow Into Area	0	0	0	0	0
Area Peak Receipts	479	454	536	562	574
Area Deliveries	-2	-2	-2	-2	-2
Area Peak Expected Flow	472	446	527	553	564

$10^3m^3/d$

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	13508	12793	15099	15840	16162
Flow Into Area	0	0	0	0	0
Area Peak Receipts	13508	12793	15099	15840	16162
Area Deliveries	-38	-44	-48	-48	-52
Area Peak Expected Flow	13297	12585	14857	15589	15903

mmcf/d

PS

Gas Year	2006/07	2007/08	2008/09	2009/10	2010/11
Peak Productive Capability	479	454	536	562	574
Flow Into Area	0	0	0	0	0
Area Peak Receipts	479	454	536	562	574
Area Deliveries	-1	-2	-2	-2	-2
Area Peak Expected Flow	472	447	527	553	564

PS = Peak Summer
PW = Peak Winter

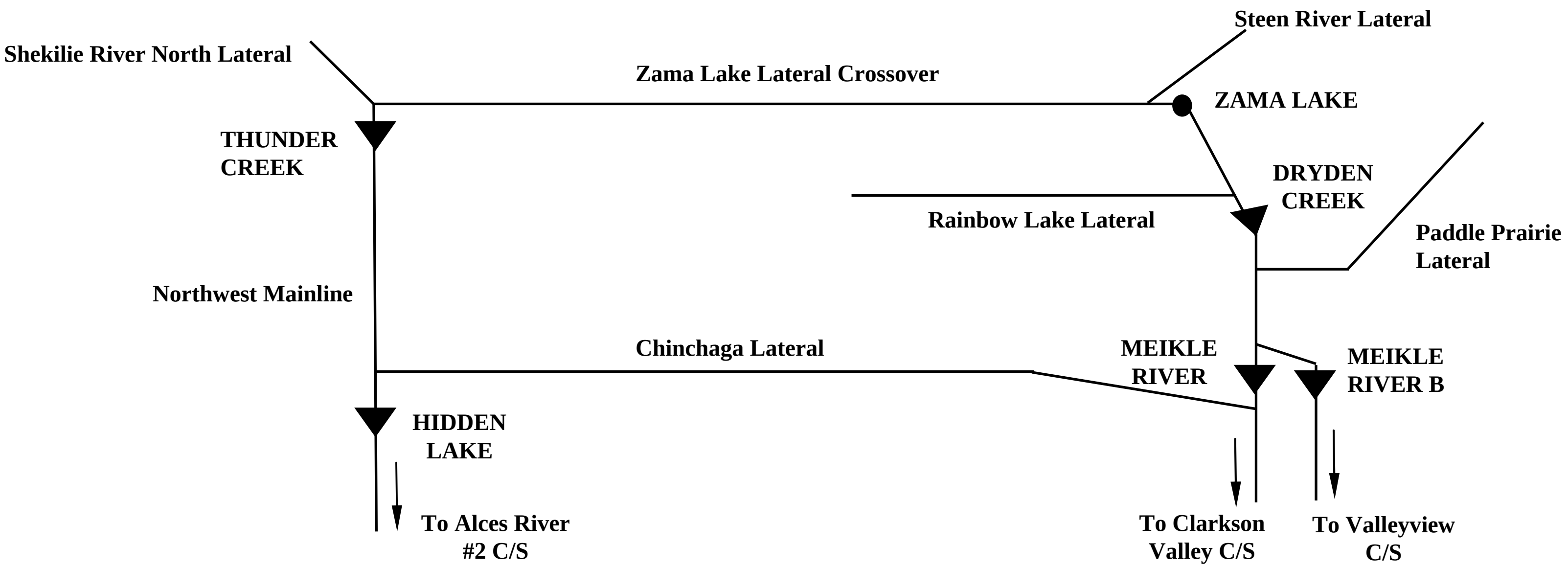
APPENDIX 5

FLOW SCHEMATICS

Flow schematics for each of the design areas are presented for each applicable season and Gas Year.

The flow schematics may differ from the design flow requirements shown in Appendix 4. This is because the detailed flow schematic information is taken directly from the hydraulic simulations whereas design flow requirements are estimated for the entire design area.

2007/08 GAS YEAR
UPPER PEACE RIVER DESIGN SUB AREA
WINTER DESIGN



LEGEND

● EXISTING RECEIPT POINTS
■ EXISTING DELIVERY POINTS
▲ EXISTING COMPRESSION
— EXISTING PIPELINE (NGTL)

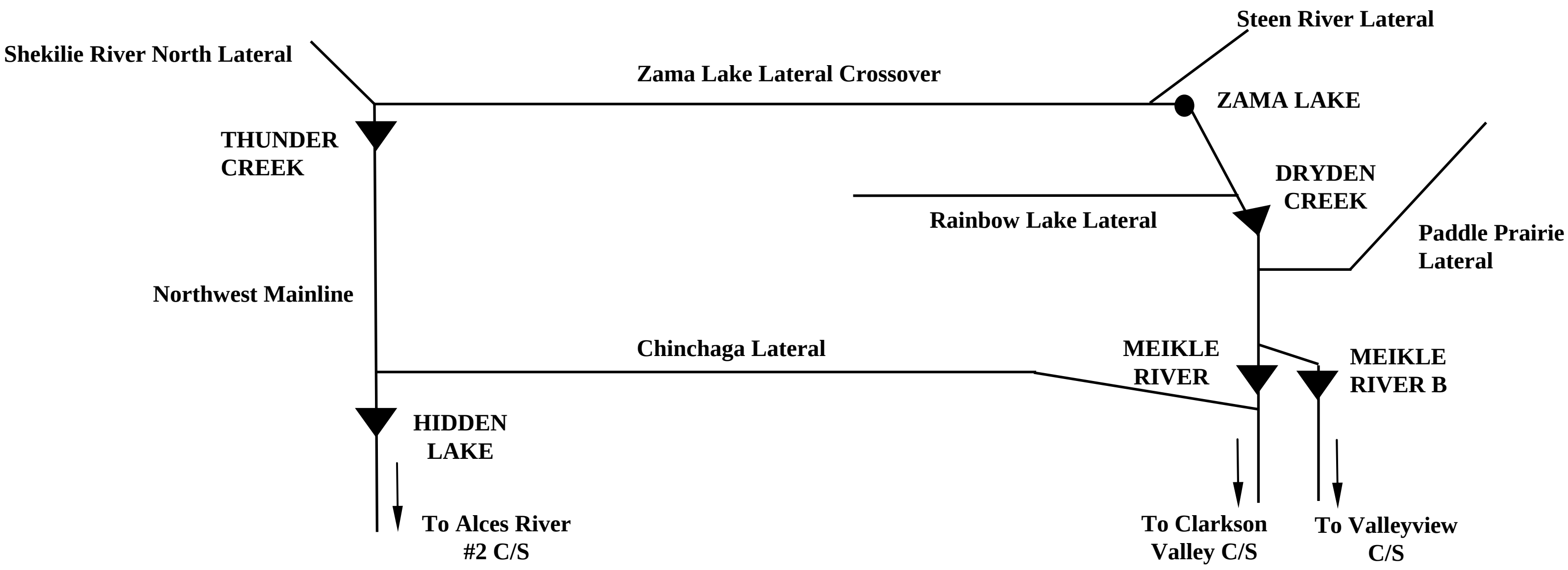
COMPRESSOR STATION SUMMARY

	THUNDER CREEK	HIDDEN LAKE	DRYDEN CREEK	MEIKLE RIVER	MEIKLE RIVER B
P_{sct} (kPa$_g$)	8124	7476	5176	4515	4515
P_{dis} (kPa$_g$)	8123	7475	5655	5650	5428
Flow ($10^6 m^3$/d @ STP)	5.2	13.5	4.4	5.4	0
Fuel ($10^3 m^3$/d @ STP)	0	0	6	21	0
Power Avail (MW)	2.8	9.3	3.4	6.5	3.3
Power Req'd (MW)	0.0	0.0	0.6	1.8	0.0
Compression Ratio	N/A	N/A	1.09	1.25	N/A
T_{sct} (°C)	4.7	4.4	3.1	2.3	4.0
T_{dis} (°C)	4.7	4.4	11.2	22.0	4.0
T_{amb} (°C)	-1.0	1.0	0.0	0.0	0.0

NOTES:

- NOT ALL EXISTING RECEIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS

2007/08 GAS YEAR
UPPER PEACE RIVER DESIGN SUB AREA
SUMMER DESIGN



LEGEND

● EXISTING RECEIPT POINTS
■ EXISTING DELIVERY POINTS
▲ EXISTING COMPRESSION
— EXISTING PIPELINE (NGTL)

NOTES:
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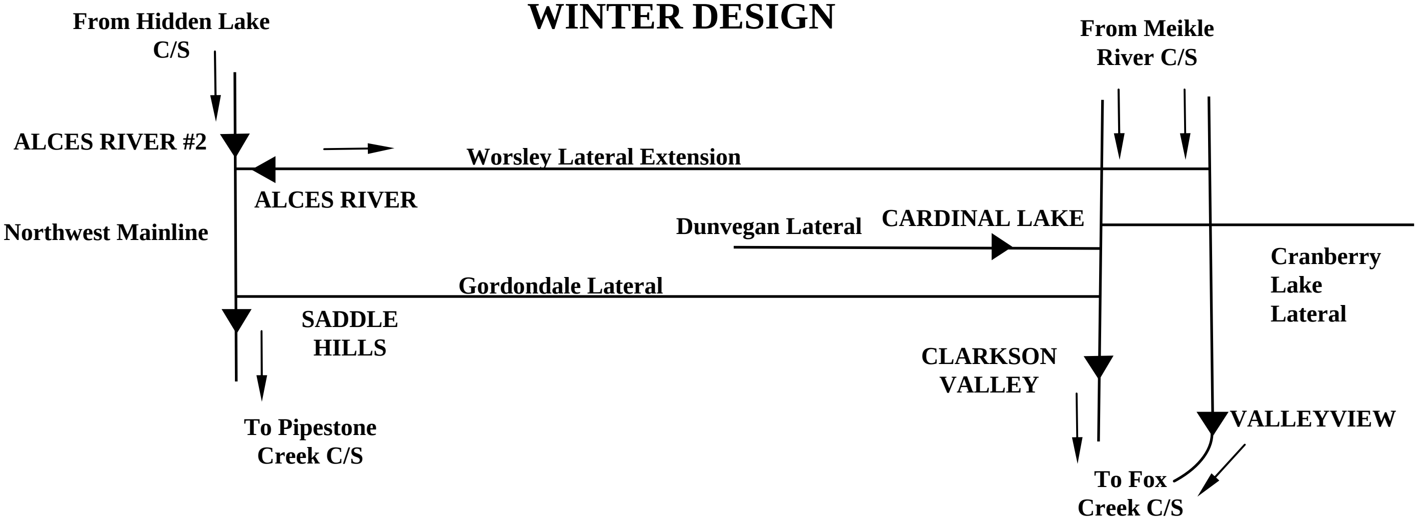
COMPRESSOR STATION SUMMARY

	THUNDER CREEK	HIDDEN LAKE	DRYDEN CREEK	MEIKLE RIVER	MEIKLE RIVER B
P_{sct} (kPa_g)	8031	7260	5076	4214	4214
P_{dis} (kPa_g)	8030	7259	5655	5650	5364
Flow ($10^6 m^3/d$ @ STP)	5.8	14.9	4.8	5.9	0
Fuel ($10^3 m^3/d$ @ STP)	0	0	8	29	0
Power Avail (MW)	2.6	8.1	3.0	5.7	2.9
Power Req'd (MW)	0.0	0.0	0.8	2.6	0.0
Compression Ratio	N/A	N/A	1.11	1.33	N/A
T_{sct} (°C)	13.3	12.8	12.7	11.7	14.0
T_{dis} (°C)	13.3	12.8	22.9	38.3	14.0
T_{amb} (°C)	19.0	19.0	19.0	19.0	19.0

2007/08 GAS YEAR
CENTRAL PEACE RIVER DESIGN SUB AREA
WINTER DESIGN



COMPRESSOR STATION SUMMARY

	ALCES RIVER	ALCES RIVER #2	SADDLE HILLS	CARDINAL LAKE	CLARKSON VALLEY	VALLEY-VIEW
P_{sct} (kPa$_g$)	5754	7162	6878	5483	5110	5455
P_{dis} (kPa$_g$)	7160	7161	6876	5482	6303	6128
Flow ($10^6 m^3/d$ @ STP)	0	16.6	16.6	2.8	15.1	0
Fuel ($10^3 m^3/d$ @ STP)	0	0	0	0	58	0
Power Avail (MW)	3.1	10.0	16.2	2.8	15.0	3.0
Power Req'd (MW)	0.0	0.0	0.0	0.0	4.3	0.0
Compression Ratio	N/A	N/A	N/A	N/A	1.23	N/A
T_{sct} (°C)	4.0	5.2	3.4	5.2	2.8	4.0
T_{dis} (°C)	4.0	5.2	3.4	5.2	20.0	4.0
T_{amb} (°C)	1.0	1.0	2.0	2.0	3.0	3.0

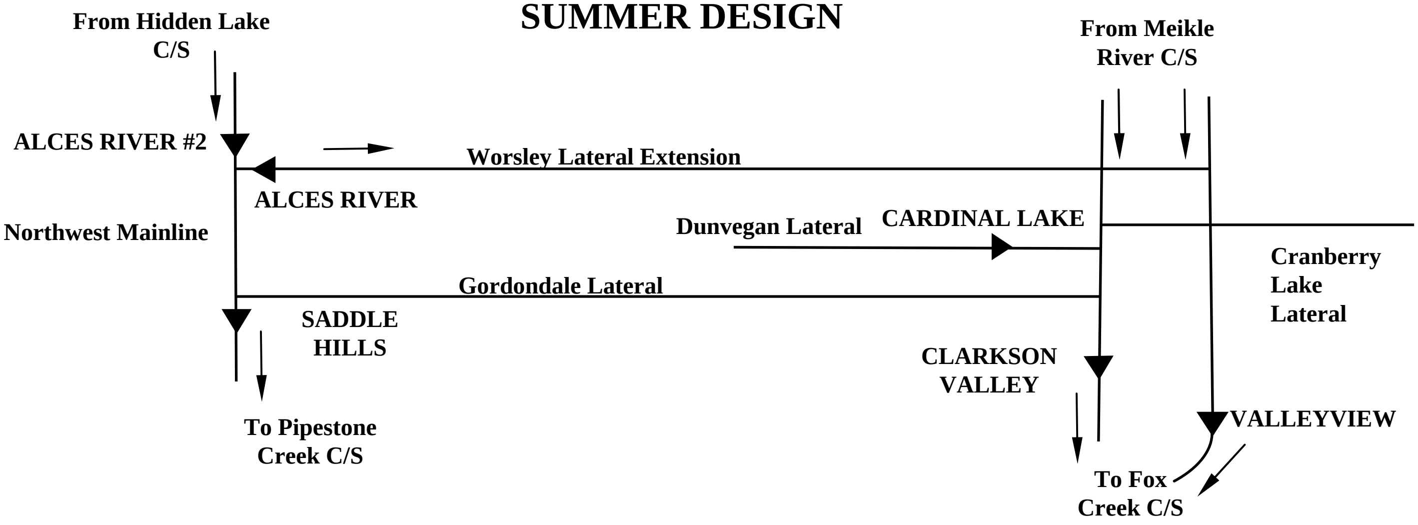
LEGEND

- ● EXISTING RECEIPT POINTS
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- — EXISTING PIPELINE (NGTL)

NOTES:

- NOT ALL EXISTING RECEIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- ALCES RIVER STATION IS OFF, LINE PRESSURES INDICATED

2007/08 GAS YEAR
CENTRAL PEACE RIVER DESIGN SUB AREA
SUMMER DESIGN



LEGEND

● EXISTING RECEIPT POINTS
■ EXISTING DELIVERY POINTS
▲ EXISTING COMPRESSION
— EXISTING PIPELINE (NGTL)

NOTES:
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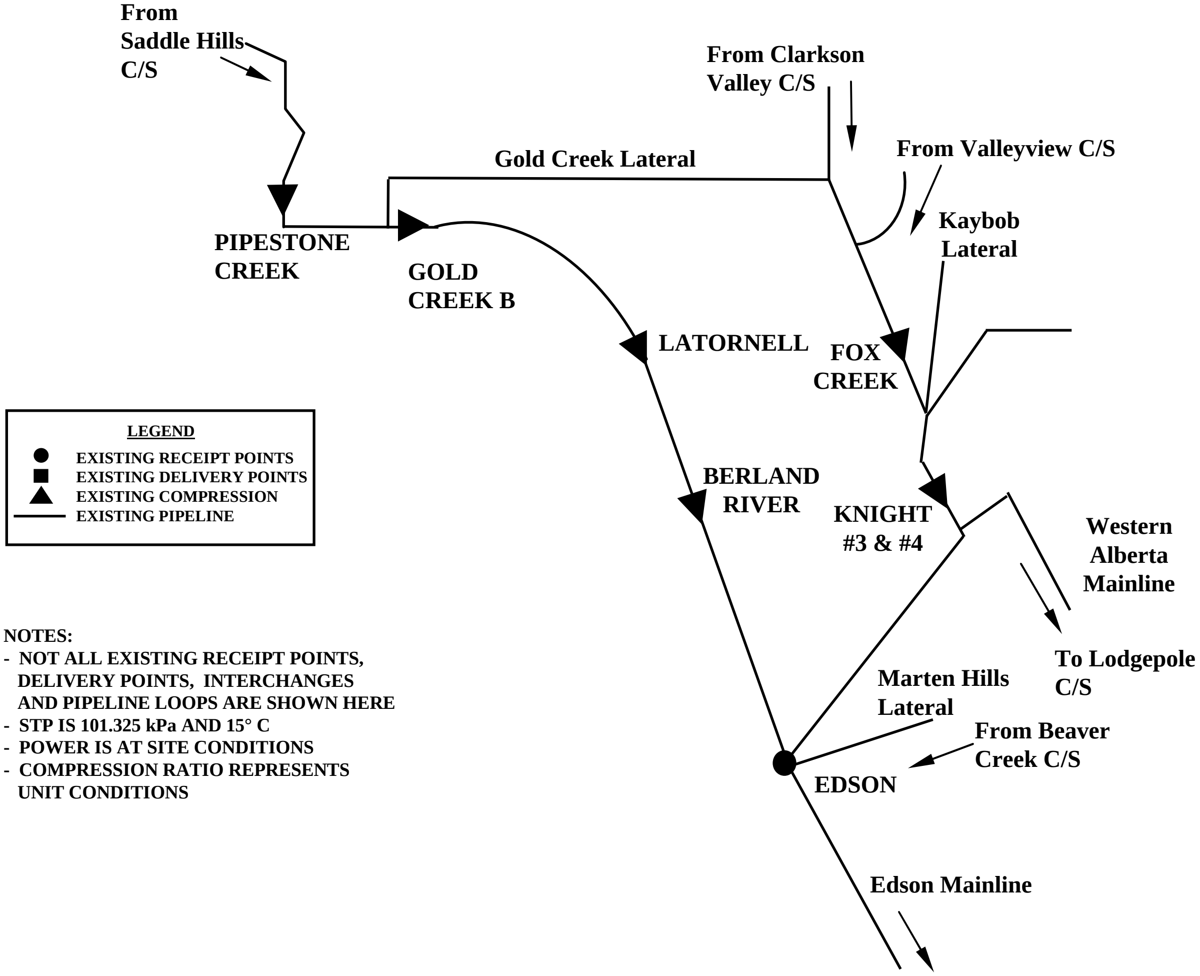
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- ALCES RIVER STATION IS OFF, LINE PRESSURES INDICATED

COMPRESSOR STATION SUMMARY

	ALCES RIVER	ALCES RIVER #2	SADDLE HILLS	CARDINAL LAKE	CLARKSON VALLEY	VALLEY-VIEW
P_{sct} (kPa$_g$)	5775	6824	6434	5414	4931	5389
P_{dis} (kPa$_g$)	6820	6822	6432	5413	6308	6071
Flow ($10^6 m^3/d$ @ STP)	0	18.4	18.4	3.1	16.7	0
Fuel ($10^3 m^3/d$ @ STP)	0	0	0	0	72	0
Power Avail (MW)	2.8	9.2	14.6	2.8	13.7	2.6
Power Req'd (MW)	0.0	0.0	0.0	0.0	5.9	0.0
Compression Ratio	N/A	N/A	N/A	N/A	1.27	N/A
T_{sct} (°C)	14.0	13.5	12.6	14.7	12.4	14.0
T_{dis} (°C)	14.0	13.5	12.6	14.7	33.4	14.0
T_{amb} (°C)	19.0	19.0	19.0	19.0	19.0	19.0

2007/08 GAS YEAR
LOWER PEACE RIVER DESIGN SUB AREA
WINTER DESIGN



NOTES:
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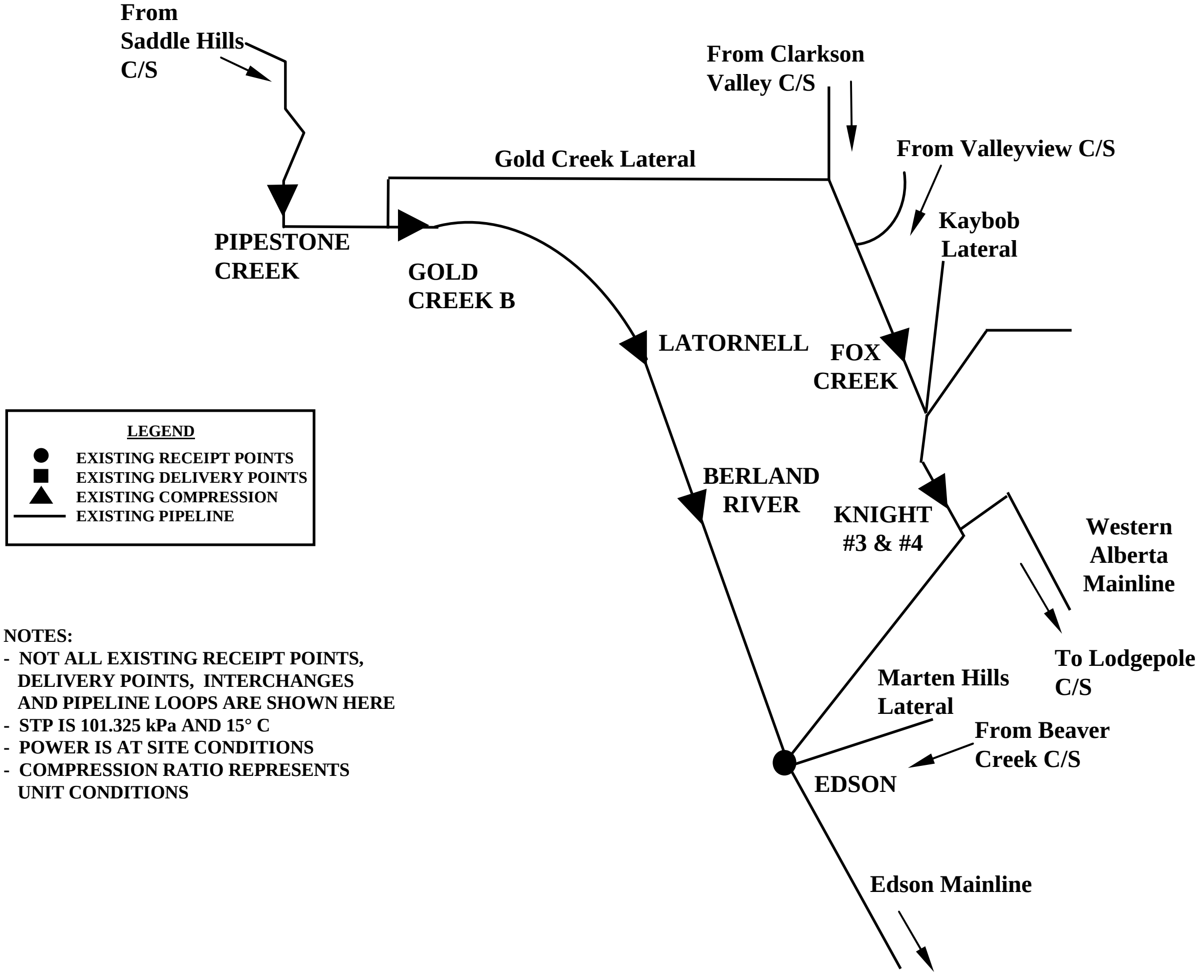
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS

COMPRESSOR STATION SUMMARY

	PIPESTONE CREEK	GOLD CREEK B	LATOR-NELL	BERLAND RIVER	FOX CREEK	KNIGHT #3 & #4
P_{sct} (kPa$_g$)	6760	6289	7444	7067	5689	5294
P_{dis} (kPa$_g$)	6759	8201	7442	8260	5687	5293
Flow ($10^6 m^3/d$ @ STP)	20.2	45.3	45.5	52.5	18.4	21.2
Fuel ($10^3 m^3/d$ @ STP)	0	148	0	103	0	0
Power Avail (MW)	28.0	34.1	27.6	24.0	11.5	26.1
Power Req'd (MW)	0.0	16.7	0.0	11.9	0.0	0.0
Compression Ratio	N/A	1.30	N/A	1.17	N/A	N/A
T_{sct} (°C)	4.0	6.5	17.6	11.4	5.8	2.6
T_{dis} (°C)	4.0	28.8	17.6	24.9	5.7	2.6
T_{amb} (°C)	3.0	3.0	3.0	3.0	3.0	3.0

2007/08 GAS YEAR
LOWER PEACE RIVER DESIGN SUB AREA
SUMMER DESIGN



NOTES:
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- STP IS 101.325 kPa AND 15° C
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS

COMPRESSOR STATION SUMMARY

	PIPESTONE CREEK	GOLD CREEK B	LATOR-NELL	BERLAND RIVER	FOX CREEK	KNIGHT #3 & #4
P_{sct} (kPa_g)	6260	5566	7100	6589	5523	5061
P_{dis} (kPa_g)	6259	8058	7098	8268	5521	6133
Flow ($10^6 m^3/d$ @ STP)	22.6	50.3	50.3	58.0	20.7	23.6
Fuel ($10^3 m^3/d$ @ STP)	0	202	0	142	0	63
Power Avail (MW)	25.1	30.9	25.2	21.8	10.3	23.5
Power Req'd (MW)	0.0	27.4	0.0	19.9	0.0	6.4
Compression Ratio	N/A	1.44	N/A	1.25	N/A	1.21
T_{sct} (°C)	13.6	14.1	31.6	22.3	16.3	12.0
T_{dis} (°C)	13.6	44.8	31.6	42.5	16.3	28.2
T_{amb} (°C)	19.0	18.0	18.0	18.0	18.0	18.0

2007/08 GAS YEAR
MARTEN HILLS DESIGN AREA
WINTER DESIGN

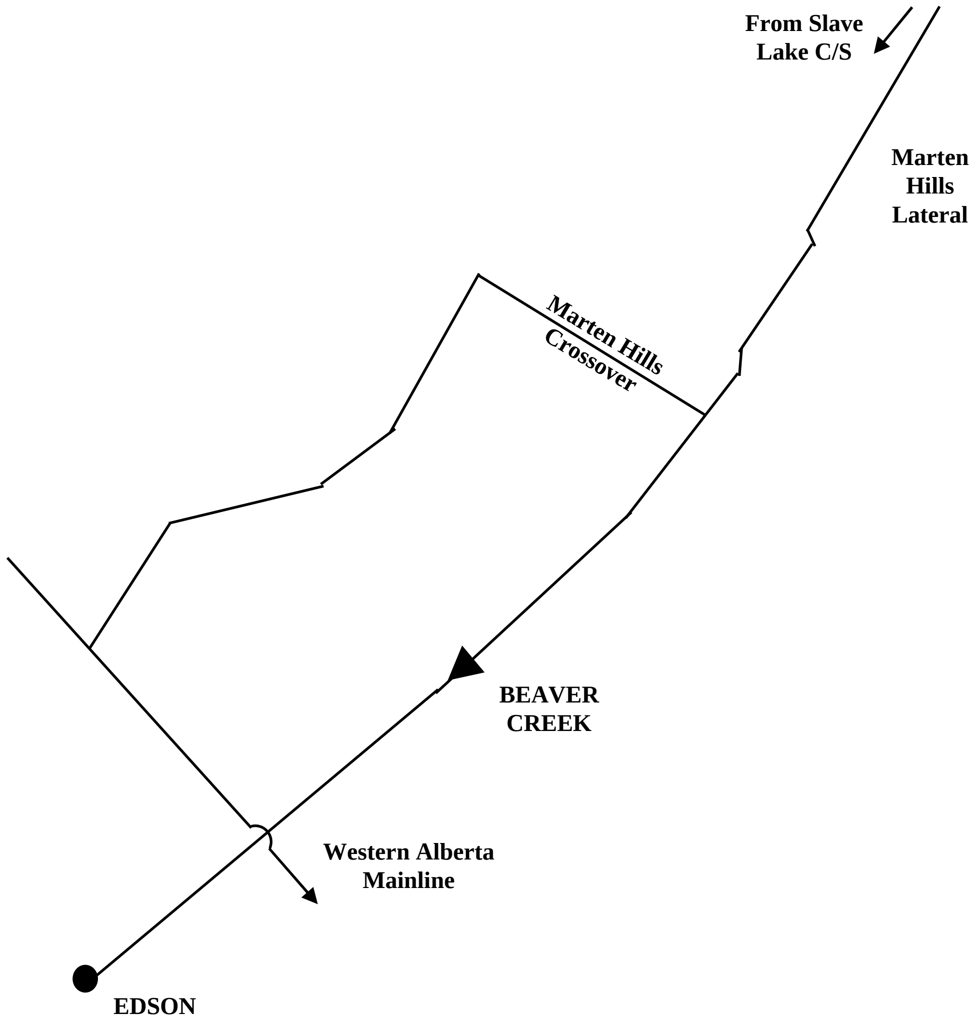
COMPRESSOR STATION SUMMARY

	BEAVER CREEK
P_{sct} (kPa$_g$)	6051
P_{dis} (kPa$_g$)	6360
Flow ($10^6 m^3$/d @ STP)	5.2
Fuel ($10^3 m^3$/d @ STP)	10
Power Avail (MW)	2.8
Power Req'd (MW)	0.5
Compression Ratio	1.05
T_{sct} (°C)	4.7
T_{dis} (°C)	10.4
T_{amb} (°C)	3.0

LEGEND

●	EXISTING RECEIPT POINTS
▲	EXISTING COMPRESSION
—	EXISTING PIPELINE (NGTL)

NOTE:
- NOT ALL EXISTING RECEIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS



2007/08 GAS YEAR
MARTEN HILLS DESIGN AREA
SUMMER DESIGN

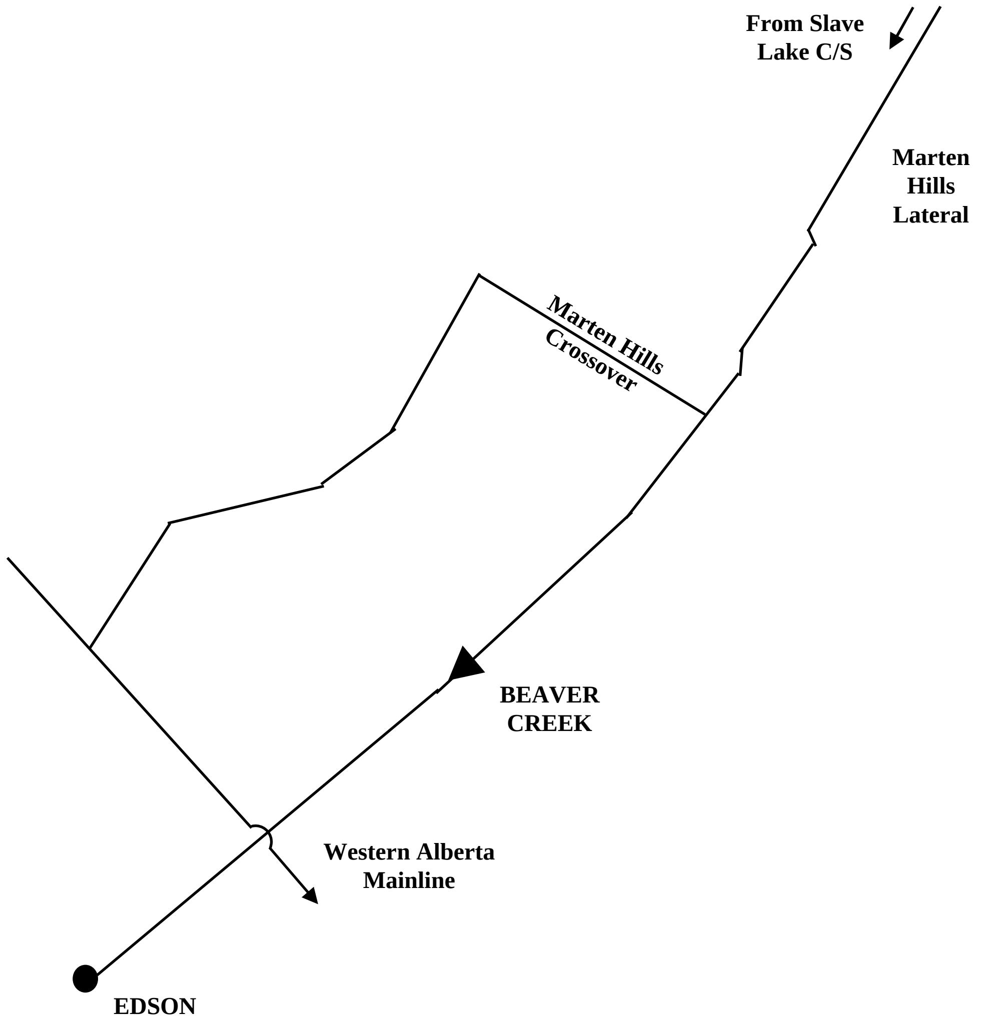
COMPRESSOR STATION SUMMARY

	BEAVER CREEK
P_{sct} (kPa$_g$)	6015
P_{dis} (kPa$_g$)	7354
Flow (10^{6}m^3/d @ STP)	5.8
Fuel (10^{3}m^3/d @ STP)	24
Power Avail (MW)	2.6
Power Req'd (MW)	1.9
Compression Ratio	1.22
T_{sct} (°C)	10.0
T_{dis} (°C)	29.0
T_{amb} (°C)	18.0

LEGEND

● EXISTING RECEIPT POINTS
▲ EXISTING COMPRESSION
— EXISTING PIPELINE (NGTL)

NOTE:
- NOT ALL EXISTING RECEIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS



2007/08 GAS YEAR
NORTH OF BENS LAKE DESIGN AREA
WINTER DESIGN

COMPRESSOR STATION SUMMARY

	FIELD LAKE	HANMORE LAKE	BENS LAKE A	BENS LAKE B	BENS LAKE C,D	SMOKY LAKE D
P_{sct}(kPa$_g$)	7433	7458	6006	7501	7499	7516
P_{dis}(kPa$_g$)	8501	7458	6005	7501	7499	7516
Flow ($10^6 m^3$/d @ STP)	4.1	3.9	0.8	3.0	1.5	0.3
Fuel ($10^3 m^3$/d @ STP)	10	0	0	0	0	0
Power Avail (MW)	6.3	6.5	14.4	3.2	7.7	15.2
Power Required (MW)	0.8	0.0	0.0	0.0	0.0	0.0
Compression Ratio	1.14	N/A	N/A	N/A	N/A	N/A
T_{sct} (˚C)	4.8	4.8	5.0	5.1	5.0	5.0
T_{dis} (˚C)	16.7	4.8	5.0	5.1	5.0	5.0
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	2.0

	PELICAN LAKE	WOODEN HOUSE	BUFFALO NORTH	WAND. RIVER	LEISMER	SLAVE LAKE
P_{sct}(kPa$_g$)	6557	7388	7287	7313	6857	4542
P_{dis}(kPa$_g$)	8979	7387	7283	7312	6856	6017
Flow ($10^6 m^3$/d @ STP)	5.4	5.4	10.9	2.2	2.6	5.2
Fuel ($10^3 m^3$/d @ STP)	22	0	0	0	0	30
Power Avail (MW)	2.9	10.6	5.0	2.9	0.9	3.8
Power Required (MW)	2.2	0.0	0.0	0.0	0.0	2.8
Compression Ratio	1.36	N/A	N/A	N/A	N/A	1.32
T_{sct} (˚C)	4.5	4.6	5.3	4.7	3.5	3.5
T_{dis} (˚C)	30.5	4.6	5.3	4.7	3.4	35.2
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	3.0

LEGEND

- ● EXISTING RECEIPT POINTS
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- ── EXISTING PIPELINE (NGTL)
- ⧓ EXISTING CONTROL VALVE
- - - - OTHER PIPELINE SYSTEMS

NOTE:
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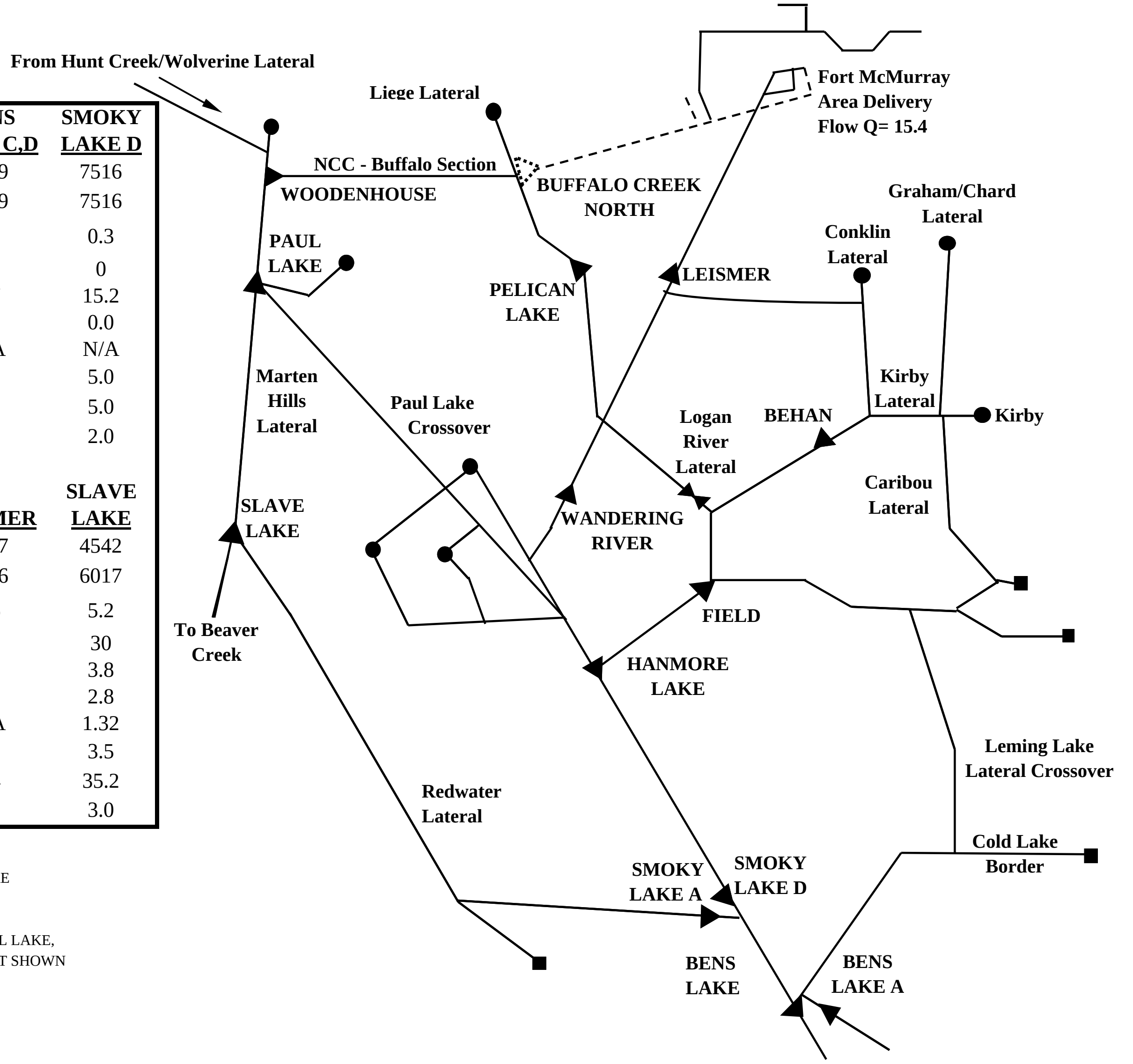
- STP IS 101.325 kPa AND 15° C
- POWER IS AT SITE CONDITIONS
- COMPRESSOR CONDITIONS FOR COMPRESSION AT PAUL LAKE, SMOKY LAKE 'A', HANMORE LAKE 'A', AND BEHAN NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d



2007/08 GAS YEAR
NORTH OF BENS LAKE DESIGN AREA
SUMMER DESIGN WITH PROPOSED 2007/08 SUMMER FACILITIES

COMPRESSOR STATION SUMMARY

	FIELD LAKE	HANMORE LAKE	BENS LAKE A	BENS LAKE B	BENS LAKE C,D	SMOKY LAKE D
P_{sct}(kPa$_g$)	7234	7159	5954	7189	7187	7208
P_{dis}(kPa$_g$)	7234	7159	5953	5953	7187	7208
Flow ($10^6 m^3$/d @ STP)	0.6	0.0	0.7	0.0	2.8	1.8
Fuel ($10^3 m^3$/d @ STP)	0	0	0	0	0	0
Power Avail (MW)	6.1	7.0	13.1	3.3	7.1	16.5
Power Required (MW)	0.0	0.0	0.0	0.0	0.0	0.0
Compression Ratio	N/A	N/A	N/A	0.00	N/A	N/A
T_{sct} (˚C)	11.0	11.0	13.9	14.0	14.0	11.1
T_{dis} (˚C)	11.0	11.0	13.9	14.0	14.0	11.1
T_{amb} (˚C)	19.0	19.0	20.0	20.0	20.0	19.0

	PELICAN LAKE	WOODEN HOUSE	BUFFALO NORTH	WAND. RIVER	LEISMER	SLAVE LAKE	PAUL LAKE #2
P_{sct}(kPa$_g$)	6511	6690	6293	7069	6688	5120	7099
P_{dis}(kPa$_g$)	6511	6689	6290	7069	6688	5122	7099
Flow ($10^6 m^3$/d @ STP)	1.6	8.6	10.6	1.8	2.1	5.4	7.6
Fuel ($10^3 m^3$/d @ STP)	0	0	0	0	0	0	0
Power Avail (MW)	2.8	9.7	4.5	2.8	0.9	3.6	14.1
Power Required (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Compression Ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A
T_{sct} (˚C)	11.2	12.1	9.5	10.8	10.8	10.0	51.4
T_{dis} (˚C)	11.2	12.1	9.5	10.8	10.8	10.0	51.4
T_{amb} (˚C)	20.0	19.0	20.0	20.0	20.0	18.0	19.0

LEGEND

- ● EXISTING RECEIPT POINTS
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- —— EXISTING PIPELINE (NGTL)
- ⋈ EXISTING CONTROL VALVE
- - - - OTHER PIPELINE SYSTEMS
- ········ PROPOSED FACILITIES

NOTE:
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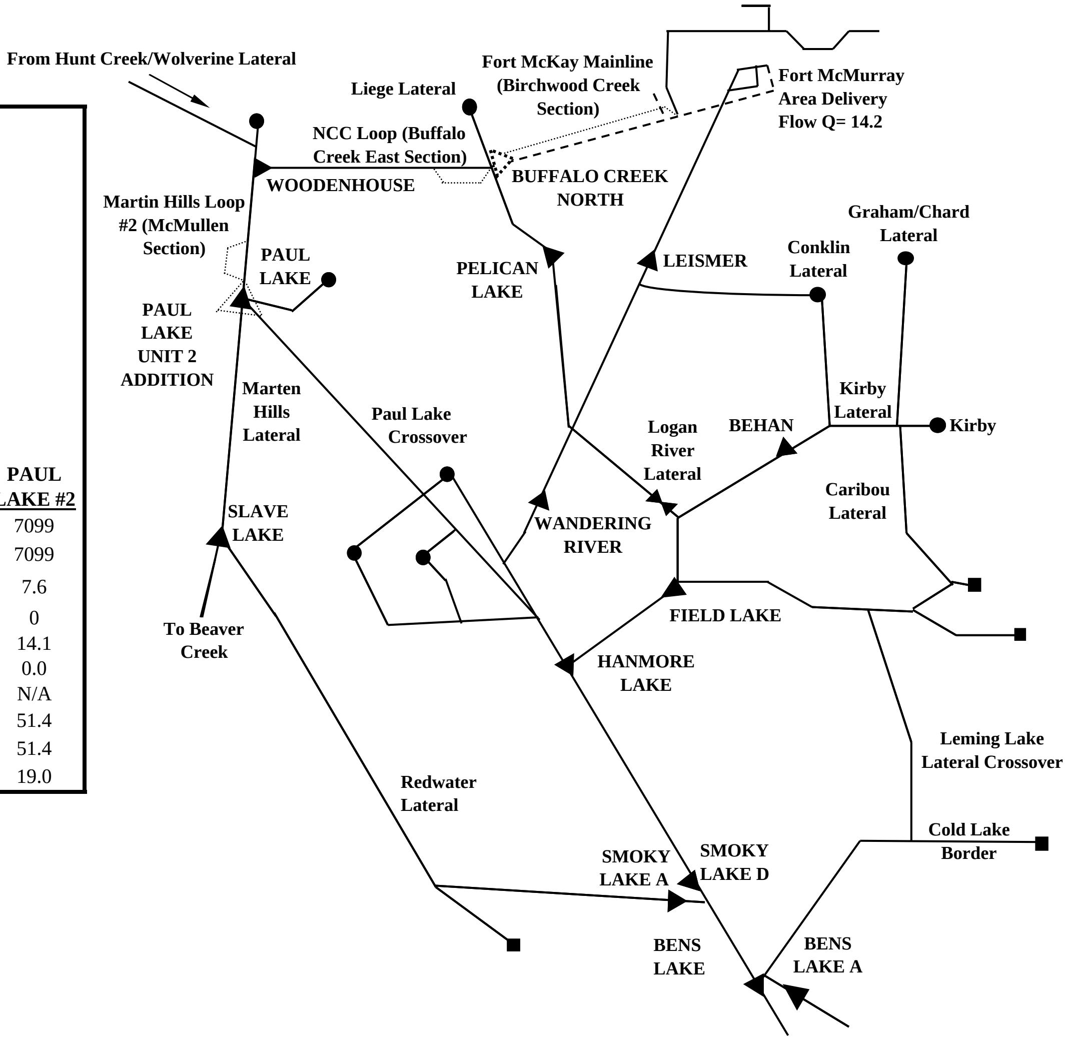
- POWER IS AT SITE CONDITIONS
- COMPRESSOR CONDITIONS FOR COMPRESSION AT PAUL LAKE, SMOKY LAKE 'A', HANMORE LAKE 'A', AND BEHAN NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d
- COMPRESSOR STATIONS WITH ZERO FLOW ARE CONSIDERED BYPASSED

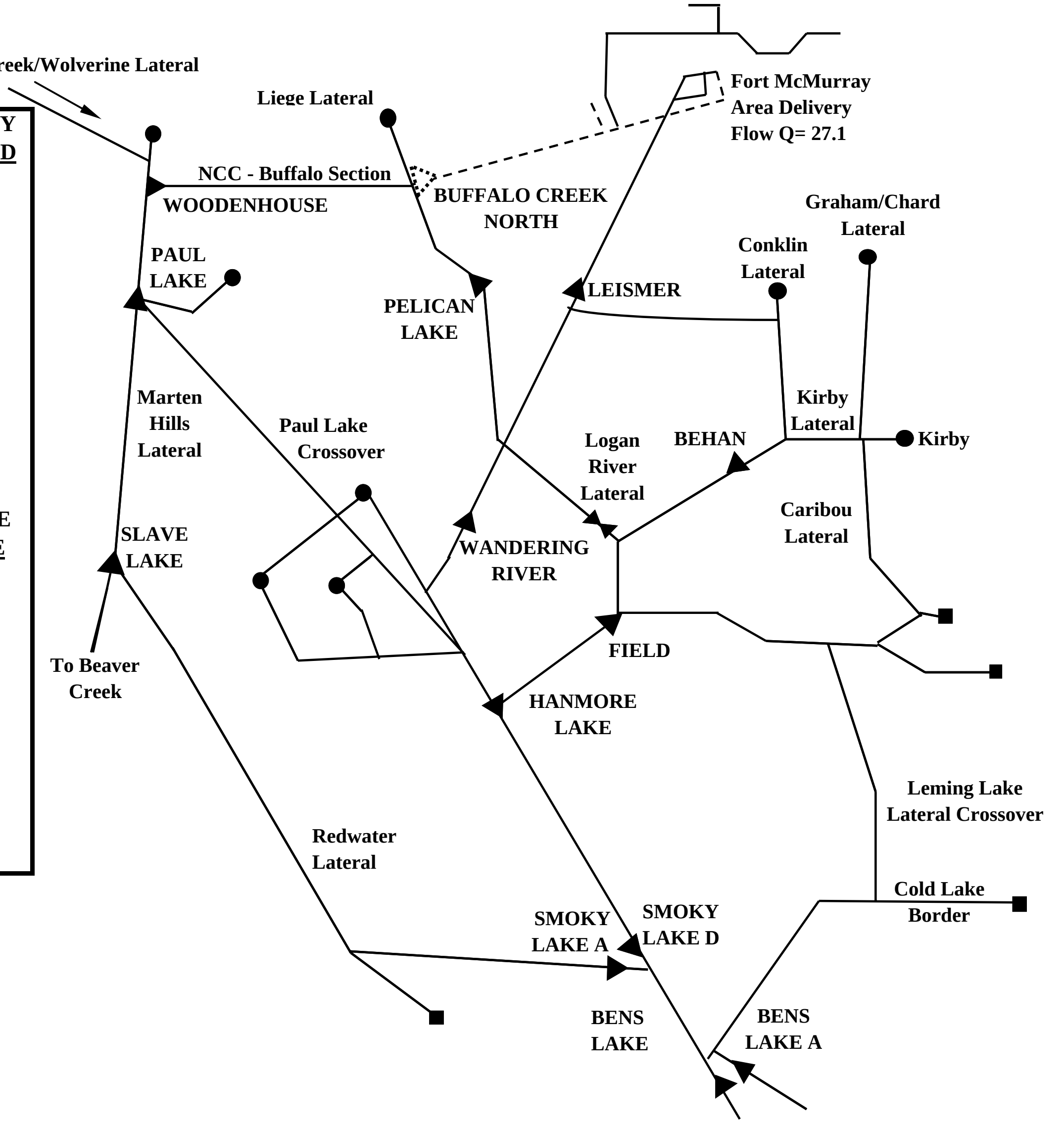


2007/08 GAS YEAR
NORTH OF BENS LAKE DESIGN AREA
WITH MAXIMUM DELIVERIES TO THE FORT MCMURRAY AREA
WINTER DESIGN

COMPRESSOR STATION SUMMARY

	FIELD LAKE	HANMORE LAKE	BENS LAKE A	BENS LAKE B	BENS LAKE C,D	SMOKY LAKE D
P_{sct}(kPa$_g$)	7326	7938	6000	8245	7609	8111
P_{dis}(kPa$_g$)	9462	7938	7646	8259	8379	8108
Flow ($10^6 m^3$/d @ STP)	8.9	0.0	3.0	0.0	29.8	0.0
Fuel ($10^3 m^3$/d @ STP)	28	0	15	0	36	0
Power Avail (MW)	6.3	6.5	14.4	3.2	7.7	15.2
Power Required (MW)	3.0	0.0	1.1	0.0	4.5	0.0
Compression Ratio	1.29	N/A	1.27	N/A	1.10	N/A
T_{sct} (˚C)	3.5	5.3	4.4	16.2	8.3	7.0
T_{dis} (˚C)	24.1	5.3	26.3	16.3	16.7	7.0
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	2.0

	PELICAN LAKE	WOODEN HOUSE	BUFFALO NORTH	WAND. RIVER	LEISMER	SLAVE LAKE
P_{sct}(kPa$_g$)	7221	5937	7855	6578	7231	4067
P_{dis}(kPa$_g$)	9000	9500	9198	9401	8187	6004
Flow ($10^6 m^3$/d @ STP)	4.5	15.1	19.2	5.3	5.0	4.5
Fuel ($10^3 m^3$/d @ STP)	15	72	33	31	11	30
Power Avail (MW)	2.9	10.6	5.0	2.9	0.9	3.8
Power Required (MW)	1.3	8.7	3.8	2.6	0.9	2.8
Compression Ratio	1.24	1.59	1.17	1.42	1.13	1.47
T_{sct} (˚C)	4.9	4.0	14.0	1.7	4.7	3.7
T_{dis} (˚C)	22.7	39.4	26.2	32.0	15.7	40.9
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	3.0



LEGEND

- ● EXISTING RECEIPT POINTS
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- —— EXISTING PIPELINE (NGTL)
- ⋈ EXISTING CONTROL VALVE
- - - - OTHER PIPELINE SYSTEMS

NOTE:
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- POWER IS AT SITE CONDITIONS
- COMPRESSOR CONDITIONS FOR COMPRESSION AT PAUL LAKE, SMOKY LAKE 'A', HANMORE LAKE 'A', AND BEHAN NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d
- COMPRESSOR STATIONS WITH ZERO FLOW ARE CONSIDERED BYPASSED

2007/08 GAS YEAR
NORTH OF BENS LAKE DESIGN AREA
WITH MAXIMUM DELIVERIES TO THE FORT MCMURRAY AREA
SUMMER CAPABILITY WITHOUT PROPOSED 2007/08 SUMMER FACILITIES

COMPRESSOR STATION SUMMARY

	FIELD LAKE	HANMORE LAKE	BENS LAKE A	BENS LAKE B	BENS LAKE C,D	SMOKY LAKE D
P_{sct}(kPa$_g$)	6973	7928	4641	6188	7760	8087
P_{dis}(kPa$_g$)	8886	7928	6224	8191	8251	8085
Flow (10^6m^3/d @ STP)	8.4	0.0	3.6	4.4	20.8	0.0
Fuel (10^3m^3/d @ STP)	27	0	25	23	32	0
Power Avail (MW)	6.1	7.0	13.1	3.3	7.1	16.5
Power Required (MW)	2.8	0.0	1.8	2.3	2.5	0.0
Compression Ratio	1.27	N/A	1.33	1.32	1.06	N/A
T_{sct} (˚C)	8.8	13.1	9.6	35.1	16.4	17.0
T_{dis} (˚C)	29.5	13.1	40.1	31.8	22.3	17.0
T_{amb} (˚C)	19.0	19.0	20.0	20.0	20.0	19.0

	PELICAN LAKE	WOODEN HOUSE	BUFFALO NORTH	WAND. RIVER	LEISMER	SLAVE LAKE
P_{sct}(kPa$_g$)	6294	5947	7639	6473	6510	5691
P_{dis}(kPa$_g$)	9278	9311	8940	8928	7350	6352
Flow (10^6m^3/d @ STP)	5.2	14.8	19.6	5.4	4.6	14.8
Fuel (10^3m^3/d @ STP)	27	80	37	31	11	29
Power Avail (MW)	2.8	9.7	4.5	2.8	0.9	3.6
Power Required (MW)	2.8	9.7	4.5	2.5	0.9	2.7
Compression Ratio	1.47	1.56	1.17	1.37	1.13	1.11
T_{sct} (˚C)	10.4	11.4	20.0	7.6	10.4	11.3
T_{dis} (˚C)	43.9	44.9	33.9	36.2	21.9	22.1
T_{amb} (˚C)	20.0	19.0	20.0	20.0	20.0	18.0

LEGEND

●	EXISTING RECEIPT POINTS
■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
───	EXISTING PIPELINE (NGTL)
⧓	EXISTING CONTROL VALVE
- - -	OTHER PIPELINE SYSTEMS

NOTE:
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- COMPRESSOR CONDITIONS FOR COMPRESSION AT PAUL LAKE, SMOKY LAKE 'A', HANMORE LAKE 'A', AND BEHAN NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d
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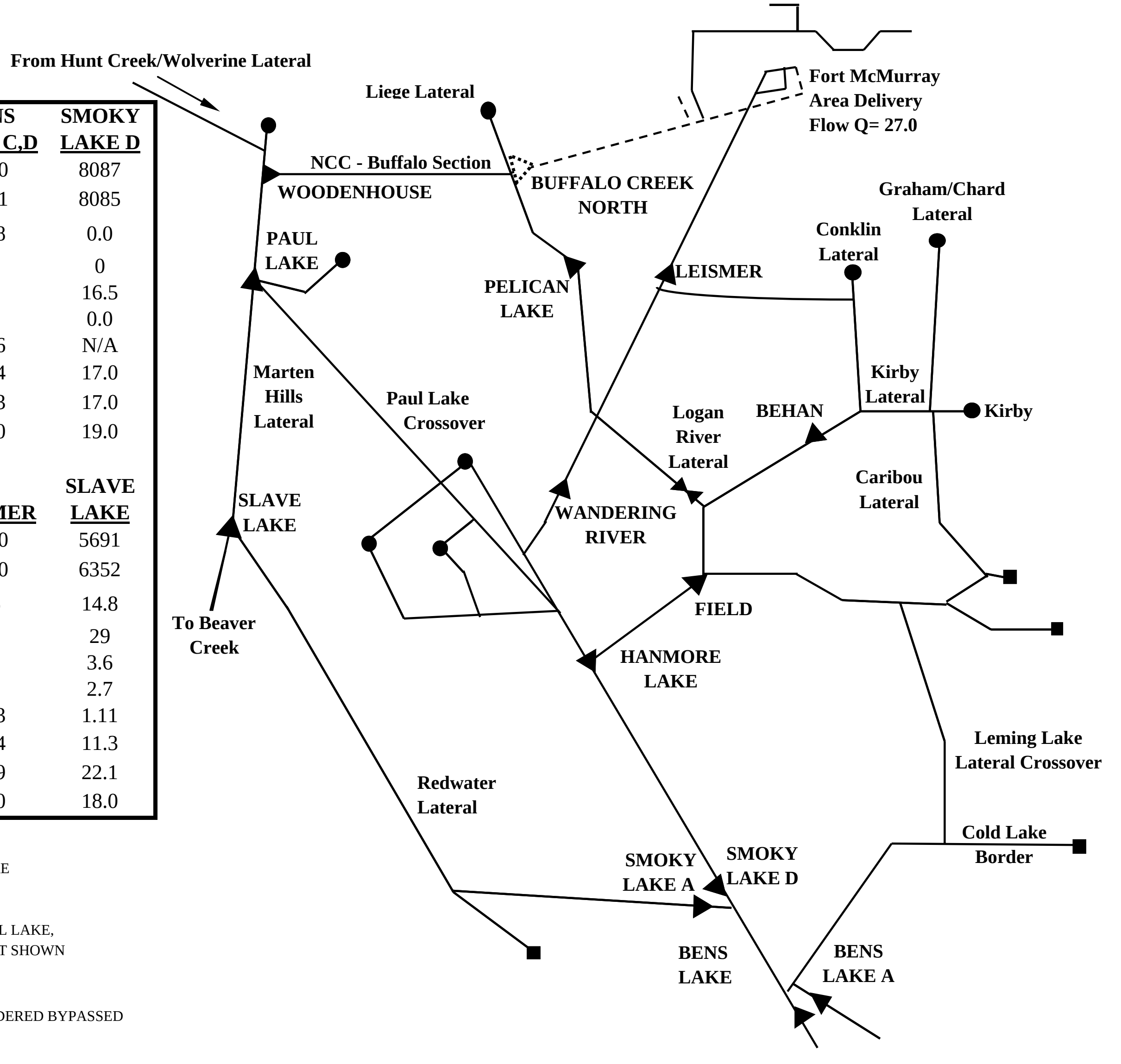

2007/08 GAS YEAR
NORTH OF BENS LAKE DESIGN AREA
WITH MAXIMUM DELIVERIES TO THE FORT MCMURRAY AREA
SUMMER DESIGN WITH PROPOSED 2007/08 SUMMER FACILITIES

COMPRESSOR STATION SUMMARY

	FIELD LAKE	HANMORE LAKE	BENS LAKE A	BENS LAKE B	BENS LAKE C,D	SMOKY LAKE D	
P_{sct}(kPa$_g$)	7015	7861	4653	6232	7453	8085	
P_{dis}(kPa$_g$)	9004	7860	6267	8274	8372	8082	
Flow (10^6m^3/d @ STP)	8.2	0.0	3.6	4.3	26.1	0.0	
Fuel (10^3m^3/d @ STP)	27	0	25	23	52	0	
Power Avail (MW)	6.1	7.0	13.1	3.3	7.1	16.5	
Power Required (MW)	2.8	0.0	1.8	2.3	5.2	0.0	
Compression Ratio	1.28	N/A	1.34	1.32	1.12	N/A	
T_{sct} (˚C)	9.2	13.7	9.8	35.5	16.8	18.3	
T_{dis} (˚C)	30.5	13.7	40.6	34.2	27.2	18.3	
T_{amb} (˚C)	19.0	19.0	20.0	20.0	20.0	19.0	
	PELICAN LAKE	**WOODEN HOUSE**	**BUFFALO NORTH**	**WAND. RIVER**	**LEISMER**	**SLAVE LAKE**	**PAUL LAKE #2**
P_{sct}(kPa$_g$)	6656	7844	7782	6451	6954	5650	7262
P_{dis}(kPa$_g$)	9599	9930	7765	9032	8187	6307	9930
Flow (10^6m^3/d @ STP)	5.6	20.8	26.0	5.1	3.5	14.8	19.5
Fuel (10^3m^3/d @ STP)	27	58	0	30	11	29	92
Power Avail (MW)	2.8	9.7	4.5	2.8	0.9	3.6	14.1
Power Required (MW)	2.8	6.9	0.0	2.5	0.9	2.7	9.0
Compression Ratio	1.44	1.26	1.00	1.39	1.17	1.11	1.36
T_{sct} (˚C)	10.4	15.2	16.4	8.0	10.7	11.2	26.9
T_{dis} (˚C)	41.6	35.6	16.3	37.6	25.9	22.1	44.9
T_{amb} (˚C)	20.0	19.0	20.0	20.0	20.0	18.0	19.0

LEGEND

- ● EXISTING RECEIPT POINTS
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- —— EXISTING PIPELINE (NGTL)
- ⧓ EXISTING CONTROL VALVE
- - - - OTHER PIPELINE SYSTEMS
- ········ PROPOSED FACILITIES

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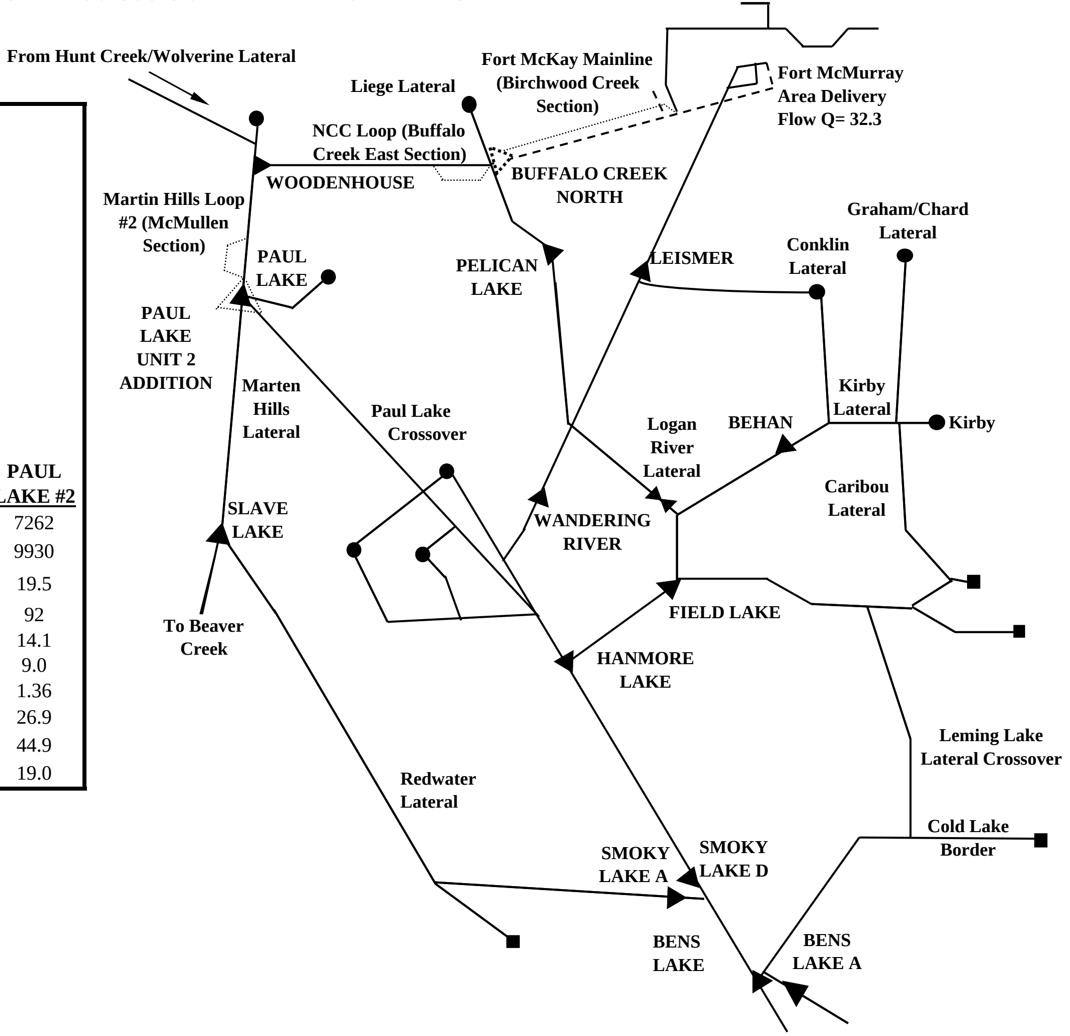

2007/08 GAS YEAR
SOUTH OF BENS LAKE DESIGN AREA
WINTER DESIGN

COMPRESSOR STATION SUMMARY

	DUSTY LAKE	GADSBY	FARRELL LAKE	OAKLAND
P_{sct}(kPa$_g$)	5946	5883	5722	5584
P_{dis}(kPa$_g$)	5945	5883	5723	5587
Flow ($10^6 m^3$/d @ STP)	6.5	11.7	13.4	14.9
Fuel ($10^3 m^3$/d @ STP)	0	0	0	0
Power Avail (MW)	29.0	28.9	27.6	13.8
Power Required (MW)	0.0	0.0	0.0	0.0
Compression Ratio	N/A	N/A	N/A	N/A
T_{sct} (˚C)	5.3	8.8	5.1	4.9
T_{dis} (˚C)	5.3	8.8	5.1	4.9
T_{amb} (˚C)	2.0	3.0	4.0	4.0

	PRINCESS A	CAVENDISH
P_{sct}(kPa$_g$)	5301	4051
P_{dis}(kPa$_g$)	5695	5040
Flow ($10^6 m^3$/d @ STP)	20.3	4.1
Fuel ($10^3 m^3$/d @ STP)	18	11
Power Avail (MW)	17.0	4.5
Power Required (MW)	2.5	1.3
Compression Ratio	1.07	1.24
T_{sct} (˚C)	4.2	4.6
T_{dis} (˚C)	11.2	23.7
T_{amb} (˚C)	6.0	5.0

LEGEND

■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
—	EXISTING PIPELINE (NGTL)
⧓	EXISTING CONTROL VALVE

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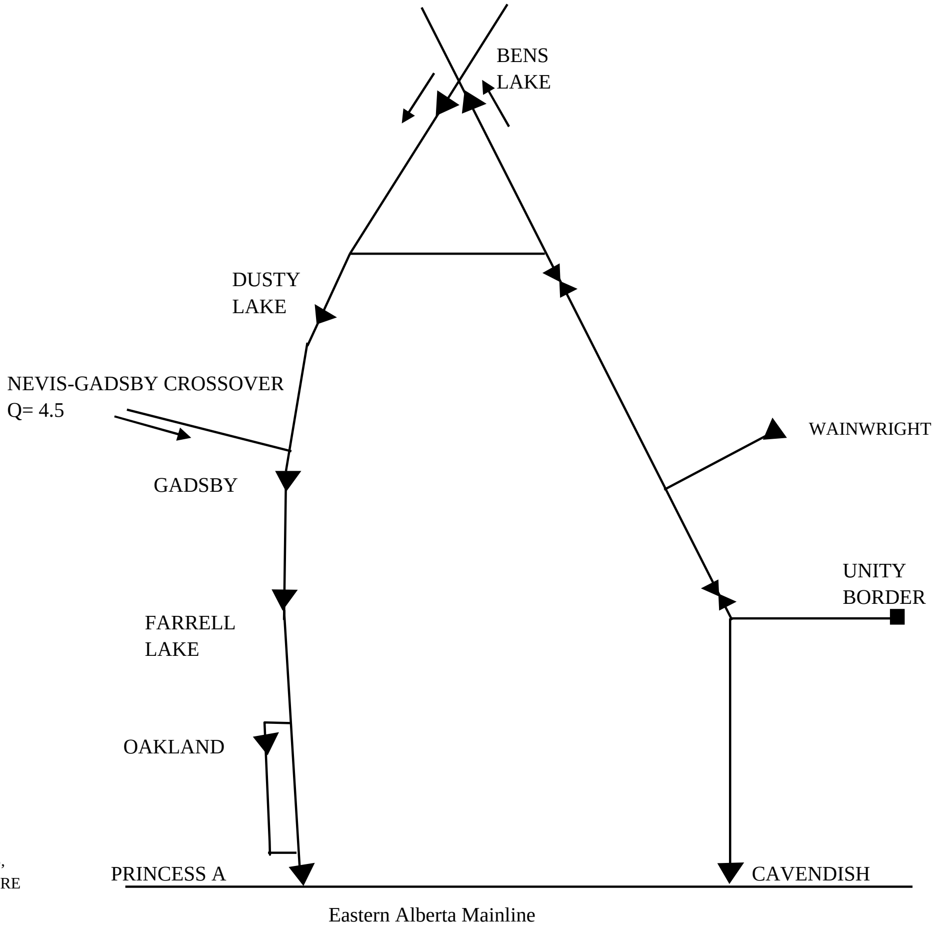
- COMPRESSOR CONDITIONS FOR LATERAL COMPRESSION AT WAINWRIGHT NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d

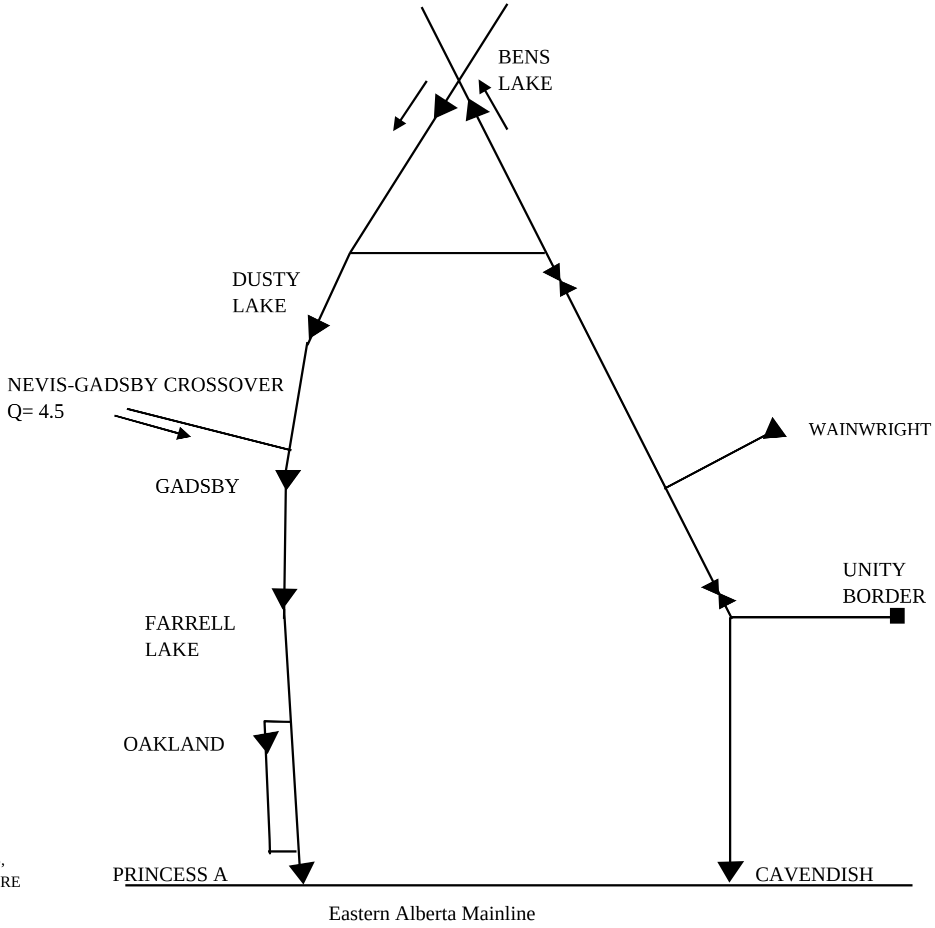


2007/08 GAS YEAR
SOUTH OF BENS LAKE DESIGN AREA
SUMMER DESIGN WITH PROPOSED NORTH OF BENS 2007/08 SUMMER FACILITIES

COMPRESSOR STATION SUMMARY

	DUSTY LAKE	GADSBY	FARRELL LAKE	OAKLAND
P_{sct}(kPa_g)	5882	5804	5617	5449
P_{dis}(kPa_g)	5882	5804	5618	5452
Flow ($10^6 m^3$/d @ STP)	7.6	12.7	14.2	14.8
Fuel ($10^3 m^3$/d @ STP)	0	0	0	0
Power Avail (MW)	25.8	25.8	25.0	12.2
Power Required (MW)	0.0	0.0	0.0	0.0
Compression Ratio	N/A	N/A	N/A	N/A
T_{sct} (˚C)	14.0	14.3	13.6	13.8
T_{dis} (˚C)	14.0	14.3	13.6	13.8
T_{amb} (˚C)	20.0	20.0	20.0	20.0

	PRINCESS A	CAVENDISH
P_{sct}(kPa_g)	5234	4160
P_{dis}(kPa_g)	5692	5035
Flow ($10^6 m^3$/d @ STP)	20.4	3.7
Fuel ($10^3 m^3$/d @ STP)	21	9
Power Avail (MW)	17.0	4.0
Power Required (MW)	3.0	1.1
Compression Ratio	1.09	1.21
T_{sct} (˚C)	13.5	13.7
T_{dis} (˚C)	21.9	31.0
T_{amb} (˚C)	22.0	23.0



LEGEND

■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
—	EXISTING PIPELINE (NGTL)
⧓	EXISTING CONTROL VALVE

NOTE:
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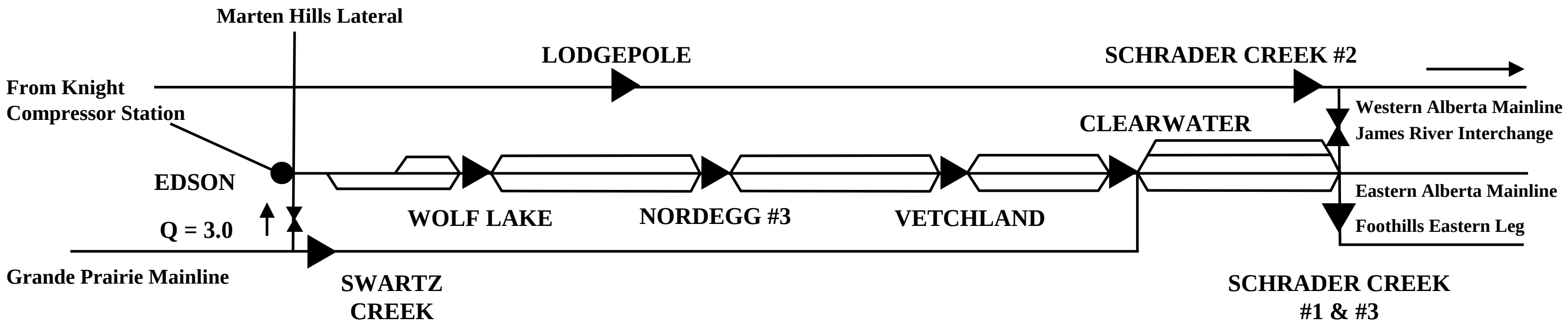
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d

2007/08 GAS YEAR
EDSON MAINLINE DESIGN SUB AREA
WINTER DESIGN



COMPRESSOR STATION SUMMARY

	SWARTZ CREEK	WOLF LAKE	NORDEGG #3	VETCHLAND	CLEARWATER	LODGEPOLE
P_{sct} (kPa$_g$)	7499	5167	7422	4903	4789	4751
P_{dis} (kPa$_g$)	8500	5167	7421	4903	6450	5564
Flow (10^{6}m^3/d @ STP)	59.0	31.4	59.0	35.9	46.8	12.5
Fuel (10^{3}m^3/d @ STP)	105	0	0	0	158	25
Power Avail (MW)	27.3	23.8	30.9	46.5	41.0	2.9
Power Req'd (MW)	10.3	0.0	0.0	0.0	20.8	2.9
Compression Ratio	1.13	N/A	N/A	N/A	1.34	1.17
T_{sct} (°C)	13.3	5.4	14.1	4.2	6.0	4.6
T_{dis} (°C)	23.7	5.4	14.1	4.2	32.6	18.4
T_{amb} (°C)	3.0	3.0	4.0	4.0	4.0	3.0

LEGEND

● EXISTING RECEIPT POINTS
▲ EXISTING COMPRESSION
— EXISTING PIPELINE (NGTL)
⋈ EXISTING CONTROL VALVE

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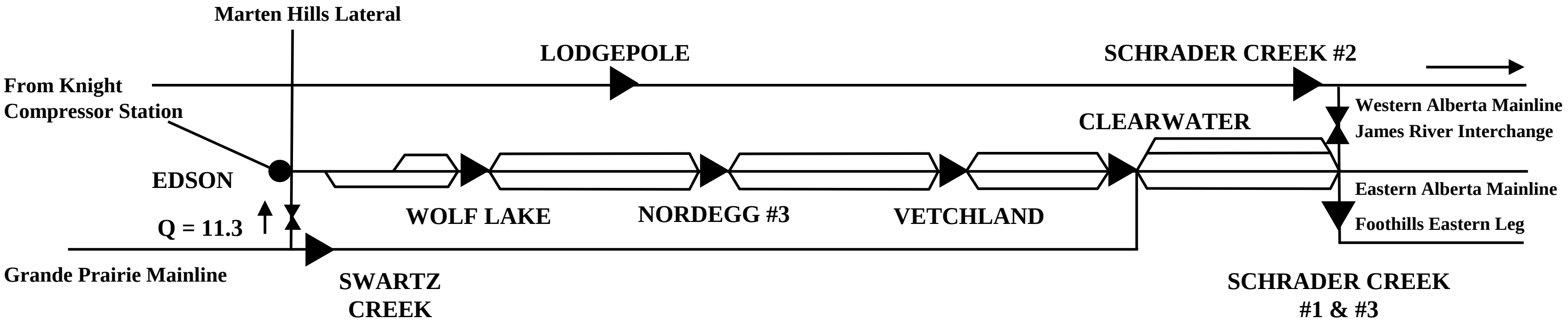
- FOR SCHRADER CREEK EAST COMPRESSOR STATION CONDITIONS SEE EASTERN ALBERTA MAINLINE DESIGN SUB AREA
- FOR SCHRADER CREEK #2 COMPRESSOR STATION CONDITIONS SEE WESTERN ALBERTA MAINLINE DESIGN SUB AREA
- Q, FLOW IN 10^{6}m^3/d

2007/08 GAS YEAR
EDSON MAINLINE DESIGN SUB AREA
SUMMER DESIGN



COMPRESSOR STATION SUMMARY

	SWARTZ CREEK	WOLF LAKE	NORDEGG #3	VETCHLAND	CLEARWATER	LODGEPOLE
P_{sct} (kPa_g)	7249	5912	7409	5515	5327	5157
P_{dis} (kPa_g)	8500	5911	7407	5514	6450	5767
Flow ($10^6 m^3/d$ @ STP)	57.3	42.4	57.3	47.4	59.5	14.5
Fuel ($10^3 m^3/d$ @ STP)	122	0	0	0	142	23
Power Avail (MW)	24.7	21.6	28.7	42.4	38.0	2.5
Power Req'd (MW)	13.6	0.0	0.0	0.0	17.9	2.5
Compression Ratio	1.17	N/A	N/A	N/A	1.21	1.12
T_{sct} (°C)	25.9	15.8	27.7	11.5	12.4	12.1
T_{dis} (°C)	40.1	15.8	27.7	11.5	30.3	22.4
T_{amb} (°C)	18.0	18.0	18.0	18.0	18.0	18.0

LEGEND

● EXISTING RECEIPT POINTS
▲ EXISTING COMPRESSION
— EXISTING PIPELINE (NGTL)
⋈ EXISTING CONTROL VALVE

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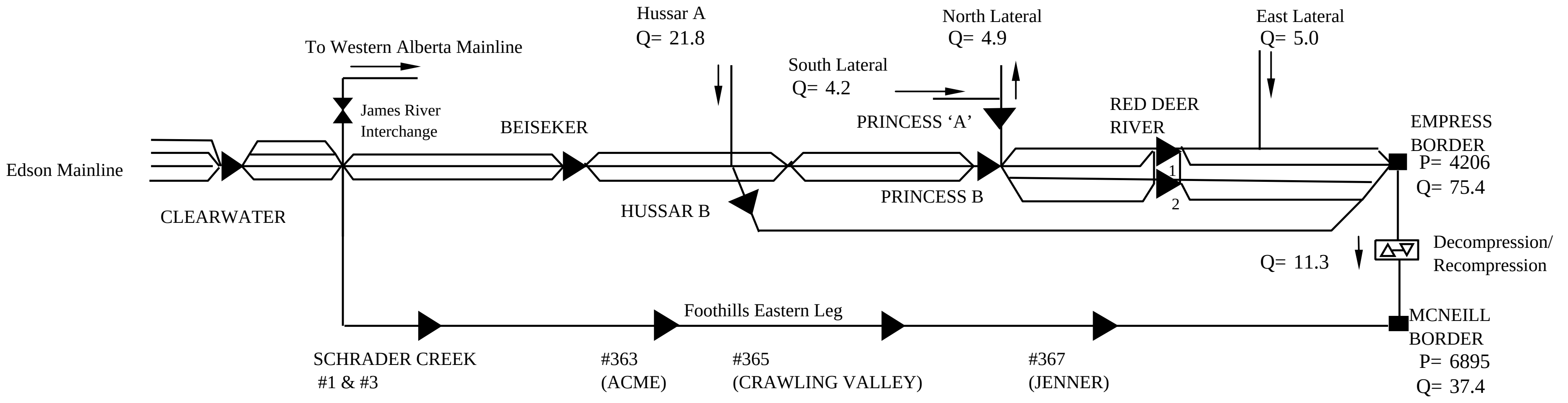
- FOR SCHRADER CREEK #2 COMPRESSOR STATION CONDITIONS SEE WESTERN ALBERTA MAINLINE DESIGN SUB AREA
- Q, FLOW IN $10^6 m^3/d$

2007/08 GAS YEAR
EASTERN ALBERTA MAINLINE DESIGN SUB AREA
(JAMES RIVER TO PRINCESS AND PRINCESS TO EMPRESS/MCNEILL)
WINTER DESIGN



COMPRESSOR STATION SUMMARY

	BEISEKER	HUSSAR B	PRINCESS B	RED DEER RIVER #1	RED DEER RIVER #2	SCHRADER CREEK #1 & #3	#363	#365	#367
P_{sct}(kPa$_g$)	5419	5254	4619	4428	4428	5638	7773	7505	7201
P_{dis}(kPa$_g$)	5418	5253	4617	4427	4427	8000	7772	7503	7199
Flow ($10^6 m^3$/d @ STP)	57.4	33.8	52.3	30.0	22.8	26.1	26.1	26.1	26.1
Fuel ($10^3 m^3$/d @ STP)	0	0	0	0	0	109	0	0	0
Power Avail (MW)	20.7	13.5	20.7	24.2	24.2	37.6	25.1	21.4	40.6
Power Required (MW)	0.0	0.0	0.0	0.0	0.0	13.7	0.0	0.0	0.0
Compression Ratio	N/A	N/A	N/A	N/A	N/A	1.41	N/A	N/A	N/A
T_{sct} (˚C)	6.4	5.0	4.3	3.8	4.4	19.5	14.0	8.3	5.5
T_{dis} (˚C)	6.4	5.0	4.3	3.8	4.4	26.8	14.0	8.3	5.5
T_{amb} (˚C)	5.0	5.0	6.0	6.0	6.0	4.0	5.0	5.0	6.0

LEGEND

■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
—	EXISTING PIPELINE (NGTL)
⋈	EXISTING CONTROL VALVE

NOTE:
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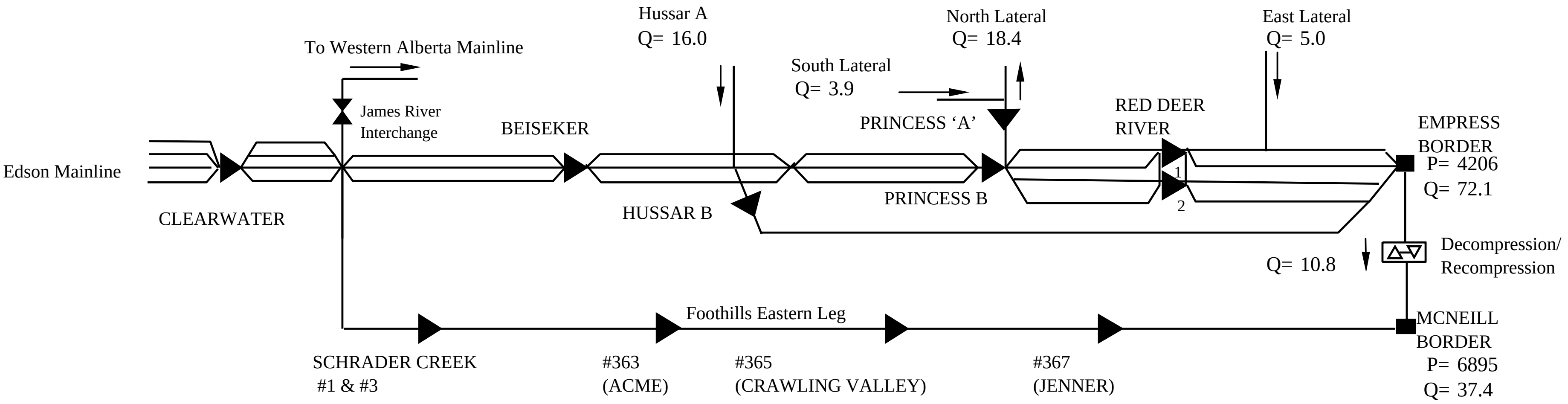
- Q, FLOW IS IN 10^6 m^3/d
- P, PRESSURE IS IN kPa$_g$
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- FOR CLEARWATER COMPRESSOR STATION CONDITIONS SEE EDSON MAINLINE DESIGN SUB ARE
- FOR PRINCESS 'A' COMPRESSOR STATION CONDITIONS SEE THE SOUTH OF BENS LAKE DESIGN ARE

2007/08 GAS YEAR
EASTERN ALBERTA MAINLINE DESIGN SUB AREA
(JAMES RIVER TO PRINCESS AND PRINCESS TO EMPRESS/MCNEILL)
SUMMER DESIGN



COMPRESSOR STATION SUMMARY

	BEISEKER	HUSSAR B	PRINCESS B	RED DEER RIVER #1	RED DEER RIVER #2	SCHRADER CREEK #1 & #3	#363	#365	#367
$P_{sct}(kPa_g)$	5779	5497	4573	4404	4404	6210	7869	7568	7232
$P_{dis}(kPa_g)$	5777	5497	4572	4402	4402	8115	7867	7566	7230
Flow ($10^6 m^3$/d @ STP)	74.2	37.0	46.6	27.2	20.7	26.6	26.6	26.6	26.6
Fuel ($10^3 m^3$/d @ STP)	0	0	0	0	0	110	0	0	0
Power Avail (MW)	18.6	11.9	20.5	21.5	21.5	33.3	22.5	18.1	35.8
Power Required (MW)	0.0	0.0	0.0	0.0	0.0	10.8	0.0	0.0	0.0
Compression Ratio	N/A	N/A	N/A	N/A	N/A	1.30	N/A	N/A	N/A
T_{sct} (˚C)	16.1	14.1	11.4	12.7	13.5	26.8	19.7	16.0	14.2
T_{dis} (˚C)	16.1	14.1	11.4	12.7	13.5	27.9	19.7	15.9	14.2
T_{amb} (˚C)	20.0	21.0	22.0	22.0	22.0	18.0	20.0	21.0	23.0

LEGEND

■ EXISTING DELIVERY POINTS
▲ EXISTING COMPRESSION
— EXISTING PIPELINE (NGTL)
⧓ EXISTING CONTROL VALVE

NOTE:
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- STP IS 101.325 kPa AND 15° C
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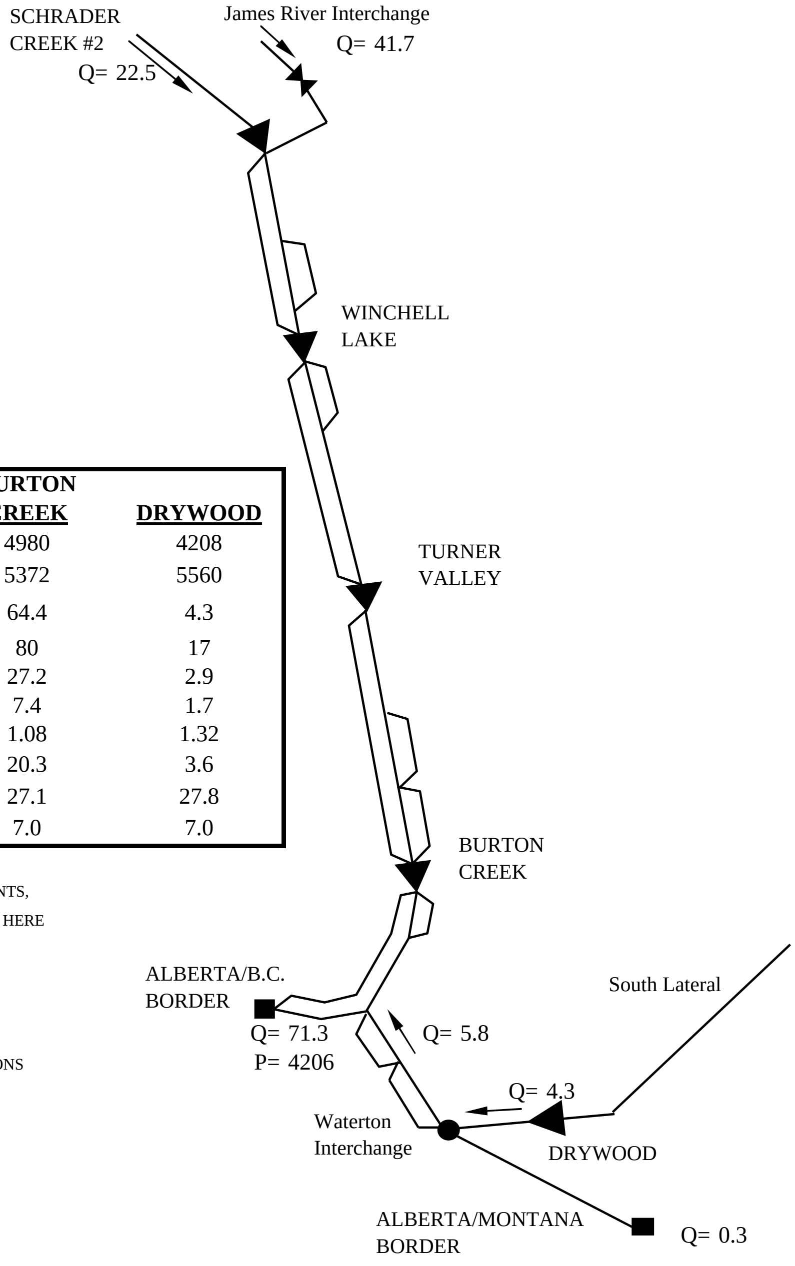
- Q, FLOW IS IN 10^6 m^3/d
- P, PRESSURE IS IN kPa_g
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- FOR CLEARWATER COMPRESSOR STATION CONDITIONS SEE EDSON MAINLINE DESIGN SUB ARE
- FOR PRINCESS 'A' COMPRESSOR STATION CONDITIONS SEE THE SOUTH OF BENS LAKE DESIGN ARE

2007/08 GAS YEAR
WESTERN ALBERTA MAINLINE DESIGN SUB AREA
WINTER DESIGN



COMPRESSOR STATION SUMMARY

	SCHRADER CREEK #2	WINCHELL LAKE	TURNER VALLEY	BURTON CREEK	DRYWOOD
P_{sct}(kPa$_g$)	3774	4872	4581	4980	4208
P_{dis}(kPa$_g$)	5803	5822	5824	5372	5560
Flow ($10^6 m^3$/d @ STP)	22.5	66.5	63.0	64.4	4.3
Fuel ($10^3 m^3$/d @ STP)	82	126	208	80	17
Power Avail (MW)	13.1	23.2	45.6	27.2	2.9
Power Required (MW)	13.1	17.3	23.4	7.4	1.7
Compression Ratio	1.53	1.19	1.27	1.08	1.32
T_{sct} (˚C)	1.4	11.9	22.6	20.3	3.6
T_{dis} (˚C)	36.1	27.3	44.8	27.1	27.8
T_{amb} (˚C)	4.0	5.0	6.0	7.0	7.0

LEGEND

●	EXISTING RECEIPT POINTS
■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
—	EXISTING PIPELINE (NGTL)
⋈	EXISTING CONTROL VALVE

NOTE:
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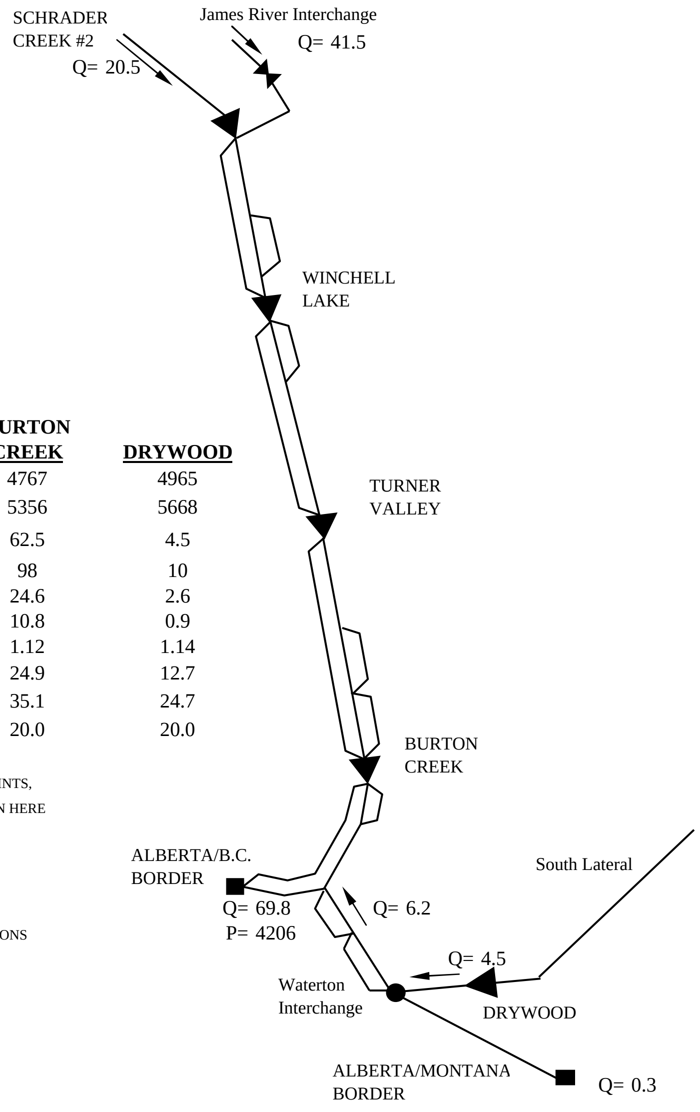
- Q, FLOW IS IN 10^6 m^3/d
- P, PRESSURE IS IN kPa$_g$
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS

2007/08 GAS YEAR
WESTERN ALBERTA MAINLINE DESIGN SUB AREA
SUMMER DESIGN



COMPRESSOR STATION SUMMARY

	SCHRADER CREEK #2	WINCHELL LAKE	TURNER VALLEY	BURTON CREEK	DRYWOOD
P_{sct}(kPa$_g$)	3839	4886	4481	4767	4965
P_{dis}(kPa$_g$)	5800	5700	5600	5356	5668
Flow (10^{6}m^3/d @ STP)	20.5	64.5	60.9	62.5	4.5
Fuel (10^{3}m^3/d @ STP)	76	117	201	98	10
Power Avail (MW)	11.8	21.1	41.7	24.6	2.6
Power Required (MW)	11.8	15.5	22.0	10.8	0.9
Compression Ratio	1.50	1.16	1.25	1.12	1.14
T_{sct} (˚C)	7.7	21.2	30.7	24.9	12.7
T_{dis} (˚C)	41.5	34.9	44.9	35.1	24.7
T_{amb} (˚C)	18.0	19.0	19.0	20.0	20.0

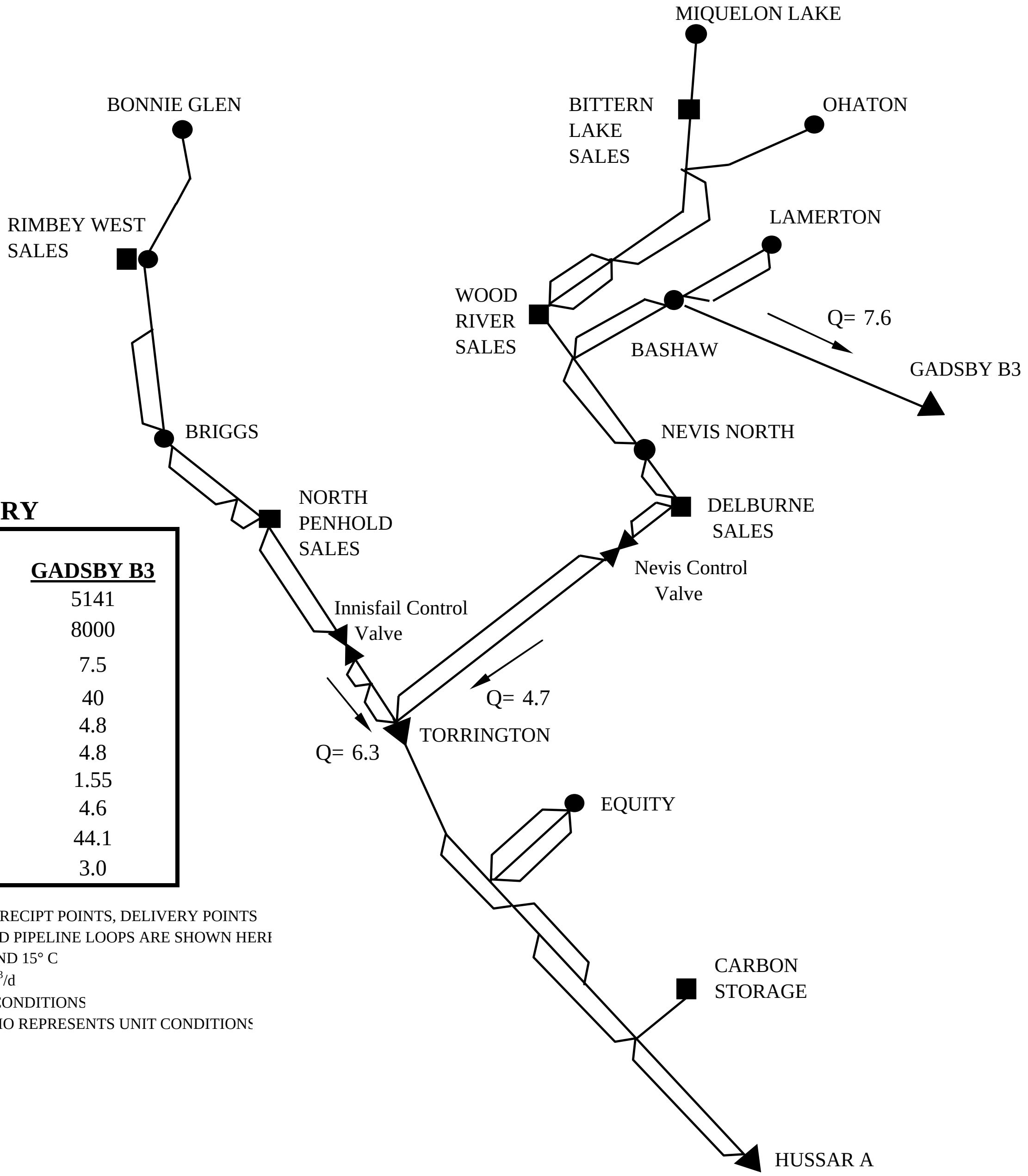
LEGEND

●	EXISTING RECEIPT POINTS
■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
—	EXISTING PIPELINE (NGTL)
⋈	EXISTING CONTROL VALVE

NOTE: - NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- Q, FLOW IS IN 10^6 m^3/d
- P, PRESSURE IS IN kPa$_g$
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS

REVISED

2007/08 GAS YEAR
RIMBEY - NEVIS DESIGN AREA
WINTER DESIGN



COMPRESSOR STATION SUMMARY

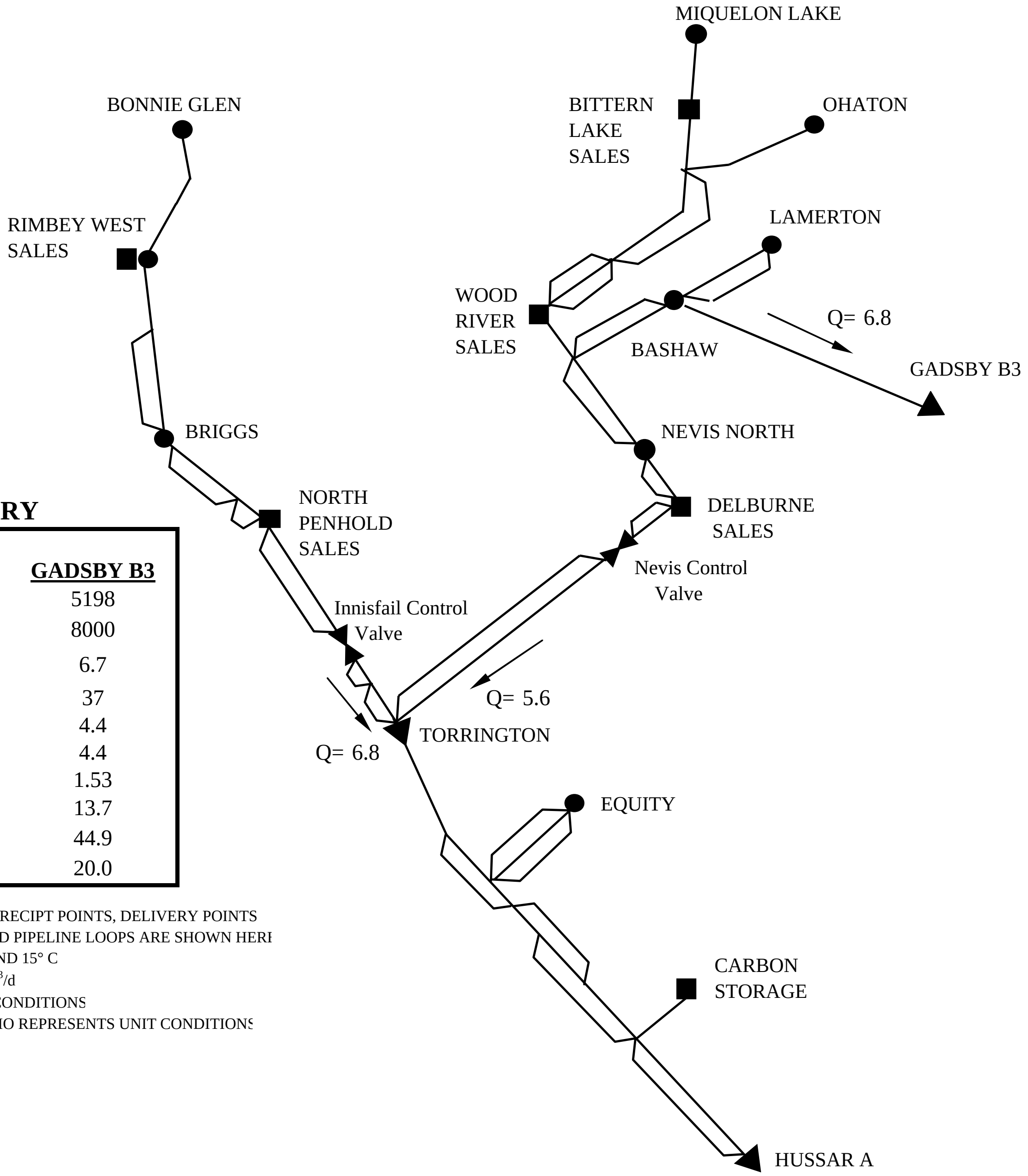
	TORRINGTON	**HUSSAR A6,7**	**GADSBY B3**
P_{sct}(kPa$_g$)	5456	5029	5141
P_{dis}(kPa$_g$)	5454	5915	8000
Flow ($10^6 m^3$/d @ STP)	11.0	21.9	7.5
Fuel ($10^3 m^3$/d @ STP)	0	47	40
Power Avail (MW)	7.4	27.0	4.8
Power Required (MW)	0.0	5.0	4.8
Compression Ratio	N/A	1.17	1.55
T_{sct} (˚C)	4.8	4.6	4.6
T_{dis} (˚C)	4.8	18.3	44.1
T_{amb} (˚C)	4.0	5.0	3.0

LEGEND

●	EXISTING RECEIPT POINTS
■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
—	EXISTING PIPELINE (NGTL)
⋈	EXISTING CONTROL VALVE

NOTE:
- NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERI
- STP IS 101.325 kPa AND 15° C
- Q, FLOW IS IN 10^6 m^3/d
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS

2007/08 GAS YEAR
RIMBEY - NEVIS DESIGN AREA
SUMMER DESIGN



COMPRESSOR STATION SUMMARY

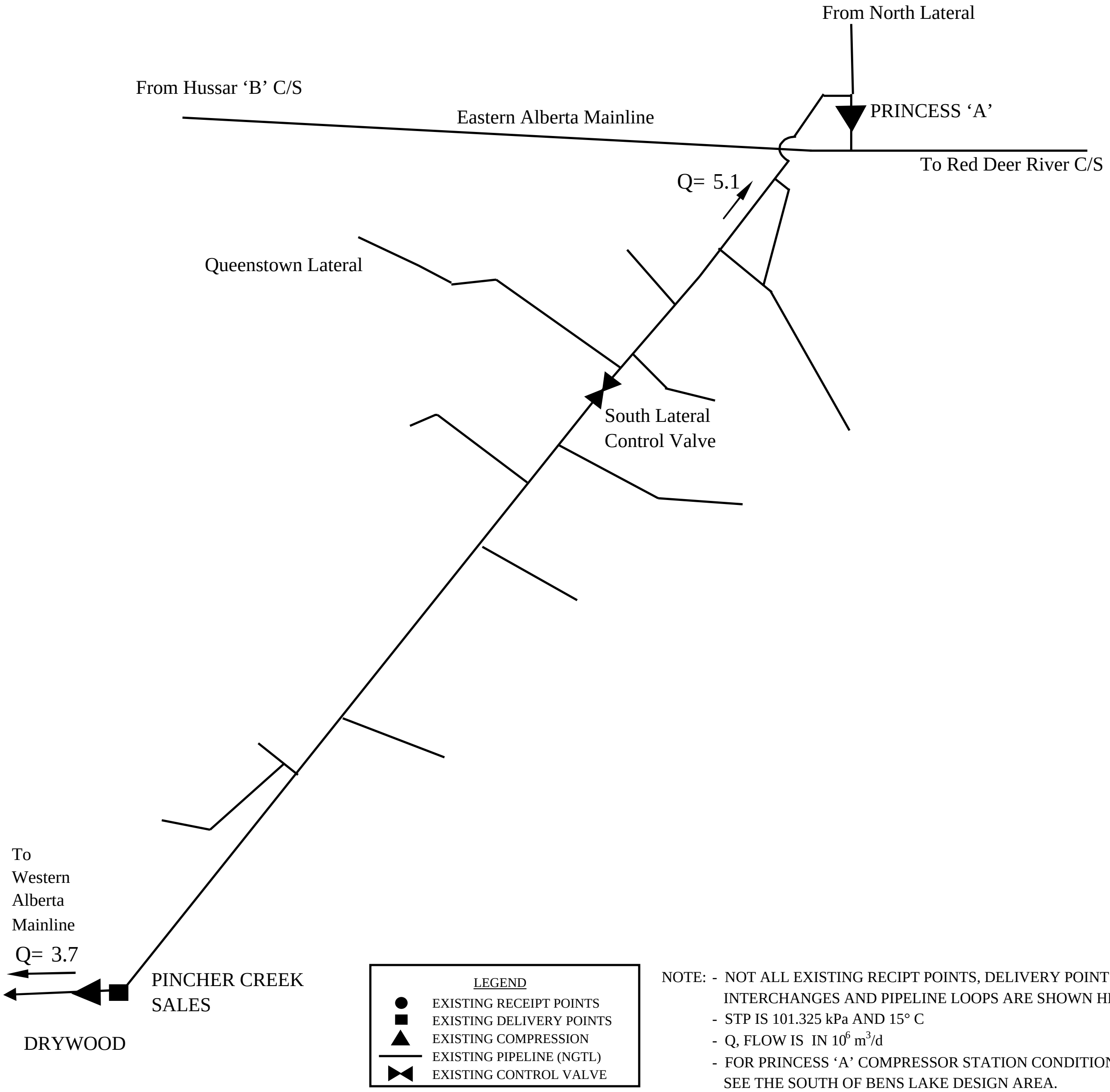
	TORRINGTON	HUSSAR A6,7	GADSBY B3
$P_{sct}(kPa_g)$	5304	4748	5198
$P_{dis}(kPa_g)$	5302	5915	8000
Flow ($10^6 m^3/d$ @ STP)	12.3	23.2	6.7
Fuel ($10^3 m^3/d$ @ STP)	0	58	37
Power Avail (MW)	6.6	23.8	4.4
Power Required (MW)	0.0	7.5	4.4
Compression Ratio	N/A	1.24	1.53
T_{sct} (˚C)	13.7	13.0	13.7
T_{dis} (˚C)	13.7	32.1	44.9
T_{amb} (˚C)	19.0	21.0	20.0

LEGEND

●	EXISTING RECEIPT POINTS
■	EXISTING DELIVERY POINTS
▲	EXISTING COMPRESSION
─	EXISTING PIPELINE (NGTL)
⋈	EXISTING CONTROL VALVE

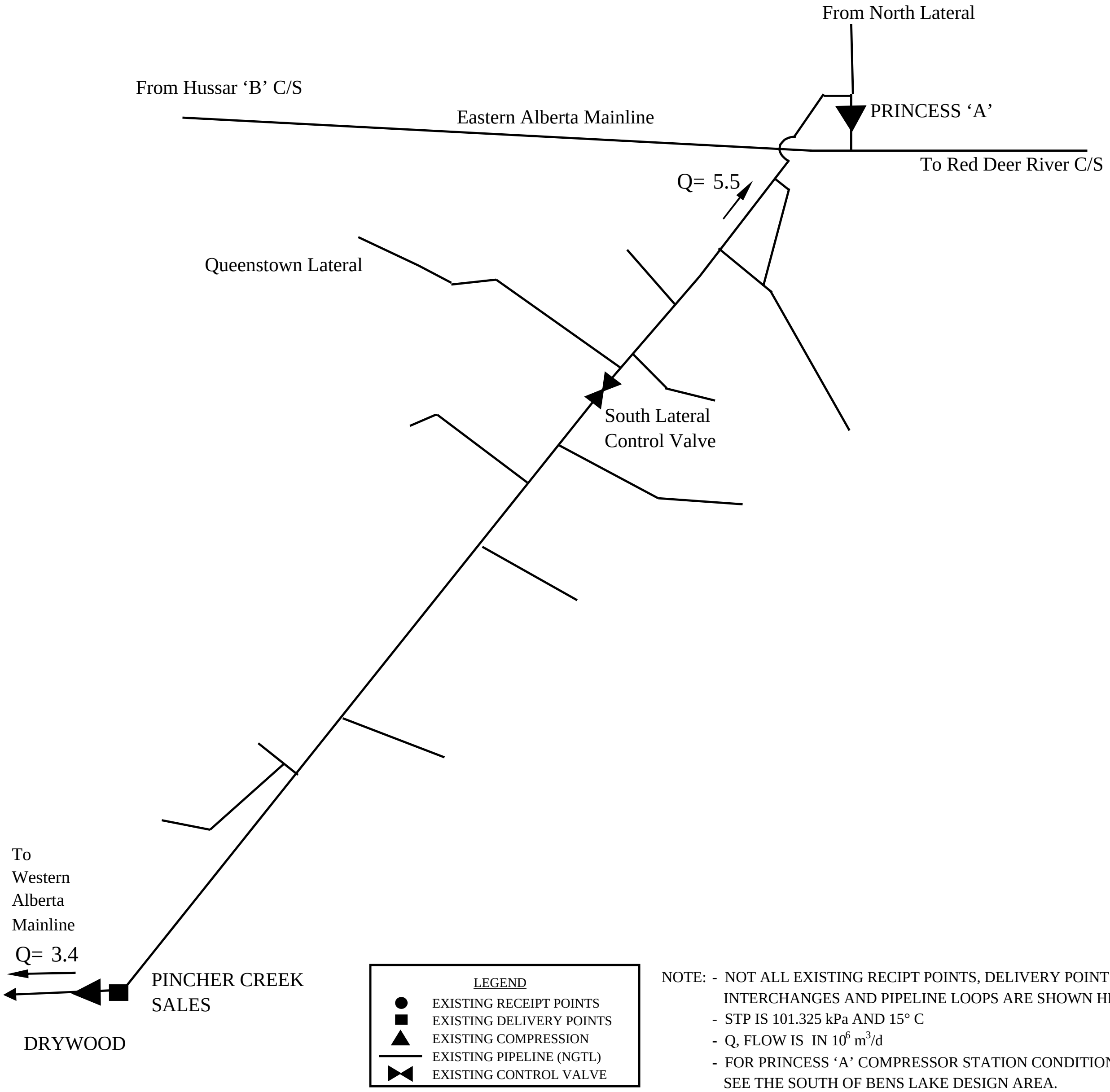
NOTE:
- NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERI
- STP IS 101.325 kPa AND 15° C
- Q, FLOW IS IN 10^6 m^3/d
- POWER IS AT SITE CONDITIONS
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS

2007/08 GAS YEAR
SOUTH AND ALDERSON DESIGN AREA
WINTER DESIGN



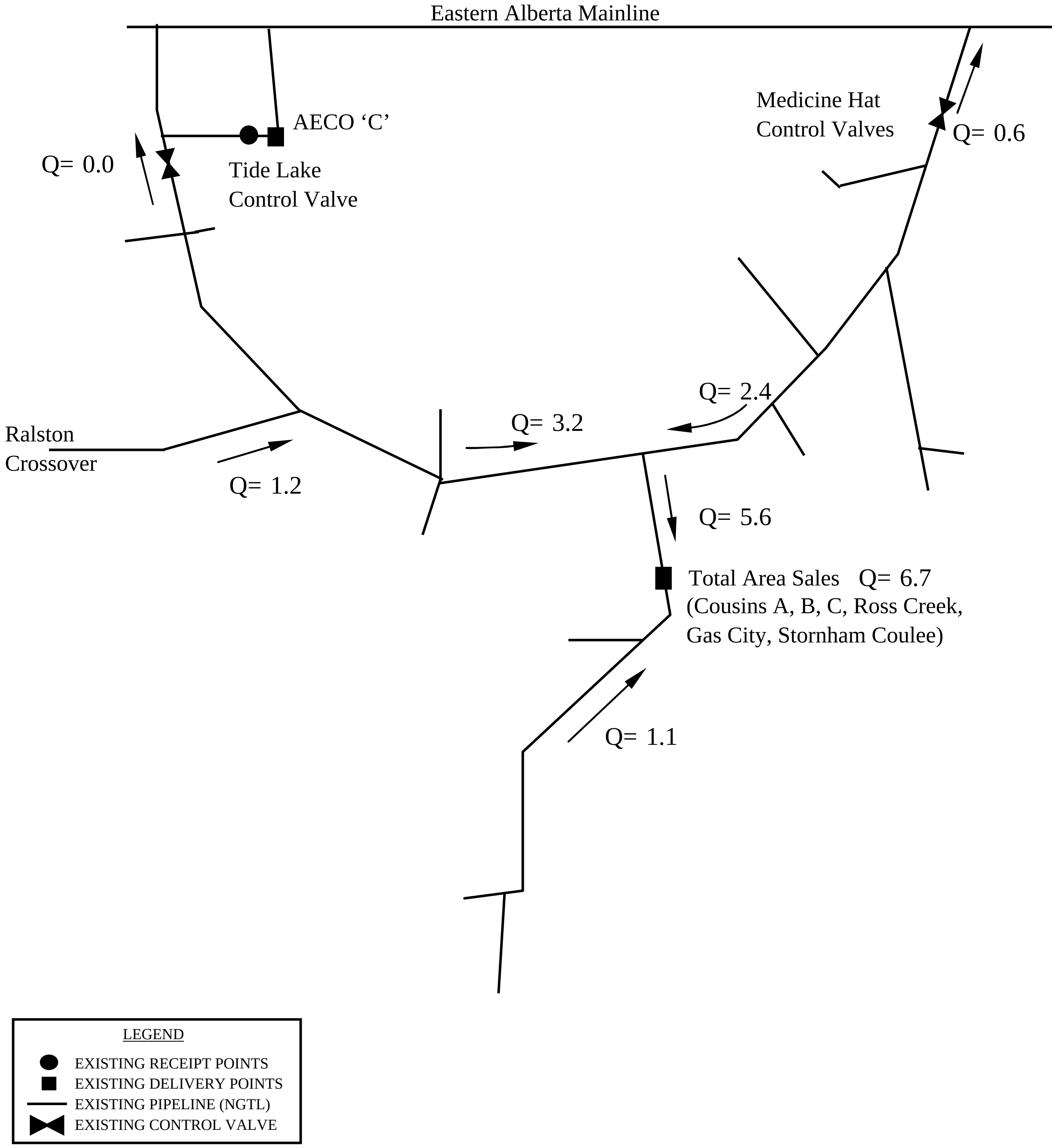
NOTE: - NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- Q, FLOW IS IN 10^6 m^3/d
- FOR PRINCESS ‘A’ COMPRESSOR STATION CONDITIONS SEE THE SOUTH OF BENS LAKE DESIGN AREA.
- FOR DRYWOOD COMPRESSOR STATION CONDITIONS SEE WESTERN ALBERTA MAINLINE DESIGN SUB AREA.

2007/08 GAS YEAR
SOUTH AND ALDERSON DESIGN AREA
SUMMER DESIGN



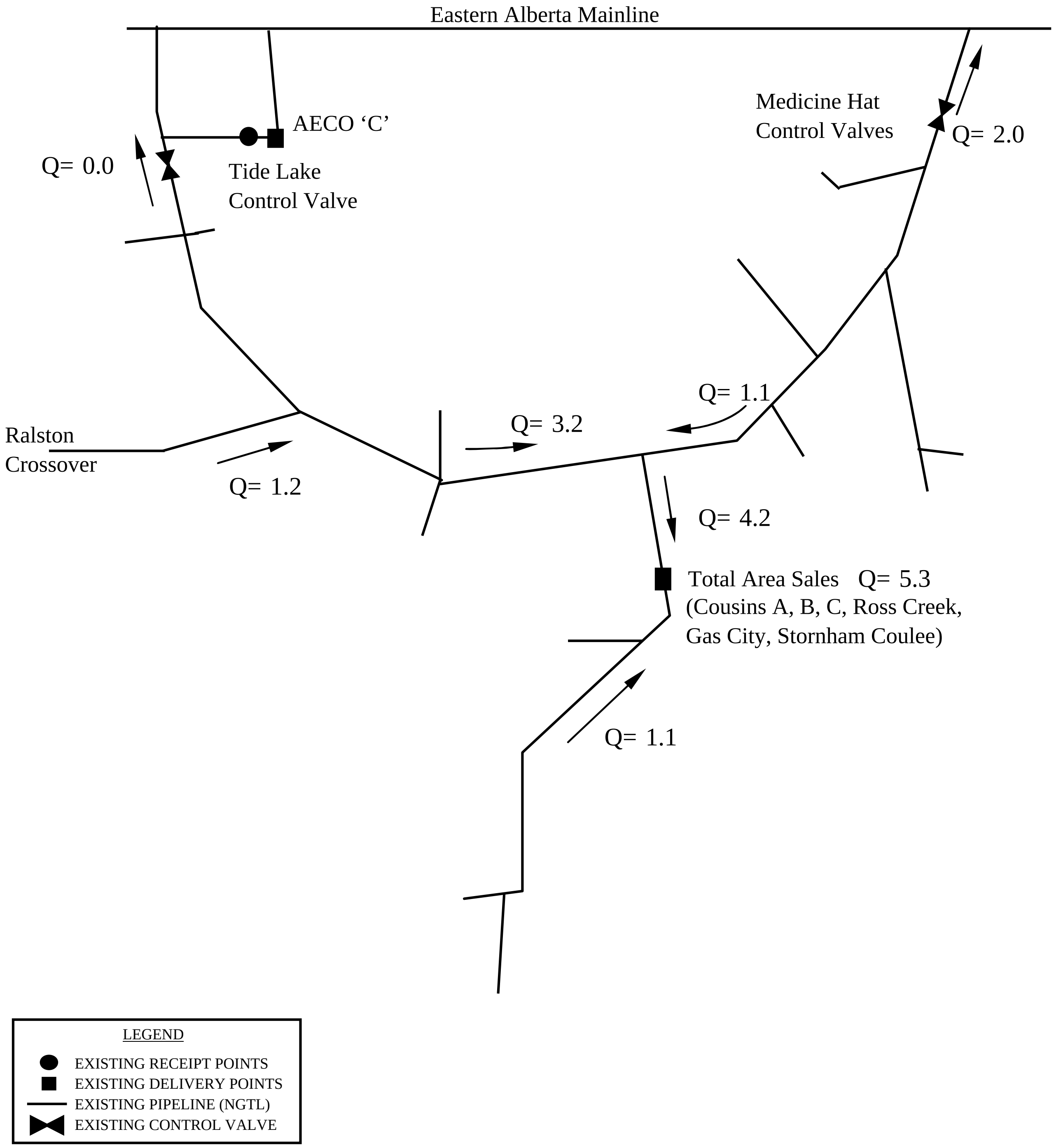
NOTE: - NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- Q, FLOW IS IN 10^6 m^3/d
- FOR PRINCESS 'A' COMPRESSOR STATION CONDITIONS SEE THE SOUTH OF BENS LAKE DESIGN AREA.
- FOR DRYWOOD COMPRESSOR STATION CONDITIONS SEE WESTERN ALBERTA MAINLINE DESIGN SUB AREA.

2007/08 GAS YEAR
MEDICINE HAT DESIGN AREA
WINTER DESIGN



NOTE: - NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- Q, FLOW IS IN 10^6 m^3/d

2007/08 GAS YEAR
MEDICINE HAT DESIGN AREA
SUMMER DESIGN



NOTE: - NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- STP IS 101.325 kPa AND 15° C
- Q, FLOW IS IN 10^6 m^3/d

APPENDIX 6

SECTION L FACILITIES

This Section describes facilities that were applied for following the issuance of the December 2005 Annual Plan which were not identified or were significantly revised from the facilities identified in the December 2005 Annual Plan. These facilities were applied for under Section L of Board Informational Letter IL 90-8 and are referred to as "Section L Facilities".

METER STATIONS

This Section describes meter stations that were proposed from December 1, 2005 to November 30, 2006.

SECTION L FACILITIES

FACILITIES	PROJECT SCOPE	FILED FOR CAPITAL COST
Sunday Creek South Lateral Loop #2	7.1 km of NPS 12 pipeline 5.3 km of NPS 10 pipeline	$6,800,000
Thunder Extension	26.5 km of NPS 16 pipeline	$26,000,000
Total		**$32,800,000**

METER STATIONS

FACILITIES	PROJECT SCOPE	CAPITAL COST
Cattail Lake Meter Station	type 440 meter	$400,000
Chapel Rock Meter Station	type 440-2 meter	$260,000
Cheecham West #2 Sales Meter Station	2-1280 turbine meters	$650,000
Chickadee Creek #2 Meter Station	type 440 meter	$250,000
Dawes Lake Sales Meter Station	2-640 turbine meters	$600,000
Doig River Meter Station	type 440 meter	$460,000
Duvernay Meter Station	type 440 meter	$68,000
Eaglesham South Meter Station	type 442 meter	$600,000
Goosequill West Meter Station	type 440-2 meter	$27,500
Jackfish Sales Meter Station	type 2-1280 turbine meters (delayed)	$870,000
Jarvis Bay Meter Station	type 440-2 meter	$570,000
Joffre East Meter Station	type 660 meter	$400,000
Keivers Lake Meter Station	type 440-2 meter	$45,000
Kettle River North #2 Sales Meter Station	2-440 turbine meters	$500,000
Kotcho River Meter Station	type 442 meter	$650,000
Lamerton South Meter Station	type 440 meter	$400,000
Mahihkan Sales Meter Station	2-1616 ultrasonic meters	$470,000
Mayberne Meter Station	type 660 meter	$332,000
Mega River Meter Station	type 442 meter	$185,000
Mega River #2 Meter Station	type 440 meter	$350,000
Porters Butte Meter Station	type 440-2 meter	$430,000
Resthaven Meter Station	type 880 meter	$500,000
Resthaven North Meter Station	type 660 meter	$362,000
Ridgevalley Meter Station	type 440-2 meter	$60,000
Sawn Lake East Meter Station	type 422 meter	$72,000
Shady Oak Meter Station	2-1080 meters	$1,200,000
Shekilie River East Meter Station	type 660 meter	$408,000
Snowfall Creek North Meter Station	type 440-2 meter	$77,000
Tucker Lake Sales Meter Station	type 2-860 turbine meters	$750,000
Veda Meter Station	type 442 meter	$131,000
Total		**$12,077,500**

Note: List as of November 30, 2006

APPENDIX 7

Appendix 7 consists of the Alberta System map.
The map is too large to display here in detail.

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