Canadian Energy Research Institute

Capacity of the Western Canada Natural Gas Pipeline System

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CHAPTER 1
BACKGROUND

1.1 Background

The performance of the pipeline system into and out of Western Canada is a critical issue for the North American natural gas marketplace over the next decade, as additional supplies from within the Western Canada Sedimentary Basin (WCSB) and from Canadian and US northern frontiers transit the area.

The main issues relate to understanding the capacities of the existing pipeline system and its' transportation corridors in connecting supply regions and sources to the demand centers, particularly with respect to its future expansion, as new supply regions need to be connected.

The study is motivated by the expected changes in the regional distribution of gas production within Western Canada, and by the introduction of new gas flows from northern sources—the Mackenzie Delta and the North Slope of Alaska. These changes are expected to have significant impacts on pipeline capacity utilization within and from Western Canada. Pipeline capacity utilization will also be impacted by changes in deliveries to accommodate increased gas requirements for planned oil sands projects in northeastern Alberta. Alternative scenarios will consider the timing and sequencing of volumes of natural gas entering or bypassing the Canadian pipeline systems from a variety of potential supply sources.

Current high prices and the expectation that they will remain so for many years are affecting natural gas demand. However, the anticipated roll back in demand as a result of high prices has not been overwhelming. In fact, the recent high prices elicited only a five percent reduction of US total natural gas demand.

Increasing gas demand for power generation has driven changes in seasonal demand and storage injection patterns. Power developers, in funding new gas pipeline and storage infrastructure, are playing a prominent role in the development of the transportation system. This in turn, places more stress on market area infrastructure—requiring additional investments to avoid localized bottlenecks. Continued investments are required both to keep pace with rapid growth in gas demand for power generation, and the realignment of supplies away from traditional US supply regions.

In the face of higher prices, fuel switching from natural gas to either residual fuel oil or distillate by industrial end-users creates only a relatively small short-term demand reduction. Feedstock use of gas, which is a major contributor to the industrial demand, has already declined. There is also a real possibility of widespread manufacturing shutdowns which could have a significant impact on the US economy and overall demand for natural gas.

These demand responses have offered only a limited degree of flexibility to-date and certainly have not solved the overall supply-demand tightness in the North American natural gas market. There is little to suggest that demand will not continue, at least at its present level, and that supply will have to be augmented. These issues will be identified and detailed in the various scenarios used in the project analyses.

The North American pipeline system was *"designed"* primarily to move gas from the Gulf Coast and Mid-Continent, either north into the Northeast and Midwest consuming regions, or west toward California. Traditional flows are changing as more supplies originate from the North and East. Frontier supplies, liquefied natural gas (LNG), Arctic gas, and Atlantic Canadian gas now make up a larger share of the North American mix, and investments in the pipeline system designed to accommodate the new centers of supply will change flow patterns. With a more diverse geography of supply the gas pipeline system has taken on more characteristics of hubs and networks. This evolution has already occurred in the Midwest and is developing within a few other supply regions, including Alberta.

Dramatic increases in gas demand in California spurred by surges in power loads and below-normal hydroelectric generation revealed supply bottlenecks into the state of California in the late 90s and later. Several small projects increased deliverability into the state but the most significant capacity increases occurred on Kern River, PGE GT NW and Transwestern pipeline systems. Aggressive supply growth in the Rockies began to outstrip available export capacity, and several increases to export capacity from the Rockies came online in 2002-2003. With major new supplies in Atlantic Canada (SOPE, Panuke and LNG) taking some pressure off regional prices in Boston, planned pipeline projects designed to facilitate movement of this new supply throughout the northeast and relieve bottlenecks into New York have been delayed, due mainly to supply uncertainties.

As some of the known Frontier supplies become necessary to feed the US Lower-48 gas demand, infrastructure will need to be developed to enable access to markets. It could be moved via one or more of several pipelines or by various types of tankers.

There are three proposed options for removal of Alaskan North Slope natural gas from Alaska. First, by construction of a Trans-Alaska pipeline into Alberta and onward to the US Lower-48. Second, from a GTL facility near Prudhoe Bay Alaska and then by pipeline to the Kenai Peninsula-Cook Inlet area for export via tanker to the US West Coast or to Asian markets. Third, by construction of a pipeline from Prudhoe Bay, Alaska to the Kenai Peninsula-Cook inlet where the gas would be converted to LNG and exported via tanker to California.

Canada's northern frontiers harbor several areas of natural gas resources. The extension of the WCSB northwards into the Mackenzie Valley Corridor area of the NWT has the capability of connecting the resource potential of several major areas: the Mackenzie Valley and Yukon; the entire onshore-offshore Mackenzie-Beaufort Basin; and the High Arctic Islands, with CNG tankers delivering gas into the head of the pipeline.

The High Arctic Islands resources could also be connected by LNG (or GTL) tankers to markets on North America's eastern seaboard. In fact, LNG is expected to play an increasing role in meeting demand with accompanying expansion of one or more of the existing re-gasification facilities. It now seems likely that LNG might be delivered into several areas of the North American continent thereby creating additional demand for pipeline take-away capacity. These likely areas are the Canadian Maritime Provinces of Nova Scotia and New Brunswick, and the province of Quebec; Florida from re-gasification facilities in the Bahamas; the Gulf Coast from offshore floating re-gasification facilities; and into the US west coast and southwest via Baja, Mexico.

Increased supplies of LNG into certain market areas could have a displacement effect on other supplies that would affect the transportation system. These potential impacts need to be assessed.

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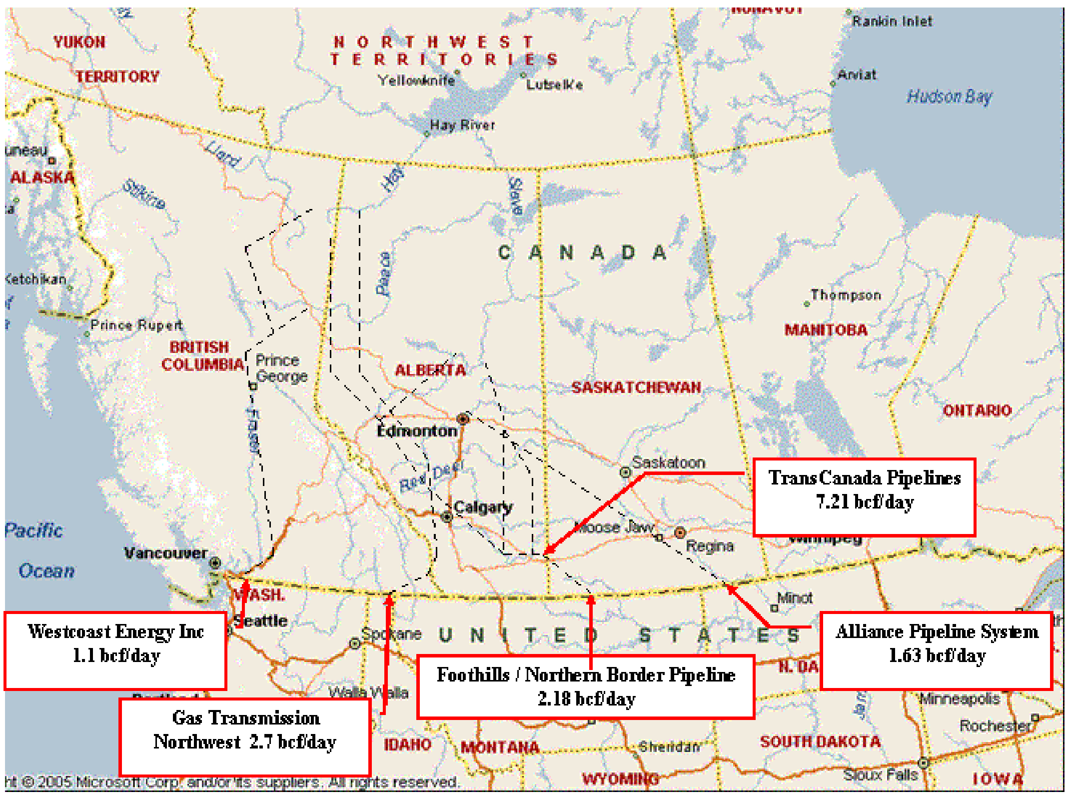
CHAPTER 2
INTRODUCTION

The existing pipeline infrastructure in Western Canada (Alberta and British Columbia) has an *average annual export capacity* of 14,890 mmcf/day (419,500 e^{3}m^3/day)[1], against a *peak day observed export capacity* of 16,090 mmcf/d (453,300 e^{3}m^3/day). Figure 2.1 details the breakdown of this basin capacity into the contributing pipelines that export natural gas out of Alberta and British Columbia for deliveries to eastern Canada and the United States.

Figure 2.1
Current Export Capacities by Pipeline



Export deliveries from the Alliance Pipeline and the Foothills/Northern Border Pipeline have historically been close to the capacity of each pipeline. However, Gas Transmission North West, Westcoast Energy and TCPL East have seen declining deliveries in volumes since the year 1999. This is partially due to a consumer response to higher prices, and partially due to an increased industrial usage of natural gas in the Alberta Oil Sands area and partially due to declining production from conventional gas resources in the Western Canada Sedimentary Basin (WCSB).

[1] TCPL, Canadian Mainline Throughput Study, Appendix G,2006

Alberta currently accounts for 81 percent of the total Canadian production with British Columbia the next largest supplier at 13 percent. Alberta's *annual average production* of natural gas peaked in 2001 at 14,353 mmcf/day (404,381 e^3m^3/day), and has declined to its current 2005 level of 13,527 mmcf/day (381,110 e^3m^3/day)[2], which represents an annual decline of 1.5 percent. With two of the export pipelines maintaining their delivery levels, coupled with the declining basin production and increasing Alberta usage, the result has been an annual average border delivery for Gas Transmission Northwest to decline by 4.6 percent per year and TCPL east to decline by 3 percent per year since the year 2000.

Table 2.1 indicates the border delivery details for the five export pipelines that will be examined in this study.

Table 2.1
Border Delivery Volumes

Pipeline	Border Point	2005/2006 Design Capacity	2005 Annual Average Daily Rate
		mmcf/day	mmcf/day
TCPL Eastern Mainline	Empress, Alberta	7210	5315
Foothills/NBPL	Monchy,Saskatchewan	2180	2100
TCPL Western Mainline	ABC Border, Alberta	2770	1790
Alliance Pipeline	Elmore, Saskatchewan	1630	1630
Westcoast Energy Pipeline	Sumas, British Columbia	1100	1050
	Total	14890	11885

The *average annual export volume* for the year 2005 was approximately 11,885 mmcf/day (334,850 e^3m^3/day)[3], which results in a system wide utilization factor of 79 percent.

TCPL's system design for Alberta indicates that the Empress border (TCPL East) has *firm service* of 3210 mmcf/day (90,440 e^3m^3/day)[4], the McNeill border (Foothills/Northern Border) has *firm service* of 1620 mmcf/day (45,640 e^3m^3/day) and the Alberta, British Columbia border (Gas Transmission Northwest) has a *firm service* of 2300 mmcf/day (64,800 e^3m^3/day). In 2005 deliveries to the Empress and McNeill border points was above the firm service levels, whereas deliveries to the ABC Border were below the firm service obligation level.

The Alliance Pipeline has a *firm service* obligation of 1325 mmcf/day (37,330 e^3m^3/day)[5], but operates at levels of 20 percent above this value.

[2] EUB, EIB-ST98-2006, Alberta's Energy Reserves 2005 and Supply/Demand Outlook
[3] TCPL, System Utilization and Reliability Monthly Report, December 2005
[4] TCPL, Nova Gas Transmission Ltd, December 2005 Annual Plan, December 2005
[5] Alliance, December 2005 Mainline Capacity Forecast, December 2005

Westcoast Energy Inc. deliveries to the Sumas border averaged 1050 mmcf/d (29,580 e^3m^3/day) in 2005.

One of the goals of this study is to determine how much spare capacity will exist in the future, including the intra Alberta, intra British Columbia and export pipelines that could be utilized to transport volumes of gas from the Mackenzie Valley Gas Pipeline and the Alaska Highway Gas projects.

After determining the available spare capacity, the remaining question is how much new capacity will be needed to handle these increased volumes. Before this can be answered, the study must first forecast the production from conventional and unconventional resources for Alberta and British Columbia, and determine the future flow rates in the various sections of the existing pipeline system. The following sections describe the current situation for pipelines, production volumes, demand requirements and export obligations for BC and Alberta.

2.1 British Columbia

The following paragraphs which describe the current and recent history of the Natural Gas pipeline industry in British Columbia was derived from the NEB document entitled "The British Columbia Natural Gas Market, An Overview and Assessment" (April 2004), and other publications and data elements from the British Columbia Oil and Gas Commission. These sources were used to define the starting point for the production forecasting model used in this study as detailed in Chapter 5.

British Columbia, the second largest supplier of natural gas in Canada, has continued to expand its production level from two to three bcf/day over a 10 year period, 1994 to 2004. British Columbia is uniquely positioned to access the Pacific Northwest and California markets by means of the export connection at Sumas, British Columbia. At the same time British Columbia can access eastern Canada, the US mid continent and Atlantic export markets by utilizing the interconnecting pipelines with Alberta. For this study, the potential flow into Alberta was taken to be the annual provincial production plus imports from the Yukon and Kitimat (LNG) minus the provincial demand and an estimate of the Sumas export volume. The residual volume would either deliver directly, or by volume displacement, to the Alberta interconnecting pipelines. This interconnecting flow volume would connect with the TransCanada pipeline system (TCPL Alberta) in northwest Alberta for transport to eastern delivery points. Future drilling profiles, LNG imports, and export deliveries to the United States (Sumas) will impact the BC volumes that move east into Alberta. This variable flow volume will have an impact on the available space capacity on the TCPL Alberta and TCPL eastern mainline systems at a point in time when the Alaska gas volumes are proposed to come on stream.

Prior to the year 2000, the British Columbia pipeline system consisted of a single major pipeline, owned by Westcoast Energy, that connected the northeast BC supply area with the lower mainland market (Vancouver) and the United States export market (Washington, Oregon and California). Smaller connections at Boundary Lake and Gordondale permitted gas to flow eastward to Alberta connecting with the TCPL Alberta pipeline system (Figure 2.2). The Gordondale pipeline is bidirectional and permits Westcoast to either deliver or receive gas supplies from Alberta. In recent years, several smaller pipelines have been constructed to connect gas fields in British Columbia along the Alberta/British Columbia border, specifically to move gas into the Western Peace River pipeline system in Alberta (Figure 2.3). These connections permit BC gas to connect with the eastern Canadian markets as well as the West North Central (WNC), East North Central (ENC), Pacific Northwest (PAC) and California markets in the United States. The largest of these border pipelines includes the CNRL pipeline that originates in the Ladyfern area, capacity 680 mmcf/day (19,100 e^3m^3/day) and the Ekwan pipeline that connects the Sierra area, capacity 418 mmcf/day(11,800 e^3m^3/day). In total these pipelines have a capacity of 1700 mmcf/day (49,700 e^3m^3/day) but to date the maximum volume transported to Alberta has been 845 mmcf/day (23,800 e^3m^3/day). The Alliance pipeline system was constructed in 2000 to transport primarily liquid rich Alberta gas to the Chicago market; however, this pipeline also connects with supplies in British Columbia and is capable of transporting 500 mmcf/day (14,087 e^3m^3/day) out of the province.

The Westcoast Energy transmission pipeline (now owned by Duke Gas Transmission) gathers gas from northeast British Columbia primarily from the Fort St. John and Fort Nelson areas and transports it south to the Vancouver and lower mainland area, as well as the export point at Sumas, British Columbia. The Southern Mainline portion of the Duke system commences at the point where the Fort Nelson, Fort St. John and Pine River laterals join. From this point, the pipeline consists of a 30 inch mainline coupled with a complete 36 inch loop and partial 42 inch loops. The pipeline utilizes 11 compressor stations with size variations from 15,000 hp (11 megawatts) to 45,000 hp (34 megawatts) to transport the gas the 546 miles to the export point at Sumas. At Sumas, approximately 60 percent of the gas heads south into the Pacific Northwest area of the United States, while Teresen Gas takes receipt of the other 40 percent for delivery to the lower mainland and Vancouver Island. The Southern Mainline has a current capacity of 2085 mmcf/day (58,742 e^3m^3/day). Gas export volumes at Sumas peaked in 1998 at 1167 mmcf/day which equated to approximately 55 percent of the Pacific Northwest demand for gas in 2001[6]

Historical information from the British Columbia Oil and Gas Commission (BCOGC) indicates that, with the exception of the EnCana Ladyfern gas area, gas production in British Columbia has consistently grown since the mid 1990s until current day. This cannot be said for the demand side of the equation. The demand for natural gas both for domestic use and export to the United States (Sumas) peaked in 2002 and has been declining ever since. The reason for the curtailment in gas demand can be viewed as a response to higher prices as residential and commercial consumers have taken measures to reduce consumption. Residential demand efficiencies in the form of household insulation, efficient furnaces and reduced thermostat settings, coupled with forest industries switching to wood chip fuel, and the general slow down as a result of the softwood lumber dispute has resulted in reducing demand. However, BC's population and the Pacific Northwest continue to grow, which is expanding the new house market and should

[6] NEB, The British Columbia Natural Gas Market, An Overview and Assessment, April 2004

stabilize the gas demand. The NEB has estimated a growth in BC demand of about 1 percent per year and the I5 corridor (Everett / Seattle, Washington and Portland, Oregon) of about 2.5 percent per year[6].

The incremental production increases is outpacing the growth in demand attached to the Southern Mainline which has led to increased flows being absorbed by the Alberta pipeline system for delivery further east to Ontario and Chicago.

Table 2.2 details the disposition of natural gas supply for the province of British Columbia for the year 2004, as published by the British Columbia Oil and Gas Commission, and a computer generated forecast for 2005. Historical gas production was used to determine the initial production rates and the decline rates from existing gas wells. These calculated values were used in the computer model to forecast the 2005 production. The 2005 forecast was compared to the actual provincial disposition and a history match factor was determined to calibrate the computer model. Figure 2.2 shows the forecast estimate for 2005.

Table 2.2
British Columbia Supply / Demand Balance

Program Simulator results (2005)

	2004	2005		
	e9m3/yr	**e9m3/yr**	**mmcf/day**	**bcf/yr**
Raw Gas Production	31	33	3174	1159
Gas Imports (AB, YU, NWT)	2	3	254	93
Plant Shrinkage, Fuel, Losses	4	5	453	165
Enhance Oil Production Injection	1	1	125	46
Exports to Alberta		10	999	365
Exports to the United States	21	11	1076	393
British Columbia usage	8	8	775	283
Balance	-1	0	0	0

Figure 2.2
Northeast BC pipeline systems

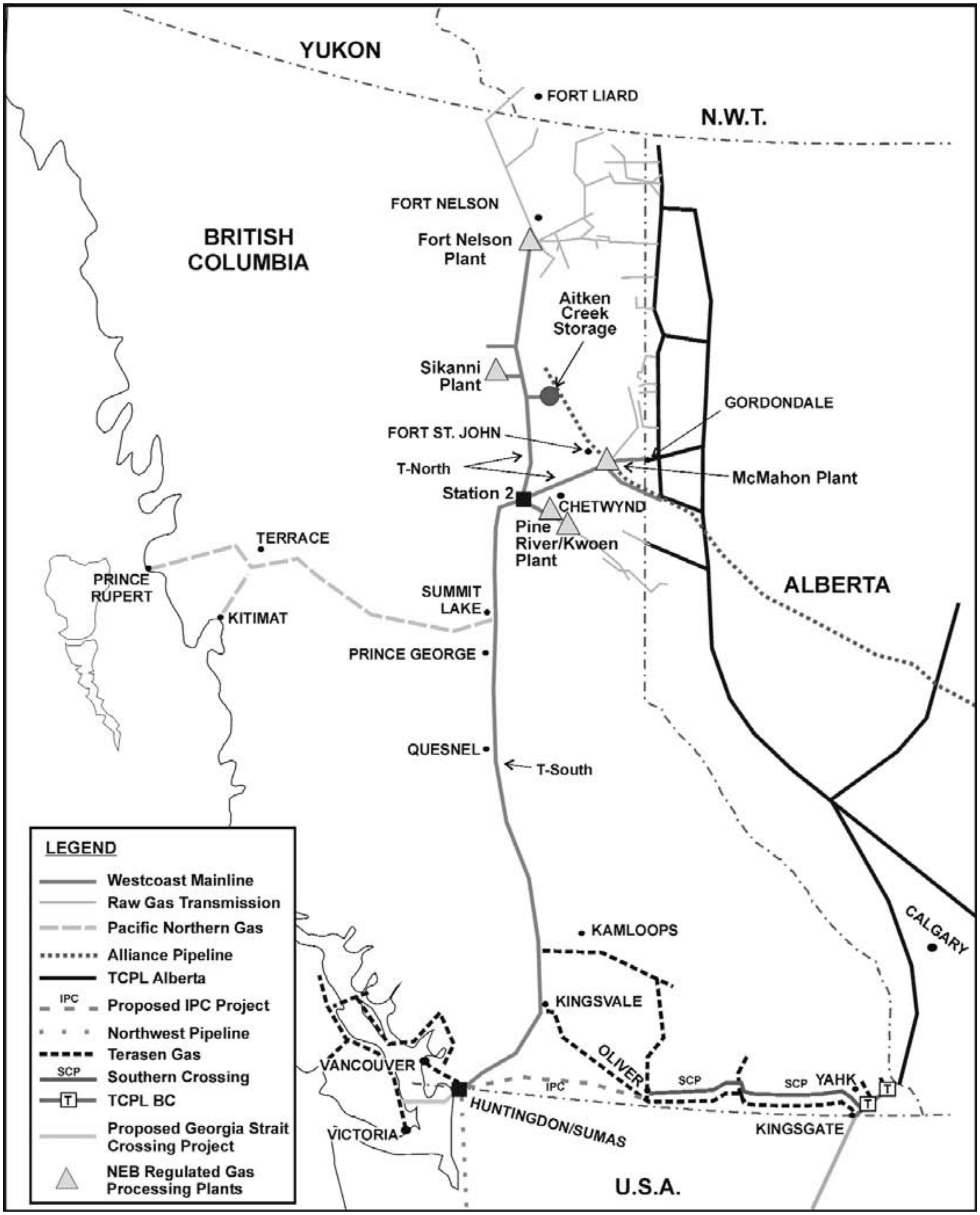
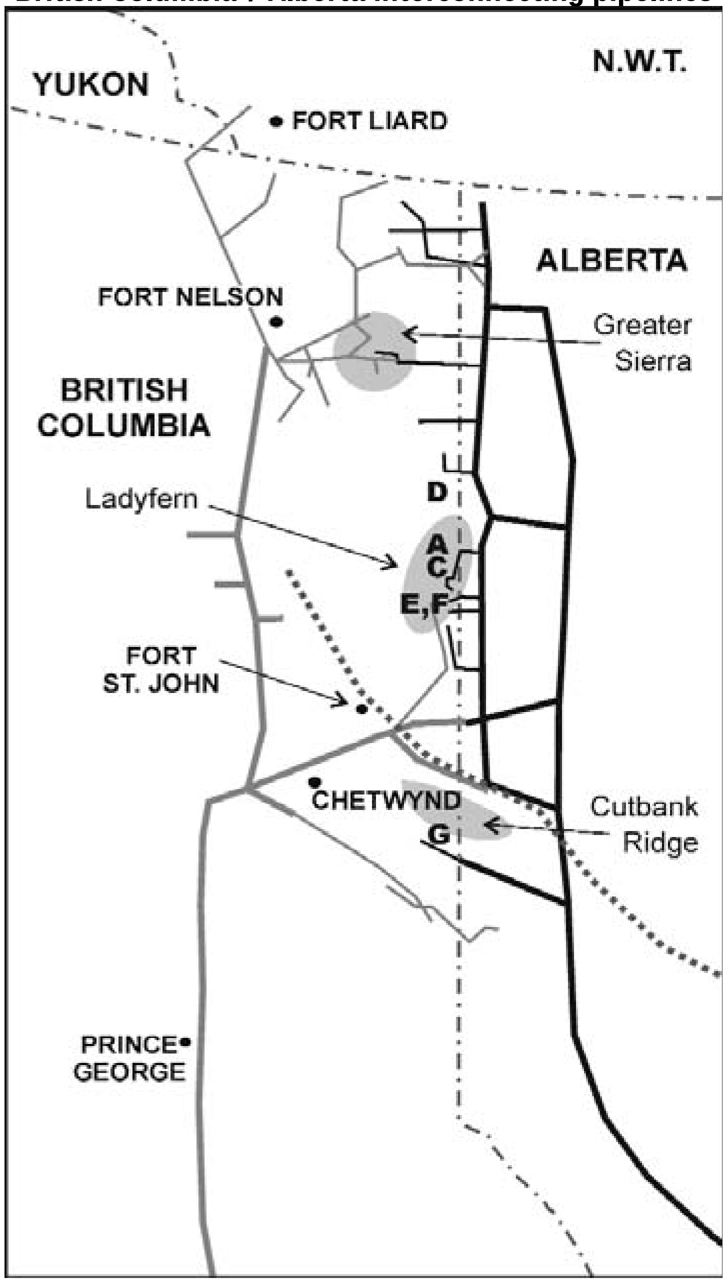


Figure 2.3
British Columbia / Alberta interconnecting pipelines



Legend

A	Pioneer, Chinchaga
B	PennWest, Wildboy
C	Murphy, Chinchaga
D	Canadian Hunter
E	EnCana, Ladyfern
F	CNRL, Ladyfern
G	EnCana, Tupper
H	EnCana Ekwan

2.2 Alberta

Alberta is the main producer of natural gas in Canada, accounting for 81 percent of the total production. Of this percentage, 12 percent is used in Alberta, 33 percent in eastern Canada and 55 percent is exported to the United States. Table 2.3 shows the disposition of Alberta's natural gas production for the year 2004.

Table 2.3
Alberta Gas Disposition (2004)

EUB 2004 GAS Distribution	Annual e3m3	Annual bcf	mmcf/day
Total Raw gas production	167,774,007	5955	16304
Imports	8,721,886	310	848
Total Raw supply	176,495,893	6264	17151
Injection	8,711,146	309	847
Flared	639,879	23	62
Fuel (Field use)	11,213,740	398	1090
Vented	397,230	14	39
Shrinkage (Field Plants)	10,958,339	389	1065
Total Field usage	31,920,334	1133	3102
Gross Marketable Supply to Pipeline	144,575,559	5,132	14,049
Fuel	4,225,633	150	411
Shrinkage (Straddle Plants)	4,573,655	162	444
Total Pipe usage	8,799,288	312	855
Net Supply	135,776,271	4819	13194
Alberta (Res,Com,El.Gen,Other)	15,929,483	565	1548
Export to BC	906,269	32	88
Export to SK	2,982,515	106	290
Export to MN	1,303,595	46	127
Export to ON	23,778,273	844	2311
Export to QU	1,595,925	57	155
Export to USA	74,425,239	2642	7232
Alberta Industrial-PetChem,Oil Sands)	14,854,966	527	1444
Total Demand	135,776,265	4819	13194
BALANCE	6	0	0

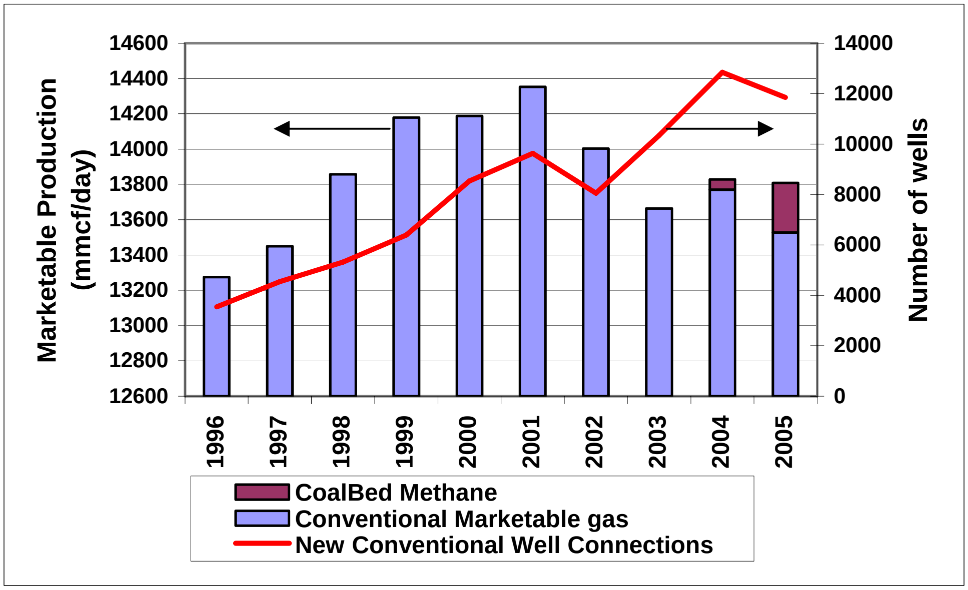
TCPL Alberta, Foothills Pipeline and Alliance Pipeline export natural gas out of the province of Alberta. Approximately 85 percent of the gas is transported on the TCPL Alberta system including the Foothills Pipelines connection with Northern Border pipeline[7]. The remaining

[7] TCPL, NOVA Gas Transmission Ltd, December 2005 Annual Plan

percentage is transported on the Alliance Pipeline which delivers virtually all of its gas to the Elmore, Saskatchewan border point. Canadian exports to the United States in 2004 averaged 8,725 mmcf/d (245,818 e^3m^3/day), of which 83 percent came from Alberta.

Production from Alberta peaked in 2001, partially due to the construction of the Alliance pipeline system and partially due to a result of the number of new well connections being driven by increased market prices (Figures 2.4, 2.5 and 2.6).

Figure 2.4
Alberta Marketable Gas Production and New Well Connections



The marginal set back in new well connections in 2002 was a result of the market price falling back to the four dollar level (Canadian dollars per gigajoule). The subsequent years (2003 and 2004) show the gas well connections in Alberta expanding at a rate of 25 percent per year, again driven by increased market prices. However, the resulting increase in production from conventional gas resources was only marginal when compared to the number of well connections. Part of the reason for the declining production is the fact that the drilling focus has been heavily weighted towards the shallow gas plays in the southeastern part of the province. The attraction to this area of the province is the low risk, low cost drilling and easy connection to the transmission system. The downside to this attraction is that the wells that are being connected have lower initial production rates and decline faster than the historical gas connections. This, coupled with the decline in production from existing wells, has caused the decline in conventional production from the province. Figure 2.4 also indicates that deliveries from the basin remained relatively stable as a result of increased production from Coalbed Methane (CBM). In 2005, approximately 3200 wells were connected for CBM production, resulting in an additional production rate of 280 mmcf/day. CBM production has grown to over

500 mmcf/day (2005) and TCPL has forecasted that CBM production will grow to 1500 mmcf/day by 2015 and 1900 mmcf/d by 2020[8].

Figure 2.5
Alberta marketable gas production and Annual Average AECO "C" market price

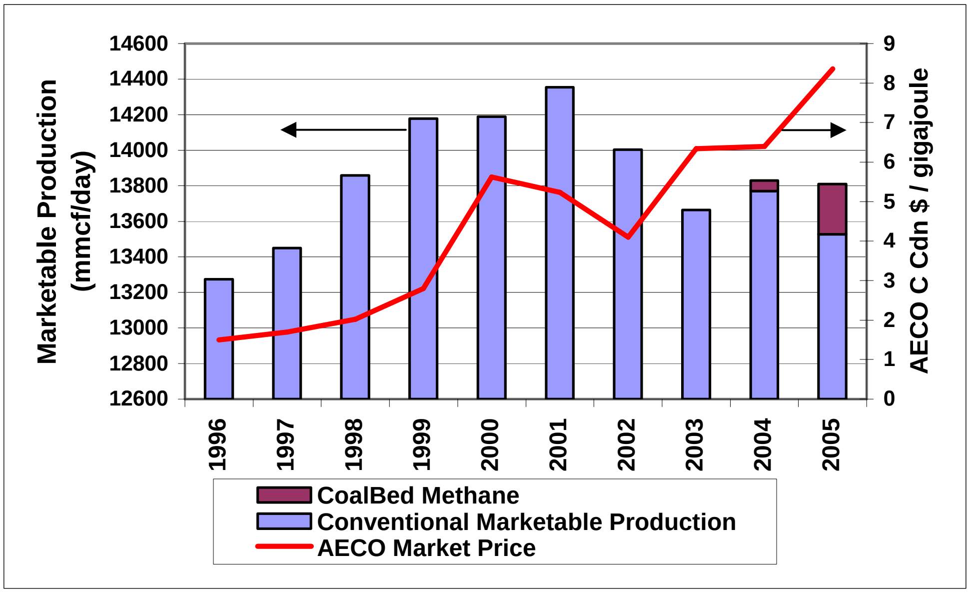
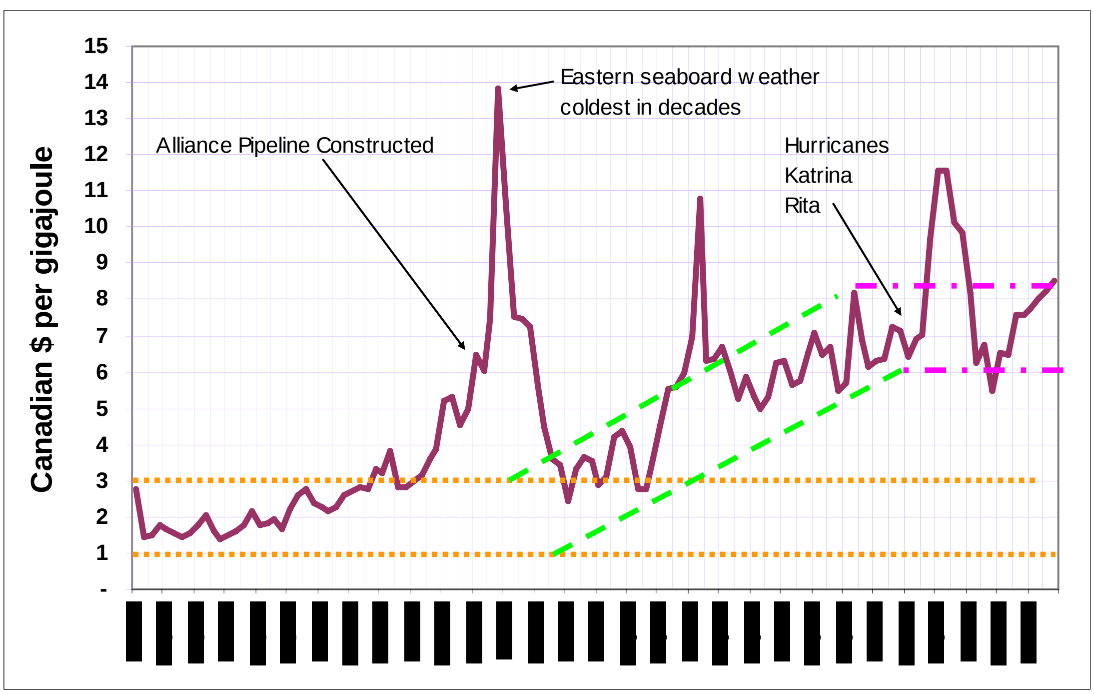


Figure 2.6
AECO "C" Monthly Average Market Prices



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8 TCPL, Canadian Mainline Throughput Study, Keystone Pipeline Transfer Application, June 2006

Chapter 5 discusses the methodology used in this study to determine a supply forecast for the WCSB basin in general and Alberta in particular. The Alberta pipeline system collects gas from approximately 1000 locations (TCPL Alberta and Alliance) within the province of Alberta, and delivers gas to 170 locations and 4 major export locations. This system has evolved over the past 40 years and, as a result of increasing and decreasing supply volumes from each of these receipt points, the amount of spare capacity can be significantly different between sections of the pipeline system. Since the level of spare capacity within the provincial pipeline system is of significant importance in determining the possible routes for handling frontier gas volumes, the basin forecast must be subdivided into smaller areas so as to properly model the flow volumes within each of the pipeline segments. Each pipeline segment can then be analyzed to determine how much spare capacity is available in each year.

Figure 2.7 indicates the three major areas (Peace River Project Area, North and East Project Area, and Mainline Project Area) used by TCPL for designing their pipeline system.

- The Peace River Design Area comprises the Upper Peace River Design Sub Area, the Central Peace River Design Sub Area, the Lower Peace River Design Sub Area, and the Marten Hills Sub Area.

- The North and East Project Area comprises the Upstream Bens Lake Design Area and the Downstream Bens Lake Design 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.

TCPL further divides these areas into sub design areas (Figures 2.8, 2.9 and 2.10) and this study has assigned a "Pipeline Influence Area" (PIA) for mainline and lateral pipes within these sub areas. The Pipeline Influence Areas are identified in Tables 5.1 and 5.2 and Figure 5.1.

- The Upper Peace River Design Sub Area comprises the Peace River Mainline from Zama Lake to the Meikle River Compressor stations (PIA 22), and the Northwest Mainline from Bootis Hill Meter Station to Hidden Lake Compressor Station (PIA 21).

- The Central Peace River Design Sub Area comprises the Western Alberta Mainline from Meikle River Compressor Station to the Clarkson Valley and Valleyview Compressor stations (Section 17), and the Northwest Mainline from Hidden Lake to Saddle Hills compressor stations (PIA 16 and PIA 20).

- The Lower Peace River Design Sub Area comprises the Grande Prairie Mainline from Saddle Hills to the Edson Meter Station and the Clarkson Valley / Valleyview compressor stations to the Edson Meter Station (PIA 13, PIA 14 and PIA 15). The Marten Hills Design Area is also included (PIA 18).

- The Upstream Bens Lake Design Area comprises several sub laterals, the Flat Lake Lateral above the Bens Lake Compressor Station and the Marten Hills Lateral above the Slave Lake Compressor (PIA 12, PIA 18 and PIA 19).

- The Downstream Bens Lake Design Area comprises the Flat Lake Lateral, the Wainwright Lateral and the North and East Laterals all downstream of Bens Lake Compressor (PIA 7 and PIA 8).

- The Mainline Project Area comprises the Edson mainline Design Sub Area, the Eastern Alberta Mainline Design Sub Area (James River to Empress) and the Western Alberta Mainline Design Sub Area (PIA 9, PIA 10, PIA 3, PIA 5, PIA 4, PIA 23).

- The remaining Pipeline Influence Areas connect into the areas detailed above as connecting laterals (Sections 1, 2, and 6) or supply gas to Edmonton (PIA 11) or Calgary (PIA 2).

Figures 2.7, 2.8 and 2.9 show the relationship between TCPL's design sub areas and the Pipeline Influence areas used in the study.

Figure 2.7
TCPL Alberta Transmission System

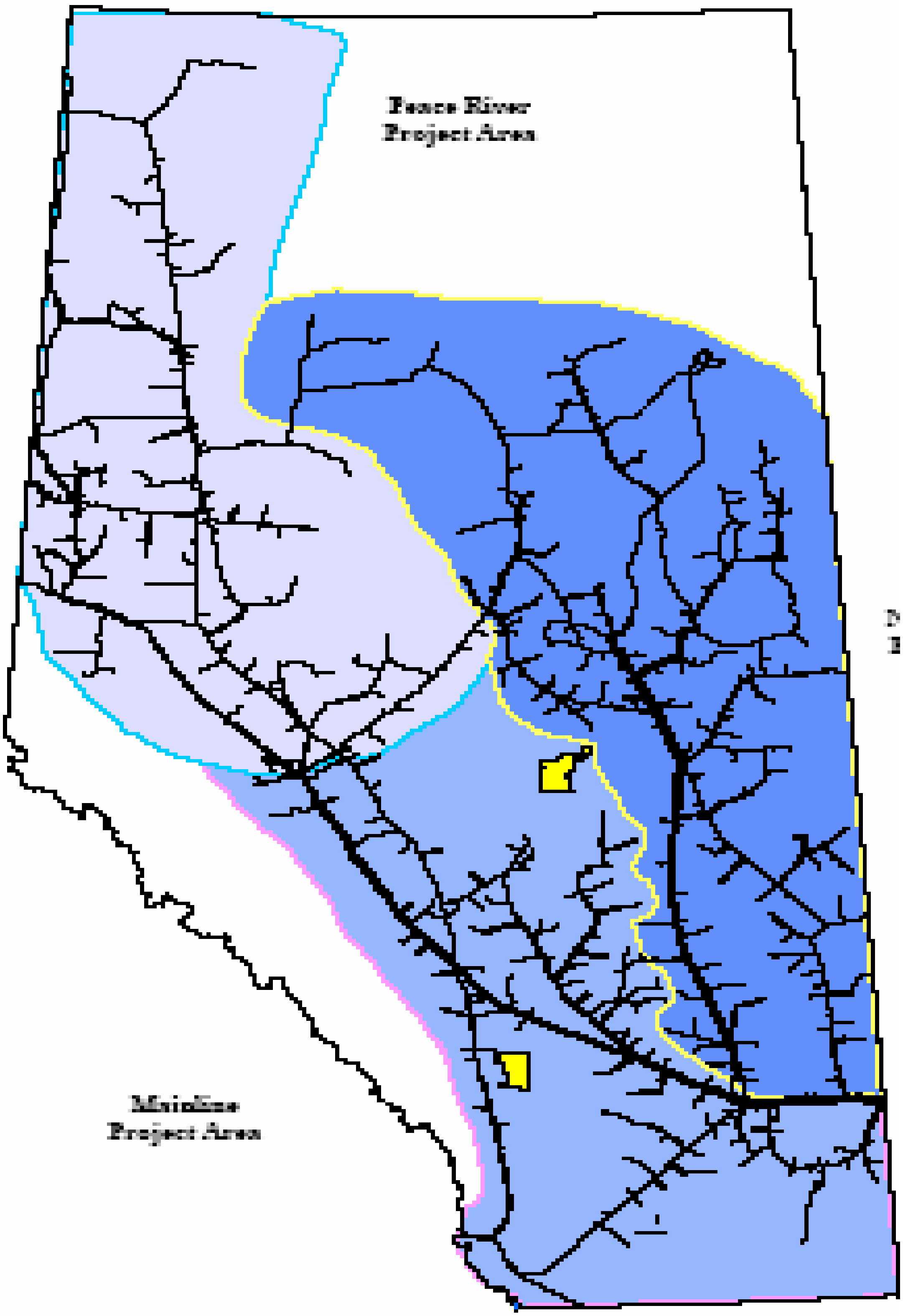


Figure 2.8
Peace River Design Area

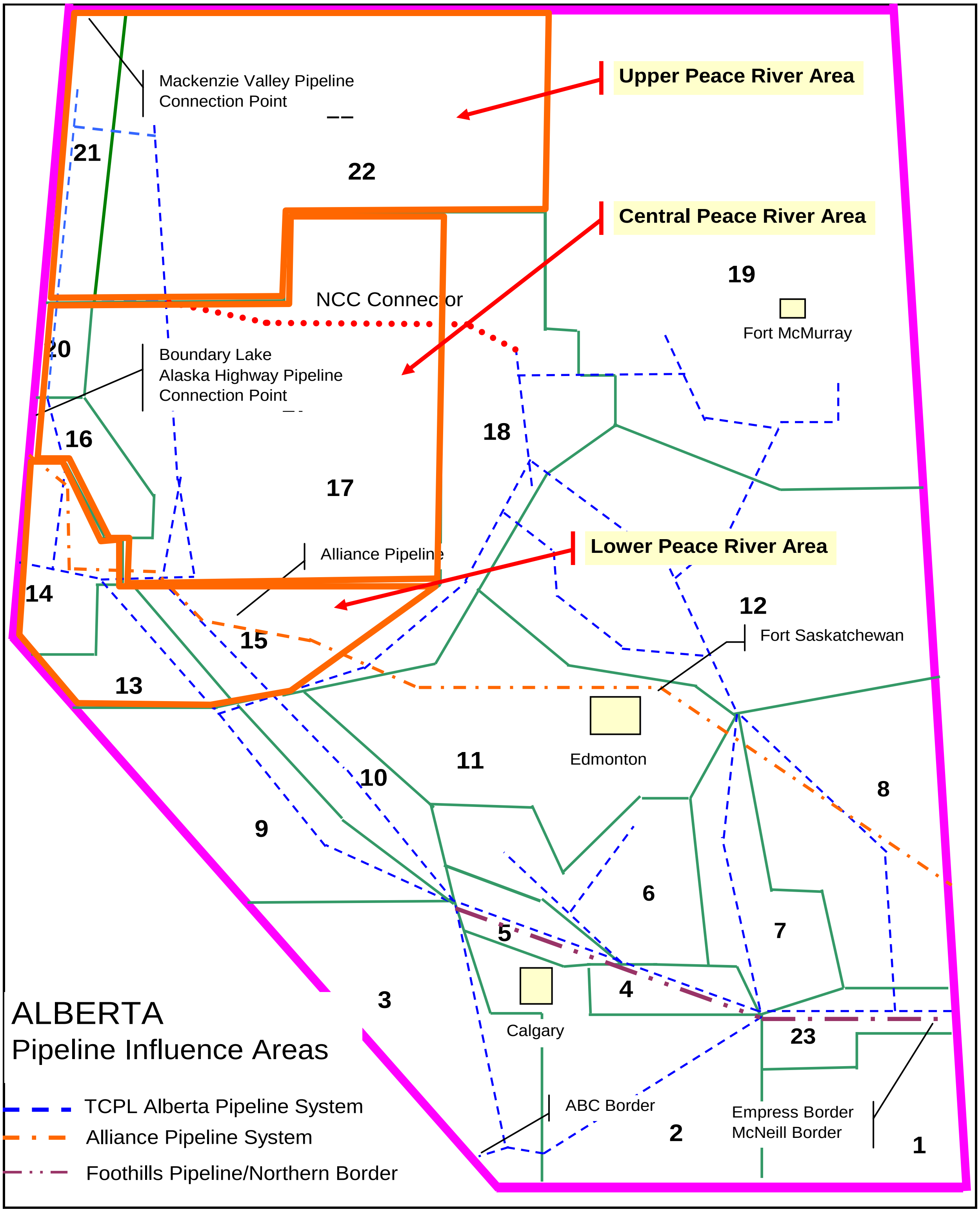


Figure 2.9
Edson - Empress Design Area

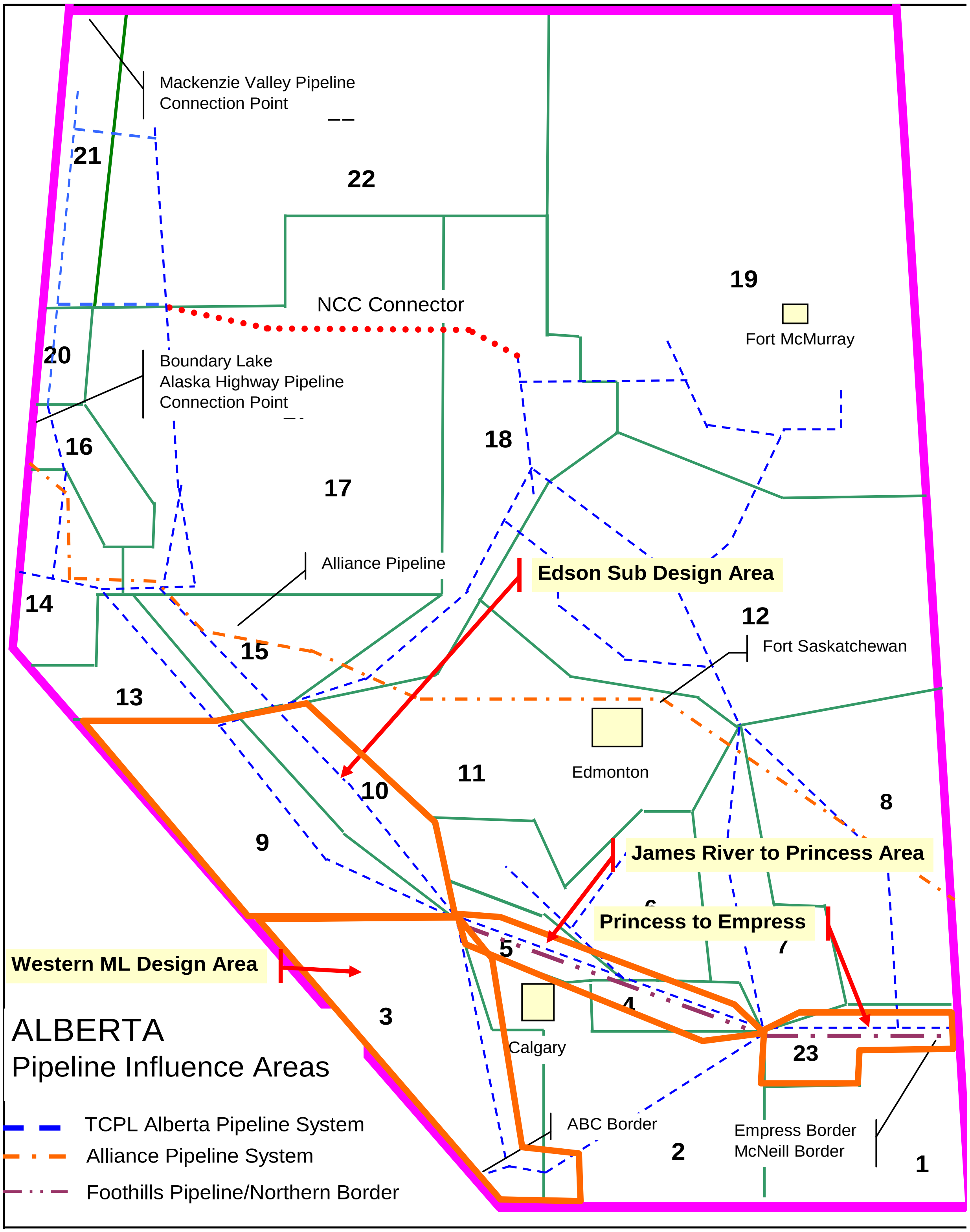
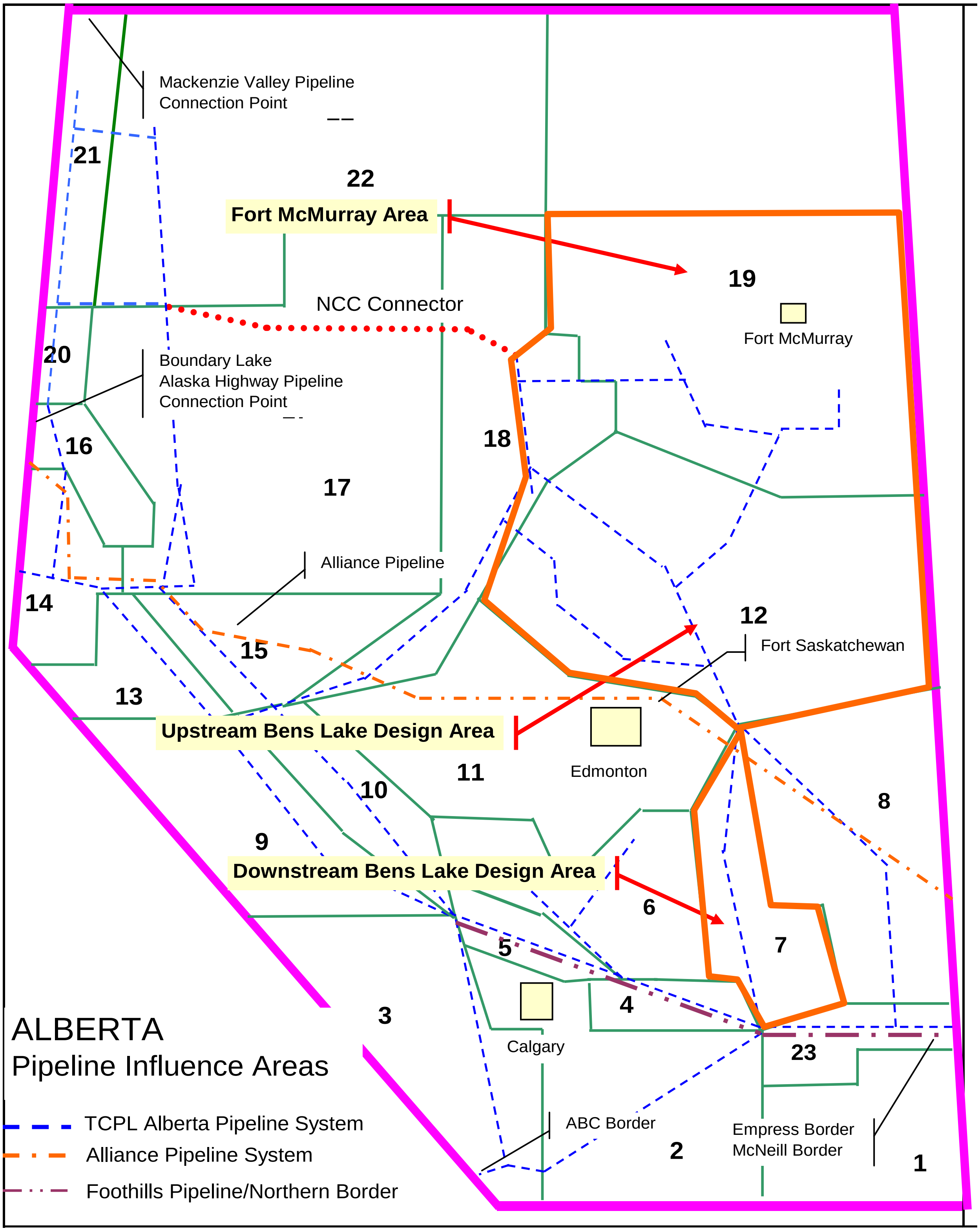


Figure 2.10
Bens Lake / Fort McMurray Design



CHAPTER 3
WESTERN CANADA EXPORT PIPELINES

3.1 Gas Transmission Northwest

The Gas Transmission Northwest Pipeline, also known as the GTN System, transports gas from the Canadian/United States border near Kingsgate, British Columbia to the Oregon/California border, where it interconnects with the Pacific Gas and Electric Company at Malin, California (Figure 3.2). Alberta is the primary source for gas supply for the GTN system, which utilizes the TCPL BC System to connect to TCPL's Alberta System. The pipeline is 614 miles in length (Kingsgate to Malin), made up of one 36 inch and one 42 inch pipe that run parallel to each other, with 12 compressor stations utilizing 29 gas turbines ranging from 10 megawatts to 23 megawatts of power. The GTN System has a capacity of 2760 mmcf/day (77,760 e^3m^3/day) from Kinsgate and delivers 1975 mmcf/day (55,645 e^3m^3/day) to the California border. Average daily volume for 2005 was 65 percent of capacity. Currently, there are no expansion projects anticipated for the GTN system since it has capacity that is not being fully utilized. If the situation presented itself where additional volumes were required to be transported, the capacity could be increased by adding additional loop and compression. A 500 mmcf/day (14,085 e^3m^3/day) increase would require approximately 60 miles of 36 inch loop pipe and ten additional gas turbines at existing compressor sites. A 1000 mmcf/day (28,174 e^3m^3/day) would require 275 miles of 36 inch loop and thirteen additional gas turbines.

The Energy Information Agency in the United States has forecasted a growth in the demand for natural gas in the Pacific Northwest census region (Washington, Oregon and California) of 2800 mmcf/day by 2020[9]. California and the I5 corridor (Seattle/Portland) are expected to be the predominate growth areas[9]. Meeting this demand growth is based on the following estimates and assumptions and represented by Figure 3.1.

- The GTN supply at Kingsgate is taken from the study base case and assumes that decline in production will be shared on a prorated basis with the provincial export pipelines except the Alliance pipeline which has contracted supply to 2020.
- Westcoast Energy deliveries to the lower mainland will increase at 1 percent and export volumes at Sumas will increase at 2.5 percent above current levels.
- The Kitimat LNG terminal will export an additional 140 mmcf/day at the Sumas border point for delivery into the Pacific Northwest.
- The Costa Azul LNG terminal in Mexico will deliver 50 percent of the send out volume to California.

[9] EIA, Annual Energy Outlook 2006, Energy Information Agency, United States, February 2006

- A new LNG terminal will be constructed in Mexico for deliveries to California starting in 2010.

- A new LNG terminal will be constructed in California starting in 2015.

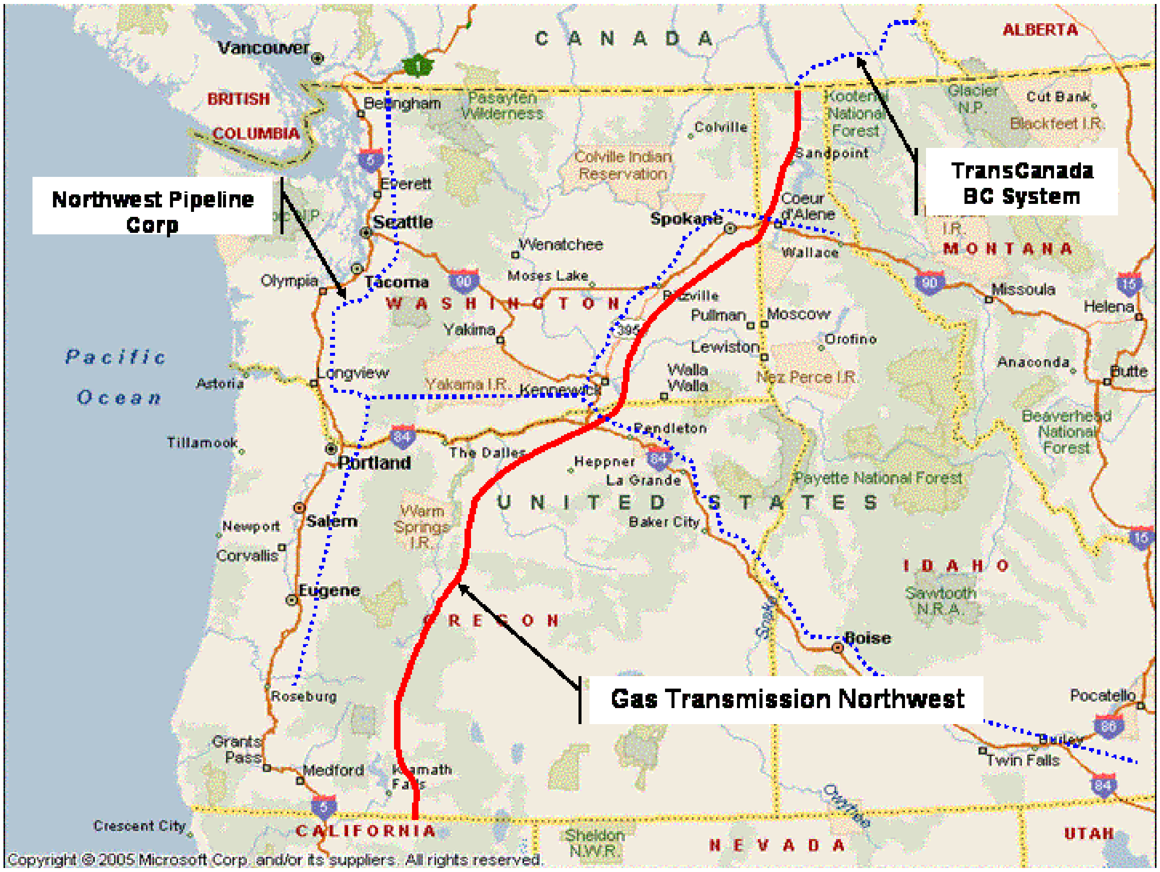
- Mid Continent deliveries to California will remain at their 2005 levels. Refer to Chapter 7 for a discussion on the potential of the mid continent pipelines.

This study has assumed that much of this demand will be supplied by a combination of gas supply from the Energie Costa Azul LNG terminal in Mexico, a new LNG terminal in Mexico and Southern California, maintained supply from the Rockies supply area and increased export volumes from the Kitimat LNG terminal in British Columbia directed to the I5 corridor increased demand. Figure 3.1 indicates that a potential deficiency still exists in the California market.

Figure 3.1
Pacific Northwest and California Supply / Demand Balance

					2005	2010	2015	2020
					tcf/yr	tcf/yr	tcf/yr	tcf/yr
Pacific Northwest								
	Supply		Gas Transmission NorthWest Pipeline	1	0.65	0.53	0.28	0.06
			Northwest Pipeline Corp (Rockies)	2	0.04	0.04	0.04	0.04
			Northwest Pipeline Corp (Sumas)	3	0.28	0.32	0.36	0.41
			Increase Supply (Sumas)	4	0.00	0.02	0.06	0.06
			Incerase Supply (Kitimat LNG)	5	0.00	0.06	0.06	0.06
			Pacific Northwest Demand (EIA estimate)		0.50	0.56	0.60	0.67
	Balance		Surplus (+) / Deficiency (-)		0.48	0.41	0.20	-0.04
	Comments	1	GTN receipts at Kingsgate					
		2	NWP deliveries from Rockies					
		3	Westcoast Energy will increase exports at 2.5% per year into the I5 corridor					
		4	Assumed new exports volumes at Sumas					
		5	Assumed Kitimat LNG export volumes					
California								
	Supply		California local Supply		0.34	0.38	0.36	0.36
			GTN residual supply to California		0.48	0.41	0.20	-0.04
			Kern River Pipeline Supply	6	0.45	0.45	0.45	0.45
			TransWestern Pipeline Supply	6	0.87	0.87	0.87	0.87
			El Paso Pipeline Supply	6	0.25	0.25	0.25	0.25
			LNG imports to California	7	0.00	0.00	0.31	0.31
			LNG imports from Mexico	8	0.00	0.16	0.31	0.47
	Demand		California Demand (EIA estimate)		2.39	2.71	2.90	3.24
			Surplus		0.00	0.00	0.00	0.00
			Deficiency		0.00	0.19	0.15	0.57
	Comments	6	Mid continent Pipes into the California market assumed to remain at current levels					
		7	California LNG terminal (85% LF)					
		8	LNG (Costa Azul) assumed delivery to California (50% volume) plus a second termin					

Figure 3.2
Gas Transmission Northwest Corporation



3.2 Foothills/Northern Border Pipeline

The Northern Border Pipeline system, also referred to as the NBPL System, transports gas from the Canada/US border near Monchy, Saskatchewan to Iowa, Illinois and Indiana, where it interconnects with several interstate pipelines (Figure 3.3). Alberta is the primary source for gas supply for the NBPL system which connects to TCPL's Alberta system by way of the Foothills Alberta pipeline system and the Foothills Saskatchewan pipeline system. The pipeline is 1654 miles in length (James River, Alberta to North Hayden, Indiana), made up of a 42 inch and 36 inch pipe with 22 compressor stations utilizing 24 gas turbines with the predominate size being 26 megawatt units. The NBPL System has a capacity of 2180 mmcf/day (61,420 e^3m^3/day) from Monchy and delivers 2220 mmcf/day (62,545 e^3m^3/day) to locations between Ventura, Iowa and North Hayden, Indiana. Gas volumes from the Williston Basin in North Dakota make up the difference between the Alberta supply and the transported volume. Average daily volume for 2005 was 95 percent of capacity. There are currently no expansion projects indicated for the NBPL System but this pipeline system could be expanded to carry additional volumes of Alaska gas when it becomes available. A 500 mmcf/day (14,085 e^3m^3/day) increase would require approximately 305 miles of 42 inch loop and four additional gas turbines at existing compressor sites. A 1000 mmcf/day increase (28,174 e^3m^3/day) would require 585 miles of 42 inch loop and five additional gas turbines. The addition of a complete 42 inch loop and expanding each station with the addition of 29 megawatt gas turbines would more than double the capacity to 4450 mmcf/day (125,375 e^3m^3/day).

Figure 3.3
Northern Border Pipeline / Alliance Pipeline

3.3 Alliance Pipeline System

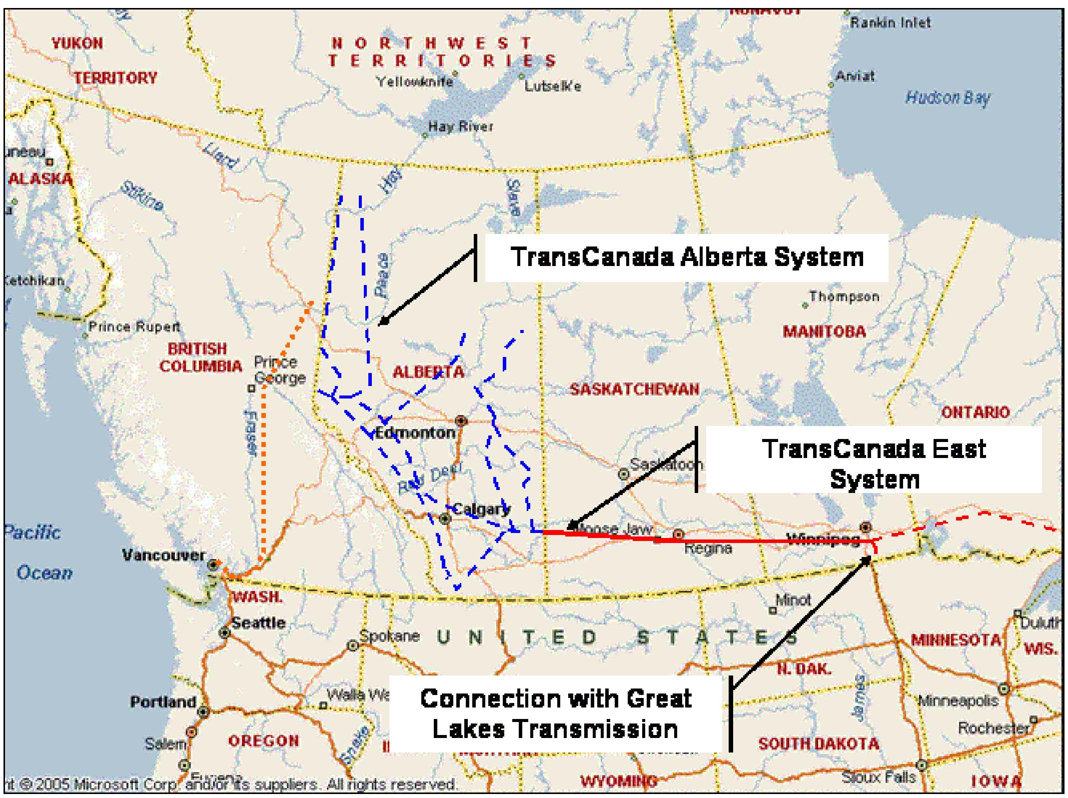
The Alliance Pipeline system transports rich natural gas from northeastern British Columbia and northwestern Alberta through Saskatchewan, North Dakota, Minnesota and Iowa to its terminus at Aux Sable Illinois (Figure 3.3). The pipeline is 1984 miles in length (Aitken Creek, British Columbia to Aux Sable, Illinois), made up of a 42 inch and 36 inch pipe with 14 compressor stations utilizing 15 gas turbines with the predominate size being 23 megawatt units. The receipt capacity of the pipeline is 1630 mmcf/day (46,485 e^3m^3/day) with 1610 mmcf/day crossing the Canada/US border and 1570 mmcf/day (43,670 e^3m^3/day) delivered to the terminus.

Completely looping the existing pipeline system from Fort Saskatchewan, Alberta to the Illinois terminal with 36 inch loop and constructing the twelve intermediate compressor stations (23 megawatt gas turbines) would increase the capacity to 3500 mmcf/day (98,609 e^3m^3/day). Adding a second 23 megawatt gas turbine to each station would further increase the capacity to 4475 mmcf/day (126,080 e^3m^3/day). Utilizing a 48 inch loop instead of the 36 inch loop, a fully powered system (two units per station) would result in a capacity of 6264 mmcf/day (176,480 e^3m^3/day).

3.4 TransCanada Eastern Mainline

The TransCanada mainline, also referred to as TCPL East, transports gas from Empress, Alberta, which is situated on the Alberta/Saskatchewan border, through Saskatchewan and Manitoba to a point south of Winnipeg. At this point 30 percent of the gas is directed south to connect with the Great Lakes Transmission Pipeline while the remaining 70 percent is directed to the TCPL Central system for delivery to Ontario, Quebec and the eastern export points into the United States (Figure 3.4). The current capacity is 7210 mmcf/d (203,130 e^3m^3/day) and the 2005 average daily deliveries were 5315 mmcf/day (149,745 e^3m^3/day) which equates to a 74 percent load factor.

Figure 3.4
TCPL East Pipeline System

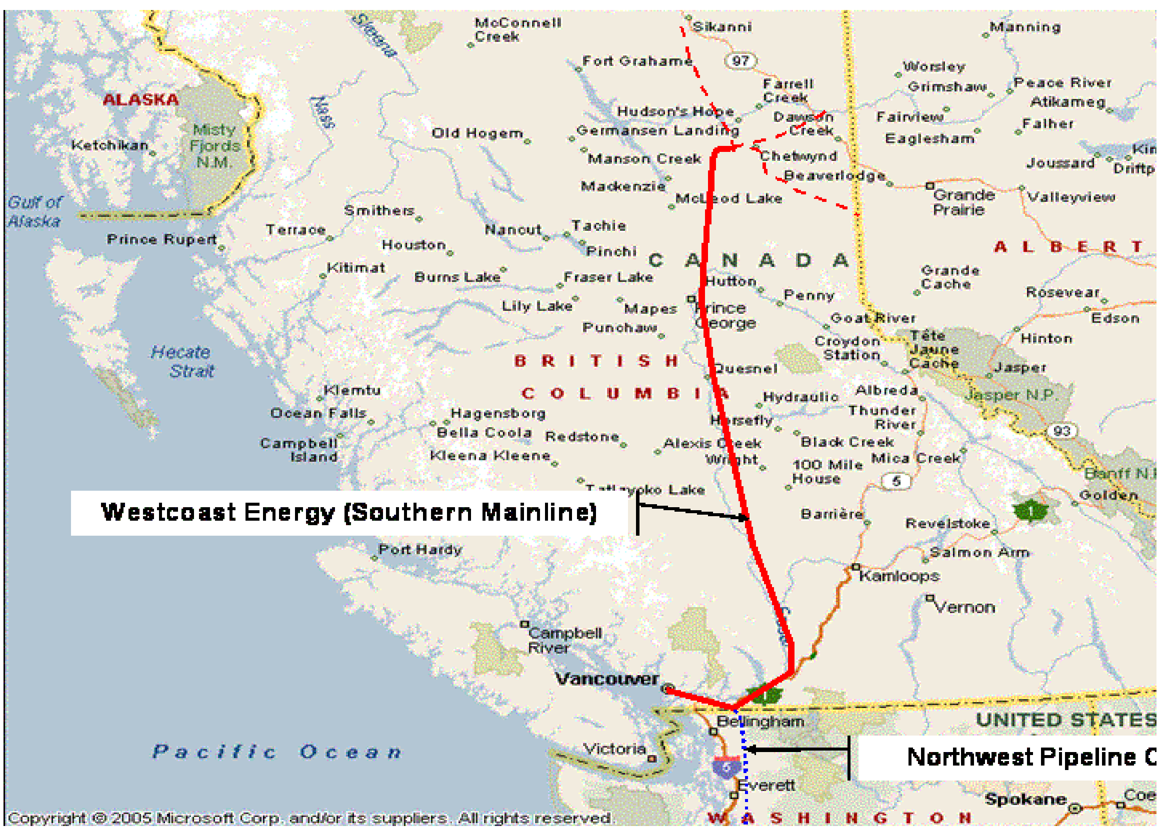


TCPL has put in an application to convert the original 34 inch pipeline from gas service to oil service. Removing this pipe from gas service would effectively reduce the capacity to 6695 mmcf/day (188,625 e^3m^3/day), which would still leave approximately 1300 mmcf/day of spare capacity in 2005. As a result of the forecasted dwindling supplies, the base case indicates that this spare capacity will increase to 1785, 1950, 2200 and 2470 mmcf/day for the years 2016 to 2019.

3.5 West Coast Energy Pipeline

The Westcoast Energy transmission pipeline gathers gas from northeast British Columbia, primarily from the Fort St. John and Fort Nelson areas, and transports it south to Vancouver and the lower mainland, and the export point at Sumas, British Columbia (Figure 3.5). The southern mainline, which is that portion of the system that starts where the gathering pipelines from Fort St. John and Fort Nelson join together and terminates at the Sumas export point, has a current capacity of 2085 mmcf/day (58,742 e^3m^3/day). Average daily volume for 2005 was 82 percent of capacity. This study has assumed that the LNG terminal at Kitimat, British Columbia will be constructed with 130 mmcf/day of the 550 mmcf/day average send out volume being directed to the export markets in Washington and Oregon. The remaining 420 mmcf/day will move east through Alberta to the eastern markets by means of volume displacement. This increased volume, coupled with increases in demand in the lower mainland, will require incremental expansion of the southern mainline by 2012.

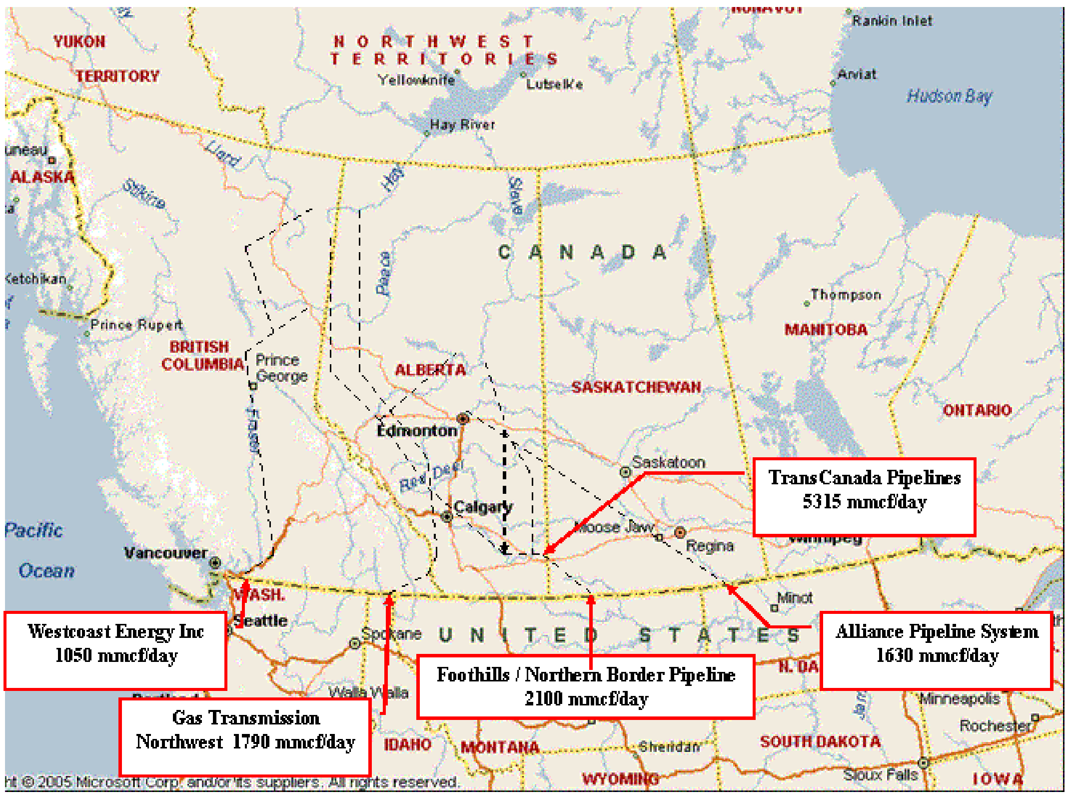
Figure 3.5
WestCoast Energy Pipeline



3.6 Provincial Transmission Pipelines.

The average annual export volume for the year 2005 was approximately 11,885 mmcf/day (334,850 e^3m^3/day)[10], or a system wide utilization rate of 79 percent. For the purpose of this study, and to give the computer models a starting point, the border obligations were assumed to be the 2005 annual average daily rate for the McNeill border, the Alberta/British Columbia border (connection to Gas Transmission NorthWest), Elmore, Saskatchewan (the Alliance Pipeline) and Sumas, British Columbia (Westcoast Energy/Duke Gas Transmission). The Empress border is assumed to receive the residual volume from the Alberta production including British Columbia imports, after the above mentioned export assumptions and the Alberta demand have been satisfied. Figure 3.6 indicates the annual average daily export volumes for the various export locations.

Figure 3.6
Alberta Average Day Export Volumes (2005)



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[10] TCPL, System Utilization and Reliability Monthly Report, December 2005

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CHAPTER 4
FRONTIER PIPELINES

4.1 The Mackenzie Valley Pipeline

The Mackenzie Valley Pipeline is assumed to start production in 2012 with an initial flow rate of 820 mmcf/d (23,270 e^3m^3/day), growing to 1200 mmcf/d (33,810 e^3m^3/day) and maintaining that level for 13 years to the end of the forecast. The 761 mile (1224 kilometer), 30 inch pipeline with four stations and one heater station will have an annual average capacity of 1295 mmcf/day (36,490 e^3m^3/day) receipt volume and 1275 mmcf/day (35,920 e^3m^3/day) delivered volume to the NWT/AB border (Figure 4.1). This production volume will be supported by the three anchor fields in the Mackenzie Delta, Niglintgak, Parsons Lake, and Taglu, plus several smaller discoveries which are assumed to be available for production in 2012. Natural gas liquids production for the first six years of the project is expected to be in the range of 13,000 barrels/day. These assumptions correspond to Case number 2 in the 2004 update to the Economic Impacts of the Mackenzie Valley Pipeline prepared by Wright Mansell Research Ltd.[11]

The Mackenzie Valley Pipeline can be expanded to handle 1600 mmcf/day (45,080 e^3m^3/day) by adding four additional intermediate stations, and 1950 mmcf/day (54,940 e^3m^3/day) by doubling the number of units at each of the eight compressor sites.

Figure 4.1 details two expansion options for the Alberta integrated pipeline system proposed by TransCanada (TCPL) to handle the volumes associated with the Mackenzie Valley pipeline. Route "A" indicates that, if constructed by TCPL, the North Central Corridor (NCC), connecting the Upper Peace River area with the Upper Bens Lake area, will handle some, or all, of the Upper Peace River (Alberta) volumes plus some, or all, of the Mackenzie Gas volumes. Route "B" will carry the Mackenzie Gas volumes south through the existing pipeline system for delivery to the export markets.

The NCC is perceived to be a facility that addresses three issues:

1. Address the growth in gas supply in the Peace River area, reducing the requirement for additional facilities that would otherwise be necessary downstream of the Peace River area.

2. Address the growth in deliveries to the Fort McMurray area.

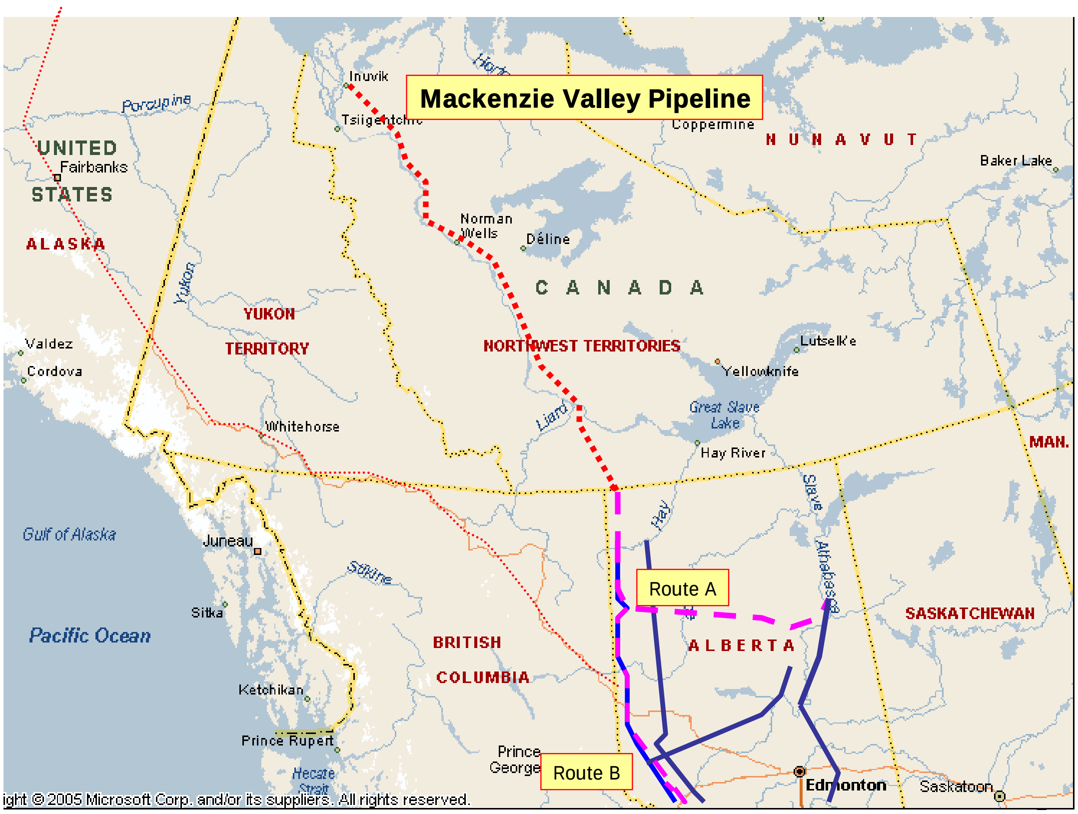
3. Minimize the fuel gas requirements associated with the Alberta integrated system.

This study assumes the NCC will be constructed to handle 700 mmcf/day (19,720 e^3m^3/day) which eliminates the need for additional facilities in the Lower Peace River and Edson Mainline sub areas (refer to Section 7.6). The demand for gas in the Fort McMurray area is such that, in

[11] Wright Mansell Research Ltd, An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Development, August 2004.

addition to the NCC volumes, the gas supply from the Fort McMurray, Bens Lake and North lateral areas plus additional volumes from the Princess compressor point would be required. Constructing the NCC to handle larger volumes would permit the Bens Lake / North Lateral areas to continue flowing south to Princess, but this would result in the utilization factor for the Lower Peace river, Edson and James River to Princess areas, decreasing.

Figure 4.1
The Mackenzie Valley Pipeline



The Inuvik area gas plant is expected to recover 90 percent of the “pentanes plus” and 50 percent of the butanes. The ethane and propane volumes, plus the residual of the butanes and pentanes, will remain in the gas stream for delivery to the TCPL Alberta integrated pipeline system at the Alberta/Northwest Territories border. Assuming that these volumes flow south and eventually reach the James River crossover point, additional liquids would be extracted at both the Empress Straddle plant facility and the Cochrane straddle plant facility. Table 4.1 is a representation of the raw gas components, liquid recoveries at Inuvik, sales gas components entering Alberta and the liquids potential for the Alberta straddle plants. This chart assumes that the gas stream from the Mackenzie Delta fields will produce approximately 34,300 barrels per day (5.445 m^3 per day) with 13,000 barrels extracted at Inuvik and 21,300 barrels extracted in Alberta.

Volumes of gas that are transported through the NCC facility will not be processed by a straddle plant, resulting in lost liquid volumes. This study has assumed that marketable gas volumes from the Upper Peace River and eastern side of the Central Peace River areas will be directed to the NCC corridor, thus allowing the Mackenzie Valley volumes to flow south connecting with the existing straddle plants at Cochrane and Empress. This assumes that the ethane and propane volumes contained within the Mackenzie Valley gas stream are more significant than the residual components within the Peace River supply volumes. An economic comparison of directing flow streams towards or away from straddle plant operations was not considered in this study.

Table 4.1
Mackenzie Valley Gas Pipeline
Liquid Recovery Potential

MACKENZIE VALLEY Pipeline						
	Mackenzie Gathering System Plant Inlet composition	Mackenzie Recovery efficiency	Mackenzie Gathering Plant Liquid Recovery	Mackenzie Gathering System Plant Exit composition	AB Straddle Recovery efficiency	AB Straddle Plant Liquid Recovery
	%	%	bbls	%	%	bbls
Methane	94.1	0	0	95.4	0	0
Ethane	2.3	0	0	2.3	65	11500
Propane	0.6	0	0	0.6	85	4000
Butane	1.2	50	5500	0.6	90	5000
Pentanes	0.8	90	7500	0.1	100	800
CO2	1.0	0	0	1.0	0	0
Total	100		13000	100		21300

Table 4.2 provides a cost estimate of the Mackenzie Valley pipeline from Inuvik to the Alberta / Northwest Territories border. This cost estimate is based on baseline 2002 Canadian dollar estimates taken from the COLTKBR Mackenzie Gas Project cost estimate report[12]. From these baseline numbers, appropriate escalation factors were applied to labor and materials to arrive at a 2004 estimate. This estimate of $3.566 billion (2004 Canadian dollars) was compared against the Wright Mansell Research report[13], which indicated the pipeline portion of the project, based on project sponsors input, would be $3.5 billion (2004 Canadian dollars).

In August 2006, Imperial Oil Ltd. indicated that the cost of the project had jumped in expected cost and, although Imperial did not give any particulars, it is assumed that materials have increased in cost by 20 percent and labor by 30 percent. Taking these factors into account, the estimate for the Mackenzie Valley pipeline is $4.377 billion (2006 Canadian dollars), for the gas pipeline, plus an additional $0.7 billion (2006 Canadian dollars) for the liquids line. The liquids line will bring extracted liquids from Inuvik to Norman Wells to connect with existing pipeline systems.

[12] COLTKBR, Detailed System Optimization, Mackenzie Gas Project, December 2003
[13] Wright Mansell Research Ltd, An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas,2004

Table 4.2
Mackenzie Valley Pipeline Cost Estimate

Cost Parameters		Units	2002 Cdn dollars	Escalation to 2006			
Pipeline Steel		$/tonne	1120	90			
External coating		$/1000 m2	13000	35			
Internal coating		$/1000 m2	4200	35			
Buoyancy control		$/dia inch km	485	35			
Miscellaneous material		% pipe	3.25	35			
Freight and Handling		$/tonne	540	35			
Construction		$/dia inch km	19525	45			
Infrastructure		$/dia inch km	8500	35			
Logistics		$/dia inch km	1860	35			
EPCM		% of cost	9	0			
Contingency		% of cost	25	0			
Station Base cost		1000$	32837	45			
Cost per power unit		1000$/kw	1.7298	35			
Chiller Base cost		1000$	5950	45			
Chille cost per power unit		1000$/kw	0.354	35			
Heater Station Base Cost		1000$	500	45			
Heater Station power unit		1000$/kw	0.666	35		12	
Inuvik to NWT/AB Border		Diameter	Length	Operating Pressure	Yield Strength	Wall thickness	Weight
		inches	miles	psi	psi	inches	lbs per foot
Pipeline	1.1	30	761	2610	80000	0.614	192.5
Pipeline	1.2	0	0	0	0	0	0
Pipeline	1.3	0	0	0	0	0	0
		Number of Stations	Number of units per station	unit size	Number of chillers	Chiller unit size	Heater Station
				megawatts		megawatts	megawatts
Compression	1.4	1	5	10	5	10	0
Compression	1.5	4	1	10	1	10	0
Compression	1.6	1	0	0	0	0	5
		Inlet flow	exit flow	fuel gas			
		mmcf/d	mmcf/d	mmcf/d			
Year 1 Flow		**813**	**800**	**13**			
Year 2 Flow		**1230**	**1200**	**30**			
		1000 cdn dollars					
Pipeline Cost		**$3,655,790**					
Compressor Cost		**$629,931**					
Chiller Cost		**$86,149**					
Heater Cost		**$5,221**					
Total Cost		**$4,377,090**					

Note: In March 2007, following the publication of this study (Volume 1), Imperial Oil Limited re-estimated the cost for the Mackenzie Valley Pipeline. For an updated cost estimate refer to Volume 2 of this study.

4.2 The Alaska Highway Pipeline

For the purpose of this study, the Alaska Highway Pipeline is assumed to start production in 2016 with an initial flow rate of 3300 mmcf/day (92,974 e^3m^3/day) growing to 4500 mmcf/day (126,780 e^3m^3/day) in year 3 and maintaining that volume out past the forecast period. There is speculation that the Prudhoe Bay fields are capable of delivering 6000 mmcf/day (169,045 e^3m^3/day) which is investigated as a scenario later in the report. The pipeline route is comprised of 745 miles (1200 kilometers) of pipe within the state of Alaska and 940 miles (1512 kilometers) within the Yukon Territory and the province of British Columbia, connecting to the TCPL Alberta System at Boundary Lake on the border between Alberta and British Columbia (Figure 4.2).

Figure 4.2
Alaska Highway Pipeline and WCSB Export Pipelines

The current design of the pipeline is centered on using either a 48 inch (1220 millimeter) diameter or a 52 inch (1320 millimeter) diameter pipeline. The study has assumed that a unit size equivalent to the LM2500 gas turbine will be used on the pipeline with multiple units at each station. Table 4.3 and Figure 4.3 show the relationship between station spacing, number of units and average capacity. Actual compressor station locations, site elevations and compressor unit sizes will indicate the resultant pipeline capacity but, for this study, utilizing the LM2500 gas turbine (2 units per station with chillers in permafrost areas) with 120 mile spacing, a 48 inch pipeline will yield an annual average capacity of approximately 4750 mmcf/day (133,825 e^3m^3/day) receipt volume and 4625 mmcf/day (130,300 e^3m^3/day) delivered to Boundary Lake.

Under this design, the capacity with four units per station would be approximately 5850 mmcf/day (164,800 e^3m^3/day) receipt volume and 5810 (163,690 e^3m^3/day) delivered to Boundary Lake.

Table 4.3
Alaska Highway Capacity Alternatives

			LM2500		LM2500			Annual
Pipe Size	Spacing		Summer		Winter			Average
			28080 HPA		30550 HPA			Capacity
	miles		mmcf/day	CR	mmcf/day	CR		mmcf/day
48 inch, 1.04 wt,2500psi	100	1 unit	4075	1.19	4185	1.2		4130
		2 units	5020	1.32	5145	1.34		5083
		3 units	5605	1.44	5720	1.47		5663
		4 units	6015	1.56	6130	1.61		6073
		5 units						
48 inch, 1.04 wt,2500psi	110	1 unit	3940	1.19	4055	1.21		3998
		2 units	4845	1.33	4960	1.35		4903
		3 units	5405	1.46	5525	1.49		5465
		4 units	5795	1.59	5905	1.63		5850
		5 units						
48 inch, 1.04 wt, 2500 psi	120	1 unit	3825	1.2	3925	1.21		3875
		2 units	4695	1.34	4805	1.36		4750
		3 units	5235	1.48	5340	1.51		5288
		4 units	5605	1.61	5710	1.66		5658
		5 units						
52 inch, 1.12 wt, 2500 psi	120	1 unit	4410	1.17	4530	1.18		4470
		2 units	5450	1.29	5580	1.31		5515
		3 units	6095	1.4	6240	1.43		6168
		4 units						

Figure 4.3
Alaska Highway Pipeline Alternatives

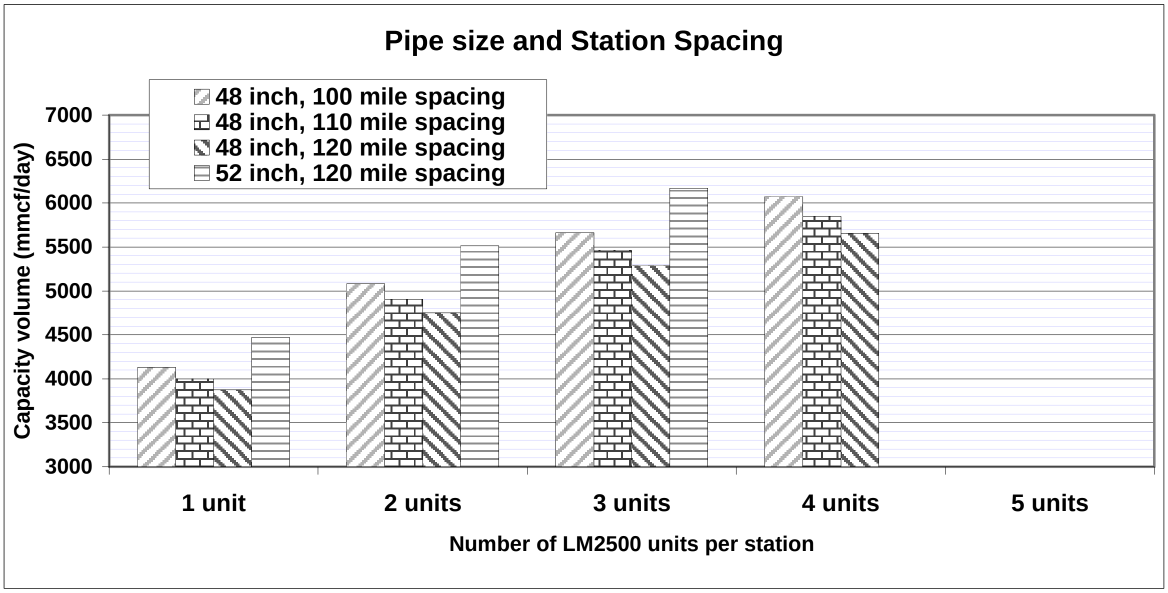


Table 4.4 is a representation of the marketable gas components for the gas stream entering Alberta and the liquids potential (barrels/day) for the Alberta straddle plants. This chart assumes the gas stream will either enter the existing TCPL Alberta pipeline system to have the liquids removed at Empress or Cochrane, or a new straddle plant will be constructed at Fort Saskatchewan, prior to the gas entering the Alliance Pipeline System.

Table 4.4
Liquid Recovery Potential

ALASKA HIGHWAY Pipeline							
					Alaska Gathering System Plant Exit composition	AB Straddle Recovery efficiency	AB Straddle Plant Liquid Recovery
					%		bbls
	Methane				89.90	0	0
	Ethane				6.30	65	115000
	Propane				2.40	85	59000
	Butane				0.35	90	10000
	Pentanes				0.05	100	2000
	CO2				1.00	0	0
	Total				100		186000

As indicated before, the economic merits of constructing a new straddle plant facility at Fort Saskatchewan compared to mixing gas streams with Alberta volumes and utilizing the existing facilities was not considered as part of this study.

Tables 4.5 and 4.6 provide a cost estimate of the Alaska Highway Gas Project broken down into the Alaska section (745 miles) and the Yukon/British Columbia section (940 miles). This project assumes that year one will have a flow of 3070 mmcf/day (94,946 e^3m^3/day) which represents the constructed pipeline with one unit (LM2500) per station. Year three will have all the compressor units installed (two LM2500 units per station).

Table 4.5
Alaska Highway Pipeline Cost Estimate
Alaska Section

Cost Parameters		Units	2002 Can $	Esc % to 2006 $			
Pipeline Steel		$/tonne	1120	90			
External coating		$/1000 m2	13000	35			
Internal coating		$/1000 m2	4200	35			
Buoyancy control		$/dia inch km	485	35			
Miscellaneous material		% pipe	3.25	35			
Freight and Handling		$/tonne	540	35			
Construction		$/dia inch km	19525	45			
Infrastructure		$/dia inch km	8500	35			
Logistics		$/dia inch km	1860	35			
EPCM		% of cost	9	0			
Contingency		% of cost	25	0			
Station Base cost		1000$	32837	45			
Cost per power unit		1000$/kw	1.7298	35			
Chiller Base cost		1000$	5950	45			
Chille cost per power unit		1000$/kw	0.354	35			
Heater Station Base Cost		1000$	500	45			
Heater Station power unit		1000$/kw	0.666	35			
Alaska Section		Diameter	Length	Operating Pressure	Yield Strength	Wall thickness	Weight
		inches	miles	psi	psi	inches	lbs per foot
Pipeline	1.1	48	745	2500	80000	1.04	521
Pipeline	1.2	0	0	0	0	0	0
Pipeline	1.3	0	0	0	0	0	0
		Number of Stations	Number of units per station	unit size	Number of chillers	Chiller unit size	Heater Station
				megawatts		megawatts	megawatts
Compression	1.4	1	5	16	5	16	0
Compression	1.5	6	2	23	2	16	0
Compression	1.6	0	0	0	0	0	0
		Inlet flow	exit flow	fuel gas			
		mmcf/d	mmcf/d	mmcf/d			
Year 1 Flow		**3070**	**3035**	**35**			
Year 3 Flow		**4635**	**4570**	**65**			
		1000 cdn dollars					
Pipeline Cost		**$7,257,228**					
Compressor Cost		**$1,625,344**					
Chiller Cost		**$190,381**					
Heater Cost		**$0**					
Total Cost		**$9,072,953**					

Note: In March 2007, following the publication of this study (Volume 1), Imperial Oil Limited re-estimated the cost for the Mackenzie Valley Pipeline. This revised estimate contributed to an updated cost estimate for the Alaska section of the Alaska Highway Pipeline. For an updated cost estimate refer to Volume 2 of this study.

Table 4.6
Alaska Highway Pipeline Cost Estimate
Yukon / British Columbia Section

Yukon/British Columbia		Diameter	Length	Operating Pressure	Yield Strength	Wall thickness	Weight
		inches	miles	psi	psi	inches	lbs per foot
Pipeline	2.1	48	940	2500	80000	1.04	521
Pipeline	2.2	0	0	0	0	0	0
Pipeline	2.3	0	0	0	0	0	0
		Number of Stations	Number of units per station	unit size	Number of chillers	Chiller unit size	Heater Station
				megawatts		megawatts	megawatts
Compression	2.4	6	2	23	2	16	0
Compression	2.5	0	0	0	0	0	0
Compression	2.6	0	0	0	0	0	0
		Inlet flow	exit flow	fuel gas			
		mmcf/d	mmcf/d	mmcf/d			
Year 1 Flow		**3035**	**3000**	**35**			
Year 3 Flow		**4570**	**4500**	**70**			
		1000 cdn dollars					
Pipeline Cost		**$9,156,771**					
Compressor Cost		**$930,205**					
Chiller Cost		**$143,522**					
Heater Cost		**$0**					
Total Cost		**$10,230,499**					

Note: In March 2007, following the publication of this study (Volume 1), Imperial Oil Limited re-estimated the cost for the Mackenzie Valley Pipeline. This revised estimate contributed to an updated estimate for the Yukon/British Columbia section of the Alaska Highway Pipeline. For an updated cost estimate refer to Volume 2 of this study.

CHAPTER 5
METHODOLOGY

5.1 Model Methodology

The primary objective of this study is to determine the amount of spare capacity that currently exists and to estimate the amount of spare capacity that might exist in the future for the pipelines that export gas from the two western provinces (GTN, Alliance, NBPL, Westcoast and TCPL east), and the transmission pipelines that operate within the two western provinces (Alliance, Westcoast and TCPL Alberta).

TCPL Alberta, Westcoast Energy and Alliance pipelines operate pipelines that gather gas from supply areas within Alberta and British Columbia. The amount of spare capacity within these provincial pipeline systems will vary from area to area as a result of the changing natural gas supply patterns in the future. In order to estimate these changing supply patterns, CERI first divided the physical pipeline systems into 36 "Pipeline Influence Areas" (PIA) and then developed a computer model to estimate the future deliverability potential for each area. The elements that contribute to the pipeline area performance and resulting capacity determinations are as follows:

- The geographical layout of the intra provincial pipeline systems.
- The number of new well connections per year.
- The initial production rates for new well connections by area.
- The rate of decline in existing production rates by area.
- The rate of decline for new well connections for each year after connection.
- New supply forecasts (LNG, Mackenzie Valley Gas, and Alaska Highway Gas).
- The provincial demand for natural gas and the potential for change in that demand as a result of efficiency changes (oil sands purchase gas requirements).
- Export obligations.

5.2 Pipeline Influence Areas

A "Pipeline Influence Area" encompasses a section of the pipeline system that in itself gathers natural gas between locations where other laterals join the pipeline or points where the pipeline route bifurcates into laterals, connectors or additional mainlines. Tables 5.1 and 5.2 and Figures 5.1 and 5.2 detail the 36 areas used in the study

Table 5.1
British Columbia Influence Areas

AREA	Area Description	Map Reference
30	Pine River plant, Sukunka, Grizzly	NTS 093-I 093-J
31	Burlington Noel Plant, Cutbank Noel	NTS 093-P
32	D/S McMahon Plant to CS 2	DLS 78-21W6
33	D/S McMahon Plant to Gordondale Border	DLS 78-16W6
34	McMahon Plant Supply, Boundary, Buick,Tommy Lakes,Beatton River	DLS 85-20W6
35	Ladyfern	NTS 094-H-1
36	Burlington Ring Plant	NTS 094-H-16
37	Devon Kahntah plant	NTS 094-J-2
38	Encana Ekwan, Sierra	NTS 094-I-10
39	DEFS Peggo plant	NTS 094-P-8
40	Penn West Wildboy plant, Helmet North	NTS 094-P-10
41	D/S Fort Nelson plant to CS2	NTS 094-B,094-G
42	U/S Fort Nelson plant, Sirerra, Yoyo, Beaver River, Kotaneelee NWT	NTS 094-J, 094-O

Table 5.2
Alberta Pipeline Influence Areas

Area	Area Description	Abbreviation
1	Medicine Hat lateral, Suffield block	Medicine Hat
2	South Lateral, Letbridge area	South Lateral
3	James River to Alberta/British Columbia border	Foothills ML West
4	Hussar compressor stationto Princess compressor station	James R-Princess
5	James River to Hussar compressor station	James R-Princess
6	Rimbey / Nevis areas to Hussar "A" compressor	Rimbey Lateral
7	North Lateral, Bens Lake to Proncess "A"	North Lateral
8	East Lateral, Bens Lake to Cavendish compressor station	East Lateral
9	Edson mainline, Edson to James River	Edson Mainline
10	Foothills mainline, Mcleod River to James River	Edson Mainline
11	Edmonton supply area	Edmonton
12	Up stream Bens Lake compressor to Tweedie,Calling Lake, Big Bend	U/S Bens Lake
13	Edson mainline, Gold Creek to Edson	Lower Peace
14	Saddle Hills compressor station to Gold Creek compressor station	Lower Peace
15	Foothills mainline, Valleyview compressor to Knight compressor station	Lower Peace
16	Gordondale, Boundary Lake, Teepee creek areas	Central Peace
17	Peace River pipeline, Meikle River compressor - Valleyview compressor	Central Peace
18	Marten Hills lateral up to Darling Creek area	Marten Hills
19	Fort McMurray area, Liege, Cold Lake, Wandering River compressor	Fort McMurray
20	Hidden Valley compressor station to Alces River compressor	Central Peace
21	Hidden Valley compressor north to AB/NWT border	Upper Peace
22	Zama - Meikle River compressor	Upper Peace
23	Princess to Empress mailine section	Princess-Empress

Figure 5.1
Alberta Pipeline Influence Areas

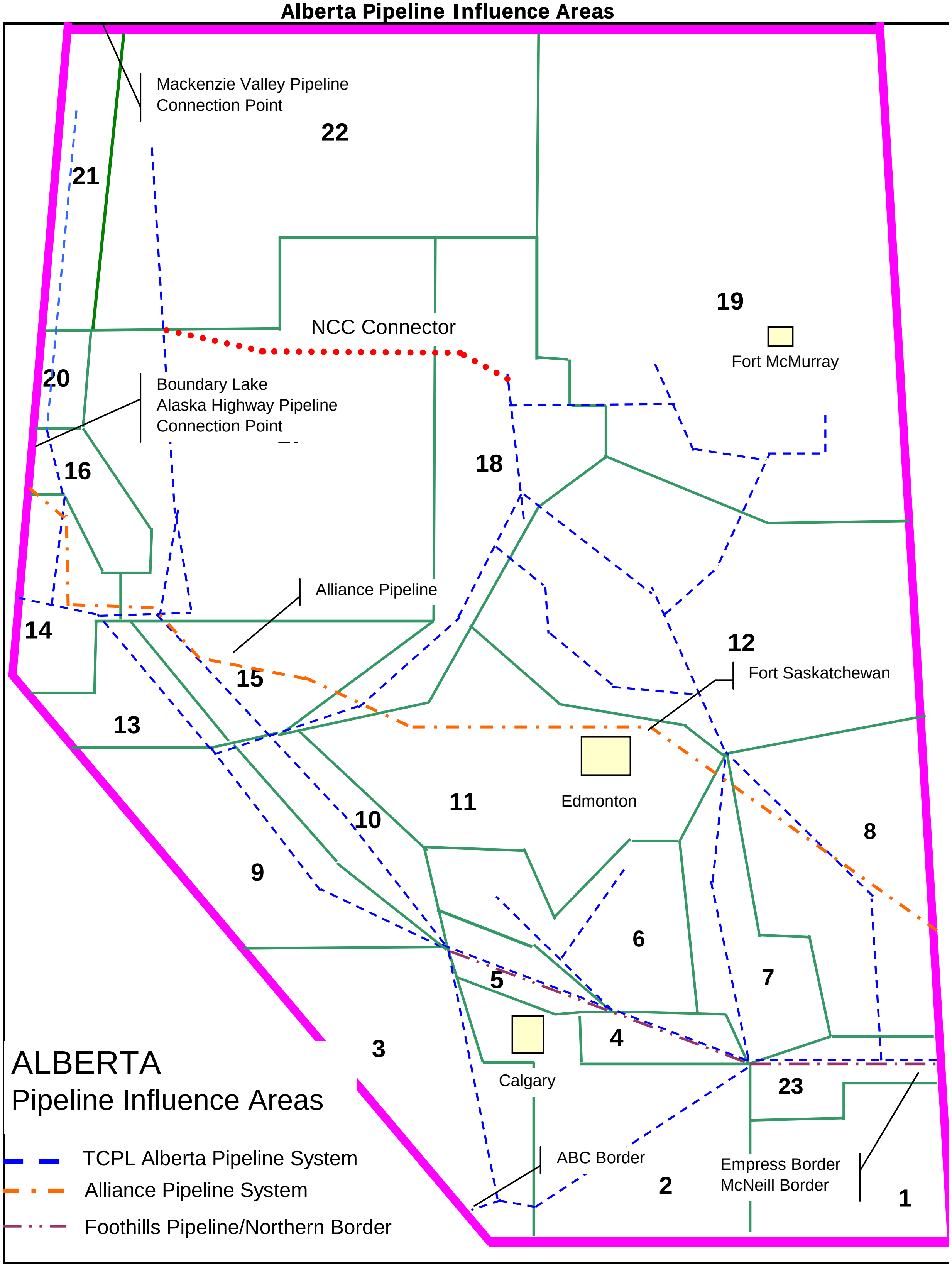
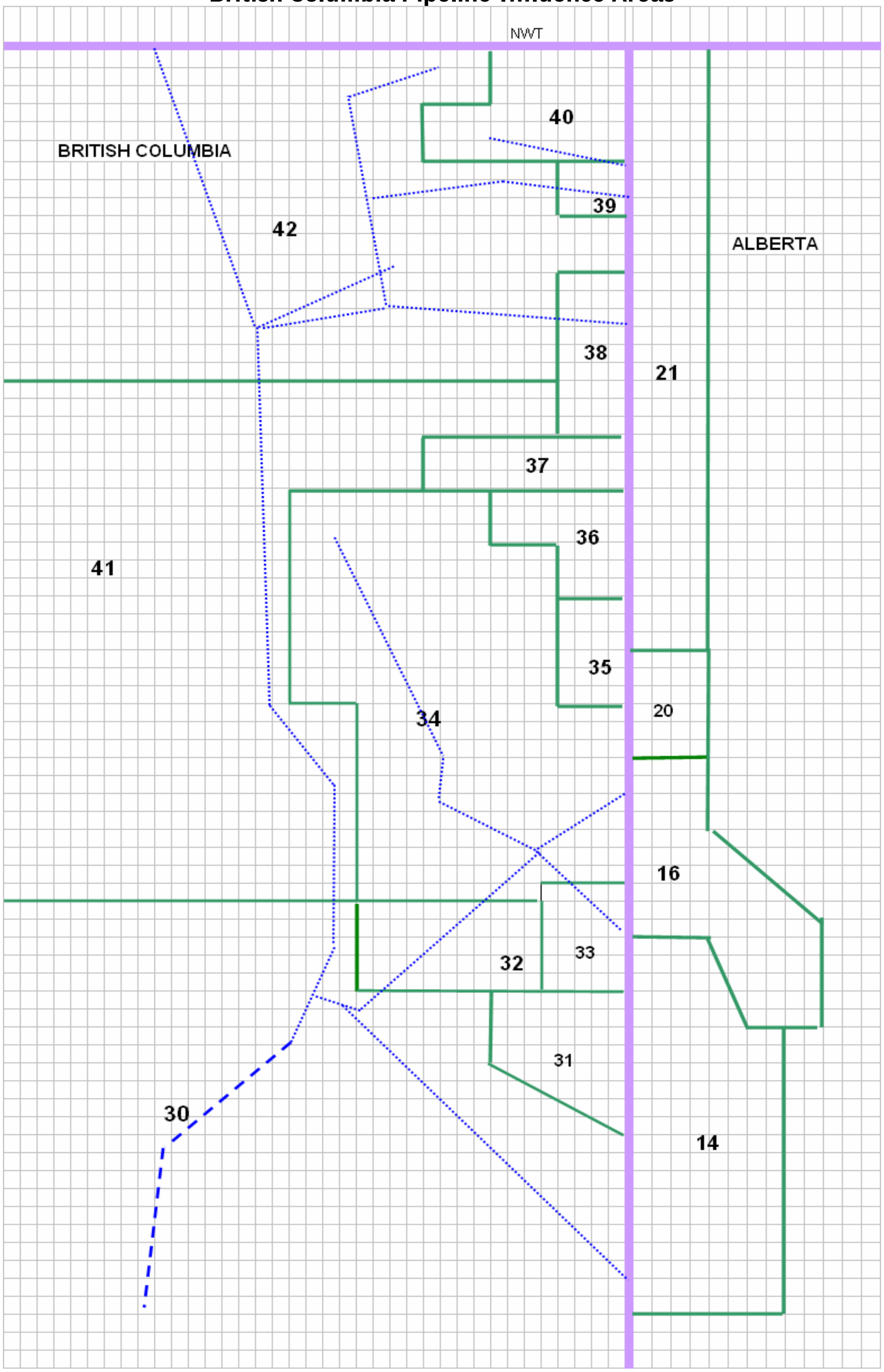


Figure 5.2
British Columbia Pipeline Influence Areas



5.3 New Connections

With the exception of the 2002 drilling season, new well connections in Alberta have continuously grown from just under 4,000 wells in 1996 to 13,244 wells in 2005. British Columbia has also experienced a strong growth in new well connections expanding from 120 wells in 1996 to 1,168 well connections in 2005. This growth can be characterized by higher than average but stable prices in the late 1990s, followed by price escalation in 2000/01 driven by severe weather conditions on the east coast, and a constant increase in price between the September 11, 2001 tragedy and the hurricane season of 2005. The year 2005 saw gas prices move up dramatically as a result of increased demand for gas over the hot summer followed by supply disruptions as a result of hurricanes Katrina and Rita. Prices at AECO "C" spiked at values in excess of ten dollars Canadian per gigajoule but have since dropped back to the seven dollar level. The current supply/demand relationship for the North American Gas market is currently at a delicate balancing point as continental supplies have reached a plateau while demand continues to rise.

The Base Case was generated by starting from the EUB ST98-2006 Alberta reserves report which assumes "the number of new well connections in the province will remain high, at 12,000 wells per year"[14]. The EUB forecast extends out to the year 2015. For this study, the Base Case assumes the number of new well connections can be maintained out to the year 2020. The British Columbia forecast mimics the rational behind the EUB forecast and establishes the BC new well connections at 1,100 wells per year. The ability to maintain these connection levels is predicated on the fact that the drilling fleet is growing at 5 percent per year and the number of drillable locations have increased as a result of the EUB modifying the drilling densities for development within the Mannville or shallower formations. The British Columbia portion of the basin is behind Alberta in its development, thus the degree of drillable locations remains relatively high.

Base Case curves are used to determine the basin deliverability forecast, while the other three curves are used to bracket the basin response to alternate connection schedules. Figure 5.3 illustrates the four well connection forecasts. The "AB High Case" assumes the expanding rig fleet (approximately 25-35 new rigs per year)[15] will continue, along with the increased rig utilization will result in a new well connection growth of 3.5 percent to a maximum of 18,000 connections. The "AB Growth Case" assumes a slightly less aggressive growth of 2 percent per year to a maximum of 15,000 connections, based on the assumption that some of the new rigs will be directed to CBM development projects. The "AB Low Case" assumes that gas prices will retreat below the $6 Canadian per gigajoule as a result of recent high gas prices curtailing demand growth in the future and new LNG supplies coming on stream and supplying an ever increasing portion of the supply mix.

[14] EUB, ST98-2006, Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015, May 2006

[15] CAODC, Average Weekly Rig Count Mar 2004 – June 2006, Canadian Association of Oil Well Drilling Contractors, June 2006

Figure 5.4 illustrates the new well connection forecast for the province of British Columbia using the same assumptions as described for Alberta. The "BC High Case" uses a 2 percent growth instead of the 3.5 percent based on the assumption that gas development in British Columbia will encompass a higher degree of expensive exploration, whereas Alberta development is predominately infill drilling. The "BC Base Case" assumes new well connections of 1100 wells per year for the next 15 years followed by a nominal decline.

Figure 5.3
Alberta New Well Connection Forecasts

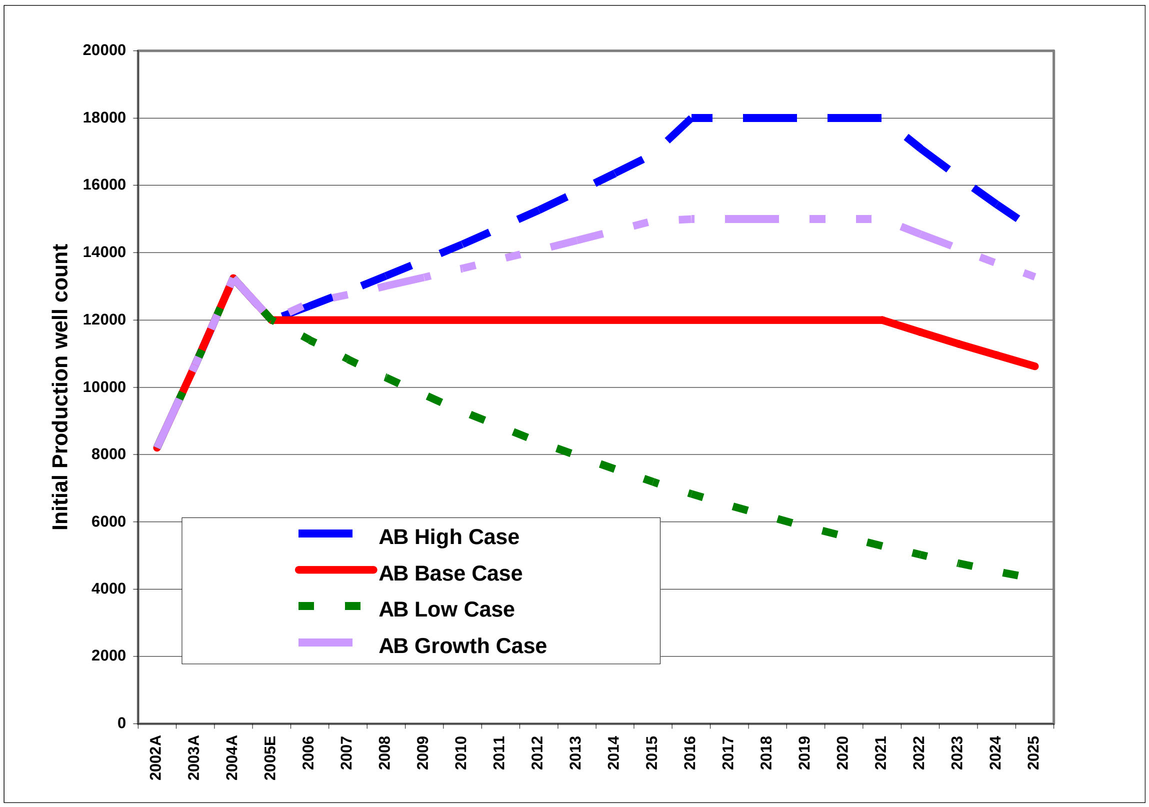
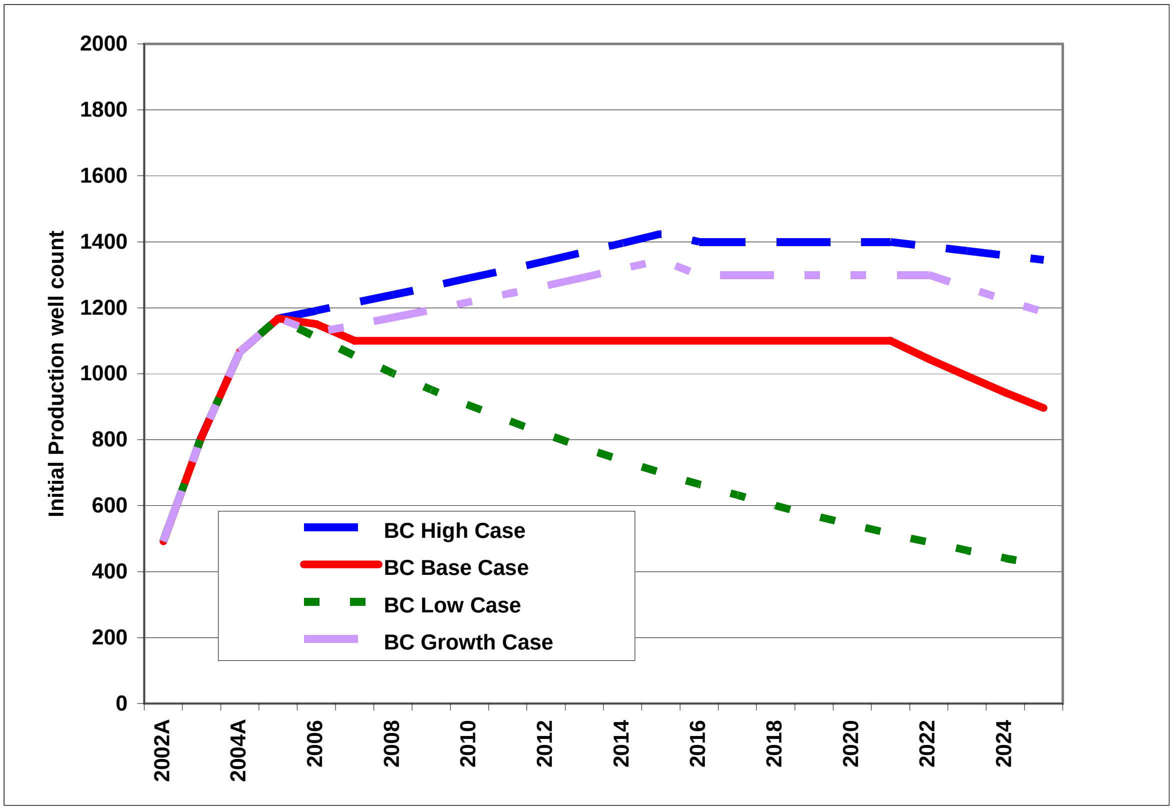


Figure 5.4
British Columbia New Well Connection Forecasts



5.4 Initial Production Rates

In determining a future production forecast, one of the main elements is the expected initial production rate for the new well connections detailed in Section 5.3. Production from these new well connections adds to production from established reserves and yet-to-be-discovered ultimate potential resources. The combined production stream partially replaces the loss of production as a result of normal production decline and partially expands the total supply volume. New well connections today start at much lower rates than wells placed on production in previous years simply because a significant portion of the new wells are drilled into existing pools that have declining pool pressures as a result of production from existing wells. This declining pool pressure leads to a lower initial production rate. Drilling in the southeast part of Alberta typically has lower initial production rates because the reserves are shallower and less productive than conventional drilling in other areas of the province.

This study utilized the historic production data obtained from the EUB and BCOGC in order to estimate the new well production rate for the different pipeline influence areas. Each well that started production within a given year is grouped together, complete with the first 12 months (may be non consecutive months) of production data (daily production rates). For each area, an average rate is determined for the first year of production, and all the years from 1995 forward are plotted and extrapolated to 2005. This results in the estimated initial daily production rate for each area as detailed in Tables 5.3 and 5.4. The degradation of these initial rates was assumed to be 3 percent[16] per year and production from these new wells is assumed to decline at the indicated decline percentage for each year after the initial year of production.

Table 5.3
Production Forecast Input Parameters

Area	Initial Production Rate 2005	Annual decline	Year 1	Year 2	Year 3	Year 4	Year 5
	mcf/day	%	%	%	%	%	%
30	2133	3	38	18	22	26	10
31	967	3	44	22	20	20	20
32	733	3	35	28	24	20	18
33	492	3	44	30	25	15	15
34	332	3	35	28	20	18	18
35	192	3	38	36	20	20	15
36	284	3	24	20	20	18	15
37	51	3	20	18	16	12	12
38	321	3	35	28	24	20	18
39	532	3	35	28	24	20	18
40	527	3	32	22	16	12	10
41	804	3	30	30	18	18	10
42	827	3	30	20	18	16	16

[16] EUB, ST98-2006, Albert's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015, May 2006

Table 5.4
Alberta Production Forecast Input

Area	Initial Production Rate 2005	Annual decline	Year 1	Year 2	Year 3	Year 4	Year 5
	mcf/day	%	%	%	%	%	%
1	40	3	32	25	21	18	18
2	65	3	32	25	21	18	18
3	939	3	32	25	21	18	18
4	56	3	32	25	21	18	18
5	49	3	32	25	21	18	18
6	77	3	32	25	21	18	18
7	59	3	32	25	21	18	18
8	47	3	32	25	21	18	18
9	426	3	32	25	21	18	18
10	144	3	32	25	21	18	18
11	119	3	32	25	21	18	18
12	70	3	32	25	21	18	18
13	545	3	32	25	21	18	18
14	613	3	32	25	21	18	18
15	279	3	32	25	21	18	18
16	314	3	32	25	21	18	18
17	212	3	32	25	21	18	18
18	138	3	32	25	21	18	18
19	87	3	32	25	21	18	18
20	147	3	32	25	21	18	18
21	65	3	32	25	21	18	18
22	125	3	32	25	21	18	18
23	41	3	32	25	21	18	18

5.5 Unconventional Gas Supply

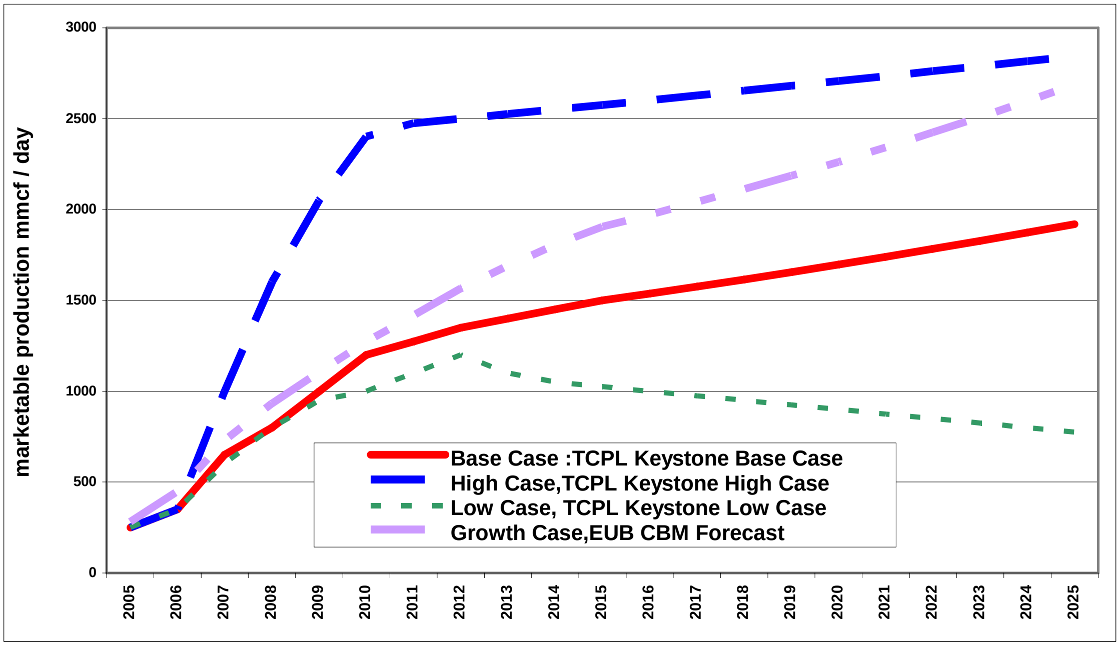
Coalbed methane (CBM), also know as natural gas from coal, is the methane gas found in coal both as absorbed gas and as free gas. Coal is found in large quantities in British Columbia and Alberta, and methane gas is present in some form in all types of coal. However, the gas content, pressure, depth and water content of the coal seam will determine if CBM production is economic or not. Currently, the Horseshoe Canyon Coal Formation, which exists in the area between Edmonton and Calgary, is the focus of much of the CBM production to date. CBM production has reached the 390 mmcf/day (11070 e^3m^3/day) level based on 4,588 producing wells averaging 90 mcf/day/well.[17] The Horseshoe Canyon trend encompasses approximately 880 townships (31,800 sections) of land of which less than half is developable. The rest of the resource is either inaccessible because it underlies populated areas or the coal thickness or gas content is below economic limits. Development of the Horseshoe Canyon will require an additional 30,000 to 50,000 wells which would result in a peak production rate of around 1500 to 2500 mmcf/day (42,260 – 70,435 e^3m^3/day). Development of the Mannville formations is less predictable as a result of the potential problems of dealing with the produced water which is not present in the Horseshoe Canyon formation. Figure 5.5 details the CBM forecasts used in the study and entered as external forecasts. The Base Case, Low Case and High Case were taken from the Mainline Throughput study, submitted to the NEB as part of the TransCanada Keystone Pipeline application. The Growth Case is adopted from the EUB CBM production forecast from the ST98-2006 report[18] .

In the future, unconventional natural gas in the form of coalbed methane will be a larger contributor to the provincial supply that it is today. CBM is a resource that depends heavily on drilling in order to achieve any kind of flow levels. The average initial production rate for conventional natural gas wells in Alberta (excluding the southeast shallow gas system) is approximately 248 mcf/d (7.0 e^3m^3/day), while the average CBM well has an initial production rate of approximately 85 to 105 mcf/d (2.5 to 3.0 e^3m^3/day). CBM wells tend to decline by 60 percent in the first three to four years, while conventional wells decline by 30 - 40 percent in the first three to four years. The net result is five to six CBM wells are required to match the average conventional gas wells production. The wells required for the CBM resource are considered in excess of the wells required for the conventional resource production.

[17] TCPL, Canadian Mainline Throughput Study, Appendix G,2006

[18] EUB, ST98-2006, Albert's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015, May 2006

Figure 5.5
Alberta CBM Marketable Gas Forecast



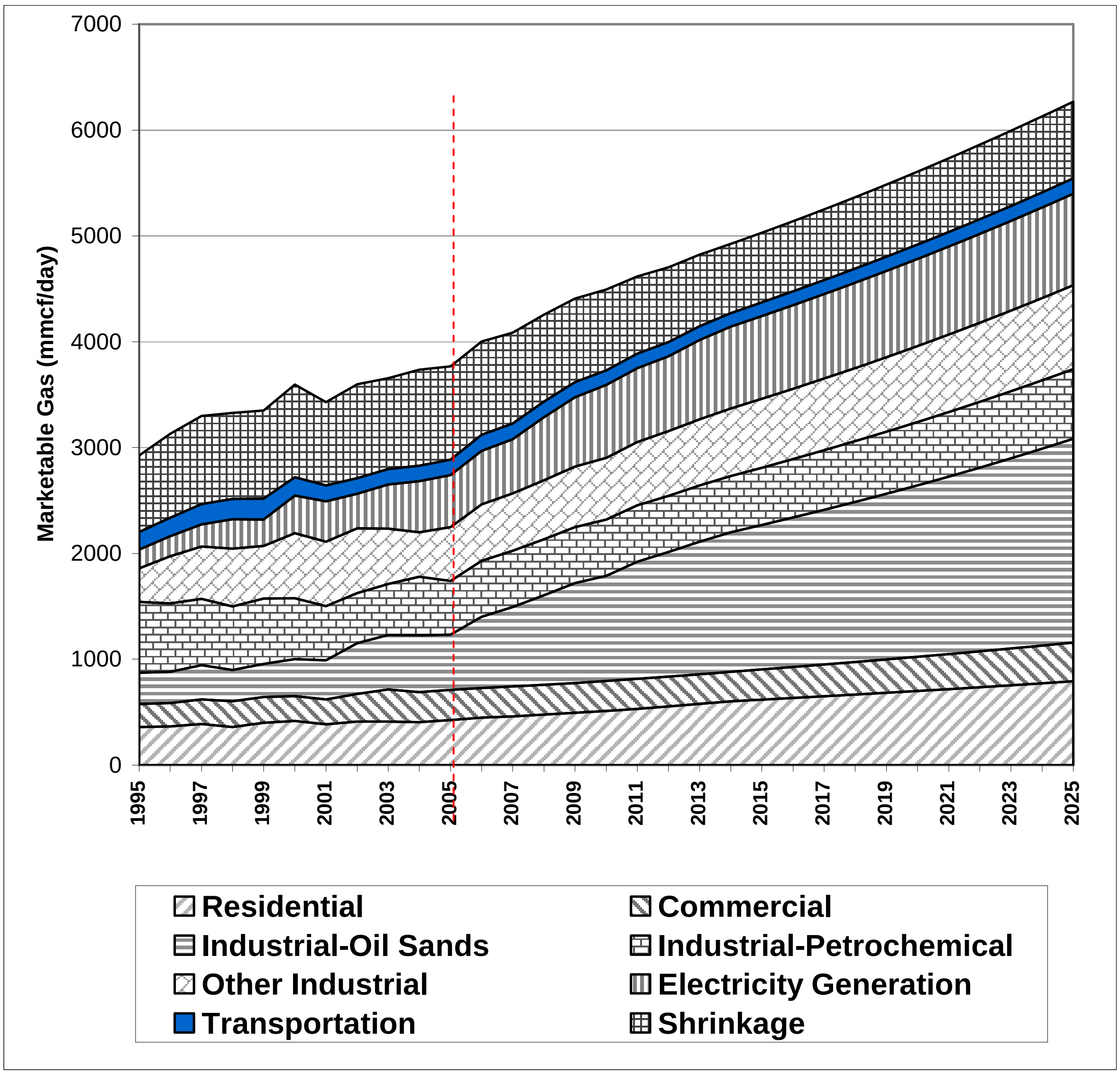
5.6 Alberta Demand

The demand for natural gas in Alberta is taken from the EUB ST98-2006 document. The following characteristics taken from the EUB document define the basis of this forecast as presented in Figure 5.6.

- Residential gas requirements are expected to grow moderately at an annual average rate of four percent per year.
- Commercial gas demand is expected to remain flat for the forecast period.
- The industrial-oil sands demand for natural gas is expected to increase dramatically and is directly related to the growth in the number of oil sands projects. High prices may promote employing technology that will reduce the dependency on natural gas as an energy feedstock. The assumption is that the projects that are currently under construction relying on natural gas will continue using natural gas until such time as the economics of retrofitting a process change makes sense. Projects like the Opti/Nexen project are designed to be almost self sufficient by utilizing technology to produce synthetic gas from the ashphaltines. Projects that are in development may follow this lead.
- Industrial-Petrochemical and other industrials are expected to remain relatively flat with only marginal growth.

- Electricity generation is expected to increase in natural gas consumption as a function of new plants being built to handle the increasing electrical load.
- Straddle plant operations is expected to remain flat for the next few years followed by a gradual decline as a function of the decline in basin deliveries to the export pipelines.

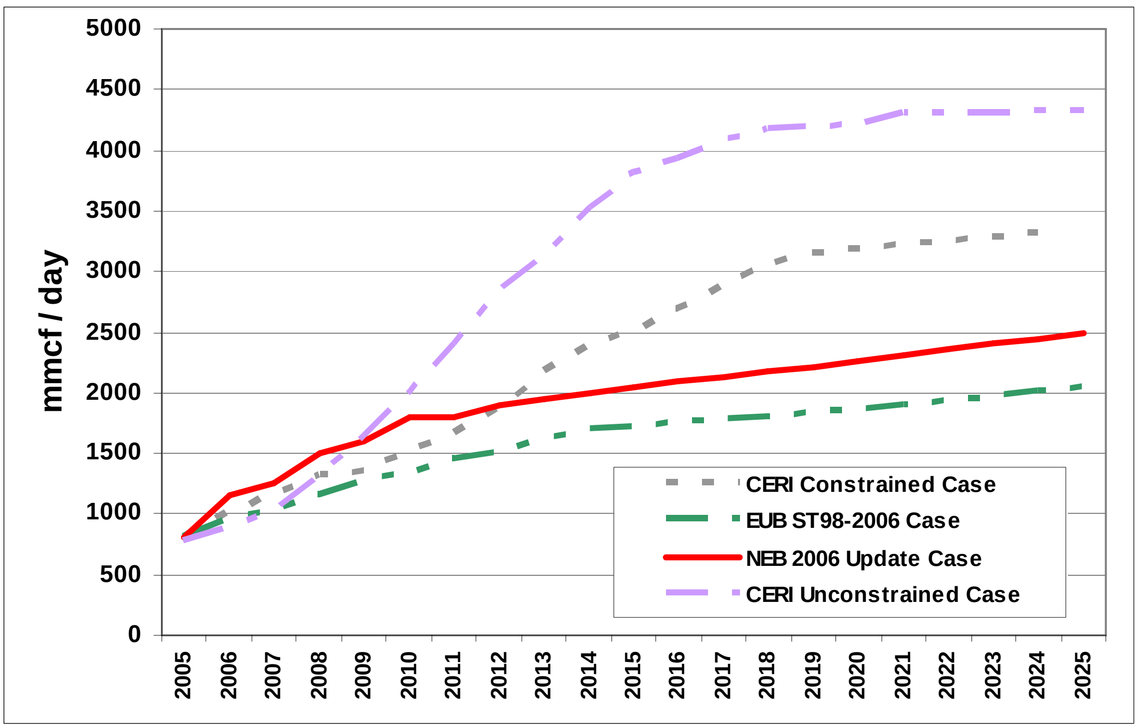
Figure 5.6
Alberta Marketable Gas Demand by sector
(EUB ST98-2006)



5.7 Oil Sands Demand

Oil sands development requires the equivalent energy of 0.7 to 1.25 mmcf/day (32 to 40 e^3m^3/day) to produce one barrel of oil. The input energy to this process is currently leaning heavily towards natural gas and should remain that way until gas prices reach a level that forces new energy sources to be utilized. In Figure 5.7, the "Base Case" for this study has adopted the base case identified in the NEB Oils Sands Update document[19]. The "Low Case" comes from the EUB ST98-2006 report[20]. The "High Case" comes from CERI's unconstrained development case whereas the "Growth Case" came from CERI's constrained case[21].

Figure 5.7
Purchase Gas requirements for Oil Sands Development

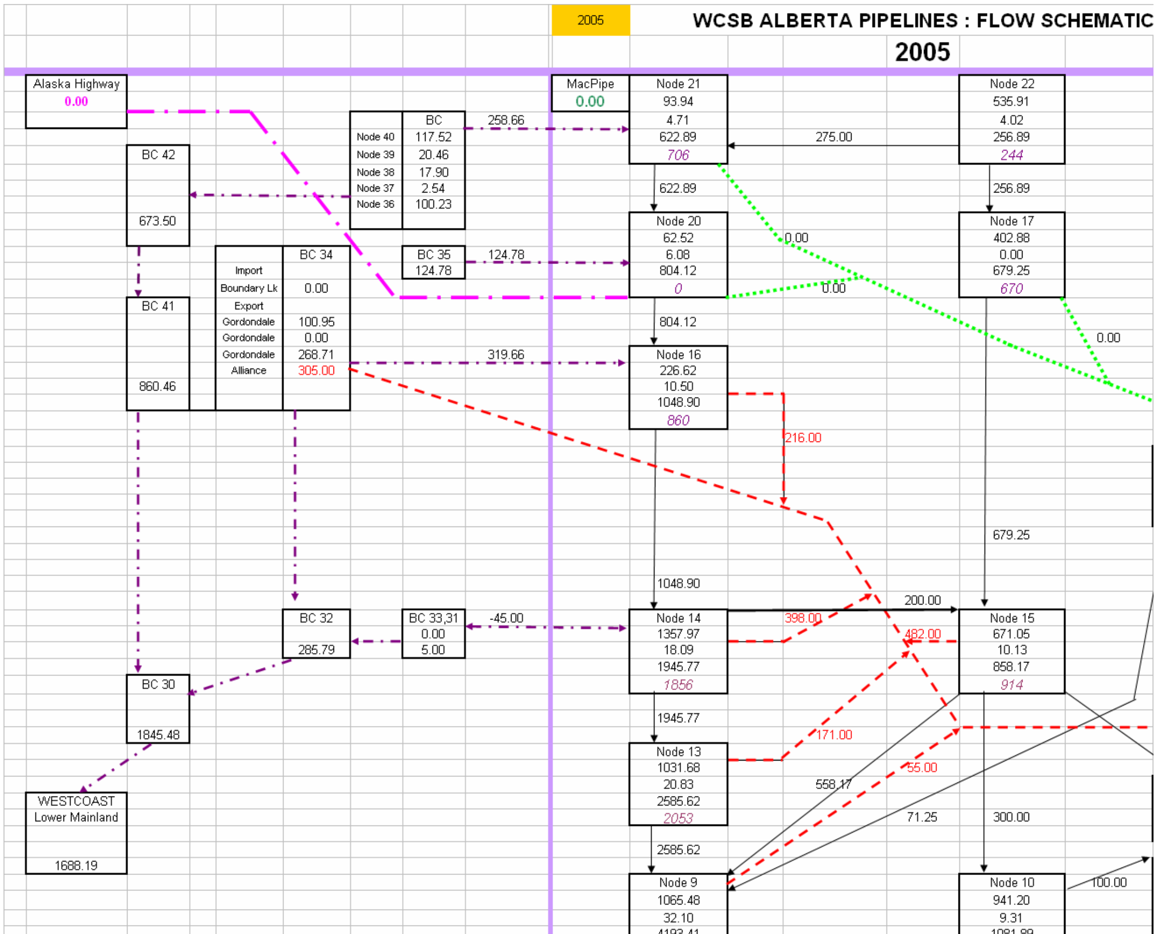


5.8 Model Output

Figures 5.8 and 5.9 are schematic views of the flow connections between the pipeline influence areas. This is the model[22] representation of the physical pipeline systems for British Columbia and Alberta.

[19] NEB, Canada's Oil Sands, Opportunities and Challenges to 2015 : An Update, June 2006
[20] EUB, ST98-2006, Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006-2015, May 2006
[21] CERI, Oilsands Industry Update: Production Outlook and Supply Cost 2006 to 2020, November 2006
[22] CERI, Internal computer program.

Figure 5.8
Pipeline Connectivity: British Columbia and West Alberta



August 28,2006 BASE CASE

Assumptions
(1) Alberta gas well connection profile = AB reference case
(2) British Columbia gas well connection profile = BC reference case
(3) Alaska Highway is not included
(4) Kitimat LNG is included
(5) James River volumes directed to Foothills Western system assumed to maintain 2005 deliveries followed by decline as basin declines
(6) Foothills/Norther Border set decline to basin decline
(7) Alliance pipeline remains at capacity until 2020
(8) Fort McMurray requirements = Oil Sands reference case
(9) North Central Corridor constructed
(10) Flows to Clarkson and Valleyview compressors held at 270 mmcf/d
(11) Flow to lodgepole held at 550 mmcf/d

Figure 5.9
Pipeline Connectivity: East Alberta

Summary

Historic Capacity	Design Area	Historic Capacity	Design Flow (05/06)	Simulated Flow	Space Capacity	
e3m3/d		mmcfd	mmcfd	mmcfd	mmcfd	
45000	Upper Peace	1597	993	880	717	
79500	Central Peace	2822	1490	1728	1094	
115000	Lower Peace	4082	3370	3444	638	
7000	Marten Hills	248	75	71	177	
175000	Edson ML Sub	6211	4790	5275	936	
205000	James R - Princess	7276	5320	5717	1560	
249000	Princess - Empress	8838	5360	7731	1106	Empress and McNeill
85000	James R - ABC	3017	2930	1704	1313	
188625	Empress - Winnipeg	6695	5560	5756	939	
50000	Upper Bens Lake	1775	425	961	813	
55000	Lower Bens Lake	1952	925	145	1807	
25000	To Fort McMurray	887		804	83	
TCPL deliveries	Fort McMurray		804			
TCPL deliveries	Red Deer/Edm		856			
TCPL deliveries	Calgary/Med Hat		805			
TCPL deliveries	Grand Prairie		100			

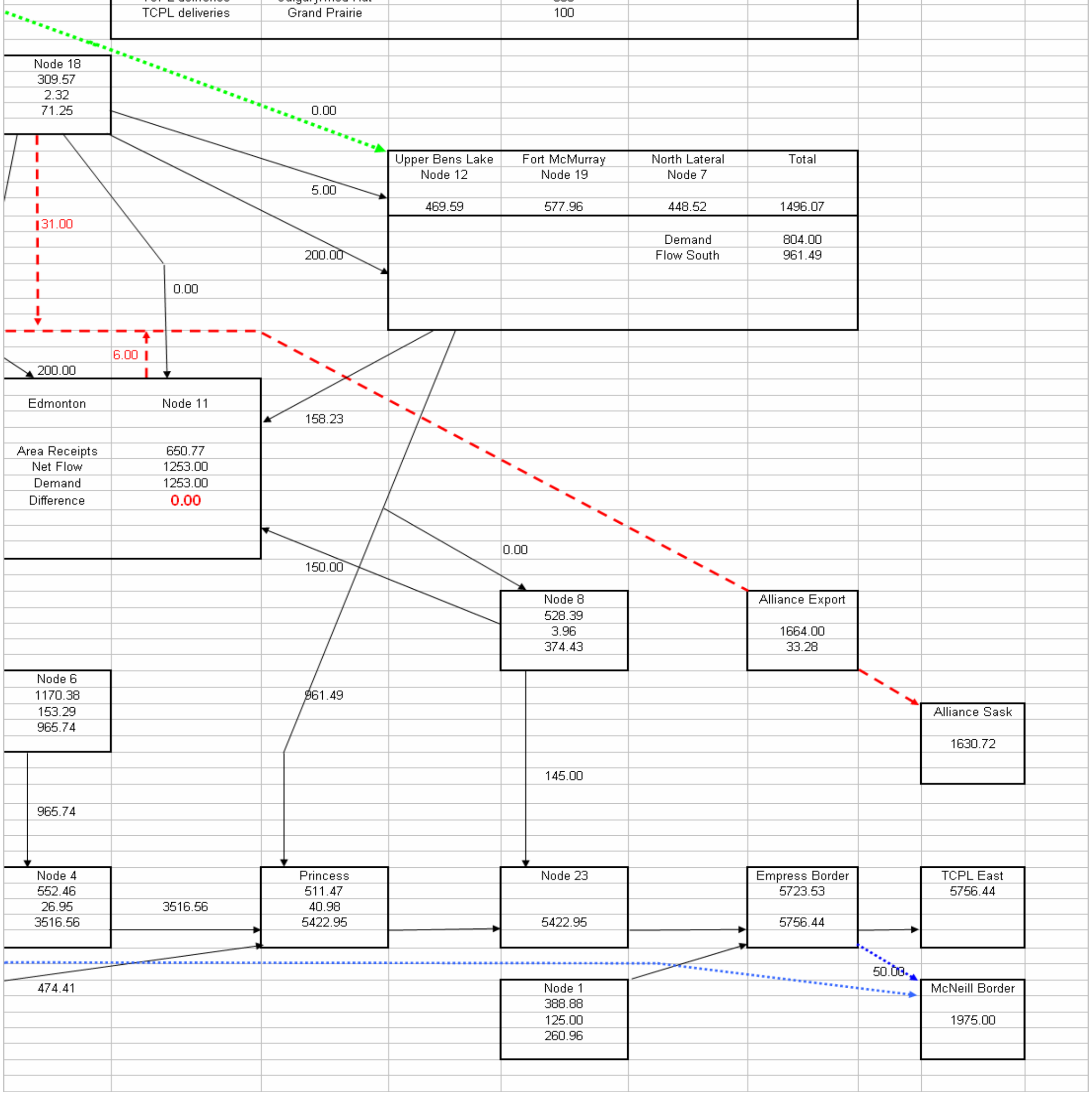
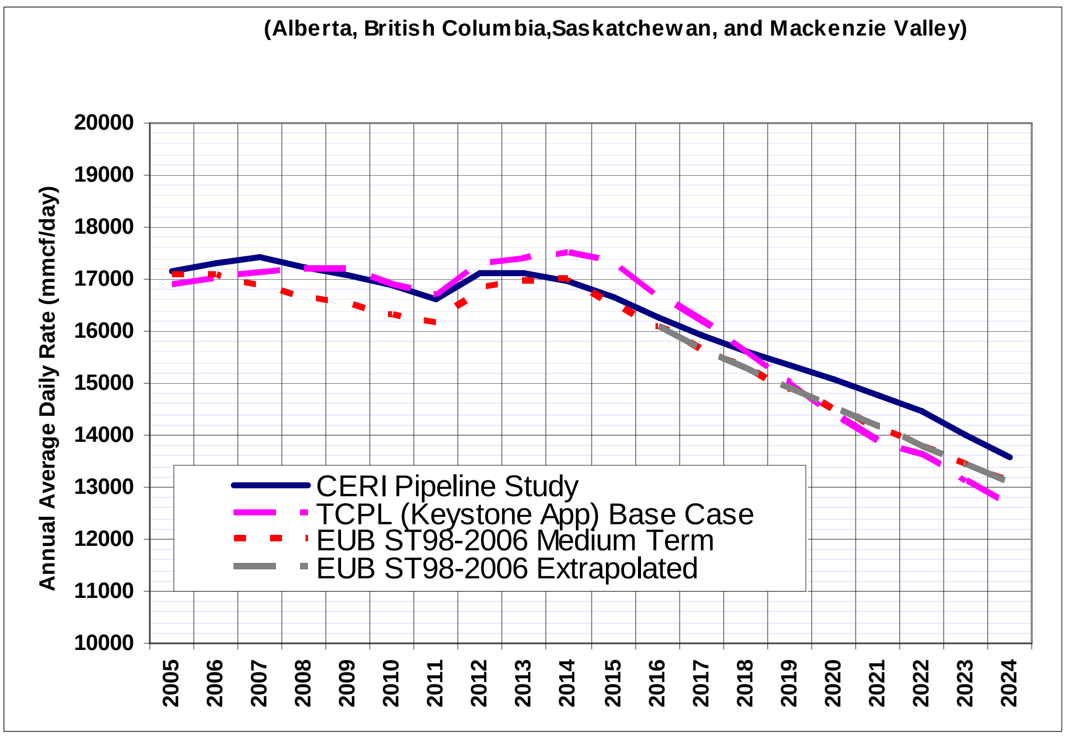


Figure 5.10 compares CERI's WCSB Pipeline Study supply forecast with two other forecasts. The dashed line is from the TCPL's Keystone Pipeline transfer application and represents the WCSB conventional and unconventional supply forecast. The dotted line represents the EUB ST98-2006 forecast for Alberta production augmented with the NEB Saskatchewan production forecast[23] and the BC supply forecast from the CERI pipeline study.

TCPL has included a forecast of unconventional tight gas supply from the Jean Marie carbonates of northeast BC in their forecast. Figure 5.10 has augmented this tight gas forecast into the CERI and EUB forecasts in order to compare the total WCSB forecasts.

Figure 5.10
Production Forecast Comparison



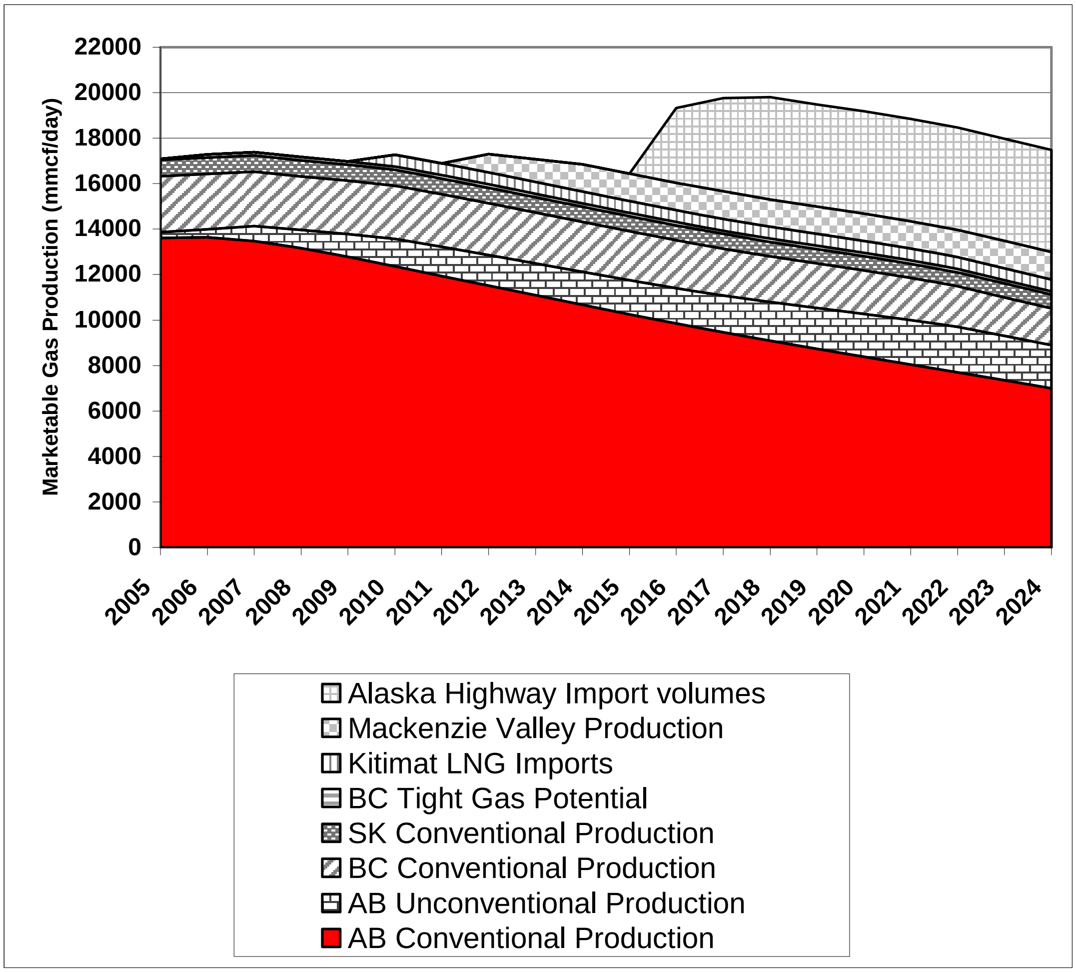
Due to the complexity of developing tight gas resources, this pipeline study does not include the tight gas forecast in the base case but does include the TCPL forecast as a sensitivity case and is detailed in Figure 6.7.

Figure 5.11 details the base case supply forecast for the WCSB including British Columbia, Alberta, and Saskatchewan and appends the estimated production forecast for the Mackenzie Valley, Kitimat LNG and Alaska Highway. The Alberta and British Columbia conventional production forecasts are derived from the procedure outlined in this chapter. The unconventional (CBM) production forecast was taken from the base case used in TCPL's Keystone application[24].

[23] NEB, Canada's Energy Future: Scenarios for Supply and Demand to 2025, July, 2003
[24] TCPL, Canadian Mainline Throughput Study, Keystone Pipeline Transfer Application, June 2006

The Saskatchewan production forecast was taken from the NEB[25] 2003 supply and demand outlook. The Mackenzie Valley gas forecast was taken from the Wright Mansell report on the Mackenzie Valley Pipeline[26].

Figure 5.11
Western Canada Gas Production Forecast
(including Mackenzie Valley and Alaska Highway production)

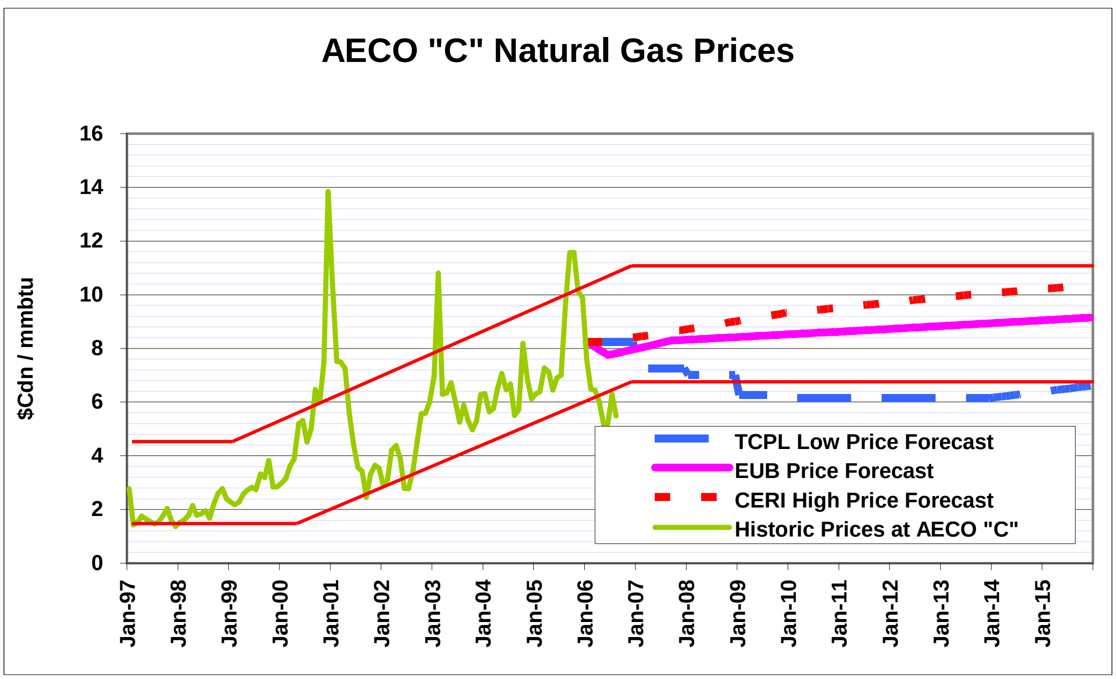


[25] NEB, Canada's Energy Future: Scenarios for Supply and Demand to 2025, July, 2003
[26] Wright Mansell Research Ltd, An Evaluation of the economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas, 2004

5.9 Price Forecast

The new well connection forecast shown in Figures 5.3 and 5.4 is based on the EUB "Alberta plant gate price forecast" as described in the ST98-2006 report[20]. Figure 5.12 details this forecast (corrected to AECO "C" and dollars per mmbtu basis), the TCPL low price forecast, as described in the Keystone application, and a CERI estimate of a "High Case" forecast. This figure also shows historic gas prices, including the recent downward trend since January 2006. This 2006 downward trend can be viewed as a supply side issue, with respect to excess gas storage levels, which may drag on into 2007 if North America experiences another warm winter. However the fundamental relationship between gas supply and demand, as shown in the price spikes in recent years, indicates that this relationship is precariously balanced. Recent announcements of curtailed drilling programs will be reflected on the supply side (negative impact) while lower prices will be reflected on the demand side (positive impact) which should result in a return to a more expected supply demand relationship. This study has assumed that gas prices will return to the EUB forecasted level after the storage levels return to an intra year consumption pattern.

Figure 5.12
AECO "C" Gas Price Forecast
(Cdn $/mmbtu)



CHAPTER 6
SCENARIOS

6.1 Base Case Pipeline Simulation

In the Base Case, recorded production data for the year 2004 was assigned to one of the 37 pipeline influence areas that were used to represent the pipeline systems for British Columbia and Alberta. New well connections were forecasted for four cases (low case, base case, growth case and high case), with the base case adopting the view point of a flat well connection profile for the next 15 years. The remaining three cases reflect a pessimistic, continued growth and optimistic view point to new well connections. These cases are used to determine the sensitivity of new well connections on pipeline flow volumes.

This flat profile, of 12,000 new well connections for Alberta, was adopted from the EUB ST98-2006 document (2005 to 2015) and extended to the year 2020. The same assumption was applied to the British Columbia portion of the basin at a rate of 1,100 new well connections per year. New well connections for Alberta have grown from 8,200 wells in 2002, 10,655 wells in 2003, and 13,244 wells in 2004, to approximately 12,000 wells in 2005. New well connections (BC) for the years 2002 to 2005 have been 493, 804, 1,070 and 1,163 respectively.

Initial productivity flow rates, existing production decline rates and future well connection decline rates were calculated based on historic production values. Flow volumes in the various sections were compared against pipeline design information for the purpose of history matching the simulation program. A history match factor was applied to the initial production rates in order to calibrate the start year of the forecast to actual recorded volumes for 2005 and further calibrated to an estimate of the 2006 production levels (January to October, extrapolated to December).

The extraneous assumptions used in the base case are as follows:

- Well connections in British Columbia and Alberta are based on the “Base Case” new well connection profile.
- Alberta demand is based on the “Base Case” demand forecast from the EUB ST98-2006 report with oil sands purchase gas requirements from the NEB Oil Sands Update 2006 documents. British Columbia demand is assumed to grow at 1 percent per year from the 2005 base.
- LNG supply at Kitimat, British Columbia is assumed to be available in 2010 with an average daily send out rate of 520 mmcf/day (17,190 e^3m^3/day) based on an 85 percent load factor. This LNG supply is assumed to split with 25 percent going to the Sumas export point and 75 percent displacing BC gas for delivery to Alberta and export points leaving Alberta.

- The current export volume at Sumas is assumed to increase at 2.5 percent above the 2005 delivery and the destination is assumed to be the Pacific Northwest and California areas.

- Alliance pipeline export volumes are held at 1630 mmcf/day (45,920 e^3m^3/day) until 2020, after which a 10 percent decline per year is applied (refer to Section 7.7)

- Foothills/Northern Border Pipeline export volumes are held at 1975 mmcf/d (55,640 e^3m^3/day) until 2008 after which a 6 percent decline per year is applied until 2015 followed by a 25 percent decline to the end of the forecast.

- Gas Transmission Northwest export volumes are held at 1790 mmcf/day (50,430 e^3m^3/day) until 2008 after which a 6 percent decline per year is applied until 2015 followed by a 25 percent decline to the end of the forecast.

- TCPL east receives the residual gas after Alberta demand and the export volumes mentioned above have been removed.

- The North Central Corridor is assumed to be constructed by 2012 with a capability of transporting 700 mmcf/day (19,720 e^3m^3/day) from the Upper Peace River area to the Upper Bens Lake area. This volume was established to limit any additional pipeline development in the Central Peace River and Lower Peace River areas.

Figure 6.1 compares the border deliveries for seven specified years against the current indicated capacity (“Capacity”), plus any additional capacity that has been proposed (“Add Capacity”), minus any capacity reductions ("Rem Capacity") as in the case of the TCPL Keystone project.

The vertical axis on the left side of the diagram relates to the current capacity of the pipeline area and is indicated as the boxed (blue in color) area spanning the individual bars. The vertical axis on the right side of the diagram indicates the average daily rate (mmcf/day) and relates to the individual vertical bars that represent a series of years (2006, 2012, 2014, 2016, 2018, 2019, and 2020) for the simulation.

Figure 6.1 indicates that deliveries by the Alliance pipeline are constant at 1630 mmcf/day (45,925 e^3m^3/day), while the Northern Border, Gas Transmission Northwest (TCPL West Design Area) and TCPL East are declining as a result of declines in the basin projected supply. By 2016, TCPL East will be operating at 73 percent utilization assuming the Keystone project proceeds with the conversion of the 34 inch pipeline from Empress to Winnipeg. If this project were not to proceed, the utilization factor would drop to 67 percent.

Figure 6.1
WCSB Export Pipeline
Base Case Border Deliveries versus Export Capacity

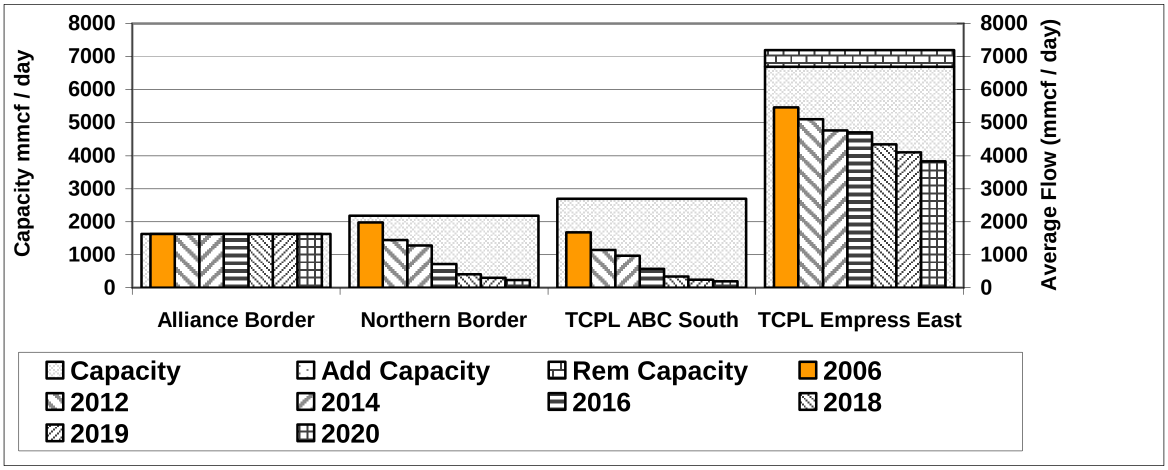


Figure 6.2 compares the selected design area deliveries for seven specified years against the current indicated capacity of the section. The Base Case has assumed that the NCC is constructed to transport 700 mmcf/day, which is sufficient to just negate any facility requirements in the Lower Peace River and Edson Sub design areas. The Upper Peace area requires 600 mmcf/day of additional capacity to handle the projected new volumes originating from the area.

Figure 6.2
Base Case Section Volumes and Capacities (Alberta North West)

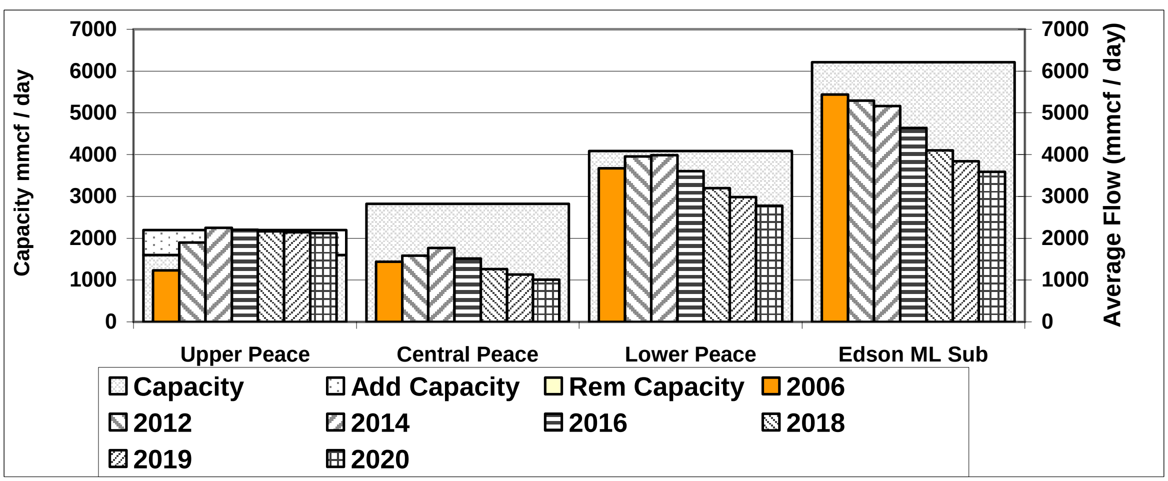


Figure 6.3 examines four sections in the southern part of Alberta between the James River crossover and the western and eastern border points. The James River to Princess area reflects a less dramatic decline over time primarily as a result of the new supplies originating from the

northwest part of the province, whereas the Princess to Empress section is indicating a more dramatic decline as a result of increasing volumes flowing north to Bens Lake and away from the Empress export point.

The base case indicates that the spare capacity for the Princess to Empress section of the TCPL Alberta System in the years 2016 through 2018 will be 3300 mmcf/day, 3600 mmcf/day and 3970 mmcf/day, respectively. The section between Empress and Winnipeg, for the same years will have spare capacities of 2490 mmcf/day, 2640 mmcf/day and 2860 mmcf/day. The Northern Border Pipeline for the same years will have spare capacities of 1460 mmcf/day, 1640 mmcf/day and 1775 mmcf/day (Figure 6.1).

Figure 6.3
Base Case Section Volumes and Capacities (Alberta South East)

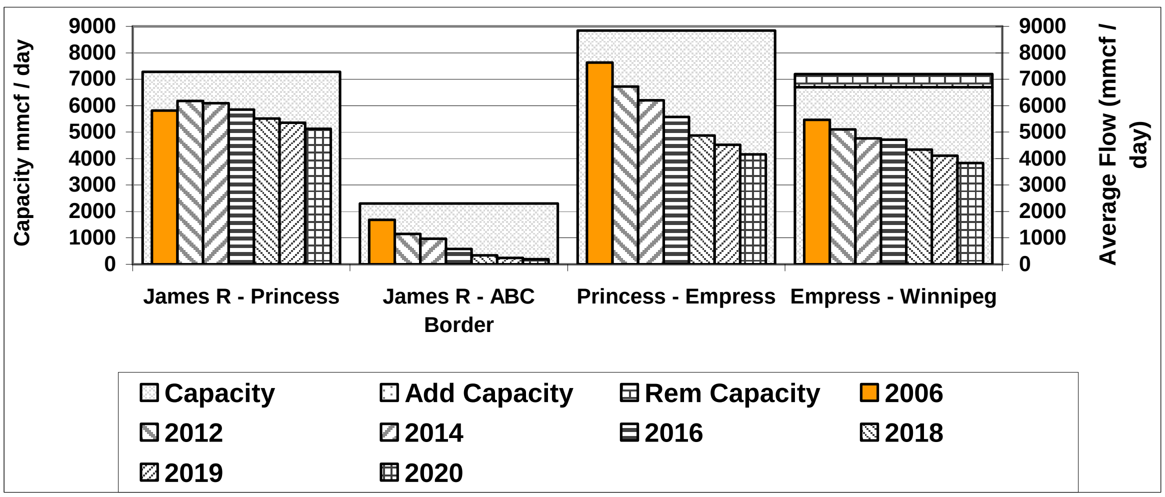
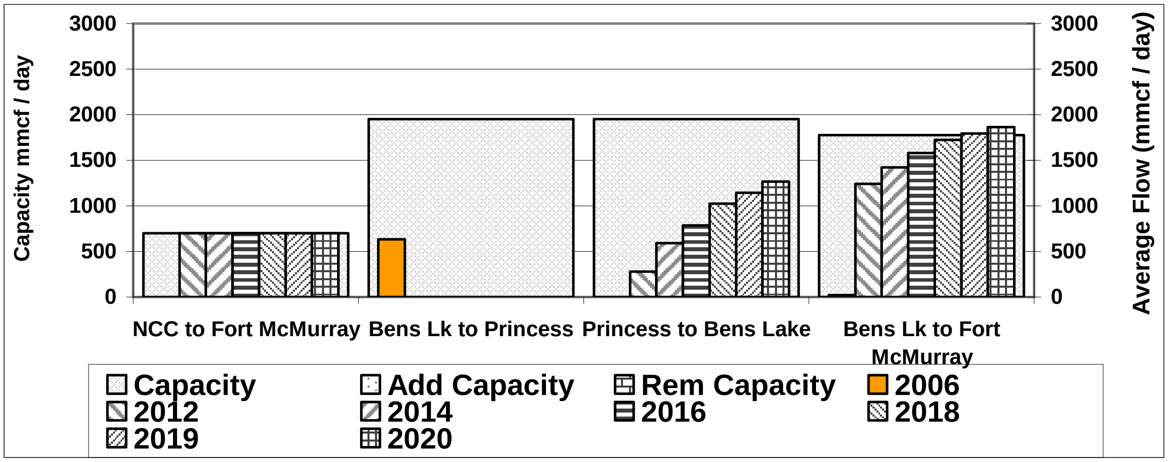


Figure 6.4 demonstrates the flow volumes into and out of the Fort McMurray area as a result of increased natural gas requirements. The NCC connector to the Upper Bens Lake area shows the 700 mmcf/day assumed flow from the Peace River area. The current flow direction for the Bens Lake to Princess is south towards the Princess compressor station, but by 2012, the flow direction reverses and supply volumes from Princess are transported north to the Upper Bens Lake area.

Figure 6.4
Base Case Section Volumes and Capacities (Fort McMurray)



In the Base Case, the border deliveries to TCPL East drop from 5768 mmcf/day (162,510 e^3m^3/day) in 2006 to 3850 mmcf/day (108,500 e^3m^3/day) in 2020. As indicated previously, this assumes the deliveries to the other border points continue to decline (with the exception of the Alliance pipeline) as the basin production declines.

In Figure 6.5, the TCPL east delivery is compared against the Canadian demand east of Alberta[27] and the volumes delivered to the eastern export points connecting with The Great Lakes Transmission Company, Portland Natural Gas Pipeline Company, Iroquois Pipeline Company and the St. Clair River interchange. To demonstrate the change in export potential the solid portion of the vertical bar in Figure 6.5 represents the 2005 actual export volume. Export volumes for the GTN pipeline, Alliance pipeline and Northern Border pipeline are shown on the graph for reference purposes but are not directly related to the TCPL east deliveries versus the eastern demand.

Figure 6.5 indicates that gas supply for the export market in the United States will fall by 40 percent in 2010, 60 percent by 2015 and 100 percent by 2020. This decline is reflected in the deliveries to the eastern export points (connected to TCPL East), the Northern Border export at Monchy, Saskatchewan and the Gas Transmission export at Kingsgate, British Columbia.

[27] NEB, Canada's Energy Future: Scenarios for Supply and Demand to 2025, July, 2003

Figure 6.5
TCPL East Canadian Demand and Export Potential

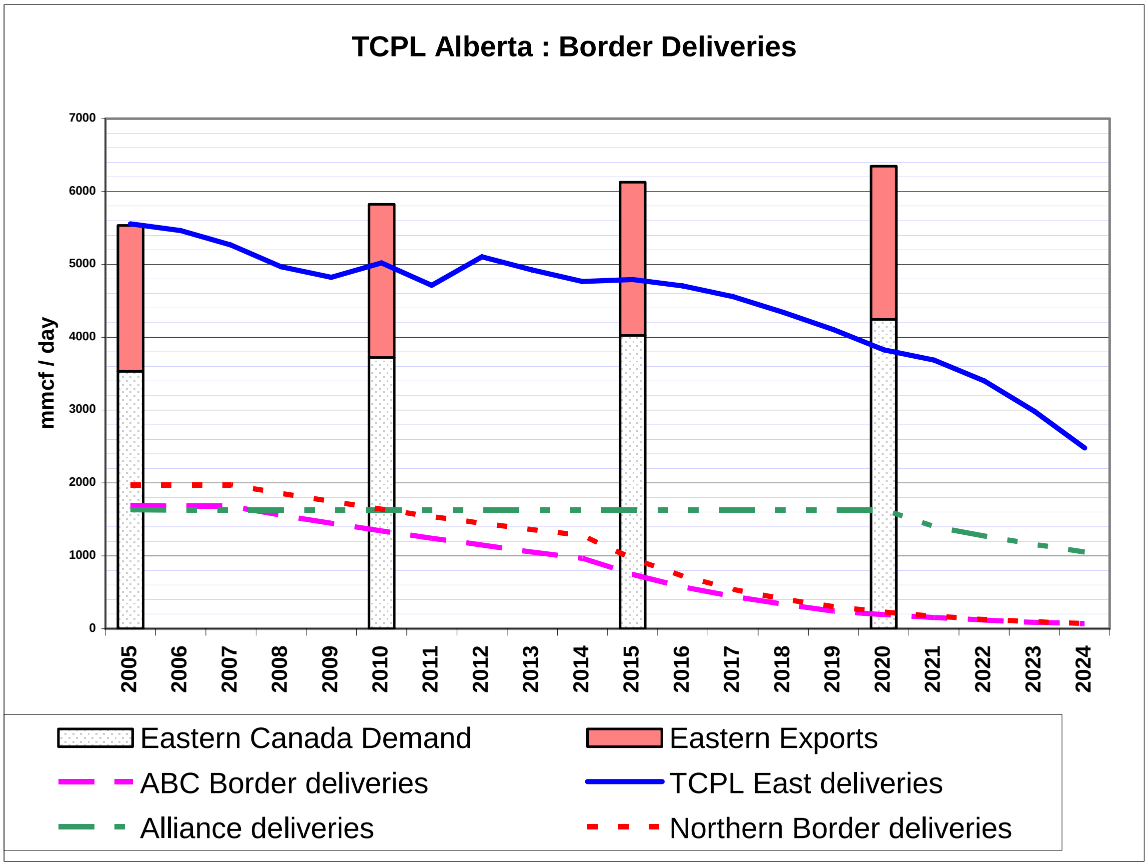
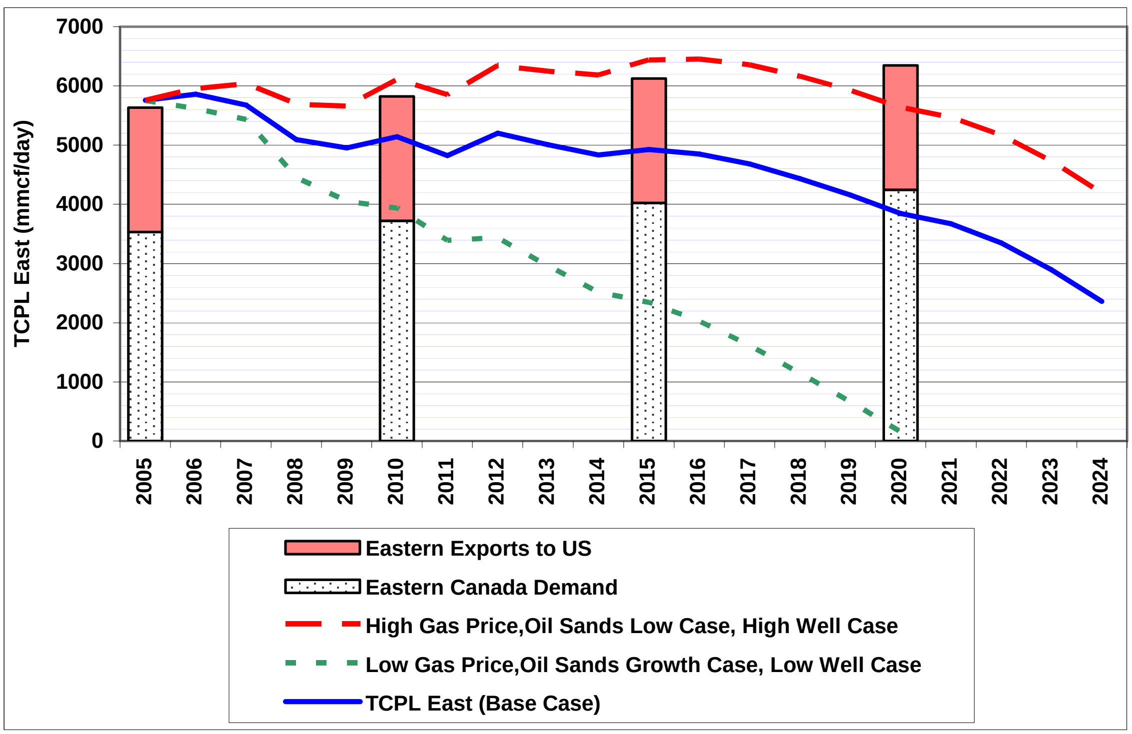


Figure 6.6 shows the potential effect well connections, and its relationship to gas prices, could have of the deliveries to the TCPL east mainline. This sensitivity case assumes all other parameters related to the Base Case remain constant with the exception that gas prices will affect the gas requirements in the oil sands development area and the rate at which new wells are drilled and connected for production.

The dashed line in this Figure assumes a high gas price will lead to reduced oil sands demand (Figure 5.7, EUB ST98-2006 case) and higher drilling activity resulting in higher well connections (Figure 5.3, AB growth case and Figure 5.4, BC growth case). This scenario indicates that the WCSB basin can support both the Canadian demand and continued eastern export deliveries (at the 2005 level) out past the year 2018.

The dotted line assumes a low gas price leading to increased oil sands demand (Figure 5.7, CERI constrained case) and lower drilling activity resulting in reduced new well connections (Figure 5.3, AB low case and Figure 5.4, BC low case). The drilling and connection of new wells are reduced as the downward trend in market price results in the reduction of exploration and development drilling. This scenario indicates that the WCSB basin will have difficulty supplying the Canadian demand with only minimal exports (with the exception of the Alliance pipeline) past the year 2010.

Figure 6.6
Base Case Sensitivities

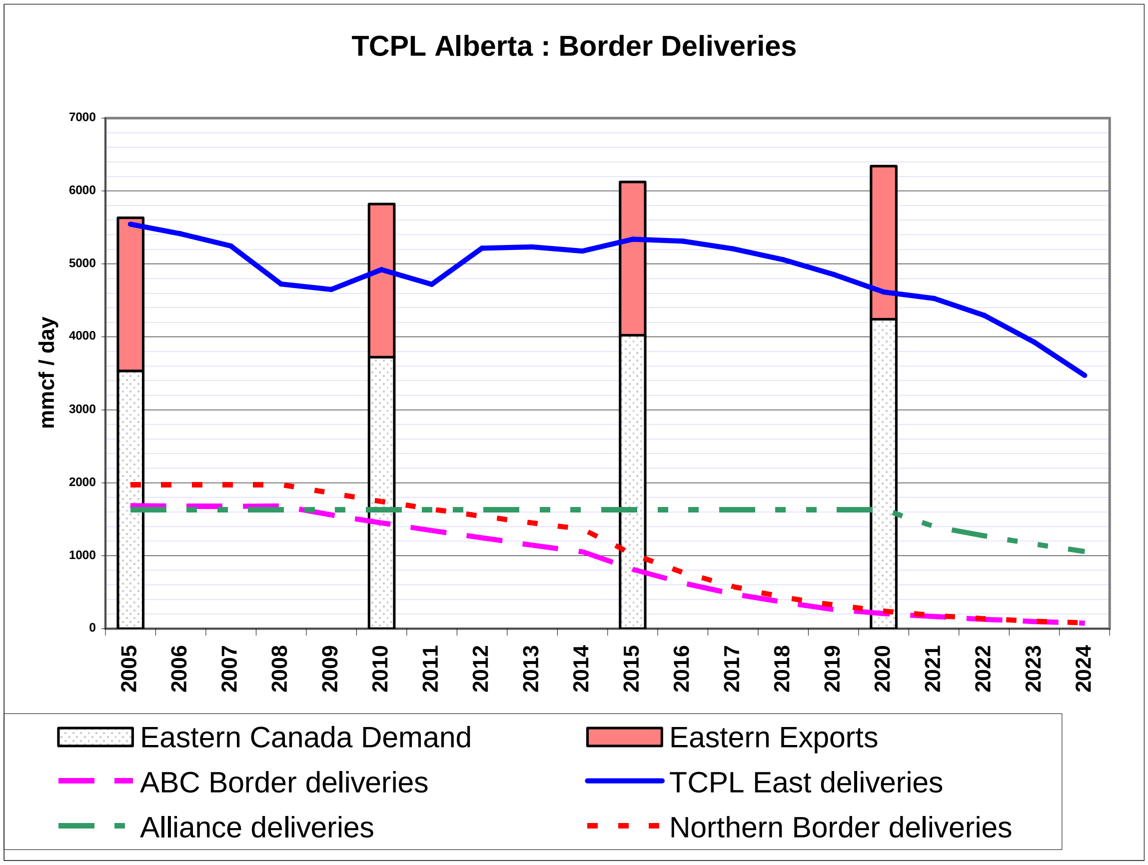


Tight gas resources exist in the WCSB and are defined as low-permeability sandstone and carbonate reservoirs where reservoir stimulation or drilling technology is required to establish economic flow rates and recovery[28]. Even though we have seen recent upward movement in gas prices, which would tend to be supportive of tight gas exploration and development, these same higher prices have precipitated the gas industry drilling low cost, low productivity conventional gas wells and unconventional CBM wells. Time and consistent gas pricing should lead to the development of this resource but the degree of its contribution to the WCSB production volumes is questionable. For the purpose of measuring the potential impact of production from tight gas resources (specifically the Jean Marie carbonates of northeast B.C.), Figure 6.7 demonstrates the effect tight gas production will have on the TCPL east border delivery assuming all other

[28] Forward Energy Group, Western Canada Tight Gas Resource Characterization Project, April 2006

parameters in the base case remain as described. The forecast of tight gas production from the Jean Marie formation was adopted from the TCPL Keystone application.[29]

Figure 6.7
Base Case Sensitivity with BC Tight Gas Potential



[29] TCPL, Canadian Mainline Throughput Study, Keystone Pipeline Transfer Application, June 2006

6.2 Scenario # 1: Alaska Gas transported on TCPL integrated system without North Central Corridor expansion

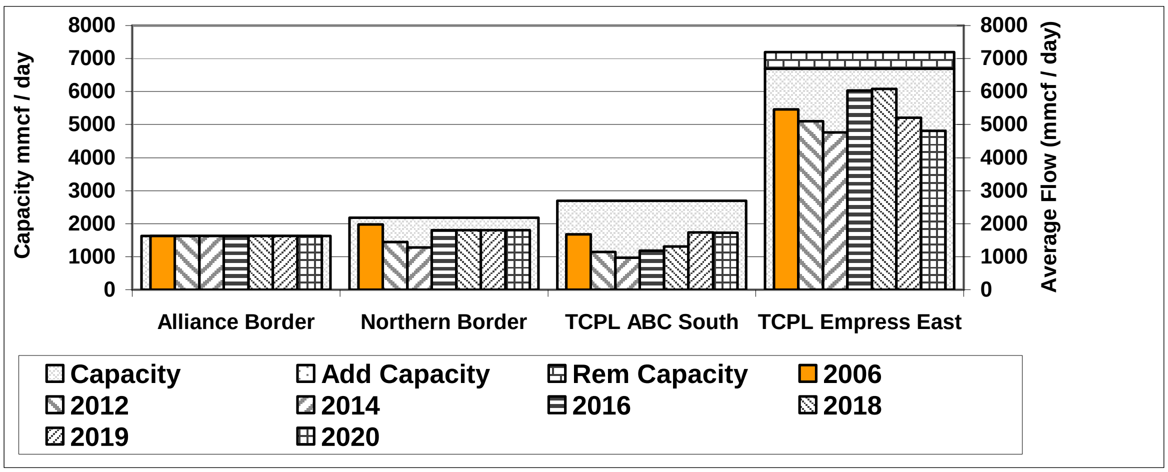
Scenario # 1 assumes that Alaska gas will connect to the TCPL Alberta system at Boundary Lake, Alberta, where it will be mixed with Alberta gas streams. The combined stream will be transported to James River where some of the gas will head south to be processed at the Cochrane straddle plant and the rest will head east in the TCPL Alberta mainline and Foothills Alberta mainline to be processed at the Empress straddle plant. This scenario measures the effect on the mainline systems as a result of not expanding the North Central Corridor. Assumptions used for this scenario are as follows:

- Well connections in British Columbia and Alberta are based on the “Base Case” new well connection profile.
- Alberta demand is based on the “Base Case” demand forecast from the EUB ST98-2006 report with oil sands purchase gas requirements from the NEB Oil Sands Update 2006 documents. British Columbia demand is assumed to grow at 1 percent per year from the 2005 base.
- LNG supply at Kitimat, British Columbia is assumed to be available in 2010 with an average daily send out rate of 520 mmcf/day (17,190 e^3m^3/day) based on an 85 percent load factor. This LNG supply is assumed to split with 25 percent going to the Sumas export point and 75 percent displacing BC gas for delivery to Alberta and export points leaving Alberta.
- The current export volume at Sumas is assumed to increase at 2.5 percent above the 2005 delivery and the destination is assumed to be the Pacific Northwest and California areas.
- Alliance pipeline export volumes are held at 1630 mmcf/day (45,920 e^3m^3/day) until 2020, after which a 10 percent decline per year is applied(refer to Section 7.7)
- Foothills/Northern Border Pipeline export volumes are held at 1975 mmcf/d (55,640 e^3m^3/day) until 2007 after which a 6 percent decline per year is applied until 2016. At this point in time the Alaska volumes enter Alberta and the export volumes are assumed to recover to a flow volume of 1800 mmcf/day. TCPL east and NBPL will have an operational load factor of 90 percent.
- Gas Transmission Northwest export volumes are held at 1790 mmcf/day (50,430 e^3m^3/day) until 2007 after which a 6 percent decline per year is applied until 2016. At this point in time the Alaska volumes enter Alberta and the export volumes are assumed to recover gradually returning to the 2005 level.
- TCPL east receives the residual gas after Alberta demand and the export volumes mentioned above have been removed.

- The North Central Corridor is assumed to be constructed by 2012 with a capability of transporting 700 mmcf/day (19,720 e^3m^3/day) from the Upper Peace River area to the Upper Bens Lake area.

Figure 6.8 shows the effect on border deliveries as a result of Alaska Gas being transported on TCPL's Alberta System without expanding the North Central Corridor. This scenario allows the border delivery for Gas Transmission Northwest to recover to their 2005 delivery levels while the NBPL and TCPL east also recover to a 90 percent load factor. This assumes the Keystone project reduces the capability for the Empress to Winnipeg section to 6695 mmcf/day.

Figure 6.8
Scenario # 1 (utilizing TCPL Integrated System)
Border deliveries versus export capacity



Figures 6.9 and 6.10 indicate that the Central Peace, Lower Peace, Edson Sub Design, and James River to Princess areas, would need to be expanded to handle the incremental flow volumes. Spare capacity in these sections would be utilized and facilities would need to be added or modified to handle an additional 2900 mmcf/day for the Central Peace River area, 3500 mmcf/day for the Lower Peace River area, 2250 mmcf/day for the Edson to James River area and 1500 mmcf/day for the James River to Princess area. The Princess to Empress and Empress to Winnipeg sections would have sufficient spare capacity to handle the increased flow.

Scenario # 1 requires extensive expansion of the Boundary Lake to Princess sections of the TCPL Alberta system and requires a flow reversal in the Bens Lake to Princess section in order to meet the Fort McMurray demand. Scenario # 2 investigates the expansion of the North Central Corridor as a more efficient method of handling flows on the integrated system.

Figure 6.9
Scenario # 1 (utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta North West)

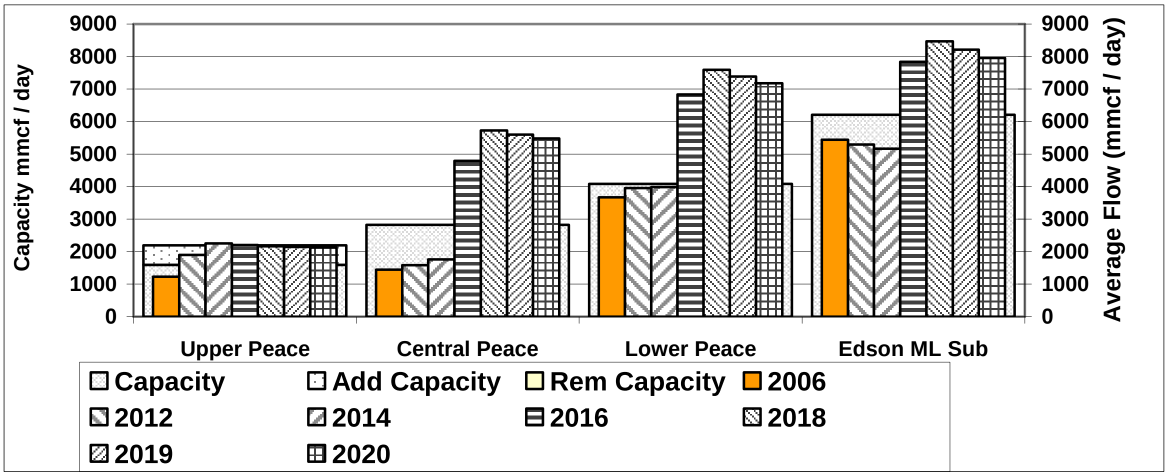


Figure 6.10
Scenario # 1 (utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta South East)

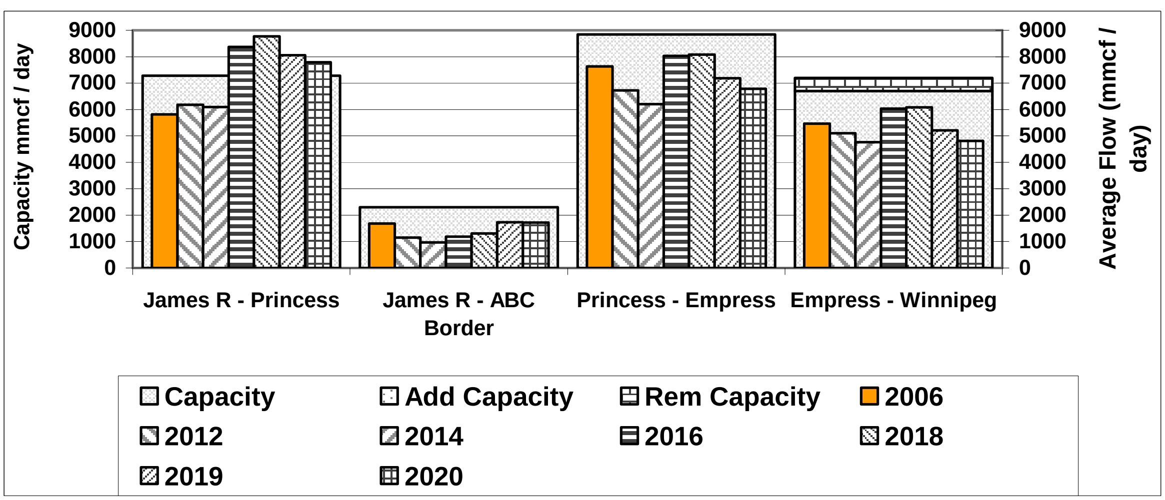
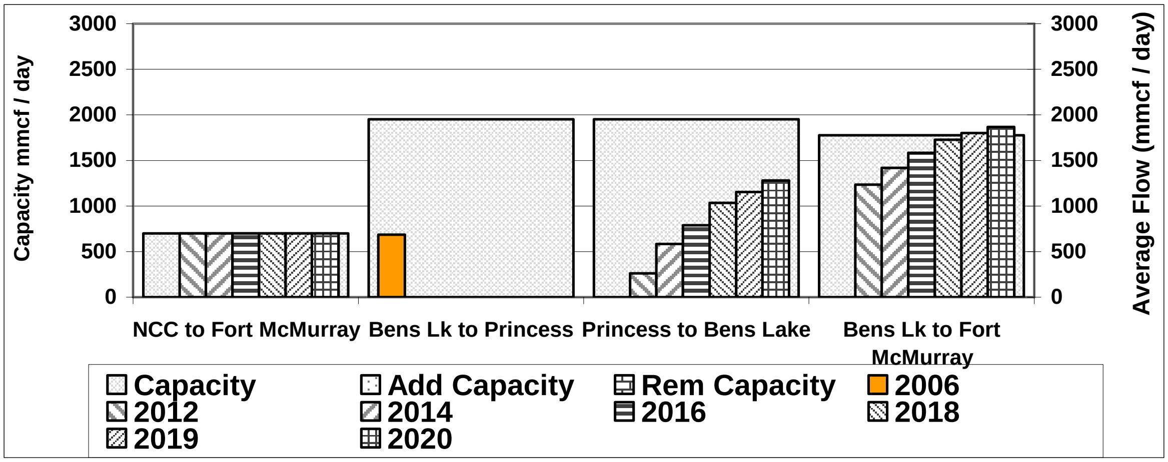


Figure 6.11 shows that the flow direction from Bens Lake to Princess must reverse, resulting in the flow of gas being transferred from the mainline (Princess Compressor station) north to Bens Lake area and ultimately to Fort McMurray.

Figure 6.11
Scenario # 1 (utilizing TCPL Integrated System)
Section Volumes and Capacities (Fort McMurray)



In Figure 6.12, the deliveries to the Gas Transmission Northwest and Northern Border Pipelines are held at the 2005 level until 2007 followed by a 6 percent decline until the Alaska volumes are connected to the system. Some of the Alaska volumes have been allocated to the GTN pipeline system under the assumption that deliveries to the California market will gradually recover to the 2005 level. The Northern Border Pipeline and the TCPL East pipeline are assumed to share the transportation of the residual Alaska volumes with each pipeline operating at a 90 percent load factor in the initial years.

Figure 6.12
TCPL East Canadian Demand and Export Potential

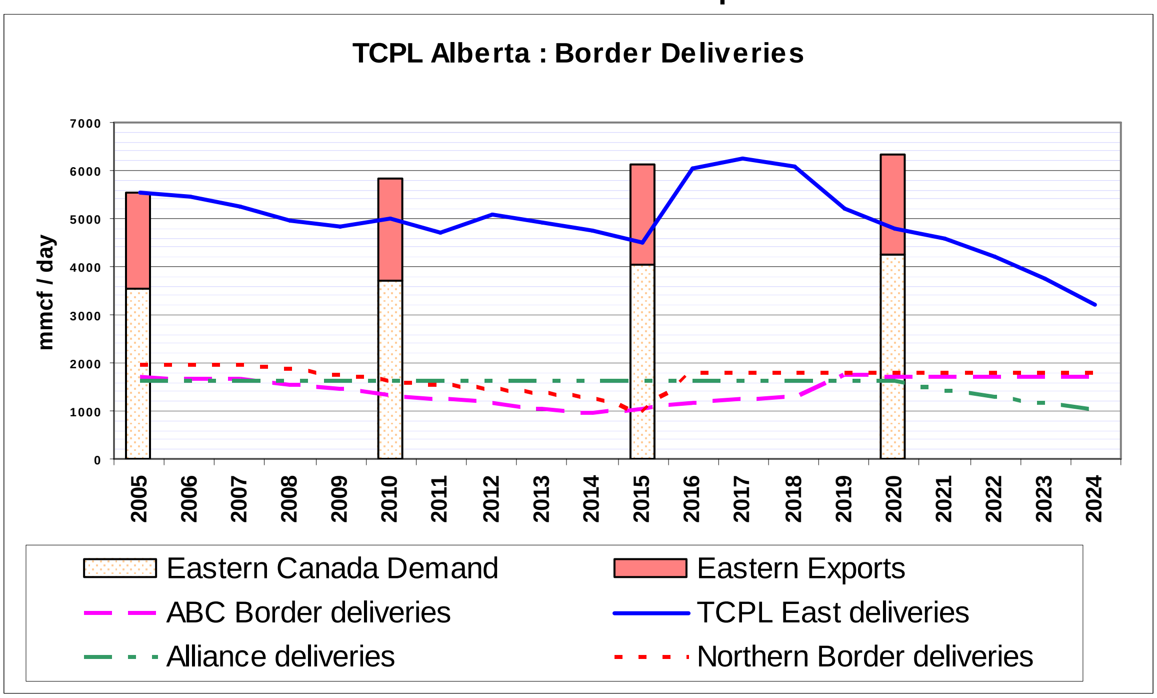
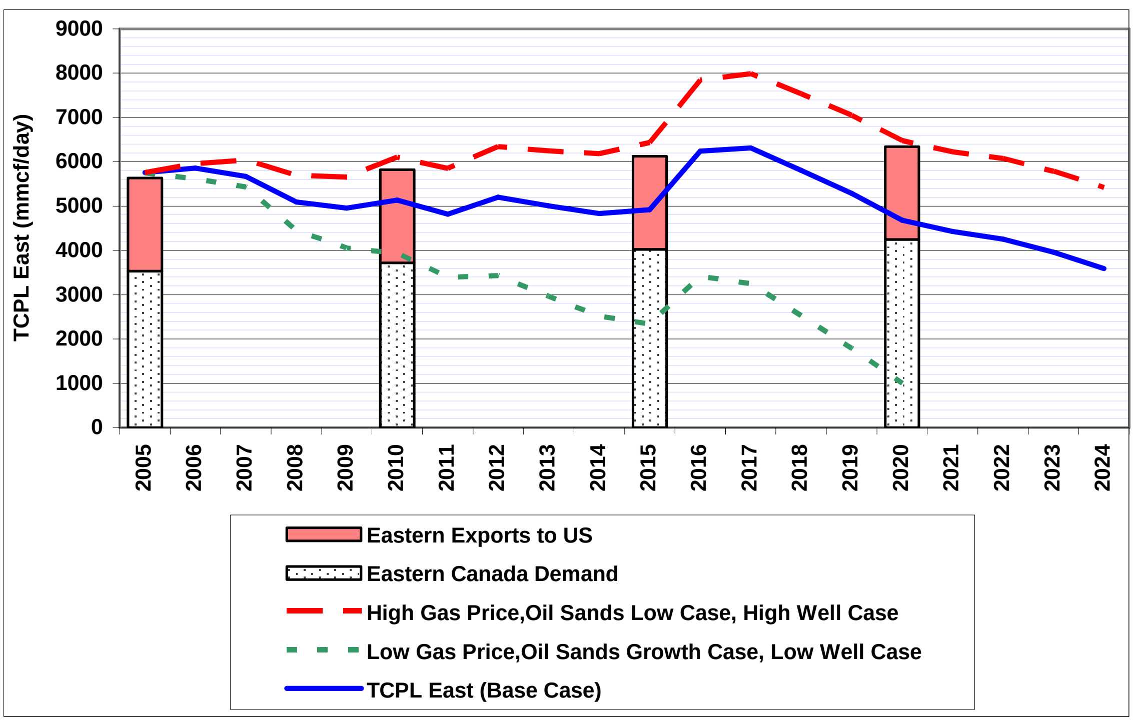


Figure 6.13 shows the potential effect gas prices could have on the deliveries to the TCPL east mainline. The dashed line in this Figure assumes a high gas price will lead to reduced Oil Sands demand and higher drilling activity resulting in higher well connections. Under this sensitivity, the Alaska Gas volumes allocated to the TCPL East system are in excess of the Canadian demand and 2005 export volume. The EIA has forecasted a demand increase of 2400 mmcf/day[30] up to 2020 for the West North Central and the East North Central with 85 percent of the growth occurring prior to 2016. The Alaska gas in this context will be competing with the mid continent supplies and potential LNG imports from the Gulf of Mexico.

The dotted line assumes a low gas price leading to increased oil sands demand (Figure 5.7, CERI constrained case) and lower drilling activity resulting in reduced new well connections (Figure 5.3, AB low case and Figure 5.4, BC low case). The drilling and connecting of new wells are reduced as the market price reduces exploration and development drilling.

Figure 6.13
Scenario # 1 Sensitivities



[30] EIA, Annual Energy Outlook 2006, Energy Information Agency, 2006

6.3 Scenario # 2: Alaska Gas transported on TCPL integrated system with North Central Corridor expansion)

Scenario # 2 assumes that Alaska gas will connect to the TCPL Alberta system at Boundary Lake, Alberta where it will be mixed with Alberta gas streams. The combined stream will be transported to James River, where some of the gas will head south to be processed at the Cochrane straddle plant, and the rest will head east in the TCPL Alberta mainline and Foothills Alberta mainline to be processed at the Empress straddle plant. This scenario examines the effect on the TCPL Alberta System if the North Central Corridor is expanded to handle a volume of 2300 mmcf/day thereby reducing the mainline facility requirements south of the Peace River area and offering a better utilization of the Bens lake south to Princess lateral. This scenario effectively takes all the gas from the Upper Peace area, Central Peace area and Mackenzie Valley and directs the flow towards Upper Bens Lake area with some of the residual volumes flowing south and reconnecting with the mainline at Princess and on to Empress, where liquids can be removed from the stream. The volumes of gas delivered to the Upper Bens Lake area will not have liquids recovered from the marketable gas stream.

The assumptions used for this scenario are as follows:

- Well connections in British Columbia and Alberta are based on the “Base Case” new well connection profile.

- Alberta demand is based on the “Base Case” demand forecast from the EUB ST98-2006 report with Oil Sands purchase gas requirements from the NEB Oil Sands Update 2006 documents. British Columbia demand is assumed to grow at 1 percent per year from the 2005 base.

- LNG supply at Kitimat, British Columbia is assumed to be available in 2010 with an average daily send out rate of 520 mmcf/day (17,190 e^3m^3/day) based on an 85 percent load factor. This LNG supply is assumed to split, with 25 percent going to the Sumas export point and 75 percent displacing BC gas for delivery to Alberta and export points leaving Alberta.

- The current export volume at Sumas is assumed to increase at 2.5 percent above the 2005 delivery and the destination is assumed to be the Pacific Northwest and California areas.

- Alliance pipeline export volumes are held at 1630 mmcf/day (45,920 e^3m^3/day) until 2020, after which a 10 percent decline per year is applied (refer to Section 7.7).

- Foothills/Northern Border Pipeline export volumes are held at 1975 mmcf/d (55,640 e^3m^3/day) until 2007 after which a 6 percent decline per year is applied until 2016. At this point in time the Alaska volumes enter Alberta and the export volumes are assumed to recover to a flow volume of 1800 mmcf/day. TCPL east and NBPL will have an operational load factor of 90 percent.

- Gas Transmission Northwest export volumes are held at 1790 mmcf/day (50,430 e^3m^3/day) until 2007 after which a 6 percent decline per year is applied until 2016. At this point in time the Alaska volumes enter Alberta and the export volumes are assumed to recover gradually returning to the 2005 level.

- TCPL east receives the residual gas after Alberta demand and the export volumes mentioned above have been removed.

- The North Central Corridor is assumed to be constructed by 2012 and is capable of transporting 700 mmcf/day (19,720 e^3m^3/day) from the Upper Peace River area to the Upper Bens Lake area. The corridor is further expanded in 2016 to handle 2300 mmcf/day (64,800 e^3m^3/day) to facilitate a more optimal utilization of the Bens Lake to Princess lateral rather than expanding the western mainlines.

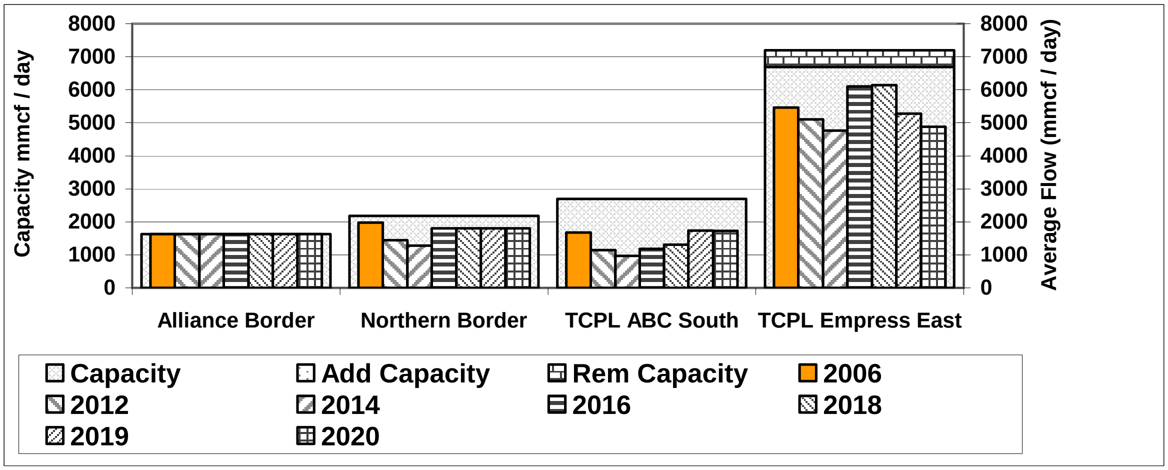
The NCC pipeline will transport all the gas from the Upper Peace and Central Peace areas (north of Boundary Lake Lateral) and the Mackenzie Gas over to the Upper Bens Lake area, which results in the Central Peace area carrying almost the total volume of Alaska gas in 2018. Expansion of the NCC connector would involve two intermediate compressor stations and a second 30 inch loop line to handle the 2300 mmcf/day flow volume.

The existing pipeline in the Central Peace and the Lower Peace area would need to be expanded and/or reconfigured to handle the required volume (Figure 6.15). The facilities required would include the addition of 134 miles of 48 inch pipe, 119 miles of 36 inch pipe, five 23 megawatt compressor additions and a new compressor station near Wembley, Alberta.

Figure 6.15 indicates that the Edson Sub Design area would also require additional facilities to handle the increased volume. This can be accomplished by adding one intermediate station on the Swartz Creek to Clearwater loop line.

The James River to Princess, Princess to Empress, and Empress to Winnipeg has sufficient spare capacity to handle the increased flow (Figures 6.15 and 6.16).

Figure 6.14
Scenario # 2 Expanded NCC (utilizing TCPL Integrated System)
Border deliveries versus export capacity (Alberta North West)



As in Scenario # 1, the utilization rate for the Empress to Winnipeg section approaches 90 percent after accounting for the reduced capacity of the Keystone project.

Figure 6.15
Scenario # 2 (utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta North West)

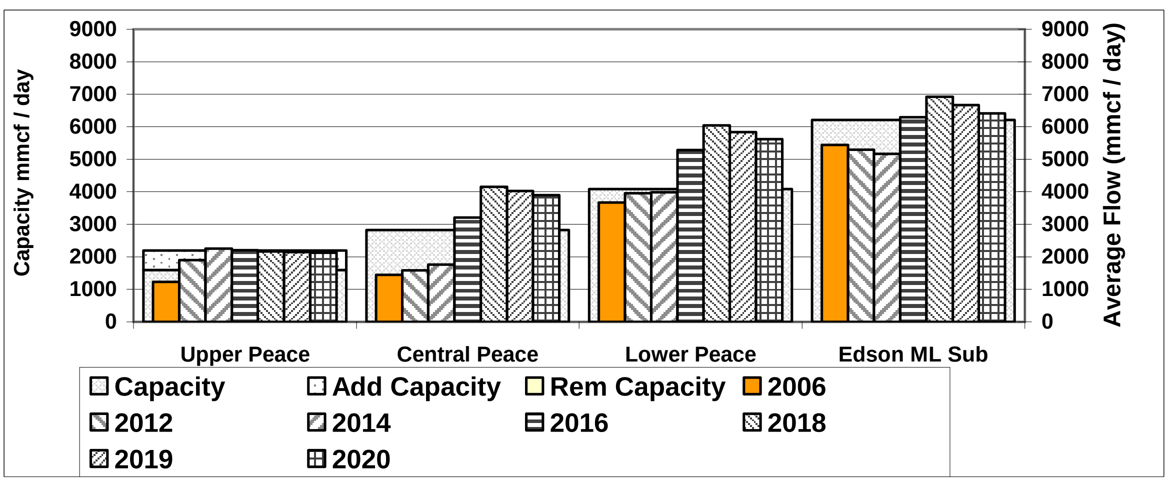


Figure 6.16
Scenario # 2 Expanded NCC (utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta South East)

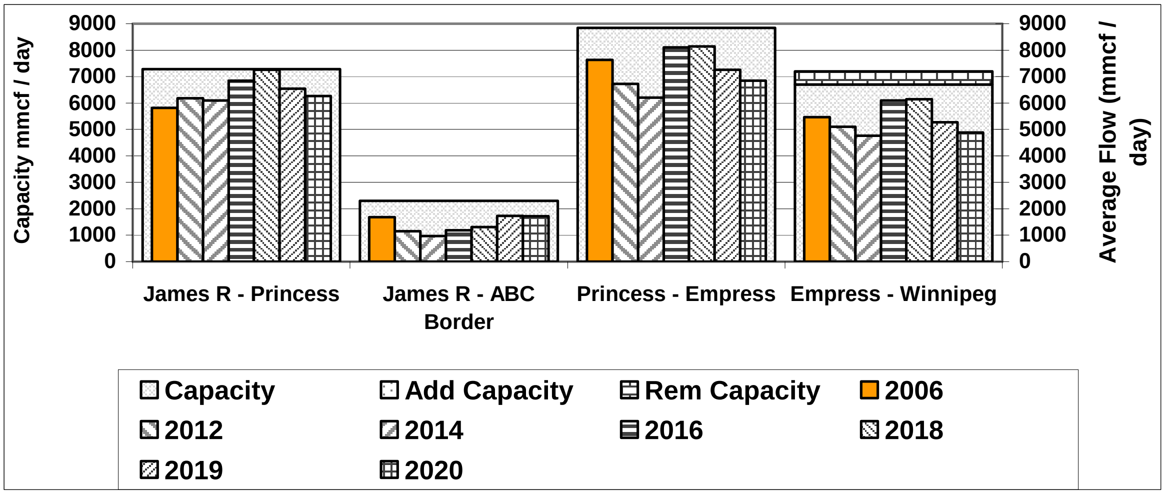
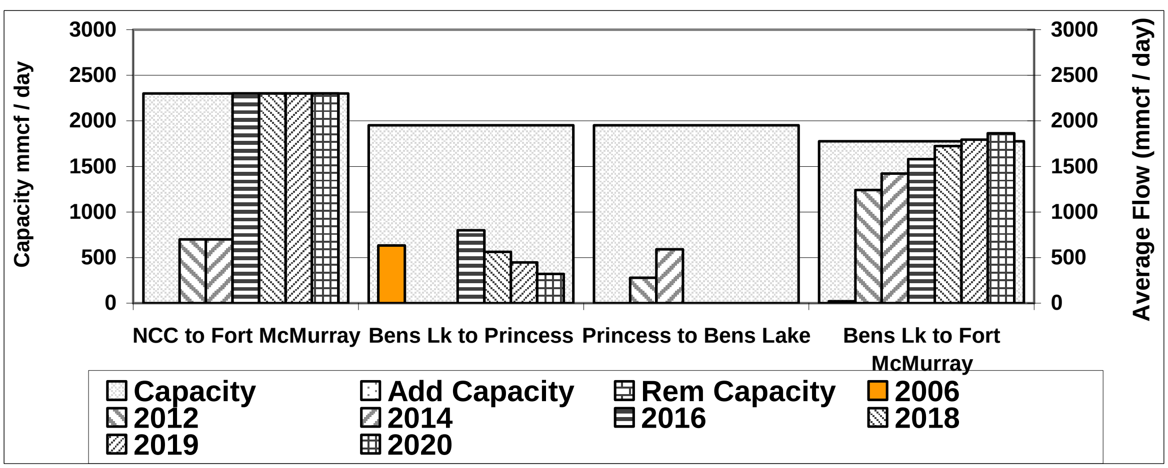


Figure 6.17 shows flows on the Bens Lake to Princess lateral return to their normal south flow direction following expansion of the North Central Corridor.

Figure 6.17
Scenario # 2 Expanded NCC (utilizing TCPL Integrated System)
Section Volumes and Capacities (Fort McMurray)



In Figure 6.18, the deliveries to the Gas Transmission Northwest and Northern Border Pipelines are held at the 2005 level until 2007 followed by a 6 percent decline until the Alaska volumes are connected to the system. Some of the Alaska volumes have been allocated to the GTN pipeline system under the assumption that deliveries to the California market will gradually recover to the 2005 level. The Northern Border Pipeline and the TCPL East pipeline are assumed to share the transportation of the residual Alaska volumes with each pipeline operating at a 90 percent load factor in the initial years.

Figure 6.18
TCPL East Canadian Demand and Export Potential

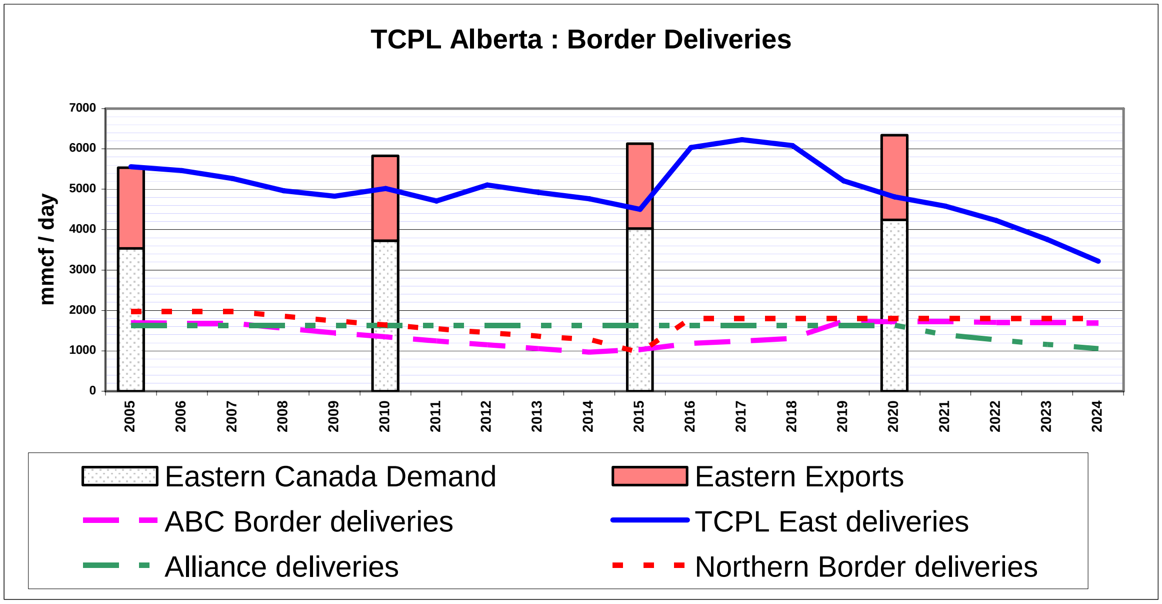
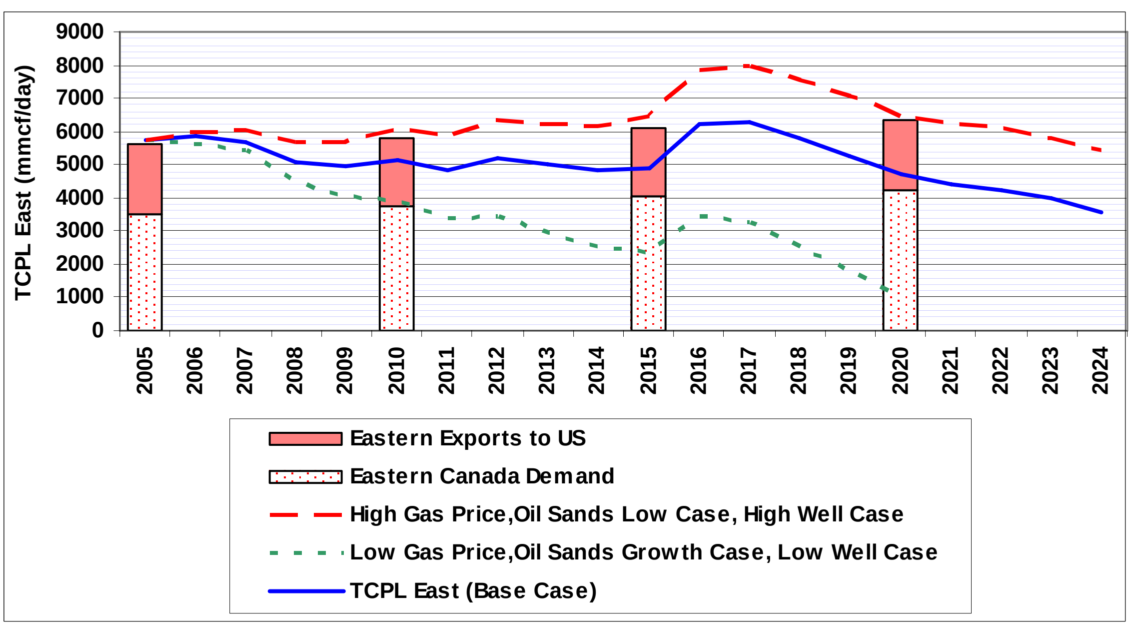


Figure 6.19 shows the potential effect gas prices could have on the deliveries to the TCPL East mainline. Refer to comments associated with Figure 6.13.

Figure 6.19
Scenario # 2 Sensitivities



6.4 Scenario # 3: Alaska Gas transported on TCPL integrated system and Alliance Pipeline System

Scenario # 3 assumes that the Alaska gas will follow two different paths in order to get to market. The Alliance pipeline has a current capacity of 1630 mmcf/day (46,485 e^3m^3/day) from Fort Saskatchewan to Aux Sable, Illinois. The addition of twelve intermediate compressor stations and adding a complete 36 inch loop would boost the pipeline capacity to 3500 mmcf/day (100,720 e^3m^3/day). In addition, a connector pipeline (355 miles of 36 inch with 2 compressor stations each with a single LM2500 unit) would need to be constructed from Boundary Lake to Fort Saskatchewan to deliver 1875 mmcf/day to the start of the expanded Alliance pipeline. This connector pipeline is assumed to operate at 2500 pounds per square inch. Construction of a straddle plant at Fort Saskatchewan could be economic based on the liquids available.

After accounting for the volumes transferred to Alliance, the remaining gas would be transported on the TCPL system south to James River. In order to eliminate the need for additional facilities on the Lower Peace and Edson sub area, this scenario assumes the NCC will be expanded to handle 2300 mmcf/day.

In addition, the following assumptions apply to this scenario:

- Well connections in British Columbia and Alberta are based on the "Base Case" new well connection profile.

- Alberta demand is based on the "Base Case" demand forecast from the EUB ST98-2006 report with oil sands purchase gas requirements from the NEB Oil Sands Update 2006 documents. British Columbia demand is assumed to grow at 1 percent per year from the 2005 base.

- LNG supply at Kitimat, British Columbia is assumed to be available in 2010 with an average daily send out rate of 520 mmcf/day (17,190 e^3m^3/day) based on an 85 percent load factor. This LNG supply is assumed to split with 25 percent going to the Sumas export point and 75 percent displacing BC gas for delivery to Alberta and export points leaving Alberta.

- The current export volume at Sumas is assumed to increase at 2.5 percent above the 2005 delivery and the destination is assumed to be the Pacific Northwest and California areas.

- Alliance pipeline export volumes are held at 1630 mmcf/day (45,920 e^3m^3/day) until 2016, after which the system will be expanded to handle an additional 1945 mmcf/day (54,800 e^3m^3/day) of Alaska gas.

- Foothills/Northern Border Pipeline export volumes are held at 1975 mmcf/d (55,640 e^3m^3/day) until 2007 after which a 6 percent decline per year is applied until 2016. At this point in time the Alaska volumes enter Alberta and the export volumes are assumed to recover to a flow volume of 1800 mmcf/day. TCPL east and NBPL will have an operational load factor of 90 percent.

- Gas Transmission Northwest export volumes are held at 1790 mmcf/day (50,430 e^3m^3/day) until 2007 after which a 6 percent decline per year is applied until 2016. At this point in time the Alaska volumes enter Alberta and the export volumes are assumed to recover gradually returning to the 2005 level.

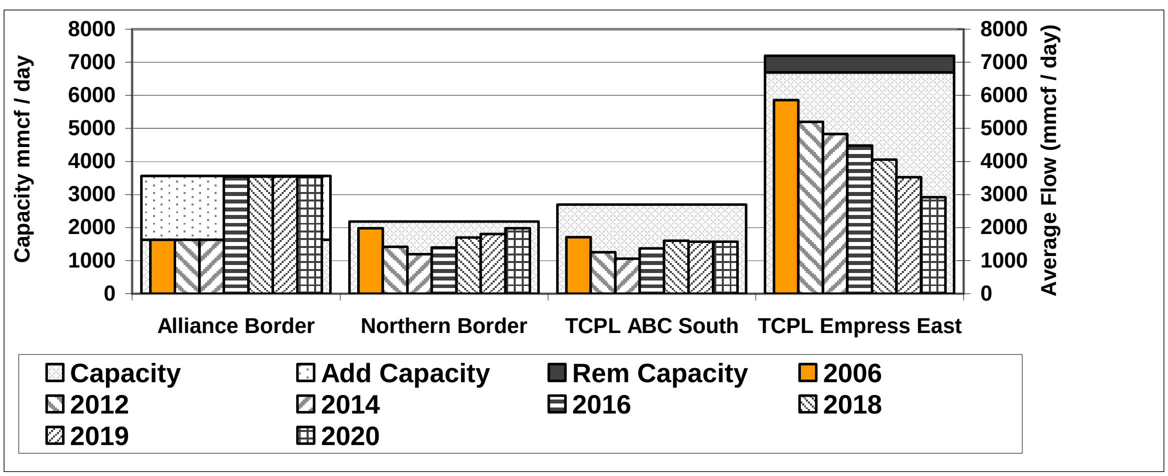
- TCPL east receives the residual gas after Alberta demand and the export volumes mentioned above have been removed.

- The North Central Corridor is assumed to be constructed by 2012 and is capable of transporting 700 mmcf/day (19,720 e^3m^3/day) from the Upper Peace River area to the Upper Bens Lake area. The corridor is further expanded in 2016 to handle 1700 mmcf/day (70,435 e^3m^3/day) to facilitate a more optimal utilization of the Bens Lake to Princess lateral rather than expanding the western mainlines.

- The Alaska volume is split with 1890 mmcf/d directed to Alliance pipeline at Fort Saskatchewan. This volume can be handled on the Alliance system if it is looped and the intermediate stations are constructed

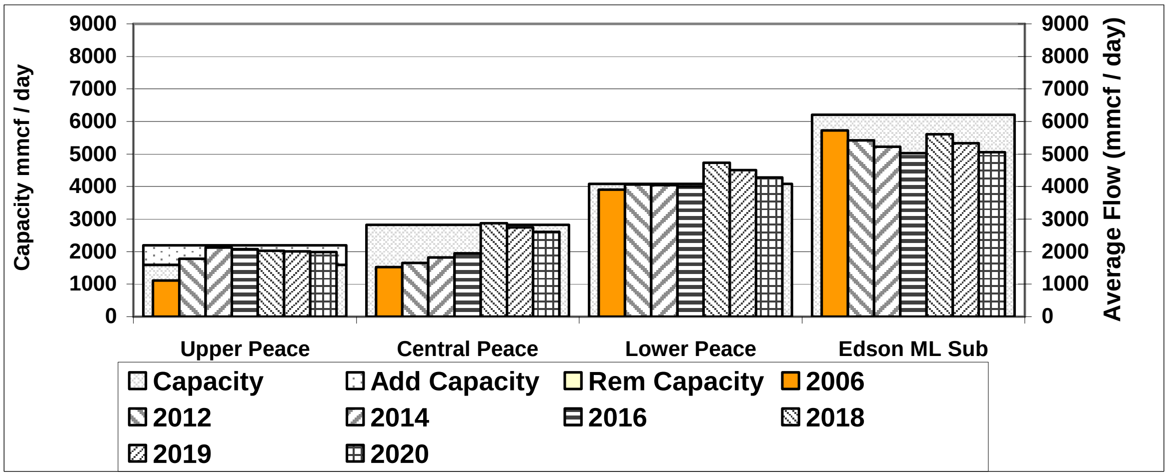
Figures 6.20 shows that with the increased flow on the Alliance System, coupled with the recovered deliveries to the GTN and Northern Border pipelines, the utilization of the TCPL system downstream of James River continues to decline.

Figure 6.20
Scenario # 3 (TCPL/Alliance transportation)
Border deliveries versus export capacity



A small expansion to the Lower Peace River area (Figure 6.21) in the form of completing the loop down stream of Gold Creek, coupled with power additions at three of the compressor stations, will increase the capacity to handle the Alaska volumes.

Figure 6.21
Scenario # 3 (TCPL/Alliance transportation)
Section Volumes and Capacities (Alberta North West)



With the exception of the facilities mentioned above for the Lower Peace River area, the Alaska volumes can be handled by the existing mainline facilities between Gold Creek, Alberta (exit of the Lower Peace River area) and Winnipeg.

Figure 6.23 shows the expansion of the NCC to handle a flow of 1700 mmcf/day.

Figure 6.24 shows the potential effect gas prices could have on the deliveries to the TCPL East mainline. These sensitivity curves assume all other parameters related to the base case remain constant with the exception that gas prices will affect the purchase gas requirements for oil sands development and the rate at which new wells are drilled and connected for production. Refer to comments associated with Figure 6.13.

Figure 6.22
Scenario # 3 (TCPL/Alliance transportation)
Section Volumes and Capacities (Alberta South East)

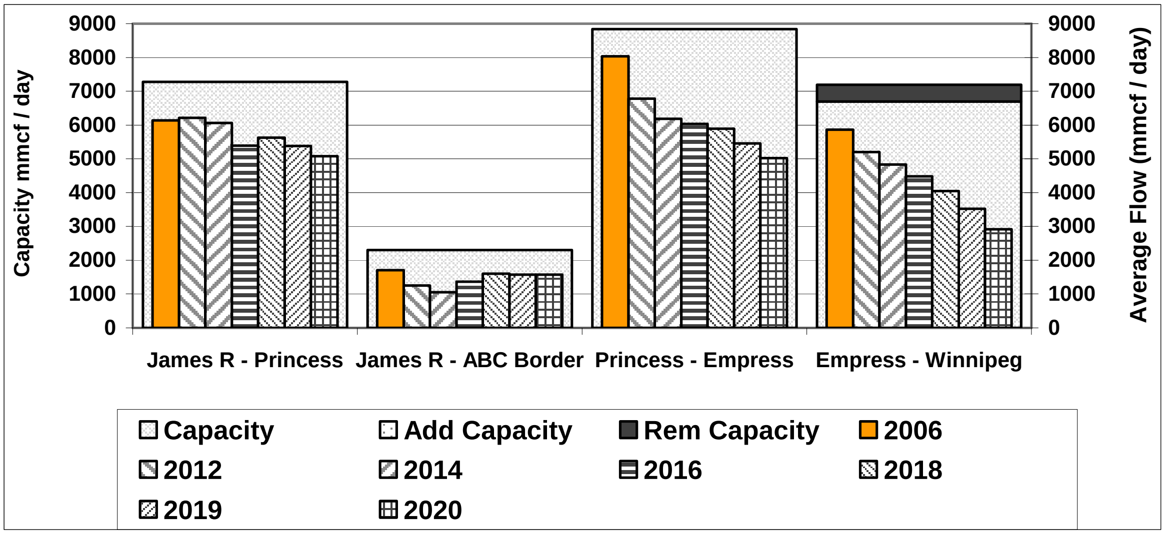
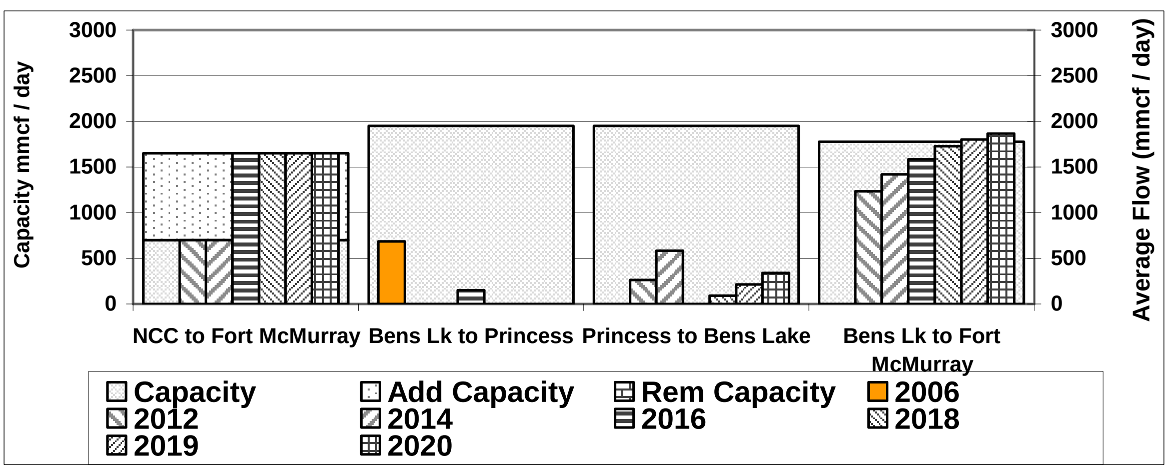


Figure 6.23
Scenario # 3 (TCPL/Alliance transportation)
Section Volumes and Capacities (Fort McMurray)



In 2018, the Alaska volumes are split with 1890 mmcf/d going to the Alliance Pipeline, 1300 mmcf/day going to the GTN system and 1200 mmcf/day going to NBPL, which results in TCPL East receiving approximately 4100 mmcf/day.

Figure 6.24 shows the effect on border deliveries as a result of transferring 1890 mmcf/day of Alaska gas to the Alliance Pipeline.

Figure 6.24
Scenario # 3 (TCPL/Alliance transportation)

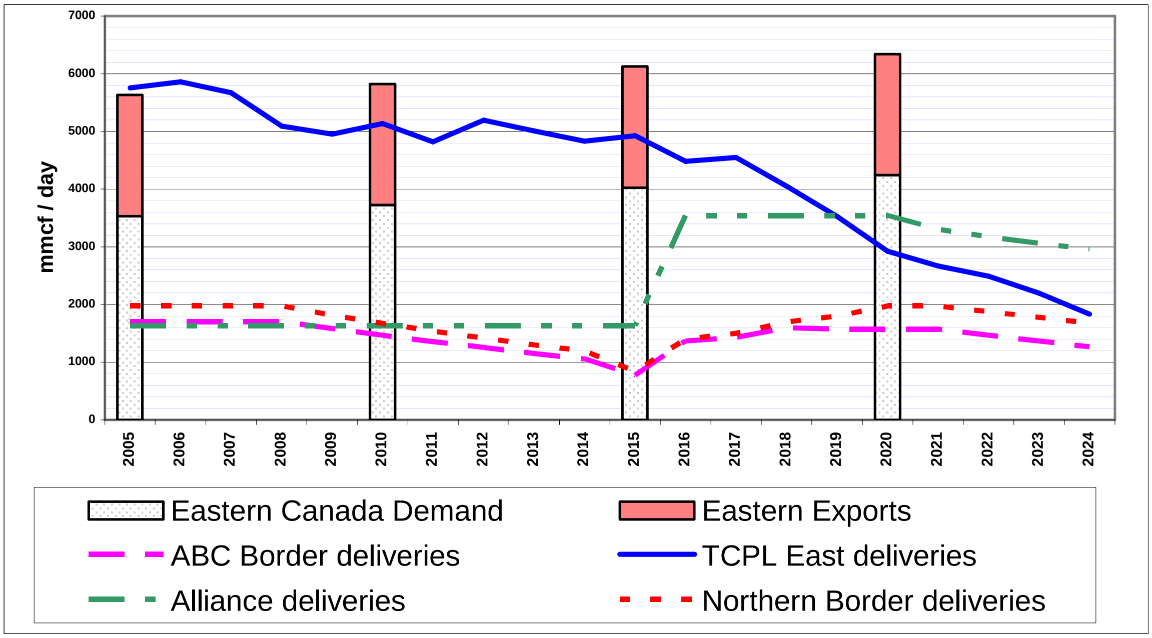
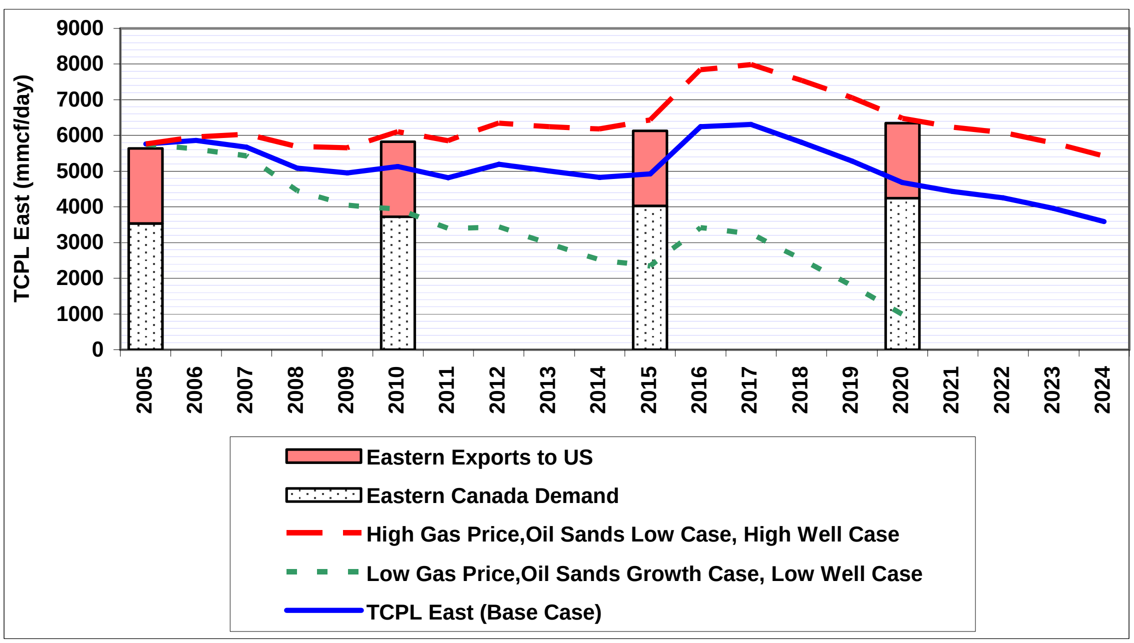


Figure 6.25
Scenario # 3 Sensitivities



6.5 Scenario # 4: Alaska Gas transported on the Alliance Pipeline System

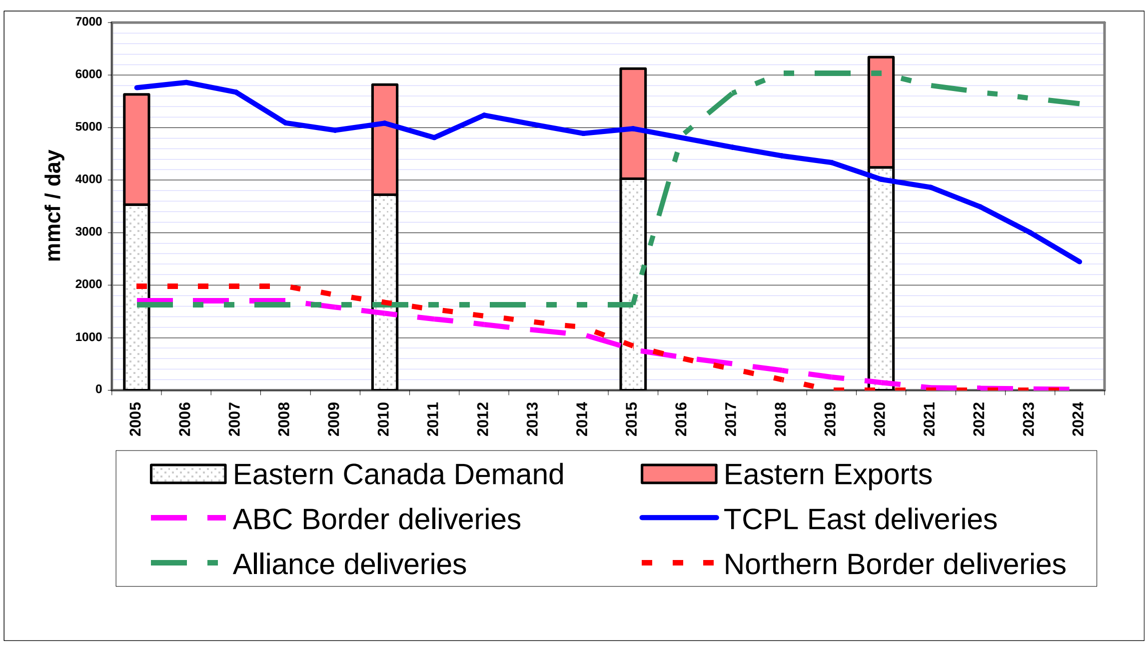
Scenario # 4 assumes the total Alaska volume would be transported on an expanded Alliance Pipeline. This scenario also assumes that the GTN deliveries to the California market will not recover to their 2005 level and the market would be supplied by LNG imports and mid continent gas supplies. The Northern Border pipeline is assumed not to recover from declining basin deliveries and residual supplies are directed towards eastern Canadian demand.

In Scenario #3 the Alliance pipeline was assumed to be expanded by constructing the intermediate compressor stations and adding a complete 36 inch loop. In Scenario #4, the Alliance pipeline will need to be expanded by utilizing a 48 inch loop.

The addition of twelve intermediate compressor stations, adding a complete 48 inch loop (1505 miles) and expanding 24 stations with the addition of a 29 megawatt compressor would boost the pipeline capacity to 6264 mmcf/day (176,480 e^3m^3/day). In addition, a connector pipeline (355 miles) of 42 inch with 2 compressor stations, each with twin 25 megawatt gas turbines, would need to be constructed from Boundary Lake to Fort Saskatchewan. This connector pipeline is assumed to operate at 2500 pounds per square inch. Construction of a straddle plant at Fort Saskatchewan could be economic based on the liquids available.

Figure 6.26 demonstrates the effect this level of expansion will have on the TCPL east deliveries.

Figure 6.26
Scenario # 4 Alaska volumes to Alliance 48 inch Capacity



CHAPTER 7
NOTES ON KEY ASSUMPTIONS

This chapter is intended to briefly identify issues surrounding some of the key assumptions used in the study and to detail the reasons for arriving at a specific position.

Some of the issues described below could not be analyzed because of the lack of detailed information. In these situations, a reasonable assumption was adopted. In other situations, the subject matter was outside the scope of the study and thus not analyzed. And finally, in some situations the assumption is based on external information that assisted in arriving at a reasonable assumption.

7.1 Consideration of Heavier Hydrocarbon Gas Streams on Existing Pipelines

This study has assumed that the compositional makeup of the Alaskan gas stream will have no effect on the integrity of the existing pipeline systems that gather and export natural gas from Alberta and British Columbia.

The point of contention here is the belief that, in the event of a pipeline rupture, a "rich gas" stream may contribute to "Dynamic Fracture Propagation" (DFP) in pipeline systems where the toughness of the steel is insufficient to arrest the crack. The question is directed at the existing pipeline systems that developed over time where the degree of toughness can be different from section to section and mainline to loop lines.

"Pipelines could contain defects introduced during steel and pipe making, and pipeline construction. Although significant pre-service defects are very rare in recently constructed pipelines, that initial defect population could expand as pipelines continue service, due to defects introduced by outside forces, including mechanical damage defects, or defects that nucleate and grow in service. Such defects may be blunt (for example due to corrosion) or sharp (for example due to stress corrosion cracking or effects of hydrogen embrittlement)."[31] In the unlikely event of a failure of a high pressure gas pipeline, the rupture allows the gas to exhaust, which establishes a decompression front propagating away from the origin limited by the acoustic velocity of the gas. If the acoustic velocity is less than the velocity of the fracture front, the result can lead to a running fracture or a DFP. For a gas, the de-compositional behavior depends on its operating pressure, temperature, composition and more importantly the amount of heavier hydrocarbon elements. For a pipeline, the velocity of a propagating fracture is a function of the stress in the pipeline and the ability of the steel to resist a ductile-fracture or its degree of toughness.

Table 4.4 details the assumed composition of the gas stream that will be transported by the Alaska Highway Pipeline from Prudhoe Bay, Alaska to Boundary Lake, Alberta. From this point the gas stream could be directed towards Fort Saskatchewan, Alberta and on to Chicago by way of

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[31] Fracture Propagation Control in Onshore Transmission Pipelines, Onshore Pipeline Technology Conference, Istanbul, Dec 1998, Brian N Leis and Robert J Eiber

the Alliance Pipeline System, or the stream could enter the TCPL Alberta integrated system where it will be mixed with Alberta conventional gas streams for transportation to the Alberta border points to connect with Canadian domestic and US export pipelines. The Alliance pipeline was constructed to provide a Charpy-vee notch (CVN) toughness of approximately 200 joules at 1178 BTU's per cubic foot whereas pipelines constructed prior to 1997 provide a CVN toughness of approximately 100 joules at 1050 BTU's per cubic foot. The assumption that the hydrocarbon composition of Alaskan gas will not affect the integrity of the existing pipeline systems is based on the following:

- The Peace River section of the TCPL Alberta system currently receives gas with a hydrocarbon makeup similar to that of the Alaska gas. Alberta conventional gas entering the pipeline system north of Boundary Lake has an average ethane content of 6.0 percent as compared to the 6.3 percent for the Alaskan gas, and a propane content of 1.8 percent as compared to 2.4 percent for the Alaskan gas. Alberta conventional gas entering the TCPL Alberta system south of Gold Creek has ethane and propane contents greater than the Alaskan gas. The mixing of these gas streams will not significantly alter the compositional make up of the existing gas stream.

- Prior to the construction of the Alliance Pipeline, the composition of gas streams entering the TCPL Alberta System in the Kaybob and Deep Basin areas contained ethane and propane compositions in excess of 12 percent and 6 percent, respectively. Most of these gas streams are now carried on the Alliance pipeline.

- In the event the North Central Corridor is constructed and results in gas volumes from the Peace River area being transported to the Upper Bens Lake area, the Alaska gas will be diluted only minimally by conventional sources. However, the compositional makeup of the Alaskan gas is not significantly different than the composition that the pipeline is currently being exposed to.

- Detailed information regarding the type of steel (yield stress, thickness and toughness) used in the various sections of the TCPL Alberta system was not available for this study, thus limiting the ability to investigate this subject in more detail.

7.2 Pressure Constraints on the TCPL Alberta System

This study has assumed that the operating pressure of the Alaska Pipeline System will not be a problem at the Boundary Lake connection.

The Alaska Highway Pipeline is proposed to operate with a maximum operating pressure (MOP) of 2500 pounds per square inch. At Boundary Lake, the pressure of the gas stream will be approximately 1900 pounds per square inch (based on a flow volume of 4500 mmcf/day) as a result of the last station on the BC section being situated 120 miles upstream from Boundary

Lake. The TCPL Alberta system has a maximum operating pressure of 1200 pounds per square inch at the point where the Alaska pipeline will interconnect. The following assumptions have been made with regard to pressure considerations at Boundary Lake:

- If the majority of the gas stream is directed to the Fort Saskatchewan connection with the Alliance pipeline then the connector pipeline between these two points will be designed to operate at 2500 pounds per square inch and any volumes of gas directed to the TCPL Alberta System will need to be pressure regulated down to 1200 pounds per square inch.

- If the majority of the gas stream is directed to the TCPL Alberta system, then the discharge pressure at the last upstream compressor station will be set to yield a pressure of 1200 pounds per square inch at Boundary Lake. Any residual gas going to Fort Saskatchewan will require a compressor station at Boundary Lake to boost the pressure to 1750 pounds per square inch to match the operating pressure of the Alliance Pipeline.

7.3 Potential Impact of a Straddle Plant at Fort Saskatchewan, Alberta

The relative economics of constructing a new straddle plant at Fort Saskatchewan compared to utilizing the existing plants at Empress and Cochrane were not accounted for in this study because they are considered outside the scope.

If Alaska gas volumes enter the TCPL Alberta pipeline system, the liquids contained within the gas stream will be removed either by the Empress or Cochrane straddle plant operations. The combined capacity of the five Empress Plant operations is 8700 mmcf/day (245,110 e^3m^3/day); while the Cochrane facility will have a capacity of 2500 mmcf/day (70,435 e^3m^3/day) after the cryogenic train number four comes online in 2008. Scenario #1 which accounted for all of the Alaskan gas being transported on the TCPL Alberta system resulted in a flow at Empress of 8011 mmcf/day, and at Cochrane a flow level of 1650 mmcf/day, which is still below the plant capacity levels. Under the scenario where the California market does not take the gas from the Gas Transmission Northwest system, these volumes would be redirected to flow eastward, resulting in the flow volume at Empress exceeding the plant capacity by 3 percent.

If gas volumes are directed to the Fort Saskatchewan area, the assumption is made that a new straddle plant operation will be constructed to remove the liquids prior to the flow entering the Alliance pipeline. The assumption is also made that, if a significant portion of the Alaska volumes are directed to Fort Saskatchewan, then the connector pipeline will operate at 2500 pounds per square inch and the inlet pressure to the straddle plant will be in the order of 1900 pounds per square inch with the exit pressure matching the Alliance line pressure at that point. If a smaller quantity of gas is directed to Fort Saskatchewan then the connector pipeline will operate at 1750 pounds per square inch and the inlet pressure to the plant will be approximately 1240 pounds per square inch.

7.4 Kitimat LNG Terminal

This study has included the Kitimat LNG terminal as part of the base case and has assumed an operational load factor of 85 percent.

The Kitimat LNG terminal to be located at Emsley Cove, British Columbia has been proposed to be developed with a send out capacity of 620 mmcf/day (17,470 e^3m^3/day). The projected on stream date is 2009. Kitimat LNG has received its provincial and federal environmental permit and can now proceed with development of the project. Gas supply for the terminal will come from an Australian company.

In July of 2006, Kitimat LNG Inc. entered into a partnership with Pacific Trails Pipelines for the purpose of developing the natural gas transmission pipeline system to connect the LNG terminal to Westcoast Energy's pipeline system at Summit Lake, British Columbia. This pipeline connection will give Kitimat LNG access to the lower mainland of BC, and the export markets of Washington, Oregon and California.

7.5 California Demand Considerations

This study has assumed that volumes of gas transported on the GTN system will decrease as production from the WCSB basin decreases and will recover when the Alaska gas enters the markets starting in 2016.

Figure 3.1 details the potential deficiency in the California market as a result of declining supplies from Alberta that are connected to the Gas Transmission Northwest pipeline. This deficiency will exist even after accounting for new LNG imports from Mexico and California and increased deliveries from the proposed Kitimat LNG terminal and assuming the US interstate pipelines will operate at their capacity levels. What is not accounted for in this assumption is the potential for new supplies of gas from Wyoming entering the California market in addition to flows moving to the Illinois market area. The Rockies Express Pipeline was originally designed to transport gas from Sweetwater, Wyoming to Illinois, Indiana and Ohio, and is projected to be on stream in 2008. However, the Overthrust Expansion Project is intended to connect the Sweetwater area to the existing Kern River Gas Transmission System. This means that the Wyoming gas will have access to the California market (assuming Kern River is expanded to handle the volumes) and could displace Alberta gas as the WCSB basin declines. This could result in the flow volumes on the GTN system not recovering to the 2005 level as assumed. Should this transpire, these volumes would be directed towards TCPL east.

7.6 North Central Corridor Design Capacity

The North Central Corridor (NCC) is a connector pipeline that TCPL has proposed to construct in the northern part of the province in order to efficiently move natural gas from the Peace River area to the Upper Bens Lake area for the purpose of supplying the oil sands development near Fort McMurray. TCPL has indicated that it is more economical from a fuel usage point of view to move gas east to the Bens Lake area and south to Princess, than it is to maximize (and possibly expand) the Peace River to James River to Princess mainline.

This study did not have sufficient details to examine and compare fuel requirements for the two routes. As a result, the size of the NCC connector (volume to be transported) was established for each scenario as the quantity of gas required to maximize the flow in the Peace River to Princess (via James River) pipeline sections with minimal or no facility expansions in these areas. The size of the connector was further limited to the volumes of gas in the Upper Peace River and Central Peace River areas above the Boundary Lake Lateral.

As a result of these considerations, the NCC was sized to handle a volume of 700 mmcf/day (in the base case), which eliminates the need for additional facilities in the Lower Peace River and Edson Mainline areas. Additional facilities down stream of James River would not be required because of the available spare capacity. In Scenario # 2, the NCC would need to be expanded to handle 2300 mmcf/day. In Scenario # 3, the NCC would need to be expanded to handle 1700 mmcf/day.

These flow levels should be considered minimum volumes as larger capacities for the NCC might prove to be more economic as a result of greater fuel savings.

7.7 Alliance Pipeline Future Contracts

Volumes of gas that flow on the Alliance Pipeline are associated with contractual obligations that have a primary term that extends out to 2015. There is an automatic extension to these contracts for an additional 5 years unless the contractor exercises a "Notice of Termination" available in 2010. For this study, the assumption has been made that the Alliance pipeline will remain full out to 2020, followed by a prorated share of the basin decline after that point. This assumption is based on the following:

- Alliance receives its gas from areas of Alberta and British Columbia (PIA areas 13, 15, 14, 16, and 34) where 20 percent of the 2005 drilling took place with an average initial production rate of 715 mmcf/day.
- The Western Plains area of Alberta contains approximately 37 percent[32] of the total yet-to-be-established reserves for Alberta. The Alliance receipt areas access the north half of this area which, from a geological point of view, may be more prolific.

[32] EUB, ST98-2006, Alberta's Energy Reserves 2005 and Supply/Demand Outlook, 2006

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CHAPTER 8
CONCLUSIONS

1. The initial design for the Mackenzie Valley Pipeline calls for 761 miles of 30 inch pipeline with a lead station consisting of five, 10 megawatt compressor units with associated gas chiller units, four, 10 megawatt intermediate compressor stations with associated gas chiller units and one heater station. The cost of the gas pipeline from Inuvik gathering area to the Northwest Territories/Alberta border was estimated to be $2.86 billion Canadian dollars in 2002[33] and $3.88 billion Canadian dollars in 2004[34]. Imperial Oil Ltd. has suggested that ballooning prices for labor and materials has driven the cost up but has not indicated by how much. Assuming a 20% increase in materials and a 30% increase in labor costs, the current cost estimate would be $4.377 billion Canadian dollars (2006 dollars). The initial flow rate for the pipeline will be 820 mmcf/day (23,102 e^3m^3/day) growing to 1230 mmcf/day (34,650 e^3m^3/day) in year three. This relates to 800 mmcf/day and 1200 mmcf/day delivered to the AB/NWT border. At the 1200 mmcf/day level, it is anticipated that 13,000 barrels per day of natural gas liquids will be recovered at the Inuvik processing facility and 21,300 barrels per day are available to be extracted from the gas stream in Alberta. Expansion options for the pipeline are 1600 mmcf/day (45,080 e^3m^3/day) with the addition of 4 additional compressor stations and 1950 mmcf/day (554,940 e^3m^3/day) by adding an additional compression unit at each station.

2. A definitive design for the Alaska Highway Pipeline has not been submitted as of the writing of this report. A reasonable design for this pipeline calls for 745 miles of 48 inch pipe in Alaska and 940 miles of 48 inch pipe in the Yukon Territory and British Columbia. In addition, a lead station at the Prudhoe Bay location consisting of five, 16 megawatt compressor units with associated gas chiller units, six intermediate compressor stations (twin 23 megawatt units) with associated gas chiller units in Alaska and seven intermediate compressor stations (twin 23 megawatt units) with associated gas chiller units in the Yukon Territory and British Columbia. The total capacity for this pipeline would be 4750 mmcf/d (133,825 e^3m^3/day) receipt at Prudhoe Bay and 4500 mmcf/day delivered to Boundary Lake, Alberta. Assuming the same costing parameters utilized for the Mackenzie Valley Pipeline, including the 20% increase in materials and a 30% increase in labor cost, the current cost estimate would be $9.072 billion Canadian dollars (2006 dollars) for the Alaska section and $10.23 billion Canadian dollars (2006 dollars) for the Canadian section. At the average day level of 4500 mmcf/day, it is anticipated that 186,000 barrels per day of liquids would be available for extraction in Alberta. The exact location of the liquid extraction will depend on which pipeline or pipelines transport the volumes through Alberta.

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[33] ColtKBR, Detailed System Optimization, Mackenzie Gas Project, December 2003
[34] Wright Mansell Research, An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Project and Mackenzie Gas, August 2004

Under this design, the pressure of the gas stream at Boundary Lake will be 1900 pounds per square inch. If the flow is directed to the Fort Saskatchewan Area and a connection with the Alliance Pipeline System, Boundary Lake is the next logical place for a mainline compressor. If the flow is directed to the TCPL Alberta System, the pressure will need to be regulated down to the current system maximum operating pressure (1200 PSI) either at the Boundary Lake connection or by reducing the discharge pressure of the last upstream compressor.

3. The Alliance Pipeline System transports liquid rich gas from British Columbia and Alberta to Aux Sable, Illinois, a distance of 969 miles in Canada and 888 miles in the United States. The current pipeline is constructed of medium pressure (1200 pounds per square inch) 42 inch pipe up stream of the Windfall Compressor Station and 36 inch high pressure (1750 pounds per square inch) pipe downstream of the Windfall compressor station. The current receipt capacity of the pipeline is 1635 mmcf/day (46,065 e^3m^3/day) with 1580 mmcf/day delivered to the terminus. The system can be expanded by constructing the intermediate compressor stations (average 60 miles spacing) to add 525 mmcf/day (14,790 e^3m^3/day) new capacity. Adding the intermediate stations and looping the entire distance with a 36 inch loop would add 1875 mmcf/day (54,800 e^3m^3/day) of new capacity. With the further addition of a second 25 megawatt compressor unit at each station, the capacity flow would be 4475 mmcf/day (126,080 e^3m^3/day) or an incremental increase in capacity of 2845 mmcf/day (80,155 e^3m^3/day). The Alliance pipeline could be utilized to transport the total Alaska volume by looping the entire system downstream of Fort Saskatchewan with a 48 inch loop, constructing the intermediate compressor stations and adding an additional 29 megawatt gas turbine at every station. The capacity of this design would be 6265 mmcf/day (176,510 e^3m^3/day) or an incremental capacity of 4650 mmcf/day (131,010 e^3m^3/day)

   The connection from Boundary Lake, Alberta to Fort Saskatchewan, Alberta will depend on the volume that will be transported to the Alliance pipeline, plus any volume shrinkage as a result of removing liquids at Fort Saskatchewan. Assuming Alliance is expanded to handle 1890 mmcf/day of incremental capacity then the connector would require 355 miles of 36 inch pipe (2500 pounds per square inch) with 3 compressor stations (LM2500 units). The capacity would be 2140 mmcf/day (60,290 e^3m^3/day). The delivery pressure of the gas stream under this design would be 1890 pounds per square inch. Under this design, doubling the units at each station will increase the capacity to 2530 mmcf/day (71,280 e^3m^3/day). Assuming Alliance will transport all the volumes from Alaska then the connector would require 355 miles of 42 inch pipe (2500 pounds per square inch) with twin LM2500 units at each station. The delivered volume would be 4470 mmcf/day (125,940 e^3m^3/day) at a pressure of 1900 pounds per square inch.

4. The Gas Transmission Northwest pipeline transports natural gas from Kingsgate, British Columbia to Malin, Oregon, a distance of 614 miles. The pipeline operates at 925 pounds per square inch and consists of a 36 inch mainline and a 42 inch loop for the entire

distance. The current receipt capacity of the pipeline is 2755 mmcf/day (77,620 e^3m^3/day); with 1965 mmcf/day (55,360 e^3m^3/day) delivered to the California border. The capacity can be increased by 500 mmcf/day (14,090 e^3m^3/day) by adding 58 miles of 36 inch loop and increasing the power available at ten of the compressor sites through the addition of 16 megawatt units. The capacity can be further increased by 1000 mmcf/day (28,170 e^3m^3/day) by adding 264 miles of 36 inch loop and increasing the power available at twelve of the compressor sites through the addition of 16 megawatt units.

5. The Northern Border Pipeline transports natural gas from the Canada/US border near Monchy, Saskatchewan to Iowa, Illinois and Indiana where it interconnects with several interstate pipelines. Supply for this export pipeline comes from a connection with the Foothills Alberta pipeline system and the Foothills Saskatchewan pipeline system. These two pipelines transport gas from the James River interchange on the TCPL Alberta system to the McNeill export point on the Alberta/Saskatchewan border and finally to Monchy, Saskatchewan. The current receipt capacity of the pipeline is 2205 mmcf/day (62,125 e^3m^3/day) with 1620 mmcf/day (55,360 e^3m^3/day) delivered to Ventura, Iowa and 390 mmcf/d delivered to North Hayden, Indiana. The capacity can be increased by 500 mmcf/day (14,090 e^3m^3/day) by adding 484 miles of 42 inch loop and increasing the power available at two of the compressor sites through the addition of 12 megawatt units. The capacity can be further increased by 1000 mmcf/day (28,170 e^3m^3/day) by adding 1012 miles of 42 inch loop and increasing the power available at five of the compressor sites through the addition of 12 megawatt units.

6. The Westcoast Energy Pipeline gathers gas from northeast British Columbia and transports it south to Vancouver and the lower mainland and exports volumes to the United States at Sumas, British Columbia. The southern mainline is the portion of the pipeline system starting at compressor station number 2 that transports the gathered volumes to the lower mainland. The current receipt capacity of the pipeline is 2085 mmcf/day (58,740 e^3m^3/day) with 1100 mmcf/day (55,360 e^3m^3/day) available for the export market and the remainder for Vancouver and Vancouver Island. In the event the Southern Mainline is expanded to move the Kitimat LNG volumes (570 mmcf/day) from Station 4A to the Sumas export point, an additional 233 miles of 42 inch loop pipe will be required. This study has assumed that 25 percent of the LNG volumes will be directed to the export market with the remaining 75 percent displacing BC volumes which will move east to Alberta, eastern Canada and the export markets.

7. The TCPL East pipeline system transports gas from the Alberta/Saskatchewan border just downstream of the Empress Straddle plant facility and transports it to a point just south of Winnipeg, Manitoba. At this point, the flow splits with approximately 2300 mmcf/day (64,800 e^3m^3/day) heading south to the Emerson connection with Great Lakes Transmission company and the remaining volumes going to TCPL Central pipeline system for deliveries to Ontario, Quebec and exports to the US. This pipeline system is made up

of six parallel pipes (34 , 34, 36, 42, 48, 48 inch) with compressors spaced approximately every 55-60 miles and has a current annual average capacity of 7210 mmcf/day (203,135 e^3m^3/day). TCPL has proposed removing one of the 34 inch pipelines from gas service and converting it to oil service as part of their Keystone pipeline project. Removing this pipe will result in a reduced annual average capacity of 6695 mmcf/day (188,625 e^3m^3/day)

8. In the Base Case, the North Central Connector is assumed to be constructed to handle 700 mmcf/day. Designing the NCC for this volume of gas should be considered the minimum size as it will just eliminate the need for the Lower Peace facilities and offer a more direct route for delivering gas to the Upper Bens Lake area to service the oil sands projects in the Fort McMurray area. The final design for this connector may in fact be to transport a larger volume as a result of taking fuel gas considerations into account. The data available to this study was not sufficient to analyze the fuel gas implications across the entire TCPL integrated system. In either case, expansion facilities will be required in the Upper Peace River area to handle the increased volumes from the area coupled with the Mackenzie Valley Gas. The Upper Peace will require new facilities to handle an additional 500 mmcf/day (14,090 e^3m^3/day)

9. The Empress straddle plant can currently process 8700 mmcf/day (245,510 e^3m^3/day) while the Cochrane facility has a process capacity of 2500 mmcf/day (70,435 e^3m^3/day) after the addition of the new cryogenic train number four. The new configuration is planned to be fully operational in 2008.

10. Assuming that the proposed Alaska volume of 4500 mmcf/day (126,780 e^3m^3/day) is to be transported from Boundary lake, Alberta to Chicago, Illinois, utilizing the TCPL system, the following system facilities would need to be added:

    - 142 miles of 42 inch loop pipe between Boundary Lake and Edson
    - 119 miles of 36 inch loop pipe between Boundary Lake and Edson
    - five 23 megawatt station additions between Boundary Lake and Edson
    - One new 29 megawatt compressor station near Wembley, Alberta
    - One new 29 megawatt compressor station between Edson and James River.
    - 355 miles of 36 inch loop on the NCC connector and two 23 mega watt station additions
    - Expansion of the Viking Gas Transmission System to carry the gas from Emerson Manitoba to Chicago, Illinois.

11. Assuming that the proposed Alaska volume of 4500 mmcf/day (126,780 e^3m^3/day) is to be transported from Boundary Lake, Alberta to Chicago, Illinois utilizing the Alliance pipeline system, the following system facilities would need to be added:

- 355 mile of 42 inch pipe between Boundary Lake and Fort Saskatchewan
- Two new compressor stations with twin 25 megawatt compressor units between Boundary Lake and Fort Saskatchewan.
- 1505 miles of 48 inch loop pipe between Fort Saskatchewan and Chicago.
- 12 new compressor stations with one 23 megawatt and one 29 megawatt unit
- 12 compressor station additions with one 29 megawatt unit.

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