Canadian Energy Research Institute

Capacity of the Western Canada Natural Gas Pipeline System

VOLUME 2

Peter H. Howard P.Eng
David McColl
Dinara Mutysheva
Paul R. Kralovic

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Authors:
Peter Howard
David McColl
Dinara Mutysheva
Paul Kralovic

CANADIAN ENERGY RESEARCH INSTITUTE
#150, 3512 – 33 STREET NW
CALGARY, ALBERTA
CANADA T2L A6

TELEPHONE: (403) 282-1231

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CHAPTER 1
INTRODUCTION

The performance of the pipeline system in Western Canada will be 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) along with Canadian and US northern frontiers, transit the area.

This study is motivated by 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 natural gas volumes entering or bypassing the Canadian pipeline systems from a variety of potential supply sources.

Volume 2 of the study consists of four chapters. Chapter 2 provides a brief description of the base case and possible flow scenarios as described in Volume 1 of the report. Chapter 3 describes the method of capital costing, individual pipeline expansion scenarios and the method of determining the possible increase or decrease in annualized tolls for several of the major pipelines. Chapter 4 contains a list of conclusions.

Volume 2 focuses the analysis on four scenarios that deal with transporting Alaskan gas to the mid continent area near Chicago.

- Scenario “3” examines the change in annual tolls as a result of transporting approximately 40 percent of the Alaskan gas volume by the Alliance Pipeline system and the remaining 60 percent by a combination of TCPL Alberta, Northern Border pipeline, TCPL East and TCPL Northern Ontario. This equates to a split at Boundary Lake, Alberta of 1890 mmcf/day to Alliance and 2610 mmcf/day to TCPL Alberta.

- Scenario “3A” examines the change in annual tolls as a result of transporting approximately 60 percent of the Alaskan gas volume by the Alliance Pipeline system and the remaining 40 percent by a combination of TCPL Alberta, Northern Border pipeline, TCPL East and TCPL Northern Ontario. This equates to a split at Boundary Lake, Alberta of 2730 mmcf/day to Alliance and 1770 mmcf/day to TCPL Alberta.

- Scenario “4” examines the change in annual tolls as a result of transporting 100 percent of the Alaskan gas by the Alliance Pipeline system.

- Scenario “5” examines the change in annual tolls as a result of transporting 100 percent of the Alaskan gas by the TCPL Alberta, Northern Border pipeline, TCPL East and TCPL Northern Ontario.

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CHAPTER 2
WESTERN CANADA EXPORT AND FRONTIER PIPELINES

2.1 Background

The existing pipeline infrastructure in Western Canada (Alberta and British Columbia) has an average annual export capacity of 14,890 mmcf/day (419,510 e^3m^3/day)[1] for the 2005/2006 design year. The average annual export capacity is a measure of 100 percent design capacity, taking into account seasonal temperature swings, minus a percentage to cover planned maintenance and unplanned outages. Figure 2.1 details the break down 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 Capacity by Pipeline

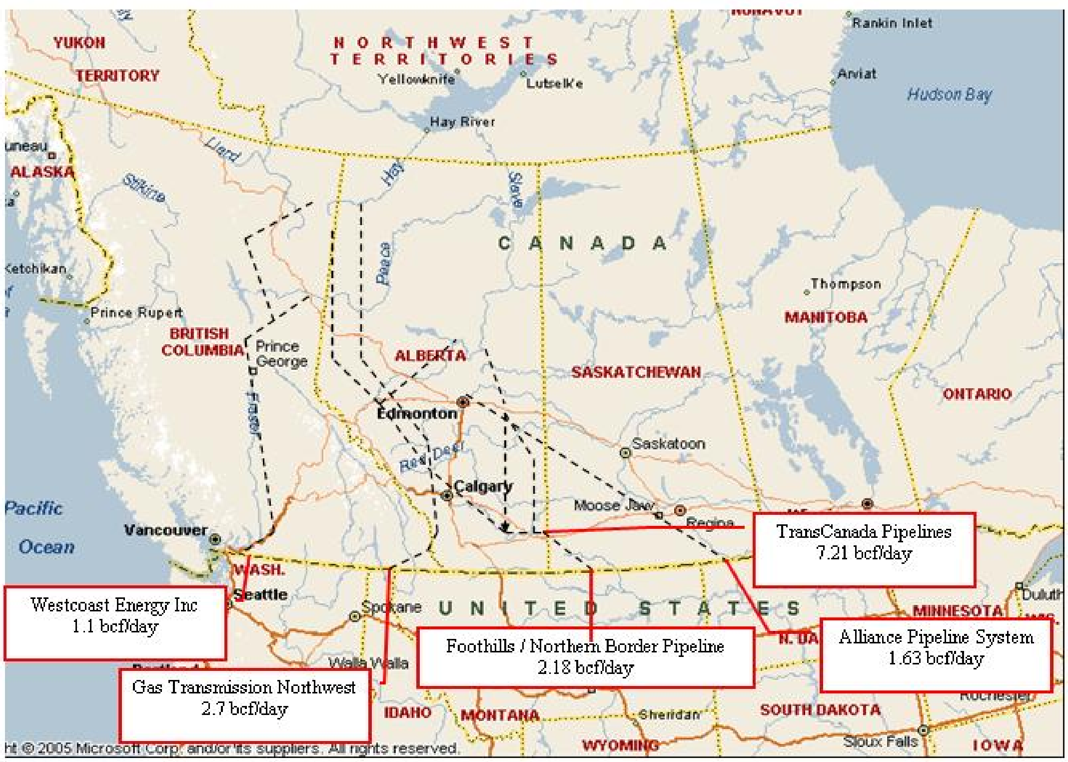


Table 2.1 compares the 2005/2006 design capacity with the 2005 annual average daily export volumes for the various export locations. The 2005 annual average daily export volume is 12,433 mmcf/day (350,290 e^3m^3/day).

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

The TCPL East mainline throughput is comprised of gas volumes received from Alberta at the exit of the Empress straddle plant, Alberta sourced volumes received downstream of Empress, delivered by the Suffield Pipeline, and Saskatchewan sourced volumes of gas delivered to the mainline by the TransGas pipeline system. The current capacity of the TCPL East pipeline system is 7,210 mmcf/day (203,135 e^3m^3/day) which results in a current utilization factor of 88 percent.[2] Converting one of the existing 34 inch gas pipelines to oil service between Empress and Winnipeg as part of TCPL's Keystone project will reduce the design capacity of this section to 6,695 mmcf/day (188,625 e^3m^3/day).

Table 2.1
Existing Border Delivery Volumes

Pipeline	Border Point	2005/2006 Design Capacity	2005 Annual Average Daily Rate	2005 Average utilization	
		mmcf/day	mmcf/day	%	
TCPL Eastern Mainline	Empress, Alberta	7210	5470	88	*
	Suffield Pipeline		360		
	Transgas receipts		490		
Foothills/NBPL	Monchy,Saskatchewan	2180	1978	91	
TCPL Western Mainline	ABC Border, Alberta	2770	1780	64	
Alliance Pipeline	Elmore, Saskatchewan	1630	1605	98	
Westcoast Energy Pipeline	Sumas, British Columbia	1100	750	68	
	Total	14890	12433	83	

* TCPL East includes Empress, Suffield Pipeline (AB sourced gas) and Transgas receipts

The Alliance Pipeline and the Foothills/Northern Border Pipeline have operated at close to their individual capacity levels since the year 2000, while the other three export pipelines have seen varied utilization rates, directionally declining over the same time frame. The Alliance pipeline has a firm service obligation of 1325 mmcf/day delivery to Chicago, but since the second year of production in 2001, the pipeline has operated with an Authorized Overrun Service (AOS) in excess of 18 percent, thus yielding an average annual utilization rate of 98 percent. The primary term of Alliance contract obligations extends to 2015 with a provision that shippers may extend the service for a minimum of one year at a time by giving written notice five years in advance.

The Northern Border Pipeline contracts are currently coming to completion (2005/2006) and it is assumed that flow movement on this pipeline will tend towards the interruptible type as flow from the Alberta portion of the WCSB appears to have reached a plateau and is expected to start declining in the near future. Over the past four years, the Northern Border pipeline has operated at an average annual utilization rate of 95 percent. Flow on this pipeline peaked in 2000 but has been declining at 2 percent per year since 2002.

[2] TCPL reduces the Prairies capacity by 0.3 bcf/day to account for the transportation of downstream fuel.

The TCPL Alberta Western Mainline delivers gas to the Alberta/British Columbia border near Coleman, Alberta where Foothills BC transports the gas to Gas Transmission Northwest (GTN) at Kingsgate, British Columbia, a distance of 106 miles. The GTN pipeline reached its peak annual average receipt volume of 2,350 mmcf/day in 1998. Since that point in time and excepting the year 2000, the annual receipt volume has declined an average of 4 percent per year. In 2006, and based on 10 months of actual data it appears that deliveries to the GTN pipeline will marginally recover to an average annual receipt volume of 1,750 mmcf/day. Volumes delivered to the southeast part of British Columbia are added to the GTN deliveries for a total transport volume on the Foothills BC system. This results in an average utilization rate of 64 percent.

Volumes of gas delivered by TCPL to the Empress Meter station connect with the TCPL East (TCPL Eastern mainline) pipeline for transportation to Ontario, Quebec and the United States. These deliveries peaked in 1999 at an annual average flow rate of 7,095 mmcf/day. Between 1999 and 2004, except in the year 2001, delivered volumes from TCPL to this pipeline declined from its peak to an annual average flow of 5,669 mmcf/day for 2004. In 2001, the marketable gas production from Alberta grew by approximately 1.5 percent over the year 2000 and the Alliance pipeline ramped up to full capacity resulting in reduced volumes delivered to the Empress Meter station. In the following year (2001), imports of gas from British Columbia coupled with reduced deliveries to the GTN pipeline resulted in an up swing of deliveries to Empress. In 2004 and 2005, marketable gas production in Alberta remained relatively constant while deliveries to Empress increased, based on further increases in imports from British Columbia coupled with reduced deliveries to the GTN. This situation resulted in an 11 percent increase in average deliveries to the Empress Meter station.

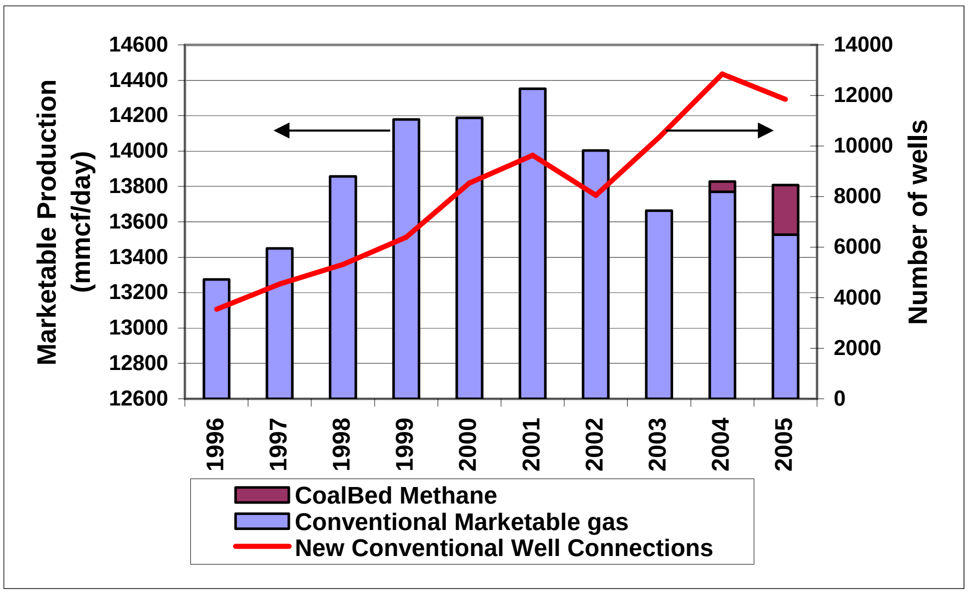
Results of the computer simulation program used for this study suggest that production from Alberta will marginally increase in 2006 and 2007 followed by a gradual decline as new supplies struggle to replace the existing declining production. In the face of declining production and the potential for increased gas consumption in Alberta, deliveries to the export points from the WCSB will gradually decline over time.

The EUB[3], CERI[4] and the NEB[5] are forecasting an increase in industrial usage of natural gas in the Alberta oil sands sector. This, coupled with a perceived decline in production from conventional gas resources from Alberta, as indicated in Figure 2.2, will lead to reduced deliveries to the TCPL East pipeline. Although quantities of gas from coal bed methane (CBM) (Alberta's Horseshoe Canyon Coal seam) have grown over the past several years, this increase has just managed to hold the line on total marketable gas production from Alberta (Figure 2.2). In the future, further advances in CBM production will reduce the degree of production decline from the WCSB but will not be able to reverse the declining trend.

[3] EUB, EIB-ST98-2006, Alberta's Energy Reserves 2005 and Supply/Demand Outlook.
[4] CERI, Oil Sands Update: Production outlook and Supply Costs 2006-2020, December 2006.
[5] NEB, Oilsands Industry Update: Production Outlook and Supply Cost 2006 to 2020, November 2006.

Although Westcoast Energy (now Duke Gas Pipeline) has also seen declining deliveries over the past several years, the NEB is forecasting[6] a marginal growth in demand as a result of the expanding housing market in the BC lower mainland and the forecasted market potential along the I5 corridor in the Pacific Northwest. Gas supply for these expanding markets will come from the expanding gas industry in Northeastern British Columbia and the development of the LNG terminal at Kitimat, British Columbia. Excess deliverability in BC will continue to be exported to Alberta but will not increase significantly above its current levels.

Figure 2.2
Alberta Marketable Gas Production and New Well Connections



2.2 Base Case Forecast

One of the goals of this study is to determine the spare capacity that could potentially exist in the future for the intra provincial and export pipelines. This spare capacity could be utilized to assist in transporting the volumes of gas from the Mackenzie Valley Gas Pipeline and the Alaska Highway Gas Pipeline to market. In order to determine the amount of spare export capacity, the study first forecasted the future supply of natural gas originating from the WCSB. After accounting for projected demand for gas in Alberta and BC, the study determined the spare capacity for the intra Alberta, intra BC and export pipelines. Alberta production connected to the Suffield pipeline along with Saskatchewan sourced production transported by Transgas, and delivered to TCPL, were connected to the TCPL East pipeline downstream of Empress.

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 pipeline

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

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 adjusted to match 2006 production levels (January to October, extrapolated to December). These assumptions along with the following conditions, defined the base case for this study.

- Well connections in British Columbia and Alberta are based on the “Base Case” new well connection profile. For Alberta, 12,000 new well connections were assumed for the years 2006 to 2020. For British Columbia, 1,100 new well connections were assumed for the years 2006 to 2020. These assumptions are paralleled by 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”[7]. British Columbia has also experienced a strong growth in new well connections, reaching 1,168 new well connections in 2005, which contributes to the assumption of 1,100 new well connections in British Columbia for the next 15 years.

- 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 east and south of Alberta. The justification for the inclusion of this supply source in the base case is based on the following points:

    1. 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 to connect the LNG terminal with the Westcoast Energy’s southern mainline system at Summit Lake, British Columbia.

    2. Kitimat LNG Inc has received both its provincial and federal environmental certificates.

    3. Kitimat LNG Inc. has signed a Heads of Agreement with Liquefied Natural Gas Ltd. of Australia that would see the Australian company supply 1.8 million metric tonnes per year of liquefied natural gas to the Kitimat LNG Terminal. This covers about 38 percent of the terminal capacity.

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

[7] EUB, ST98-2006, Alberta’a Energy Reserves 2005 and Supply/Demand Outlook 2006-2015, May 2006.

- 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. The Primary term of Alliance contract obligations is for 15 years to 2015. Shippers may extend the service for a minimum of one year at a time by giving written notice five years in advance. The current firm service obligation is 1,325 mmcf/day but historically the pipeline has been operating with an Authorized Overrun Service (AOS) of approximately 18 to 19 percent. Recorded flow volumes indicate that the pipeline utilization factor is approximately 99 percent, assuming the extension in supply from 2015 to 2020 is based on the position of the Alliance supply sources being in the more prolific deeper part of the basin in Alberta and British Columbia.

- In any year, the supply availability from Alberta sources and BC Imports is reduced by the Alliance pipeline supply volumes and the requirement for natural gas in Alberta, including the Oil Sands purchase gas volumes, to determine the net exportable volume. The export volume available in any year is assumed to be shared equally by the Foothills/Northern Border pipeline, Gas Transmission Northwest and the TCPL East mainline.

- 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.

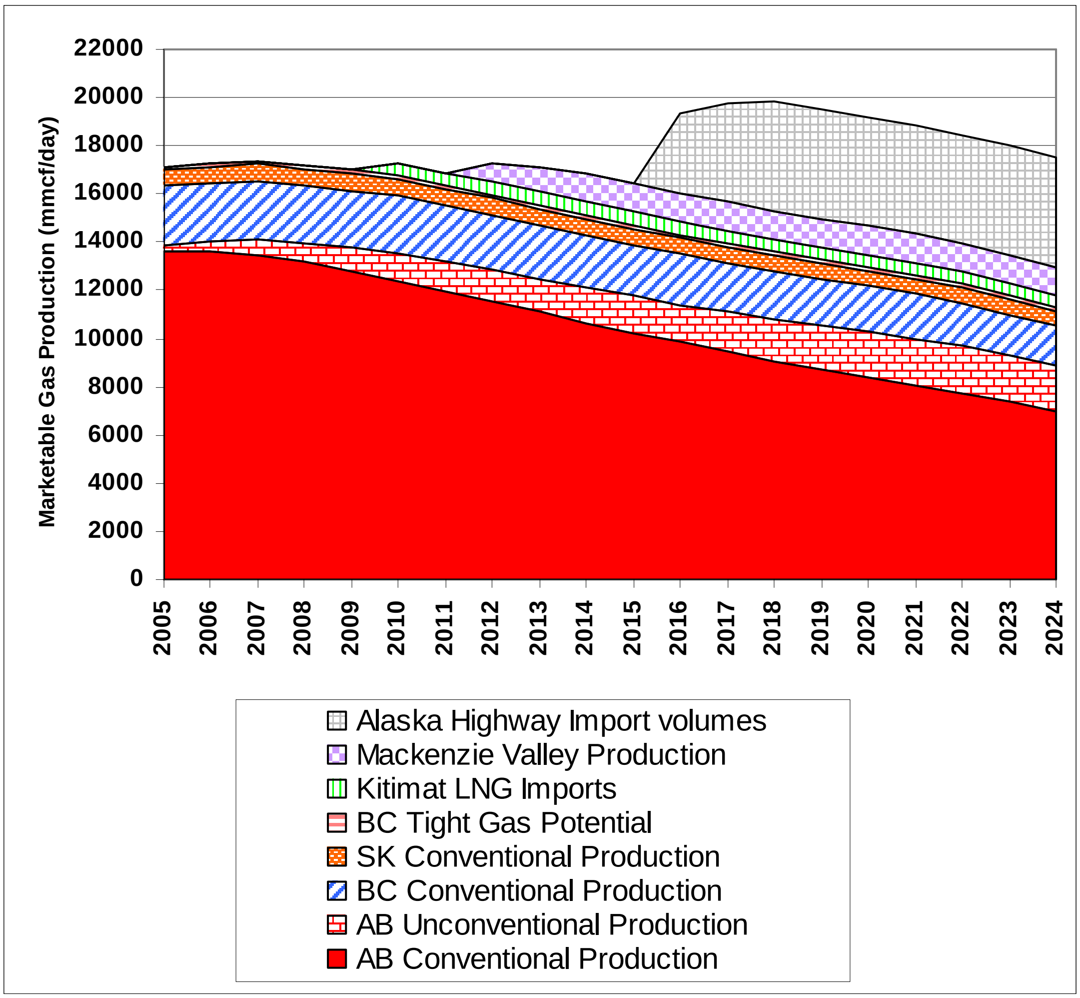
- Gas Transmission Northwest export volumes are held at 1790 mmcf/day (50,430 e^3m^3/day) until 2008 after which a 6 percent decline per year is applied until 2015 followed by a 25 percent decline to the end of the forecast.

- From a computer modeling point of view, TCPL East receives the residual gas after accounting for Alberta conventional and unconventional gas supply, British Columbia imports, Mackenzie Valley imports, Alberta domestic and Oil Sands demand and deliveries to the GTN and NBPL pipelines mentioned above.

- 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. Additional volumes could be transported on this pipeline based on an economic evaluation of system utilization and fuel gas requirements but for this study the 700 mmcf/day level is sufficient to limit the volume flowing south through the Lower Peace design area to the existing section capacities. Flow volumes along the Edson mainline and the eastern and western mainlines down stream of James River are all below the stated current section capacities.

Figure 2.3 details the base case supply forecast for the WCSB including British Columbia, Alberta and Saskatchewan. It appends the estimated production forecasts for the Mackenzie Valley Gas Pipeline project, the Kitimat LNG terminal and the Alaska Highway Gas project. The Alberta and British Columbia conventional supply curve represented in Figure 2.3 was determined through the use of a computer model that takes into account historical information to determine initial production rates for new wells, current production rates for existing wells and decline rates for all wells. History match factors are determined to calibrate the model results with historical data for 2005 and 2006. Saskatchewan conventional supply[8], British Columbia tight gas[9], Kitimat LNG[10] and Mackenzie Valley supply[11] were determined from external sources and appended to the chart.

Figure 2.3
Western Canada Gas Production Forecast
(Including Mackenzie Valley and Alaska Highway production)



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[8] NEB, Canada's Energy Future: Scenarios for Supply and Demand to 2025, July 2003.
[9] TCPL, Canadian Mainline Throughput Study, Keystone Pipeline Transfer Application, June 2006.
[10] Pan EurAsian Enterprises Inc, North American Terminal Survey, Liquefied Natural Gas Import and Regasification.
[11] Wright Mansell Research Ltd, An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development, 2004.

Figures 2.4 and 2.5 compare the base case border deliveries for seven specified years against the current indicated capacity (Capacity) along with 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 these diagrams relates to the capacity of the individual export pipelines and is shown as the boxed area spanning the individual bars. The vertical axis on the right side of the diagram relates to the average daily flow rate (mmcf/day) for the individual export pipelines and is shown as the individual vertical bars for the years 2006, 2012, 2014, 2016, 2018, 2019, and 2020.

Figure 2.4 shows that delivery volumes by the Alliance pipeline are held 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. Figure 2.4 shows the Alberta sourced volumes at the exit of the Empress Straddle Plant. This volume is supplemented by Alberta sourced gas delivered downstream of Empress by the Suffield Pipeline along with Saskatchewan sourced gas delivered by TransGas Limited.

Figure 2.5 shows the deliveries to the GTN pipeline, which delivers gas to the Idaho, Oregon and California markets, also declining as a result of the projected decline in supply from the Alberta portion of the WCSB. This Figure also shows the projected deliveries from the Southern Mainline section of the Duke Gas Pipeline in British Columbia. Increases in deliveries to the BC lower mainland and exports to the growth markets along the I5 corridor in Washington State are a result of increased development of new gas supplies in Northeast BC and the construction of the LNG terminal at Kitimat, British Columbia.

Figure 2.4
WCSB Export Pipelines: Alberta East Deliveries
Base Case Border Deliveries versus Export Capacity

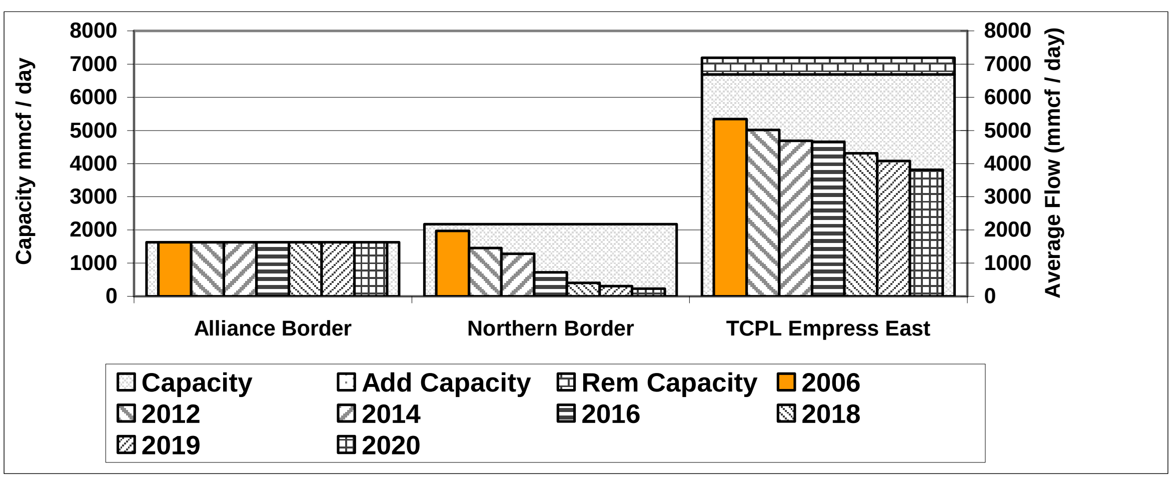
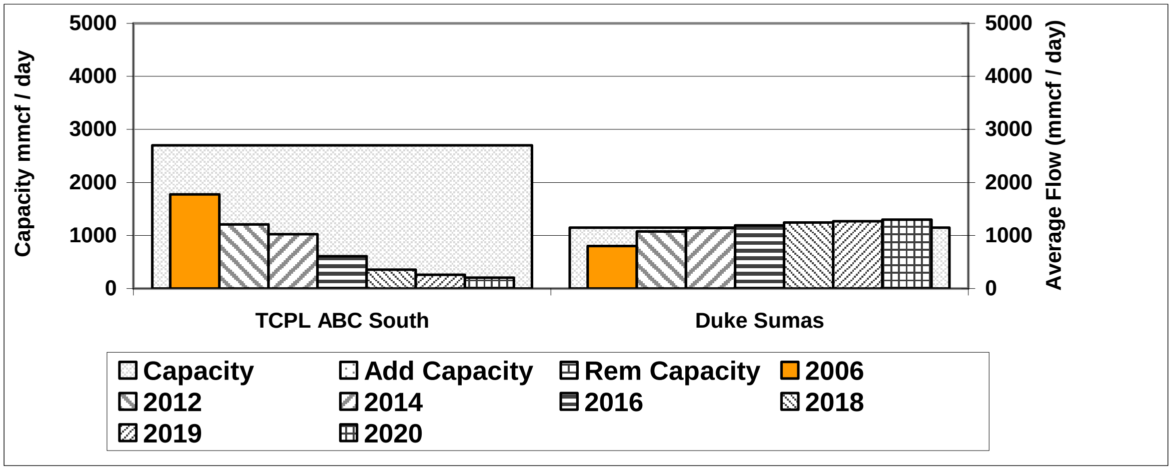


Figure 2.5
WCSB Export Pipelines: PNW Deliveries
Base Case Border Deliveries versus Export Capacity



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CHAPTER 3
COST AND TOLL PARAMETERS

The following section describes the method used for determining capital costs for new facility additions and the method used to determine the pipeline transportation toll.

3.1 Capital Cost Estimation Procedure: Northern Pipelines

For the Mackenzie Valley Pipeline, the initial costing elements were obtained from a report prepared by COLTKBR[12] for Imperial Oil Resources Ventures Limited which focused on the "Conceptual and Preliminary Engineering for the Mackenzie Gas Project". Figure 3.1 lists the line items (cost elements), units and line item values expressed in 2002, 2004 and 2006 Canadian dollars. The 2002 line values were taken directly from the COLTKBR report to establish a base line cost estimate and a starting point for the CERI cost estimation program.

The COLTKBR report estimated the total cost of the gas pipeline including compressors, chillers and heaters at $2.863 billion Canadian dollars (2002 dollars). In 2004, another estimate contained within a report prepared by Wright Mansell Research Ltd[13] for the Government of the Northwest Territories and TransCanada PipeLines Limited indicated the cost of the pipeline had increased to $3.8 billion Canadian dollars. The cost elements used to arrive at that estimate are shown in Figure 3.1 expressed as 2004 dollars. In June 2006, Imperial Oil Ltd indicated that the estimated cost of the project was suffering from "ballooning prices for labor and materials amid an energy development boom".[14] It was suggested at that time that a 20 to 30 percent increase was not unrealistic. Accounting for these increases the estimated cost of the pipeline would be $4.377 billion Canadian dollars (2006 dollars). Finally, in March 2007, Imperial Oil Ltd estimated the cost of the Mackenzie Valley Pipeline at $7.8 billion Canadian dollars[15] (2006 dollars). This dramatic increase in the cost estimate was primarily as a result of improved understanding of the costs of developing extensive infrastructure in remote areas of the north.

In Figure 3.1 the 2006 cost values for pipeline and compression materials and overhead costs have been based on recent estimates for pipeline construction in Alberta while the pipeline construction, infrastructure and compression station construction costs have been established from the Imperial Oil estimate for the Mackenzie Valley Pipeline.

Since this study is only concerned with the pipeline cost and resulting tolls for the gas pipeline, the capital cost estimates in Figure 3.2 for the Mackenzie Valley Gas development project are for

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[12] COLTKBR report WP-005-D27-3, Rev 0, "Detailed System Optimization, Mackenzie Gas Project" December 4, 2003.
[13] Wright Mansell Research Ltd, "An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development: An Update", August 21, 2004.
[14] Broiles, Randy, Calgary Herald, August 25, 2006, Page E4.
[15] Imperial Oil Ltd, Letter to NEB, "Mackenzie Gas Project, Project Cost Estimate and Schedule Update", March 12, 2007.

the gas pipeline only. Other costs related to the liquids pipeline, gathering system, processing plant and field development are considered upstream of the gathering system gate.

The cost parameters used for the Mackenzie Valley Pipeline were also used to determine a cost estimate for the Alaska Highway pipeline from Prudhoe Bay, Alaska to Boundary Lake, Alberta. The cost estimates in Figures 3.3 and 3.4 break the estimate into the sections in Alaska and the sections in the Yukon Territory and British Columbia.

Figure 3.1
Northern Pipeline Cost Estimating Parameters

			COLTKBR		CERI		CERI
Cost Parameters		Units	2002 Cdn dollars	Esc %	2004 Cdn dollars		2006 Cdn dollars
Pipeline Steel		$/tonne	1,120	65	1,792		1,960
External coating		$/1000 m2	13,000	12	14,560		17,160
Internal coating		$/1000 m2	4,200	12	4,704		5,544
Buoyancy control		$/dia inch km	485	12	543		640
Miscellaneous material		% pipe	3.25	12	3.25		13
Freight and Handling		$/tonne	540	12	605		713
Construction		$/dia inch km	19,525	20	23,430		60,528
Infrastructure		$/dia inch km	8,500	20	10,200		26,350
Logistics		$/dia inch km	1,860	12	2,083		2,455
EPCM		% of cost	9		9		13
Contingency		% of cost	25		25		25
AFUDC							10
Station Base cost		1000$	32837	20	39,404		101,795
Cost per power unit		1000$/kw	1.7298	12	1.937		2.283

3.2 Summary of Costs and Tolls for Northern Pipelines

Figures 3.2, 3.3 and 3.4 summarize the required facilities, flow volumes, capital costs and tolls for the Mackenzie Valley Pipeline and the Alaska Highway Pipeline.

The details represented in Figure 3.2 are for the gas pipeline portion of the Mackenzie Valley project from the exit of the Inuvik gas processing plant to the border between the Northwest Territories and the province of Alberta. Total capital cost for this pipeline section is estimated to be $7.82 billion Canadian dollars (2006 dollars) and the estimated average firm transportation toll for years 2 thru 6 would be $2.28 per thousand cubic feet or $2.18 per million British Thermal Units (btus) assuming a heat content of 1045 btu/cuft. In addition to the reservation charge, the variable charge for the fuel usage would be approximately $0.16 Cdn/mcf based on a fuel gas price of $6.50 Cdn/mcf.

Figure 3.2
Mackenzie Valley Pipeline: Northwest Territories Section
(Receipt Volume = 1230 mmcf/day)

		Inuvik to NWT/AB Border
1	Pipeline	761 miles 30 inch, 2610 psi, X80 Steel
2		
3	Compression	lead station: 5 x 10 megawatt units
4		4 intermediate stations: 1 x 10 megawatt units
5	Chillers	lead station: 5 x 10 megawatt chilling units
6		4 intermediate stations: 1 x 10 megawatt chilling units
7	Design Flow	Receipt volume = 1,230 mmcf/day
8		Fuel = 30 mmcf/day
9		Delivered volume = 1,200 mmcf/day
10		Heating Value = 1045 btu/cuft
11	Cost estimate	Pipeline cost = $6,559 million
12		Compression = $1,122 million
13	.	Chillers = $137 million
14		Total Cost = $7,821 million
15	Unit costs	Pipeline $8.6 million per mile
16		Compression = $224 million per station
17		
18	Tolls	Existing transportation toll = $0.00 /mcf ($0.00 per mmbtu)
19		Five year average (Yr 2-6) Toll = $2.28 /mcf ($2.18/mmbtu)
20	*costs expressed as 2006 Canadian dollars	

The Alaska Highway pipeline is divided into two sections, the United States section between Prudhoe Bay, Alaska and the Alaska/Yukon border, and the Canadian section between the Alaska/Yukon border and Boundary Lake, Alberta. The total capital cost for the Alaska section (Figure 3.3) is estimated to be $14.5 billion Canadian dollars (2006 dollars) and the estimated average firm service toll for the first five years would be $1.13 per thousand cubic feet or $1.04 per million btus assuming a heat content of 1090 btus/cuft (Figure 3.3). In addition to the reservation charge, the variable charge for the fuel usage would be approximately $0.09 Cdn/mcf based on a fuel gas price of $6.50 Cdn/mcf.

The Yukon and British Columbia section of the Alaska Highway Pipeline (Figure 3.4) is estimated to cost $16.4 billion Canadian dollars (2006 dollars) and the estimated average firm service toll for the first five years would be $1.36 per thousand cubic feet or $1.25 per million btus assuming a heat content of 1090 btus/cuft (Figure 3.4). In addition to the reservation charge, the variable charge for the fuel usage would be approximately $0.10 Cdn/mcf based on a fuel gas price of $6.50 Cdn/mcf.

Figure 3.3
Alaska Highway Pipeline: Alaska Section
(Receipt Volume = 4635 mmcf/day)

		Prudhoe Bay to Alaska/Yukon Border
1	Pipeline	745 miles 48 inch, 2500 psi, X80 Steel
2		
3	Compression	lead station: 5 x 16 megawatt units
4		6 intermediate stations: 2 x 23 megawatt units
5	Chillers	lead station: 5 x 16 megawatt chilling units
6		6 intermediate stations: 2 x 16 megawatt chilling units
7	Design Flow	Receipt volume = 4,635 mmcf/day
8		Fuel = 65 mmcf/day
9		Delivered volume = 4570 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $11,854 million
12		Compression = $2,380 million
13	.	Chillers = $256 million
14		Total Cost = $14,491 million
15	Unit costs	Pipeline $15.9 million per mile
16		Compression = $340.0 million per station
17		Chillers =$36 million per station
18	Tolls	Existing Transportation Toll = $0.00 / mcf ($0.00 / mmbtu)
19		Five year average (Yr 2-6) Toll = $1.13 / mcf ($1.04 / mmbtu)
20	*costs expressed as 2006 Canadian dollars	

Figure 3.4
Alaska Highway Pipeline: Yukon/British Columbia Section
(Receipt Volume = 4570 mmcf/day)

		Alaska/Yukon Border to Boundary Lake, Alberta
1	Pipeline	940 miles 48 inch 2500 psi X80 Steel
2	Compression	6 intermediate stations: 2 x 23 megawatt units
3		
4	Chillers	6 intermediate stations: 2 x 16 megawatt chilling units
5		
6	Design Flow	Receipt volume = 4,570 mmcf/day
7		Fuel = 70 mmcf/day
8		Delivered volume = 4500 mmcf/day
9		Heating Value = 1090 btu/cuft
10	Cost estimate	Pipeline cost = $14,957 million
11		Comrpession = $1,240 million
12	.	Chillers = $200 million
13		Total Cost = $16,399 million
14	Unit costs	Pipeline $15.9 million per mile
15		Compression = $207 million per station
16		Chillers =$33 million per station
17		
18	Tolls	Existing Transportation Toll = $0.00 / mcf ($0.00 / mmbtu)
19		Five year average (Yr 2-6) Toll = $1.36 / mcf ($1.25 / mmbtu)
20	*costs expressed as 2006 Canadian dollars	

3.3 Capital Cost Estimation Procedure: Canadian and US Pipelines

For pipeline additions within Alberta, Saskatchewan and the northern United States the values for the line cost elements were initially obtained from a report published by the Canadian Energy Pipeline Association (CEPA) in October 2005.[16] That estimate was for the cost of construction for a theoretical gas pipeline system in Alberta and British Columbia stated in 2005 Canadian dollars. These values were subsequently compared and adjusted to bring the cost estimating line values in line with recent (2006) bids for construction projects within Alberta. In addition to the CEPA line items an additional item of an allowance for funds used during construction (AFUDC) was included to reflect early material commitments as a part of modern pipeline projects. Also, based on the most recent project estimates higher percentages for miscellaneous materials, Engineering, Procurement and Construction Management (EPMC) and Contingency charge was incorporated. These increases reflect the current cost to develop a project, including design, estimating, permitting, safety management, environment, legal costs, and community relations.

Figure 3.5
Western Canada / Northern United States Cost Estimating Parameters

					CEPA		CERI
Cost Parameters		Units			2005 Cdn dollars		2006 Cdn dollars
Pipeline Steel		$/tonne			1,570		1,960
External coating		$/1000 m2			13,780		17,160
Internal coating		$/1000 m2			4,452		5,544
Buoyancy control		$/dia inch km			514		640
Miscellaneous material		% pipe			3.25		13
Freight and Handling		$/tonne			175		220
Construction		$/dia inch km			11,200		18,368
Infrastructure		$/dia inch km			1,500		1,875
Logistics		$/dia inch km			800		1,000
EPCM		% of cost			3.75		12
Contingency		% of cost			5		20
AFUDC							10
Station Base cost		1000$			8000		9,995
Cost per power unit		1000$/kw			1.937		2.283

[16] CEPA, "The Importance of Timely Construction of New Pipeline Infrastructure To Canada and Canadians", October 2005.

3.4 Alliance Pipeline Ltd

The Alliance Pipeline system, which came on stream in December 2000, transports high energy, rich natural gas from northeastern British Columbia and northwestern Alberta to its terminus in the state of Illinois. The mainline portion of the system, extending from Fort Saskatchewan, Alberta to Aux Sable, Illinois, consists of a high pressure transmission pipeline made up of 1,646 miles of 36-inch steel pipe operating at a pressure of 1750 pounds per square inch. The mainline is divided into the Canadian section, from Fort Saskatchewan, Alberta to Elmore, Saskatchewan, and the United States section from Elmore to Aux Sable, Illinois. The current capacity of the mainline section is 1626 mmcf/day (45,810 e^3m^3/day) receipt volume, and 1575 mmcf/day (44,374 e^3m^3/day) delivered to Aux Sable.

In July 2006, Alliance received approval from the US Department of Transportation (DOT) to operate the United States portion of the pipeline system at a higher pressure, consistent with an 80 percent adjusted maximum allowable operating pressure, as opposed to the normal 72 percent factor. The ability to operate at a higher safety factor level is based on the type of steel and the metallurgical properties used in its pipe construction. Operating at the higher pressure is estimated to reduced the fuel requirement by approximately 5 mmcf/day (17 percent fuel saving) on the US section of the pipeline. This efficiency has not been taken into account in the determination of the capacity of the pipeline.

The financial elements, as of mid year 2006, that were used to determine the future toll for the pipeline are as follows[17]:

Canadian toll parameters (2006 thousand Canadian $)

o Average transmission plant, pipe mains	$1,723,643
o Average transmission plant, compression	$550,357
o Average general plant	$53,235
o Average Undistributed plant	$454,208
o Accumulated depreciation	$565,055
o Annual Operation and Maintenance expense	$56,470
o Annual Property taxes	$17,015
o Annual Income Taxes	$32,055
o Debt Equity ratio	70/30
o Debt cost	7.22%
o Equity return	11.25%
o Fuel	2.7%
o Estimated toll without fuel (2007)	$0.65 Cdn/mcf
o Estimated fuel component (2007)	$0.17 Cdn/mcf[18]

[17] Alliance Pipeline Limited Partnership, 2006 Toll Calculation Forecast, Gas Plant in Service and Depreciation, Schedule C, 2006.
[18] Assuming $6.50 Cdn/ mcf.

United States toll parameters (2006 thousand Canadian $)

o Average transmission plant, pipe mains	$1,420,241
o Average transmission plant, compression	$731,640
o Accumulated depreciation	$342,000
o Annual Operation and Maintenance expense	$60,371
o Annual Property taxes	$13,615
o Annual Income Taxes	$21,983
o Debt Equity ratio	70/30
o Debt cost	5.74%
o Equity return	12%
o Fuel	1.8%
o Estimated toll without fuel (2007)	$0.55 Cdn/mcf
o Estimated fuel component (2007)	$0.12 Cdn/mcf[19]

Figures 3.6 and 3.7 demonstrate the future throughput volumes and effective transportation toll for the Canadian and American sections of the Alliance Pipeline system. As mentioned before, the primary term of Alliance contract obligations is for 15 years to 2015. Shippers may extend the service for a minimum of one year at a time by giving written notice five years in advance. In the base case, the study has assumed that this pipeline will remain full until 2020 followed by a decline as a result of declining production from the basin. The combined reservation toll (Figures 3.6 and 3.7) for the Alliance pipeline for the 2007-2020 period would range from $1.20 to $1.08 Cdn/mcf, assuming the deliveries are maintained at the current firm service level (1,335 mmcf/day), along with the 19 percent authorized overage service. In addition to the reservation charge, the variable charge for the fuel usage would be approximately $0.30 Cdn/mcf based on a fuel gas price of $6.50 Cdn/mcf. This results in a total toll of $1.50 to $1.38 Cdn/mcf.

[19] Assuming $6.50 Cdn/ mcf.

Figure 3.6
Alliance Pipeline: Base Case Tolls
Fort Saskatchewan, Alberta to Elmore, Saskatchewan

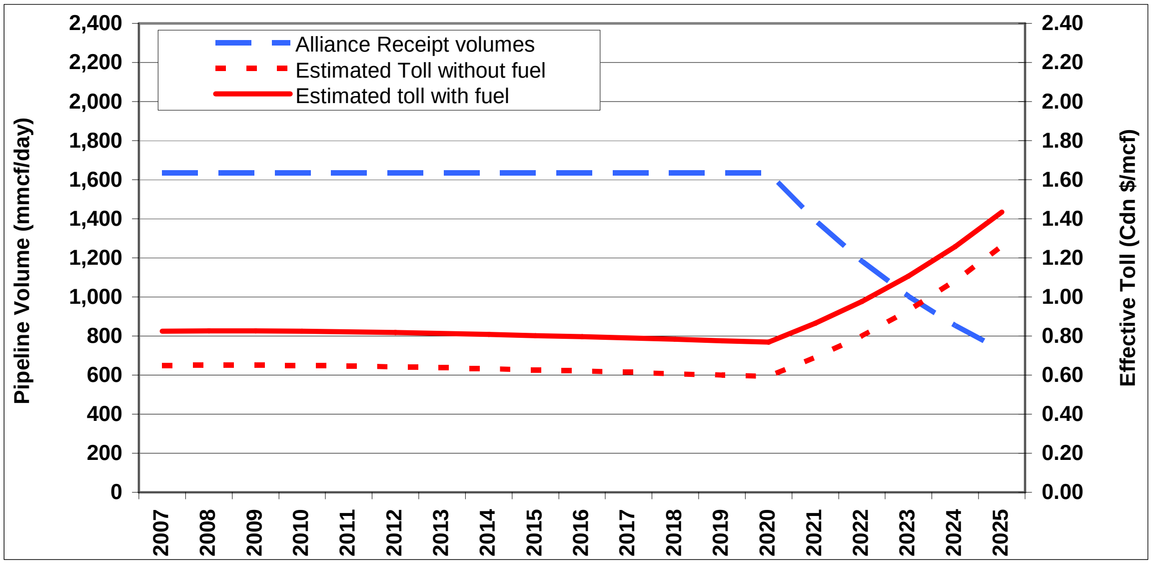
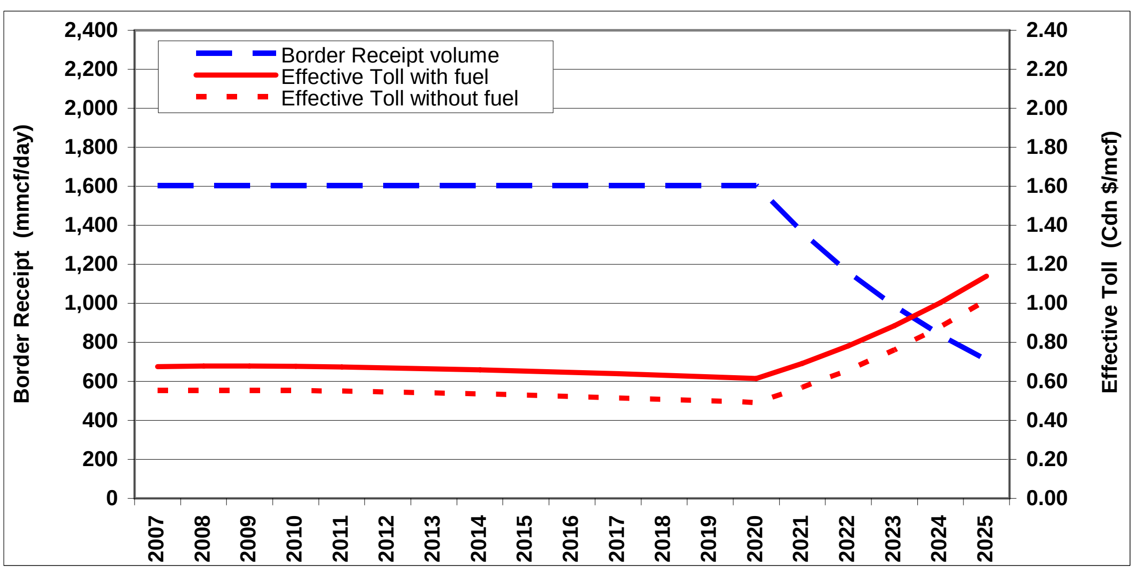


Figure 3.7
Alliance Pipeline: Base Case Tolls
Elmore, Saskatchewan to Aux Sable Illinois



3.5 Alliance Pipeline Ltd: Scenario #3 (Alaska Volume to Alliance =1890 mmcf/day)

The addition of twelve intermediate compressor stations and a complete 36 inch loop from Fort Saskatchewan to Aux Sable would boost the pipeline capacity to 3505 mmcf/day (98,750 e^3m^3/day). This expansion would permit the pipeline to handle an additional volume of 1875 mmcf/day assumed to be from the Alaskan gas pipeline.

In addition, a connector pipeline consisting of 355 miles of 36 inch pipe and three compressor stations (each with a single 16 megawatt gas turbine) would be constructed to connect Boundary Lake, Alberta to Fort Saskatchewan, Alberta. The Boundary lake receipt volume would be 1890 mmcf/day, with 1875 mmcf/day delivered to the Alliance pipeline system at Fort Saskatchewan.

The connector pipeline is estimated to cost $1.6 billion Canadian dollars (2006 dollars) with an estimated average firm service toll for the first five years of $0.42 Cdn/mcf or $0.38 per million btus assuming a heat content of 1090 btus/cuft (Figure 3.8). In addition to the reservation charge, the variable charge for the fuel usage would be approximately $0.05 Cdn/mcf based on a fuel gas price of $6.50 Cdn/mcf.

Figure 3.8
Alliance Pipeline: Scenario # 3, Costs
Boundary Lake, Alberta to Fort Saskatchewan, Alberta
(Alaska incremental flow volume = 1890 mmcf/day)

		Boundary lake, Alberta to Fort Saskatchewan, Alberta
1	Pipeline	355 miles 36 inch, 2500 psi, X80 Steel
2		
3	Compression	lead station: 1 x 16 megawatt units
4		2 intermediate stations: 1 x 16 megawatt units
5	Chillers	
6		
7	Design Flow	Receipt volume = 1,890 mmcf/day
8		Fuel = 15 mmcf/day
9		Delivered volume = 1,875 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $1,467 million
12		Compression = $142 million
13	.	
14		Total Cost = $1,609 million
15	Unit costs	Pipeline $4.1 million per mile
16		Compression = $71 million per station
17		
18	*costs expressed as 2006 Canadian dollars	

The expansion of the Alliance pipeline mainline between Fort Saskatchewan, Alberta and the US border at Elmore, Saskatchewan as well as the US border and Aux Sable, Illinois would cost $2.60 billion Canadian dollars (Figure 3.9) and $3.60 billion Canadian dollars (Figure 3.11), respectively. Figures 3.10 and 3.12 indicate that the combined reservation toll for the Alliance pipeline for the 2017-2021 period would range from $1.25 to $1.30 Cdn/mcf. In addition, the variable charge for fuel usage would be approximately $0.27 Cdn/mcf based on a fuel gas price of $6.50 Cdn/mcf. This results in a total toll of $1.52 to $1.57 Cdn/mcf.

Figure 3.9
Alliance Pipeline: Scenario # 3, Costs
Fort Saskatchewan, Alberta to Elmore, Saskatchewan
(Alaska incremental flow volume = 1890 mmcf/day)

		Fort Saskatchewan, Alberta to Elmore, Saskatchewan
1	Pipeline	616 miles 36 inch, 1750 psi, X80 Steel
2		
3	Compression	5 intermediate stations: 1 x 30 megawatt units
4		
5	Chillers	
6		
7	Design Flow	Receipt volume = 3500 mmcf/day
8		Fuel = 48 mmcf/day
9		Delivered volume = 3451 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $2,088 million
12		Compression = $524 million
13	.	
14		Total Cost = $2,613 million
15	Unit costs	Pipeline $3.4 million per mile
16		Compression = $104 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

Figure 3.10
Alliance Pipeline: Scenario # 3, Tolls
Fort Saskatchewan, Alberta to Elmore, Saskatchewan
(Alaska incremental flow volume = 1890 mmcf/day)

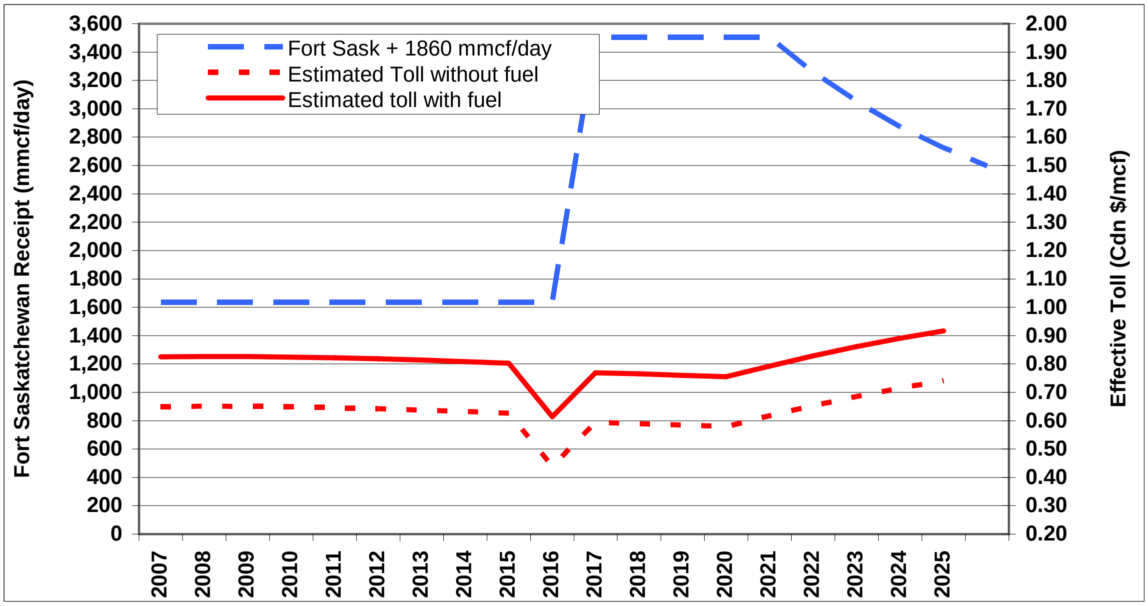
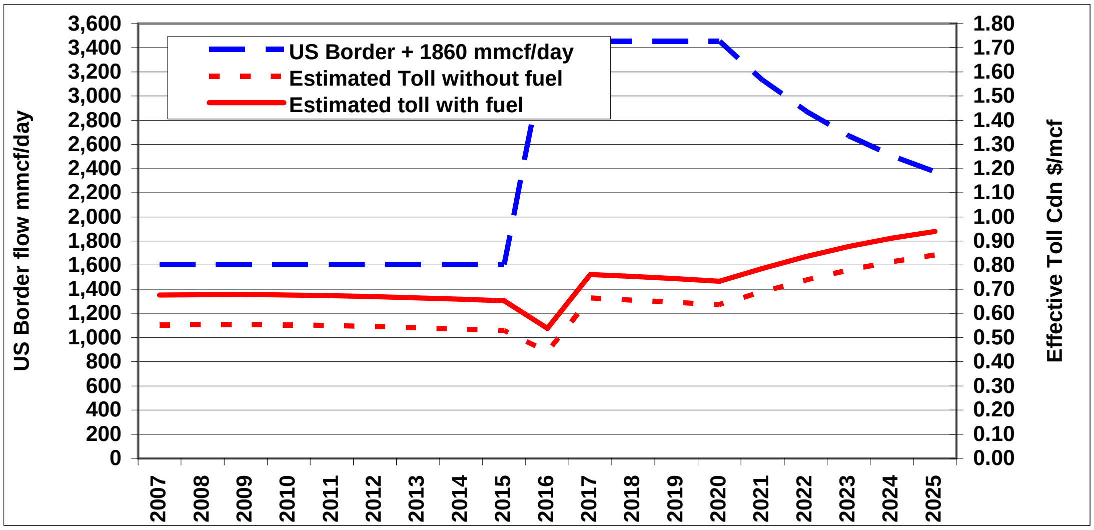


Figure 3.11
Alliance Pipeline: Scenario # 3, Costs
US Border to Aux Sable, Illinois
(Alaska incremental flow volume = 1890 mmcf/day)

		Elmore, Saskatchewan to Aux Sable, Illinois
1	Pipeline	883 miles 36 inch, 1750 psi, X80 Steel
2		
3	Compression	3 intermediate stations: 1 x 30 megawatt units
4		4 intermediate stations: 1 x 23 megawatt units
5	Chillers	
6		
7	Design Flow	Receipt volume = 3450 mmcf/day
8		Fuel = 63 mmcf/day
9		Delivered volume = 3388 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $2,993 million
12		Compression = $650 million
13	.	
14		Total Cost = $3,643 million
15	Unit costs	Pipeline $3.4 million per mile
16		Compression = $93 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

Figure 3.12
Alliance Pipeline: Scenario # 3, Tolls
US Border to Aux Sable, Illinois
(Alaska incremental flow volume = 1890 mmcf/day)



3.6 Alliance Pipeline Ltd: Scenario #3A (Alaska Volume to Alliance =2730 mmcf/day)

The addition of twelve intermediate compressor stations, expansion of all stations and a complete 36 inch loop from Fort Saskatchewan to Aux Sable would boost the pipeline capacity to 4338 mmcf/day (122,218 e^3m^3/day). This expansion would permit the pipeline to handle an additional 2715 mmcf/day of Alaskan gas volumes.

In addition, a connector pipeline consisting of 355 miles of 42 inch pipe and three compressor stations (each with a single 21 megawatt gas turbine) would need to be constructed from Boundary Lake, Alberta to Fort Saskatchewan, Alberta. The connector receipt volume would be 2730 mmcf/day with 2715 mmcf/day delivered to the Alliance high pressure pipeline system at Fort Saskatchewan, Alberta.

The connector pipeline is estimated to cost $2.05 billion dollars (Figure 3.13), and the estimated average toll for the first five years is $0.36 Cdn/mcf or $0.33 per million British Thermal units (btus), assuming a heat content of 1090 btus/cuft. In addition, the variable charge for fuel usage would be approximately $0.04 Cdn /mcf based on a fuel gas price of $6.50 Cdn /mcf.

The expansion of the Alliance pipeline mainline between Fort Saskatchewan, Alberta and the US border at Elmore, Saskatchewan as well as the US border and Aux Sable, Illinois would cost $3.36 billion dollars (Figure 3.14) and $4.78 billion dollars (Figure 3.16), respectively. Figures 3.15 and 3.17 indicate that the combined reservation toll for the Alliance pipeline for the 2017-

2021 period will range from 1.12 to $1.16 Canadian dollars per thousand cubic feet. In addition, the fuel component of the toll will be approximately $0.33 Cdn $/mcf based on a fuel gas price of $6.50 Cdn $/mcf. This results in a total toll of $1.45 to $1.49 Cdn/mcf.

Figure 3.13
Alliance Pipeline: Scenario # 3A, Costs
Boundary Lake, Alberta to Fort Saskatchewan, Alberta
(Alaska incremental flow volume = 2730 mmcf/day)

		Boundary lake, Alberta to Fort Saskatchewan, Alberta
1	Pipeline	355 miles 42 inch, 2500 psi, X80 Steel
2		
3	Compression	lead station: 1 x 21 megawatt units
4		2 intermediate stations: 1 x 21 megawatt units
5	Chillers	
6		
7	Design Flow	Receipt volume = 2,730 mmcf/day
8		Fuel = 15 mmcf/day
9		Delivered volume = 2,715 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $1,871 million
12		Compression = $176 million
13	.	
14		Total Cost = $2,047 million
15	Unit costs	Pipeline $5.3 million per mile
16		Compression = $58.7 million per station
17		
18	*costs expressed as 2006 Canadian dollars	

Figure 3.14
Alliance Pipeline: Scenario # 3A, Costs
Fort Saskatchewan, Alberta to Elmore, Saskatchewan
(Alaska incremental flow volume = 2730 mmcf/day)

		Fort Saskatchewan, Alberta to Elmore, Saskatchewan
1	Pipeline	616 miles 36 inch, 1750 psi, X80 Steel
2		
3	Compression	1 intermediate stations: 2 x 23 megawatt units
4		4 intermediate stations: 2 x 30 megawatt units
5		5 station additions 1 x 33 megawatt units
6		
7	Design Flow	Receipt volume = 4338 mmcf/day
8		Fuel = 100 mmcf/day
9		Delivered volume = 4238 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $2,100 million
12		Compression = $1,257 million
13	.	
14		Total Cost = $3,358 million
15	Unit costs	Pipeline $3.4 million per mile
16		Compression = $125 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

Figure 3.15
Alliance Pipeline: Scenario # 3A, Tolls
Fort Saskatchewan, Alberta to Elmore, Saskatchewan
(Alaska incremental flow volume = 2730 mmcf/day)

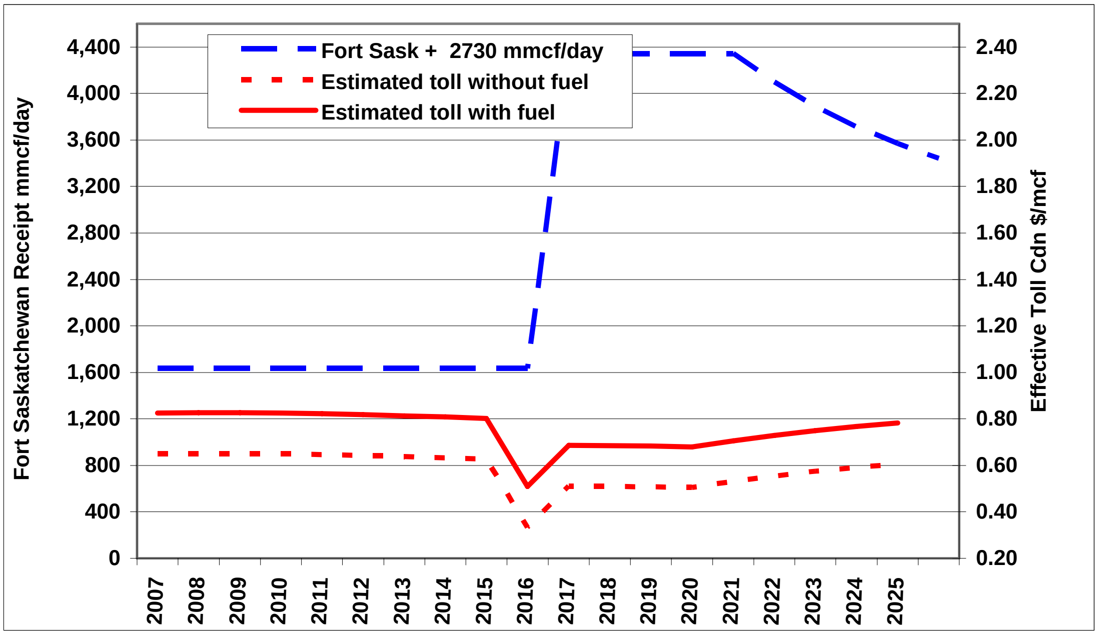
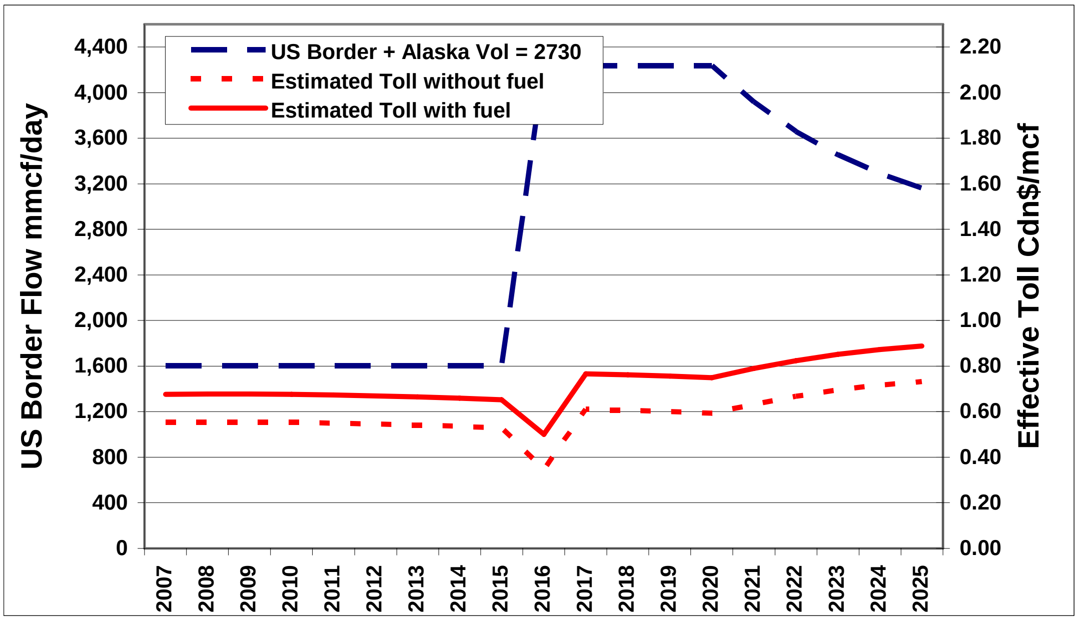


Figure 3.16
Alliance Pipeline: Scenario # 3A, Costs
Elmore, Saskatchewan to Aux Sable, Illinois
(Alaska incremental flow volume = 2730 mmcf/day)

		Elmore, Saskatchewan to Aux Sable, Illinois
1	Pipeline	883 miles 36 inch, 1750 psi, X80 Steel
2		
3	Compression	7 intermediate stations: 2 x 30 megawatt units
4		2 station additions: 1 x 33 megawatt units
5		5 station additions: 1 x 30 megawatt units
6		
7	Design Flow	Receipt volume = 4238 mmcf/day
8		Fuel = 131 mmcf/day
9		Delivered volume = 4107 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $3,011 million
12		Compression = $1,772 million
13	.	
14		Total Cost = $4,783 million
15	Unit costs	Pipeline $3.4 million per mile
16		Compression = $126 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

Figure 3.17
Alliance Pipeline: Scenario # 3A, Tolls
US Border to Aux Sable, Illinois
(Alaska incremental flow volume = 2730 mmcf/day)



3.7 Alliance Pipeline Ltd: Scenario #4 (Alaska volume to Alliance =4500 mmcf/day)

The addition of twelve intermediate compressor stations, expanding each compressor station and a complete 48 inch loop would boost the pipeline capacity to 6,094 mmcf/day (171,692 e3m3/day). This expansion would permit the pipeline to handle an additional 4500 mmcf/day of Alaskan gas volumes available at Boundary Lake.

In addition, a connector pipe consisting of 355 miles of 48 inch pipe and three compressor stations (each with a single 23 megawatt gas turbine) would need to be constructed from Boundary Lake, Alberta to Fort Saskatchewan, Alberta. The connector receipt volume would be 4500 mmcf/day with 4470 mmcf/day delivered to Alliance at Fort Saskatchewan, Alberta .

The connector pipeline is estimated to cost $2.59 billion dollars (2006 dollars) and the estimated average firm service toll for the first five years would be $0.27 Cdn/mcf or $0.24 per million btus assuming a heat content of 1090 btus/cuft (Figure 3.18). In addition, the variable charge for fuel usage would be approximately $0.04 Cdn/mcf based on a fuel gas price of $6.50 Cdn/mcf.

Figure 3.18
Alliance Pipeline: Scenario #4, Costs
Boundary Lake, Alberta to Fort Saskatchewan, Alberta
(Alaska incremental flow volume = 4500 mmcf/day)

		Boundary lake, Alberta to Fort Saskatchewan, Alberta
1	Pipeline	355 miles 48 inch, 2500 psi, X80 Steel
2		
3	Compression	lead station: 1 x 21 megawatt units
4		2 intermediate stations: 2 x 23 megawatt units
5	Chillers	
6		
7	Design Flow	Receipt volume = 4,500 mmcf/day
8		Fuel = 30 mmcf/day
9		Delivered volume = 4,470 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $2,314 million
12		Compression = $280 million
13	.	
14		Total Cost = $2,595 million
15	Unit costs	Pipeline $6.5 million per mile
16		Compression = $94 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

The expansion of the Alliance pipeline between Fort Saskatchewan, Alberta and the US border at Elmore, Saskatchewan as well as the US border and Aux Sable, Illinois would cost $4.58 billion dollars (Figure 3.19) and $6.47 billion dollars (Figure 3.21), respectively. Figures 3.20 and 3.22 indicate that the combined reservation toll for the Alliance pipeline for the 2017-2021 period would range from $0.98 to $1.00 Cdn/mcf. In addition, the variable charge for fuel usage would be approximately $0.30 Cdn/mcf, based on a fuel gas price of $6.50 Cdn/mcf. This results in a total toll of $1.29 to $1.30 Cdn/mcf.

Figure 3.19
Alliance Pipeline: Scenario #4, Costs
Fort Saskatchewan, Alberta to Elmore, Saskatchewan
(Alaska incremental flow volume = 4500 mmcf/day)

		Fort Saskatchewan, Alberta to Elmore, Saskatchewan
1	Pipeline	616 miles 48 inch, 1750 psi, X80 Steel
2		
3	Compression	5 intermediate stations: 2 x 30 megawatt units
4		5 station additions 1 x 37 megawatt units
5		
6		
7	Design Flow	Receipt volume = 6094 mmcf/day
8		Fuel = 106 mmcf/day
9		Delivered volume = 5988 mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $3,237 million
12		Compression = $1,341 million
13	.	
14		Total Cost = $4,579 million
15	Unit costs	Pipeline $5.2 million per mile
16		Compression = $134 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

Figure 3.20
Alliance Pipeline: Scenario #4, Tolls
Fort Saskatchewan, Alberta to Elmore, Saskatchewan
(Alaska incremental flow volume = 4500 mmcf/day)

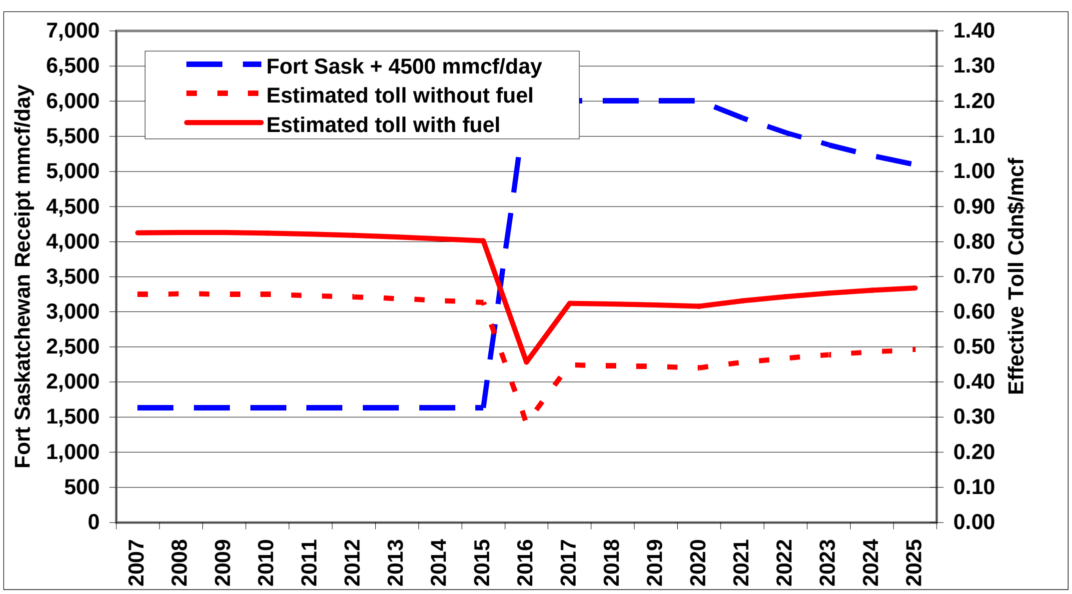
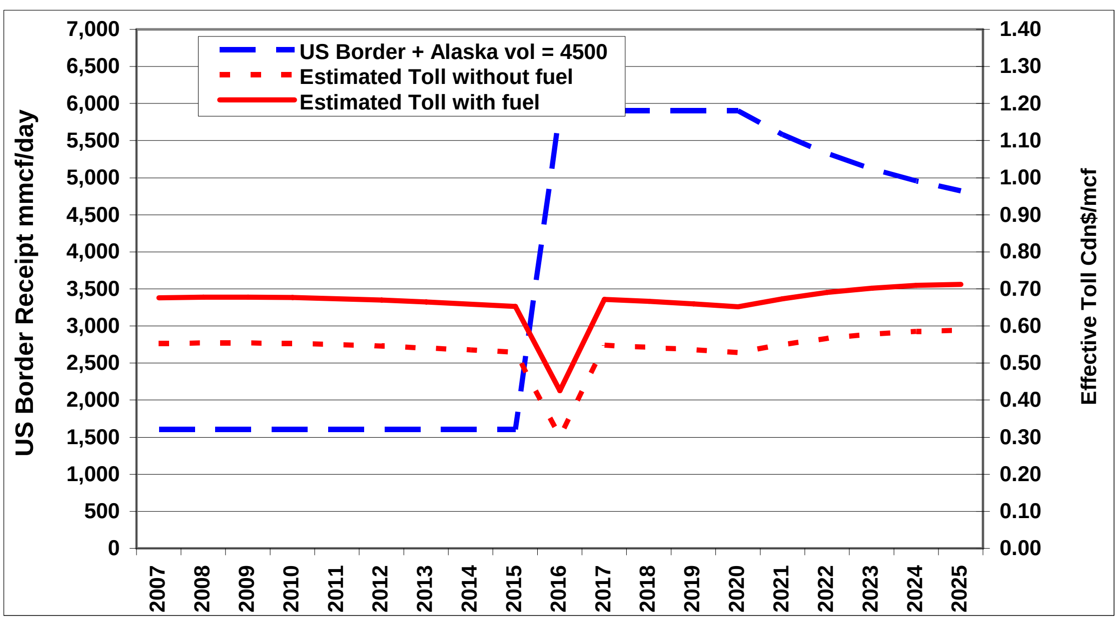


Figure 3.21
Alliance Pipeline: Scenario #4, Costs
Elmore, Saskatchewan to Aux Sable, Illinois
(Alaska incremental flow volume = 4500 mmcf/day)

		Elmore, Saskatchewan to Aux Sable, Illinois
1	Pipeline	883 miles 48 inch, 1750 psi, X80 Steel
2		
3	Compression	7 intermediate stations: 2 x 30 megawatt units
4		2 station additions: 1 x 37 megawatt units
5		5 station additions: 1 x 33 megawatt units
6		
7	Design Flow	Receipt volume = 5988 mmcf/day
8		Fuel = 140 mmcf/day
9		Delivered volume = 5848mmcf/day
10		Heating Value = 1090 btu/cuft
11	Cost estimate	Pipeline cost = $4,641 million
12		Compression = $1,828 million
13	.	
14		Total Cost = $6,470 million
15	Unit costs	Pipeline $5.2 million per mile
16		Compression = $130 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

Figure 3.22
Alliance Pipeline: Scenario #4, Tolls
US Border to Aux Sable, Illinois
(Alaska incremental flow volume = 4500 mmcf/day)



3.8 TCPL Alberta Integrated System

The TransCanada Alberta system transports natural gas from several geographical locations within the province of Alberta and moves it through pipelines for delivery within Alberta or connection to one of the three major export delivery points at Empress, Alberta, McNeill, Alberta and the Alberta/British Columbia border near Coleman, Alberta. TCPL also receives gas imported from British Columbia, connecting to the system in the Upper Peace and Central Peace River areas of the province, and in the future from the Mackenzie Valley Gas Pipeline connecting to the system in the northwest corner of the province. The system currently receives natural gas at 976 metered locations and delivers natural gas to 170 delivery points within Alberta in addition to the three major export points that connect to pipelines delivering natural gas to eastern Canada and the United States. The gross plant, in service as of mid year 2006, and the interim revenue requirements for 2007 that were used as the starting point in the determination of the annualized toll for the Alberta System, are as follows[20,21].

- Canadian toll parameters (2006 thousand Canadian $)

Gross transmission plant, pipe mains	$5,020,000
Gross transmission plant, compression	$2,292,000
Gross metering plant	$799,000
Accumulated depreciation	$3,126,000
Operation and Maintenance expense	$204,000
Property taxes	$78,400
Income Taxes	$124,100
Debt Equity ratio	65/35
Debt cost	7.83%
Equity return	8.51%
Fuel	0.9%
Estimated toll without fuel (2007)	$0.27 Cdn/mcf
Estimated fuel component (2007)	$0.08 Cdn/mcf[22]

Figure 3.23 shows the annual relationship between the Alberta receipt volumes[23] (including BC imported volumes and Mackenzie Valley pipeline volumes), Alberta domestic natural gas requirements (Alberta Demand) and net export volumes leaving Alberta for the study base case. The volume of gas available for export out of the province on the TCPL Alberta system (Alberta Export) is a function of the Alberta marketable receipt volumes (Alberta plus imports) minus the volumes attributable to the Alliance Pipeline, minus volumes transported by other domestic pipelines, and minus the Alberta domestic requirements (Alberta Demand).

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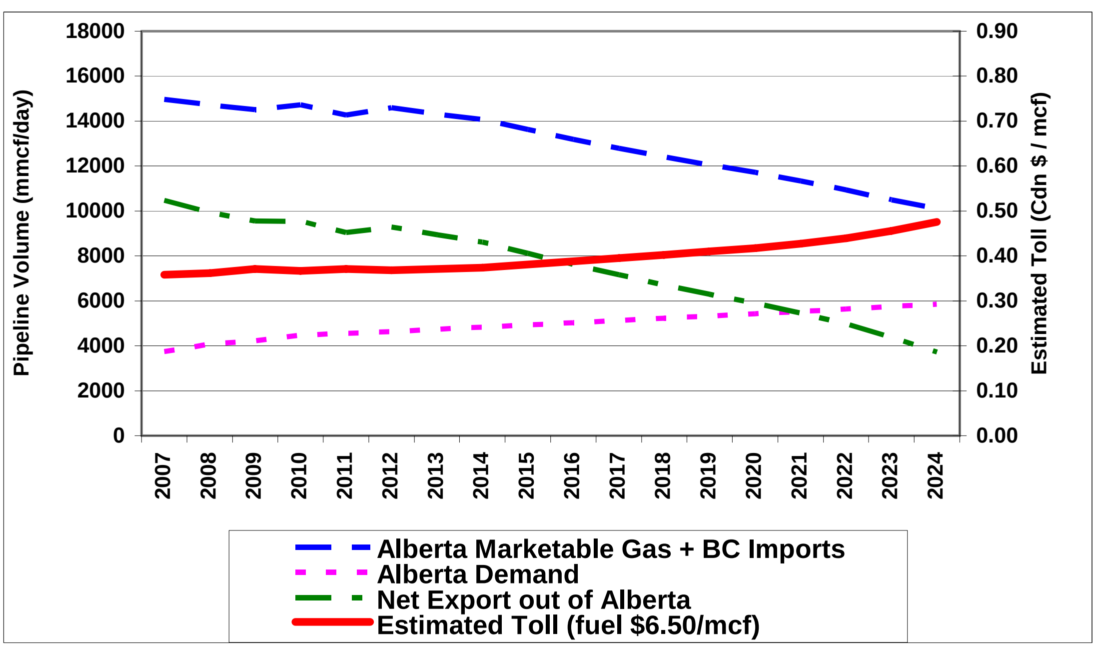
[20] NOVA Gas Transmission Ltd, 2007 Interim Rates, Attachment A "Calculation of 2007 Interim Revenue Requirements.
[21] TransCanada Corporation, Consolidated Financial Statements, Notes to consolidated financial statements February 27, 2006 (Note 4 Plant, Property and Equipment, December 31, 2005).
[22] Assuming $6.50 Cdn/ mcf.
[23] Total Alberta marketable gas production connected to the TCPL Alberta pipeline, Atco Pipelines, Suffield pipeline and other smaller pipelines.

Figure 3.23 also indicates the future estimated toll for transported volumes of gas within the TCPL Alberta integrated system (right hand scale). This estimated toll includes an average of the "AB Receipt – NIT[24]' and 'NIT-Empress' components of the toll structure.

In the base case, the TCPL Alberta system receipt volume declines by 9 percent prior to the estimated connection date of the Alaska Highway Pipeline in 2016, while deliveries to the export market decline by approximately 22 percent in the same time frame. This situation is a direct result of the decline in the basin production coupled with the increased demand for natural gas in the Oil Sands projects. The volume of gas exported at each of the three export points on the TCPL Alberta system was assumed to decline proportionately to the net exportable volume available in any given year.

In the Base Case the Alberta system average receipt/delivery firm service toll increases from the current $0.35 Cdn/mcf to approximately $0.39 Cdn/mcf between 2007 and 2016. This is a total toll and a fuel charge of $0.08 Cdn/mcf has been included in this number based on a fuel gas price of $6.50 Cdn/mcf. In this time frame, TCPL Alberta transports increasing volumes of gas for delivery within Alberta (Alberta Demand) and reduced volumes of gas for delivery outside of Alberta (Net Export out of Alberta). As a result of this change in flow direction, the toll on the TCPL Alberta system remains relatively insensitive to the declining export volumes for the period of time between 2007 and 2016.

Figure 3.23
TCPL Alberta: Base Case
Volumes and Tolls



[24] NIT, Nova Inventory Transfer.

3.9 TCPL Alberta Integrated System: Scenario #3A (Alaska Volume to TCPL=1770 mmcf/day)

The Alaska volume delivered to Boundary Lake, Alberta will start in 2016 and reach the 4,500 mmcf/day level by 2018. After accounting for the volume transferred to the Alliance Pipeline, the remaining gas would be transported on the TCPL Alberta system from Boundary Lake, Alberta, south to James River, Alberta and then east to Empress, Alberta or south to the ABC border. Scenario 3A assumes that for the years 2018 and beyond, the transfer volume to the Alliance Pipeline would be 2,730 mmcf/day resulting in a volume delivered to the TCPL Alberta system equaling 1,770 mmcf/day.

In the Base Case, it was assumed that the North Central Corridor (NCC) would be constructed prior to 2012 with a receipt capacity of 700 mmcf/day. This connector pipeline would permit gas volumes to move from the Upper Peace River area to the Upper Bens Lake area to assist in supplying natural gas to the Oil Sands projects. In order to minimize the addition of facilities between Boundary Lake, Alberta and Edson, Alberta (Central and Lower Peace areas) the study assumed the NCC connector would be expanded to a capacity of 1,700 mmcf/day. For this scenario, this level of development of the NCC connector minimizes the facilities required in the Lower Peace River, Edson mainline and the eastern and western mainline systems within Alberta. Figure 3.24 summarizes the facilities required and capital cost estimate for the expansion of the TCPL Alberta system. The cost of the original construction of the NCC prior to 2012, the expansion of the NCC to handle the additional volume and the expansion facilities in the Peace River area were included as rolled in costs in order to determine the resultant toll for the Alberta System (Figure 3.25).

Figure 3.24
TCPL Alberta: Scenario #3A, Facilities and Costs
Boundary Lake, Alberta to Empress, Alberta
(Alaska incremental flow volume = 1770 mmcf/day)

		TCPL Alberta
1	Pipeline	68 miles 30 inch, 1200 psi, X80 Steel
2		40 miles 42 inch, 1200 psi, X80 Steel
3		250 miles 36 inch, 1226 psi, X80 Steel (NCC connector)
4		
5	Compression	1 new stations: 1 x 16 megawatt units (Wembley)
6		1 new stations: 1 x 23 megawatt units (NCC connector)
7		1 exp station: 1 x 10 megawatt unit (NCC connector)
8	Design Flow	Receipt volume
9		Fuel
10		Delivered volume
11		Heating Value = 1050 (Average)
12	Cost estimate	Pipeline cost = $1042 million
13		Compression = $94.5 million
14	.	
15		Total Cost = $1,136 million
16	Unit costs	Pipeline $2.9 million per mile
17		Compression = $46 million per station
18		
19	*costs expressed as 2006 Canadian dollars	

Figure 3.25
TCPL Alberta: Scenario # 3A, Flows and Tolls
Boundary Lake, Alberta to Empress, Alberta
(Alaska incremental flow volume = 1770 mmcf/day)

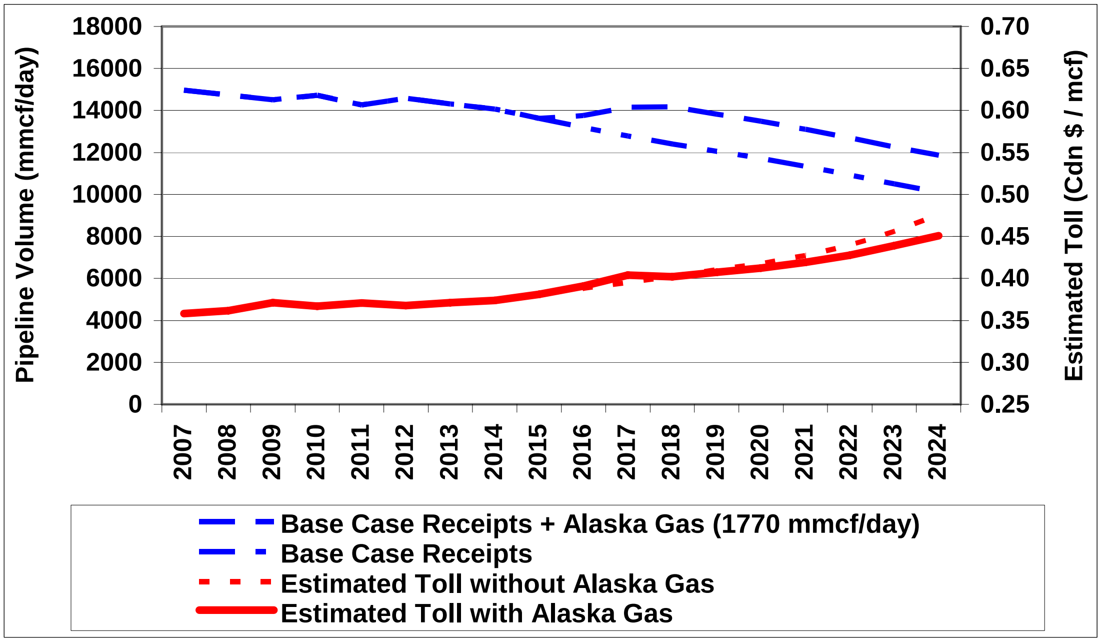


Figure 3.25 indicates that the addition of 1770 mmcf/day of Alaska volumes to the base case volumes for TCPL Alberta, commencing in 2016, results in an saving of two to three cents per thousand cubic feet in tolling charges for the 2021 to the end of the forecast.

3.9.1 TCPL Alberta Integrated System: Scenario #3 (Alaska Volume to TCPL=2610 mmcf/day)

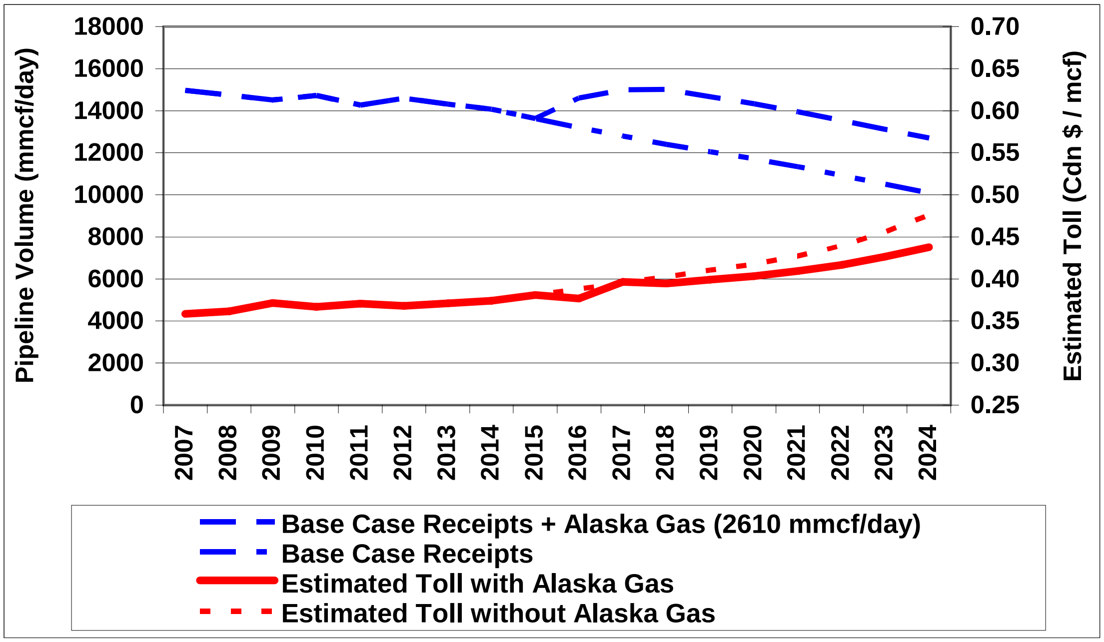
Scenario 3 assumes the transfer volume at Boundary Lake to the Alliance Pipeline system would be 1,890 mmcf/day. As a result of this assumption, the gas volume delivered to TCPL Alberta would be 2,610 mmcf/day. In the Base Case, it was assumed that the NCC would be constructed prior to 2012, with a capacity of 700 mmcf/day. In order to minimize the addition of facilities between Boundary Lake, Alberta and Edson, Alberta (Central and Lower Peace areas) the study assumed the NCC connector would be expanded to a capacity of 2,100 mmcf/day. For this scenario, this level of development of the NCC connector minimizes the facilities required in the Lower Peace River, Edson mainline and the eastern and western mainline systems within Alberta. Figure 3.26 summarizes the facilities required, and capital cost estimate for the expansion of the TCPL Alberta system. The cost of the original construction of the NCC prior to 2012, the expansion of the NCC to handle the additional volume and the expansion facilities in the Peace River area were included as rolled in costs in order to determine the resultant toll for the Alberta System (Figure 3.27).

Figure 3.26
TCPL Alberta: Scenario # 3, Facilities and Costs
Boundary Lake, Alberta to Empress, Alberta
(Alaska incremental flow volume = 2610 mmcf/day)

		TCPL Alberta
1	Pipeline	107 miles 30 inch, 1200 psi, X80 Steel
2		40 miles 42 inch, 1200 psi, X80 Steel
3		275 miles 36 inch, 1200 psi, X80 steel (NCC)
4	Compression	1 new stations: 1 x 21 megawatt units
5		1 new stations: 1 x 16 megawatt units
6		2 expansion stations: 1 x 23 megawatt units (NCC)
7	Design Flow	Receipt volume
8		Fuel
9		Delivered volume
10		Heating Value = 1050
11	Cost estimate	Pipeline cost = $1,209 million
12		Compression = $262 million
13	.	
14		Total Cost = $1,471 million
15	Unit costs	Pipeline $2.8 million per mile
16		Compression = $52 million per station
17		
20	*costs expressed as 2006 Canadian dollars	

The addition of 2610 mmcf/day of Alaska volumes to the base case volumes transported by TCPL Alberta, commencing in 2016, results in an average saving of two to three cents per thousand cubic feet in tolling charges (Figure 3.27) for the 2018 to 2021 time period. This savings grows to five cents per thousand cubic feet near the end of the forecast.

Figure 3.27
TCPL Alberta: Scenario # 3, Flows and Tolls
Boundary Lake, Alberta to Empress, Alberta
(Alaska incremental flow volume = 2610 mmcf/day)



3.9.2 TCPL Alberta Integrated System: Scenario #5 (Alaska Volume to TCPL=4500 mmcf/day)

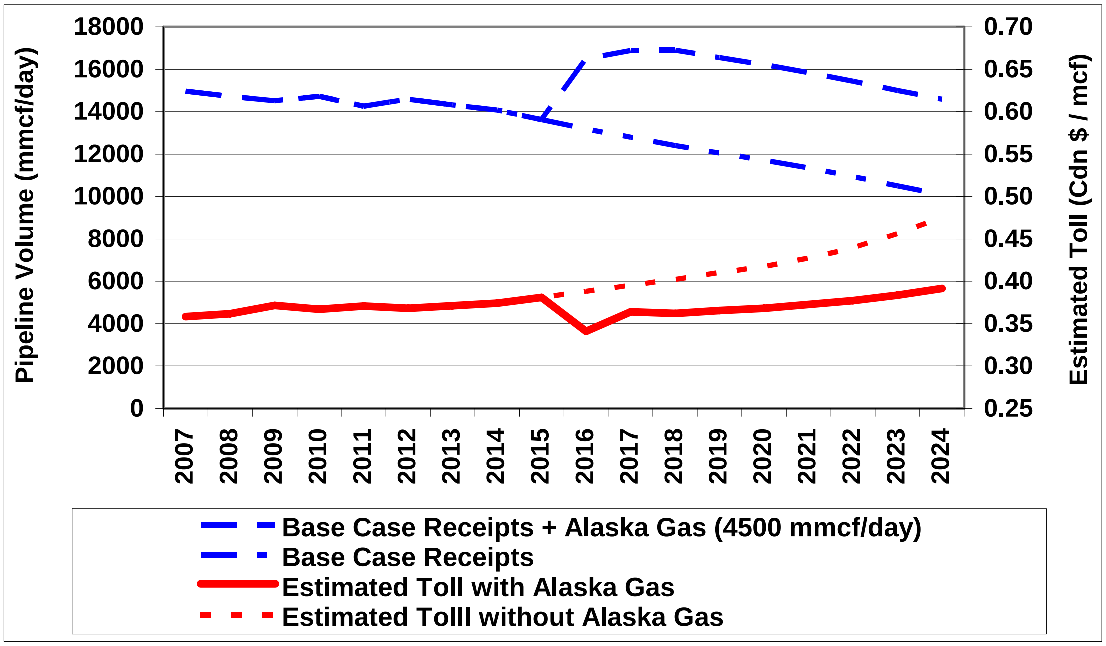
Scenario 5 assumes the total volume of Alaska gas would be delivered to TCPL Alberta at Boundary Lake. In the Base Case, it was assumed that the NCC would be constructed prior to 2012, with a capacity of 700 mmcf/day. In order to minimize the addition of facilities between Boundary Lake, Alberta and Edson, Alberta (Central and Lower Peace areas) the study assumed the NCC connector would be expanded to a capacity of 2,300 mmcf/day. For this scenario, this level of development of the NCC connector minimizes the facilities required in the Lower Peace River, Edson mainline and the eastern and western mainline systems within Alberta. Figure 3.28 summarizes the facilities required, and capital cost estimate for the expansion of TCPL Alberta. The cost of the original construction of the NCC prior to 2012, the expansion of the NCC to handle the additional volume and the expansion facilities in the Upper Peace River area were included as rolled in costs in order to determine the resultant toll for the Alberta System (Figure 3.29).

Figure 3.28
TCPL Alberta: Scenario # 5, Facilities and Costs
Boundary Lake, Alberta to Empress, Alberta
(Alaska incremental flow volume = 4500 mmcf/day)

		TCPL Alberta
1	Pipeline	105 miles 30 inch, 1200 psi, X80 Steel
2		83 miles 36 inch, 1200 psi, X80 Steel
3		40 miles 42 inch, 1200 psi, X80 Steel
4		275 miles 36 inch, 1200 psi, X80 (NCC)
5	Compression	2 new stations: 1 x 16 megawatt units
6		1 new stations: 1 x 23 megawatt units
7		2 expansion stations: 1 x 23 megawatt units (NCC)
8		1 new stations: 1 x 23 megawatt units (NCC)
9	Design Flow	Receipt volume
10		Fuel
11		Delivered volume
12		Heating Value = 1050
13	Cost estimate	Pipeline cost = $1,450 million
14		Compression = $339 million
15	.	
16		Total Cost = $1,789 million
17	Unit costs	Pipeline $2.9 million per mile
18		Compression = $56 million per station
19		
20	*costs expressed as 2006 Canadian dollars	

The Alaska Highway pipeline is assumed to commence operation in 2016 with an initial flow volume of 3300 mmcf/day. It is further assumed that the pipeline will reach its design flow level of 4500 mmcf/day, delivered to Boundary Lake, in 2018. The addition of 4500 mmcf/day to the transported volume by TCPL Alberta, commencing in 2018, results in an approximate saving of five to seven cents per thousand cubic feet in tolling charges (Figure 3.29) for the 2018 to 2021 time period. This saving grows to almost ten cents per thousand cubic feet by the end of the forecast

Figure 3.29
TCPL Alberta: Scenario # 5, Flows and Tolls
Boundary Lake, Alberta to Empress, Alberta
(Alaska incremental flow volume = 4500 mmcf/day)



3.10 Empress/McNeill to Chicago

Volumes of gas delivered to the Empress/McNeill export location can be delivered to the mid west area of the United States by means of the TCPL East system, the Northern Border Pipeline System or a combination of the two.

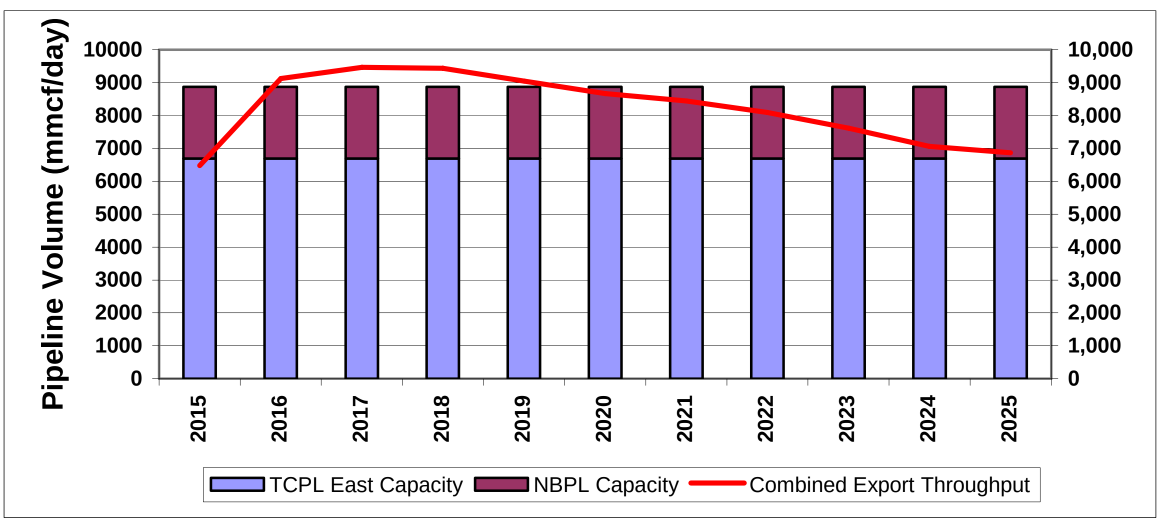
The TCPL East system transports Alberta gas received at Empress, Alberta, along with additional volumes from the Suffield pipeline and TransGas connections, to a point south of Winnipeg, Manitoba where the flow can follow two separate paths. At the Winnipeg bifurcation point, gas can be transported by the Great Lakes Gas Transmission System (capacity 2,200 mmcf/day) for delivery to the St. Claire area and connection with the Dawn hub or by the TCPL Northern Ontario System (capacity 4,500 mmcf/day) and TCPL Eastern Zone for delivery to the Toronto area and connection with the Dawn hub. Exchange volumes on the Union Gas Dawn/Parkway system, the Vector Pipeline[25] and ANR Pipeline systems[26] would result in gas being delivered to the Chicago area markets.

[25] Vector Pipeline extends from south of Chicago to the St. Claire connection with Union Gas Pipeline and the Dawn, Ontario hub.
[26] ANR Pipeline transports natural gas from Texas and the Gulf of Mexico to Illinois, Michigan, Indiana, Ohio and the St Claire connection with Union Gas.

The Foothills Saskatchewan pipeline receives gas at the McNeill border station located next to the Empress border station and delivers gas to the Northern Border pipeline at the US export point near Monchy, Saskatchewan. The current capacity for the Northern Border pipeline is 2,180 mmcf/day.

The current capacity of the TCPL East pipeline, which covers the distance between Empress, Alberta and Winnipeg, is 7,210 mmcf/day. The Keystone oil pipeline project results in the TCPL East capacity being reduced to 6,695 mmcf/day in 2009. Figure 3.30 compares this reduced capacity against the volumes of gas available at the Empress/McNeill export point based on the flow assumptions used for scenario #5. This Figure indicates that the combined base case flow and Alaska Gas volume (4,500 mmcf/day) will exceed the down stream capacity at Empress by approximately 0.1 bcf/day for two years, 2016 and 2019, and approximately 0.4 bcf/day for the two intermediate years. However, it should also be noted that under scenario #5 the volumes of gas flowing southward to the GTN pipeline were assumed to be significantly below the capacity of that pipeline. In fact a nominal increase in the base case volumes moving on the GTN pipeline would result in Northern Border and TCPL East handling all of the Alaska Gas volume without any facility additions.

Figure 3.30
TCPL East and Northern Border Pipelines
Capacity versus Empress Flow Volume



3.11 Foothills Saskatchewan Pipeline

The Foothills Alberta Pipeline parallels the TCPL Alberta pipeline system from Caroline, Alberta to Empress, Alberta. Transportation tolls for this section of the Foothills Pipeline system (Zone 6) are included in the TCPL Alberta integrated toll under the financial item Transportation by Others (TBO).

At Empress the flow stream is processed by five straddle plant operations (capacity 8700 mmcf/day) before being directed to the TCPL East mainline and the Foothills Saskatchewan pipeline. The Foothills Saskatchewan pipeline operates as one tolling zone (Zone 9) within Foothills Pipe Lines Ltd and transports gas from the McNeill Border to Monchy, Saskatchewan. Custody of the natural gas is passed to Northern Border Pipelines Ltd at this point. The financial elements for Foothills Pipelines Ltd (Zone 9), as of year end 2006, and used as the starting point in the determination of the annualized tolls are as follows [27]:

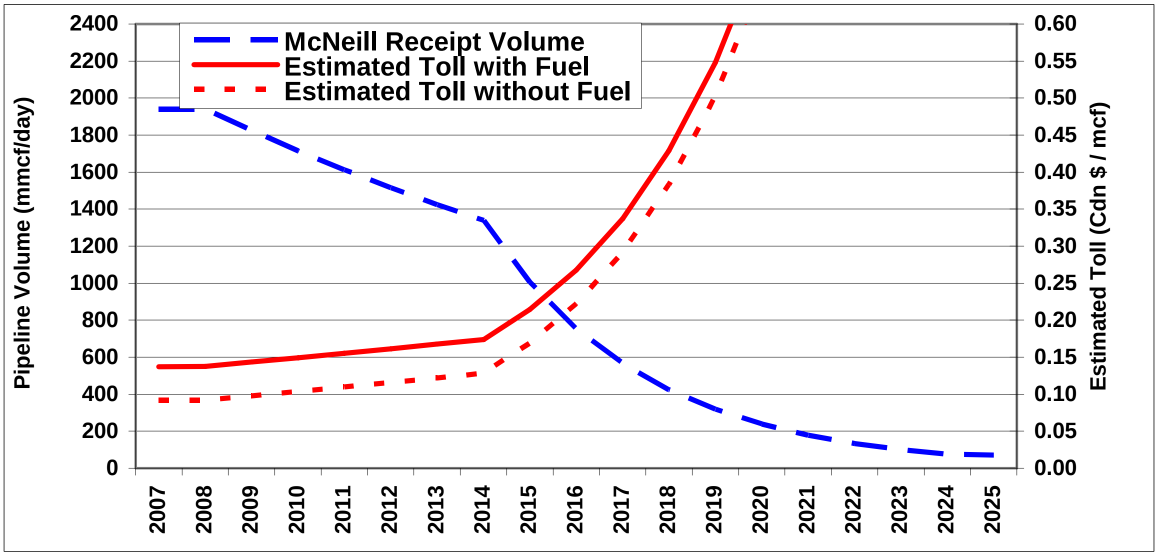
- Canadian toll parameters (2006 thousand Canadian $)[28,29]

    - Average transmission plant, pipe mains $342,300
    - Average transmission plant, compression $192,300
    - Accumulated depreciation $225,000
    - Operation and Maintenance expense $10,122
    - Property taxes $5,182
    - Income Taxes $11,080
    - Debt Equity ratio 64/36
    - Debt cost 4.94%
    - Equity return 8.88%
    - Fuel 0.7%
    - Estimated toll without fuel (2007) $0.09 Cdn/mcf
    - Estimated fuel component (2007) $0.05 Cdn/mcf[30]

Figure 3.31 demonstrates the annual relationship between the throughput volume and the effective transportation toll for the Foothills Saskatchewan (FPL-Zone 9) pipeline as a result of the assumptions used in the base case. Under these assumptions, deliveries to the Foothills/NBPL pipelines are maintained at the 2005 volume level for three years, followed by an 8 percent decline in receipt volumes for the subsequent six years prior to the proposed on stream data for Alaska gas. The base case does not include the Alaska volumes of gas which results in a continued decline in the net exportable quantity of gas leaving Alberta after 2015. This decline is also reflected in deliveries to the GTN pipeline to California. The market requirements and producer net backs will ultimately determine the level of flow in each of these pipelines but for this study it was assumed that reductions in exportable gas volumes leaving Alberta would be reflected equally in these export pipelines.

[27] Foothills Pipelines Ltd., 2006 Effective Rates, Schedule C-1 (Zone 9) and Schedule Summary.
[28] Transcanada Corporation, Consolidated Financial Statements.
[29] Foothills Pipe Lines Ltd, 2006 Effective Rates.
[30] Assuming $6.50 Cdn/ mcf.

Figure 3.31
Foothills Pipe Lines (Saskatchewan)
Base Case Volumes and Tolls



As described previously, delivery of gas to the Empress/McNeill border points is forecasted to decline as a result of declining basin production and demand increases in the Oil Sands sector in Alberta. The net result of this situation is an increase of pipeline spare capacity in the export pipelines which leads to an increase in transportation tolls for those pipelines. Transporting Alaska volumes to the US midwest would involve utilizing part, or all, of the spare capacity on the TCPL East, TCPL Northern Ontario, TCPL Eastern Zone, Great Lakes Transmission and Northern Border pipelines. In order to estimate a suitable split in the flows directed to each of the export pipeline systems, a range of incremental flow volumes was investigated and the resultant tolls were compared. Figures 3.32, 3.35 and 3.38 show the volume profiles on the three export pipelines as a result of adding incremental flows of 400, 600, and 1200 mmcf/day. These Figures also show the volume profile, assuming the incremental Alaska volumes reach the capacity level of each pipeline. Figures 3.33, 3.36 and 3.39 show the effect on future toll structures as a result of varying the flows transported by these pipelines.

From these curves it can be estimated that in order to minimize the effect of reduced flows and increasing tolls, a minimum volume of 1200 mmcf/day should be directed to the Northern Border pipeline. Under scenario 3A, 1200 mmcf/day would be directed to NBPL, and 430 mmcf/day to TCPL East. Under scenario 3, approximately 1200 mmcf/day would be directed to each pipeline. Finally, under scenario 5, approximately 1750 mmcf/day would be directed to NBPL and 2620 mmcf/day to TCPL East. This effectively reflects the operation of these pipelines at their capacity levels for several years until the continued decline in the WCSB basin flows again causes the load factors to fall.

Figure 3.32
Foothills Pipe Lines (Saskatchewan)
Base Case plus Incremental Flow Comparison

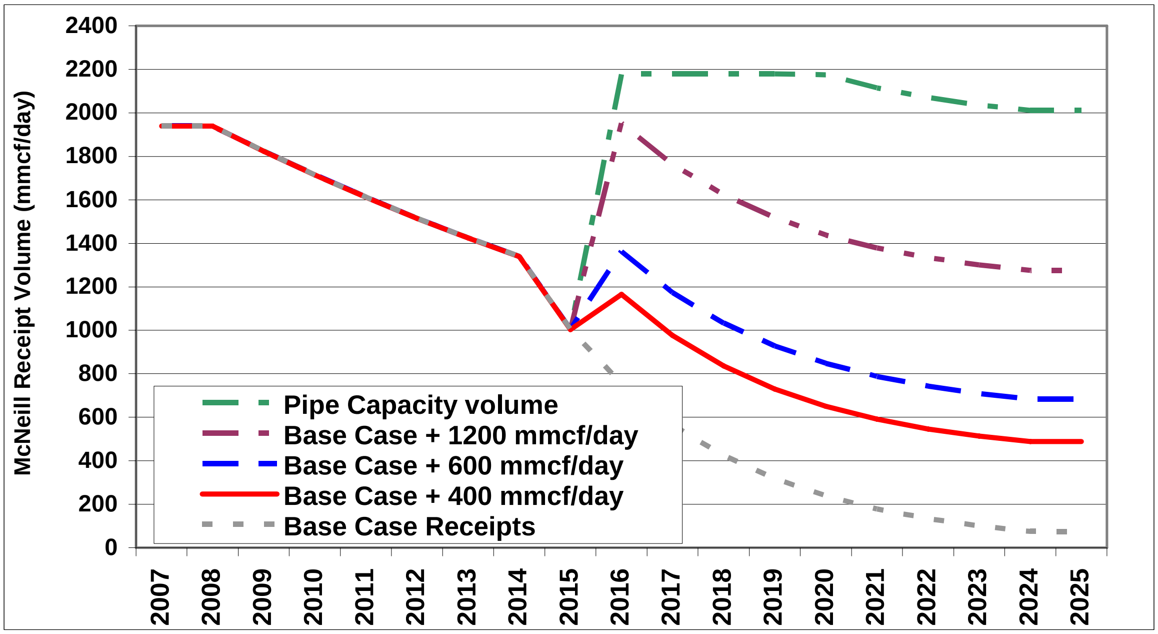
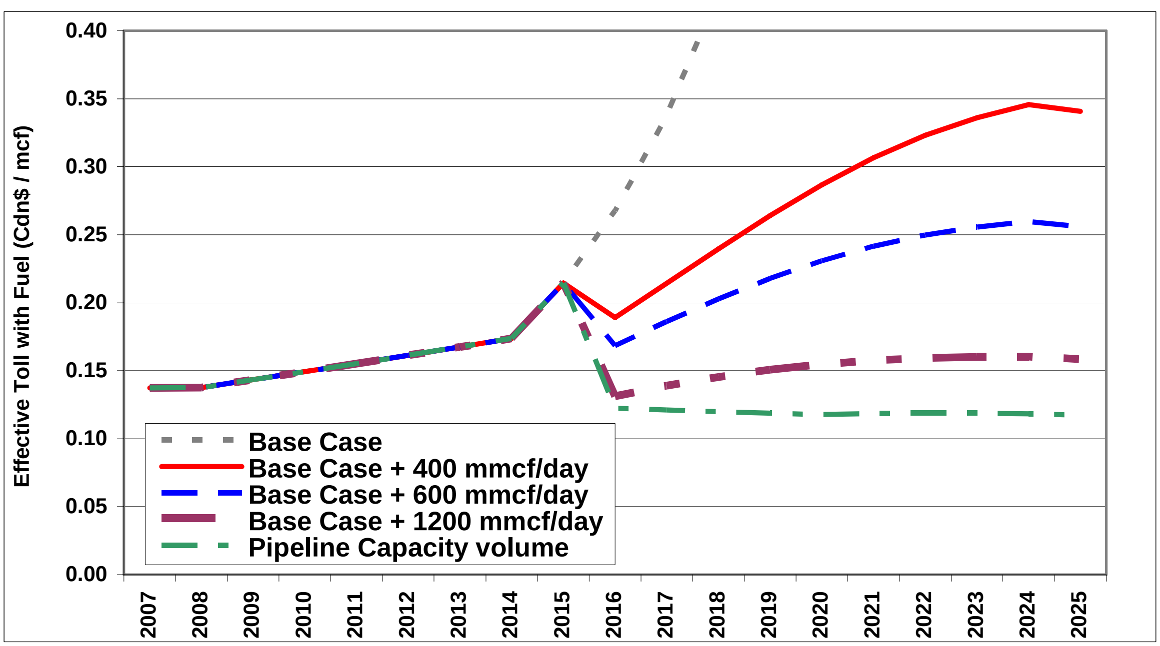


Figure 3.33
Foothills Pipe Lines (Saskatchewan)
Base Case plus Incremental Toll Comparison



3.12 Northern Border Pipeline (NBPL)

The Northern Border Pipeline receives the majority of its transport volume from the Foothills Saskatchewan pipeline near Monchy, Saskatchewan and transports that volume to Iowa, Illinois and Indiana, where it interconnects with several interstate pipelines. The financial elements for the Northern Border Pipeline as of mid year 2006 and used for the starting point in the determination of the annualized tolls are as follows[31]:

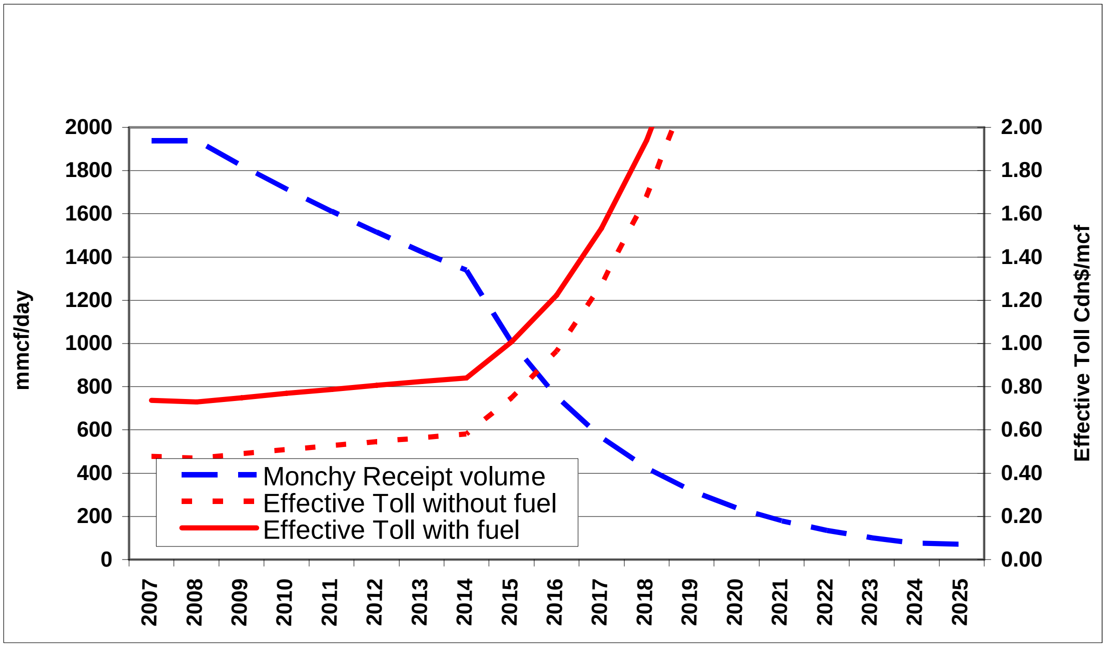
- Canadian toll parameters (2006 thousand Canadian $)

Average transmission plant, pipe mains	$2,133,800
Average transmission plant, compression	$644,790
Accumulated depreciation	$1,150,000
Annual Operation and Maintenance expense	$24,884
Annual Property taxes	$30,945
Annual Income Taxes	$49,978
Debt Equity ratio	51/49
Debt cost	7.01%
Equity return	12.5%
Fuel	4%
Estimated toll without fuel (2007)	$0.47 Cdn/mcf
Estimated fuel component (2007)	$0.26 Cdn/mcf[32]

Figure 3.34 demonstrates the annual relationship between the throughput volume and the effective transportation toll for the NBPL as a result of the assumptions used in the base case. Under these assumptions, deliveries to the Foothills/NBPL pipelines are maintained at the 2005 volume level for three years followed by an 8 percent decline in receipt volumes for the subsequent six years prior to the proposed on stream data for Alaska gas. The base case does not include the Alaska volumes of gas which results in a continued decline in the net exportable quantity of gas leaving Alberta after 2015. This decline is also reflected in deliveries to the GTN pipeline to California. The market requirements and producer net backs will ultimately determine the level of flow in each of these pipelines, but for this study it was assumed that reductions in exportable gas volumes leaving Alberta would be reflected equally in these export pipelines

[31] Northern Border Pipeline Company, Submission to the Federal Energy Regulatory Commission on Facilities and Operating costs (2006).
[32] Assuming $6.50 Cdn/ mcf.

Figure 3.34
Northern Border Pipeline: Monchy to Chicago
Base Case: Volumes and Tolls



Figures 3.35 and 3.36 show the annual receipt volume and expected toll as a result of directing quantities of Alaska gas to the Foothills Saskatchewan pipeline for delivery to the Northern Border Pipeline. The assumptions used for the Foothills Saskatchewan pipeline are replicated in these Figures to estimate the level of flow that would minimize the combined toll for use of these pipelines and the TCPL East, and TCPL Northern Ontario pipelines.

Figure 3.35
Northern Border Pipeline: Monchy to Chicago
Base Case plus Incremental Flow Comparison

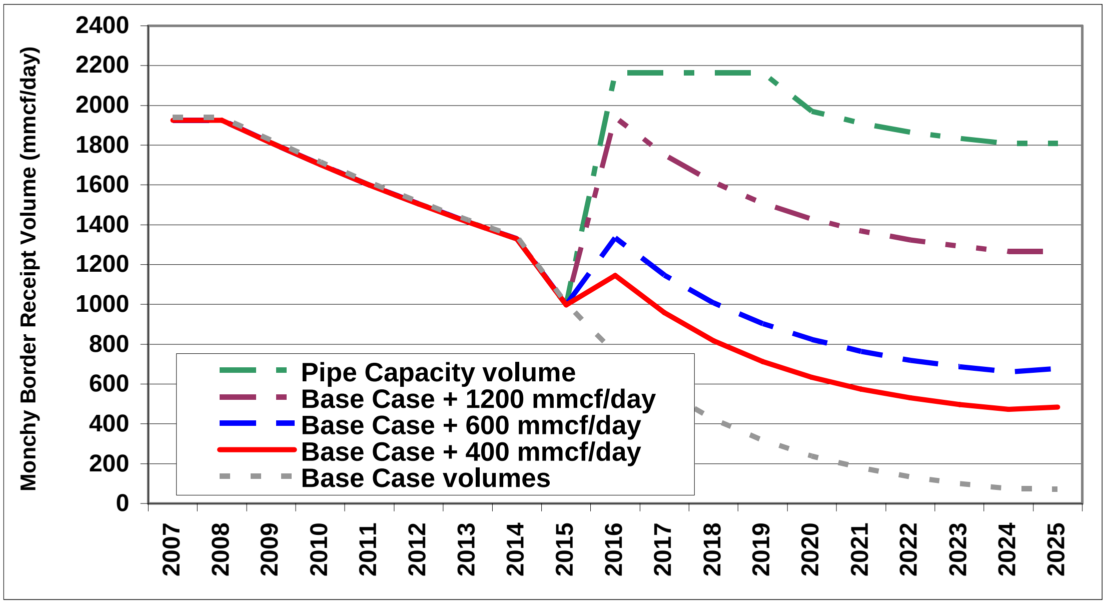
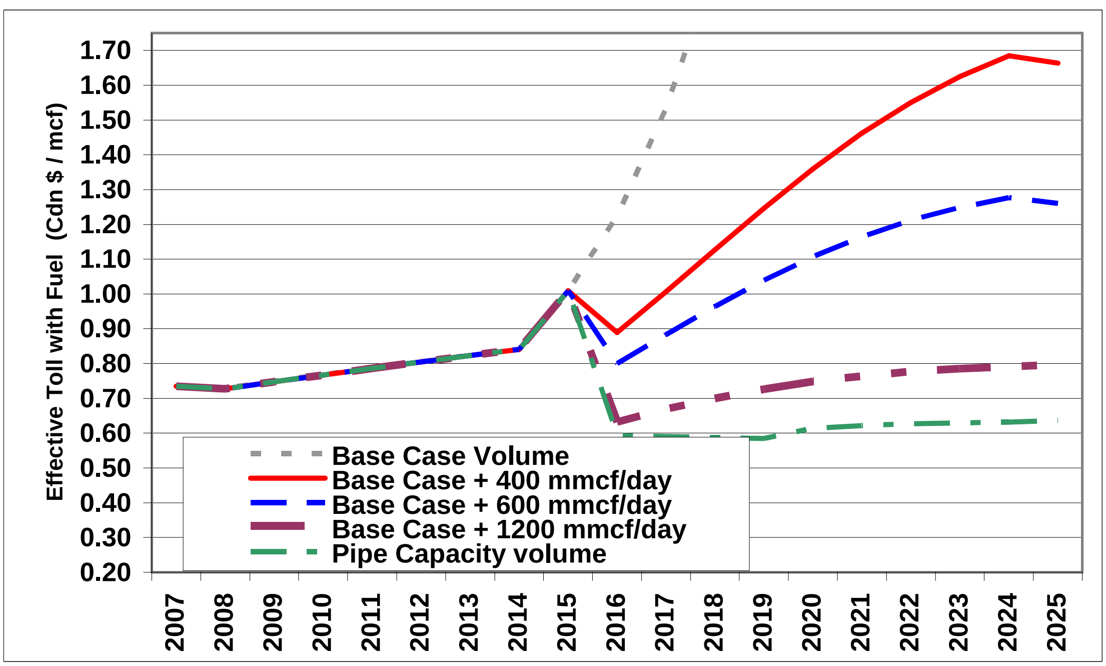


Figure 3.36
Northern Border Pipeline: Monchy to Chicago
Base Case plus Incremental Toll Comparison



3.13 TCPL East Mainline

The TCPL East mainline delivers gas to the Ontario/Quebec markets and to the US border at Emerson, Manitoba. The Viking Gas Transmission pipeline (capacity 400 mmcf/day) receives gas at Emerson, Manitoba and delivers gas to the Chicago area through a connection with the ANR Interstate pipeline. The Great Lakes Gas Transmission pipeline (capacity 2,200 mmcf/day) receives gas at Emerson, Manitoba and delivers gas to the Michigan market and southern Ontario by way of the import connection near St. Claire, Ontario.

It was estimated that forty percent of the gas plant in service, depreciation, operating costs and other parameters outlined in TransCanada's Consolidated Financial statements would be attributable to the TCPL East portion of the total TCPL system. Applying this estimate to the elements required to run the tolling program resulted in a transportation toll that approximated the indicated toll from the TCPL Toll Calculator website for the year 2007.

The financial elements, for the TCPL East pipeline (Empress, Alberta to Emerson, Manitoba) as of year end 2005 and used for the starting point in the determination of the annualized tolls are as follows[33,34]:

- Canadian toll parameters (2006 thousand Canadian $)
  - Average transmission plant, pipe mains $3,494,130
  - Average transmission plant, compression $1,319,594
  - Accumulated depreciation $1,984,733
  - Annual Operation and Maintenance expense $69,665
  - Annual Property taxes $49,536
  - Annual Income Taxes $75,829
  - Debt Equity ratio 57/43
  - Debt cost 7.83%
  - Equity return 10.25%
  - Fuel 1.9%
  - Estimated toll without fuel (2007) $0.35 Cdn/mcf
  - Estimated fuel component (2007) $0.12 Cdn/mcf[35]

Figure 3.37 demonstrates the annual relationship between the throughput volume and the effective transportation toll for the TCPL East pipeline as a result of the assumptions used in the base case. Under these assumptions, deliveries to the TCPL East pipeline are maintained at the 2005 volume level for three years followed by an 8 percent decline in receipt volumes for the subsequent six years prior to the proposed on stream data for Alaska gas. Since the base case has not assumed any Alaska volumes, the net exportable quantity of gas leaving Alberta would

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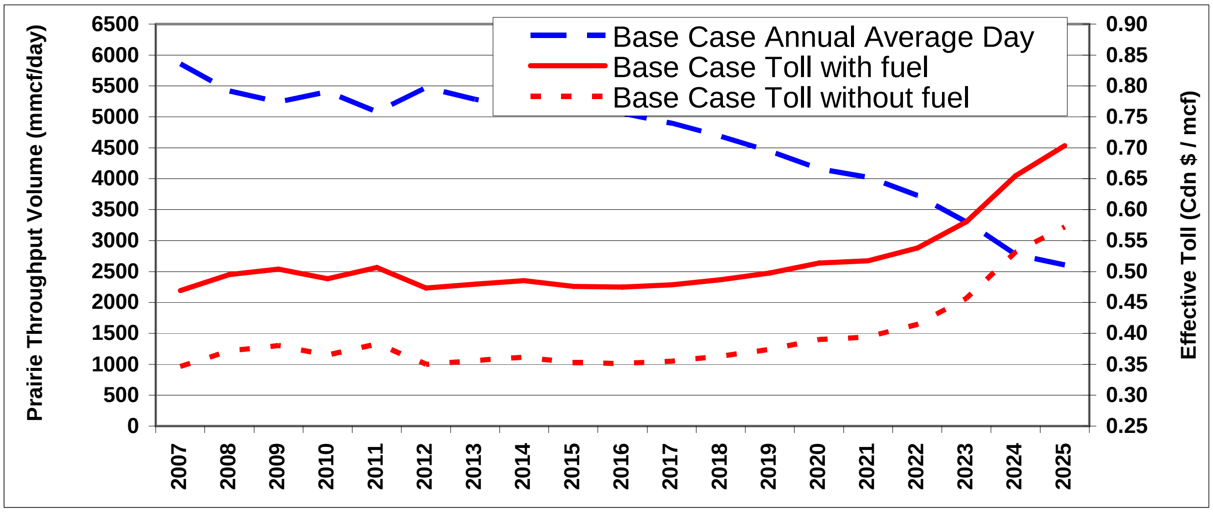
[33] TransCanada Corporation, Consolidated Financial Statements, Note 4 Plant, Property and Equipment, February 2006.
[34] TransCanada Corporation, Consolidated Financial Statements, Notes on Consolidated Statements, February 2006.
[35] Assuming $6.50 Cdn/ mcf.

continue to decline after 2015 at a rate of 25 percent as a result of the increasing decline in forecasted production.

Figure 3.37
TCPL East: Volumes and Tolls
Empress, Alberta to Emerson, Manitoba
Base Case



The assumptions used for the Foothills Saskatchewan pipeline and Northern Border pipeline are replicated in Figures 3.38 and 3.39 to estimate the level of flow that would minimize the combined toll for use of both pipelines

Figure 3.38
TCPL East
Empress, Alberta to Emerson, Manitoba
Base Case plus Incremental Flow Comparison

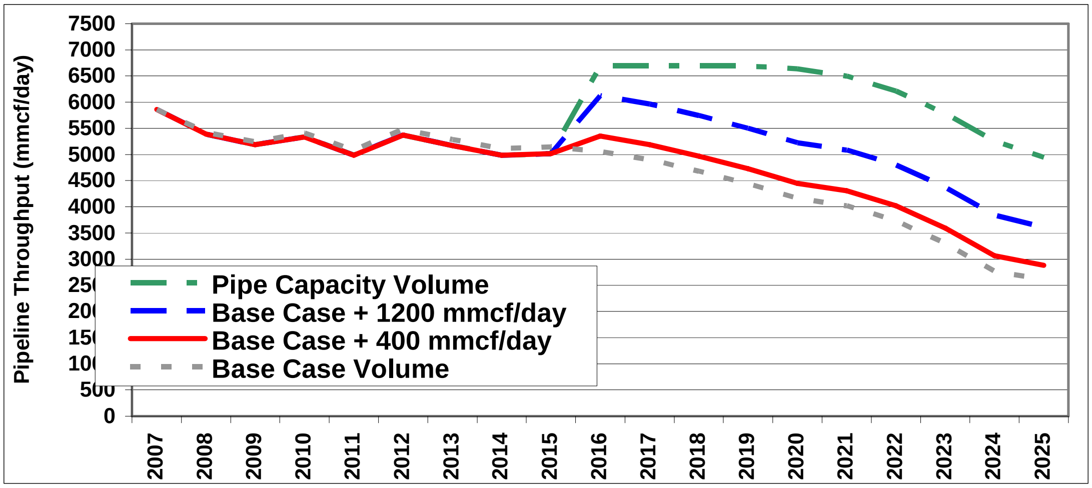
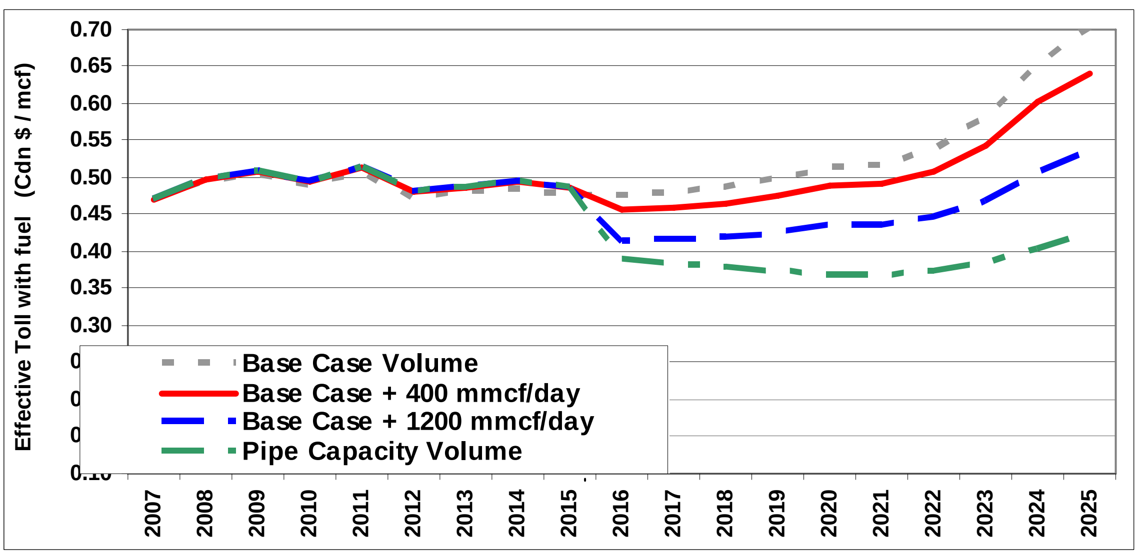


Figure 3.39
TCPL East
Empress, Alberta to Emerson, Manitoba
Base Case plus Incremental Toll Comparison



3.14 TCPL Northern Ontario Mainline

The TCPL Northern Ontario mainline transports gas from the Winnipeg bifurcation point[36], northeast over the Great Lakes to the Central Ontario delivery area and the Dawn gas trading hub. Gas from the Great Lakes Pipeline is re-imported into the area at the St. Claire River, and the Union Gas connection (Dawn Parkway) allows gas to move towards the Quebec markets exporting to the United States by the Iroquois Pipeline, Empire State pipeline, Portland Natural Gas Pipeline and others.

It was estimated that fifty percent of the gas plant in service, depreciation, operating costs and other parameters outlined in TransCanada's Consolidated Financial statements would be attributable to the TCPL Northern Ontario and Central Ontario regions of the total TCPL system. Applying this estimate to the elements required to run the tolling program resulted in a transportation toll that approximated the indicated toll from the TCPL Toll Calculator website for the year 2007.

The financial elements, for the TCPL Northern Ontario as of year end 2005 and used for the starting point in the determination of the annualized tolls are as follows[37,38]:

- Canadian toll parameters (2006 thousand Canadian $)
  - o Average transmission plant, pipe mains $4,367,662
  - o Average transmission plant, compression $1,824,253
  - o Accumulated depreciation $2,480,917
  - o Annual Operation and Maintenance expense $87,082
  - o Annual Property taxes $61,920
  - o Annual Income Taxes $94,787
  - o Debt Equity ratio 57/43
  - o Debt cost 7.83%
  - o Equity return 10.25%
  - o Fuel 2.3%
  - o Estimated toll without fuel (2007) $0.64 Cdn/mcf
  - o Estimated fuel component (2007) $0.15 Cdn/mcf[39]

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[36] TCPL Compressor Station 41, south of Winnipeg, Manitoba. Prairies Throughput splits with approximately 35 percent of flow directed south to Emerson export point and 65 percent directed to Northern Ontario mainline.
[37] TransCanada Corporation, Consolidated Financial Statements, Note 4 Plant, Property and Equipment, February 2006.
[38] TransCanada Corporation, Consolidated Financial Statements, Notes on Consolidated Statements, February 2006.
[39] Assuming $6.50 Cdn/ mcf.

Figure 3.40
TCPL Northern Ontario Mainline:
Winnipeg, Manitoba to Southern Ontario Delivery Area
Base Case

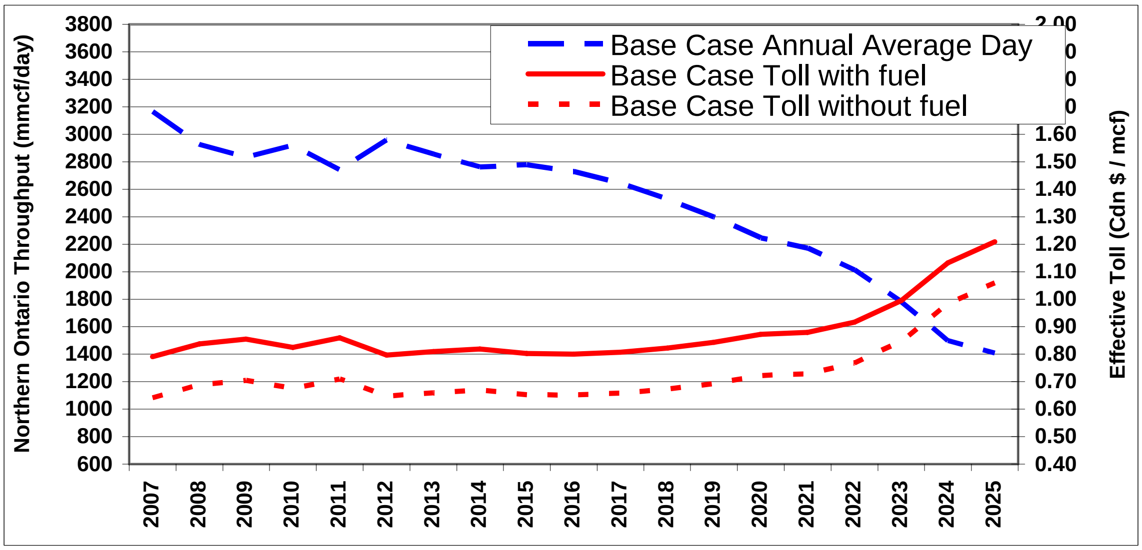


Figure 3.41
TCPL Northern Ontario Mainline:
Winnipeg, Manitoba to Southern Ontario Delivery Area
Base Case plus Incremental Flow Comparison

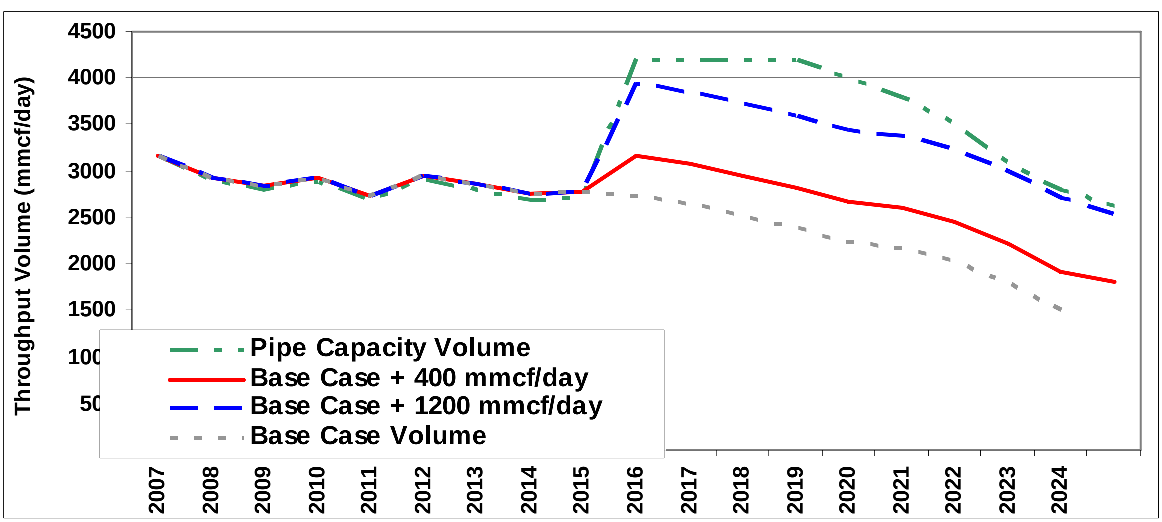
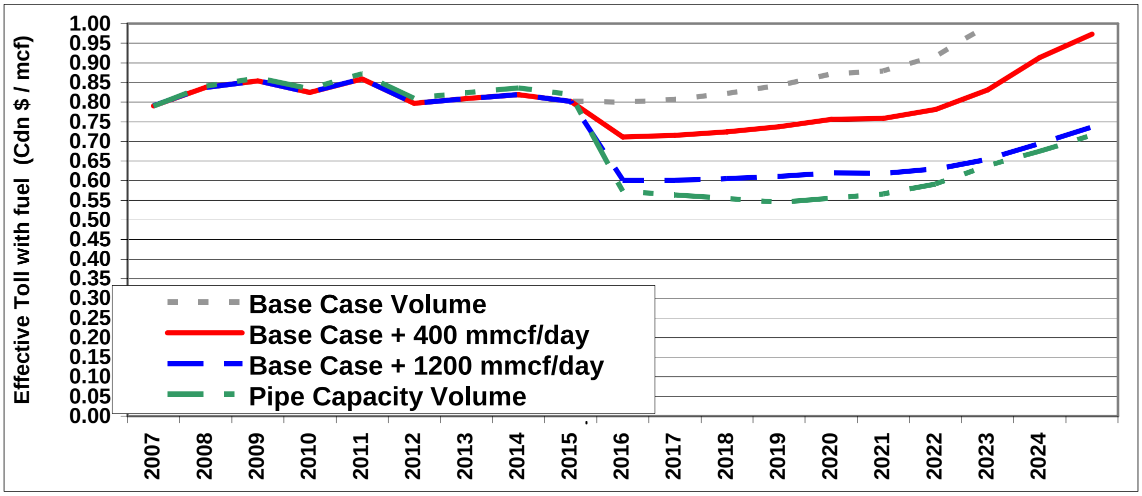


Figure 3.42
TCPL Northern Ontario Mainline:
Winnipeg, Manitoba to Southern Ontario Delivery Area
Base Case plus Incremental Toll Comparison

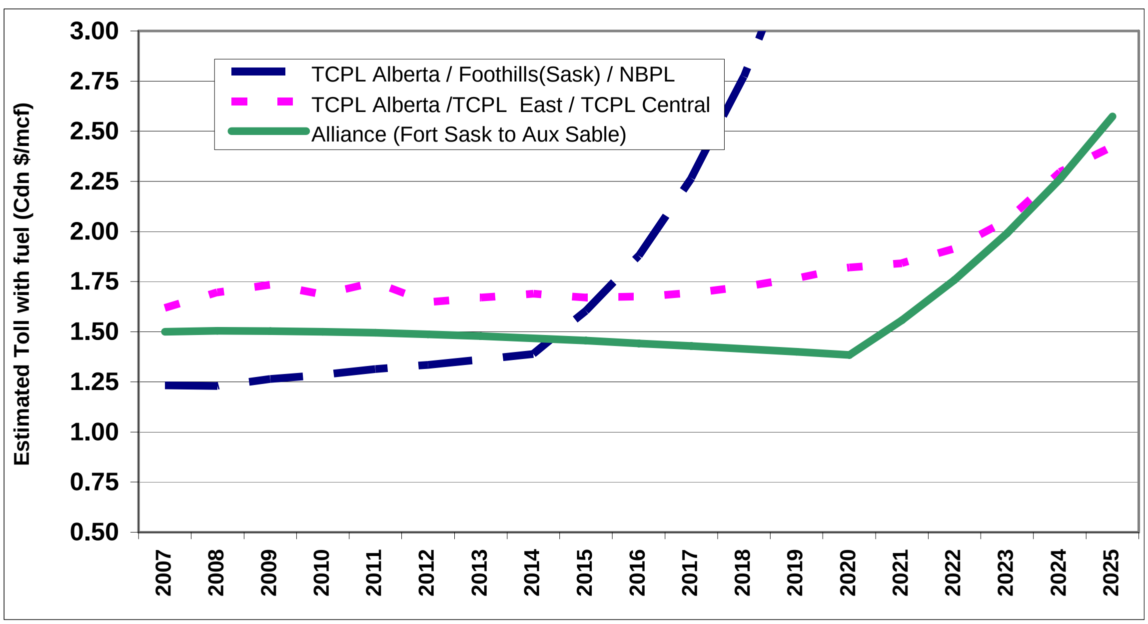


CHAPTER 4
CONCLUSIONS

1. The estimated cost of constructing the Mackenzie Valley Pipeline from the exit of the Inuvik gas processing plant to the Alberta Northwest Territories (gas pipeline only) would be $7.8 billion (2006 Canadian dollars). Based on a receipt volume of 1,230 mmcf/day at Inuvik, Northwest Territories, the transportation toll for the Inuvik volumes would be $2.28 Cdn/mcf along with a fuel charge of $0.16 Cdn/mcf based on a fuel price of $6.50 Cdn/mcf.

2. The estimated cost of constructing the Alaska Highway pipeline from Prudhoe Bay, Alaska to Boundary Lake, Alberta would be $30.9 billion (2006 Canadian dollars). Based on a receipt volume of 4635 mmcf/day at Prudhoe Bay, the transportation toll for the Alaskan volumes would be $2.49 Cdn/mcf along with a fuel charge of $0.19 Cdn/mcf based on a fuel price of $6.50 Cdn/mcf.

3. The estimated tolls for the Alliance (Alberta to Chicago), TCPL East (TCPL Alberta to Toronto) and Northern Border (TCPL Alberta to Chicago) pipelines using the assumed base case flows are as follows:



4. The estimated cost of expanding the Alliance Pipeline system to handle Alaska Gas volumes based on the scenarios assumed in this study are as follows:

Scenario	Volume	Boundary Lake to Fort Saskatchewan	Fort Saskatchewan to US Border	US Border to Aux Sable	Total
		million Cdn $	million Cdn $	million Cdn $	million Cdn $
3	1890 mmcf/day	$1,609	$2,465	$3,450	$7,524
3A	2730 mmcf/day	$2,047	$3,358	$4,783	$10,188
4	4500 mmcf/day	$2,595	$4,579	$6,470	$13,644

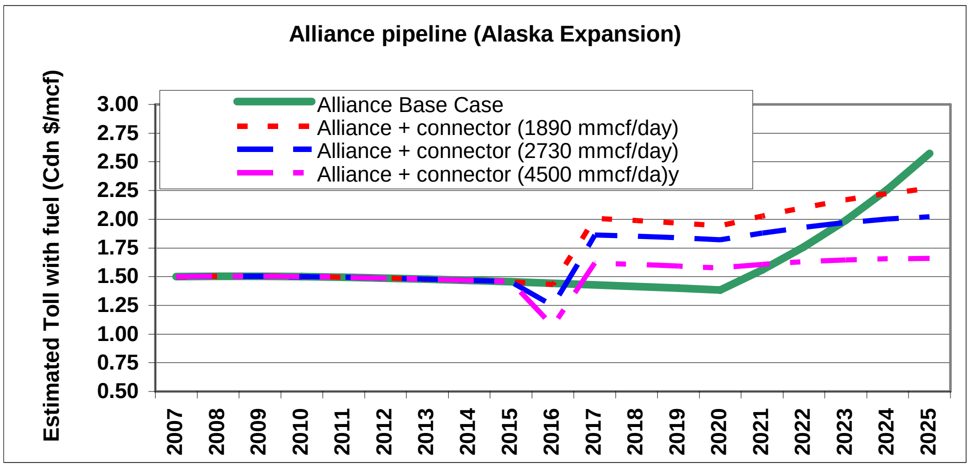
5. The estimated cost of expanding the TCPL System to handle Alaskan gas volumes based on the scenarios assumed in this study are as follows:

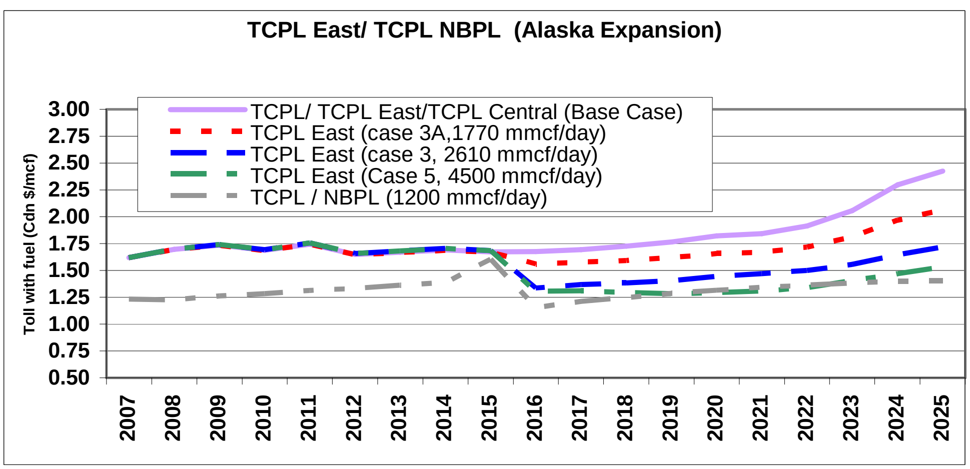
Scenario	Volume	TCPL Alberta	Northern Border	TCPL East	Total
		million Cdn $	million Cdn $	million Cdn $	million Cdn $
3A	1770 mmcf/day	$1,136	$0	$0	$1,136
3	2610 mmcf/day	$1,471	$0	$0	$1,471
5	4500 mmcf/day	$1,789	$0	$0	$1,789

6. Expansion of facilities downstream of Boundary Lake, Alberta at the same point in time where the Alaska Highway pipeline is being constructed could result in an elevated “hot” market for materials and labour. Comparing the size of the expansion (pipe and compression) required on the Alliance and TCPL systems, and understanding that construction would overlap the Alaska Highway construction, there exists a strong potential for increased cost estimates and the potential for project cost overruns. This comparison would conclude that the expansion of the TCPL system would offer less of an impact on the construction costs for both projects because of fewer expansion facilities required to permit the transportation of Alaskan gas to market. Both TCPL Alberta and Alliance could construct and absorb some of the facilities into their existing operations prior to the start of construction of the Alaska Highway pipeline but the carrying costs for the TCPL Alberta system would be much less than that for the Alliance pipeline.

7. The size of the investment that is required to expand the Alliance pipeline to handle the incremental Alaska volumes is such that long term contractual commitments will be required while utilizing the existing spare capacity on the TCPL Alberta system coupled with minimal facility additions would require significantly less commitments.

8. Based on the scenarios that were investigated in this study, the variance in tolls for the Alliance pipeline would either increase by five cents per mcf (scenario 3A) or decrease by fifteen cents per mcf (scenario 4). The increase in toll is primarily due to the escalated costs countering the economies of scale that are normally envisaged by a pipeline expansion. The addition of the connector pipeline from Boundary Lake Alberta to Fort Saskatchewan would add an additional thirty to forty cents per mcf to the Alaska gas transportation toll depending on the flow volume. By comparison, the combined toll for the TCPL Alberta, TCPL East and TCPL Central pipeline systems would see a reduced toll of between five cents (scenario 3) and twenty five cents (scenario 5). In this case the utilization of the spare capacity in the existing pipeline system overshadows the escalated costs for the incremental facilities.





It has been assumed that a minimum volume of 1,200 mmcf/day of Alaska gas would be directed to the Northern Border pipeline which results in the toll on this pipeline remaining relatively constant at $1.25 to $1.35 per mcf (including the TCPL Alberta toll) over the forecast period. In total, utilizing the spare capacity on the TCPL Alberta system and the associated connector pipelines coupled with the minimal new facility requirement to transport the Alaska gas volumes results in a twenty to thirty cent per mcf toll saving for the Alaskan gas shippers when compared to expanding the Alliance pipeline system. This saving would be realized by not only the Alaskan gas shippers but also the existing shippers that transport gas from British Columbia and Alberta to Chicago and eastern Canada.

9. Utilizing the existing infrastructure of the TCPL Alberta pipeline system and the connections with the Gas Transmission Northwest (GTN), Northern Border (NBPL), Iroquois, Empire and TCPL East pipeline systems provide the Alaskan Gas shippers access to multiple markets in the Pacific Northwest, California, eastern Canada, Chicago and the North East United States. It is difficult to quantify the value of access to multiple markets but these connections would permit shippers to optimize flow direction and market deliveries and ultimately product value.

   Scenario 5 indicated that the volume arriving at the Empress/McNeill border points would exceed the downstream take away capacity for a four year period. This comment is based on the assumption that none of the 4,500 mmcf/day of incremental gas would move on the GTN system towards the Pacific Northwest and California. Directing a modest amount of gas (100-300 mmcf/day) to the GTN system would permit the TCPL East and Northern Border to handle the remaining volume within their respective capacity limits. Any delay in the construction of the Alaska gas pipeline would reduce the incremental facilities and the Empress/McNeill border points would be capable of handling the total incremental volume.

10. The introduction of a large incremental volume (4,500 mmcf/day) to the Chicago market could negatively impact the gas price in that market unless incremental take away capacity to downstream markets is available or constructed. The TCPL East with its connections to the Iroquois, Empire and Portland Natural Gas pipeline systems and the Northern Border pipeline have the ability to transport incremental volumes to eastern Canada, New England, and the Mid Atlantic in addition to the Mid Continent markets. Incremental facilities may be required on some of these pipelines but the reduced tolls on the TCPL system as a result of transporting the incremental volumes would increase the net back value of gas entering these markets for all shippers

11. Deliveries to the Dawn hub by way of the TCPL mainline system have historically received a higher market price than the Chicago market. Connection to the Chicago and the Dawn markets by means of the NBPL and TCPL East pipelines would permit optimization of market deliveries to maximize producer net back value.

12. The Foothills Saskatchewan pipeline segment could face increasing tolls as a result of declining export volumes available at the McNeill border point. The addition of a minimum of 1,200 mmcf/day of Alaska Gas would permit the rolled in toll on the Foothills Saskatchewan pipeline to return to the current toll level of between fourteen and seventeen cents per mcf.

13. The Northern Border pipeline system could also face increasing tolls as a result of declining export volumes available at the McNeill border point.. The addition of an incremental volume of 1200 mmcf/day would permit the rolled in toll on the Northern Border pipeline to return to the current toll level of between seventy and eighty cents per mcf including fuel.

14. Assuming the delivery to the Foothills Saskatchewan pipeline is 1,200 mmcf/day for cases 3 and 3A, the incremental volume for the TCPL East pipeline would be 430 mmcf/day and 1,206 mmcf/day, respectively. For scenario 5 the transportation of Alaska Gas would be handled by both NBPL and TCPL East with each pipeline operating at capacity.

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APPENDIX A

SCENARIOS FOR TRANSPORTATION OF ALASKA GAS

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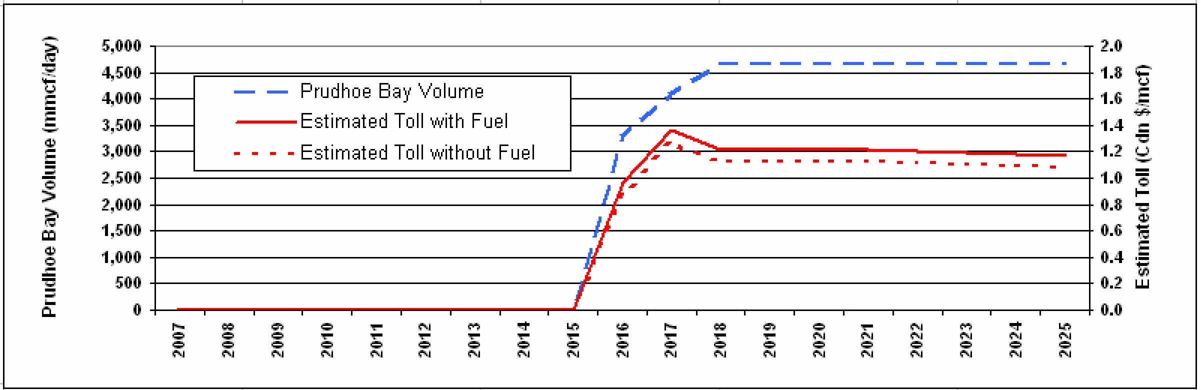
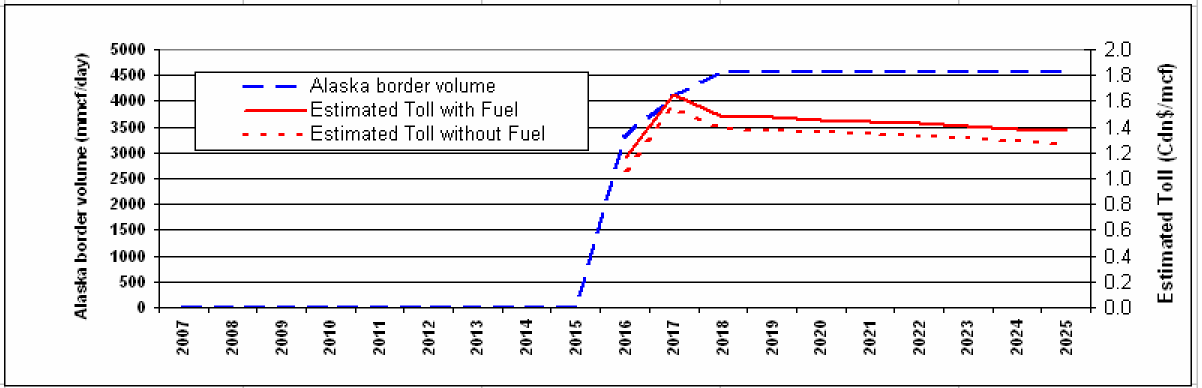
WCSB PIPELINE STUDY : Scenarios forTransportation of Alaska Gas

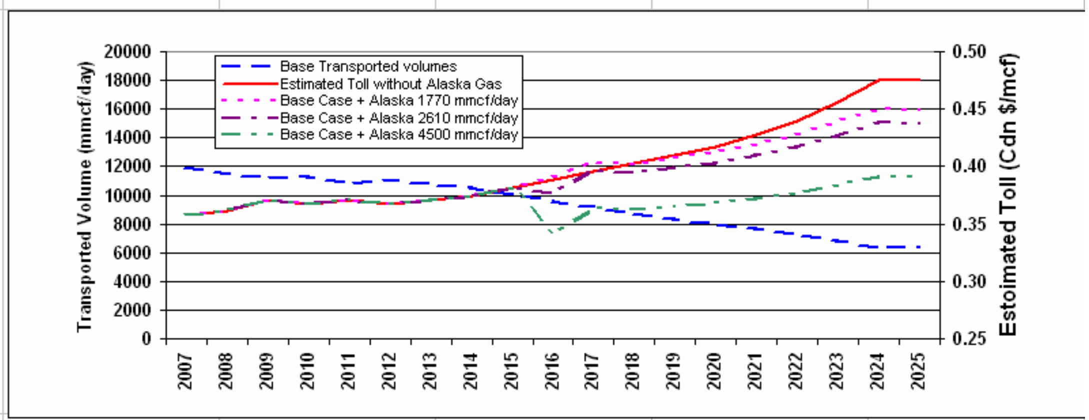
			Scenario # 2	Scenario # 3	Scenario # 3A	Scenario # 4	Scenario # 5
			0% to Alliance 100% to TCPL	40% to Alliance 60% to TCPL	60% to Alliance 40% to TCPL	100% to Alliance 0% to TCPL	0% to Alliance 100% to TCPL
Prudhoe Bay to Yukon Border						NOTE : Total Alaska volume delivered to Chicago/Dawn	NOTE : Total Alaska volume delivered to Chicago
	Pipeline		745 miles 48 inch	745 miles 48 inch	745 miles 48 inch	745 miles 48 inch	745 miles 48 inch
	Compression		1 stn (5 x 16 mw)	1 stn (5 x 16 mw)	1 stn (5 x 16 mw)	1 stn (5 x 16 mw)	1 stn (5 x 16 mw)
	Compression		6 stns (2 x 23 mw)	6 stns (2 x 23 mw)	6 stns (2 x 23 mw)	6 stns (2 x 23 mw)	6 stns (2 x 23 mw)
	Inlet Flow	mmcf/day	4635	4635	4635	4635	4635
	Exit Flow	mmcf/day	4570	4570	4570	4570	4570
	Fuel	mmcf/day	65	65	65	65	65
	Pipeline Cost	1000 cdn $	$11,854,000	$11,854,000	$11,854,000	$11,854,000	$11,854,000
	Compression Cost	1000 cdn $	$2,637,000	$2,637,000	$2,637,000	$2,637,000	$2,637,000
	Total Cost	1000 cdn $	$14,491,000	$14,491,000	$14,491,000	$14,491,000	$14,491,000



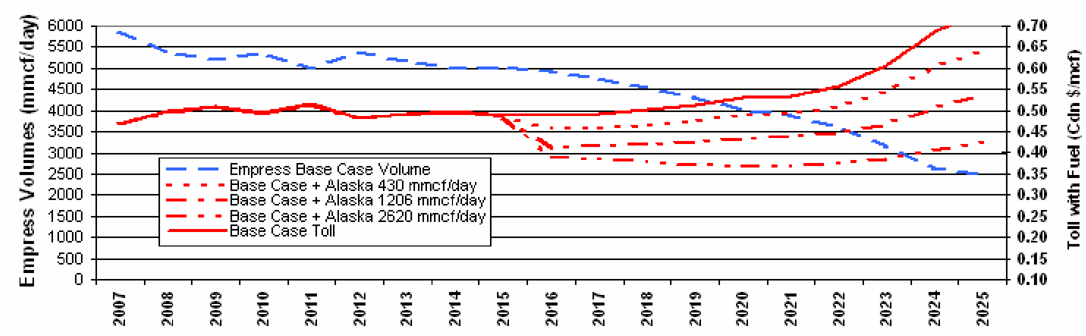
				Scenario # 2	Scenario # 3	Scenario # 3A	Scenario # 4	Scenario # 5
				0% to Alliance 100% to TCPL	40% to Alliance 60% to TCPL	60% to Alliance 40% to TCPL	100% to Alliance 0% to TCPL	0% to Alliance 100% to TCPL
Yukon Border to BC/AB Border								
	Pipeline			940 miles 48 inch	940 miles 48 inch	940 miles 48 inch	940 miles 48 inch	940 miles 48 inch
	Compression			6 stns (2 x 23 mw)	6 stns (2 x 23 mw)	6 stns (2 x 23 mw)	6 stns (2 x 23 mw)	6 stns (2 x 23 mw)
	Compression							
	Inlet Flow	mmcf/day		4570	4570	4570	4570	4570
	Exit Flow	mmcf/day		4500	4500	4500	4500	4500
	Fuel	mmcf/day		70	70	70	70	70
	Pipeline Cost	1000 cdn $		$14,957,000	$14,957,000	$14,957,000	$14,957,000	$14,957,000
	Compression Cost	1000 cdn $		$1,440,000	$1,440,000	$1,440,000	$1,440,000	$1,440,000
	Total Cost	1000 cdn $		$16,397,000	$16,397,000	$16,397,000	$16,397,000	$16,397,000

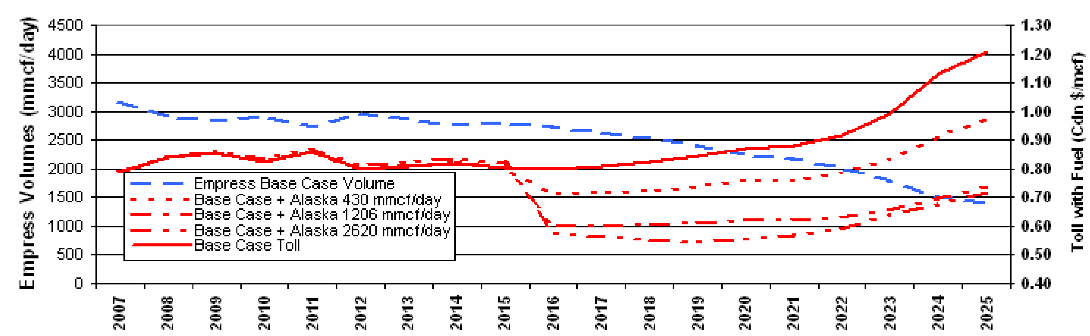


				Scenario # 2	Scenario # 3	Scenario # 3A	Scenario # 4	Scenario # 5
				0% to Alliance 100% to TCPL	40% to Alliance 60% to TCPL	60% to Alliance 40% to TCPL	100% to Alliance 0% to TCPL	0% to Alliance 100% to TCPL
TCPL Alberta								
	Pipeline			105 miles 30 inch	107 miles 30 inch	68 miles 30 inch	no exp	105 miles 30 inch
	Pipeline			40 miles 42 inch	40 miles 42 inch	40 miles 42 inch	no exp	40 miles 42 inch
	Pipeline			83 miles 36 inch			no exp	83 miles 36 inch
	Compression			1 new 23 mw (Wembley)	1 new 21 mw (Wembley)	1 new 16 mw (Wembley)	no exp	1 new 23 mw (Wembley)
	Compression			1 x 16 mw additions	1 x 16 mw additions		no exp	1 x 16 mw additions
	Compression			1 new 16 mw (Swartz Lat)	1 new 21mw (Swartz Lat)		no exp	1 new 16 mw (Swartz Lat)
	Pipeline	NCC		275 miles 36 inch	275 miles 36 inch	250 miles 36 inch	no exp	275 miles 36 inch
	Compression	NCC		2 x 23 megawatt expansion	2 x 23 megawatt station	1 x 23 megawatt station	no exp	2 x 23 megawatt expansion
	Compression	NCC		1 x 23 megawatt station				1 x 23 megawatt station
	AB Receipts	mmcf/day	2018	11200	11200	11200	11200	11200
	BC Imports	mmcf/day	2018	410	410	410	410	410
	Inlet Flow	mmcf/day	Alaska	4500	2610	1770	0	4500
	TCPL(Empress)	mmcf/day	Base	4340	2480	1680	0	4340
	NBPL (McNeill)	mmcf/day	Base	305	305	305	0	305
	Pipeline Cost	1000 cdn $		$1,450,442	$1,209,607	$1,042,029	$0	$1,450,442
	Compression Cost	1000 cdn $		$339,034	$262,206	$94,528	$0	$339,034
	Total Cost	1000 cdn $		$1,789,476	$1,471,813	$1,136,557	$0	$1,789,476

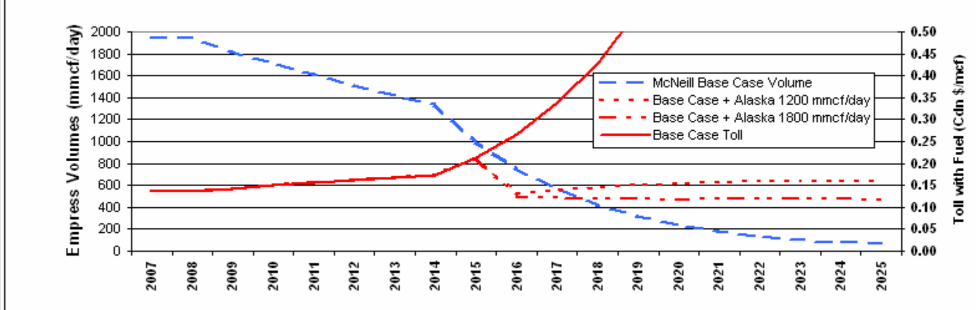


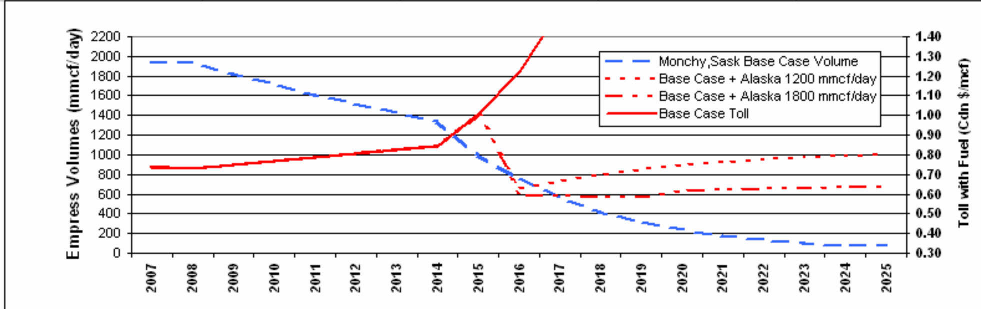
Empress to Emerson								
	Pipeline			no exp	no exp	no exp	no exp	no exp
	Compression			no exp	no exp	no exp	no exp	no exp
	Compression			no exp	no exp	no exp	no exp	no exp
	TCPL(Empress)	mmcf/day	Base	4500	4500	4500	4500	4500
	TCPL(Empress)	mmcf/day	Alaska	1737	1860	1680	0	2420
	TCPL(Empress)	mmcf/day	Total	6237	6360	6180	4500	6920
	Pipeline Cost	1000 cdn $		0	0	0	0	0
	Compression Cost	1000 cdn $		0	0	0	0	0
	Total Cost	1000 cdn $		0	0	0	0	0



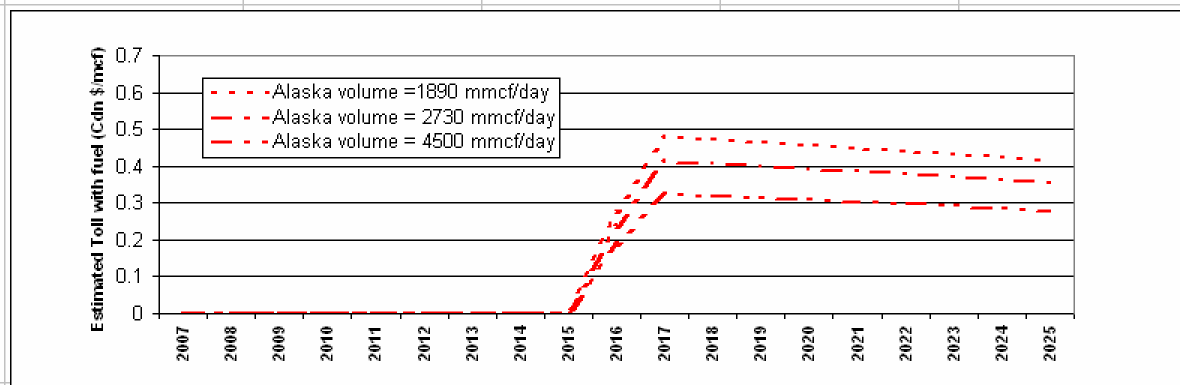


				Scenario # 2	Scenario # 3	Scenario # 3A	Scenario # 4	Scenario # 5
				0% to Alliance 100% to TCPL	40% to Alliance 60% to TCPL	60% to Alliance 40% to TCPL	100% to Alliance 0% to TCPL	0% to Alliance 100% to TCPL
Northern Border to Chicago								
	Pipeline			no exp	no exp	no exp	no exp	no exp
	Compression			no exp	no exp	no exp	no exp	no exp
	Compression			no exp	no exp	no exp	no exp	no exp
	Inlet Flow	mmcf/day	base	305	305	305	305	305
	Inlet Flow	mmcf/day	Alaska	1495	1475	0	0	1855
	Inlet Flow	mmcf/day	Total	1800	1780	305	305	2160
	Fuel	mmcf/day						
	Exit flow	mmcf/day						
	Pipeline Cost	1000 cdn $		$0	$0	$0	$0	$0
	Compression Cost	1000 cdn $		$0	$0	$0	$0	$0
	Total Cost	1000 cdn $		$0	$0	$0	$0	$0

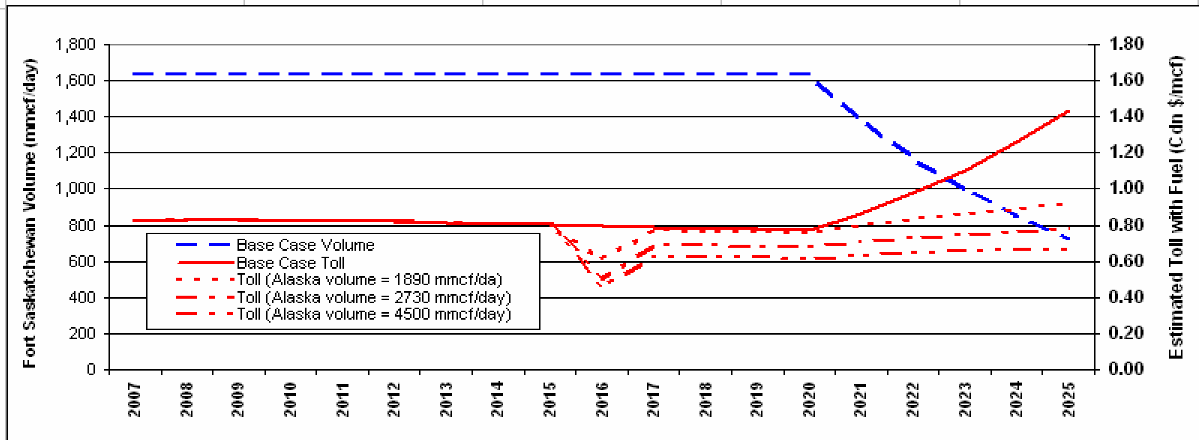




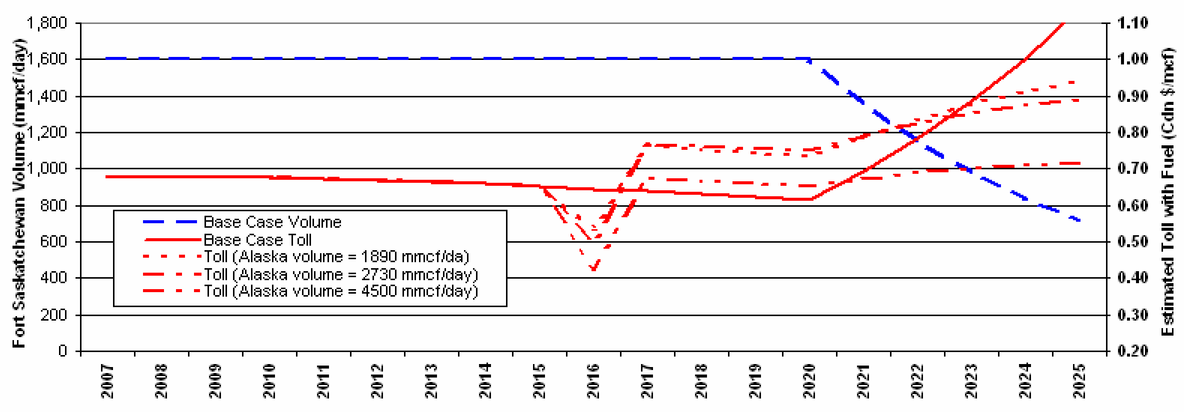
				Scenario # 2	Scenario # 3	Scenario # 3A	Scenario # 4	Scenario # 5
				0% to Alliance 100% to TCPL	40% to Alliance 60% to TCPL	60% to Alliance 40% to TCPL	100% to Alliance 0% to TCPL	0% to Alliance 100% to TCPL
BC/AB Border to Fort Sask								
	Pipeline			no exp	355 miles 36 inch	355 miles 42 inch	355 miles 48 inch	no exp
	Compression			no exp	1 stn (1 x 16 mw)	1 stn (1 x 21 mw)	1 stn (2 x 23 mw)	no exp
	Compression			no exp	2 stns (1 x 16 mw)	2 stns (1 x 21 mw)	2 stns (2 x 23 mw)	no exp
	Inlet Flow	mmcf/day	Alaska		1890	2730	4500	
	Fuel	mmcf/day	Alaska		12	15	27	
	Exit Flow	mmcf/day	Alaska		1878	2715	4473	
	Pipeline Cost	1000 cdn $			$1,467,010	$1,871,679	$2,314,899	
	Compression Cost	1000 cdn $			$142,526	$176,053	$280,897	
	Total Cost	1000 cdn $			$1,609,536	$2,047,732	$2,595,796	



				Scenario # 2	Scenario # 3	Scenario # 3A	Scenario # 4	Scenario # 5
				0% to Alliance 100% to TCPL	40% to Alliance 60% to TCPL	60% to Alliance 40% to TCPL	100% to Alliance 0% to TCPL	0% to Alliance 100% to TCPL
Fort Sask to CAN/US Border								
	Pipeline			no exp	616 miles 36 inch	616 miles 36 inch	616 miles 48 inch	no exp
	Compression			no exp	5 stns (1 x 30 mw)	1 stn (2 x 23 mw)	5 stn (2 x 30 mw)	no exp
	Compression			no exp		4 stns (2 x 30 mw)	5 stns (1 x 37 mw)	no exp
	Compression					5 stns (1 x 33 mw)		
	Inlet Flow	mmcf/day	Base		1630	1630	1630	
	Inlet Flow	mmcf/day	Alaska		1871	2715	4465	
	Fuel	mmcf/day			41	78	84	
	Exit Flow	mmcf/day			3460	4267	6011	
	Pipeline Cost	1000 cdn $			$2,100,000	$2,100,000	$3,237,958	
	Compression Cost	1000 cdn $			$524,839	$1,257,000	$1,341,703	
	Total Cost	1000 cdn $			$2,624,839	$3,357,000	$4,579,661	



				Scenario # 2	Scenario # 3	Scenario # 3A	Scenario # 4	Scenario # 5
				0% to Alliance 100% to TCPL	40% to Alliance 60% to TCPL	60% to Alliance 40% to TCPL	100% to Alliance 0% to TCPL	0% to Alliance 100% to TCPL
CAN/US Border to Aux Sable								
	Pipeline			no exp	883 miles 36 inch	883 miles 36 inch	883 miles 48 inch	no exp
	Compression			no exp	3 stns (1 x 30 mw)	7 stn (2 x 30 mw)	7 stn (2 x 30 mw)	no exp
	Compression			no exp	4 stns (1 x 23 mw)	5 stns (1 x 30 mw)	2 stns (1 x 37 mw)	no exp
	Compression					2 stns (1 x 33 mw)	5 stns (1 x 33 mw)	
	Inlet Flow	mmcf/day	Base		1604	1604	1604	
	Inlet Flow	mmcf/day	Alaska		1856	2656	4406	
	Fuel	mmcf/day			54	103	115	
	Exit Flow	mmcf/day			3406	4157	5895	
	Pipeline Cost	1000 cdn $			$3,011,000	$3,011,000	$4,641,423	
	Compression Cost	1000 cdn $			$650,058	$1,772,019	$1,828,912	
	Total Cost	1000 cdn $			$3,661,058	$4,783,019	$6,470,335	



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