HEAVY OIL IN SASKATCHEWAN: BUILDING ON STRENGTHS

A Technical Report Prepared by
Saskatchewan Energy and Mines

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SECURITY AND PROSPERITY
THROUGH RESPONSIBLE
ENERGY DEVELOPMENT

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I. INTRODUCTION

Saskatchewan has vast heavy oil reserves located in the west-central part of the province. About 90 per cent of the 2.8 billion cubic meters or 17.6 billion barrels of heavy oil is located in the Lloydminster area, with the remainder located in the Kindersley district just south of the Lloydminster area.

The history of oil production in Saskatchewan predates the discovery of Leduc in Alberta in 1947. The first oil well in the province was drilled in 1945 near Lloydminster. The well produced 14° API crude at a rate of 33 barrels per day (B/D). Since this historical discovery, the production of heavy oil has increased gradually, and in 1992 the province produced 79 thousand B/D.

In many years, especially the more recent ones, the production pattern has not been matched with investment trends. Since 1982/83, the relative proportion of heavy oil drilling has declined significantly. This study is designed to analyze trends in heavy oil investment, production, economics and markets. The study examines both the past and existing trends and looks at prospects for the future. The focus of the study is to determine the causes for a lack of investment, especially long term, in the heavy oil sector and evaluate the opportunities and constraints for long term sustainability of this industry.

The issues are studied under six chapters. Chapter 2 provides industry background with the key resource characteristics, reserve potential, and production and investment trends.

Chapter 3 provides a detailed analysis of the heavy oil markets. It looks at markets both in Canada and in the United States and examines possible future trends. It also examines refinery capacities and recent developments therein and how these developments will affect heavy oil requirements.

Chapter 4 details the logistics of shipping heavy oil from producing areas to various markets.

Chapter 5 establishes the economics of heavy oil production in Saskatchewan. It considers all relevant cost components including the various taxes and royalties and derives netbacks to the producers.

Chapter 6 discusses issues of relevance affecting the heavy oil industry including the thrust of environmental safeguards.

Finally, Chapter 7 presents a summary of trends and issues discussed in the report. An analysis of these trends is critical since it sets the background for policies that will shape the future of the heavy oil sector and ensure its sustainability in the long term.

II. THE RESOURCE, ITS PRODUCTION & TECHNOLOGICAL DEVELOPMENTS

A. SASKATCHEWAN HEAVY OIL CHARACTERISTICS

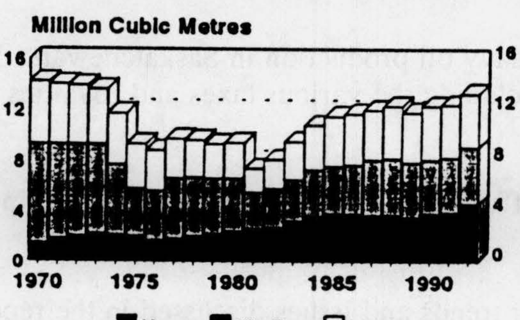
Saskatchewan heavy oil accumulation areas are located near the towns of Lloydminster and Kindersley in the west-central portion of the province. (See attached Map) In the Lloydminster area, heavy oil occurs mainly in the upper part of Mannville Group of sedimentary rocks. In the Kindersley area heavy oil is primarily located in the Bakken Formation of Mississippian age (see Appendix; Figure 26). The currently established

FIGURE I

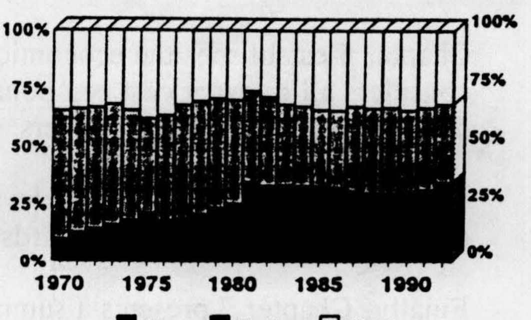
HEAVY OIL RESERVOIR CHARACTERISTICS

	Lloydminster	Kindersley
Porosity	>30%	24 - 31%
Net Pay	2 - 10 m	4 - 11 m
Oil Gravity	12 - 18 °API	12 - 17 °API
Producing Depth	450 - 750 m³	740 - 875 m³
Oil-In-Place	1.5 Billion m³	

SASKATCHEWAN CRUDE OIL PRODUCTION



SASKATCHEWAN OIL PRODUCTION BY CRUDE TYPE



Source: Saskatchewan Energy & Mines

total oil-in-place with economic potential in the Mannville and Bakken Formations has been estimated at 2.8 billion cubic meters or 17.6 billion barrels (new pool developments may add substantially to this value in the future). Conventional primary production techniques can be expected to recover in the order of 5 per cent of the oil-in-place. However, the estimated potential for oil recovery using both primary and enhanced recovery techniques may amount to 3,770 million barrels or 600 million cubic meters amounting to just over 20 per cent of the total oil-in-place. (This estimate may be optimistic given the limitations of the existing state of technology.) With ultimate recovery factors substantially larger than those of primary recovery alone, there is potential to produce significant quantities of heavy oil in the future.

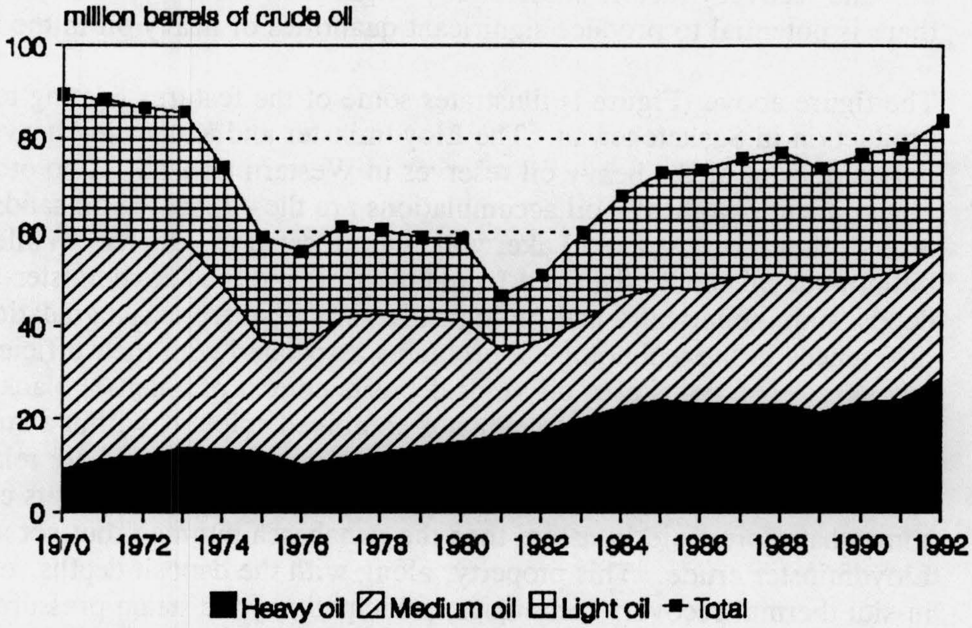
The figure above (Figure I) illustrates some of the features relating to heavy oil production in Saskatchewan. The Lloydminster and Kindersley heavy oil reserves are only a portion of the heavy oil reserves in Western Canada. Two other very large, but non-conventional heavy oil accumulations are the Athabasca oil sands and the very heavy oil deposits at Cold Lake, which are located in Alberta. While the Athabasca bituminous oil sands, the Cold Lake heavy oil and the Lloydminster-type heavy oil deposits are generically and geologically similar, there exists gradational but significant differences in the technological problems associated with their efficient and economic recovery. The Athabasca oil sands deposits consist of a dense, black, viscous, bitumen containing relatively large amounts of combined sulphur, within a largely unconsolidated sand matrix. The deposits currently exploited are relatively close to the surface and are, therefore, surface mined. The Cold Lake deposits contain heavy oil somewhat more fluid in nature than the Athabasca bitumen, but not as light as the Lloydminster crude. This property, along with the deposit depths, results in the use of in-situ thermal recovery techniques, principally cyclic steam pressure.

The Lloydminster and Kindersley area heavy oils offer substantial opportunities in the near term for additions to the supply of liquid hydrocarbon fuels. This is due to the acceptability of the crude to a number of refineries, the ability to use conventional production techniques and the relatively well known resource base. New production techniques are also steadily improving the production economics and resource recovery.

B. THE PRODUCTION

For much of the 1970s and the first half of the 1980s, production of heavy oil increased significantly and at a much faster pace than the other two types of Saskatchewan crude (Figure 2). In 1969, the province produced 8 million barrels of heavy oil, accounting for 9 per cent of the total provincial production of oil. In 1985, production reached 24 million barrels. Since 1986, production has fluctuated from year to year. In 1992, the province produced 28.8 million barrels representing 34 per cent of total production. The production of medium and light oil has declined for much of this time period, both in absolute terms and in its share of total production. In 1969, medium and light oil production accounted for 54 per cent and 36 per cent of total production as compared to 35 per cent and 34 per cent respectively for medium and light oil in 1988. In 1992 the relative shares of these two crude types were 33.5 per cent and 32 per cent respectively.

FIGURE 2
HISTORICAL PRODUCTION BY TYPE OF CRUDE

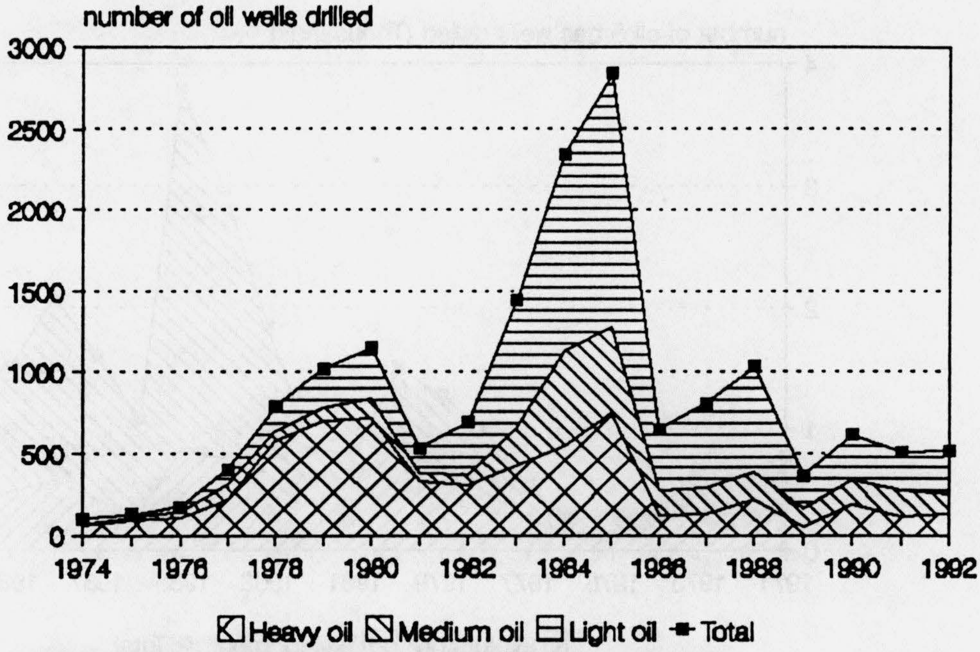


Source: Reservoir Annual, Energy & Mines

Although the production of heavy oil has increased through the last two decades both in absolute and relative terms, investment has declined significantly in relative terms since 1982/83 and, in most years, in absolute terms. In the early 1970s drilling for heavy oil constituted approximately 50 per cent of the total drilling in the province (Figure 3). In 1978 new records were established for heavy oil drilling which accounted for 73 per cent of the total oil well drilling. However, in 1989 only 14 per cent of the total oil well drilling took place in the heavy oil areas. The heavy oil well drilling increased again in 1990, 1991 and 1992, and was respectively 29 per cent, 22 per cent and 25.7 per cent of the provincial share. Similar trends are evident in 1993 as well. To the end of July, 1993, 28% of the total oil wells drilled were for heavy oil. Overall, medium and light oil well drilling has increased since 1982 and 1983.

It is important to note that the per barrel cost of heavy oil operations is significantly higher than similar costs for light and medium oils. For example, the operating cost for Kindersley heavy is 50 per cent - 100 per cent higher than the medium/light crudes. Costs for Lloydminster heavy are 30 per cent - 75 per cent greater than other crudes.

FIGURE 3
HISTORICAL DRILLING BY TYPE OF CRUDE

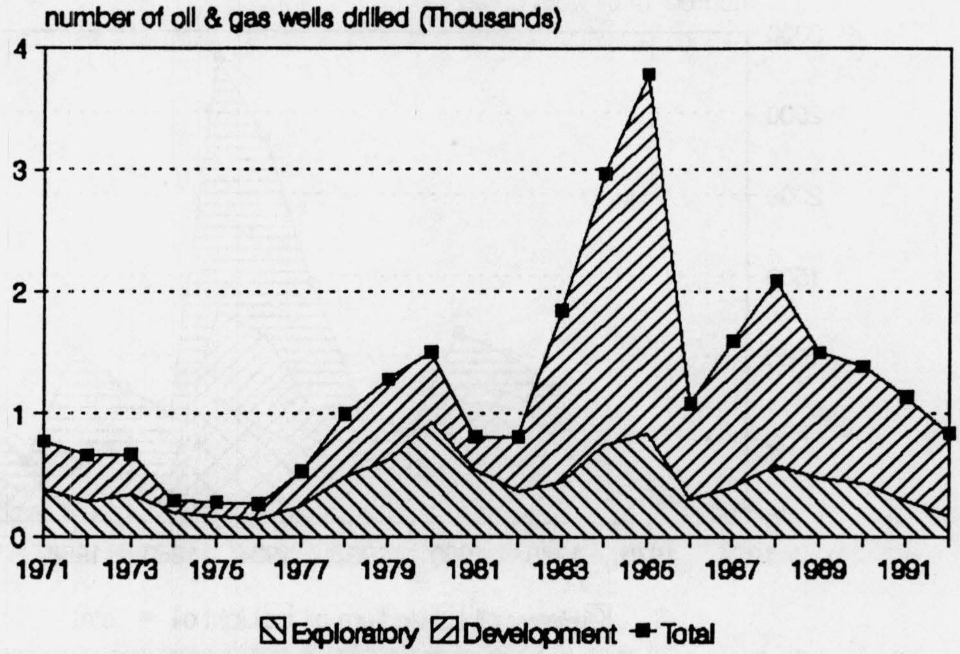


Source: Saskatchewan Energy & Mines (Economic & Fiscal Analysis)

While heavy oil holds the largest potential for development because of immense reserves of oil-in-place, only a small portion of this resource has been established. At the end of 1992, approximately 7.5 per cent of the initial oil-in-place was deemed recoverable as compared to 22 per cent and 18 per cent for medium and light oil respectively.

It is also important to note the change in the composition of drilling in the last two decades. While the relative proportions of exploratory and development drilling varied from year to year, the general trend in the 1970s was an increase in the proportion of exploratory wells (Figure 4). However, since 1981, the proportion of exploratory wells has declined considerably. (Due to a lack of data, it is difficult to analyze individual trends in the three categories of crudes, light, medium and heavy). This trend has taken a toll on the level of established reserves. For heavy oil, the ratio of cumulative production to initial established reserves has increased significantly from 55 per cent in 1981 to 63 per cent in 1992.

FIGURE 4
HISTORICAL DRILLING BY CATEGORY



Source: Mineral Statistics Yearbook, Energy & Mines

The above discussion points to a growing problem in the heavy oil industry. Due to a lack of investment, productive capacity will tend to decline in the long term. In the short term, due to poor economics, shut-ins will occur resulting in under-utilization of the existing capacity. (In this report, shut-ins are described as a ratio of total non-operating wells to total capable wells.) Table 1 exhibits production trends in recent years. Note that production declined continuously between 1986 and 1989, coinciding with the decline in oil prices. Production increased in 1990, 1991 and 1992 due in part to the firming of oil prices resulting from the Gulf War and in part due to the technological changes with horizontal wells becoming more significant in terms of their share in total production.

1989 experienced an alarming level of shut-ins. These shut-ins are largely the result of lower prices and netbacks rather than lack of markets.

TABLE 1
SASKATCHEWAN HEAVY OIL PRODUCTION
(thousand cubic meters)

	1980	1981	1982	1983	1984	1985	1986	
Heavy oil	2380	2604	2723	3209	3581	3834	3722	
% of total oil		25.5	35.2	33.6	33.6	33.2	33.0	31.9
Shut-ins(%)*		28.1	33.3	29.6	27.3	26.8	25.2	40.0

	1987	1988	1989	1990	1991	1992	
Heavy oil	3694	3681	3421	3768	3870	4590	
% of total oil		30.7	30.1	29.2	30.9	31.2	34.4
Shut-ins(%)*		35.0	43.0	48.0	40.0	46.1	54.9

* shut-ins are calculated as a ratio between operating and capable wells.

Source: Energy & Mines

C. TECHNOLOGICAL DEVELOPMENTS IN HEAVY OIL RECOVERY

Under primary production conditions, natural reservoir energy drives the reservoir fluids from the productive zone into the production wellbore. In heavy oil reservoirs in Saskatchewan, there is very little energy available to displace the reservoir fluids, and an artificial lift system must be used to bring the fluid to the surface.

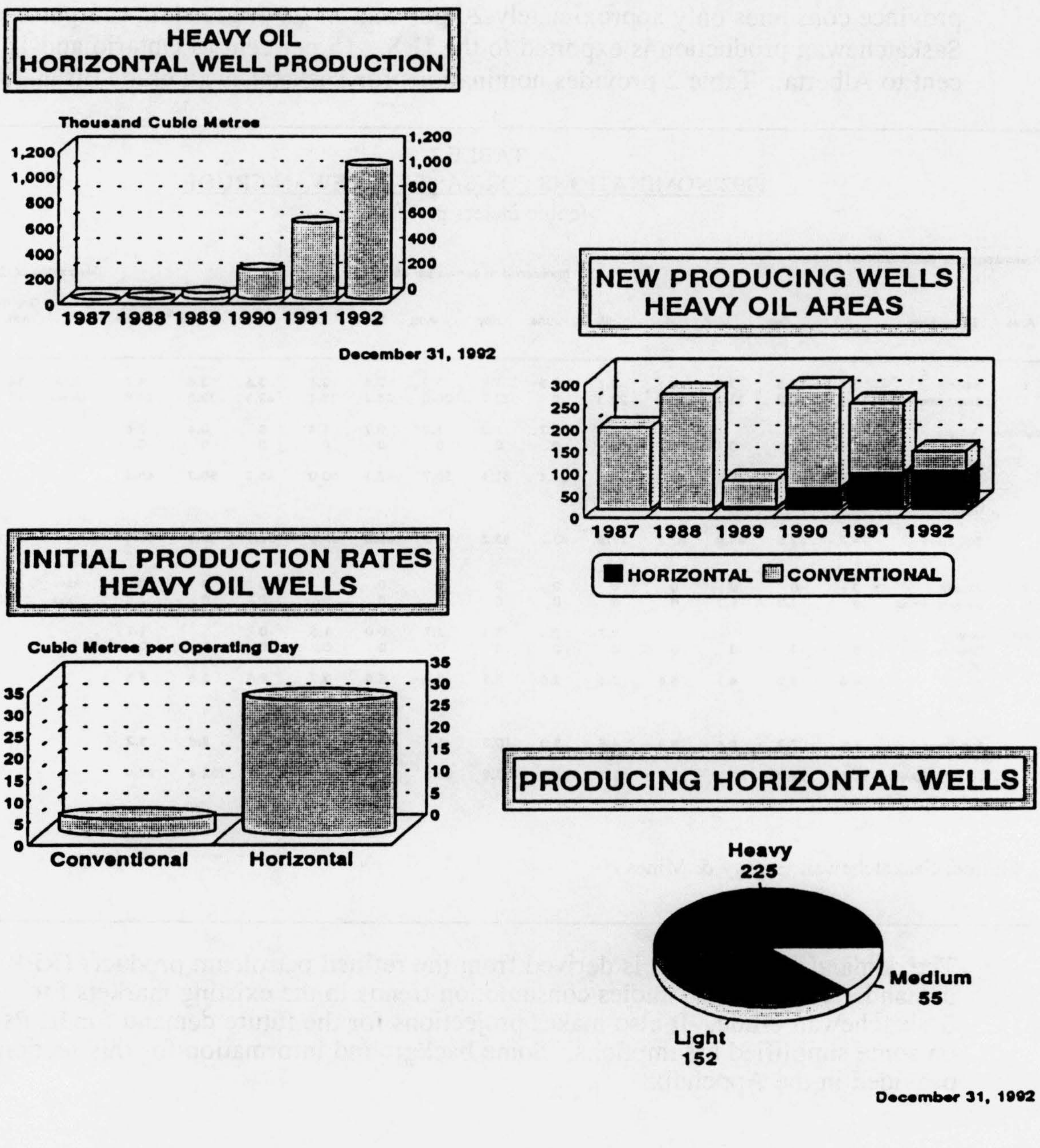
Several thermal enhanced oil recovery (EOR) projects have been initiated in Saskatchewan using conventional vertical well technology. The thermal recovery methods that have been tested include cyclic steam stimulation, steam flooding, and in-situ combustion. By far the most successful thermal technique has been cyclic steam stimulation followed by steamflooding. In Saskatchewan a few thermal EOR projects are in operation using the steam flood method. These include Husky Pikes Peak, Sceptre Tangleflags, Saskoil Plover Lake and Elan Cactus Lake North.

Another new technological development has assisted in increasing extraction from the heavy oil reservoirs. Horizontal well technology, whose purpose is to expose more of the productive reservoir than can be done with a vertical wellbore, is being used increasingly in the heavy oil area. This technology has real opportunities to increase not only production rates but perhaps, more importantly, ultimate recovery. Research is still underway to determine the contribution of horizontal wells to ultimate recovery. There is no doubt, however, that horizontal wells have become significant producers of heavy oil in the province.

In heavy oil reservoirs, horizontal wells have been used to reduce or prevent water or gas coning, increase recovery from low energy reservoirs, and improve the effectiveness of enhanced recovery projects. The impact of horizontal drilling on heavy oil activity in Saskatchewan is evident in Figure 5.

Horizontal well technology is now being used in EOR projects, especially in thermal oil recovery from heavy oil reservoirs using steam. Horizontal wells can be used as injectors or producers, although to date horizontal wells in Saskatchewan have been drilled primarily as producers. The main advantages of the use of horizontal wells are improved sweep efficiency, enhanced producible reserves, and a decrease in the number of wells required for field development. A horizontal well can replace several vertical wells, reducing investment and operating costs. The main disadvantage of horizontal wells is their initial costs, although great strides have been made to bring down the prices of these wells. A most significant example of horizontal wells being used for heavy oil EOR is at Tangleflags North, where horizontal wells are producing large volumes of oil using a vertical steam flood process.

FIGURE 5



Source: Saskatchewan Energy & Mines

III. MARKETS

While Saskatchewan is the second largest producer of crude oil in Canada, it is the fourth-smallest consumer of oil in the nation. It is a net exporter of crude oil. The province consumes only approximately 20 per cent of its production. 55 per cent of Saskatchewan production is exported to the U.S., 15 per cent to Ontario and 10 per cent to Alberta. Table 2 provides nominations for Saskatchewan crude oil in 1992.

TABLE 2

1992 NOMINATIONS FOR SASKATCHEWAN CRUDE

(cubic meters per day)

1992 Nominations for Saskatchewan Crude

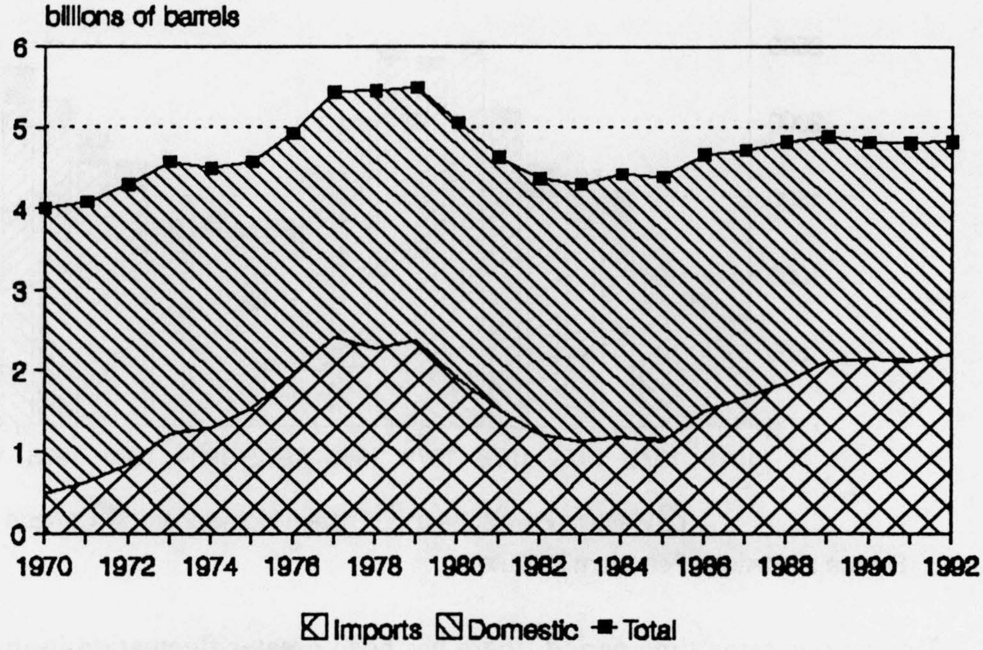
		(thousands of barrels per day)													Description of Crude			
Type Area	Destination	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Daily Average		Gravity API	Density Kg/m3	Sulphur %
Heavy I	Alberta	3.5	3.5	3.5	4.1	3.1	7.9	7.9	7.9	3.8	3.5	3.5	3.6	4.7	Raw	14	972	3.6
	Saskatchewan	19.3	25.3	23.2	22.6	22.3	0	22.6	30.0	36.2	35.1	42.9	39.5	26.6	Blend	22	922	2.9
"Lloydminister"	Ontario						0.7	1.3	1.7	0.7	1.4	0	0.4	0.6				
	Quebec	0	0	0	0	0	0	0	0	0	0	0	0	0				
	USA I																	
	USA II	51.9	38.7	38.2	40.5	52.5	35.1	61.4	50.7	43.1	50.0	46.3	50.3	46.5				
	USA III																	
	USA IV																	
	Sub Total	74.7	67.5	64.9	67.2	77.9	43.7	93.2	90.3	83.8	90.0	92.7	93.8	78.4				
Heavy II	Alberta	0	0	0	0	0	0	0	0	0	0	0	0	0	Raw	14	972	3.0
	Saskatchewan	0	1.3	1.3	0	0	0	0	0	0	0	0	0	2.6	Blend	22	922	2.1
"Kindersley"	Ontario					1.7	2.4	5.1	2.1	0.0	1.5	0		1.1				
	Quebec	0	0	0	0	0	0	0	0	0	0	0	0	0				
	USA I																	
	USA II	4.9	5.9	4.1	5.6	3.5	2.6	5.5	6.5	6.5	3.7	9.0	8.6	5.5				
	USA III																	
	USA IV																	
	Sub Total	4.9	7.2	5.4	5.5	4.6	5.0	10.6	8.6	6.5	5.2	9.0	8.6	9.2				
	TOTAL HEAVY	79.6	74.7	70.3	72.7	82.5	48.7	103.8	98.9	90.3	95.2	101.7	102.4	87.6				

Source: Saskatchewan Energy & Mines

The demand for crude oil is derived from the refined petroleum products (RPP) demand. This chapter studies consumption trends in the existing markets for Saskatchewan crude. It also makes projections for the future demand for RPPs based on some simplified assumptions. Some background information for this section is provided in the Appendix.

A. DEMAND FOR CANADIAN AND SASKATCHEWAN CRUDE OIL IN THE UNITED STATES

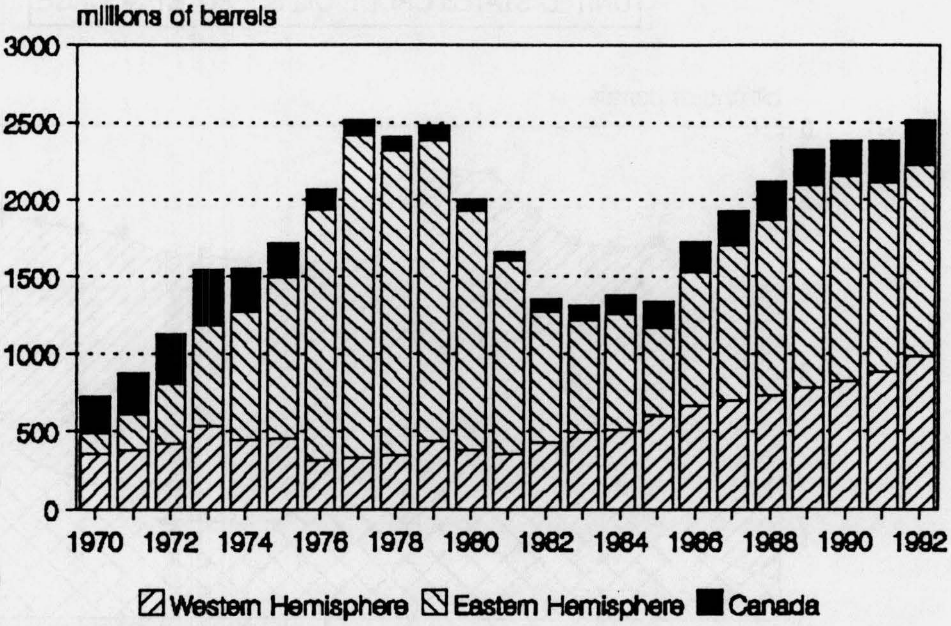
FIGURE 6
UNITED STATES CRUDE OIL SUPPLY BY SOURCE



Source: American Petroleum Institute

The prime export market for Canadian crude oil is the United States. The U.S. refineries have increasingly relied on imports to meet changes in demand. Throughout the 1970s and 1980s there have been large swings in crude oil demand from the U.S. refineries as refined petroleum product demand changed. These large swings were reflected in the demand for imported crude as the supply of the U.S. crude remained fairly steady for much of the time period (Figure 6). However, since 1985, domestic supplies have been dwindling, resulting in increased imports.

FIGURE 7
UNITED STATES CRUDE OIL IMPORTS
BY SOURCE

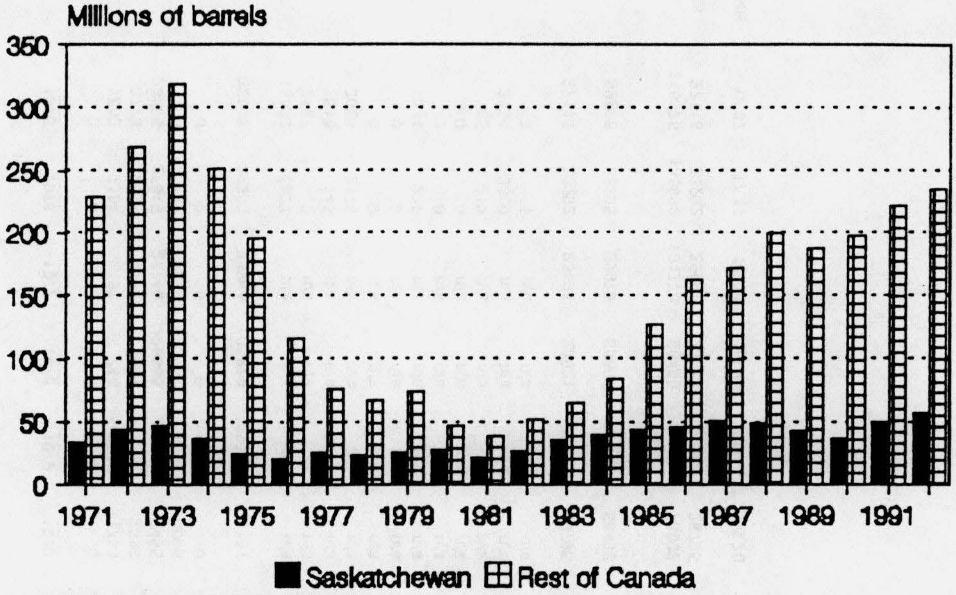


Source : American Petroleum Institute

During this same time period, there has been greater fluctuation in imports from the Eastern Hemisphere (essentially the Middle East) countries. Among the Western Hemisphere countries, Canada was the largest crude oil exporter until 1975. In 1970, Canadian crude represented 70 per cent while Venezuelan crude represented 28 per cent. However, following the introduction of Mexican crude in 1974, Canada's share of imports from Western Hemisphere countries into the U.S. has dwindled, while crude from Mexico and Venezuela has increased. In 1992, Canadian imports represented 30 per cent of the Western Hemisphere imports.

There has been an overall change in the type of crude imported and processed in the U.S. First of all, the decline in the U.S. domestic production has been primarily in sweet crude oil. Second, the increase in imports has come from the heavier crudes such as the Mexican, Venezuelan and the Middle Eastern. On a relative basis, Canada also has reduced its exports of lighter crudes and increased exports of heavier crudes.

FIGURE 8
CANADIAN CRUDE OIL EXPORTS
TO THE U.S.



Source: American Petroleum Institute
Saskatchewan Energy and Mines

Total crude oil exports from Canada to the United States fell dramatically from levels in the late 1970s, although there has been some turnaround since 1982. During the same period, the amount of Saskatchewan crude imported into the United States remained fairly constant, reaching approximately 57 million barrels in 1992 (Figure 8). What has changed dramatically for Saskatchewan exports into the United States are the destination points. In 1971 Saskatchewan exported 33,673,523 barrels to the United States with Minnesota as the largest purchaser of Saskatchewan crude at 29,746,330 barrels (88 per cent). There were 1,967,482 barrels (5.8 per cent) sold to Michigan, 1,022,297 barrels (3.0 per cent) sold to Wisconsin and 831,378 barrels (2.4 per cent) were sold to New York. By 1992, the market shares had changed dramatically. Exports from Saskatchewan to the United States totalled 49,604,897 barrels, of which 15,545,626 barrels (31 per cent) were sold to Illinois, 15,373,892 barrels (31 per cent) were sold to Indiana, 11,690,738 barrels (23 per cent) were sold to Minnesota, 3,045,425 barrels (6 per cent) were sold to Pennsylvania, 2,252,521 barrels (4.5 per cent) were sold to Ohio, and 1,433,652 barrels (3 per cent) were sold to Wisconsin. Sales to Illinois and Indiana, which were insignificant in 1971, now make up a little more than half of all Saskatchewan crude oil exports. Table 3 provides a historical summary of Saskatchewan crude oil deliveries between 1975 - 1992. Note that despite these changing markets, most of Saskatchewan crude exports have remained within PADD II.

TABLE 3
SUMMARY OF SASKATCHEWAN CRUDE OIL DELIVERIES
(barrels)

Destination	1975	1976	1977	1978	1979	1980	1981	1982	1983
Alberta	0	0	0	0	0	0	0	1338	1898
Saskatchewan	1863	2397	2161	746	2589	1753	607	586	1030
Manitoba	3723	2055	1762	1694	2377	2396	2011	936	689
Ontario	26506	27819	27745	29668	20490	17455	15422	14460	11864
Quebec	0	232	2616	3871	7291	10098	7527	7104	8142
Nova Scotia	0	0	0	0	0	0	0	0	1274
Total - Canada	32092	32503	34284	35979	32746	31701	25567	24424	24897
Minnesota (II)	15800	16827	n/a	n/a	n/a	n/a	n/a	n/a	21119
Illinois (II)	3187	0	n/a	n/a	n/a	n/a	n/a	n/a	9318
Indiana (II)	518	145	n/a	n/a	n/a	n/a	n/a	n/a	2501
Wisconsin (II)	3006	2478	n/a	n/a	n/a	n/a	n/a	n/a	974
Pennsylvania (I)	0	0	n/a	n/a	n/a	n/a	n/a	n/a	0
Wyoming (IV)	0	0	n/a	n/a	n/a	n/a	n/a	n/a	0
Michigan (II)	1364	226	n/a	n/a	n/a	n/a	n/a	n/a	357
Ohio (II)	0	0	n/a	n/a	n/a	n/a	n/a	n/a	0
Texas (III)	0	0	n/a	n/a	n/a	n/a	n/a	n/a	0
New York (I)	85	312	n/a	n/a	n/a	n/a	n/a	n/a	638
North Dakota (II)	3154	3300	n/a	n/a	n/a	n/a	n/a	n/a	0
Montana (IV)	3	4	n/a	n/a	n/a	n/a	n/a	n/a	0
Total - USA	27116	23292	25691	23621	25211	26795	21638	26676	34907
Grand Total	59208	55795	59975	59600	57957	58496	47205	51100	59804
Canada - Exports	219175	135690	101778	90490	99081	73002	59904	78041	100142
Saskatchewan - Exports	27116	23292	25691	23621	25211	26795	21638	26676	34907
Sask % of Canada Exports	12.37	17.17	25.24	26.10	25.44	36.70	36.12	34.18	34.86

Destination	1984	1985	1986	1987	1988	1989	1990	1991	1992
Alberta	1607	0	2484	2227	2298	2273	2129	1797	3535
Saskatchewan	1509	4317	5407	3259	3316	5274	8979	8134	10602
Manitoba	0	0	0	0	0	0	0	0	0
Ontario	15119	16749	15794	15726	17035	15230	21241	18245	12990
Quebec	7223	6698	5127	3759	5272	6871	5829	2385	2
Nova Scotia	3178	1241	0	0	0	0	0	0	0
Total - Canada	28636	29005	28812	24971	27921	29649	38178	30561	27128
Minnesota (II)	24743	19218	16475	15224	15452	14888	12366	11691	12651
Illinois (II)	10607	18086	25726	30915	27560	18978	10588	15546	17634
Indiana (II)	3195	3284	1470	2439	2518	2409	7572	15374	18988
Wisconsin (II)	896	1010	975	904	863	888	1424	1434	1717
Pennsylvania (I)	265	382	616	45	1603	2529	4005	3045	2477
Wyoming (IV)	0	0	0	0	925	519	0	0	0
Michigan (II)	200	0	344	10015	0	89	0	0	0
Ohio (II)	0	1146	0	0	51	2124	697	2252	2920
Texas (III)	0	656	0	0	0	0	0	0	0
New York (I)	0	0	0	0	0	0	0	0	0
North Dakota (II)	0	0	0	0	0	0	0	0	0
Montana (IV)	0	0	0	0	0	0	172	264	287
Total - USA	39906	43782	45606	59541	48972	42423	36824	49605	56673
Grand Total	68541	72787	74418	84512	76893	72072	75002	80166	83802
Canada - Exports	124687	170808	208163	221980	249077	230043	220395	270903	291616
Saskatchewan - Exports	39906	43782	45606	59541	48972	42423	36824	49605	56673
Sask % of Canada Exports	32.00	25.63	21.91	26.82	19.66	18.44	16.71	18.31	19.43

Source: Saskatchewan Energy & Mines

PADD is a geographic aggregation of the 50 states and the District of Columbia into five districts, originally designed in 1950 by the Petroleum Administration for Defense for the purposes of administration. These are an outgrowth of the World War II Petroleum Administration for War Districts. A map showing the Petroleum Administration for Defense Districts (PADD) is shown in Figure 9.

Heavier grades of Saskatchewan crude oil have made up the majority of exports to the United States in recent years. Kindersley light and Southeast light, both of which are about 34-36° API only accounted for 42,880 barrels (6817.4 cubic meters) per day in 1992, equivalent to 58 per cent of the total light oil production. Approximately 5,031 barrels of the Kindersley light (768 cubic meters) per day, was shipped to PADD II, while 6,950 barrels (1105 cubic meters) per day of Southeast light was shipped to PADD I and 30,707 barrels (4882 cubic meters) per day was shipped to PADD II. Minimal amounts of light oil, 207 barrels (33 cubic meters) of Kindersley light and 182 barrels (29 cubic meters) of Southeast light was also shipped to PADD IV. Note that this was the first time that Saskatchewan crude was shipped to PADD IV. (It is important to distinguish between Kindersley Light and South East Light. The latter are more sour and compete with the more sour crudes in the U.S. such as the West Texas Sour, and the former are sweeter crudes that compete with West Texas Intermediate.)

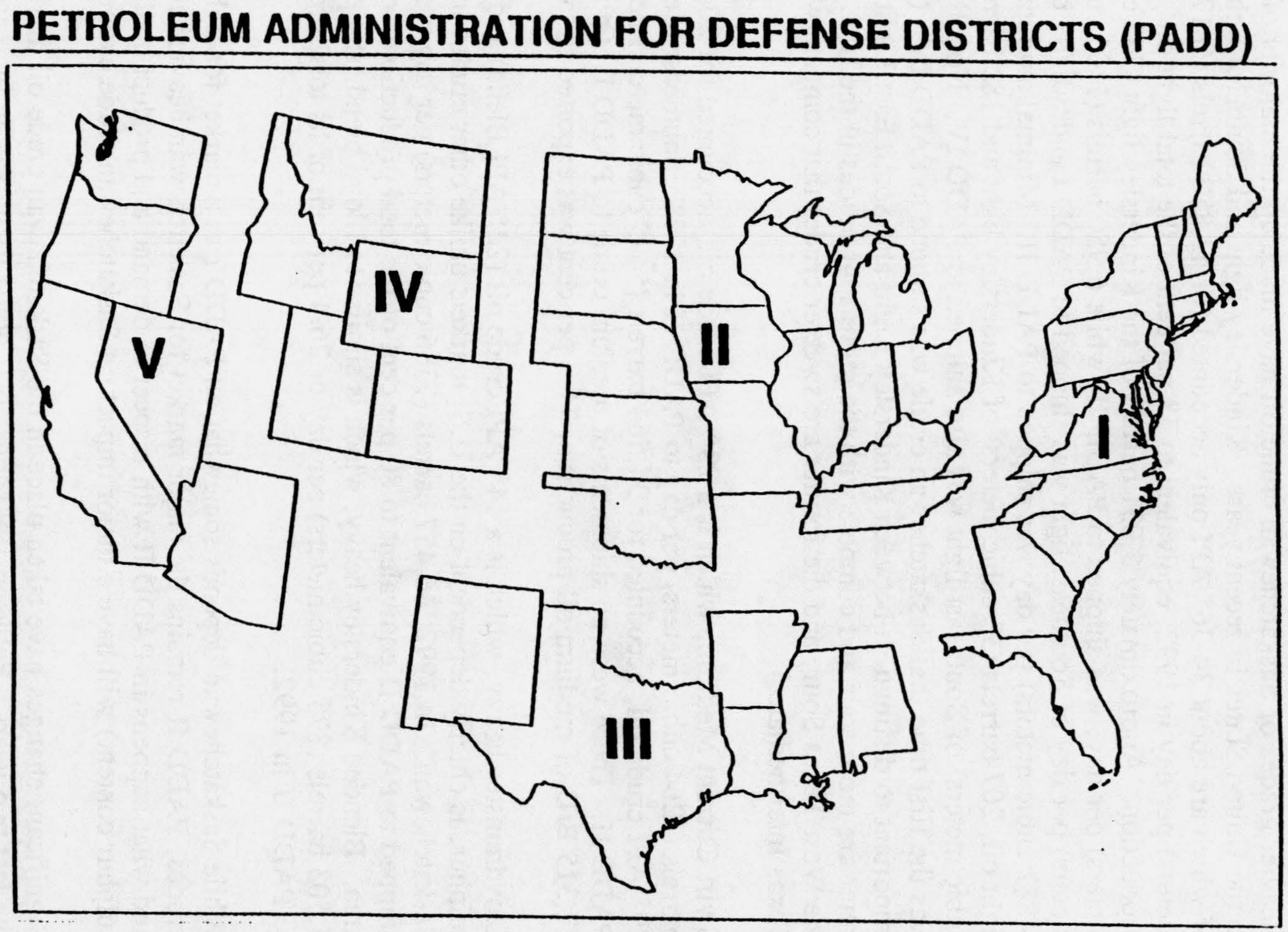
Swift Current Medium, which is a 23° API crude oil, accounted for 20,529 barrels (3264 cubic meters) per day to PADD II in 1992. Southeast Medium, a 29° API crude oil, accounted for 34,564 barrels (5495 cubic meters) per day to PADD II. There were no shipments of medium crude to PADD I. Of the total 77,315 B/D of medium oil production, 71.3 per cent was exported to the U.S.

Lloydminster heavy, which is a 14° API crude oil (22° API Blend) and high in sulphur, is chiefly dependent on the U.S. markets unlike other crudes in Saskatchewan. In 1992, 46,457 barrels (7386 cubic meters) per day were shipped to PADD II equivalent to 80 per cent of the total production from this area. Blended Kindersley heavy, which is similar to Lloyd blend, shipped about 5,503 barrels (875 cubic meters) per day or 26.4 per cent of its total production to PADD II in 1992.

While Saskatchewan depends somewhat on PADD I as a market for lighter crudes, PADD II remains the major market for Saskatchewan heavier crudes and what happens in PADD II with respect to demand and product quality (i.e. sulphur content) will have a major impact on Saskatchewan crude exports.

Significant changes have taken place in the Saskatchewan crude oil markets in the last two years. Between 1990 and 1992, while there was an increase of 8 per cent in total sales to all markets, sales of Saskatchewan crude to Canada declined by 25 per cent and sales to the United States increased by 47 per cent. The decline in the domestic market resulted largely from a loss of Montreal

FIGURE 9
PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS (PADD)

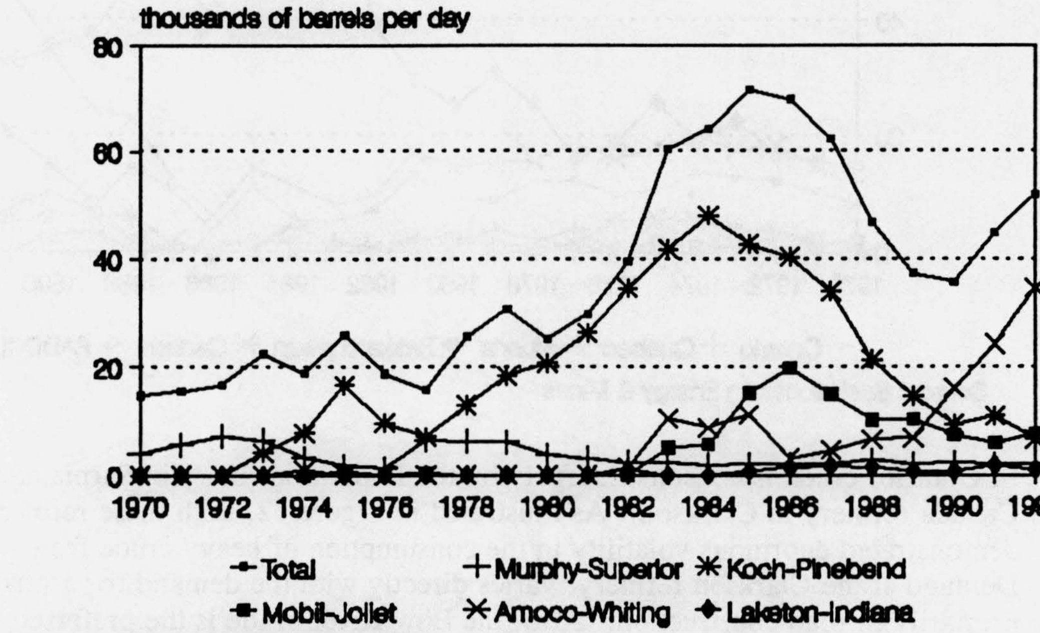


Source: Crude Oil Supply Options for Ontario and Quebec by Purvin & Gertz, Inc. November, 1990

market and the decline in sales to the Imperial Oil refinery in Sarnia, Ontario. (Imperial Oil's production in the province has declined in recent years as the company has sold its interests.) The 1993 trends may be similar, except domestic sales of heavy oil will increase with the Bi-Provincial Upgrader coming fully onstream.

Within PADD II, there are currently five major buyers of Saskatchewan heavy, the Murphy refinery at Superior, Wisconsin; Koch refinery at Pine Bend Minnesota; Mobil refinery at Joliet, Illinois; Amoco refinery at Whiting, Indiana; and Laketon refinery at Laketon, Indiana. Other refineries such as Total at Alma, Michigan and Ashland at St. Paul, Minnesota bought significant volumes in the 1970s, but none in recent years. Figure 10 indicates the trends in heavy oil nominations in the PADD II area. (Data on crude oil deliveries by type of crude and final destination is unavailable. However, in the last ten years, variation between the total crude deliveries and nominations have averaged only 5%. Therefore, nominations data is used to demonstrate the market trends for various type of crudes.) Note that Amoco's purchases of heavy oil have increased constantly since it started buying Saskatchewan crude in 1982. In 1992, it bought the largest volume of heavy oil.

FIGURE 10
HEAVY CRUDE NOMINATIONS TO PADD II
BBLS/D

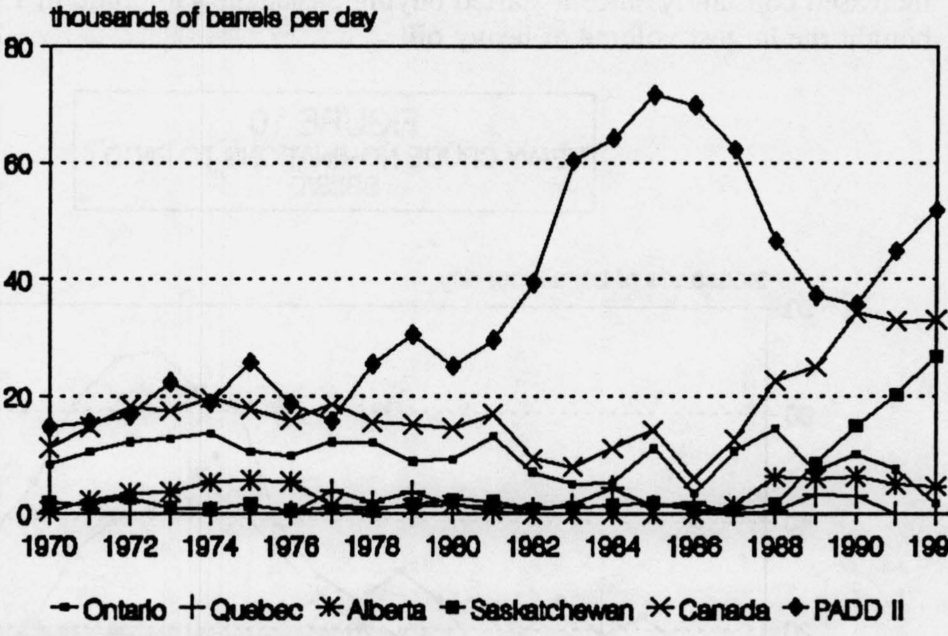


Source: Saskatchewan Energy & Mines

B. DEMAND FOR SASKATCHEWAN HEAVY CRUDE IN CANADA

Over the past twenty years, heavy crude oil sales from Saskatchewan to various parts in Canada have varied from 6,000 B/D in 1986 to 33,147 B/D in 1992 increasing from 8 per cent to 33 per cent of total sales. In much of this period, Ontario has been the largest consumer of Saskatchewan heavy crude. Figure 11 illustrates Saskatchewan nominations to various destinations over the period, 1970-1992. Since 1989, nominations within the Saskatchewan market have superseded the Ontario sales. This reflects the start-up of the Co-Op/NewGrade Upgrader.

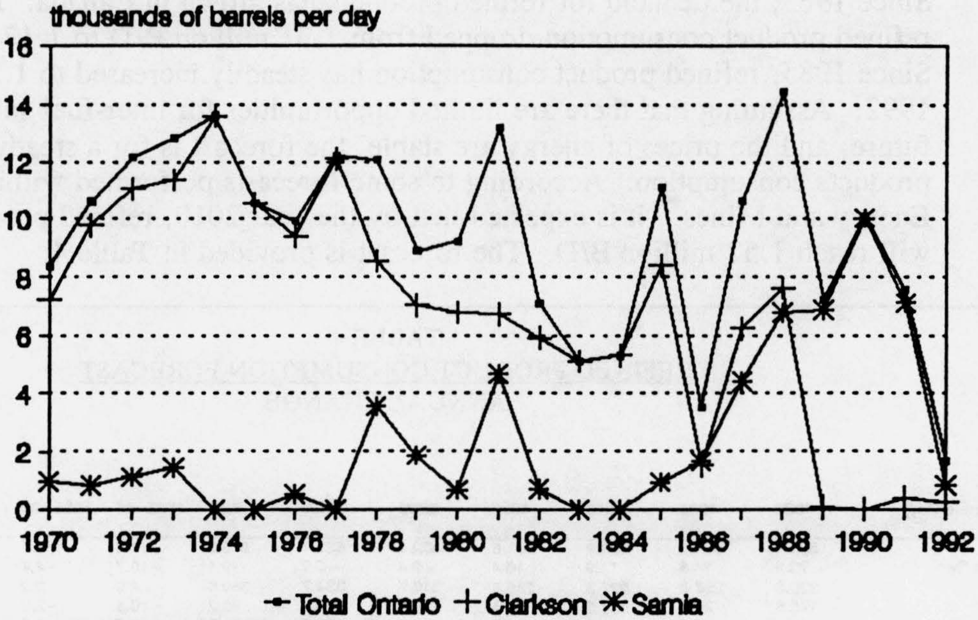
FIGURE 11
HEAVY OIL NOMINATIONS
BBLS/D



Source: Saskatchewan Energy & Mines

In Ontario, crude is consumed largely by the Imperial refinery in Sarnia and the Petro Canada refinery in Clarkson. As illustrated in Figure 12, both these refineries have demonstrated enormous volatility in the consumption of heavy crude from year to year. Demand at the Clarkson refinery, varies directly with the demand for asphalt used primarily in road construction. Also, the Bow River crude is the preferred crude, therefore, the demand for Saskatchewan heavy varies inversely with the supply of Bow River crude. At the Sarnia refinery, the Cold Lake crude may be preferred since Imperial Oil is the producer of this crude.

FIGURE 12
HEAVY OIL NOMINATIONS TO ONTARIO
BBLS/D



Source: Saskatchewan Energy & Mines

At both these refineries, there is some flexibility to the type of crude used, therefore, one type of crude can be replaced by another. The refineries are constantly optimizing their return and in doing so, they choose the mix of crudes that can best generate a particular slate of refined products. In this process, prices of various available feedstocks, costs of refining from alternate operating units, transportation and storage and distribution constraints are all taken into account. Planned as well as unplanned shut-downs also affect the final deliveries of heavy crude.

In 1987, the Lloydminster Refinery of Husky Oil also re-started its purchases of heavy crude. During the 1988-1992 period consumption of heavy by this plant averaged approximately 20 per cent of total heavy oil sales in Canada.

In the future, purchases at the Regina Upgrader are expected to continue at similar levels. Sales to the Lloydminster refinery are expected to continue in the future. Also, sales to the Bi-Provincial Upgrader began in the later part of 1992 and will continue in the future.

C. DEMAND VS SUPPLY - REFINERY UTILIZATION RATES IN CANADA

Since 1985, the demand for refined products has grown in Canada. From 1982 to 1985 refined product consumption dropped from 1.31 million B/D to 1.17 million B/D. Since 1985, refined product consumption has steadily increased to 1.2 million B/D in 1992. Assuming that there are limited opportunities for inter-fuel substitution in the future, and the prices of energy are stable, the forecast is for a steady growth in refined products consumption. According to some forecasts performed within Saskatchewan Energy and Mines*, it is expected that by the year 2010, refined product consumption will reach 1.52 million B/D. The forecast is provided in Table 4.

TABLE 4
REFINED PRODUCT CONSUMPTION FORECAST
ANNUAL CHANGE

(Thousands of Barrels/Day)	1982	1985	1990	1995	2000	2005	2010	1982-85	1985-90	1990-95	1995-00	2000-05	2005-10
Gasoline	580.6	564.0	584.9	581.6	602.3	623.7	645.8	-1.5	0.7	0.7	0.7	0.7	0.
Kerosene & Stove Oil	20.8	14.8	11.9	10.4	9.4	9.7	10.1	-10.7	-4.4	-2.0	-2.0	0.7	0.
Diesel Fuel Oil	229.8	258.6	287.8	288.4	310.7	334.7	360.6	4.0	2.2	1.5	1.5	1.5	1.
Light Fuel Oil	178.6	128.5	109.5	94.4	89.8	94.4	99.2	-10.8	-2.9	-1.0	-1.0	1.0	1.0
Heavy Fuel Oil	145.2	77.9	97.2	93.7	98.4	103.5	108.7	-18.7	4.5	1.0	1.0	1.0	1.0
Aviation Gasoline	3.1	3.0	2.8	2.1	2.0	2.0	2.1	-0.7	-1.4	-0.7	-0.7	0.0	1.0
Aviation Turbo Fuel	70.0	74.1	86.2	82.1	88.5	95.3	102.7	1.9	3.1	1.5	1.5	1.5	1.
Total	1239.5	1122.6	1194.8	1194.0	1280.0	1392.5	1515.0	-3.2	1.3	1.4	1.4	1.7	1.

Source: Statistics Canada, Catalogue 57-003, Table 1D

N.B. Petroleum coke is omitted from the detailed breakdown in this table, but is included in the total figure.
N.B. The 1995 and on projections were made using the actual 1991 figures as a base.

On the other hand, refinery capacity in Canada has declined considerably. From 1980 to 1991, refinery capacity in Canada decreased from 2,150 thousand B/D to 1,974 thousand B/D or by 9 per cent. In 1992, the total effective crude capacities for Canadian refineries and their utilization rates in various jurisdictions was as follows:

* The key assumptions underlying the demand forecast are as follows: average economic growth of 2.8 per cent a year for the forecast period; price inflation at 3.0 per cent for the forecast period; no further inter-fuel substitution; stable energy prices with WTI not exceeding US $25 per barrel; no efficiency gains in consuming fuels; and population growth of 2.0 per cent a year.

	Capacities B/D	Utilization Rate (%)
Atlantic	381,666	74.6
Quebec	334,430	84.0
Ontario	616,528	74.7
Prairies	445,206	80.7
British Columbia	148,817	88.5
Total	1,926,647	80.0

Source: The Canadian Oil Market, Vol VIII, #4, Winter 1992

Major reorganization has occurred in recent years in the British Columbia refinery sector. In 1991, the 18,870 B/D refinery in Taylor, B.C. was closed down by Petro Canada. This refinery was used largely to supply transportation fuels and asphalt to the northeastern part of the province. This closure was the first since a number of refineries were closed in the early to mid-eighties due to a recession driven drop in product demand.

Petro Canada had started to run the Port Moody refinery after the closure of the Taylor refinery; but this refinery also closed in May, 1993. The Shellburn refinery in Vancouver owned by Shell closed in June, 1993. The Turbo refinery at Balzac closed in May 1992. The Esso refinery in Vancouver is also scheduled to close in mid-1994, after which there will only be one large refinery, the Chevron refinery in Burnaby, operating in B.C. It is expected that the refined products will be transported into B.C. from Edmonton refineries through the Trans-Mountain pipeline or shipped from the Seattle area through trucks or tankers.

In Ontario, the Clarkson refinery owned by Petro Canada is going through major reconfiguration. By late 1993, this refinery was going to stop crude runs and the manufacture of fuel products. It will, however, continue to produce lubricants and asphalt by using semi-refined products as feedstock.

According to the Petroleum Monitoring Agency, the downstream sector incurred a loss of $192 million in the first half of 1992. Many of the closures in this decade have resulted from a slowdown in demand and a grim financial performance in the downstream sector; but these types of changes are expected only over the short term. In the longer term, especially after all rationalizations are made, refinery capacity may expand in response to an increased demand. Since the utilization rates vary within jurisdictions, expansions will take place at different times in different areas. Currently B.C. has the highest utilization rate and Ontario the lowest.

The refiners may also opt for increasing the imports of refined petroleum products to meet the growing demand rather than investing in expansions. Such has been the experience in Quebec, where after rationalizations in early 1980s, there was an increase in imports. The forecasts for refined product consumption in Canada suggest that the need for extra refining capacity can be delayed until the early 2000s (possibly longer if imports are increased). Currently, Canada imports approximately 125,000 B/D of refined petroleum products from the U.S., Europe and the far East. Canada also exports approximately 240,000 B/D of refined petroleum products. The majority of trade in refined petroleum products takes place with the U.S. (40 per cent of imports & 80 per cent of exports) which is a fairly stable source of both exports and imports for Canada.

D. REFINERY CAPACITY UTILIZATION IN THE UNITED STATES

In the United States, refining capacity has decreased from 18,051 thousand B/D in 1981 to 14,965 thousand B/D in 1992 or by 17 per cent. A lot of the refining stock that has been rationalized is old stock. Much of this older stock was small scale, which entailed high unit production costs and poor profitability. These smaller plants also lacked the process sophistication to run a variety of crudes and produce a full range of higher value products. As demand fell in the U.S., these higher cost plants could not compete successfully for the available market and were forced to close.

As of January 1, 1992, the total effective crude capacities and the utilization rates for the various PADD areas in the U.S. are as follows:

	Capacity B/D	Utilization Rate (%)
PADD I	1,408,755	88.4
PADD II	3,362,200	90.8
PADD III	6,888,250	90.7
PADD IV	499,875	91.0
PADD V	2,806,300	93.1
Total	14,965,480	91.0

Source: API

The demand for crude oil by refineries in the U.S. has been increasing steadily since 1985:

TABLE 5
U.S. CRUDE OIL DEMAND
('000 B/D)

	1985	1988	1989	1990	1991	1992
PADD I	919	1300	1281	1289	1246	1276
PADD II	2704	2916	2908	3011	3053	3109
PADD III	5467	6213	6376	6303	6250	6299
PADD IV	434	451	458	460	455	433
PADD V	2318	2637	2664	2646	2612	2619
Total	1184	13517	13689	13708	13617	13738

Source: API (1992 data is not available)

Demand for the major refined products in the U.S. dropped from 14.7 million B/D in 1978 to 11.9 million B/D in 1982. In this time period, all fuel consumption dropped with the exception of aviation fuel. Residual fuel oil suffered the largest loss. Since 1984, product demand has grown and further growth into the future is expected.

Table 6 illustrates consumption trends in the U.S. for various refined petroleum products. Table 7 illustrates similar trends for PADD II, our main market in the U.S. Detailed consumption trends for each of the RPPs during the period 1970-1992 are provided in the Appendix.

TABLE 6
REFINED PRODUCT CONSUMPTION FORECAST - UNITED STATES
ANNUAL CHANGE

(Million Barrels/ Day)	1982	1987	1990	1995	2000	2010	(Growth Rates) 1982-85*	1985-90	1990-95	1995-00	2000-10
Gasoline	6,534	7,205	7,400	7,585	7,727	7,824	3.3%	0.5%	0.5%	0.4%	0.1%
Distillate	2,661	2,975	3,130	3,351	3,5522	3,911	3.8%	1.0%	1.4%	1.2%	1.0%
Jet A	804	1,180	1,308	1,454	1,598	1,765	13.6%	2.1%	2.3%	1.8%	1.0%
JP-4	208	204	206	214	222	228	-0.6%	0.2%	0.8%	0.7%	0.3%
Aviation Gas	25	25	26	27	28	30	0.0%	0.8%	0.8%	0.7%	0.7%
Residual	1,667	1,264	1,301	1,306	1,442	1,758	-8.8%	0.6%	0.1%	2.0%	2.0%
Total	11,899	12,853	13,371	13,937	14,569	15,516	2.6%	1.3%	1.4%	1.5%	0.7%

*The growth rates are not obtained from the source, but calculated for the purpose of presentation in this report.
Source: Crude Oil supply options for Ontario & Quebec by Purvin & Gertz, Inc. November, 1990.

Combining existing capacity with the refined petroleum product consumption forecast provided by Purvin and Gertz, refining stock will have to be added by the mid to late 1990s to satisfy U.S. demand increases. Even if imports of refined product are increased, it could only be done for a couple of years before new stock addition would be required. The age of current refineries in the United States add to the argument that new capacity could be added by the mid 1990s.

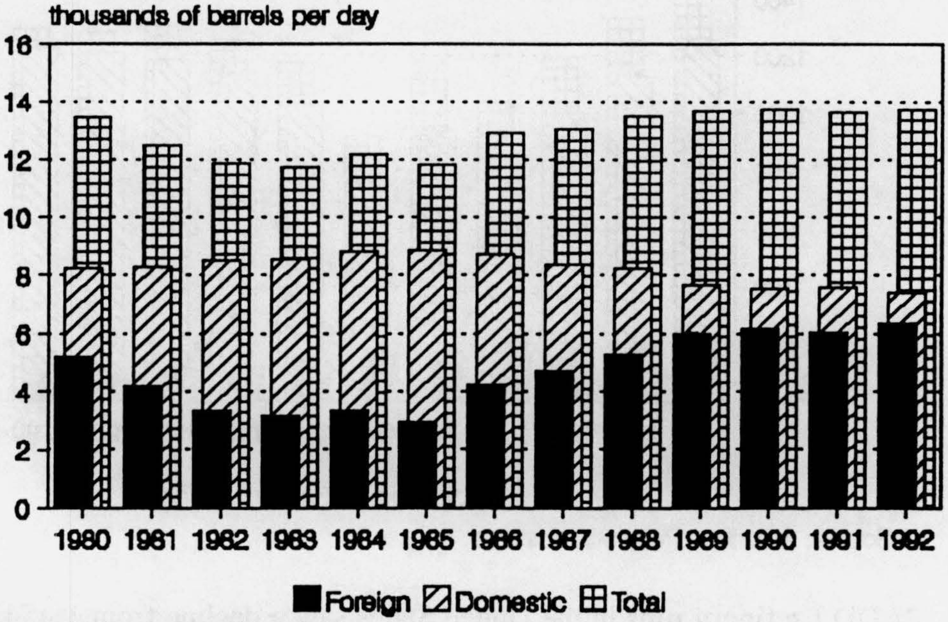
TABLE 7
REFINED PRODUCT CONSUMPTION FORECAST - UNITED STATES PADD II
ANNUAL CHANGE

(Thousand Barrels/ Day)	1982	1987	1990	1995	2000	2010	(Growth Rates) 1982-85*	1985-90	1990-95	1995-00	2000-10
Gasoline	2,092	2,123	2,208	2,198	2,172	2,065	0.5%	0.8%	-0.1%	-0.2%	-0.5%
Distillate	792	817	874	919	959	1,028	1.0%	1.4%	1.0%	0.9%	0.7%
Jet A	158	250	264	291	320	353	18.5%	1.1%	2.0%	1.9%	1.0%
Residual	102	61	62	63	70	85	-15.7%	0.3%	0.3%	2.1%	2.0%
Total	3,144	3,251	3,408	3,471	3,521	3,531	1.1%	1.6%	0.03%	0.5%	0.3%

*The growth rates are not obtained from the source, but calculated for the purpose of presentation in this report.
Source: Crude Oil supply options for Ontario & Quebec by Purvin & Gertz, Inc. November, 1990.

E. CRUDE OIL REFINERY RUNS IN THE UNITED STATES: FOREIGN VERSUS DOMESTIC CRUDES

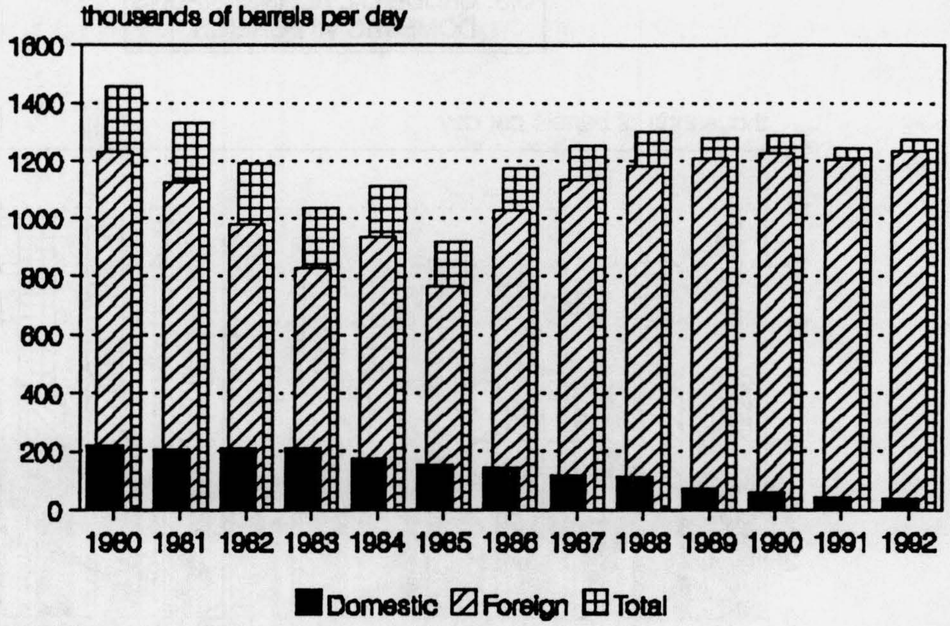
FIGURE 13
U.S. CRUDE OIL REFINERY RUNS
DOMESTIC vs FOREIGN



Source: American Petroleum Institute

Crude oil refinery runs are reflected in figures 13 through 18. Refinery runs in the United States decreased steadily until 1985, chiefly as a result of lower gasoline consumption. Up until 1985, the decrease in crude oil refinery runs was seen in a large decrease in the foreign crude component. In 1980, foreign crudes made up 39 per cent of the total U.S. refinery runs. By 1985, the share of foreign crude in the U.S. refinery runs was 25 per cent. However, since 1985, the trend has reversed and domestic crude runs decreased to 55 per cent while foreign crude increased to 45 per cent.

FIGURE 14
PADD I CRUDE OIL REFINERY RUNS
DOMESTIC vs FOREIGN

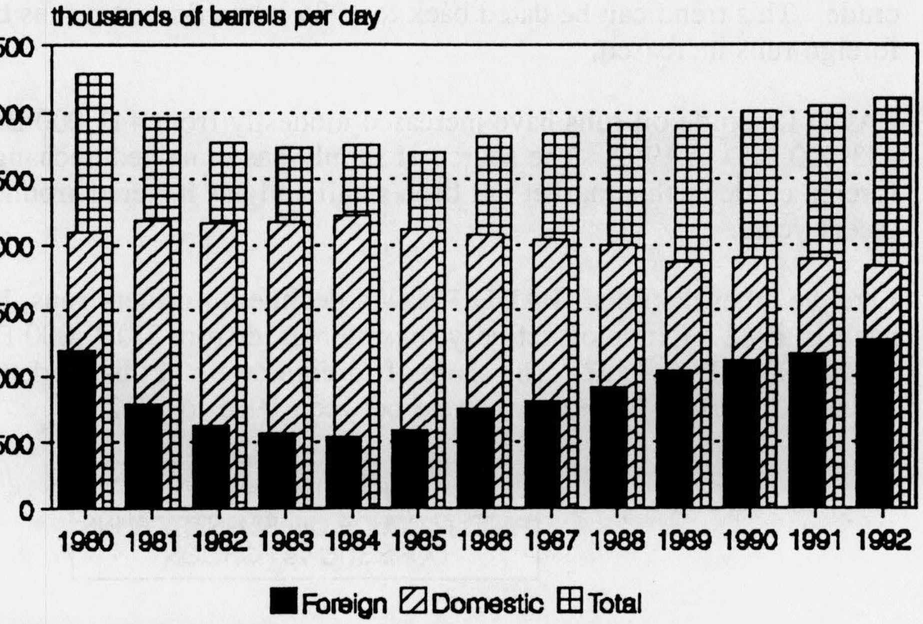


Source: American Petroleum Institute

PADD I refinery runs in the United States saw a decline from 1,454,000 B/D in 1980 to 919,000 B/D in 1985. Since then, refinery runs have increased to 1,276,000 B/D in 1992. The majority of crude in this market has been foreign and the large fluctuations in total refinery runs have been reflected in the demand for foreign crude. The domestic component, which was 221,000 B/D in 1980 dropped to 39,000 B/D in 1992.

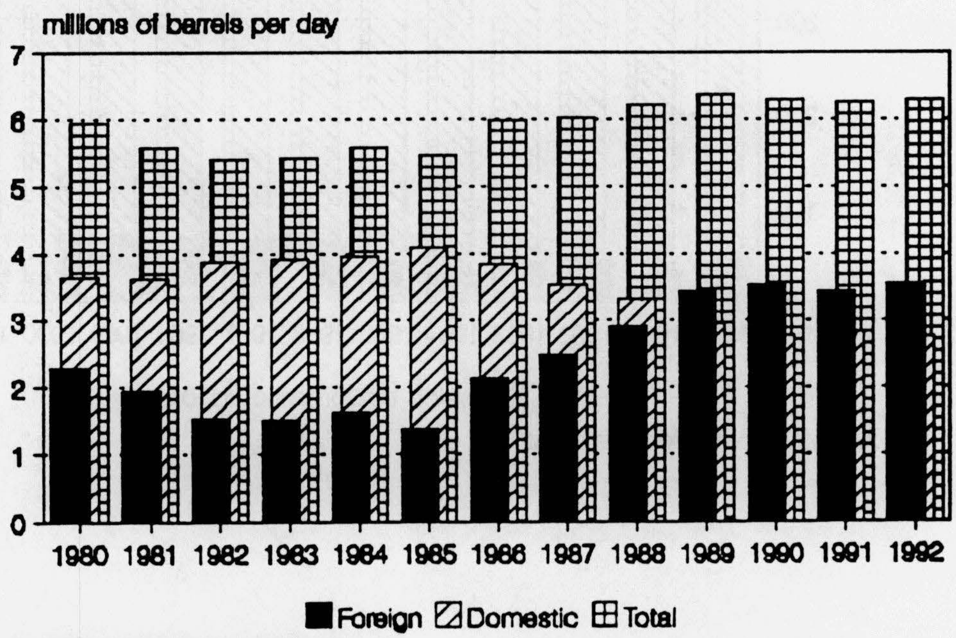
Crude oil refinery runs in PADD II declined from 3,296,000 B/D in 1980 to 2,704,000 B/D in 1985. Since then, crude oil runs have increased to 3,109,000 B/D in 1992. During these years, the amount of domestic crude has remained steady at about 2,000,000 B/D and the fluctuations have occurred in foreign supplies. The share of foreign crude has increased significantly in PADD II from 19 per cent in 1984 to 41 per cent in 1992.

FIGURE 15
PADD II CRUDE OIL REFINERY RUNS
DOMESTIC vs FOREIGN



Source: American Petroleum Institute

FIGURE 16
PADD III CRUDE OIL REFINERY RUNS
DOMESTIC vs FOREIGN



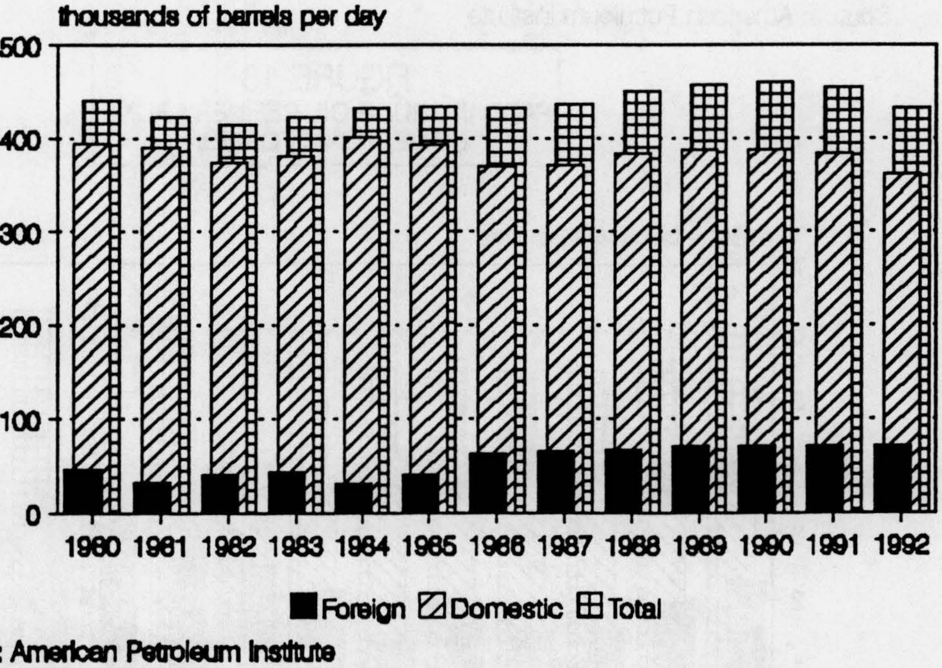
Source: American Petroleum Institute

As in other districts, crude oil refinery runs declined in PADD III until 1985. The decline, however, was not as severe as in other districts. What is noticeable in PADD III is the shift in dominant crude source. Until 1988, crude oil runs in PADD III were dominated by domestic crudes. Since 1988, the dominant supply has been foreign crude. This trend can be dated back to 1985 when domestic runs began to decline and foreign runs increased.

PADD IV crude oil runs have increased modestly from 441,000 B/D in 1980 to 433,000 B/D in 1992. The source of supply has remained unchanged. The share of foreign crude in this market has been small and has hovered around 16 per cent in recent years.

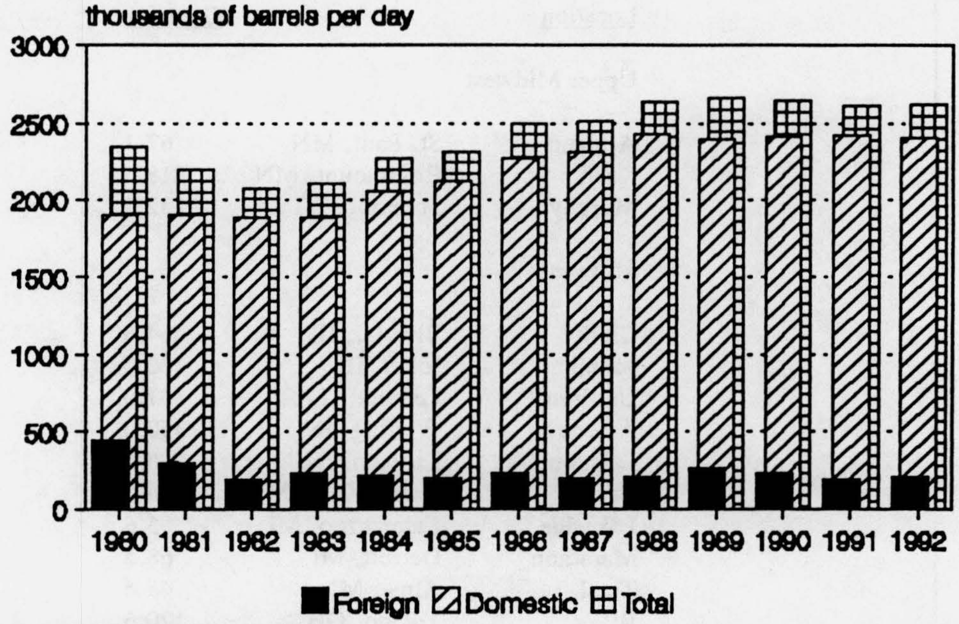
Like the other districts, PADD V saw a decline in refinery runs, but the trend reversed itself in 1982. Crude oil refinery runs increased from 2,079,000 B/D in 1982 to 2,619,000 B/D in 1992. The share of foreign crude in this market has remained small and has fluctuated from year to year between 1985 to 1992.

FIGURE 17
PADD IV CRUDE OIL REFINERY RUNS
DOMESTIC vs FOREIGN



Source: American Petroleum Institute

FIGURE 18
PADD V CRUDE OIL REFINERY RUNS
DOMESTIC vs FOREIGN



Source: American Petroleum Institute

F. REFINERY CAPACITY IN PADD II

PADD II can be broken into 3 regions; Mid Continent, which consists of Oklahoma, Kansas, Nebraska, Missouri and Iowa; Midwest, which consists of Illinois, Michigan, Indiana, Kentucky, Tennessee and Ohio; Upper Midwest, which consists of Wisconsin, Minnesota, North and South Dakota. Currently, Canadian crude travels mostly to the Midwest and Upper Midwest in PADD II.

Canadian crude oil travels to PADD II via the Lakehead Pipeline. There are currently 15 refineries in PADD II with access to the Lakehead Pipeline and a combined capacity of 1.5 million B/D.

PADD II, although a significant producer of crude oil, depends on imports and transfers for about 70-75 per cent of its crude supply. The dependence on transfers and imports will increase steadily as the production of crude oil in PADD II declines. The dependence on imports will increase even more significantly in the future as the interstate transfer from traditional domestic sources declines with production.

TABLE 8
PADD II Refineries With Access to Lakehead Pipeline
('000 B/D)

Location		Capacity
Upper Midwest		
Ashland	St. Paul, MN	67.1
Koch	Rosemount, MN	218.5
Murphy	Superior, WI	32.0
Midwest		
Clark	Blue Is., IL	64.6
Mobil	Joliet, IL	180.0
UnoVen	Lemont, IL	147.0
Amoco	Whiting, IN	350.0
Laketon	Laketon, IN	8.3
Crystal	Carson City, MI	4.0
Lakeside	Kalamazoo, MI	5.6
Marathon	Detroit, MI	68.5
Total	Alma, MI	45.6
BP	Toledo, OH	120.6
Sun	Toledo, OH	125.0
Total		1,436.0

Over one half of the Upper Midwest's 375,000 B/D refinery capacity is accounted for by the Koch refinery in Minneapolis which can run an estimated 218,000 B/D of heavy sour crude. The Upper Midwest region runs 50-60 per cent heavy sour crude, 10 per cent light sour and the remainder sweet. The sour crude in this region has historically been supplied by Canadian imports. The sweet crude has been supplied from the Williston Basin of North Dakota and as that production declines, the requirements will be filled in by Canadian imports.

The Midwest region has 22 refineries with a combined capacity of 2.2 million B/D. About 50 per cent of the capacity was designed for light sweet crude use. The distribution, however, is not balanced. The Chicago refineries run a slate that is 1/3 sweet while Ohio and Michigan refineries run a slate which is only 18 per cent sour. The Midwest has very little in terms of crude production and it only supplies about 10 per cent of its refinery runs. About 45 per cent of its supply requirements come from PADD's III and IV, the remaining 45 per cent is satisfied by imports.

G. NON TRADITIONAL MARKETS FOR SASKATCHEWAN HEAVY CRUDE

Non-traditional markets may be classified into two categories: non-traditional markets for current quality crude and markets for non-traditional crude. As explained above, the major market for Saskatchewan heavy crudes is PADD II in the U.S. It is interesting to review prospects for new markets in other PADD areas.

Markets in PADD V, PADD III and PADD I are limited due to either distance, adequate domestic supplies or competition from foreign crudes. PADD V is the largest producer of heavy oil in the U.S. producing more than 80 per cent of total heavy oil production in the U.S. Approximately 25 per cent of PADD V production is heavy oil and the production of this crude is expected to increase in the future.

Although Saskatchewan currently ships some crude to the PADD I area, the amounts are minimal. There is only one pipeline connected refinery in PADD I (United Refining Co.). Distance is a limiting factor in this area which makes other foreign crudes more desirable. In the past, Canadian imports have only contributed roughly 4 per cent to the total requirements in this area. Other foreign crudes have contributed roughly 95 per cent.

PADD III is the largest producer of crude oil in the U.S., although its production of heavy sour crude is minimal. It depends heavily on imports to supply heavy crudes; however, because of its proximity to the Gulf Coast, Mexican and other South American crudes have an advantage over Canadian crudes.

Saskatchewan has only recently begun to export minimal amounts to PADD IV, and all exports are of light oil. However, in the future, this district may provide a growing opportunity for Saskatchewan crudes, including market for heavier crudes. Currently, PADD IV has a net out-transfer of crudes to other areas in the U.S. In 1992, the district produced 460 thousand B/D of light sweet, light sour and heavy sour crudes. The total refinery runs for that district were 433 thousand B/D. In 1992, PADD IV imported approximately 80 thousand B/D of Canadian Alberta crude. The domestic production in PADD IV is expected to decline including the production of heavy sour crudes. On the other hand, the heavy sour runs are expected to rise, thus increasing the demand for imports of heavy crudes. There is also the possibility of transferring crudes to PADD II through PADD IV. This route opens up the Wood River Area to Western Canada crudes.

Canadian production of syncrude (non-traditional crude) is projected to expand in the future. The proportion of synthetic crude in the total western crude supply is expected to increase from 13 per cent in 1990 to 20 per cent in 2010. Some of this increase would come from the Bi-Provincial upgrader and the rest from increased production from the oilsands. The forecast is provided in Table 9 below.

70 per cent of current synthetic production is consumed by four refineries: Imperial Oil and Petro Canada in Edmonton consume 20,300 and 36,000 B/D; respectively; Shell Canada at Scotford consumes 61,100 B/D and Sunoco at Sarnia consumes 24,900 B/D. The remaining 30 per cent of synthetic is utilized in small quantities in refineries throughout Canada and the U.S. Midwest. Conventional light crude refineries are generally limited to processing around 10 per cent to 15 per cent of synthetic in their crude slates. This limit is largely due to the low cetane number in the distillate and high smoke point in the jet fuel product. Diesel fuel cetane number is the most critical specification for marketing synthetic crude.

TABLE 9

Synthetic Crude Oil Production

('000 B/D)

	1990	1995	2000	2005	2010
Oil Sands	210	264	264	264	264
Upgraded Heavy & Bitumen	9	101	101	101	101
Total	219	365	365	365	365

Source: Saskatchewan Energy & Mines

The markets for current quality synthetic crude are mostly located in Canada, although in recent years refiners in the U.S. Midwest have also increased demand. The synthetic crude from the existing oil sands plants is very aromatic and use at many refineries is limited. However, as the quality of syncrude is improved, refiners should be able to use more volumes than are being used now. Serious shortfalls are being projected in the supply of light crude both in Canada and the U.S. With quality improvements, synthetic crude could be interchangeable with light crude. The primary markets for improved quality crude would be the sweet crude refineries located in Canada and along the Lakehead Pipeline in the U.S.. For these refineries, the choice is between using synthetic or undertaking major capital programs to use lower quality crude.

Alberta Chamber of Resources provides the following list of qualities for an improved synthetic crude.

TABLE 10
ALBERTA CHAMBER OF RESOURCES
SYNTHETIC CRUDE MARKET ANALYSIS
(QUALITIES OF TYPICAL CRUDE OILS)

		ACR(1) Synthetic Target	Conventional Synthetic Crude	IPL Blend
Gravity, °API		30 (min)	32.8	38
Sulphur wt%			0.17	0.5
Distillation, LV%				
C3 and Lighter				1
C4's		3 (max)	2-4	1-3
C5-160°F			5	6.5
C5-350°F		15-30		
160-380°F			14	27.5
380-550°F			28	17
300-500°F				
550-650°F			16	11
350-650°F		40-50		
650-975°F		25-35		
650-1050°F			33	26
1050+°F			1	9
Properties				
C5-160°F,	Octane, (R+H)/2		60	65
C5-350°F,	Nitrogen wppm	1		
160-350°F,	N+2A, LV%		70	72
300-500°F,	Aromatics, LV%	22 (max)		
	Smoke Point, °F	20 (min)		
380-550°F,	Aromatics, LV%		38	22
	Smoke Point, °F		18	24
	Freeze PT, °F		-67	-31
380-650°F,	Sulphur, wt%		0.04	0.25
	Cetane Number		31	50
	Aromatics, LV%		45	26
	Pour Pt, °F		-45	-10
350-650°F	Cetane Number	40 (min)		
	Sulphur, wppe	500 (max)		
650-1050°F,	Sulphur, wt%		0.34	1.0
	Nitrogen, wppm		1,400	<1,200
	Gravity, °API		18	24
	'k' Factor		11.4	11.9
	Aromatics, LV%		60	40
	Polycyclic Aromatic, LV%		33	15
	Carbon/Hydrogen, wt		7.3	6.9
650-975°F, Nitrogen, wppm		1000 (max)		

NOTE: (1) Supplied by Alberta Chamber of Resources

IV. LOGISTICS

Saskatchewan heavy crude oil travels through several pipelines to reach its markets. Figures 19 & 20 provide a map of pipelines in Canada and North America. A brief description of each of the major crude pipelines in Saskatchewan, Canada and the U.S. is provided in the appendix.

From the production fields, the heavy oil is moved by truck or collection pipeline system to field batteries or collection points. It is then transmitted to one of a number of injection terminals for movement through the Manito or Husky pipeline systems. (Minimal amounts of heavy crude is trucked also and therefore, does not travel through either pipelines). Crude shipped through the Husky pipeline, goes to Hardisty in Alberta, transferring to the Interprovincial Pipeline (IPL), the major crude pipeline running through Canada. Crude which goes through the Manito system, travels to Kerrobert in Saskatchewan and then transfers on to IPL.

Both Manito and Husky pipelines are privately owned. Manito is jointly owned by Murphy and CS Resources and operated by Murphy Oil and the Husky pipeline is owned by Husky Oil and operated by its marketing arm, Husky Oil Operations, Ltd. The Manito Pipeline is regulated by the NEB, since it crosses the border at Lloydminster into Alberta. However, unlike the IPL and the Lakehead pipelines, this is a Category II pipeline and the tariff on this line is regulated on a complaint basis only. Other non-tariff aspects such as permission to construct, operate, deactivate and adherence to safety procedures are still regulated by NEB.

The Husky Pipeline is not regulated by the NEB since it is not a interprovincial pipeline. However, the line is regulated by the Alberta government on non-tariff issues. On the Saskatchewan side, the gathering system is also provincially regulated, again, only construction aspects are included as part of regulation.

The Husky Pipeline has two systems, Cold Lake to Lloydminster and Lloydminster to Hardisty. The latter system has a 12 inch line, 70 miles in length with an estimated crude capacity of 60,000 B/D. The Manito Pipeline runs from Lloydminster to Kerrobert. There are two lines on this system, a 4 inch and a 10 inch line, 70 miles in length with a capacity of 55,000 B/D on the 10 inch line.

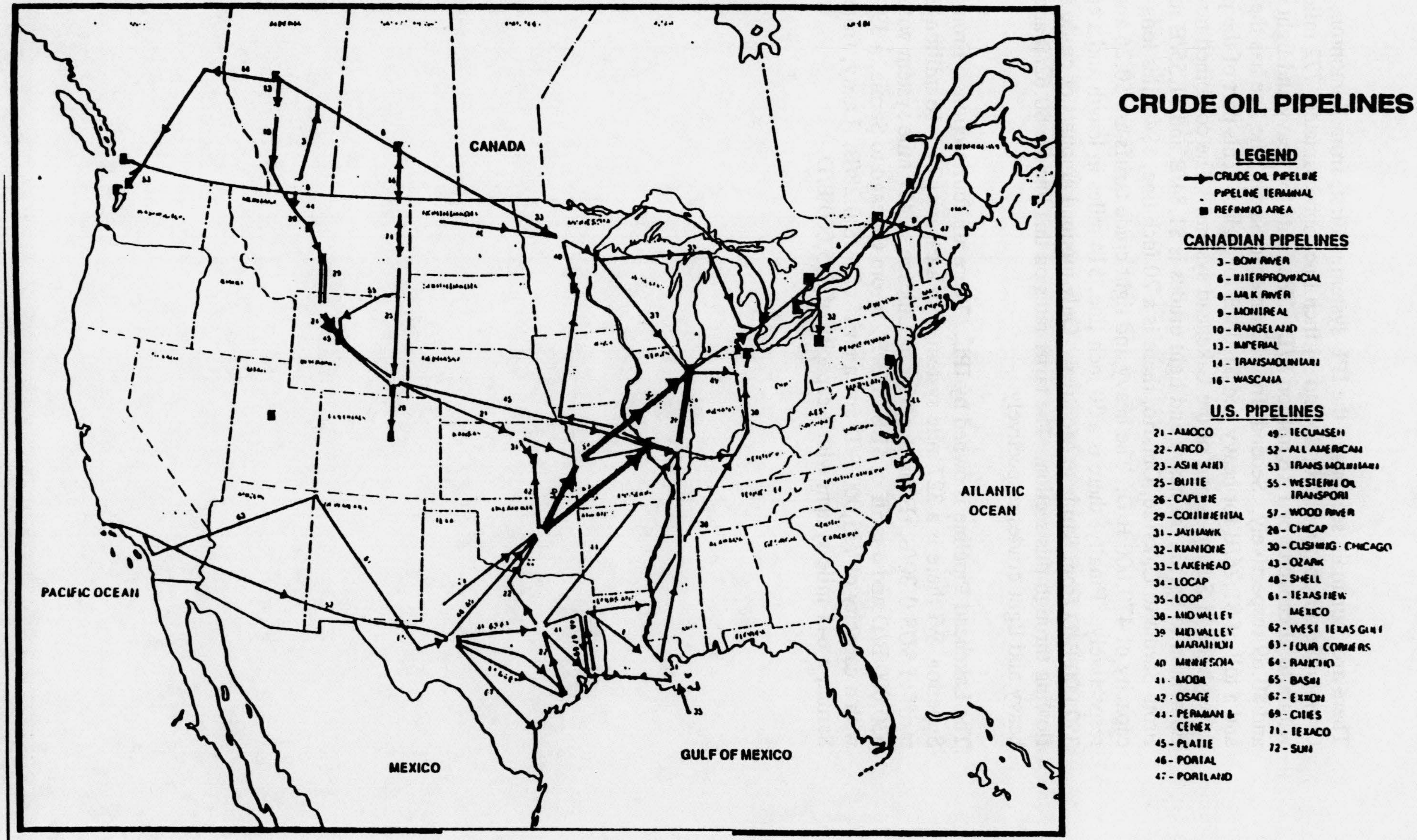
Some heavy crude in the Kindersley area is also collected through the Petro Canada system which takes crude from several batteries in the Cactus Lake area and transports crude through the Petro Canada Pipeline to the Kerrobert terminal. The heavy crude is then transferred to the IPL. This system is jointly owned by SaskOil, Petro Canada and Murphy Oil.

From either Kerrobert or Hardisty, crude travels to the Canada/U.S. border at Gretna, Manitoba. At Gretna, the crude connects to the Lakehead Pipeline which goes as far as Chicago. Crude destined for eastern Canada then travels to Sarnia through another leg of the Lakehead.

There are four main sections to the IPL system. First, from Edmonton, Alberta to Cromer, Manitoba, with 16, 24 and 34 inch lines approximately 772 miles in length with a total capacity of 1.16 million B/D. The tariff for heavy and light crude is $0.83 and $0.69 respectively. Second, from Cromer to Sarnia, the line has the same capacity and a toll of $1.26/B for heavy and $1.06/B for light. (This part of the pipeline runs through the U.S. and is part of the Lakehead system). The combined tariff from Edmonton to Sarnia for heavy and light crudes is $1.84/B and $1.55/B respectively. From Sarnia to Oakville, Ontario, there is a 20 inch line, 194 miles long with a capacity of 470,000 B/D. The heavy and light crude tariffs are $0.26 and $0.21/B respectively. Finally, there is a 30 inch line, 514 miles in length and a capacity of 350,000 B/D from Sarnia to Montreal. Only minimal amounts of crude are currently flowing through this section. The tariff rates on this line are $0.62/B and $0.52/B for heavy and light crudes respectively.

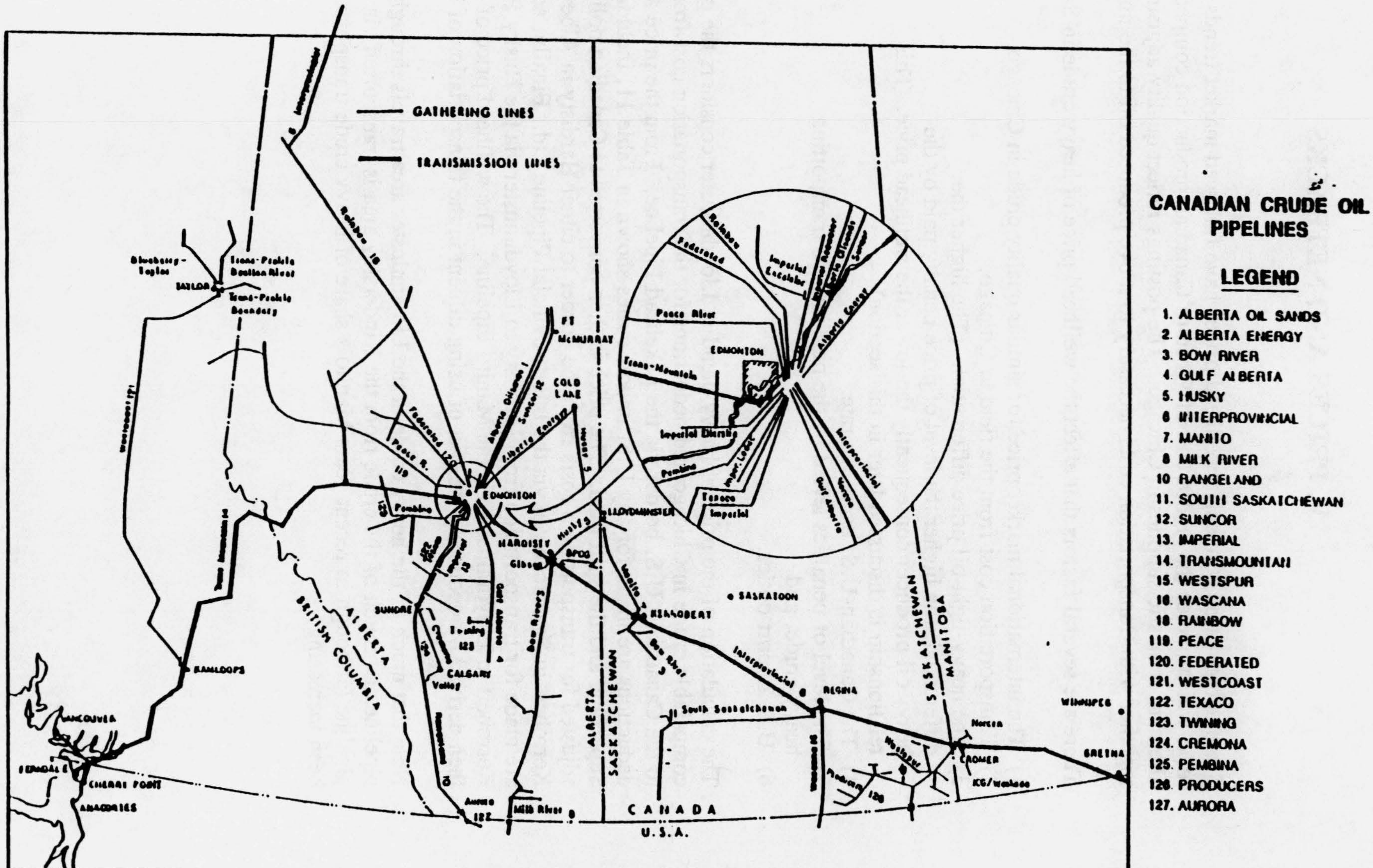
The Lakehead Pipeline is owned by IPL. There are four sections. From Gretna to Superior, WI there is a 327 mile system with a capacity of 1.16 million B/D and a tariff of $US 0.30/B. From Superior to Chicago, a 467 mile system with a capacity of 630,000 B/D and a tariff of $US 0.23/B. From Chicago to Sarnia, a 397 mile system with a capacity of 735,000 B/D and a tariff of $US 0.28/B. Lastly, from Superior to Sarnia, a 641 mile system with a capacity of 555,000 B/D.

FIGURE 19
CRUDE OIL PIPELINES



Source: Crude Oil Supply Options for Ontario and Quebec by Purvin & Gertz, Inc. November, 1990

FIGURE 20
CANADIAN CRUDE OIL PIPELINES



Source: Crude Oil Supply Options for Ontario and Quebec by Purvin & Gertz, Inc. November, 1990

V. PRICES AND NETBACKS

Since deregulation, Canadian wellhead prices have followed market trends and are at a level which makes the landed cost of Western Canadian production competitive with alternate domestic supplies in Chicago. The postings reflect quality adjustments together with transportation costs necessary to move produced oil to the marketplace.

There are several factors that effect the wellhead price of heavy crude in Saskatchewan.

1) The international market price for similar quality crude in Chicago.
2) Transportation cost from the field to Chicago.
3) The heavy-light oil price differential. (The higher the differential, the higher the level of price penalty paid by the heavy oil producer consequently the lower the wellhead price. This relationship is discussed later in this section)
4) The Canadian-U.S. exchange rate.
5) The level of penalties levied by the pipelines on transporting heavy crude, and
6) U.S. import duties.

The calculation of the price of heavy blend in Lloydminster considers the price of comparable crude in Chicago and deductions for the transportation cost from Chicago to the Canadian - U.S. border via the Lakehead Pipeline. From the price at the border, deductions are made for any U.S. import duties shown in Table 11, including the Superfund and the spill fund. The price is then converted to Canadian dollars and adjusted for transportation costs from the border to either Hardisty in Alberta or Kerrobert in Saskatchewan via the Interprovincial Pipeline Ltd. Finally, adjustments are made for transportation from Hardisty to Lloydminster via the Husky Pipeline or Kerrobert to Lloydminster via the Manito Pipeline. The wellhead price of heavy oil is then derived by deducting the cost of using diluent in the transportation of heavy oil.

Note that much of the heavy crude in the Lloydminster area travels through the Husky pipeline and much of the crude from the Kindersley area is transported via the Manito pipeline (although in recent years Manito's share of heavy crude transportation has been increasing).

TABLE 11
IMPORT TARIFFS

	Customs* User Fees	Import Duty**	Superfund & Spill Fund
Tariffs	.068 % of crude value	.0105%	.1470%

* Customs User Fees on Canadian imports were eliminated at the end of 1992.
** Import Duty on Canadian imports will expire at the end of 1993.

Source: Crude Oil Pricing Report, EMR

It is interesting to compare the actual wellhead price of Saskatchewan heavy oil with the Lloydminster blend price. Table 12 provides a comparison during the period 1987-1992.

TABLE 12
PRICES
(CDN $/B)

	1987	1988	1989	1990	1991	1992
Wellhead Price	16.41	9.43	13.13	15.82	9.37	12.36
Lloyd Blend Price @ Chicago	21.61	15.16	18.52	22.25	15.83	18.20
Variance	5.20	5.73	5.39	6.43	6.46	5.84
Due to diluent cost*	1.33	1.57	1.61	2.14	2.43	1.88
Due to transport cost	2.94	2.94	2.94	2.94	3.00	3.06
Due to tariff & other adjustments**	0.93	1.22	0.84	1.36	1.03	.90
Wellhead/Blend Price	.76	.62	.71	.71	.59	.68

* diluent cost includes the cost of shipping condensate from Hardisty to the field and back and the differential between the Edmonton par price and the Lloyd Blend price. The latter component is due to the fact that the heavy oil producer buys the condensate at the Edmonton par price but sells it at the Lloyd Blend price.
** includes import duties and pipeline losses.

Source: Saskatchewan Energy & Mines

A. PRODUCER NETBACKS:

To arrive at producer netbacks, the wellhead price is adjusted for operating costs, provincial royalties, and provincial and federal taxes. The operating costs for heavy oil, which include strictly the cost of operating wells, and does not include the return on capital, have remained constant for the last few years and in some years have actually declined. These costs can be broken down into a fixed and a variable component. In recent years, producibility per well has increased due to horizontal wells, resulting in a decline in the fixed cost components. The variable cost component has declined due to the realization of efficiencies and lower inflation. In comparison with other medium and light oil producing areas, the operating costs for heavy oil are higher largely due to sand control measures and sand corrosion.

Producer netbacks are important indicators of the health of a particular industry. Since they reflect returns to the industry, they are useful in analyzing the effects of fiscal regimes and on the distribution of economic rents. Netbacks are an important determinant of the decision to invest, and therefore, are evaluated in drilling and exploratory decisions by the petroleum industry. It should be noted, however, that an allowance for drilling and exploration costs is not made in the calculation of netbacks, - companies must pay these costs and receive a return on investment out of the netbacks.

The current Crown royalty/freehold production tax structure for conventional heavy crude oil is sensitive to both well productivity and heavy oil price. Conventional heavy oil is categorized into two vintages for royalty/tax purposes. These vintages are heavy new oil and heavy third tier oil.

The heavy new oil vintage applies to production from vertical wells drilled prior to 1994 and to production from horizontal wells drilled after March 31, 1991. The heavy new oil royalty regime is designed to capture a base royalty of 10 per cent at a reference well production rate of 20.7 B/D and a heavy oil price of $7.95/B. At the same reference production level the royalty level is adjusted to capture 25 per cent of the wellhead value in excess of $7.95/B.

The heavy third tier oil vintage applies to production from vertical wells drilled after December 31, 1993. The heavy third tier oil royalty regime is designed to capture a base royalty of 10 per cent at a reference well production rate of 20.7 B/D and a heavy oil price of $15.89/B. At the same reference production level the royalty level is adjusted to capture 25 per cent of the wellhead value in excess of $15.89/B.

The following table demonstrates the production sensitivity of the royalty regime at various heavy oil price levels.

TABLE 13
CONVENTIONAL HEAVY OIL ROYALTY RATES

Well Productivity B/D	@$7.95/B (%) New	@$7.95/B (%) Third Tier	@$12.00/B (%) New	@$12.00/B (%) Third Tier	@$15.89/B (%) New	@$15.89/B (%) Third Tier	@$20.00/B (%) New	@$20.00/B (%) Third Tier
5	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
10	5.8	5.8	9.2	5.8	10.9	5.8	11.9	7.9
20	8.9	8.9	13.9	8.9	16.3	8.9	17.8	11.9
50	10.8	10.8	16.7	10.8	19.6	10.8	21.4	14.4
100	11.4	11.4	17.7	11.4	20.7	11.4	22.6	15.2

Note that the above royalty rates have been reduced by the Saskatchewan Resource Credit (currently set at 1 per cent).

Source: Saskatchewan Energy and Mines

Heavy oil wells drilled after December 31, 1993 and incremental oil from new or expanded waterflood projects commencing operation after December 31, 1993 may qualify for certain royalty/tax reductions.

Vertical heavy oil wells may qualify for a royalty/tax incentive volume. A maximum third tier oil royalty of 5% (before application of the Saskatchewan Resource Credit) applies during the incentive volume period. The incentive volumes for vertical heavy oil wells are as follows:

Oil Well Type	Incentive Volume
Infill and re-entry	Nil
Non-infill development	12,585 B (2000 m^3)
Exploratory	50,339 B (8000 m^3)

Horizontal heavy oil wells also qualify for a royalty/tax incentive volume. The incentive volume for horizontal heavy oil wells is 75,508 barrels (12,000 m^3) of oil. A maximum third tier oil royalty of 5% (before application of the Saskatchewan Resource Credit) applies during the incentive volume period for horizontal wells not classified as short section or re-entry. Short section horizontal wells (wells with a total horizontal length of less than 300 meters) and re-entry horizontal wells (horizontal wells drilled from existing vertical well bores) pay a maximum third tier oil royalty of 10% (before application of the Saskatchewan Resource Credit) during the incentive volume period.

Oil production from qualifying reactivated heavy oil wells is subject to a maximum new oil royalty rate of 5% (before application of the Saskatchewan Resource Credit) for a period of five years from the date of reactivation. Applicable new oil royalty/tax rates will apply thereafter. Qualifying wells are oil wells that have been shut-in or suspended from January 1, 1993 to December 31, 1993 inclusive and are brought back on production after December 31, 1993.

Incremental oil from new or expanded waterflood projects does not qualify for a royalty/tax incentive volume, however, it does qualify for the third tier royalty/tax structure.

The freehold production tax rate applicable to conventional heavy oil production is determined by subtracting the freehold production tax factor (PTF) from the applicable Crown royalty rate. This calculation applies both during and after any period of reduced freehold production taxes.

Production from approved enhanced oil recovery (EOR) projects qualifies for a cost sensitive royalty regime under which projects are subject to a 10% of operating profit royalty (to a minimum of 1% of gross revenue and a maximum of 5% of gross revenue) before investment payout and a 30% of operating profit royalty (to a minimum of 5% of gross revenue) after investment payout. EOR production from freehold land is not subject to tax before investment payout and is subject to a 23% of operating profit tax after investment payout. The resulting Crown royalty and freehold production tax rates are further reduced by 1% to account for the Saskatchewan Resource Credit.

Both federal and provincial income taxes are levied on all producers. Table 14 provides a breakdown of the various cost components for heavy and medium crudes for the year 1992 including operating costs and royalty rates.

Table 15 below provides the netbacks for the period 1987-1992. Note that the netbacks have varied significantly during this period. Since operating costs, royalties and taxes have not changed significantly, the variation is largely due to changes in prices and differentials.

B. PROJECTED TRENDS IN HEAVY OIL NETBACKS:

The heavy oil differentials have varied significantly from year to year and are currently at very high levels. The differential between Lloyd blend and WTI at Chicago in 1987, 1988, 1989, 1990, 1991 and 1992 respectively was US $3.41, $4.26, $4.53, $5.87, $8.27 and $5.95. It is expected that in the future, the differentials may remain at the 1992 levels in real terms, especially in the short to medium term. Over the longer term, the differentials may widen due to declining world light oil production, and a relatively higher demand for lighter products versus the heavy fuel oil and asphalt. More stringent environmental legislation in the U.S. may also adversely impact the value of heavier crudes.

TABLE 14
PRICE AND PRODUCER COST COMPONENTS
(1992)

	Lloydminster Heavy	Kindersley Heavy	SwiftCurrent Medium
Wellhead Price ($/B)	12.52	13.30	15.73
Operating Costs($/B)*	4.54	3.92	3.67
Royalty & Freehold taxes(%)**	6.82	11.93	24.08
Federal Income Tax(%)***	28.84	28.84	28.84
Provincial Income Tax (%)***	17.00	17.00	17.00

* these operating costs merely reflect averages for that given area. Substantial variations within a given area will exist but for simplicity of presentation, these variations are not illustrated in this table.
** calculated as a per cent of price. Average royalty rate based on sliding scale (6.4 per cent - 12.4 per cent)
*** calculated as a per cent of (price-operating cost-resource allowance) where resource allowance is calculated as 25 per cent of (price-operating cost). The tax rates are the full tax rates

Source: Saskatchewan Energy & Mines

TABLE 15
PRODUCER NETBACKS*
($/B)

	1987	1988	1989	1990	1991	1992
Lloyd - Heavy	4.78	1.10	4.12	6.28	2.68	4.38
Kindersley - Heavy	5.18	2.21	4.58	6.42	3.14	4.57
Swift Current - Medium	4.18	2.94	4.95	6.39	3.80	4.13

* calculated after full federal and provincial tax.

Source: Saskatchewan Energy & Mines

Operating costs have remained more or less constant in real terms over the last five to seven years. It is expected that much of the efficiencies from rationalizations have been realized and further gains in the future may be difficult to achieve. A lower level of reserve additions due to smaller size of pools discovered in the future may also prohibit any gains in operating costs. However, technological changes such as the horizontal wells may decrease operating costs per barrel, largely due to the large volume of oil produced per day from a given well. Although, it is difficult to ascertain which factors will dominate, a modest increase in operating costs may be more likely.

The WTI price is expected to remain constant in the $18/b to $22/b range in constant 1992 dollars. Such a price level is consistent with OPEC production of 22-27 million B/D. Current demand for OPEC output is 23 million B/D.

Given the above possible trends, it is difficult to determine how netbacks will change in the future. Much will depend upon the magnitude of the various changes. Overall, the heavy oil netbacks may remain more or less constant in real terms or decrease modestly over the foreseeable future.

The level of netback is important for the survival of the industry both in the short and the long term. In the short term, lower netbacks are directly related to the level of shut-ins. The lower the netback, the higher the level of shut-in. If lower netbacks persist for a lengthy period, it may lead to permanent well abandonments. In the long term, netbacks affect the level of reinvestment directly and, therefore, the very survival of the industry. From a corporate viewpoint, when selecting investment options, investors evaluate alternative investment opportunities, including expected return on other competitive industries.

The rates of return on capital for the petroleum and other industries for the last five years are provided in Table 16. This table indicates that the rate of return in the petroleum sector between 1986 and 1992 were consistently lower than those in the other sectors. Between 1981 and 1985, the rate of return in the petroleum sector was lower than the manufacturing and other non-financial sectors, but higher than the mining sector which has also suffered from low resource prices. Overall the earnings in the petroleum sector in the 1980s were significantly lower than those in the late 1970s and this has taken a toll on the reinvestment levels.

The reinvestment rates for the petroleum industry declined dramatically both in response to lower prices and the introduction of the National Energy Program (NEP) which constrained the growth in prices, levied taxes and reduced netbacks. Table 17 indicates a somewhat lagged response between netbacks and rates of return illustrated in Table 16. A change in the rate of return leads to a change in the reinvestment ratio in the following year.

It may be appropriate to say that in Saskatchewan in recent years, shut-ins have occurred largely due to lower netbacks as opposed to a lack of market. If netbacks stay at current levels, shut-ins will remain high. If market demand is not met due to lower production, current market share may be lost.

TABLE 16
RATE OF RETURN ON CAPITAL EMPLOYED
Canadian Petroleum vs Other Non-Financial Industries
(include both upstream and downstream activities)

	Petroleum	Manufacturing	Mining	Other Non-Financial
1978	9.6	10.2	8.9	7.8
1979	13.3	12.9	15.5	8.6
1980	13.1	11.5	13.6	9.1
1981	7.7	9.3	6.2	8.8
1982	5.4	4.3	4.4	6.9
1983	3.3	8.0	1.9	7.3
1984	6.9	9.7	3.5	8.0
1985	5.8	8.8	2.0	7.9
1986	-0.9	10.5	1.2	10.5
1987	6.4	13.3	10.8	9.4
1988	4.8	17.0	11.7	12.6
1989	3.9	11.7	14.4	9.2
1990	5.1	n/a	n/a	5.8
1991	-0.8	n/a	n/a	2.5
1992	0.2	n/a	n/a	2.5

Source: Canadian Petroleum Industry Monitoring Report, Petroleum Monitoring Agency, Canada

TABLE 17
CANADIAN PETROLEUM INDUSTRY REINVESTMENT RATES

Year	%	Year	%
1978	95	1985	87
1979	92	1986	88
1980	99	1987	75
1981	136	1988	96
1982	138	1989	86
1983	101	1990	90
1984	81	1991	126
1992	90		

Source: Canadian Petroleum Industry Monitoring Report, Petroleum Monitoring Agency, Canada

The investment level has also declined significantly. The total number of wells drilled declined from a record level of 3851 in 1985 to 1079 in 1986 and to 837 in 1992. However, since 1990, there has been a rapid growth in the number of horizontal wells drilled in the province and this has at least partially compensated the relatively low level of well drilling. In Saskatchewan, 77, 146, and 212 horizontal wells were drilled in 1990, 1991 and 1992 respectively.

C. SHORT TERM TRENDS:

1993 so far has been a promising year for the oil and gas industry in general and the heavy oil sector in particular. The total number of oil and gas wells drilled to the end of July, 1993 were 449 and 441 respectively. These compare with 202 and 24 wells drilled in the same period last year. Of the total oil wells drilled this year, 28% are heavy oil with a significant proportion of horizontal wells. Overall, there is a high proportion of horizontal wells being drilled in the province - approximately 44% of the total oil wells drilled in the province so far this year have been drilled horizontally. Of these 41% of wells have been in the heavy oil area.

The sale of Crown Petroleum and Natural Gas Rights this year has been spectacular. Much of this has been due to the enormous interest and success in horizontal well drilling. The majority of the land bought this year has been in the heavy oil area and has been dominated by a few major buyers. In the four land sales held this year, the total revenue reached $83.7 million which compares to $13.7 million in the same period last year. Land sales have not been as high since 1987.

The tremendous increase in activity in the oil and gas sector in 1993 from previous years, can be attributed to several factors including lower interest rates and exchange rates, new flow-through income tax provisions for small companies, success of horizontal wells, higher natural gas prices, and above all the improved access to investment capital for smaller companies through equity markets. The lower interest rates have not only made investment more lucrative, but have also generated interest in the share markets, injecting risk capital into the industry. Lower Canadian exchange rate has improved the wellhead price and hence the netbacks.

Although the recent increase in activity in the heavy oil sector is encouraging, the factors causing this increase do not change the fundamentals of the long term sustainability of this sector. Even at higher drilling levels in 1993, only 6 per cent of total oil wells drilled were exploratory. For heavy oil, the numbers were a little higher at 7.5 per cent. The increase in activity may be short lived still requiring an action plan for the future. The increased level of development activity may well result in a return to more exploratory drilling as industry strives for some sustainability. Increased land sale activity in the province may be an indication that more thought is being given to future exploratory drilling.

VI. SPECIAL ISSUES

Besides the issues discussed in the above sections, there are several other that will affect the economics of Saskatchewan heavy oil sector. These factors may affect the demand for heavy oil, level of netbacks, supply of heavy oil, and the overall sustainability of this sector.

A. PRODUCT QUALITY ISSUES IN CANADA

Over the last few years, environmental concerns have driven most changes in the Canadian and the U.S. refining industry. Product quality requirements have been changing significantly and this has affected the demand for particular quality crude by refiners. For example, in recent years, the industry became particularly concerned with the phase out of lead in motor gasoline and the likely reduction of sulphur in diesel fuel. There was also a greater emphasis on the need for increased refinery process monitoring and tighter control of air and water emissions. Refineries have also been faced with RVP (Reid Vapour Pressure) reductions in gasoline and are now considering possible changes to produce "reformulated gasoline" in the future. These problems are common to most refineries regardless of crude source (domestic or foreign).

Over the next decade, a major change affecting the U.S. refinery industry will be the phased introduction of reformulated gasoline. Although no extensive processing changes are expected during the Phase I in 1995, it is the Phase 2 in which major changes are being expected.

For middle distillates also, the quality requirements are expected to change in the future. Discussions are focussing on the sulphur content of diesel fuel being reduced to a maximum of 0.05 per cent. It is not yet clear if this will apply to heating fuel oil. Setting a limit of 0.05 per cent will require additional hydrodesulfurization facilities. Refineries that use and are designed for light sweet crudes do not have distillate desulphurization. Refineries that are designed for sour crude probably need significant changes to increase desulphurization severity for domestic as well as foreign crudes.

In addition to this, there may be requirements in the future to reformulate diesel fuel including a reduction in the aromatic content. The aromatic levels are uncertain; however, they pose more of a problem for synthetic and heavier crudes. For low levels, even the traditional paraffinic crudes could require severe processing.

Residual fuel production is fairly low from Canadian refineries due to cat cracking, although there is very little coking. In most regions, the maximum allowable sulphur content is being reduced. Currently, Quebec requires a 2 per cent maximum, British Columbia requires a 1.1 per cent maximum, Ontario requires a 1.5 per cent maximum and the Atlantic region requires a 3 per cent maximum. In all regions, the principal source of control over sulphur in products is exercised through crude oil selection.

The light sweet crudes have a low yield of residual fuel and residual fuel sulphur content is 1 to 1.5 per cent. Light sour crudes yield more residual fuel and the residual fuel sulphur content is more than 3 per cent. The residual fuel sulphur yields on heavy sour crudes are worse and usually used for asphalt or conversion feedstock.

In all the examples cited above, the refineries may find it easier and less expensive to deal with these changes through crude oil selection rather than incurring major changes in their capital facilities and infrastructure. This may have a negative effect on the demand for heavy oil or result in the increase in differentials to the point that refinery investment becomes profitable. In the long-term, this increased investment might even lead to expanded capacity to handle lower grade crudes.

B. SARNIA-MONTREAL PIPELINE: IMPACT OF POTENTIAL REVERSAL

Deregulation and the removal of barriers to international trade have changed the pattern of oil movements in Canada. Increasingly, refiners in Montreal have come to rely on imported crude to satisfy their feedstock requirements. This has resulted from a reduction in the cost of imported crude in Montreal relative to the delivered cost of Canadian crude oil.

The Sarnia-Montreal Pipeline was built in the aftermath of the 1973 oil price shock as a security measure. The line has not been commercially viable, relying heavily on federal government subsidies to make up its revenue deficits.

Concurrently, diminishing North American production capacity has made the price of other world crudes more attractive relative to American and Canadian oil. As a result, Canadian crude has become increasingly uncompetitive in Montreal and there is no longer a demand for the pipeline in its present west-to-east configuration.

A number of options have been considered for the future of the line. These include government intervention to continue eastward flow of crude oil in the line, shutdown and decommissioning of the line, reversal of the line, conversion of the line to natural gas use and mothballing of the line.

In April of 1991, the federal government recommended that market forces be relied upon to determine the future of the line. Accordingly, it rejected the use of increased subsidies to the pipeline operator, Interprovincial Pipe Line, to maintain flow in an easterly direction.

Interprovincial Pipe Line announced on August 13, 1991 that it had signed a letter of intent with ANR Pipeline, a subsidiary of Coastal Corp. of Houston, to convert the line to move up to 400-million cubic feet of natural gas to Ontario, Quebec, and the northeastern United States. Before deciding to go ahead with a gas conversion, IPL said it would pursue to the fullest all options for retaining the line in liquids service.

Conversion of the line to natural gas use would add a competitive dimension to gas sales. However, the line's capacity to carry natural gas is limited and its operation in this mode might require ongoing subsidies.

Current estimates show that there is sufficient light crude from Western Canada to meet Ontario's needs until 1995, and possibly until 2000. Most forecasts suggest that Ontario will have to import crude oil from sources other than Western Canada sometime in the next decade. There are two ways in which offshore crude could be imported into Ontario

1. Through the U.S. Midcontinent system

or

2. Via Portland Maine and a reversed Sarnia-to-Montreal line.

Given various tolling scenarios, the cheapest option would be through Portland, Maine

The Portland pipeline runs from Portland to Montreal and is operated by Portland Pipeline Ltd (a subsidiary of Montreal Pipeline Ltd). Originally, there were three lines in place; a 12, 18 and 24 inch line.

The 12 inch line, which was built in 1941, was completely abandoned in 1984. Shell Canada leases the 18 inch line to transport natural gas to the Northeastern United States. The lease on this line allows Shell to continue this service until 1999. Portland Pipeline has indicated that this lease would not be extended beyond 1999.

Only the 24 inch line is transporting crude. The capacity of this line has been 186,000 B/D in recent years. Since its beginning, four pump stations on this line were shut down or mothballed. In 1991, a pump station was reactivated on the U.S. side of the line and the capacity of this increased to 245,000 B/D. If two Canadian pump stations were reactivated, which would require about a two year lead time, the capacity of this line could be brought up to 286,000 B/D. Portland pipeline estimates that if the remaining pumping station was reactivated and additional capital costs were incurred, the capacity could be increased to 400,000 B/D. Furthermore, if the 18 inch line were converted back to crude oil, the total capacity reached would be 580,000 B/D.

The pipeline's potential does not outweigh the capability of the dock facilities in Portland. The pier in Portland is capable of handling 124,000 dwt tankers, however, the draft restriction in the port is 45 feet. This means that the largest tanker traffic possible is limited to LR1 and small LR2 tankers (the practice has been to use LR1 tankers). Recent environmental disasters, such as the Valdez oil spill have caused a lot of pressure on shippers. Environmental pressures are growing in Maine ports like all others and shippers have to pay \$0.04/B into the oil spill contingency fund in Maine. If the Sarnia-Montreal Pipeline were reversed and shipments increased, then this toll could potentially increase with the risk.

Given the capacity of the current Sarnia-Montreal pipeline and the potential capacity of the Portland-Montreal, a reversal of the Sarnia-Montreal pipeline could have an impact on the Ontario market. Western Producers are concerned that tolls on a reversed line may be set at unfairly low rates, resulting in subsidization of crude oil imports into Ontario. They are also concerned that a prematurely reversed line would erode the wellhead price of western Canadian crude by exposing it to increased international competition in the Ontario market. Shippers, they fear, would flood the line with imported crude in order to reduce unit tolls on the line. This would depress prices artificially, forcing western producers to seek markets deeper inside the United States.

In recent developments, the Alberta Petroleum Marketing Commission with the approval of NEB decided to fill the line with 2.3 million barrels of its own crude and maintain an eastward flow of 20,000 to 30,000 B/D to the Montreal market. APMC's first shipment arrived in Montreal at the end of April'92. In the last six months, approximately 9,400 B/D have flown eastward through this pipeline.

C. SHIPPING CANADIAN CRUDE OFF THE WEST COAST

The Trans Mountain pipeline originates in Edmonton and carries crude through the Rocky Mountains to Vancouver area refineries. This line also receives crude oil from British Columbia at Kamloops from the Westcoast Pipeline and can supply the large Washington refineries on Puget Sound. Deliveries to the United States, however, have been less than 20,000 B/D in recent years because of the increased use of Alaska North Slope in this market and other US domestic crudes.

Trans Mountain pipeline capacity is about 190,000 B/D of light crude allowing for bitumen moved to the West Coast from the Alberta Energy Company and Rainbow pipelines. Prior to 1989, Trans Mountain pipeline was limited to one batch of heavy crude per month in order to maintain light crude deliveries to Vancouver and the Puget Sound refineries. In 1989, more pumping stations were added and Trans Mountain gained the ability to move up to 38,000 B/D of bitumen blend while still meeting the light crude requirements of the Vancouver refineries. In 1989, however, only 12,000 B/D of Cold Lake blend were delivered through this line.

In Westbridge, British Columbia, Trans Mountain has a marine terminal and dock used for export of light and heavy crudes. The depth of the Burrard inlet limits tanker size to the LR1 class which is 70,000 dwt. To serve small nearby asphalt refineries, small tankers up to 35,000 dwt are used. However, to ship crude across the Pacific and be economical, large LR2 tankers are needed. LR2 tankers can access the Fernadale area of Puget Sound, but tanker traffic is a contentious issue as a result of oil spill risks. In 1981, Trans Mountain proposed the construction of an offshore terminal at Low Point on the Olympic peninsula in Washington. This was to be a common use facility that would ship Alaskan and offshore crude to U.S refineries on the coast and allow offshore shipments of Canadian crude from the Trans Mountain pipeline. But the shipping option through this terminal has since been rejected.

Since the shutting down of several refineries in the B.C. area, shipments through the

Trans Mountain pipeline to the Vancouver area have decreased, although, some of the displaced crude is flowing to the Washington area. In the past, due to shipments to the West coast, some pressure has been taken away from the IPL system flowing eastward from Edmonton. Since the IPL capacity problem effects only the heavy crudes from Saskatchewan, the existence of Trans Mountain pipeline has a positive effect on Saskatchewan heavy oil. However, this impact may have declined in recent months as the same volumes have not flown through the Trans Mountain since the closure of the Petro Canada and Shell refineries.

D. IPL APPORTIONMENTS AND PROPOSED EXPANSIONS

Due to an increase in production of oil in Alberta, the IPL is operating at capacity and has resulted in some oil production being apportioned. Apportionment, or rationing of capacity is a system devised approximately two years ago by the oil industry and approved by the National Energy Board, in which IPL distributes a proportionate amount of pipeline capacity to companies according to the amount of crude oil production they say they want to transport. In recent months, the oil industry has complained that some companies are exaggerating their production by as much as 25 per cent to ensure they get a higher portion of pipeline capacity when it is apportioned by IPL at the end of each month. It is being estimated that only 10 per cent of the total oil nominated has been shut-in due to a lack of pipeline space. Apportionment for the first eight months of the year has averaged about 27 per cent.

Almost all the capacity problem exists between Edmonton and Regina, and therefore, only the heavy crudes are affected from Saskatchewan. As stated above, the heavy crudes are transported to the IPL terminal via either the Manito pipeline which runs from Blackfoot to Kerrobert, or through the Husky pipeline which runs from Lloydminster to Hardisty. In Saskatchewan, it is being estimated that no volumes have been shut-in due to a lack of pipeline capacity. If pipeline space on IPL is unavailable, heavy crude is trucked to Regina and then shipped to its markets on the IPL system. Due to trucking, however, netbacks are adversely affected. Also, due to the apportionments, oil is being discounted by $0.50 to $1.00/B as those at the receiving end are not assured of delivery in time.

Several options were being put forth to deal with insufficient capacity. IPL is considering a $275 million expansion to carry 125,000 B/D to Eastern Canada and U.S. markets. This will equal about 8 per cent of the existing shipments. This pipeline has been approved by the NEB and is expected to start deliveries on January 1, 1995. The Alberta Energy Company was also considering a $470 million, 24 inch pipeline project, 1,240 km in length from Hardisty to Wyoming, where it was to parallel the existing Platte Pipeline System to Casper. This pipeline was expected to carry 175,00 B/D. However, the proposal to build this pipeline was later withdrawn by the Alberta Energy Company.

Saskatchewan crudes, and especially heavy oil should benefit from any of the pipeline expansions. As Alberta crudes travel south through Wyoming, more space will be available for Saskatchewan crudes. Also, market in the PADD IV area can be accessed through the pipeline to Wyoming. There is some speculation, however, that the IPL expansion into the Chicago market, may flood that market and decrease netbacks.

Pipeline capacity is the largest constraint to crude oil markets. No negative impact is expected from Free Trade Agreement (FTA) or the North American Free Trade Agreement (NAFTA). Despite NAFTA, Canadian crudes may still be desirable in our traditional markets.

E. ENVIRONMENTAL COSTS TO TANKERS

Since the Exxon Valdez Oil Spill in Alaska in 1989, increasing attention has been given to tanker safety. Industry, governments and special commissions have been investigating the issues and potential steps of action to mitigate future oil spills and ensure that funds are in place to deal with oil spills.

The Oil Pollution Act of 1990 was established by the U.S. government and is aimed at establishing rules and regulations regarding future oil spills. This act will result in many studies on establishing limits on liability, initiatives on utilizing deep water ports, and establishing procedures for monitoring and funding the implementation of regulations. The Act is still preliminary, but it is likely that additional costs will be incurred for all tanker shipments of crude oil into the U.S.

Some states have their own environmental legislation which does not limit the ship owner's liability in the event of an oil spill. In Maine, as in some other states, legislation has been in place for some years, however, the Valdez oil spill clean-up has raised concern about the potential enormous liability of a future oil spill. To obtain insurance to cover an unlimited liability is not possible and some tanker companies are insisting that the oil company, as owner of the oil, take on liability. Some tanker companies are refusing to deliver to Portland, and for those who continue to deliver, much higher insurance costs are expected to prevail. If Portland terminal is used to ship foreign crude to Sarnia through Montreal on the reversed Sarnia-Montreal Pipeline, these developments will impact negatively on the delivered cost of foreign crude in both Montreal and Sarnia.

Shipments of offshore oil supplies into Canada from Portland, or from the Gulf Coast via Chicago, enter Canada in bond. They are exempt, at the current time from the U.S. Superfund and the Oil Spill Tax. A small levy, currently $0.04, is applied by the State of Maine to all volumes entering Portland. However, this levy may increase if more crude is brought in through this route, largely because the risk of an oil spill increases with the volume of crude handled by this system.

As a result of the Exxon Valdez spill in Alaska and the NESTUCCA spill on the West Coast of Vancouver Island in 1989, a Canadian commission called the "Public Review

Panel on Tanker Safety and Marine Spills Response Capability." was established. This panel issued its report in October, 1990 with recommendations on how to improve tanker safety and how to respond to marine spills. One of the major recommendations was to levy a $2 (Cdn) per ton on all crude oil and products transported in Canadian waters. This would have been paid into the existing Ship-source Oil Pollution Fund (SOPF) and double hulled tankers would be exempt. It would be an incentive to replace the current shipping fleet with double hulled tankers. A portion of the SOPF would be used to assist in replacing the current shipping fleet with double-hulled tankers. The old SOPF was applied to all imported crude (shipments from Portland and Gulf Coast), however, it was expected that the new SOPF would only be applied to shipments in Canadian waters. Following the recommendations of this Commission, the industry agreed to establish a oil response capability, and the option to install a tax has been dropped for now. Additionally, Canada Coastguard is investigating into installing navigation aids and other such safety measures.

As the delivered cost of foreign crude to Eastern Canada or to Chicago market increases due to environmental costs imposed on tankers, the netbacks to all Canadian crudes will increase, since these crudes compete with the foreign crudes in these respective markets. As explained in the previous section, the Canadian wellhead prices are determined by netting out the transportation costs, exchange rate adjustments and any other applicable tariffs from the crude oil price in Chicago.

VII. SUMMARY

A. MARKETS

- The refined products demand in both the U.S. and Canada has grown significantly since the 1984-1985 period. In Canada, there was an average growth of 2.8 per cent per year during 1985-1990. Demand in the U.S. grew at a slightly lower rate - 1.3 per cent; however, unlike Canada, gains in U.S. demand were also experienced between 1982-1985. Further gains in demand for refined petroleum products are expected during the 1992-2010 period. Demand in the U.S. is expected to grow between 1.1 per cent - 1.5 per cent. In Canada, projected growth rates range between 1.4 per cent - 1.7 per cent. These trends will have a positive effect on demand for Saskatchewan crudes due to a growing demand for refined petroleum products.

- Refinery capital stock in both countries has declined considerably. In Canada, there was a decline of 9 per cent between 1980 and 1992. In the U.S. refining capacity declined by 17 per cent during the same period. Refineries in both countries are at, or will soon approach, full utilization. In 1992, capacity utilization in Canada was 80.1 per cent and in the U.S. 91.0 per cent. In much of the U.S., refined products demand is expected to increase at approximately 1% per annum. Although demand is expected to grow in the PADD II area as well, this area is one of the weaker regions of the country for petroleum demand growth. Nevertheless, it is not certain whether the growth in demand in Saskatchewan traditional markets will be met by an increase in the refinery capacity in PADD II or by transfers from PADD III. Some expansions in the refinery capacity of PADD II is expected due to their favorable access to Canadian markets. Saskatchewan crudes have served as a stable supply to the PADD II area in the past and it is expected that they will benefit from any further expansions in refining capacity in this area.

- Domestic supplies of U.S. crude oil east of the Rockies are in an irreversible decline, increasing U.S. dependence on foreign crudes. The share of foreign crudes in total refinery runs increased from 25 per cent in 1985 to 46 per cent in 1992. In PADD II, foreign crude share increased from 19 per cent in 1984 to 41 per cent in 1992. The decline is particularly strong for light crudes. There is a significant potential for market penetration for both heavy and light crudes from Canada. Since the conventional light crude oil in Western Canada is also in decline, these market opportunities may be exploited by non-conventional synthetic light crudes. The synthetic crude production from the existing Upgraders as well as production from any new upgrading ventures will find significant markets in the U.S. market.

- While Canadian exports to the U.S. have fluctuated over the last two decades, Saskatchewan exports have remained fairly stable. Canadian exports peaked in

1973 at approximately 365.3 million barrels, declining to 59.9 million barrels in 1981. Since then, they have increased again. Saskatchewan exports during this period have remained fairly constant at around 40 million barrels. The demand for Saskatchewan crude has been very stable, and this trend can be expected to continue.

B. SASKATCHEWAN PRODUCTION

- Production of heavy oil increased significantly, from only 8 million barrels in 1969 to 24 million barrels in 1985 contributing 33 per cent of total production. However, after 1985, production declined to as low as 17.8 million barrels in 1991. In this year approximately 55 per cent of oil wells listed as capable were shut-in due to lower prices and netbacks. The trend appears to have reversed in 1992 and so far in 1993, although this is largely as a result of horizontal wells. Despite the available capacity, the production from conventional wells is still low.

- Saskatchewan holds significant potential for additional heavy oil production. The initial oil-in-place estimates suggest that there are 17.6 billion barrels of heavy oil, as compared with 6.28 billion barrels of medium oil and 6.19 billion barrels of light oil. However, despite the high potential, the resource is relatively undeveloped. At the end of 1992, only 7.5 per cent of the initial oil-in-place was deemed recoverable using primary recovery techniques. In comparison, 22 per cent and 19 per cent of initial oil-in-place have been established for medium and light oil respectively. Historically, some of the difference can be assigned to the very nature of the resource, for example, lack of appropriate technology to extract heavy oil given the current economics.

- Since 1982/83, with the exception of 1985, investment in the heavy oil industry declined significantly in relative terms (Figure 3). In 1978, new records were established, with heavy oil drilling accounting for 73 per cent of the total wells drilled. However, by 1989, the ratio of heavy oil wells to total wells declined to only 14%. The share of medium and especially light oil well drilling has increased since 1982 and 1983. The drop in heavy oil investment in this period has largely been due to lower prices and netbacks.

- Another disturbing trend evident since 1981 across the entire oil industry, including heavy oil, is that the proportion of exploratory wells has fallen dramatically from 62 per cent to 13 per cent in 1988 and to 19 per cent in 1992 (Figure 4). The point to note is that the proportion of exploratory wells drilled even in 1984 and 1985 were significantly lower than the pre-1981 years, when the oil prices were at their peak levels.

- The rapid growth in horizontal well drilling in recent years has partially compensated for the relatively low level of investment, and has also boosted the level of oil production in the province. In 1992 and first half of 1993, due to a predominance of horizontal wells in heavy oil, the ratio of heavy oil wells drilled increased to 26 and 28% respectively. The total number of horizontal wells drilled in Saskatchewan increased from 13 wells in 1989 to 77 wells in 1990, 146 wells in 1991 and 212 wells in 1992. In comparison, 31, 82 and 92 wells were drilled in Alberta in 1990, 1991 and 1992 respectively. Approximately 52 per cent of the total horizontal wells drilled to date in Saskatchewan are for heavy oil. The early activity in horizontal well drilling was dominated by the heavy oil area, however, this pattern has started to change. In 1992, 59 per cent of the horizontal wells drilled were in the light/medium areas. The same proportion of light/medium wells were drilled to the end of July, 1993.

Between, 1987-1992, the horizontal well production for heavy oil has averaged 125 B/D as compared to an average vertical well production of 15-20 B/D. As a result, approximately 18% of total heavy oil production is from 2-3% of operating wells in the province. The long term effects of horizontal wells are yet to be known. The question is whether horizontal wells only accelerate production whether they also contribute to increased ultimate recovery?

- In the 1980s, the emphasis was on development and infill drilling, or alternatively on short term development rather than long term. Several factors may be cited for these trends. First, the industry on the whole may be maturing, resulting in a greater emphasis on development. Second, the general fiscal structure of the 1980s may have encouraged a faster return on investment through development and infill drilling. Also, programs such as the NEP had a detrimental effect on long term investment. Third, the tremendous price volatility in the 1980s may have had a negative effect on the long term view of profitability and therefore, on the type of investments.

- Due to a lack of significant exploratory drilling, the ratio of cumulative production to initial established reserves has increased for heavy oil from 55 per cent in 1981 to 63 per cent in 1992. This ratio may increase further if not supported by an improved level of exploratory drilling.

- Producer netbacks for oil vary considerably between the three types of crudes, largely due to differences in costs, prices and royalties. Both well drilling and operating costs vary not just between the types of crude but between the six producing areas. Well drilling costs in the province vary between $140,000 per well for Kindersley light area to $342,000 per well in the Estevan medium area. The operating costs vary between $3.17/B for Kindersley light to $6.55/B for Kindersley heavy. The price of oil also varies significantly. In 1988, the price of Lloydminster heavy was 45 per cent lower than the price of Kindersley-light. In 1991 the difference was 26 per cent and in 1992 the difference was again 44 per cent. The royalty rates also vary between the type of crude and the level of production. In spite of the low royalty rates applied to heavy oil, the high differentials and operating costs have resulted in low netbacks for heavy oil producers and a high level of shut-ins.

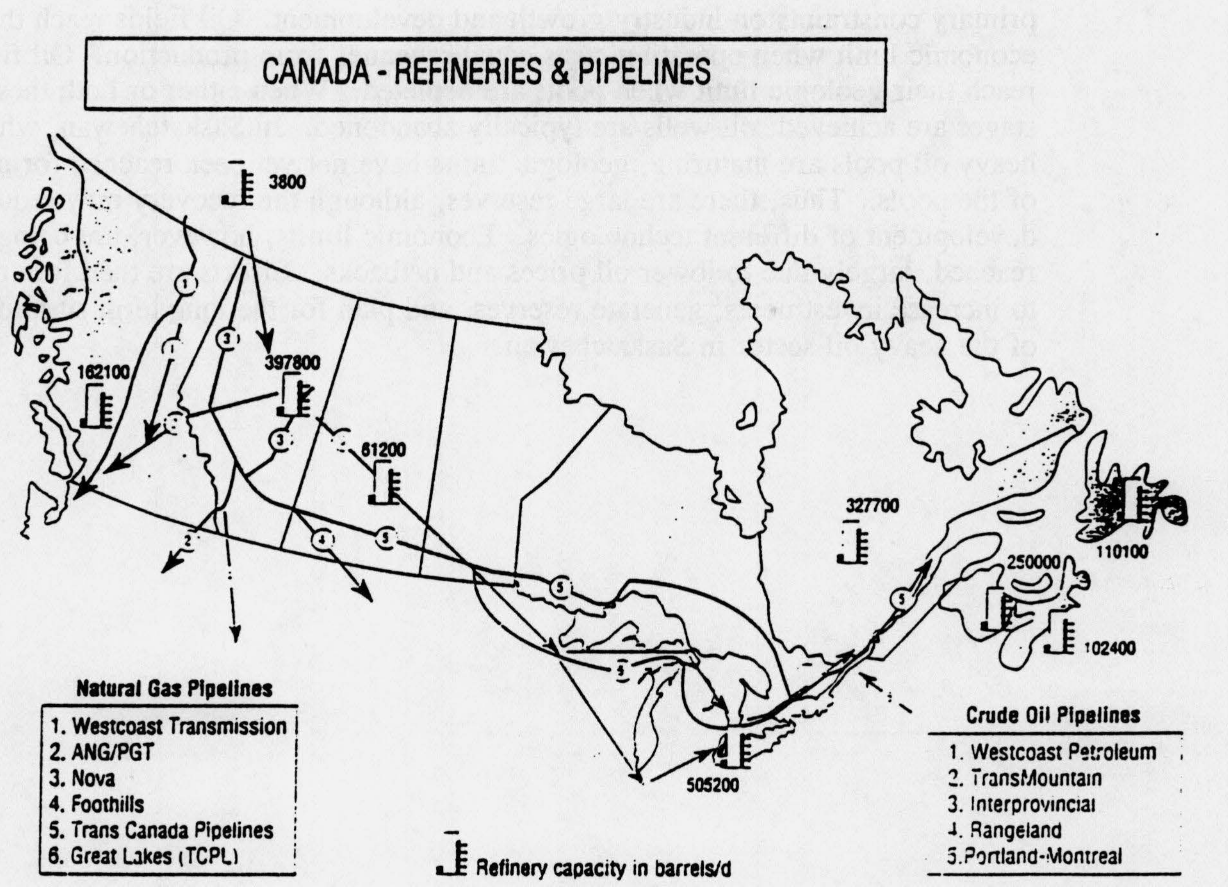
- Due to disappointing trends in investment, the life index of oil has been declining. For the entire industry, the life index in 1992 was 9.2 years. For heavy oil, the life index was 9.5 years. Of interest is the fact that for heavy oil life index peaked at 12.93 years in 1978, the year in which heavy oil drilling reached record levels. Since then, the life index has generally declined. Technology, particularly horizontal wells, may reverse the decline in the long term as we understand better the productivity of this type of well. However, in the shorter term, unless investments result in increased reserves, increased withdrawal rates may decrease the reserve life index.

- The issue for Saskatchewan heavy oil producers does not appear to be whether market opportunities to expand exist, but whether they can be captured at current prices. World prices and an adequate production to meet demand will be the primary constraints on industry growth and development. Oil fields reach their economic limit when operating costs equal revenues from production. Oil fields reach their geologic limit when pools are depleted. When either or both these stages are achieved, oil wells are typically abandoned. In Saskatchewan, while the heavy oil pools are maturing, geologic limits have not yet been reached for majority of the pools. Thus, there are large reserves, although the recovery may require the development of different technologies. Economic limits, however, are being reached, largely due to lower oil prices and netbacks. Efforts are therefore needed to increase investments, generate reserves, and plan for the long term sustainability of the heavy oil sector in Saskatchewan.

VIII. APPENDIX

A. REFINING INDUSTRY IN CANADA

FIGURE 21



Source: Petro graph, CPA

Canada's refining sector has been rationalized in the past decade as a result of highly reduced consumption of petroleum products and an altered product slate. In 1980, the refining sector in Canada had a combined capacity of about 2,327 thousand B/D. By the end of the 1980s, the capacity in this sector declined 20 per cent to 1,918 thousand B/D. Due to the existence of over capacity, especially in western Canada, consumers have enjoyed lower prices due to the competition between the refiners to maintain plant utilization.

Since 1980, the refining industry has made improvements in its processing equipment to increase the production of light products such as gasoline, middle distillates (mainly diesel) and jet fuels. The issues that will face refiners in the next decade are reductions in diesel sulphur levels and improvements in the quality of gasoline in response to continually more demanding product quality specifications. Consequently, it is less likely that refineries will be able to process heavier crudes which are already high in sulphur. Note that currently there is limited refinery capacity to process heavy crude.

The following describes the refinery capacity in various jurisdictions. Figure 21 provides the location and relative capacities of the major refining centers.

British Columbia

At the end of 1992, there were a total of 5 refineries in B.C with a combined capacity of 149,400 B/D. Since then, the Port Moody refinery owned by Petro Canada closed in May, 1993 and Shell's Shellburn refinery at Burnaby closed in June, 1993. Esso's refinery in Vancouver is expected to close in mid-1994, after which there will only be two refineries in B.C. The Chevron refinery at Burnaby has a capacity of 45,000 B/D and the Husky refinery at Prince George has a capacity of 9,600 B/D. Most of the refineries in B.C. have had the capacity of running light sweet crudes. The refineries could run some light sour crude as indicated by sulfur plant and distillate hydrotreating capabilities of 39,654 B/D.

Crude oil production in B.C. has dropped and these refineries have had to rely on pipeline transfers from Alberta. So far, there is no heavy oil conversion capability, but most of the refineries have had asphalt plants. Most asphalt production, however, has been from light crudes and only recently small volumes of heavy, including bitumens from Alberta have been used.

In the future, after the closure of three major refineries, it is expected that refined petroleum products will either be shipped from Edmonton through the Trans-Mountain pipeline or from the Seattle area through trucks or tankers.

Prairies and Northwest Territories

Currently refining capacity is rated at 440,900 B/D with most of it (378,900 B/D) situated in Alberta; 58,500 B/D of heavy oil refining capacity located in Saskatchewan and 3,500 B/D topping refinery at Norman Wells, NWT. Refineries range from the very small pentanes plus refinery at Bowden with capacity of 5,000 B/D to world scale refineries such as the Imperial Oil operation in Edmonton (164,900 B/D).

Most of the Alberta refineries use light sweet crudes. Three of the major refineries near Edmonton (Imperial Oil, Edmonton; Petro Canada, Edmonton & Shell Canada, Scotford) are designed to use significant volumes of synthetic crude oil.

The three refineries in the Edmonton area are all bitumen producers; in the long run, when economics improves, they would see incentives which could justify converting part of their capacity to bitumen feedstock, creating new markets for heavy crude and reducing the demand for diluent used for transporting bitumen. Such a decision would be weighed against the crude processing investments which have already been made in these refineries.

There is only one refinery in Saskatchewan. The 45,200 B/D Consumers' Cooperative Refinery is located in Regina. In 1988, the New Grade Upgrader was added to the Consumers Cooperative Refinery so that conventional heavy crude blend is now used as feedstock.

Asphalt is produced at three refineries in the prairies:

- **Moose Jaw Asphalt** plant uses Lloydminster and Fosterton-Dollard Crude and has a capacity of 13,500 B/D.

- **Strathcona Refinery** is a cracking refinery using light crude oil, it also includes an asphalt train to receive diluted Cold Lake Bitumen and return diluent to the field. This refinery is located in Edmonton and has a capacity of 164,900 B/D.

- **Husky Asphalt Refinery** uses Lloydminster heavy oil exclusively. However, a new pipeline can now deliver heavy oil from Lindberg and Cold Lake. This is situated on the Alberta side of the border and has a production capacity of 12,000 B/D of asphalt.

The Bi-Provincial Upgrader which started operations in 1992 uses approximately 50 per cent of its feedstock from Cold Lake Bitumen. Some of the residual from the Upgrader is used for asphalt at Husky Refinery, but most is cracked.

Typically, asphalt plants are operated during spring and summer during asphalt demand periods. The Moose Jaw and existing Husky plants return "crude tops" to heavy crude shipments to eastern markets.

Ontario

Ontario has the largest concentration of refining in Canada with a total capacity of 571,600 B/D. The sizes range from the smallest at Clarkson (41,000 B/D) to the largest at Sarnia (122,600 B/D).

Most of the refineries run light and sweet crudes and there is little possibility for using the heavier sour crudes. Imperial Oil runs light and heavy sour for its coker at Sarnia, but also requires sweet crude for lube manufacture.

Petro-Canada also requires lube crude at Clarkson. The Petro Canada refinery uses hydro-treating process to manufacture lubes. This process is less feedstock sensitive than the solvent process used by Imperial Oil. The Clarkson refinery tops light and heavy crude for production of lubes, asphalt and distillate. Some reconfiguration took place in 1992. This refinery is now concentrating on lube production by using semi-refined products as feedstock.

The Suncor refinery uses about 50 per cent synthetic crude, together with some sour and light sweet crude. It considered using a heavy oil cracker which might allow some heavy crude, but this option was deferred.

Petrosar uses light sweet crude and condensate to supplement NGL feedstock for ethylene production. Historically Shell Oil at Sarnia has used Weyburn/Midale crudes since it is a significant producer of Weyburn/Midale crudes and has a visbreaker to reduce heavy fuel oil yield. Note that Midale/Weyburn is a medium crude with a relatively high asphalt content.

Esso petroleum has a fluid coker at Sarnia which uses Cold Lake Blend. It also uses residual feedstock from light crudes in order to minimize heavy fuel oil production. Esso's heavy fuel oil use increased from 14,000 B/D in 1984 to 30,000 B/D in 1987 and additional debottlenecking is anticipated in the future.

So far there are sufficient light crude supplies for the Ontario market. After the year 2000, if light crude oil supplies are tight along with capacity, Ontario refiners may have incentive to add facilities to process more heavy crude. Also, as discussed in the Special Issues section, the Sarnia-Montreal pipeline may be reversed to carry off-shore crude to the Ontario market.

Some of Ontario's asphalt market is supplied from Quebec. There are only two asphalt plants in Ontario:

- Petro Canada Bronte refinery in Toronto has historically used Bow River crude although it is capable of processing Cold Lake and Lloyd Blend as well as synthetic crudes. Which crude is used depends on relative prices and plant operating costs.

- The Clarkson unit uses Lloydminster and Smiley-Coleville crudes for asphalt.

Quebec

There are three refineries in Quebec with a total refining capacity of 327,400 B/D. The Petro-Canada refinery in Montreal has historically used both Canadian and foreign crudes delivered by pipeline. The Ultramar refinery in St. Romuald uses foreign crude delivered by tanker. All refineries require medium and sour crudes and the Shell refinery also requires some lube crudes which are usually Venezuelan sour crudes.

These three refineries have been running mostly sweet crudes in recent years. Difficulties in disposing of high sulfur fuel oil will likely encourage these refineries to continue to favor sweet crudes if they are economically priced and available.

All three of the Quebec refineries have asphalt plants. The Petro-Canada refinery at Montreal has paving and industrial asphalt capability, visbreaking, a Canmet upgrading unit and a recently installed Cat-cracker with some residium processing capability. This refinery has the greatest heavy crude capacity in the Quebec region. The Montreal refiners use both imported and domestic crudes, although the share of domestic crudes has been declining. In recent months, only 9400 B/D has been shipped through the Sarnia-Montreal pipeline.

Atlantic Refineries

There are four refineries in the Atlantic Region, most of which were designed for sour mediums, but have mostly used light sweets in recent years (The Ultramar refinery in Halifax was designed specifically for sweet crude and uses 20,000 B/D.)

The Esso Refinery in Dartmouth and the Irving Refinery in Saint John produce asphalt mainly from imported crudes - Esso has occasionally used Cold Lake Blend at its Dartmouth Refinery but continues to favour imports. The Esso refinery has a capacity of 82,300 B/D and the Irving refinery has a nameplate capacity of 237,500 B/D. The Come-By-Chance refinery was restarted in 1988.

A summary of these refineries is provided in Table 18

TABLE 18
1992 REFINING CAPACITY IN CANADA
(Thousand B/D)

Refinery	Location	Capacity	Hydro treating	Hydro cracking	FCC	Coking	Asphalt
British Columbia							
Chevron,	Burnaby	45.0	10.0	0.0	10.7	0.0	2.5
Esso Petroleum	Vancouver	45.3	17.7	0.0	12.3	0.0	1.3
Petro-Canada	Port Moody	25.0	29.5	0.0	0.0	0.0	0.0
Husky	Prince George	9.6	7.0	0.0	2.9	0.0	1.3
Shell Canada	Burnaby	24.0	15.4	0.0	5.6	0.0	2.6
Alberta							
Esso Petroleum	Edmonton	164.8	72.4	0.0	52.8	0.0	9.4
Petro Canada	Edmonton	121.5	53.8	18.9	40.0	7.1	0.0
Husky	Lloydminster	23.0	0.0	0.0	0.0	0.0	11.8
Parkland	Bowden	6.0	6.0	0.0	0.0	0.0	0.0
Shell Canada	Scotford	68.4	42.6	38.7	0.0	0.0	0.0
Saskatchewan							
Co-Op/Newgrade	Regina	45.2	19.8	0.0	18.9	8.3	0.0
Sask Asphalt	Moose Jaw	13.3	0.0	0.0	0.0	0.0	5.5
North West Territories							
Esso Petroleum	Norman Wells	3.2	0.0	0.0	0.0	0.0	0.0
Ontario							
Esso Petroleum	Nanticoke	106.3	25.7	0.0	40.0	0.0	0.0
Esso Petroleum	Sarnia	121.5	45.5	10.4	25.0	21.0	0.0
Petro Canada	Clarkson	60.0	16.2	0.0	0.0	0.0	4.6
Petro Canada	Oakville	80.5	25.8	0.0	25.4	0.0	9.5
Polysar	Sarnia	107.0	15.0	0.0	0.0	0.0	0.0
Shell Canada	Sarnia	71.0	21.3	6.7	14.4	0.0	0.0
Suncor	Sarnia	70.4	30.4	20.0	16.0	0.0	2.5
Quebec							
Petro Canada	Montreal	90.0	35.6	14.4	17.2	0.0	14.3
Shell Canada	Montreal	120.0	61.1	11.7	25.2	0.0	7.2
Ultramar	St. Romuald	124.5	38.3	0.0	34.6	0.0	30.0
Atlantic Region							
Nfld. Refining	Come-by-Chance	105.0	50.9	35.0	0.0	0.0	0.0
Esso Petroleum	Dartmouth	82.4	44.2	0.0	25.0	0.0	5.0
Ultramar	Halifax	20.0	8.8	0.0	7.2	0.0	0.0
Irving Oil	Saint John	174.2	86.0	29.7	17.1	0.0	11.7
Total		1,927.1					

Source: Energy Mines and Resources Canada, The Canadian Oil Market, Vol VIII, No.4 Winter 1992.

B. REFINED PRODUCT CONSUMPTION IN CANADA:

The tables given below illustrate the RPP demand by various regions.

TABLE 19
REFINED PRODUCT CONSUMPTION - CANADA
ANNUAL CHANGE

(Thousands of Barrels)	1982	1985	1990	1992	1982–85	1985–90	1990–92
Gasoline	215563.5	205875.3	213495.4	209336.7	−1.5	0.7	−1.0
Kerosene & Stove Oil	7586.2	5411.1	4330.5	4106.0	−10.7	−4.4	−2.6
Diesel Fuel Oil	83867.2	94389.5	105045.1	99549.6	4.0	2.2	−2.7
Light Fuel Oil	65178.9	46190.6	39949.8	36326.2	−10.8	−2.9	−4.6
Heavy Fuel Oil	52997.4	28448.9	35488.4	30834.6	−18.7	4.5	−6.8
Petroleum Coke	557.9	1293.8	5289.7	4821.1	32.4	32.5	−4.5
Aviation Gasoline	1133.4	1110.2	1033.4	706.3	−0.7	−1.4	−17.3
Aviation Turbo Fuel	25536.7	27045.0	31461.7	29218.7	1.9	3.1	−3.6
Total	452421.3	409763.1	436093.5	414899.2	−3.2	1.3	−2.5

Source: Statistics Canada, Catalogue 57−003, Table 1D

TABLE 20
REFINED PRODUCT CONSUMPTION - ATLANTIC CANADA
ANNUAL CHANGE

(Thousands of Barrels)	1982	1985	1990	1992	1982–85	1985–90	1990–92
Gasoline	18086.4	17117.1	18241.7	17655.5	−1.8	1.3	−1.6
Kerosene & Stove Oil	1392.6	1079.3	774.3	729.0	−8.1	−6.4	−3.0
Diesel Fuel Oil	8447.2	9319.0	10953.7	10578.2	3.3	3.3	−1.7
Light Fuel Oil	12255.1	10709.7	11629.9	11398.4	−4.4	1.7	−1.0
Heavy Fuel Oil	9667.5	7752.8	8038.4	7606.3	−7.1	0.7	−2.7
Petroleum Coke	0.0	0.0	193.7	39.0	n/a	n/a	−55.1
Aviation Gasoline	76.1	80.5	50.9	40.9	1.9	−8.7	−10.4
Aviation Turbo Fuel	2665.0	2823.5	3719.8	3311.0	1.9	5.7	−5.6
Total	52589.2	48880.7	53603.1	51358.3	−2.4	1.9	−2.1

Source: Statistics Canada, Catalogue 57−003, Table 2D

TABLE 21
REFINED PRODUCT CONSUMPTION - QUEBEC
ANNUAL CHANGE

(Thousands of Barrels)	1982	1985	1990	1992	1982-85	1985-90	1990-92
Gasoline	44574.1	42355.7	45792.4	44520.6	-1.7	1.6	-1.4
Kerosene & Stove Oil	1797.6	1007.6	1424.0	1336.0	-17.5	7.2	-3.1
Diesel Fuel Oil	13152.6	14894.3	18505.9	17748.0	4.2	4.4	-2.1
Light Fuel Oil	25231.0	16338.4	13126.2	12345.0	-13.5	-4.3	-3.0
Heavy Fuel Oil	24322.7	10432.9	12959.6	11355.0	-24.6	4.4	-6.4
Petroleum Coke	5.0	537.2	502.6	541.6	374.4	-1.3	3.8
Aviation Gasoline	138.4	165.4	161.6	116.4	6.1	-0.5	-15.1
Aviation Turbo Fuel	4685.3	5313.6	6373.5	5945.8	4.3	3.7	-3.4
Total	113906.8	91044.6	98845.2	93908.4	-7.2	1.7	-2.5

Source: Statistics Canada, Catalogue 57-003, Table 7D

TABLE 22
REFINED PRODUCT CONSUMPTION - ONTARIO
ANNUAL CHANGE

(Thousands of Barrels)	1982	1985	1990	1992	1982-85	1985-90	1990-92
Gasoline	75368.4	74455.8	78475.0	77106.0	-0.4	1.1	-0.9
Kerosene & Stove Oil	1261.7	950.4	726.5	738.4	-9.0	-5.2	0.8
Diesel Fuel Oil	20318.6	24242.9	27549.4	25794.0	6.1	2.6	-3.2
Light Fuel Oil	20942.0	14327.6	10950.6	9122.8	-11.9	-5.2	-8.8
Heavy Fuel Oil	9346.0	5282.8	6911.9	5340.7	-17.3	5.5	-12.0
Petroleum Coke	552.9	717.0	1429.0	766.7	9.1	14.8	-26.0
Aviation Gasoline	255.4	269.2	290.0	132.1	1.8	1.5	-32.5
Aviation Turbo Fuel	7638.4	8949.8	8938.5	8000.0	5.4	-0.0	-5.4
Total	135682.8	129195.5	135271.4	127000.7	-1.6	0.9	-3.1

Source: Statistics Canada, Catalogue 57-003, Table 8D

TABLE 23
REFINED PRODUCT CONSUMPTION - PRAIRIES
ANNUAL CHANGE

(Thousands of Barrels)	1982	1985	1990	1992	1982-85	1985-90	1990-92
Gasoline	51580.3	48685.1	47927.2	45976.1	-1.9	-0.3	-2.0
Kerosene & Stove Oil	1895.8	1507.0	680.6	681.8	-7.4	-14.7	0.1
Diesel Fuel Oil	27475.8	30495.6	31449.1	28760.2	3.5	0.6	-4.4
Light Fuel Oil	2398.9	1590.7	1047.9	700.1	-12.8	-8.0	-18.3
Heavy Fuel Oil	1411.4	1024.6	912.7	883.7	-10.1	-2.3	-1.6
Petroleum Coke	0.0	3.1	3136.7	3441.2	n/a	297.9	4.7
Aviation Gasoline	392.5	331.5	256.6	205.1	-5.5	-5.0	-10.6
Aviation Turbo Fuel	6523.2	6203.0	6044.5	5280.3	-1.7	-0.5	-6.5
Total	91679.2	89838.8	91455.3	85928.5	-0.7	0.4	-3.1

Source: Statistics Canada, Catalogue 57-003, Tables 9D, 10D, 11D

TABLE 24
REFINED PRODUCT CONSUMPTION - BRITISH COLUMBIA
ANNUAL CHANGE

(Thousands of Barrels)	1982	1985	1990	1992	1982-85	1985-90	1990-92
Gasoline	25378.2	22639.6	22437.1	23477.4	-3.7	-0.2	2.3
Kerosene & Stove Oil	695.0	439.7	318.3	212.0	-14.2	-6.3	-18.4
Diesel Fuel Oil	13338.2	13947.1	15688.1	15983.1	1.5	2.4	0.9
Light Fuel Oil	3679.5	2746.1	2615.3	2205.2	-9.3	-1.0	8.2
Heavy Fuel Oil	8199.4	3820.4	6619.4	5418.1	-22.5	11.6	-9.5
Petroleum Coke	0.0	36.5	27.7	32.7	n/a	-5.4	8.6
Aviation Gasoline	189.3	191.2	202.5	155.4	0.3	1.2	-12.4
Aviation Turbo Fuel	3419.1	3233.0	5900.5	6150.8	-1.8	12.8	2.1
Total	54898.8	47053.5	53809.4	53634.7	-5.0	2.7	-0.1

Source: Statistics Canada, Catalogue 57-003, Table 12D

Gasoline Consumption:

Gasoline consumption in Canada increased at an average rate of 0.7 per cent a year from 1985 to 1990 after falling 1.5 per cent a year from 1982 to 1985. The reason for the weak growth was primarily a function of regional differences in automotive stock. The stock of motor vehicles is much newer in eastern Canada, as a result of the high rate of depletion caused by the amount of salt they use on winter roads. The number of fuel efficient cars introduced in the early 1980s in eastern Canada became a greater part of the total stock of cars on the road by the mid 1980s. As a result, most fuel efficiency gains were realized by 1985 and gasoline fuel consumption grew at a rate of 1.2 per cent a year. In western Canada, the stock of motor vehicles is much older and consequently, the addition of new more fuel efficient cars did not have a major impact until the late 1980s. In fact, the gasoline consumption dropped an average of 2.4 per cent a year between 1982 and 1985. However, the decline slowed as efficiency gains were fully realized with the replacement of the older stock with newer fuel efficient cars. From 1985 to 1990 gasoline consumption fell only by 0.3 per cent a year. The trends reversed, however, in 1990-92 for most parts of Canada largely due to a slowdown in the economy. Gasoline demand in B.C. was strong and grew at 2.3 per cent per year due to the high growth in that region.

In the rest of the 1990s gasoline consumption in Canada is expected to grow at a slightly higher rate than was experienced in the late 1980s in eastern Canada. This is largely due to stable energy prices. As disposable income increases and the energy prices are constant, the share of gasoline in total consumption expenditures will decrease. Consequently, people will travel more miles and purchase vehicles with less fuel-efficient engines. Gasoline consumption in Canada is forecast to grow on average at 0.7 per cent over the next two decades.

Kerosine and Stove Oil Consumption

Kerosine and stove oil are special purpose fuels. The demand for this fuel has been weak. From 1982 to 1985, the demand fell 10.7 per cent per year. Since 1985, the rate of decline has been at 4.4 per cent a year, slowing down further to 2.6 per cent between 1990 and 1992. Consumption is forecast to continue to decline at 2 per cent a year for the next decade before increasing only marginally largely due to growth and the full realization of inter-fuel substitution possibilities.

Diesel Fuel Consumption

Diesel fuel in Canada, unlike other refined products, had very strong growth in demand during the 1980s. From 1982 to 1985 annual growth in consumption averaged 3.8 per cent and from 1985 to 1990 it averaged 2.1 per cent. The large increase in diesel fuel consumption was in part due to the deregulation of the trucking industry in Canada and the relative expense of railroad transportation costs versus trucking. Transportation is very closely linked to economic growth. The demand for diesel fuel oil declined during the 1990-92 period largely due to the recession. However, it is expected that as the economy recovers, the demand for diesel will increase again, approximating 1.5 per cent annually for the next two decades.

Light Fuel Oil Consumption

In Canada, light fuel oil consumption dropped dramatically in the 1980s. From 1982 to 1985 the drop in consumption was at a rate of 10.9 per cent a year. From 1985 to 1990 the rate of drop in consumption slowed to 3.0 per cent a year. Light fuel oil consumption dropped for two reasons: first, warmer temperatures and better energy efficiency through insulation and improved furnaces decreased the need for heating oil; second, inter-product substitution in favour of natural gas took place during this period. The second reason had a much greater impact. The relative price of natural gas and the introduction of it into new markets in eastern Canada caused people to switch from oil to natural gas. Between 1990-92, light fuel oil consumption dropped further, decreasing at 4.6 per cent per year, again as a result of low growth and fuel switching. As a result of the competition, oil prices have dropped dramatically and are forecast to remain stable. Natural gas is not forecast to continue its rapid expansion into these markets as it has in recent years so the drop in light fuel oil consumption should be slower. It is expected that consumption will drop only by 1.0 per cent a year for the next decade and then increase by 1.0 per cent per year thereafter.

Heavy Fuel Oil Consumption

In Canada, as utilities switched to cheaper sources of fuel, heavy fuel oil consumption dropped dramatically at 17.2 per cent annually from 1982 to 1985. Demand, however, in the coastal provinces (British Columbia and the Atlantic Provinces) did not drop off as dramatically, as this fuel is also used for bunkering. Demand in Canada has increased at approximately 4.5 per cent a year between 1985-90 and declined by 6.8 per cent between 1990-92 period. The demand in the late 1980s has been driven primarily from the Atlantic Provinces and British Columbia. In the future, demand for bunkering is expected to grow in line with future regional economic growth as there are no ready substitutes for heavy fuel oil. Also, demand for heavy fuel oil in certain industries such as the pulp and paper and mining industries and the iron industries in Ontario is expected to increase due to the unavailability of other alternate fuels in remote locations, where these industries are located. However, the demand for heavy oil in the utility sector is expected to decrease further. It is expected that the demand for heavy fuel oil will grow at an average rate of 1.0 per cent a year in the period 1993 to 2020.

Petroleum Coke Consumption

The demand for petroleum coke is very small. From 1985 to 1990, the demand for petroleum coke increased by 32.5 per cent per year as a result of large consumption increases in the prairies. The future of petroleum coke, however, appears weak and consumption is forecast to increase only at 1.2 per cent a year from 1993 to 2010. Canadian refineries on the prairies have a problem disposing of coke as a result of high transportation costs and Canadian refineries, in general, have little opportunity to sell coke to the United States as that market is already over supplied.

Aviation Gasoline

Aviation gasoline consumption has fallen steadily since 1982. The decline was even accelerated further between 1990-92 period due to slow growth in the economy and lower demand for air travel. Consumption of aviation gasoline is forecast to continue to decline at a rate of 0.7 per cent a year for the next decade before levelling off and increasing at 1.0 per cent a year beginning in 2005.

Aviation turbo fuel consumption grew 1.9 per cent a year from 1982 to 1985. Since 1985, the consumption first increased at 3.1 per cent a year and then declined by 3.6 per cent per year in the recession period. The increase in consumption in the late 1980s resulted partly from increased travel, not only by domestic flights but by American and other foreign flights. Increased travel by American airlines offering cheaper flights to Canada has increased the amount of fuel consumption. As the economy improves, air travel is forecast to continue increasing and aviation turbo should continue to grow at a rate of 1.5 per cent until 2010.

C. REFINED PRODUCTS DEMAND IN THE UNITED STATES:

The consumption trends for each of the RPPs during the 1970-1990 period are provided in the figures given below.

Gasoline

Consumption of gasoline dropped from 1978 to 1982 and reversed thereafter as gains in vehicle miles travelled began to outweigh the mandated fuel efficiency improvements. Growth in gasoline consumption is expected to average about 0.4 per cent a year for the next decade.

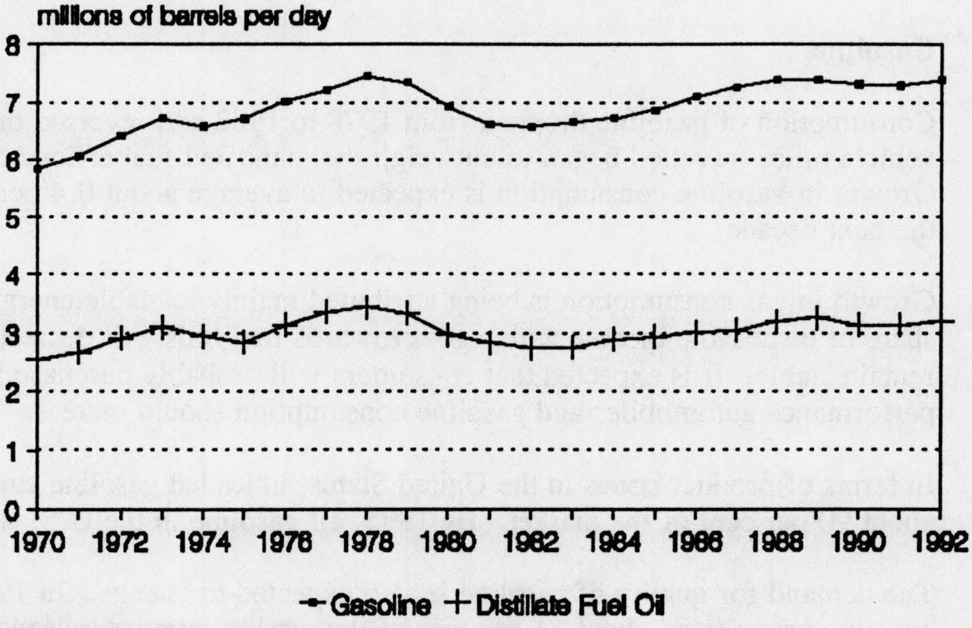
Growth in gas consumption is being attributed mainly to stable energy prices. The share of disposable income which goes towards fuel bills will decrease if energy prices remain stable. It is expected that consumers will probably purchase larger and higher performance automobiles and gasoline consumption should increase.

In terms of product issues in the United States, unleaded gasoline currently makes up about 90 per cent of the market. By 1995, all gasoline in the U.S. will be unleaded.

The demand for quality of gasoline is also expected to change. In 1985, premium gasoline represented about 13 per cent of the market, regular unleaded about 47 per cent and regular leaded about 40 per cent. By 1989, premium was 24 per cent, regular unleaded 59 per cent, and regular leaded 7 per cent.

The trend has been that the market share growth of premium is slowing (20.3 per cent in 1988 to 23.5 per cent in 1989) whereas midgrade has been increasing more rapidly (3.2 per cent in 1988 to 6.8 per cent in 1989). Expectations are that the largest gains in market share over the decade will be made by midgrade gasoline. Midgrade gasoline's share will not only increase because of lead phase out but should take market share from premium as consumers options are increased. By the end of the 1990s, midgrade is forecast to have 25 per cent of the market, premium 21 per cent and regular unleaded 54 per cent. As discussed earlier in special issues section, the changing gasoline quality will impact on requirements for specific quality crudes and refinery capabilities.

FIGURE 22
U.S. GASOLINE &
DISTILLATE FUEL OIL CONSUMPTION



Source: American Petroleum Institute

Historically, most of the gasoline consumption in the United States has been met by indigenous production. However, in recent years about 400,000 B/D has been imported from the Virgin Islands and other Caribbean sources, Brazil, Netherlands and other parts of Europe.

Diesel/No.2 Fuel Oil

Consumption in this category dropped from 3.4 million B/D in 1978 to 2.7 million B/D in 1982. The distillate fuel oil market growth will mostly come from increased transportation consumption. Continued economic growth will increase the need for trucking and therefore, diesel fuel consumption.

Consumption by railroads is about 210,000 B/D and consumption growth by this sector is expected to be slow.

The use of distillate in bunkering has been very small over the last 10 years at about 100,000 to 150,000 B/D. Growth is forecast only to be modest by this category.

Residential sector use of diesel/No. 2 fuel oil is about 60 per cent of the total. While transportation use of this fuel type has gone up, residential use has declined as natural gas and electricity consumption increased. The outlook is that most of the inter product substitution that took place during the period of high prices during the late 1970s and early 1980s is complete and growth by the residential sector should continue.

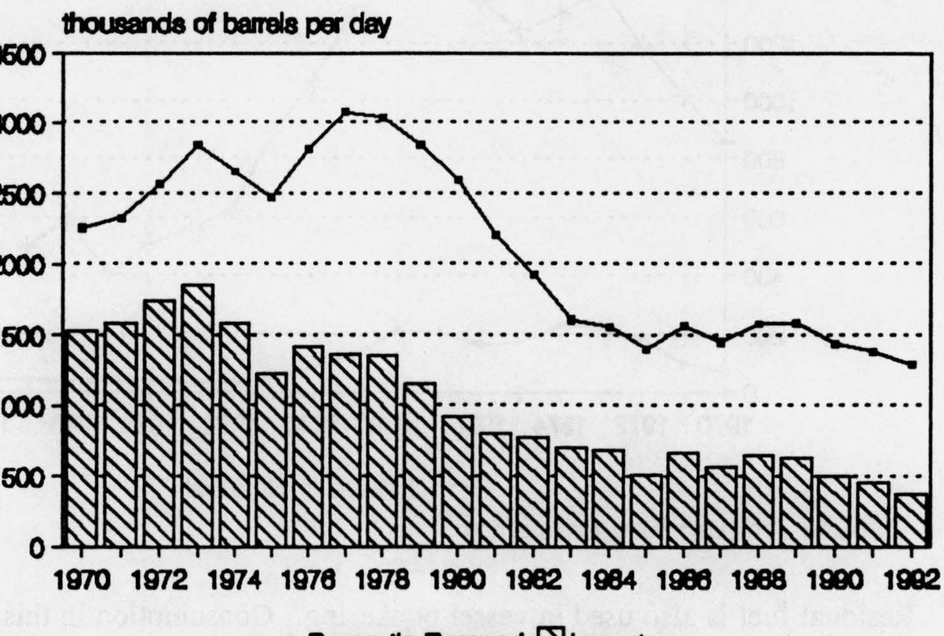
In the industrial sector, consumption dropped from 460,000 B/D to 200,000 B/D due to fuel substitution. It is expected that like the residential sector, most of the fuel substitution has already taken place and consumption should increase with economic growth.

Most distillate fuel oil consumed within the U.S. is produced domestically, however, 200,000 to 280,000 B/D are imported from Caribbean to the East Coast (Algeria and Canada are also sources of supply, but the quantities are small).

Total distillate consumption in the U.S. is forecast to grow at an average of 1.2 per cent a year and reach 3,552 million B/D in 2000 compared to 3,198 million B/D in 1992.

Residual Fuel

FIGURE 23
U.S. RESIDUAL FUEL OIL CONSUMPTION



Source: American Petroleum Institute

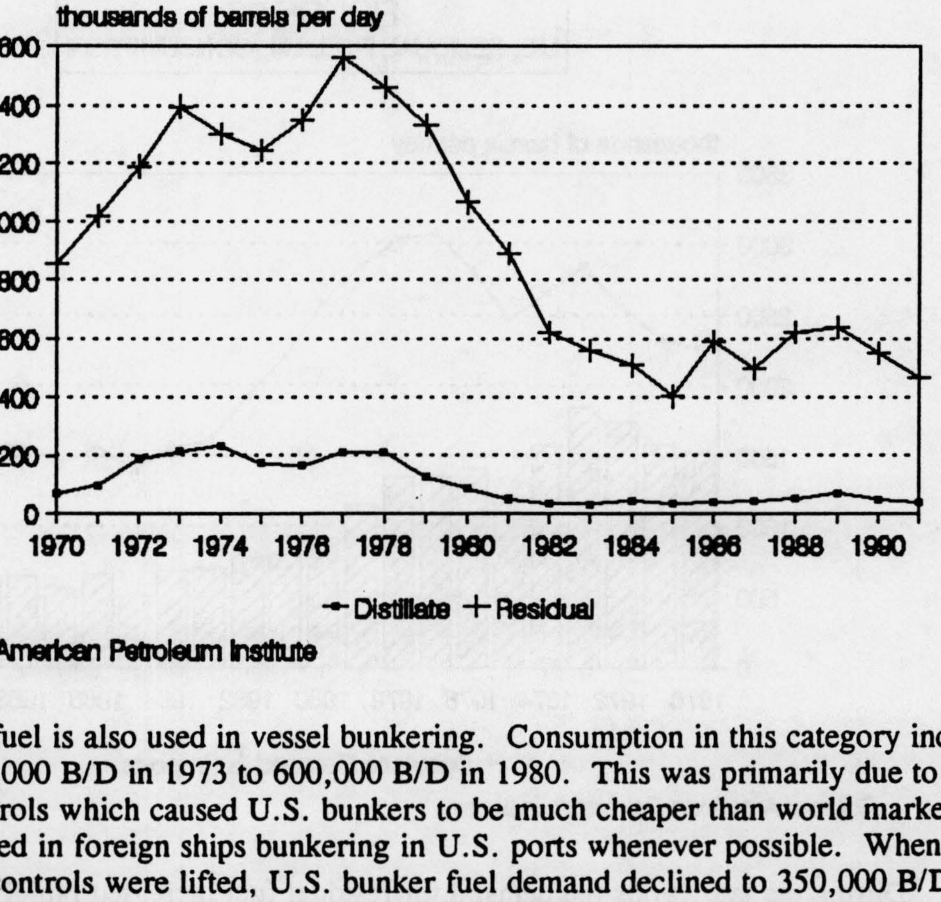
During the late 1960s the demand for residual fuel increased rapidly as utilities burned residual fuel oil in much greater quantities because of its availability and low cost.

During the 1970s residual fuel use in the United States remained high because natural gas supply was in short supply. Use of residual fuel by utilities peaked in 1977 and 1978 at about 1.6 million B/D. By 1985, demand had dropped by 400,000 B/D.

In 1986, residual fuel prices dropped below prices for competing fuels and demand increased 590,000 B/D to 1.67 million B/D. Since 1987, demand has dropped back to normal levels (1.264 million B/D in 1987 and 1.287 million B/D in 1992).
The forecast for residual fuel oil demand is of continual decline and then some growth in the late 1990s as the availability of natural gas is reduced.

Use of resid fuel by the industrial sector was as high as 855,000 B/D in 1973 and has since declined to about 300,000 B/D. A combination of fuel switching due to prices and lower economic activity have caused this trend.

FIGURE 24
U.S. DISTILLATE & RESIDUAL FUEL OIL CONSUMPTION BY UTILITIES



Source: American Petroleum Institute

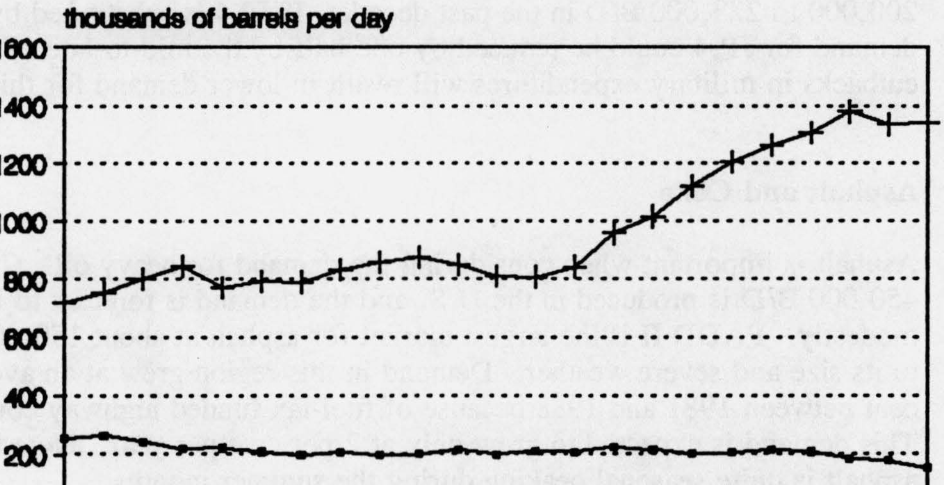
Residual fuel is also used in vessel bunkering. Consumption in this category increased from 260,000 B/D in 1973 to 600,000 B/D in 1980. This was primarily due to U.S. price controls which caused U.S. bunkers to be much cheaper than world market prices and resulted in foreign ships bunkering in U.S. ports whenever possible. When crude oil price controls were lifted, U.S. bunker fuel demand declined to 350,000 B/D. Consumption of bunker fuel for this purpose should increase as petroleum imports into the United States increase.

About 45 per cent of residual fuel oil is imported. The Caribbean tends to be the major source of supply, however, significant volumes of low sulphur resid fuel are imported from Brazil and Algeria.

The U.S. production of residual fuel should increase only gradually with the balance of demand being satisfied by imports. In PADDs III and V, balances will be maintained by exports. PADD II is currently balanced (in inter-PADD trade with PADD III - low sulphur resid is shipped from PADD III and high sulphur resid is shipped back). PADD I is satisfied in the south by shipments from PADD III and foreign imports in New York and Philadelphia.

Other Fuels Consumed in the United States

FIGURE 25
U.S. JET FUEL–NAPTHA & KEROSINE TYPE CONSUMPTION



Source: American Petroleum Institute

Kerosine is a special purpose fuel. About 41,000 B/D was consumed in 1992 compared to 130,000 B/D in 1982. About 18 per cent of demand is currently filled by imports. The outlook for kerosine fuel consumption is that it will continue to decline slightly for the next 10 years.

Aviation fuels are comprised of 3 categories:

- **Aviation Gasoline**
- **Jet A**
- **JP-4**

Aviation gasoline consumption dropped from 45,000 B/D in 1974 to 26,000 B/D in 1982. Since 1982, little has changed. Jet A fuel consumption increased in recent years as a result of deregulation of the U.S. airline industry leading to price wars in air travel and an increase in consumption. Consumption of Jet A increased from 859 million B/D in 1978 to 1,310 million B/D in 1992 and is forecast to continue to increase at 1.4 per cent a year (should reach 1500 million B/D by 2000).

JET A fuel is both exported and imported. Imports are into PADD I and have increased to over 80,000 B/D. PADD III exports about 20,000 B/D. In the future, imports are expected to increase slowly as refineries find it difficult to meet demand on both the east and west coast.

JP-4 fuel is used by the U.S. military. There have been considerations to replace this fuel with JET-A for safety reasons. Consumption of JP-4 has been in the range of 200,000 to 223,000 B/D in the past decade. If JP-4 is substituted by JET A, the demand for JP-4 could be reduced by one half by the mid-to-late 1990s. Also, cutbacks in military expenditures will result in lower demand for this product.

Asphalt and Coke

Asphalt is important when considering the demand for heavy oil. Currently about 450,000 B/D is produced in the U.S. and the demand is forecast to increase only modestly. PADD II is the largest market for asphalt at about 150,000 B/D due largely to its size and severe weather. Demand in this region grew at an average rate of 4 per cent between 1981 and 1988 because of fuel-tax funded highway construction spending. This demand is expected to grow only at 2 per cent per year. Note that the demand for asphalt is quite seasonal peaking during the summer months.

Petroleum coke is produced to upgrade bottoms of barrel rather than as intentional production. Both high and low sulphur coke is produced in the United States. High sulphur coke is used as a fuel and low sulphur is used in the anode market. Historically, the United States has been a major supplier of low sulphur coke to world markets.

D. GEOLOGY OF THE MANNVILLE AND BAKKEN FORMATION

The Mannville Group is divided into nine units: Colony, McLaren, Waseca, Sparky, General Petroleum, Rex, Lloydminster, Cummings and Dina. Within any specific area usually one or two sands will hold the bulk of the reserves. All of the sands may contain some oil, although most of the current production is from the Sparky and

Waseca sands and, to a lesser extent, the General Petroleum, Lloydminster and McLaren Sands. These are shown in Figure 26. The Mannville Group in this area mainly comprises interbedded sandstones, shales and mudstones, with the sandstones being the productive interval in most cases. Most of the sandstones are made up of either weakly consolidated or loose sand. The sands are mostly fine-grained quartz, some of them grading laterally to siltstone or shale. Grains of numerous other minerals occur in small amounts. Cross-bedding is common in these sandstones.

Oil saturation is high with porosity generally exceeding 30 per cent. Oil gravities can vary from 12 to 18° API with an equally large range of high oil viscosities. Productive reservoir sandstones are generally 2 to 10 meters thick and occur at depths between 450 - 750 meters. The productive interval is frequently underlain by a non-productive water-bearing zone and it may also be overlain by a gas cap.

The second large accumulation of heavy oil is in the Bakken formation of Mississippian age (see Figure 26) in the Kindersley area of west-central Saskatchewan. The Bakken formation generally consists of fine-grained quartz sandstones with variable, though generally good, permeability. Some of the sandstones are quite friable and porous; others are considerably more consolidated and dense.

Porosity generally ranges from 24-31 per cent and oil gravities range from 12 to 17o API. Productive Bakken Sand reservoir can vary from 4 to 11 meters in thickness and occur at depths from 740 to 875 meters. The Kindersley area also has heavy oil production from the Mannville Group, although the Bakken is the predominant producing zone in this area.

E. HEAVY OIL PRODUCTION METHODS

Primary Production Techniques

As stated earlier, the majority of Saskatchewan heavy oil deposits are contained in relatively shallow, thin zones of unconsolidated sand. When a well is placed on production, formation sand migrates often into the wellbore. Sand flow occurs when the unconsolidated load-bearing solids are transported with the reservoir fluids. The sand either collects in the wellbore, causing production to cease or be reduced to an uneconomic level, or it is brought to surface with the produced fluid, causing equipment erosion and material handling problems. Therefore, it is often considered essential to incorporate sand control measures. The most common mechanisms used for sand control in the wellbore are mechanically bridging sand by screens, liners or gravel packs.

The current standard completion practice is to drill and case into the expected productive interval and perforate the casing, allowing the mixture of reservoir material and fluids to flow freely into the wellbore. The well is typically drilled deeper than necessary, which leaves a significant volume below the perforations to allow for sand to settle out of the reservoir fluids. After a period of time, the sand builds up in the wellbore and the well is temporarily taken off production and the sand is cleaned out, after which production resumes. This procedure has the advantage of being simple and relatively inexpensive, which outweighs the extra costs of handling the additional volume of produced sand.

Horizontal Drilling

A horizontal well is defined as any well with a minimum wellbore length of 100 meters drilled at an angle of at least 80 degrees from vertical. Virtually all horizontal wells start with a vertical section drilled from surface to the start of the curved section, termed the kick-off point (KOP). From the KOP the well is drilled following a predetermined radius of curvature, generally using a continuous build section, until it reaches the desired point in the reservoir, where the horizontal drainhole is to begin.

The primary purpose of a horizontal wellbore is to expose more of the productive reservoir than can be done with a vertical wellbore. This unique feature presents some real opportunities to increase not only production rates but, more importantly, ultimate recovery. In heavy oil reservoirs, horizontal wells have been used to reduce or prevent water or gas coning, increase recovery from low energy reservoirs, and improve the effectiveness of enhanced recovery projects.

The impact of horizontal drilling on heavy oil activity in Saskatchewan is evident in Figure 5 in Chapter II.

Enhanced Oil Recovery Methods

Enhanced oil recovery (EOR) is a term applied to methods used for recovering oil from a petroleum reservoir beyond that which is recoverable by primary and waterflood methods. In heavy oil applications in Saskatchewan, EOR is limited to thermal recovery methods. The thermal recovery methods used are cyclic steam stimulation, steamflooding, and in-situ combustion.

F. MAJOR CRUDE OIL PIPELINES IN SASKATCHEWAN

Mid-Saskatchewan Pipeline (Koch): The main line runs from Coleville to Kerrobert, Saskatchewan with two feeder lines from Fusilier to Coleville and Dodsland to Coleville. The system varies from 4 to 8 inches and is 50 miles in length with an estimated capacity of 15,000 B/D. The 1990 tariff on this line was $.29/B (CDN) for heavy crude on the Coleville to Kerrobert line and $0.21/B for light crude on the Dodsland to Kerrobert line.

Manito Pipeline (Operated by Murphy and owned jointly by Murphy and CS Resources): This line runs from Blackfoot, Alberta to Kerrobert, Saskatchewan. There is a 4 and 10 inch line, 70 miles in length. Currently, the capacity of the 10" line is 55,000 B/D and on the 4" line it is 8,300 B/D. The latter is the condensate line. The tariff on this line in 1990 was $0.67/B.

South Saskatchewan Pipeline (Operated by Mobil, Union and Koch and owned by Mobil)): The main 16 inch line runs from Cantaur to Regina, Saskatchewan and smaller lines run from Rapdan to Cantaur. The 16 inch line is 187 miles in length with a capacity of 70,000 B/D. In 1990, the heavy crude oil tariff ranged from $0.40/B to $0.61/B.

Producers Pipeline (Operated by Private investors): This line runs from Midale, Saskatchewan to Cromer, Manitoba. This line is 12 and 16 inches, 110 miles long and has a capacity of 100,000 B/D. The Producers Pipeline is connected to an entire network of feeder lines. In 1990, the tariff on heavy and light crude ranged from $0.21/B to $0.56/B.

Wascana Pipeline (Operated by Murphy): This line runs from Regina, Saskatchewan to Poplar, MT. This is a 12 inch line, 160 miles long and has a capacity of 50,000 B/D. In 1990, the tariff on heavy and light crude oil was $0.26/B.

All pipelines in Saskatchewan either run to or from the InterProvincial Pipeline.

Interprovincial Pipeline requires all products in its lines to meet the following specifications:

Reid Vapour Pressure < 103 kpa @ 38 C
Basic Sediments Water < 0.5%
Inlet Temperature > 38 C < 70 C
Viscosity <250cts @ 15 C
Density < 927 kg/cubic meter @ reference temperature or receipt temperature (whichever is lower).

G. MAJOR CRUDE OIL PIPELINES IN CANADA

The main pipeline in Canada is the Interprovincial Pipeline.

Interprovincial Pipeline: There are four main routes for this pipeline in Canada.

From Edmonton, Alberta to Gretna, Manitoba there is a 16, 24 and 34 inch line, approximately 772 miles in length and a total capacity of 1,160,000 B/D. The tariff on this line is $0.79/B (CDN) for heavy and $0.67 for light.

From Gretna, Manitoba to Sarnia, Ontario, the line has the same capacity of 1,160,000 B/D and the toll on heavy is $0.70/B (CDN) and for light it is $0.61/B (CDN).

From Sarnia to Oakville, Ontario, there is a 20 inch line, 194 miles long with a capacity of 470,000 B/D. The heavy crude tariff on this line is $0.19/B and the light crude tariff is $0.21/B.

From Sarnia to Montreal, Quebec, there is a 30 inch line, 514 miles in length with a capacity of 350,000 B/D. In recent years, four out of six refineries at Montreal have shut down, hence the total deliveries to Montreal have been less than 100,000 B/D. A reversal of this pipeline from Montreal to Sarnia is now being considered. The heavy crude oil tariff on this line was $0.56/B and the light crude oil tariff was $0.48/B.

Other pipelines include:

Alberta Oil Sands Pipeline: Runs from Ft. McMurray to Edmonton, Alberta. This is a 22 inch line, 280 miles in length with an estimated capacity of 226,000 B/D. The 1990 tariff on this line was $0.50/B (CDN) for synthetic crude. Note that this line carries no blended bitumen, only synthetic crude.

Alberta Energy Pipeline: Runs from Cold Lake to Edmonton Alberta. There is a 12 and 24 inch line 150 mile in length with an estimated capacity of 215,000 B/D. The 1990 tariff on this line was $1.25/B (CDN) for heavy crude (includes cost of diluent transport).

Bow River Pipeline (Koch): This is a major gathering system with various receipt points to Hardisty, Alberta. Line sizes are 6 to 10 and 12 inches approximately 250 miles in length and an estimated capacity of 60,000 B/D. The 1990 toll on both light and heavy crude ranges from $0.30/B to $1.15/B.

Husky Pipeline (Operated by Husky): There are two systems; Cold Lake to Lloydminster, Alberta - this is a 12 inch line, 110 miles in length and has an estimated capacity of 65,000 B/D. The 1990 tariff on this line was $1.13/B for heavy crude (includes cost of adding diluent) and $0.76/B for light crude. The other system runs from Lloydminster to Hardisty, Alberta. This is a 12 inch line, 70 miles in length with an estimated crude capacity of 60,000 B/D. The 1990 tariff on this system was estimated to be \$.71/B for heavy crude (includes cost of diluent) and \$.55/B for light crude.

Milk River Pipeline (Operated by Murphy): This line runs from Wrentham, Alberta to Montana. This is a 6 inch line, 10 miles long with a capacity of 20,000 B/D. The heavy crude oil tariff on this line in 1990 was \$0.25/B (CDN).

Montreal Pipeline (Operated by Imperial, Petro-Canada and Shell): This line runs in two segments; From Portland, Maine to North Troy, Vermont the line is 24 inches, 165 miles in length with a capacity of 200,000 B/D. The heavy crude oil toll was \$0.63/B (CDN) in 1990 and the light crude oil tariff was \$0.60/B (CDN). If the Sarnia-Montreal pipeline is reversed, then this segment could be used to carry offshore crude to Montreal. This issue is discussed later in the Special Issues section.

The other segment of the Montreal runs from North Troy, Vermont to Montreal Quebec. This is also a 24 inch line, 70 miles in length and a capacity of 200,000 B/D. In 1990, the tariff on heavy crude was \$0.12/B and the tariff on light crude was also \$0.12/B.

Rangeland Pipeline (Operated by Amoco): Runs from Sundre, Alberta south to the U.S. border. This is a 12 and 16 inch line, 235 miles in length with a capacity of 118,000 B/D. In 1990, the heavy and light crude oil tariff was \$0.78/B and \$0.74/B respectively.

Suncor Pipeline (Operated by Suncor): This line runs from Ft. McMurray to Edmonton, Alberta. This is a 16 inch line, 250 miles long and a capacity of 100,000 B/D.

Imperial Pipeline (Operated by Imperial Oil): This line runs from Edmonton to Sundre Alberta. This is a 16 inch line, 130 miles long and has a capacity of 15,000 B/D. in 1990, the tariff on heavy crude oil was \$2.50/B.

Trans Mountain Pipeline (Operated as a public line): This line runs from Edmonton, Alberta to Vancouver, British Columbia. This is a 24 inch line, 723 miles long and with a capacity of 190,000 B/D. In 1990, the tariff on heavy crude was \$1.61/B and on light crude oil it was \$1.34/B.

Rainbow Pipeline (Operated by Esso, Mobil and Shell): This line runs from Three Creeks, Alberta to Edmonton and has a capacity of 235,000 B/D. In 1990, the tariff on heavy crude oil was \$0.39/B.

Peace Pipeline (Operated by 12 private companies): Runs from Gordondale, Alberta to Edmonton. The line is 12 and 24 inches, 350 miles long and has a capacity of 250,000 B/D. In 1990, the tariff on light crude was \$1.83/B.

Federated Pipeline (Operated by Home and Esso): This line runs from Swan Hills, Alberta to Edmonton. The line is 10 and 16 inches, 123 miles in length and has a capacity of 118,000 B/D. In 1990, the tariff on light crude oil was $0.48/B.

Westcoast Pipeline (Operated by Westcoast Energy): This line runs from Taylor, B.C. to Kamloops, B.C.. This is a 12 inch line, 520 miles long and has a capacity of 30,000 B/D. In 1990, the tariff on light crude oil was $0.78/B.

H. MAJOR PIPELINES IN THE UNITED STATES

All American Pipeline (Owned by Celeron): Operates two lines;

A 1,642 mile line runs from Pentland Station, California to McCamey, Texas and has a capacity of 300,000 B/D. In 1990, the tariff on this line was $1.25/B US.

A line runs from Cadiz Station California, to McCamey, Texas. In 1990, the tariff on this line was $1.00/B US.

Amoco Pipeline (Owned by Amoco Oil): Four Lines; One runs from Cushing, OK to Whiting, IN This line is 630 miles in length and has a capacity of 370,000 B/D. In 1990, the tariff on this line was $0.56/B US. Another line runs 150 miles from Laplanta, IL to Wood River, IL and has a capacity 253,000 B/D. The tariff on this line is not available. The 895 mile line that runs from Elk Basin, WY to Freeman, MO has a 245,000 B/D capacity and had a tariff of $0.77/B US in 1990. The fourth line is 234 miles long, has a capacity of 170,000 B/D and runs from Freeman, MO to Cushing, OK. In 1990 the tariff on this line was $0.33/B US.

Arco Pipeline (Owned by Atlantic Richfield Co.): This 500 mile line has a capacity of 120,000 B/D and runs from Pasadena, TX to Cushing, OK. In 1990 the tariff on this line was $0.50/B US.

Ashland Pipeline (Owned by Ashland Oil): Two Lines; The first line is 405 miles long, has a capacity of 210,000 B/D and runs from Patoka, IL to Catlettsburg, KY. In 1990, the tariff on this line was $0.25/B US. A second line is 150 miles long, has a capacity 210,000 B/D and runs from Lima, OH to Canton, OH. In 1990, the tariff on this line was $0.16/B US.

Basin Pipeline (Owned by Texaco, Shell and ARCO): This line runs from Jal, New Mexico to Cushing, Oklahoma and has a capacity of 350,000 B/D. In 1990, the tariff on this line was $0.19/B US.

Buckeye Pipeline (Owned by Pennsylvania Co.): This line is 110 miles long, has a capacity of 105,000 B/D and runs from Samaria, MI to Sarnia, Ontario. In 1990, the tariff on this line was $0.34/B US.

Butte Pipeline (Owned by Shell, Murphy, Meridian and Texaco): This line is 280 miles long, has a capacity of 128,000 B/D and runs from Baker, MT to Guernsey, WY. In 1990, the tariff on this line was $0.35/B US.

Capline (Owned by Shell, Amoco, Southcap, Marathon, Ashland, Texaco and BP): This line is 655 miles in length, has a capacity of 1,078,000 B/D and runs from St. James, LA to Patoka, IL. In 1990, the tariff on this line was $0.35/B US.

Capwood Pipeline (Owned by Shell and Clark): This line is 60 miles long, has a capacity of 225,000 B/D and runs from Patoka, IL to Wood River, IL. In 1990, the tariff on this line was $0.05/B US.

CENEX (Owned by CENEX): This 32 mile line runs from Milk River, Alberta to Cut Bank, Montana and has a capacity of 20,000 B/D.

Chicap (Owned by Unocal, Clark and Amoco): This line is 210 miles long, has a capacity of 500,000 B/D and runs from Patoka, IL to Mokena, IL. In 1990, the tariff on this line was $0.17/B US.

Conoco Pipeline (Owned by Conoco): Operates three lines;
The first line is 305 miles long, has a capacity of 121,000 B/D and runs from Pincher Creek, Alberta to Billings, MT. In 1990, the tariff on this line was $0.73/B US. A second line is 75 miles long, has a capacity of 42,000 B/D and runs from Byron, WY to Billings, MT. In 1990, the tariff on this line was $0.30/B US. A third line runs from Lance Creek, WY to Denver, CO, is 245 miles long and has a capacity of 48,000 B/D. In 1990, the tariff on the line was $0.52/B US.

Cushing-Chicago Pipeline (Owned by Arco and Unocal): This line runs from Cushing, OK to Griffith, IN, is 600 miles long and has a capacity of 300,000 B/D. In 1990, the tariff on this line was $0.40/B US.

Four Corners Pipeline (Owned by Arco): This line runs from Long Beach, California to Cadiz, California. In 1990, the tariff on this line was $0.74/B US.

Jayhawk Pipeline (Owned by Coastal States: NCRA): This line runs from Laton, KS to Whichita, KS, is 285 miles in length and has a capacity of 80,000 B/D. In 1990, the tariff on this line was $0.26/B US.

Kiantone Pipeline (Owned by United Refining): This line is 75 miles in length, has a capacity of 35,000 B/D and runs from West Seneca, NY to Warren, PA. In 1990, the tariff on this line was $0.21/B US.

Lakehead Pipeline (Owned by Interprovincial Pipeline): Operate four routes; From Gretna, Manitoba, to Superior, WI, there is a 327 mile system with a capacity of 1,160,000 B/D. In 1990, the tariff on this line was $0.30/B US. From Superior, WI to Chicago, IL, the line is 467 miles in length and has a capacity of 630,000 B/D. In 1990, the tariff on this line was $0.23/B US. From Chicago, IL to Sarnia, Ontario, the route is 397 miles in length and the line's capacity is 735,000 B/D. In 1990, the tariff on this line was $0.28/B US. Another system runs from Superior, WI to Sarnia, Ontario. This line is 641 miles in length and has a capacity of 555,000 B/D.

Locap pipeline (Owned by Shell, Marathon and Ashland): This line runs from Clovely, LA to St. James, LA, is 30 miles in length and has a capacity 1,300,000 B/D. In 1990, the tariff on this line was $0.10/B US.

LOOP Pipeline (Owned by Marathon, Texas, Shell, Ashland and Murphy): This line runs from offshore Louisiana to Clovelly, Lousiana. The capacity is 1,400,000 B/D and in 1990, the tariff on this line was $0.25/B US.

Marathon Pipeline (Owned by Marathon Oil): Operates two lines; From Patoka, IL to Lima, OH there is a 275 mile line with a capacity of 320,000 B/D. In 1990, the tariff on this line was $0.29/B US. From Benton, IL to Robinson, IL there is a 100 mile line that has a capacity of 110,000 B/D. In 1990, the tariff on this line was $0.19/B US.

Michigan-Ohio Pipeline (Owned by Total): This line runs from Samaria, MI to Sears, MI, is 155 miles in length and has a capacity of 53,000 B/D.

Mid-Valley Pipeline (Owned by Sun Oil and Sohio Oil): This line runs from Longview, TX to Lima Ohio, is 1040 miles in length and has a capacity of 400,000 B/D. In 1990, the tariff on this line was $0.52/B US.

Mid-Valley-Marathon (Owned by Mid-Valley and Marathon): This line runs from Lima, OH to Samaria, MI, is 93 miles in length and has a capacity of 280,000 B/D. In 1990, the tariff on this line was $0.12/B US.

Minnesota Pipeline (Principally owned by Ashland and Koch): This line runs from Clearbrook, MN to Minneapolis-St. Paul, MN. This line is 370 miles in length, has a capacity of 200,000 B/D and in 1990 had a tariff of $0.34/B US.

Mobil Pipeline (Owned by Mobil): Operates four pipelines.

A 250,000 B/D line runs from Midland, Texas to Corsicana, Texas.

A 158,000 B/D line runs from Corsicana, Texas to Patoka, Illinois. In 1990, the tariff on this line was $0.44/B US.

A line runs from Patoka, Illinois to Joliet, Illinois. In 1990, the tariff on this line was $0.21/B US.

A line runs from Midland, Texas to Joliet, Illinois. In 1990, the tariff on this line was $0.95/B US.

Osage Pipeline (Owned by Getty, Mobil, NCRA, and Pester): This 135 mile line runs from Cushing, Oklahoma to Dorado, Kansas and has a capacity of 170,000 B/D. In 1990, the tariff on this line was $0.18/B US.

Ozark Pipeline (Owned by Shell and Texas): This 440 mile line runs from Cushing, Oklahoma to Wood River, Illinois and has a capacity of 325,000 B/D. In 1990, the tariff on this line was $0.30/B US.

Permian (Owned by Occidental): This 32 mile line runs from Milk River, Alberta to Cut Bank, Montana and has a capacity of 10,000 B/D. In 1990, the tariff on this line was $0.50/B US.

Platte Pipeline (Owned by Marathon, Conoco, ARCO, Unocal, and Chevron): This 1,250 mile line runs from Byron, Wyoming to Wood River, Illinois and has a capacity of 173,000 B/D. In 1990, the tariff on this line was $0.97/B US.

Portal Pipeline (Owned by Hunt Oil and Meridian): This 700 mile line runs from Outlook, Montana to Clearbrook, Minnesota and has a capacity of 100,000 B/D. In 1990, the tariff on this line was $0.63/B US.

Portland Pipeline (Owned by Montreal Pipeline Company Ltd.): This 165 mile line runs from Portland, Maine to North Troy, Vermont and has a capacity of 200,000 B/D. In 1990, the tariff on this line was $0.51/B US.

Rancho Pipeline (Owned by Shell and Amoco): This line runs from Midland, Texas to Houston, Texas and has a capacity of 400,000 B/D. In 1990, the tariff on this line was $0.30/B US.

Shell Pipeline Company (Owned by Shell Oil): This 440 mile line runs from Cushing, Oklahoma to wood River, Illinois and has a capacity of 40,000 B/D. In 1990, the tariff on this line was $0.30/B US.

Tecumseh Pipeline Company (Owned by ARCO, Unocal and Ashland): This 205 mile line runs from Griffith, Indiana to Cygnet-Toledo, Ohio and has a capacity of 130,000 B/D. In 1990, the tariff on this line was $0.23/B US.

Trans-Mountain Pipeline (Operated by Trans Mountain). This 64 mile line runs from Sumas, British Columbia to Anacortes, Washington and has a capacity 260,000 B/D. In 1990, the tariff on this line was $0.30/B US.

Texaco Pipeline (Owned by Texaco): Operates two lines;

A line runs from Poplar, Montana to Baker, Wyoming. In 1990, the tariff on this line was $0.27/B US.

Another line runs from Houma, Louisiana to Port Arthur, Texas and has a capacity of 360,000 B/D. In 1990, the tariff on this line was $0.35/B US.

Texas-New Mexico Pipeline (Owned by Texaco and ARCO): This line runs from Jal, New Mexico to Houston, Texas and has a capacity of 63,000 B/D. In 1990, the tariff on this line was $0.63/B US.

Western Oil Trans. (Owned by Occidental (Permian)): This line runs from Alzada, Wyoming to Reno, Wyoming. In 1990, the tariff on this line was $0.54/B US.

West Texas-Gulf (Owned by Chevron, Citgo, Sun, Unocal and BP): This line runs from Colorado City, Texas to Nederland, Texas and has a capacity of 440,000 B/D. In 1990, the tariff on this line was $0.27/B US.

Woodpat Pipeline (Owned by Texaco and Marathon): This 60 mile line runs from Wood River, Illinois to Patoka, Illinois and has a capacity of 315,000 B/D. In 1990, the tariff on this line was $0.10/B US.

Wood River Pipeline (Owned by Koch and Williams): This 590 mile line runs from Wood River, Illinois to Pine Bend Minnesota and has a capacity of 105,000 B/D. In 1990, the tariff on this line was $1.07/B US.