PHASE II – REFINED PRODUCTS AND PETROCHEMICALS FROM BITUMEN

Prepared For

The Government of Alberta and an Industry Group

Prepared By

Purvin & Gertz, Inc.
With Assistance from CMAI

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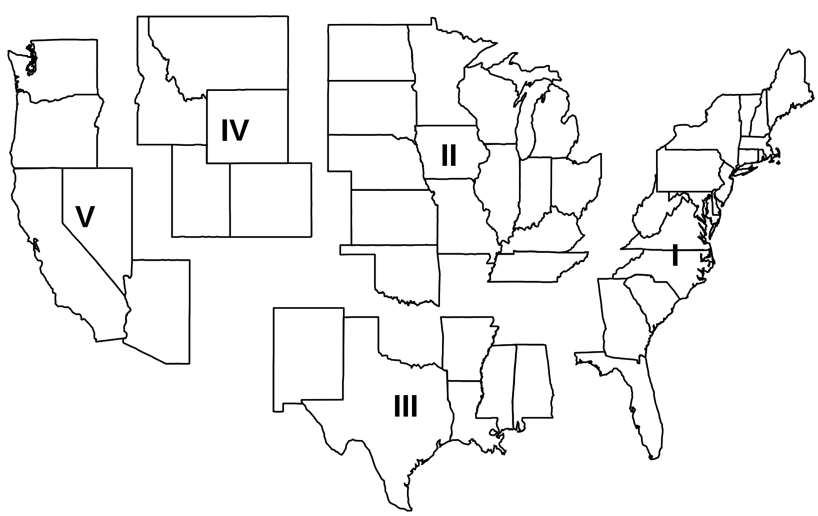
I. INTRODUCTION

This report is the conclusion of the second phase of an analysis undertaken for the Alberta Government and a group of industry participants (hereafter referred to as the “Client”). The Phase I study “Bitumen to Refined Products and Petrochemicals – A Preliminary Assessment” was completed on March 30, 2004. Based on the conclusions of that study, it was agreed by the sponsors that there was sufficient interest to undertake a further analysis to address a number of issues regarding the potential of upgrading bitumen to produce refined products and petrochemicals.

Purvin & Gertz, Inc. (PGI) was retained to confirm the economic potential of upgrading bitumen into refined products and petrochemicals. We undertook this Phase II study with the intent of examining the competitiveness of Alberta supplies into the U.S. markets, primarily California and the U.S. Midwest. The Phase I study did not take into account any price discounts that might be applicable to such new supplies. As outlined in this report, a detailed assessment was undertaken of both the Midwest (PADD II) and California (PADD V) markets, considering the potential in growth in market demand, and the ability to supply these markets utilizing domestic refineries. (See Figure I-1 showing the PADD regions in the U.S.) From this analysis, it was possible to develop market entry discounts, as well as a likely approach, applicable to new products from an Alberta project to effectively enter the market. The economics of the cases developed in Phase I were then consistent with the market entry discounts.

FIGURE I-1
U.S. PADD DISTRICTS



With prospects for strong growth in oil sands production, it is likely that all of the market options will need to be developed in order to updated adequately absorb this increased production. Therefore, in addition to examining the production of synthetic crude utilizing a standalone (base case) upgrader, we also examined the potential to expand markets for bitumen blends and for neat synthetic crude through additional investments in likely refinery candidates in the U.S. market. As a result, we were able to present a comparison of how well the Alberta projects would compare economically relative to refineries in the U.S. making investments to process such oil sands streams.

Most of the cases that were developed in the Phase I report have been updated in this report. In addition, we have added the new U.S. refinery cases. All currencies are quoted in U.S. dollars unless otherwise specified. We used an exchange rate of 0.74 cents (US) per $1.00 Canadian.

We wish to thank the sponsors of this study for their support and input. A number of client members served as advisors on a Steering Committee, and regular meetings were held to review progress and interim results.

As an industry study, we believe this report will help crystallize attention to the need that the Alberta industry needs to explore all of the options to expand markets for oil sands products. We do not believe that there is any one “right” answer, and likely a combination of options and diversification of markets, will best serve the long-term interests of the Alberta industry. Hopefully, this report will pave the way for subsequent initiatives to move forward a combination of upgrading investments within Alberta.

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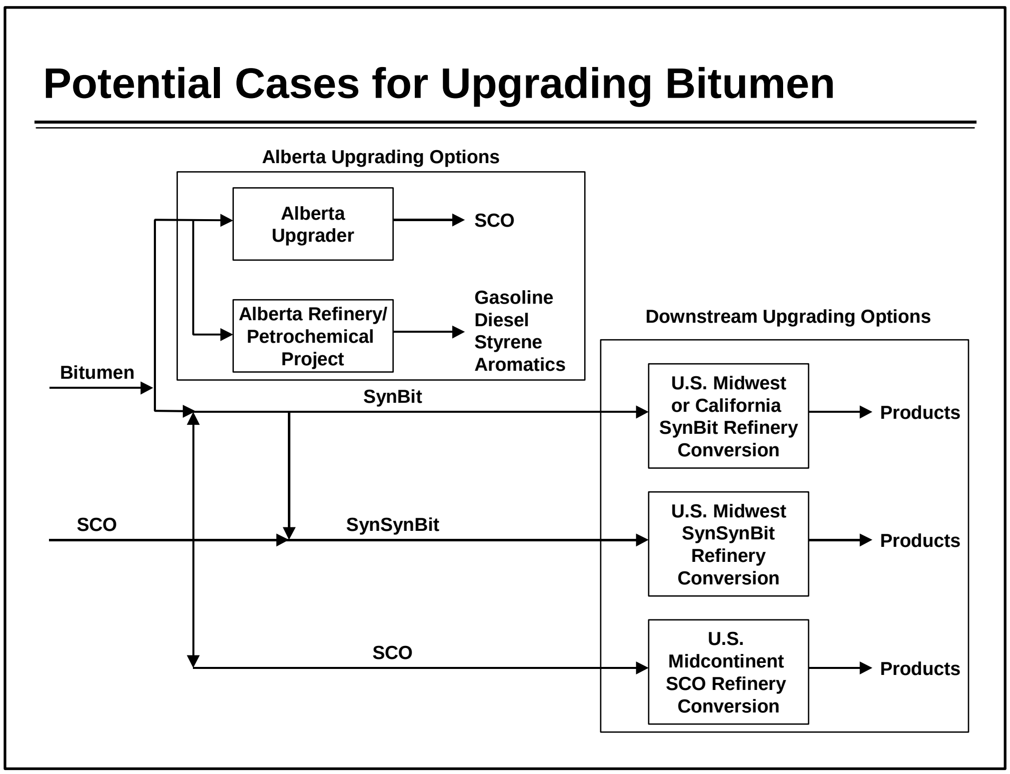
II. SUMMARY AND CONCLUSIONS

EXECUTIVE SUMMARY

With strong expectations for increased production from Alberta's oil sands, developing new market outlets is seen as a high priority for oil sands producers as well as the Alberta Government. Purvin & Gertz was retained to examine several options of producing refined products and petrochemicals from an Alberta upgrader/refinery development, and comparing them to the traditional outlets of upgrading or direct marketing of bitumen.

The cases that were evaluated are shown in the following:



The oil sands industry needs to pursue all avenues for increased market growth for oil sands products. Bitumen blend markets are expected to grow, but growth will be limited by the extent traditional heavy oil refineries will add new capital to increase their capabilities to process heavy crude. We believe there are a few opportunities for large light sour crude refineries to undergo major changes to be equipped to process heavy crude. Sweet synthetic crude (SCO) oil markets are also expected to grow, but as supplies increase, the ability of markets to readily absorb more production may become more limiting. Some light sour crude refineries may be candidates for processing SCO, rather than be converted to process heavy crudes. Faced with the prospects that existing refineries will likely be constrained in the future to process substantial volumes of heavy crude or SCO, there is interest in producing and marketing refined products so not all of the potential future market outlets are dependent on plans of existing refineries.

An Alberta refining project was considered in this analysis to process 200,000 barrels per day (B/D) of bitumen, and producing gasoline, diesel fuel and jet fuel. Intended markets would be to the U.S. Midwest (Chicago) and to California (Los Angeles). It was assumed that segregated pipelines would be available to allow Alberta products to reach each market. In addition, we considered producing styrene in addition to refined products to show the potential to also produce petrochemicals from oil sands developments. Such projects are very capital intensive, ranging from $3.2 to $5.7 billion (U.S.).

We compared the Alberta refining projects to standalone upgrading in Alberta, producing a high quality SCO. We examined the costs of retrofitting refineries to process bitumen/SCO blends (SynBit), higher concentrations of SCO and bitumen (SynSynBit), and neat SCO, as these are the alternatives to upgrading in Alberta. A detailed review of the markets for petroleum products and styrene was also undertaken.

The U.S. Midwest market, particularly the Chicago region, is sufficiently large to be able to absorb a large volume of Canadian products. Around 25% of this market is supplied by transfers from the U.S. Gulf Coast, and currently they are around 1 million B/D. If new Canadian supplies materialized, some of the growth in transfers from the U.S. Gulf Coast would be reduced. Still, only minimal price discounts would be expected.

The California market, particularly around Los Angeles, should also be able to absorb a large volume of Canadian products. This market is not as large as the Midwest, and is nearly totally satisfied by local production. There are some questions to what extent California refineries will grow to meet growing demands. Future demands are expected to be met mainly by California refineries supplemented with supplies from the U.S. Gulf Coast. If significant volumes of Canadian product reached this market, it would displace Gulf Coast supplies, and might forestall some growth of production in California. Price discounts for Alberta supplies in this market will likely be significant, unless they can be minimized by developing relationships with existing refiners. Still, the discounted California prices provided higher netbacks to Alberta than the Midwest because of the higher quality (and higher priced) products in California.

As noted in the table below, the California market provided the best rate of return for an Alberta refinery. The same refinery project, but also producing styrene, had a slightly lower return. Producing refined products for the U.S. Midwest still provided better returns than standalone upgrading.

SUMMARY OF UPGRADING AND REFINING CASES
(Barrels per Calendar Day)

			Upgrader		Refinery		
Case Name	**Case Description**	**Investment $US Million**	**Bitumen Upgraded**	**SCO or Products Produced**	**SCO Purchased**	**Bitumen Purchased**	**IRR %**
1	Alberta Bitumen Upgrader - Sweet SCO	3,351	200,000	177,600			12.2
4	Alberta Refinery - Refined Products						
	Destined to US Midwest	4,700	200,000	174,500			13.3
	Destined to California	4,842	200,000	166,200			15.4
5	Alberta Refinery - Refined Products/Styrene						
	Refined Products to US Midwest	5,363	200,000	171,400			13.2
	Refined Products to California	5,675	200,000	169,700			14.9
6	Upgrading Midwest Refinery to Process SynBit	704			48,000	52,000	19.1
7	Upgrading Midwest Refinery to Process SynSynBit	279			60,000	15,000	9.2
8	Upgrading California Refinery to Process SynBit	359			48,000	52,000	14.5
9	Upgrading Midcontinent Refinery to Process SCO	120			25,000		0.0

The most favourable economic return for the cases evaluated was based on converting a large light sour crude refinery to process 100,000 B/D of SynBit. We believe there are only a few candidates for such a major refinery rehabilitation. After these, we expect returns would diminish.

If SCO production increases to the point that new investments are required to process SCO or bitumen blends with a high portion of SCO, the returns are lower than upgrading in Alberta to produce refined products. The economics of these developments would improve if the price of SCO was lower, which reinforces that SCO prices may come under pressure as new SCO markets are sought.

While the results of this analysis show that an Alberta refining project producing products, particularly for the California market, achieves favourable economics relative to standalone upgrading, there are many commercial hurdles to consider. The ability to control capital costs in large Alberta projects is a huge issue, as such a development has a much higher capital risk than building an upgrader, or retrofitting refineries. The availability of segregated pipelines to deliver refined products to the West Coast or Chicago is also a major issue, and will require extensive analysis and discussions with the respective pipeline companies to develop an acceptable logistical solution.

If the above issues can be reasonably satisfied, then upgrading in Alberta beyond SCO to produce refined products, or refined products and petrochemicals, should be given serious consideration. Such a development has the potential to expand markets for oil sands products without reducing traditional markets for bitumen blends and SCO.

PURPOSE OF STUDY

The objectives and purpose of this study are aimed at confirming the potential of a possible new Alberta upgrading project producing refined products and petrochemicals, and comparing this to expansion or modifications of existing refineries to utilize synthetic crude/bitumen blends (SynBit) or neat synthetic crude (SCO). All of these cases are compared to a benchmark of producing and marketing a light sweet synthetic crude oil (SCO).

In this study, Purvin & Gertz examined the potential Alberta upgrading opportunities of processing bitumen to SCO, and then considered additional cases to produce refined products and petrochemicals. Each case was considered to be a unique project. We selected a conventional upgrading approach involving coking and hydrotreating. The petrochemical options were limited to recovering olefins from the upgrading operations, and producing primarily styrene and xylenes from the refining operations. Our petrochemical analysis did not include direct cracking of hydrocarbon streams to produce ethylene and other olefins.

This study examined the potential of two market regions, U.S. Midwest and California, to absorb a substantial volume of refined products from an Alberta upgrading/refining project. The analysis included primary petrochemicals produced in Alberta for use in Alberta or exported. These product options were compared to the base case of upgrading bitumen only to SCO. The prospects for supplying these markets with new supplies of petroleum products were examined in detail. Approximately 100,000 B/D of gasoline and 50,000 B/D of distillates were considered for export. The market growth potential for the Midwest and California petroleum product markets were examined. A detailed review of the North American market absorbing the styrene output from a new worldscale petrochemical plant was also undertaken.

Another objective of this study was to provide an assessment of how the Alberta projects would compare economically to modifying U.S. refineries to process SynBit, SynBit with more SCO (SynSynBit), and neat SCO.

For the U.S. Midwest, we assumed that a large 200,000 B/D light medium sour cracking refinery that produces asphalt would be used to characterize the Midwest refineries' ability and costs to be modernized to process oil sands feedstocks. For SynBit, a combination of coking and hydrocracking was considered to allow up to 50% of its feedstock switched to SynBit. For SynSynBit, the 200,000 B/D refinery was upgraded through the addition of a new hydrocracker, which allowed it to process close to 60,000 B/D of SCO and 15,000 B/D of bitumen. For neat SCO, a light sweet/sour cracking refinery of around 50,000 B/D was assumed to add a new hydrocracker so that it could process a substantial amount of SCO.

For California, a medium sour coking refinery was modified to process up to 100,000 B/D SynBit, representing approximately 40% of its feedstock, and replacing ANS crude as feedstock. Expansions of coking, catalytic cracking (FCCU), and hydrocracking were included as part of the retro-fit to accommodate the SynBit stream.

Purvin & Gertz utilized its outlook and ongoing market analysis services for refined product prices in the Midwest and U.S. West Coast. Gasoline, diesel fuel, and jet fuel were considered to be the prime petroleum products to be included in the analysis. We utilized input from the pipeline companies to develop the logistics. Market prices within these specific regions were prepared accordingly. Netback prices in Alberta from these markets using the developed logistics costs were then prepared. The netback price of SCO in Edmonton is based on Purvin & Gertz' June 2004 pricing outlook for world crudes and crude pricing in the U.S. Midwest. CMAI provided its base forecast for petrochemicals, and with freight and transportation assumptions, CMAI developed Western Canada netback prices for ethylene, styrene, propylene, benzene, and mixed xylenes for 2010 to 2020.

CASES ANALYZED

This analysis compares the merits of upgrading in Alberta versus adding upgrading to U.S. refineries. The following upgrading cases were considered.

CASES ANALYZED

		Feedstock Processed (Thousands of Barrels per Day)	
		Bitumen	**SCO**
Case 1	Upgrading in Alberta – Standalone Upgrading	200	-
Case 3	Upgrading in Alberta, Producing Diluent and Distillate	200	-
Case 4	Upgrading in Alberta, Producing Refined Products	200	-
Case 5	Upgrading in Alberta, Producing Refined Products and Petrochemicals	200	-
Case 6	Upgrading SynBit in U.S. Midwest	52	48
Case 7	Upgrading SynSynBit in U.S. Midwest	15	60
Case 8	Upgrading SynBit in California	52	48
Case 9	Upgrading U.S. Mid-Continent Refinery to Process SCO	-	25

The Alberta projects were assumed to be constructed in the Edmonton-Fort Saskatchewan vicinity. Bitumen blend from Athabasca was assumed to be delivered to the upgrading facility, and the diluent recycled back to the field. The Alberta projects were all based on using delayed coking as the primary upgrading process. For the production of refined products, the upgrading refineries included delayed coking, hydrocracking, and catalytic reforming. The petrochemical cases involved recovering some of the benzene from the gasoline, purchasing ethylene, and producing styrene.

To enable refined products to be delivered to markets in Chicago or California, we received input from both Enbridge Pipelines Inc. (Enbridge) and Terasen Pipelines (Terasen).

Enbridge will need to modify its pipeline system to accommodate the growth in oil sands products supply. If there is sufficient support for relatively large scale exports of products, the system could be modified to accommodate such deliveries. For products destined to Chicago, if Enbridge builds its proposed Southern Access crude line from Superior to Wood River, it might consider Line 14 to Chicago to be switched from crude oil to refined products. Major changes between Edmonton and Superior will also be required.

Terasen is considering a major expansion using its TMX project. It has proposed 3 phases, and Phase 3 is based on looping the pipeline and doubling its capacity over Phase 2. Such a looping could be available around 2010 if there is sufficient support to move all of the phases of this project forward in a timely manner. Phase 3 would require large increases in crude exports. With the looping, the existing line could handle all of the refined products from the Edmonton refineries and the proposed upgrader/refinery.

Transportation costs for moving the products through the modified pipelines were estimated using existing tariffs with adjustments for new terminalling facilities. For the California markets, product tanker rates were based on deliveries from Terasen's Trans Mountain Westridge terminal to Los Angeles.

In some of the cases, it was assumed that products such as propylene, xylenes, benzene and styrene would be transported to the U.S. Gulf Coast market by rail.

The U.S. refinery cases were developed to explore the merits of re-tooling existing refineries in the U.S. market so that they could process oil sands products. We selected refineries that were not traditional outlets for bitumen blends or SCO. These are refineries that typically are light sour cracking refineries, and process light crudes. The rationale for these refineries is that this refining segment should become the next market tranche to be served by oil sands products if production continues to grow.

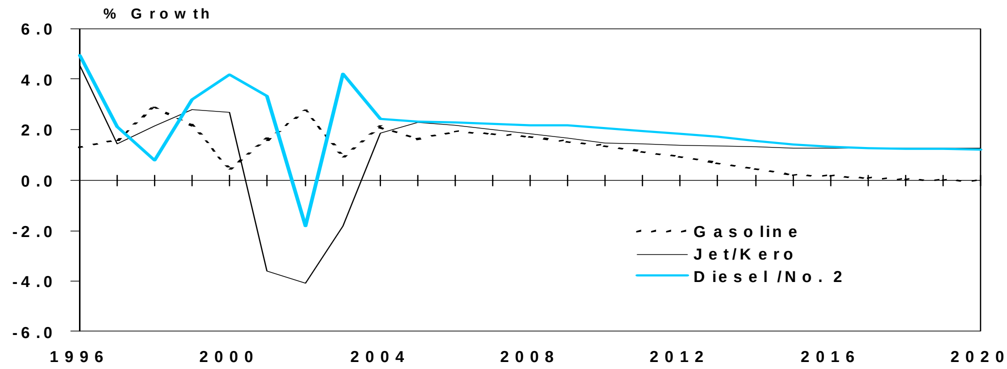
Each of the U.S. refinery cases required new investments to process significant quantities of bitumen blends or synthetic crude. The SynBit cases in the Midwest (Case 6) and in California (Case 8) represent projects that will likely be required to absorb the growing supply of Athabasca bitumen. The Midwest case was assumed to be in the Wood River area. The California case could be either at Los Angeles or San Francisco. In Case 7, we evaluated the merits of upgrading SynSynBit (80% SCO, 20% bitumen) in the Wood River area by adding primarily a hydrocracker, as the feedstock replaces the quality of typical light sour crudes currently being processed in the market. In Case 9, we evaluated the potential of upgrading a light sweet/sour cracking refinery in the Mid-Continent (Oklahoma) to process a substantial amount of SCO.

U.S. PRODUCT SUPPLY AND DEMAND

The primary petroleum product markets considered for receiving substantial volume of products from an Alberta project are in the U.S. Midwest and California. The following describes overall trends in the U.S. products market.

- The U.S. refined products demand was approximately 20 million B/D in 2003. Product demand growth is expected to slow in the future (Figure II-1) to levels averaging under 1.5% per annum, reflecting a continued reduction in the energy relationship to GDP growth, and significant increases in automotive fleet efficiencies as new technologies including hybrid vehicles and direct injection become reflected in the fleet over the next 15 years.

FIGURE II-1
U.S. PRODUCT DEMAND GROWTH RATE



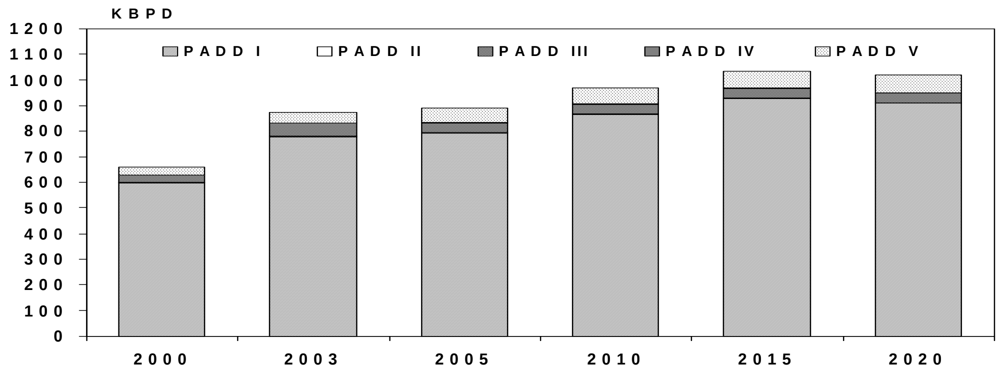
- In spite of the low rate of growth, the total demand for gasoline, jet and distillate (diesel and #2 fuel) oil is forecast to grow by 1.7 million B/D by 2010.

U. S.REFINED PRODUCTS DEMAND
(Thousand Barrels per Day)

	1985	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020	Annual % Change
Motor Gasoline	6,855	7,259	7,810	8,492	8,629	8,866	8,950	9,139	9,288	10,091	10,439	10,463	1.2
Kerosene/Jet Fuel	1,343	1,564	1,568	1,793	1,728	1,657	1,627	1,657	1,695	1,855	1,983	2,110	1.3
Distillate	2,866	3,020	3,207	3,722	3,847	3,776	3,936	4,031	4,124	4,594	4,995	5,311	1.8
Residual Fuel Oil+Asphalt	1,626	1,712	1,338	1,434	1,330	1,212	1,275	1,324	1,344	1,405	1,437	1,458	-0.3
Other Products	2,306	3,630	3,962	4,468	4,159	4,317	4,241	4,334	4,408	4,641	4,813	4,896	2.2
Total Demand	14,996	17,186	17,885	19,908	19,693	19,828	20,029	20,484	20,859	22,587	23,667	24,237	
Annual % Change		2.8	0.8	2.2	(1.1)	0.7	1.0	2.3	1.8	1.6	0.9	0.5	

- Although imports of products are expected to grow significantly, domestic refinery capacity creep should account for most of the demand growth. Imports of gasoline and gasoline blendstock are forecast to grow to over 1 million B/D by 2015, an increase of over 150,000 B/D versus 2003. Most of the imports of gasoline will continue to be imported into the U.S. East Coast (PADD I), Figure II-2. Imports into PADD II and IV are almost negligible.

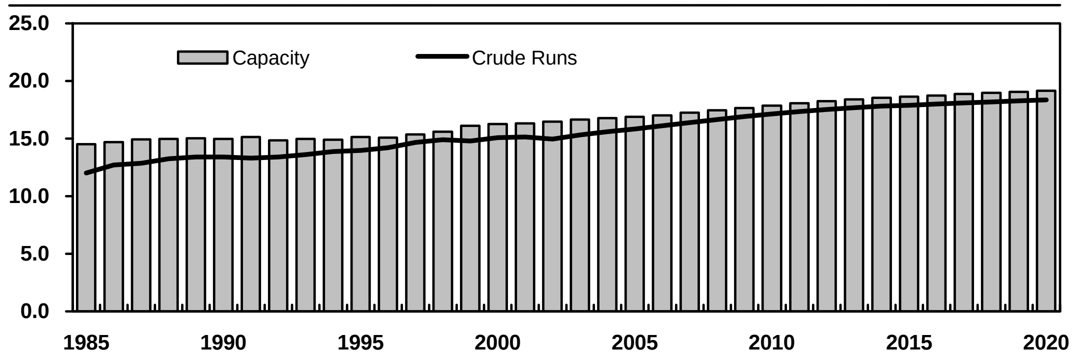
FIGURE II-2
U.S. GASOLINE IMPORTS



- Diesel imports are forecast to grow more modestly, as the low sulphur specification changes will be hard for traditional Latin America supplies to meet, and Europe will remain tight on diesel capacity for its own growth.

- U.S. refinery capacity will continue to be highly utilized, as even the small product demand growth rate remains challenging to meet due to loss of product volume to MTBE reduction, and the difficulties of meeting tightening quality specifications.

FIGURE II-3
U.S. REFINERY OPERATIONS
(Million Barrels per Day)



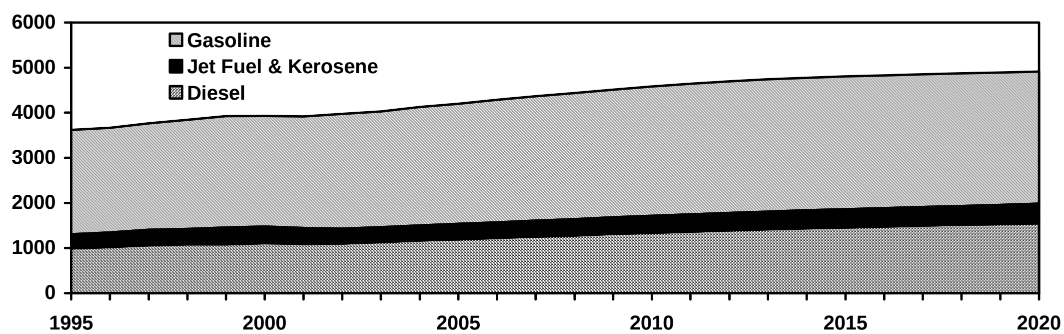
U.S. MIDWEST MARKET

PADD II in the United States consists of the fifteen states located in the upper midsection of the country. Of interest in this study, a "Midwest" region is analyzed. This Midwest region is defined as the states of Illinois, Indiana, Michigan, Wisconsin, Missouri, and Minnesota for purposes of this study.

PADD II LIGHT PRODUCT DEMAND

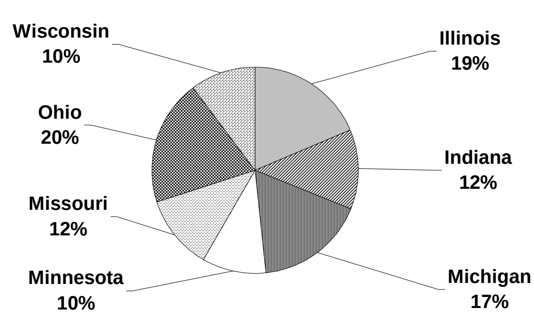
- PADD II gasoline, jet fuel and diesel product demand was 4.0 million B/D in 2003, or 28% of the U.S. total. Of this, 2.8 million B/D was manufactured within the region, and 1.2 million B/D came from the PADD III region, mainly from the U.S. Gulf Coast, via pipeline.

FIGURE II-4
PADD II LIGHT PRODUCT DEMAND
(Thousand Barrels Per Day)



- The largest concentration of demand is in the seven states surrounding Illinois, distributed as follows:

FIGURE II-5
PADD II LIGHT PRODUCT DEMAND DISTRIBUTION IN 2003
(Percent)



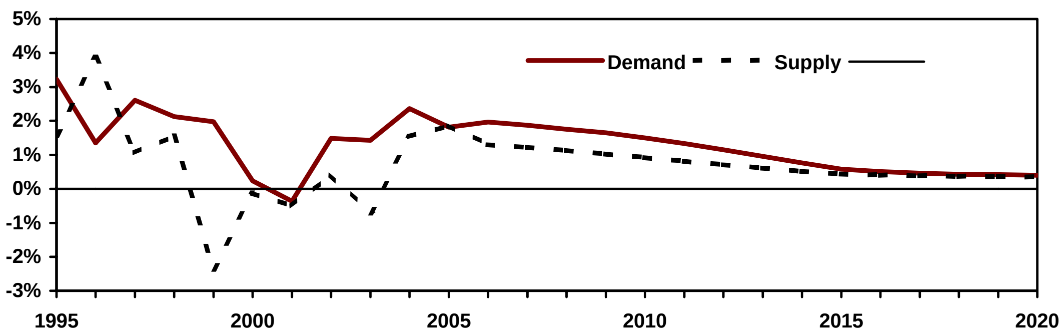
- In 2003, PADD II reformulated gasoline (RFG) demand was 377,000 B/D, or 14% of the total PADD II gasoline demand. Most of this demand is in the Illinois-Indiana (Chicago metro) area. RFG in this region requires ethanol.

- Oxygenated gasoline (10% ethanol) is required in Minnesota on a year-round basis. In 2002, the consumption of oxygenated gasoline, including RFG, in PADD II is estimated to have been 915,000 B/D, or 36% of total gasoline consumption.

PADD II LIGHT PRODUCT SUPPLY

- There are 26 operating refineries in PADD II, ranging in crude processing size from 6,000 B/D to 410,000 B/D in size, with a total capability of 3.5 million B/D. The average refinery size is 135,000 B/D.
- In 2003, PADD II demand exceeded supply of refinery products and blendstocks by 1.2 million B/D. Nearly all of the extra supply comes into the region from PADD III.
- Over the 1991-2003 period, upper Midwest refineries in operation in 2003 were expanded 1.6% per year. But, as shown below, demand growth is expected to exceed regional production growth until 2017.

FIGURE II-6
PADD II LIGHT PRODUCT DEMAND & REFINERY SUPPLY GROWTH
(% Per Year)

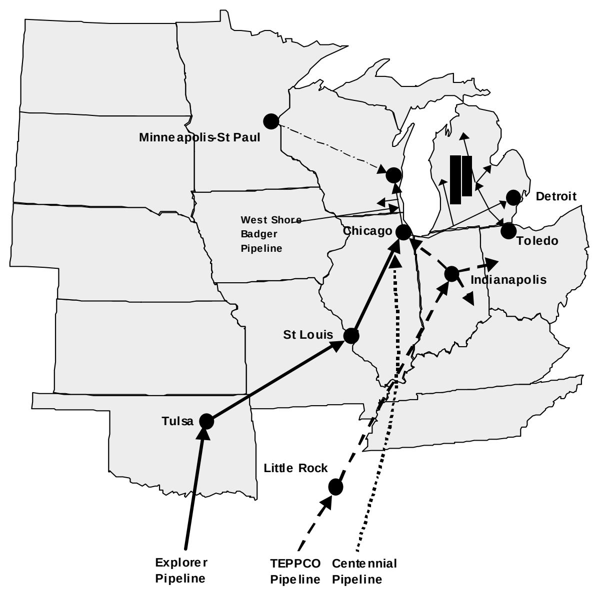


- Foreign imports to PADD II, whether from Canada or from offshore via PADD III, have been negligible in volume. Transfers from PADD III to PADD II are very substantial, however. As shown in the map in Figure II-7, there are three major pipelines moving light products from PADD III to PADD II, the Explorer, TEPPCO, and the Centennial systems. There is surplus capacity in this system, and can be readily expanded if required.

MAJOR PADD III TO PADD II PIPELINES

System	Capacity, Thousand Barrels per Day
Explorer	700
TEPPCO	450
Centennial	210 (Expandable to 320 MB/D)
Total	1,360

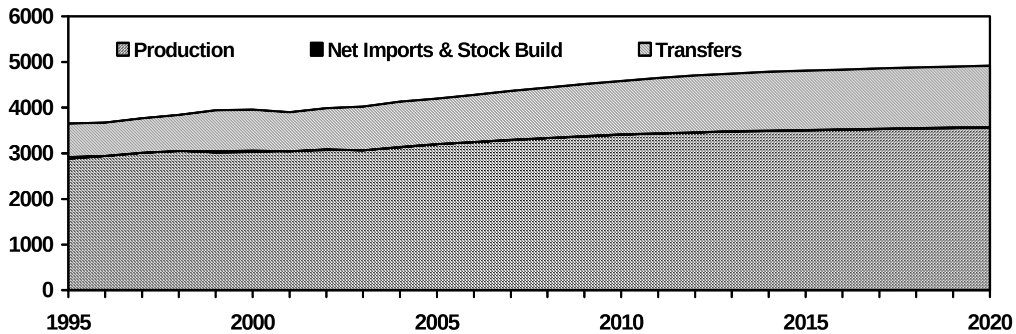
FIGURE II-7
MAJOR PIPELINES FROM PADD III TO MIDWEST



PADD II LIGHT PRODUCT SUPPLY-DEMAND BALANCES

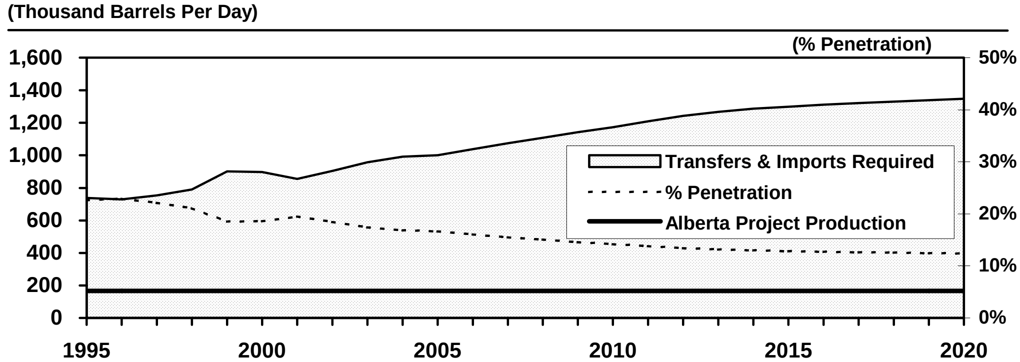
- The change in supply that would be expected on introduction of new export volumes from an Alberta upgrader is expected to be the displacement of an equal volume of transfers coming in from outside PADD II, (Figure II-8). In this analysis we compare the upgrader output to overall PADD II transfers, transfers to Chicago, transfers to the Midwest, and to Detroit. An important attribute of PADD II supply is currently a lack of foreign imports.

FIGURE II-8
PADD II LIGHT PRODUCT SUPPLY SOURCES
(Thousand Barrels Per Day)



- Overall, the Alberta project volumes would have a small impact on the PADD II supply-demand balance, and would represent 20% of current transfers into the region and 17% by 2010. Figure II-9 below shows the magnitude of the current transfers into the market, the expected production from the Alberta upgrader, and the percentage of the accessible market that the Alberta production represents.

FIGURE II-9
PADD II LIGHT PRODUCT MARKET PENETRATION
(Thousand Barrels Per Day)

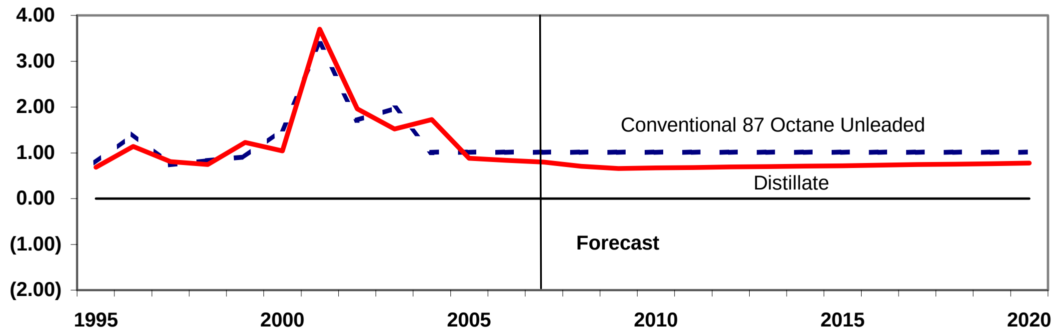


- The Midwest offers a good combination of large markets, a reasonable opportunity to compete in terms of large volumes of product imported from other regions, and reasonable access to existing supply pipelines from Western Canada. Given the existing pipeline network in this region, Chicago was chosen as the best potential receipt location for upgrader product.

CHICAGO ENTRY POINT MARKET PRICE

- Product prices at Chicago are closely related to the U.S. Gulf Coast prices plus the cost of transportation from PADD III. Going forward, the forecast price differentials for both gasoline and distillate prices have been lowered somewhat below historical values, as shown in Figure II-10. This reflects the going forward outlook of continuing pressure on refining margins in the Midwest.

FIGURE II-10
CHICAGO vs USGC REFINED PRODUCT PRICES
(Constant 2004 U.S. Dollars per Barrel)



- The price model for estimation of a netback price for the Alberta upgrader was assumed to be the Chicago price, adjusted for the differences in prices for adjacent regions supplied relative to Chicago, and, finally, an adjustment to account for the penetration of this market by the new product source. The regional volumetrically weighted average price discount relative to Chicago is computed at 0.10 cents per gallon of product. For gasoline and jet fuel sold in the "Chicago Hub" sub-region described above, a typical commercial discount appropriate to contract sales of large volumes of product should be assumed, of the order of 0.25 cents per gallon. Thus, the total discount for gasoline is estimated to be 0.35 cents per gallon, or $0.15 (US) per barrel. In the case of diesel fuel, a composite discount was computed equal to approximately 0.7 cents per gallon for 2010, declining to 0.6 cents per gallon in 2020.

MARKET ENTRY STRATEGY – OPTIONS AND RECOMMENDATIONS

- An independent wholesale market operation is not likely to penetrate the market at a satisfactory rate while providing a satisfactory netback price for products. A better strategy would be to negotiate with the larger regional net buyers of product for term contract supplies, preferably with two or more such buyers, of course. Several of the large retailers are large net buyers of product. The hypermarketers represent a large and growing segment of the market.

- Tiered pricing that allows the buyer to obtain progressively lower priced supply with increased volumes is an effective mechanism for providing an incentive for retail marketing contract partners to maximize their takes under the agreements.

- Product exchanges rather than outright purchase may be offered. It may be necessary to do some of this type of business in order to gain market entry, but the further south the product is sent, the less of a market niche it possesses.

- Chicago is recommended as the physical delivery point. Delivery to St Louis would be expected to provide a lower netback price at the upgrader than would Chicago, although because of the larger market coverage the marketing risk would be lowered.

- In order to provide the project the flexibility to market jet fuel on favorable price terms, the upgrader should be configured with the flexibility to be able to operate with or without jet fuel production.

U.S. WEST COAST MARKET ANALYSIS

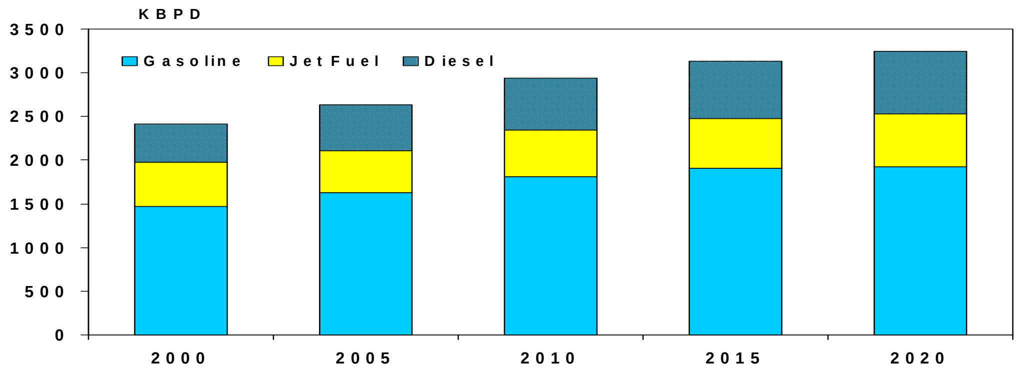
PADD V LIGHT PRODUCT DEMAND

- The U.S. West Coast is a distinct petroleum product market due to its relative geographic isolation and stringent petroleum product specifications. The West Coast is fairly self-sufficient with respect to product supply, although eastern Arizona and Washington receive pipeline supplies from PADDs III and IV, respectively. In recent years, the West Coast has been importing and receiving slightly higher volumes of domestic gasoline, high-valued gasoline blending components, and jet fuel. Other products tend to enter on an opportunistic basis or when refinery outages cause short-term supply disruptions.

- Nearly 60% of the total demand for light refined product is in the state of California, followed by Washington and Arizona at approximately 12% and 11%, respectively. Given its outlook for continued strong growth, Arizona is expected to surpass Washington in total light product demand by 2006.

- Gasoline consumption has grown rapidly over the past four years (2.4% per year) to around 1.6 million B/D currently, Figure II-11. The outlook for PADD V is for continued growth in demand. Lower growth rates are expected in the outer years as the influence of increasing efficiency, higher prices for reformulated fuels, and growth in alternative fuels begins to influence gasoline demand negatively. Nearly two-thirds of the gasoline consumption for the region takes place in California at approximately 1 million B/D.

FIGURE II-11
PADD V LIGHT PRODUCT DEMAND



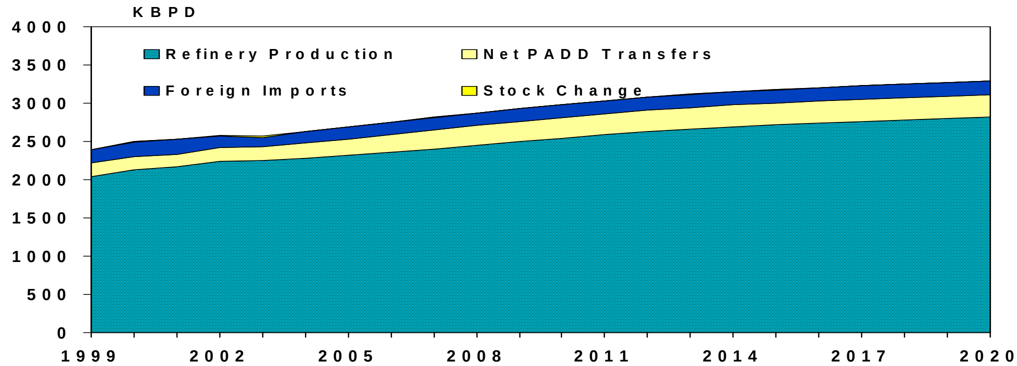
- Distillate consumption in PADD V accounts for about 13% of the U.S. total. The major reason for the low consumption rate relative to the population and level of economic activity is that there is very little distillate used for heating due to the relatively mild weather in the region. The consumption of distillate on the West Coast is heavily weighted toward transportation fuels.

- Aviation fuels demand in PADD V grew at almost 3.0% per year in the past decade. Jet fuel demand is expected to grow at an annual rate of about 2.0% through the forecast. Consumption for kerosene for uses other than jet fuel is currently about 3,500 B/D for the entire region and a slow decline is forecast.

PADD V LIGHT PRODUCT SUPPLY

- Given its relative geographic isolation, PADD V has remained fairly self-sufficient with respect to light product supply. Inter-PADD transfers from pipelines and waterborne trade as well as foreign imports provide the balance of supply to the region; however non-indigenous product historically has averaged less than 15% of the total supply, Figure II-12.

FIGURE II-12
PADD V LIGHT PRODUCT SUPPLY



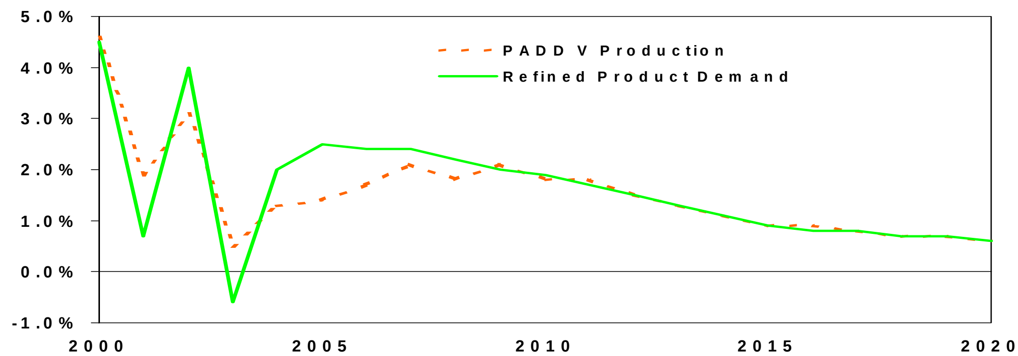
- Pipeline supply into PADD V originates from three different refined product sources; Billings, Montana (PADD IV), Salt Lake City, Utah (PADD IV), and El Paso, Texas (PADD III). Together these three pipelines have provided approximately 5 – 6% of the total light product supply to the PADD V region.

- Similar to pipeline deliveries, foreign imports have averaged less than 7% of total light product supply historically. Total refined product foreign imports have averaged approximately 160,000 B/D during the last five years. The largest volume of product imported into the region is jet fuel, accounting for roughly 40% of the total product imports. As the phase-out of MTBE from California gasoline started in 2003, component imports replaced oxygenate (MTBE) imports.

- Total crude oil refining capacity in PADD V is just over 3,000,000 B/D, making it the third largest refining region within the U.S., behind the U.S. Gulf Coast and Midwest. The refining industry is characterized by large (>100,000 B/D), complex refineries that are located in proximity to the major regional product markets in large coastal cities. The major refining regions on the West Coast are the Los Angeles, San Francisco, and Puget Sound areas.

- Although PADD V has seen some level of capacity rationalization in recent years, the region has shown its ability to creep capacity near typical levels for the overall U.S. refining average, Figure II-13. Since 1996 PADD V crude capacity has expanded by approximately 0.5% per year. During the same time period cracking (both fluid catalytic and hydrogen) as well as alkylation have expanded similarly at 0.8% and 2.0% per annum, respectively.

FIGURE II-13
PADD V REFINERY PRODUCTION VS. DEMAND GROWTH



- Although this region has some of the most complex regulations for refineries, most of these refineries are large scale, top performers with a high level of sophistication. We expect that this industry will be able to increase its production capacity further to meet the growing demand for products, with creep in productive capacity in the 1.5 to 2.0% range (Figure II-13).

PADD V PRODUCT SUPPLY REGIONS

- PADD V can be further segregated into regional supply centers, where refinery concentration of capacity and regional pipelines dictate how product is distributed to demand centers. Alaska and Hawaii operate primarily in a self-sufficient manner although some imports and intra-PADD trade does exist. The Washington/Oregon region is nearly balanced with respect to light product supply/demand, with excess production in Washington supplying northern Oregon as well as component trade to California. The California/Nevada/Arizona (CA/NV/AZ) region encompasses the largest production and consumption region within PADD V, accounting for over 70% of the PADD V totals. This region requires the largest amount of net receipts. Given net movements within this region (i.e. San Francisco to Los Angeles), the logical location for delivering product to PADD V would be the Los Angeles area, which is the major product manufacturing location and has the capability of receiving product through waterborne means of transportation.

- Additional supplies from other U.S. regions are expected to grow as their refineries “catch-up” with California in their ability to produce low sulphur fuels. Such supplies are expected to grow, and come primarily from Puget Sound and Texas.

PADD V PRODUCT PRICING MECHANISMS

- West Coast product prices are determined by a combination of local factors and interaction with other major refining markets. During normal times, product prices trend toward levels dictated by local supply/demand economics. However, the West Coast will occasionally shift out of balance and require shipments into or out of PADD V to reestablish the balance. During such times, prices are dictated by the cost of competitive supplies from external locations.

- Although volatility continues to exist, the differential between CARB specification gasoline and conventional unleaded gasoline generally has ranged from 2 to 6 cents per gallon. In spite of the sharp spike in early 2001, the differential averaged about 6 cents per gallon over the 1997-2004 period. Conventional gasoline is being phased out of the market and is losing relevance to refinery economics in the region. Currently, conventional gasoline manufactured in California is still supplied to Nevada and small portions of Arizona. Both Phoenix, Arizona and Las Vegas, Nevada have introduced their own grades of reformulated gasoline known as “Cleaner Burning Gasoline” (CBG).

- The U.S. West Coast has a very large relative demand for jet fuel due to the presence of several major international and transcontinental transportation hubs. The differential between gasoline and jet fuel is very volatile depending on the local supply/demand situation. In the low gasoline demand season, jet fuel typically becomes more expensive than even CARB unleaded gasoline. Conversely, during the strong gasoline season, gasoline prices can reach 10 to 15 cents per gallon higher than jet fuel prices. On an annual average basis, we forecast jet fuel to be 9 to 12 cents per gallon less than regular CARB gasoline.

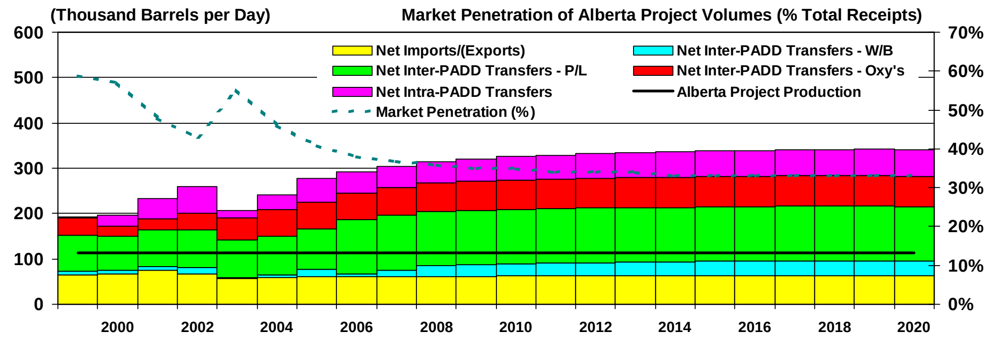
- EPA low sulphur diesel is manufactured for adjacent regional markets and a small volume of high sulphur international grade is produced and exported. Export cargo prices are linked to international prices. However, the CARB grade product is dependent only on local supply/demand factors. As a result, the differential between CARB diesel and conventional low sulphur diesel varies considerably. Our forecast is based on an annual average differential of 4.5 cents per gallon for the Los Angeles market.

ALBERTA PROJECT IMPACT ON PRICES

- It will cost around 1.0 to 1.5 cents per gallon for each product imported from Alberta to transport product from a waterborne delivery point to a marketable site (pipeline or rack location). This cost represents typical logistic mechanisms for delivery of foreign imports, which include utilization of dock and wharfage facilities, intermediate storage, and harbor to inland location pipeline tariffs.

- Based upon the forecast supply/demand balance for gasoline in the CA/NV/AZ supply region, Figure II-14, incremental non-indigenous supply of gasoline and gasoline components will come from foreign imports (~ 60,000 B/D), inter-PADD waterborne movements (~ 30,000 B/D) as well as from PADD III pipeline supply (Kinder Morgan East Line).

FIGURE II-14
GASOLINE MARKET PENETRATION – CA/NV/AZ SUPPLY REGION



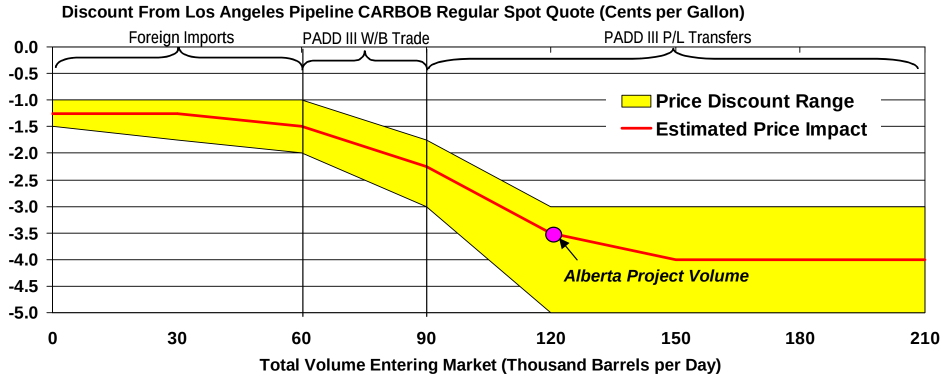
- In order for the Alberta Project to place the entire 112,500 B/D of gasoline it will be required to displace an equal volume of these incremental supply modes. Foreign imports would be the first tier to displace as they are most sensitive to price changes in the market. It is assumed a reduction in price of 0.5 – 1.0 cents per gallon would be enough disincentive for redirection of foreign imports from other locations.

- The next supply mode is waterborne transfers of product (primarily PADD III). This level of supply is typically intra-company related and is movement of primarily components from one company's facility along the U.S. Gulf Coast to its refinery on the U.S. West Coast.

- The last level of supply penetrated by the Alberta Project would be pipeline transfers from East Texas into Arizona. In this case, incremental Alberta Project volumes require refineries that supply this pipeline to reduce crude runs and/or divert product to other locations if logistically possible. In this case price discounts would have to reach level that incremental crude runs are uneconomical or alternative markets become attractive. This would require higher discounts in the range of 3-5 cents per gallon.

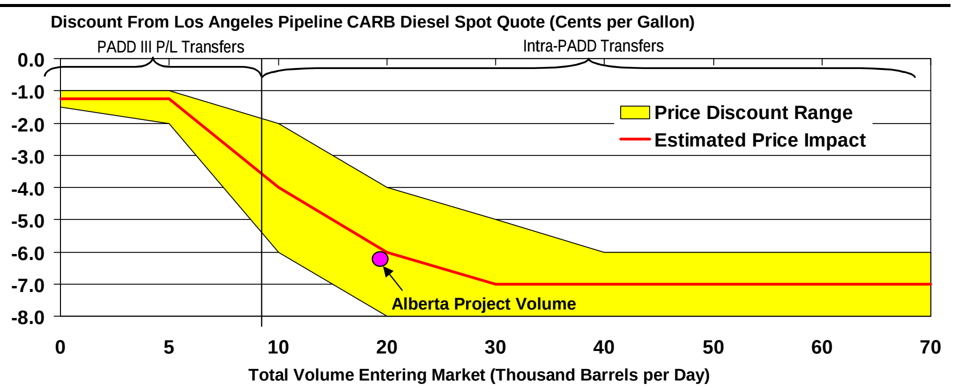
- Given the potential for a wide-range of potential discounts, the mid-point (3.3 cents per gallon) of the range is used to establish a base case discount for the Alberta Project gasoline supplied to the market, Figure II-15.

FIGURE II-15
EXPECTED MARKET RESPONSE TO ALBERTA PROJECT GASOLINE VOLUMES



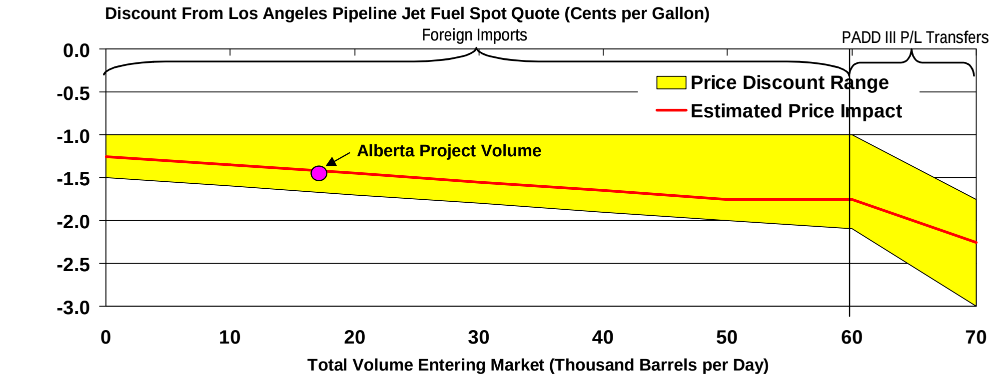
- Diesel market entry price discounts were determined using a similar methodology to gasoline, Figure II-16. The U.S. West Coast market is a net exporter of diesel, and therefore increased volumes brought into the market would exacerbate this imbalance. CARB diesel produced and delivered to the West Coast as part of the Alberta Project would require penetration into more efficient modes of supply, thereby increasing the potential discount. The discounts associated with this level of supply would have to be large enough to discourage production of CARB diesel from refineries. This level of discount is estimated to be roughly 4 – 8 cents per gallon, with a mid-point of 6.3 cents per gallon used for base case analysis.

FIGURE II-16
EXPECTED MARKET RESPONSE TO ALBERTA PROJECT DIESEL VOLUMES



- Unlike gasoline and diesel, the West Coast imports a significant amount of jet fuel to balance demand. The Alberta Project design basis calls for a relatively small volume of finished jet fuel, thus the anticipated pricing discounts are lower. Forecast supply/demand balances assume approximately 60,000 B/D of jet fuel imports for the CA/NV/AZ market requirements, which exceeds the Alberta Project jet fuel volume by nearly three times. Therefore, discounts are only of the magnitude to discourage distant foreign imports to the market. For purposes of this analysis it is assumed jet fuel would require discounts of 1.4 cents per gallon versus the quoted market price, Figure II-17.

FIGURE II-17
EXPECTED MARKET RESPONSE TO ALBERTA PROJECT JET FUEL VOLUMES



- An Alberta refinery project might consider the shipment of higher volumes of jet fuel to California, and less diesel. This would help with the logistics of refined products, because of the difficulty of shipping low sulphur diesel, and could generate slightly better returns.

CALIFORNIA RETAIL MARKETING

- The retail gasoline market in California is highly concentrated among a finite number of companies. These companies, which also operate refineries in the region, account for approximately 90% market share through company-owned/company-operated, dealer lease or branded jobber retail marketing structures.

- Some companies require net purchases of material from either other local market participants or independent sources. These imbalances have become more frequent given the high level of merger and acquisition activity along the West Coast in recent years. Two large independent gasoline suppliers, Valero and Tesoro, have emerged in the market without significant integrated retail sites. Therefore these companies provide a large percentage of the merchant supply in the area to other refining companies, independents and hypermarkets.

STRATEGY FOR ENTERING CALIFORNIA MARKET

- In the case of gasoline sales, the structure of the current market minimizes the level of spot trade that occurs between market participants. Successful entry into the market would require some level of advanced negotiations with current market participants. Those marketers who are currently in need of additional supply are engaged in longer-term contracts given the low availability of spot volume. This would require Alberta

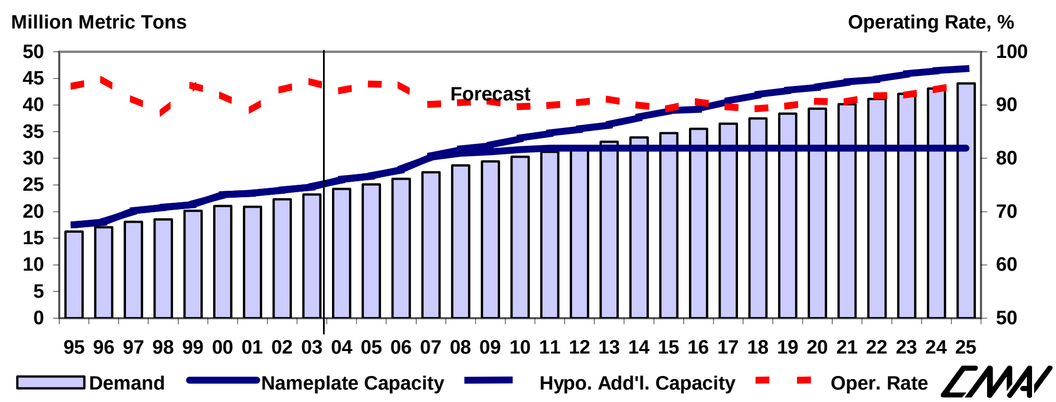
Project developers to seek long-term arrangements in advance of actual completion of construction for the facility to pre-build the market.

- Independent entry for jet fuel and diesel is likely less restrictive. Major airlines and cargo carriers are large consumers of jet fuel along the U.S. West Coast. A much larger wholesale market is available for diesel fuel, as large trucking or commercial operations purchase fuel in this manner. Independent suppliers such as Petro-Diamond and Itochu have larger wholesale diesel market shares versus the larger integrated marketers/refiners.

PETROCHEMICAL MARKET OUTLOOK

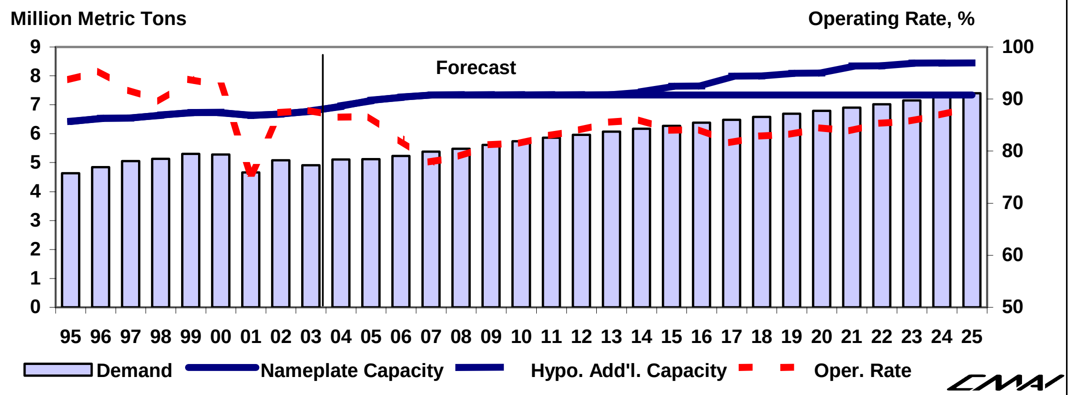
- In the period between now and 2010, the demand growth for styrene is expected to approximate GDP growth worldwide, an average annual rate of 3.9 percent, while supply is a fairly evenly matched at around 4.0 percent. This global demand growth will require an additional 2.1 million metric tons of styrene capacity to be built by 2010 to keep global operating rates at a reasonable level, Figure II-18.

FIGURE II-18
WORLD STYRENE SUPPLY & DEMAND



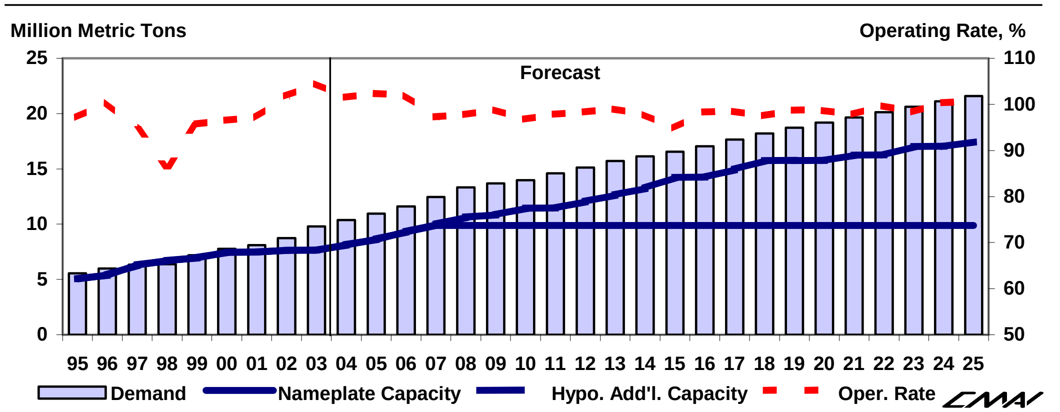
- No major additional capacity is forecasted for North America over the next several years however. In fact, CMAI does not foresee the need for any capacity additions until the 2009 – 2010 timeframe, Figure II-19. Limited styrene derivative capacity additions are partly at fault for the fairly slow growth as imports of finished goods – mostly durable goods – continue to pour in, primarily from China where costs are lower. Increased energy costs in North America also factor in.

FIGURE II-19
NORTH AMERICA STYRENE SUPPLY & DEMAND



- Northeast Asian styrene monomer consumption is forecast to grow at an average annual rate of 5.7 percent to 2010 (see Figure II-20), compared with an average rate of 7.6 percent in the last five years. Most notably, the forecasted annual growth rate for Chinese styrene consumption is 12.4 percent, although high is conservative relative to average annual growth in the last five years of 23.2 percent. This region is the highest growth market in the world, runs at over 100 percent utilization on average, has competitive feedstock supply and doesn't run its utilities on natural gas. Thanks to China's import growth and lagging self sufficiency development, it will remain in a sold out position until competitive pressures increase due to the export oriented styrene coming on stream in the Middle East.

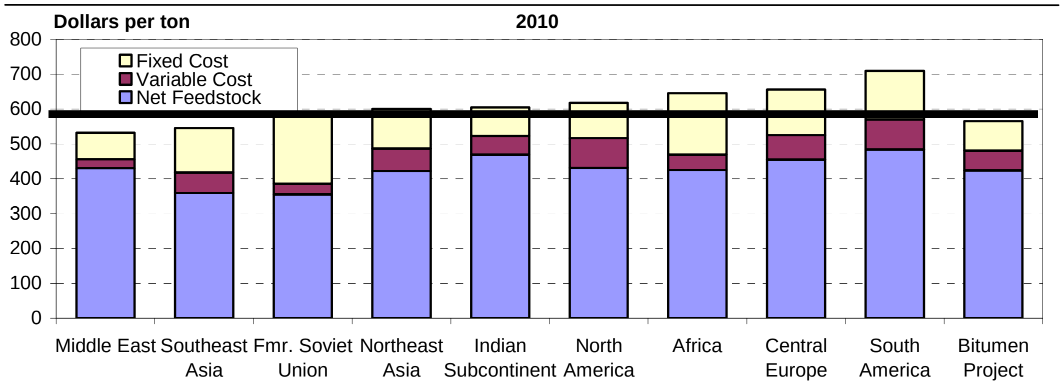
FIGURE II-20
NORTHEAST ASIA STYRENE SUPPLY & DEMAND



- A comparison of the production costs of the various regions of the world (Figure II-21) indicates that the weighted average cost of the Northeast Asian producers are about $35 per ton higher than the styrene plant in the Alberta bitumen project. The additional cost of shipping to this demand market, approximately $100 per tonne, however, renders the

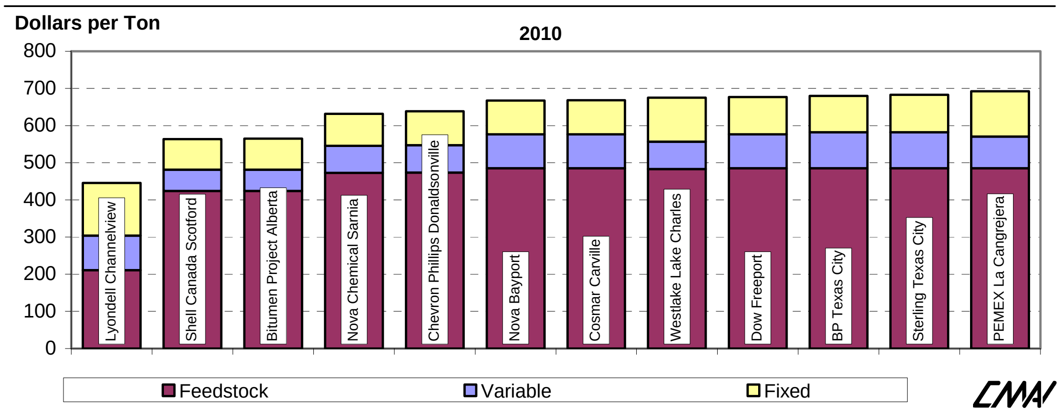
Alberta project at a disadvantage to this market. Middle Eastern producers with access to low cost ethylene enjoy production costs that are estimated to be at least $30 per tonne less than the Alberta project, before any freight advantage shipping to Asia.

FIGURE II-21
REGIONAL STYRENE CASH COSTS



- In light of this cost information, it is considered unlikely that the proposed Alberta bitumen plant would wish to principally target the Asian market. From a cost point of view however, the bitumen project should be very competitive against other North American production, Figure II-22.

FIGURE II-22
NORTH AMERICAN STYRENE PRODUCTION COSTS



- With a $100 to $120 per tonne cost advantage over the higher cost units in North America, the new Alberta project could afford to be price aggressive if necessary to “buy in” to the market. The degree to which this would be necessary however is dictated by the nature of the project participants; existing North American producer or newcomers. Our forecast for the purpose of the project economics assumed an initial discount of $100 per tonne, and phasing it out over three years.

ECONOMIC RESULTS

To compare the economic performance of each of the cases examined, we prepared discounted cash flow analyses of each case.

- We utilized our outlook for petroleum product prices (June 2004 outlook) less the expected market entry discounts, and our price forecast for bitumen and SCO. A comparison of the prices utilized are outlined below.

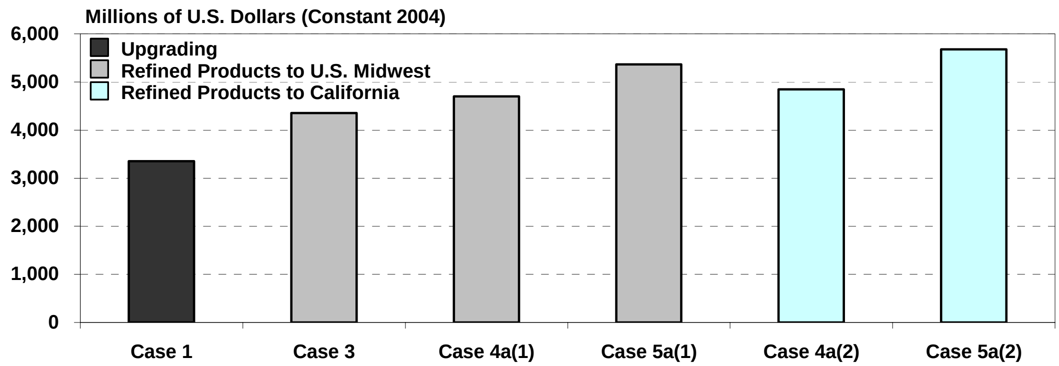
PRICES UTILIZED - 2015[(1)]

	Current Dollars	Constant $2004
WTI Cushing ($US/B)	33.02	26.55
SCO at Edmonton ($US/B)	31.58	25.40
Bitumen at Edmonton ($US/B)	13.11	10.55
Regular Gasoline at Edmonton ($US/B) [(2)]		
Netback from Chicago	37.13	29.86
Netback from Los Angeles (CARBOB)	41.35	33.26
Diesel Fuel at Edmonton ($US/B) [(2)]		
Netback from Chicago	36.41	29.29
Netback from Los Angeles (CARB)	37.40	30.18
Petrochemicals		
Styrene (cents/lb)	36.08	29.02
Mixed Xylene ($US/B)	47.57	38.26
Natural Gas at AECO, $US/MMBtu)	5.20	4.18

Note: (1) Based on Purvin & Gertz' June 2004 price outlook.
(2) Includes market entry discounts.

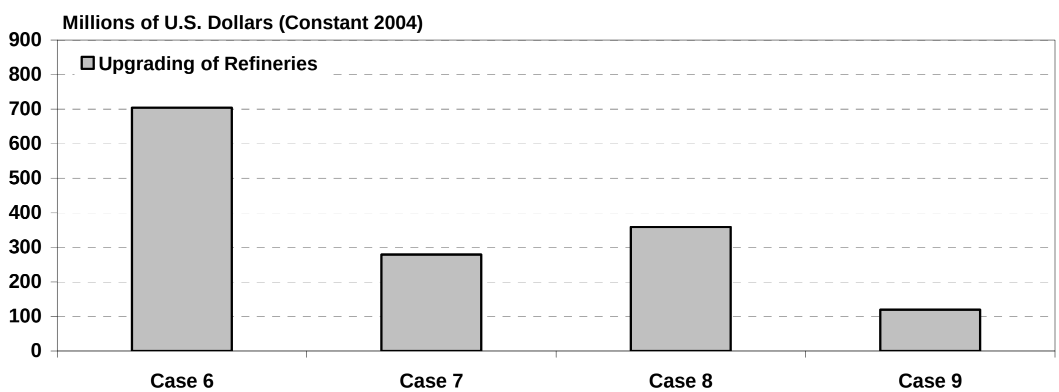
- Capital costs for the Alberta upgrading projects range from $3.35 billion for standalone upgrading to $5.68 billion for producing refined products for the California market and styrene, Figure II-23.

FIGURE II-23
ALBERTA UPGRADING PROJECTS - COMPARISON OF CAPITAL COSTS



- Capital costs for the refinery upgrading projects are much lower, Figure II-24. They are much smaller scale projects. The SynBit cases only process around 50,000 B/D of bitumen. The neat SCO case utilizes around 25,000 B/D of SCO. However, a number of these developments would be required to process the equivalent amount of bitumen as processed by the Alberta projects.

FIGURE II-24
COMPARISON OF CAPITAL COSTS UPGRADING US REFINERIES



ALBERTA BASED PROJECTS

- The base case 200,000 B/D standalone upgrader is shown to generate a return of 12.2% based on our outlook for bitumen and SCO prices. Its economics are very sensitive to both SCO and bitumen prices. If the SCO price is discounted by $1.00 per barrel, the rate of return drops to 9.9%. If bitumen prices drop by $1.50 per barrel, the rate of return increases to 14%.

ECONOMICS COMPARISON FOR MIDWEST CASES - 2015
(2004 Constant U.S. Dollars)

		Case 1	Case 3	Case 4a(1)	Case 5a(1)	Case 5a(1) Benzene
Total Capital	$ Million	**3,351**	**4,351**	**4,700**	**5,363**	**4,693**
Product Realization	$/Bbl Bitumen	23.77	27.62	29.41	31.18	28.55
Less Bitumen Cost (2015)		10.55	10.55	10.55	10.55	10.55
Gross Margin		13.23	17.07	18.86	20.64	18.00
Less Operating Costs						
Variable		3.18	4.19	4.02	3.94	3.64
Fixed		1.97	2.51	2.71	2.95	2.78
Subtotal		5.15	6.69	6.73	6.90	6.41
Net Refining Margin	$/Bbl Bitumen	8.07	10.38	12.13	13.74	11.59
Replacement Cost	$/yr Bbl	45.91	59.60	64.38	73.46	64.29
Annual Return(1)		17.6%	17.4%	18.8%	18.7%	18.0%
IRR		12.2%	12.3%	13.3%	13.2%	12.7%

Note: (1) Annual recovery of initial investment, or "Capital Recovery Factor"

- Producing refined products for the U.S. Midwest market (Case 4a(1)) results in a return of 13.3%. This case, on an incremental basis relative to standalone upgrading, generates a return of 15.7%.
- The overall economics are reduced slightly if styrene is produced to (Case 5a(1)). The relatively high cost of the styrene plant and other supporting facilities reduces the return. Incrementally, the production of styrene generates only a 12.7% return over the straight refined products case. We also examined just producing benzene, and not producing styrene, but the return was slightly less than if styrene was produced.
- Producing refined products for export to the California market (Case 4a(2)) generates more attractive returns than for the U.S. Midwest case with an IRR of 15.4%. Based on the incremental investment over Case 1, it generates a 21.3% rate of return.
- Including the production of styrene as well as refined products (Case 5a(2)) destined for the California market, the return decreases to 14.9%. Based on the incremental investment over producing only refined products, the investment for the styrene plant generates a 12.0% rate of return.

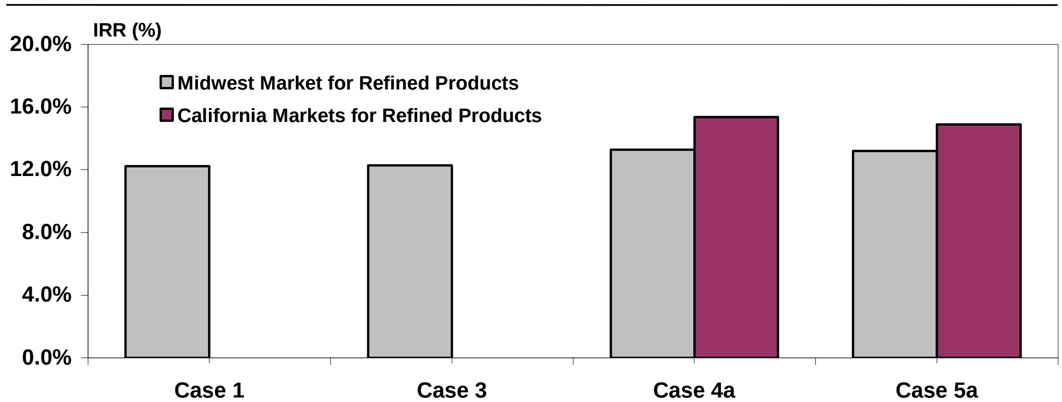
ECONOMIC COMPARISON FOR CALIFORNIA CASES - 2015
(2004 Constant U.S. Dollars, unless noted)

		Case 4a(2)	Case 5a(2)	Case 4a(2) with IsoOctane(2)
Total Capital	$ Million	**4,842**	**5,675**	**4,829**
Product Realization	$/Bbl bitumen	32.32	35.12	33.48
Less Bitumen Cost		10.55	10.55	10.55
Less IsoOctane Cost				0.72
Gross Margin		21.77	24.57	22.21
Less Operating Costs				
Variable		4.38	4.97	4.35
Fixed		2.82	3.13	2.75
Subtotal		7.20	8.10	7.10
Net Refining Margin	$/Bbl bitumen	14.58	16.47	15.11
Replacement Cost	$/yr Bbl	66.32	77.74	66.15
Annual Return, %(1)		22.0%	21.2%	22.8%
IRR		15.4%	14.9%	**16.1%**

Notes: (1) Annual recovery of initial investment, or "Capital Recovery Factor"
(2) Assumes that IsoOctane is purchased in Edmonton.

- In summary, the California based export refinery provides the best improvement over the Case 1, standalone upgrading, Figure II-25, and closely followed by including the styrene option. The California option faces more logistical hurdles and a smaller market, but it could have more upside potential if the market entry discounts can be mitigated through developing relationships with U.S. market players.

FIGURE II-25
COMPARISON OF CASES



U.S REFINERY PROJECTS

- The examples of converting U.S. refineries to process substantial amounts of oil sands supplies instead of light sour crude oil supplies provide a cost of supply comparison relative to the Alberta projects. However, it should be noted that the examples represent possible new market outlets, but such examples are limited. They do not represent a major new market outlet, but rather represent potential growth of the existing market. Thus, the potential of such developments can increase markets for bitumen blends. But, it will be a challenge to find sufficient candidates to absorb substantial volumes of bitumen in the range of 200,000 B/D of bitumen.

- Converting light sour crude refineries to process SynBit instead of traditional light sour crudes provides a favourable rate of return, particularly in the U.S. Midwest (Wood River location). A new coker project with supporting hydrotreating and sulphur recovery was estimated to be needed in Case 6, plus minor adjustments to other processing units. Around $700 million should be required to allow a typical light sour crude cracking refinery to process up to 100,000 B/D of SynBit, and generate a return of 19%.

SUMMARY: ECONOMICS FOR CONVERSION OF U.S. REFINERIES TO SYNBIT
(2004 Constant U.S. Dollars)

		Case 6 - U.S. Midwest			**Case 8 California**		
		Base Case	**Post - Project**	**Diff.**	**Base Case**	**Post - Project**	**Diff.**
Total Project Capital	$ Million			704			359
Product Realization	$/B Crude	28.25	29.87	1.61	35.88	35.90	0.02
Less Feedstock Cost		24.38	22.71	(1.67)	26.45	25.30	(1.14)
Gross Margin		**3.87**	**7.15**	**3.28**	**9.43**	**10.59**	**1.17**
Variable Expenses		1.48	2.09	0.62	2.69	2.99	0.30
Fixed Expenses		1.19	1.58	0.39	1.65	1.77	0.12
Subtotal Operating Costs		**2.66**	**3.68**	**1.01**	**4.34**	**4.76**	**0.42**
Net Refining Margin	$/B Crude	**1.21**	**3.47**	**2.26**	**5.09**	**5.84**	**0.75**
Replacement Cost	$/yr Bbl	23.97	33.60	9.64	35.98	39.92	3.94
Annual Return (1)		5.0%	10.3%	23.5%	14.1%	14.6%	19.0%
IRR				19.1%			14.5%

Note: (1) Average annual recovery of initial investment or "Capital Recovery Factor".

- California refineries are already designed to process substantial amounts of light sour crude such as ANS and in some cases, heavy crudes as well. Our analysis was limited to refineries that primarily process ANS crude, and these types of refineries have existing coking capacity. Case 8 describes processing up to 100,000 B/D of SynBit in a California light sour coking refinery. The increase in residual production requires an expansion of most of the existing processing units, but no major new units would be required. This case generated a return of 14.5%.

- We examined a case in the Wood River area to process SynSynBit instead of SynBit. SynSynBit is mostly SCO, consisting of 70% SCO and 30% bitumen, and this blend was patterned after the yields of light sour crudes. This Case, Case 7, requires the addition of a major hydrocracker unit to accommodate the extra VGO and distillate from the high amount of SCO resident in the new crude stream. As shown below, its return is more marginal than the SynBit cases. If SCO is discounted by $1 per barrel, though, the return improves favourably to over 16%.

SUMMARY: ECONOMICS FOR CONVERSION OF U.S. REFINERIES TO HIGHER LEVELS OF SCO (2004 Constant U.S. Dollars)

		Case 7 SynSynBit			Case 9 Neat SCO		
		Base Case	**Post - Project**	**Diff.**	**Base Case**	**Post - Project**	**Diff.**
Total Project Capital	$ Million			279			120
Product Realization	$/B Crude	28.25	29.59	1.34	29.66	30.55	0.89
Less Feedstock Cost		24.38	24.85	0.47	26.40	26.50	0.10
Gross Margin		**3.87**	**4.74**	**0.87**	**3.26**	**4.05**	**0.79**
Variable Expenses		1.48	1.79	0.31	1.16	1.44	0.28
Fixed Expenses		1.19	1.34	0.16	1.78	2.14	0.36
Subtotal Operating Costs		**2.66**	**3.13**	**0.47**	**2.93**	**3.58**	**0.64**
Net Refining Margin	$/B Crude	**1.21**	**1.61**	**0.40**	**0.33**	**0.47**	**0.14**
Replacement Cost	$/yr Bbl	23.97	27.79	3.82	29.17	35.72	6.55
Annual Return (1)		5.0%	5.8%	10.4%	1.1%	1.3%	2.2%
IRR				9.2%			0.0%

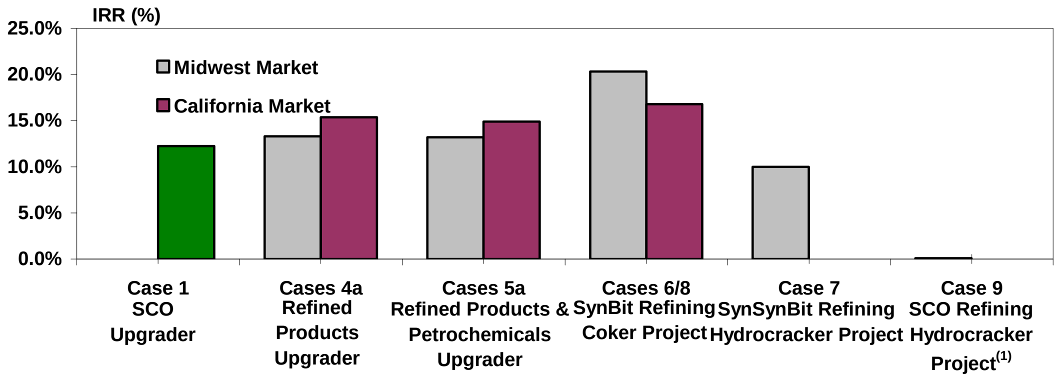
Note: (1) Average annual recovery of initial investment or "Capital Recovery Factor".

- SCO is a substitute for sweet, conventional light crude. As volumes of SCO increase, they eventually will be seeking markets in the U.S. Mid-continent, which have not so far shown much interest in SCO.

- A neat SCO refinery conversion of a light sweet/sour refinery was assumed for the U.S. Mid-continent market, Case 9. Existing light sweet crude in the crude slate was replaced with SCO. The major investment required for this case involves the addition of a new hydrocracker and expansion of the FCCU. The resulting return was very poor. A price discount of $2.00 per barrel off the forecast SCO price would be required to provide a reasonable return in the range of 15% for this case.

- In conclusion, upgrading refineries in California and the U.S. Midwest to process SynBit provided the highest returns among the range of refinery projects considered. Upgrading a Midwest refinery to process SynSynBit, or a Mid-continent refinery to process SCO, provided lower returns than the Alberta based projects, as shown in Figure II-26. Upgrading a Mid-continent refinery to process neat SCO provided a poor return.

FIGURE II-26
OVERALL ECONOMIC COMPARISON OF PROJECTS



1) Return for a Mid-Continent location is 0%

MARKET CONCLUSIONS

- The U.S. Midwest petroleum products market appears to be the more attractive market for refined products from an Alberta project based on ease of entry. It is a very large market, and at Chicago can reach an extensive product distribution infrastructure. Market entry discounts should be quite modest. The rate of return for producing products for the Midwest market at 13.3% shows some improvement relative to the base case upgrading.

- The California petroleum products market provides a higher rate of return (15.4% IRR) compared to the U.S. Midwest market (at 13.3% IRR). This occurs even with significant market entry discounts because the volume of imports from Alberta would be a larger share of the market than would occur in the Midwest.

- Entrance into the California market will be somewhat more complex commercially than would be the case in the U.S. Midwest. In California, a new supplier would likely need to make arrangements with one or several refiners or marketers in the region. The independent sector by itself is probably too small to handle such a large volume of imports. If such arrangements are made, it is likely that the market entry discounts could be reduced, and thus creating higher returns.

- If Terasen is not able to provide a segregated product pipeline from Edmonton to Vancouver, the economics of producing products for the California market become less attractive. If products were shipped as batches in sequence with crude oil batches in the crude pipeline, some contamination would occur, and a clean-up step would be required. We have not undertaken a thorough assessment of the potential to successfully clean up products, but we understand that the Western Canadian refiners are working on such a solution to enable low sulphur diesel to be shipped from Edmonton to Vancouver on the

Trans Mountain line by 2006. If the clean-up cost was as much as 3 cents (US) per gallon, the rate of return for Case 4a(2) would drop from 15.4% to 14.5%.

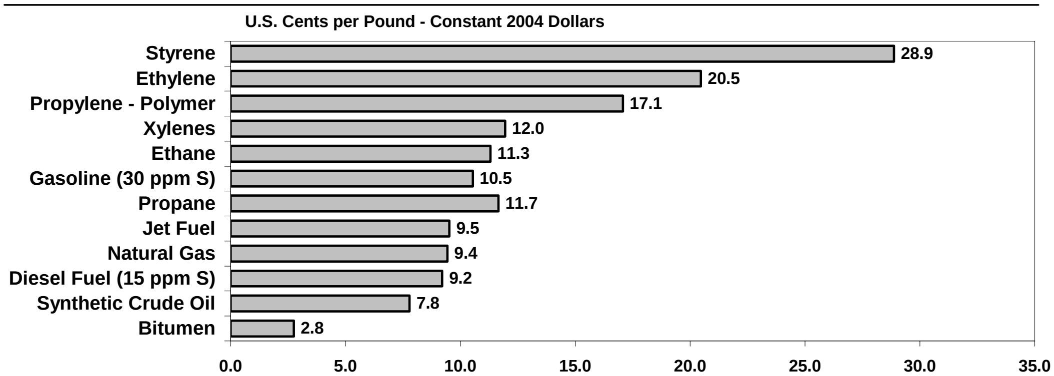
- The petrochemical cases resulted in a slight reduction in the economics relative to producing only refined products. Still, the refinery cases that include styrene production provide a better return than standalone upgrading. The petrochemical analysis suggests that there might be some potential for a new styrene project in Alberta to serve the North American market, but such a project would likely need to be developed by existing North American petrochemical producers in order to ease into the market and to put surplus product into other markets until the demand growth in North America can absorb all of the production.

CONCLUSIONS

There are many conclusions that can be drawn from the analysis in this report. The following are highlighted.

1. **Rather than market bitumen, the value added from going up the value chain is quite evident**, as shown in Figure II-27. Obviously, major investments will be required, but the work in this report suggest that upgrading to refined products, and possibly to petrochemicals, offer an attractive opportunity beyond just upgrading to SCO.

FIGURE II-27
PRODUCT AND LIGHT ENDS PRICES IN EDMONTON - 2010



2. **The most attractive options considered in this analysis involve upgrading U.S. refineries to process SynBit**. There should be a few opportunities in both the Midwest and California to allow such projects to be developed. While they should provide for some growth in market outlets for bitumen, there will likely be limitations in accommodating all of the potential bitumen blend supplies from Alberta. Further, there are many commercial complexities to such developments.

3. **Upgrading to produce only SCO still offers considerable merit, at least for the next several projects**. Although the 12% rate of return that was derived for a standalone upgrader based on our price forecasts may be considered to be nominal, such projects would likely be amenable to debt financing secured by producer throughput commitments, and this would generate higher returns on equity.

4. **Longer term, standalone upgrading prospects may come under more pressure**. Our analysis used a price forecast for SCO that we believe is adequate to support market growth of SCO into existing refineries. We concluded from this analysis, though, that our price forecast for SCO may need to be lower to encourage refineries to make investments to process more SCO or SynSynBit blends. Thus, there is some concern whether the 12% rate of return shown for the base case upgrader can be sustained if SCO supplies continue to grow substantially over the longer term.

5. **Producing refined products for export to California represents a significant and viable new market for bitumen**. Such a market development will offer major growth opportunities for bitumen producers, as well as attract new investments to Alberta. The rates of return for refining projects producing for the California market were in excess of 15%. The outlook for California product prices and refining margins provide higher results as compared to the U.S. Midwest. This market is smaller than the U.S. Midwest, and we have included significant market entry discounts for new Alberta supplies to penetrate this market.

6. **We believe the U.S. market will adequately supply California without requiring major imports**. Strong prices help this. Further, as the rest of the U.S. industry catches up with low sulphur products, it will be in a better position to serve the California market. If a new Alberta export project targets this market, it needs to move early to establish a position in California, and capture some of the growth of this market.

7. **Commercial arrangements with California marketers or refiners will likely be required to secure a position in that market**. Possibly, they would become investors in the Alberta project. The independent sector in California is probably too small to provide a market outlet for all of the products generated from an Alberta project. Such arrangements could also reduce the market entry discounts, which would result in higher returns for this option.

8. **The Chicago refined products market is a lower risk market than California, is much larger than the California market, and the distribution infrastructure at Chicago extends through much of the Midwest market**. It should be possible to penetrate this market with lower market entry discounts than expected in California.

9. **The Midwest refined products market should also be a significant new market for bitumen**. The rate of return for an Alberta refinery producing into this market was 13.3%, versus 15.4% for California. When taking into account its market size and lower market risk, it should be considered as seriously as the California market.

10. **The potential to add a styrene project to an Alberta bitumen refinery is less promising, from an economic perspective, than producing refined products.** Still, a combined refinery/petrochemical project generates a greater return than standalone upgrading. Possibly, if lower cost sources of benzene could be obtained from local refiners, or a lower cost source of ethylene could be obtained, the styrene economics could be improved.

11. **The attractiveness of exporting refined products to California is very dependent on a solution on the Trans Mountain pipeline system**. Such products should be shipped in a separate clean products pipeline, and this requires Terasen to get support to build a new crude oil pipeline to free up the existing pipeline for clean product service. If it became necessary to develop a solution that requires product clean-up at Vancouver so that products continue to be shipped in the crude oil line, it would reduce the rate of return of that option, bringing it much closer to shipping products to the Chicago market.

12. **Both logistical options need to be evaluated in further detail.** Indepth evaluations with each pipeline company are required to determine both the technical and economic viability of such options. They could be the most important driver in developing an export refinery in Alberta, and in deciding which market should be developed.

13. **Upgrading in Alberta to produce SCO or refined products/petrochemicals generates more benefits for Alberta than marketing bitumen blends.** Such projects create permanent employment opportunities, contribute to the industrial base and infrastructure base, and add to the growth of support industries. In our analysis, the bitumen producer received the same netback for all of the cases.

14. **As upgrading capacity is added in Alberta, more byproducts and specialty products will be generated that could become feedstocks for the petrochemical industry.** The recovery of ethylene, propylene, and benzene are likely the best candidates for future petrochemical use.

15. **Higher construction costs in Alberta may discourage maximizing upgrading in Alberta.** This issue must be addressed at all levels. This becomes an even greater hurdle as the Canadian dollar strengthens relative to the U.S. dollar, as labour costs are mostly in Canadian dollars.

16. **In conclusion, all of the potential market options studied in this report may be required to adequately support the potential of the Alberta oil sands resources.** Increased diversification in market approaches should provide for stronger and larger markets for oil sands production.

III. BASIS AND METHODOLOGY

This analysis compares the merits of upgrading in Alberta versus adding upgrading to U.S. refineries. In this section, we show the basis and methodology utilized in this study for the various upgrading cases considered.

CASES ANALYZED	
Case 1	Upgrading in Alberta – Standalone Upgrading
Case 3	Upgrading in Alberta, Producing Diluent and Distillate
Case 4	Upgrading in Alberta, Producing Refined Products
Case 5	Upgrading in Alberta, Producing Refined Products and Petrochemicals
Case 6	Upgrading SynBit in U.S. Midwest
Case 7	Upgrading SynSynBit in U.S. Midwest
Case 8	Upgrading SynBit in California
Case 9	Upgrading Mid-Continent Refinery to Process SCO

The starting point for our analysis was to develop a base case synthetic oil crude (SCO) production facility, with SCO quality similar to Syncrude Canada Ltd.'s production of SCO (referred to as "SSP"), after completion of the UE1 project in 2006. All cases used a 200,000 B/D basis for bitumen feed. Athabasca bitumen was assumed to be the most likely crude feed for the upgrader since it is forecast to have the largest volume growth compared to other bitumen and heavy crudes. Athabasca bitumen has a density of 8.4 API and over half is 975°F+ vacuum resid. The following table shows the properties of Athabasca bitumen used in our analysis and the quality of the upgraded SCO for the Base Case.

BITUMEN FEED AND PRODUCED SCO QUALITIES

	Bitumen	SCO
Gravity, ^{o} API	8.4	35.0
Sulfur, wt.%	4.8	0.1
Boiling Curve, Vol.%		
C4's	0.0	2.6
C5-380^{o} F, Naphtha	1.5	21.0
380-650^{o} F, Distillate	15.5	32.8
650-975^{o} F, VGO	32.0	43.6
975+^{o} F, Vacuum Resid	51.0	0.0
Properties		
Distillate Cetane Number	37.0	40.0
Kerosene Smoke Pt., mm	22.0	20.0
VGO K Factor	10.8	11.8

We assumed that the bitumen delivered to the Alberta upgrader would be diluted with C5+ condensate with a blend ratio of 26% C5+ and 74% bitumen needed to achieve the pipeline viscosity specification of 350 cst and 940 kg/m^3 density. This diluent was distilled in the upgrader crude unit and recycled by pipeline to the field production facilities.

For shipment of bitumen to U.S. refineries, we assumed it was shipped as SynBit (a blend of 52% bitumen and 48% synthetic crude).

The location of the upgrader in all cases was assumed to be near Edmonton. Currently Terasen Pipelines Inc. owns and operates the Corridor diluted bitumen pipeline which transports bitumen blend from Muskeg River north of Fort McMurray to the Athabasca Oil Sands Project (AOSP) upgrader near Fort Saskatchewan and returns diluent to the Muskeg River site. There is a significant likelihood that another pipeline system will be constructed by 2010 to bring the ever-expanding volumes of bitumen production into the Edmonton area. The construction of a 200,000 B/D upgrader near Edmonton would certainly facilitate the construction of such a pipeline. Our price forecast for Athabasca bitumen at Edmonton is based on a market price for bitumen/SCO blends (SynBit) netted back to Edmonton. The bitumen netback in the field would depend on the pipeline tariff to Edmonton.

The Edmonton region also provides a significant source of labour for constructing this facility. A 200,000 barrels per calendar day (B/D) upgrader would require a significant supply of skilled craftsmen and could influence the cost of the project depending on labour availability and productivity. This issue is discussed in Section IX under the economic results.

ALBERTA UPGRADING CASES

In the Phase I report, a number of Alberta upgrading cases were considered. Based on the results from that study, we selected the better cases and updated them for this study. The cases are described below.

ALBERTA UPGRADING CASES

Case	Description	Phase I Cases	Phase II Cases
Case 1	Basic Upgrader Producing SCO	1	1
Case 2	Similar to Case 1, but Recover Ethane/Ethylene	2	
Case 3	Add Hydrocracker, Producing Naphtha and Distillates	3	3
Case 4	Produce Refined Products		
	4a. VGO hydrocracking and catalytic reforming	4a(1) + 4a(2)	4a(1) + 4a(2)
	4b. DCC/alkylation	4b(1) + 4b(2)	
Case 5	Produce Refined Products and Primary Petrochemicals		
	5a. VGO hydrocracking and catalytic reforming, benzene and xylenes recovery with styrene	5a(1) + 5a(2)	5a(1) + 5a(2)
	5b. DCC/alkylation and propylene recovery	5b(1) + 5b(2)	

In the Phase I study, the hydrocracking cases provided more favourable results than the catalytic cracking cases. So, we continued to examine the hydrocracking cases in this Phase II study.

PROCESS DESIGN

In the development of the cases, Purvin & Gertz utilized its proprietary linear program model (LP) to size each of the processing units and to develop the material and energy balance for each case. As explained below, a number of variations were considered before arriving at the selected process designs for each of the cases.

Common to all the upgrader cases is the primary front-end upgrading. This includes the crude distillation unit, the vacuum distillation unit, and the delayed coker. All process units were designed for a 94% on stream factor to allow for scheduled maintenance shutdowns and other unit outages. This value is typical for an operation of this type. The crude distillation unit is sized for a capacity of 270,000 B/D. This provides for separation of the C5+ diluent, which is recycled, and distillation of the straight run distillate. The 650ºF+ boiling range material, which is approximately 83% of the bitumen, is diverted to the vacuum distillation unit which is sized for 177,000 barrels per stream day (B/SD) of capacity. The vacuum distillation unit produces a heavy gas oil stream and a 975°F+ vacuum bottoms stream which is sent to the delayed coker unit. The delayed coker is designed for a stream day capacity of 109,000 B/SD and produces fuel grade coke, coker heavy gas oil, coker distillate, coker naphtha, LPG's containing olefins, and fuel gas. Also common to all design cases, but not necessarily with the same capacity, are the sulphur recovery unit and the hydrogen plant. These units form the primary front-end upgrading basis for all cases.

The refinery/upgrader analysis was done with a focus on refined products for two distinct markets: the U.S. Midwest market with an emphasis on the Great Lakes region, and the California market. Although certain regions in the Midwest market such as Chicago and St. Louis require reformulated gasoline (RFG), the majority of gasoline used in the Midwest, such as in the Detroit region, is conventional non-reformulated gasoline. For this reason, our specifications for refined products in the Midwest were for 75% conventional gasoline and 25% reformulated gasoline. After 2005, the entire U.S. Midwest market will require gasoline with less than 30 ppm sulphur. For the size of the California market, gasoline and diesel specifications must meet California Air Resources Board (CARB) quality. Gasoline for California requires the use of an oxygenate such as ethanol. Most often ethanol is blended near the distribution network. Therefore, the gasoline produced from the upgrader was blended without ethanol, referred to as RBOB or CARBOB, and was priced accordingly. The market prices for refined products are discussed in Section VIII.

The first two cases which were analyzed produce SCO, naphtha and diesel, and are not regional specific products, although the diesel produced in Case 3 was assumed to be marketed only in the Midwest. Diesel quality in California requires a higher cetane value than in the Midwest, so its market price is higher; but the size of market for diesel in California is small relative to the incremental amount produced from the upgrader.

CAPITAL COSTS

Purvin & Gertz prepared capital cost estimates for each case. Purvin & Gertz utilizes a functional cost estimating tool that includes cost curves for each processing unit. The estimating models or cost curves are based on detailed cost estimates developed for other similar process units, and are periodically updated based on actual experience. All of these curves are based on a U.S. Gulf Coast location.

The total capital cost is made up of the inside battery limits (ISBL) process unit erected cost, the offsites and utilities erected cost, licensors costs, owner’s costs, escalation during construction, and contingency. The erected costs include both direct and indirect construction charges.

The accuracy of a cost estimate is dependent on the degree of engineering definition, and the amount of engineering completed. At this stage, there have only been preliminary conceptual cases developed. Thus, the expected accuracy level is in the order of $\pm$30%.

We utilized a location factor of 1.3 between the U.S. Gulf Coast and the Fort Saskatchewan area. The location factor adjustment takes into account the cost to procure and construct equipment at the site and is influenced by transportation costs, labour costs, and productivity and site specific requirements that differentiate the site from a comparable facility at the U.S. Gulf Coast, such as the need to provide winterization.

Capital costs for this study are approximately 9% higher than used in the Phase I study. The Phase II costs are shown in 2004 constant dollars, while the Phase I study was in 2003 dollars. However, the major adjustment has come from a significant increase in capital costs at the U.S. Gulf Coast for 2004, where the C.E. Index has increased by around 9% over 2003. This has the effect of raising all of the capital costs. It may be possible that the 1.3 location factor may be a little more conservative now that the U.S. Gulf Coast costs have surged in the last year. We do not have sufficient information, though, to reduce the location factor.

Capital cost over-runs have been quite prevalent in Alberta over the last few years, and this is a major issue for the development of new projects. In Section IX, we examine the sensitivity of the economic results relative to changes in the capital cost of each case.

COMMON CASES

Case 1: Upgrader

The first case, Case 1, produces a SCO similar to SSP crude planned to be produced by Syncrude Canada Ltd. upon completion of the UE1 upgrader project. In order to achieve the same quality, three high severity hydrotreater units were used to improve the crude quality to meet the specifications of 35 API and 0.2% sulphur. All unsaturated butanes from the coker unit were processed through the naphtha hydrotreater, recovered, with most blended into the SCO product in order to achieve a butane content similar to SSP. The configuration for Case 1 is illustrated in Figure III-1.

To meet the density and sulphur requirement for the SCO, the heavy gas oil hydrotreater unit achieves some hydrocracking of the heavy gas oil. The high degree of hydrotreating and mild hydrocracking requires a significant amount of hydrogen for straight run VGO and coker gas oil, which is produced from a traditional steam methane reforming unit, which uses natural gas supplemented with plant fuel gas. Although alternate technologies exist to produce hydrogen and synthesis gas from upgrader products such as coke and pitch, these were not evaluated as part of the study. As a result, this configuration and all subsequent cases are susceptible to fluctuations in natural gas price and discussed in Section IX in the sensitivity analysis.

Due to the size of the some of the process units, multiple processing trains would be necessary. For example, the heavy gas oil hydrotreater would need to have two process trains. The hydrogen plant is also very large and although new hydrogen plants are being developed for 200 MMSCF/D capacity as a single train unit, we use two 103 MMSCF/D units to improve the reliability of the entire operation. As well, the sulphur recovery unit would also need two units for reliability reasons, and we used two units each at 50% of capacity. The size of the delayed coker would require six coke drums in total which would operate in 48-hour coking cycles, composed of 24 hours of coking and 24 hours of de-coking.

The capacity of the individual process units and the capital cost estimation for Case 1 is located in Table III-1. The overall capital cost for the base case 200,000 B/D upgrader was estimated at $3.35 billion (2004 constant U.S. dollars).

CASES WHERE REFINED PRODUCTS ARE DESTINED TO U.S. MIDWEST

A total of three cases are reported for the Midwest market, using the results from Case 1 as a basis for developing the subsequent cases using the same bitumen feed rate and primary upgrading process configuration.

Case 3: Upgrading to Produce Diluent and Distillate

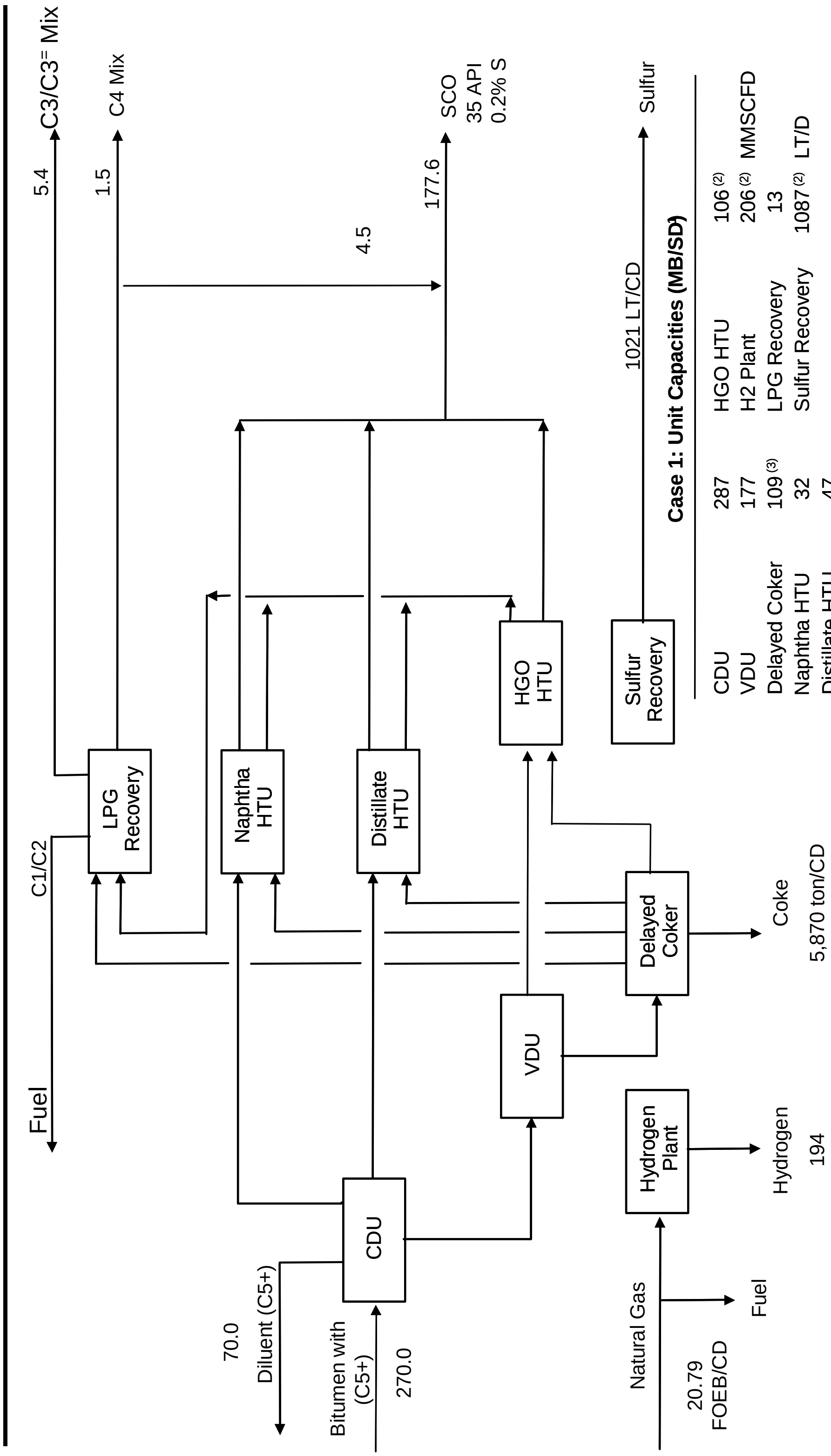
This case utilizes a heavy gas oil hydrocracker in place of the mild hydrocracker used in Case 1. It is a higher severity unit to handle all the nitrogen, sulphur, olefins and aromatics in the hydrocracker feed which is needed in a refinery operation as opposed to an upgrader. This hydrocracker converts 100% of the straight run and coker heavy gas oil feed into naphtha, ultra low sulphur diesel and jet fuel. Since capital costs for both the hydrocracker and hydrogen plant are higher in this case, total plant capital and operating costs rise. The process flow diagram for Case 3 is shown in Figure III-2.

The naphtha produced in this case is assumed to be used as a diluent for bitumen blending. The large volume of naphtha produced represents approximately one third of the diluent requirement projected in Alberta by 2015. As a result, we have used an adjusted price for the naphtha that is equal to MSW crude at Edmonton in the forecast period. The quality of the naphtha produced in this case is slightly better than C5+ condensate, having a slightly lower viscosity and density.

The production of gas, C3's and C4's are also higher in Case 3 than in Case 1 because of the hydrocracker operation. However, the incremental production is all saturated from the hydrocracking operation, so there is no increase in light olefins.

The distillate produced in Case 3 will meet the future ultra low sulphur diesel specification of 15 ppm for both Canada and the U.S. In order to achieve this specification, all distillate including the hydrocracker distillate is processed through the main distillate hydrotreater unit. This ensures that the distillate will meet the low sulphur specification, but requires a larger distillate hydrotreater than for Case 1. The hydrocracker naphtha does not require additional processing through the naphtha hydrotreater unit and can be directly blended with the naphtha streams from the naphtha hydrotreater unit. The resulting naphtha blend has a specific gravity of around 0.7 and sulphur content of 0.008 wt%. The jet fuel from the hydrocracker will meet the smoke point specification and not require any further processing. The diesel produced in this case meets the 40 cetane number specification required for the Midwest market, but not the higher CARB diesel specification for the California market. However, as previously mentioned, the California market consumes a small amount diesel relative to gasoline and as a result would not likely be able to absorb this large portion of diesel production without a major impact on diesel prices.

FIGURE III-1
CASE 1: BASE CASE UPGRADER
(MB/CD UNLESS NOTED)

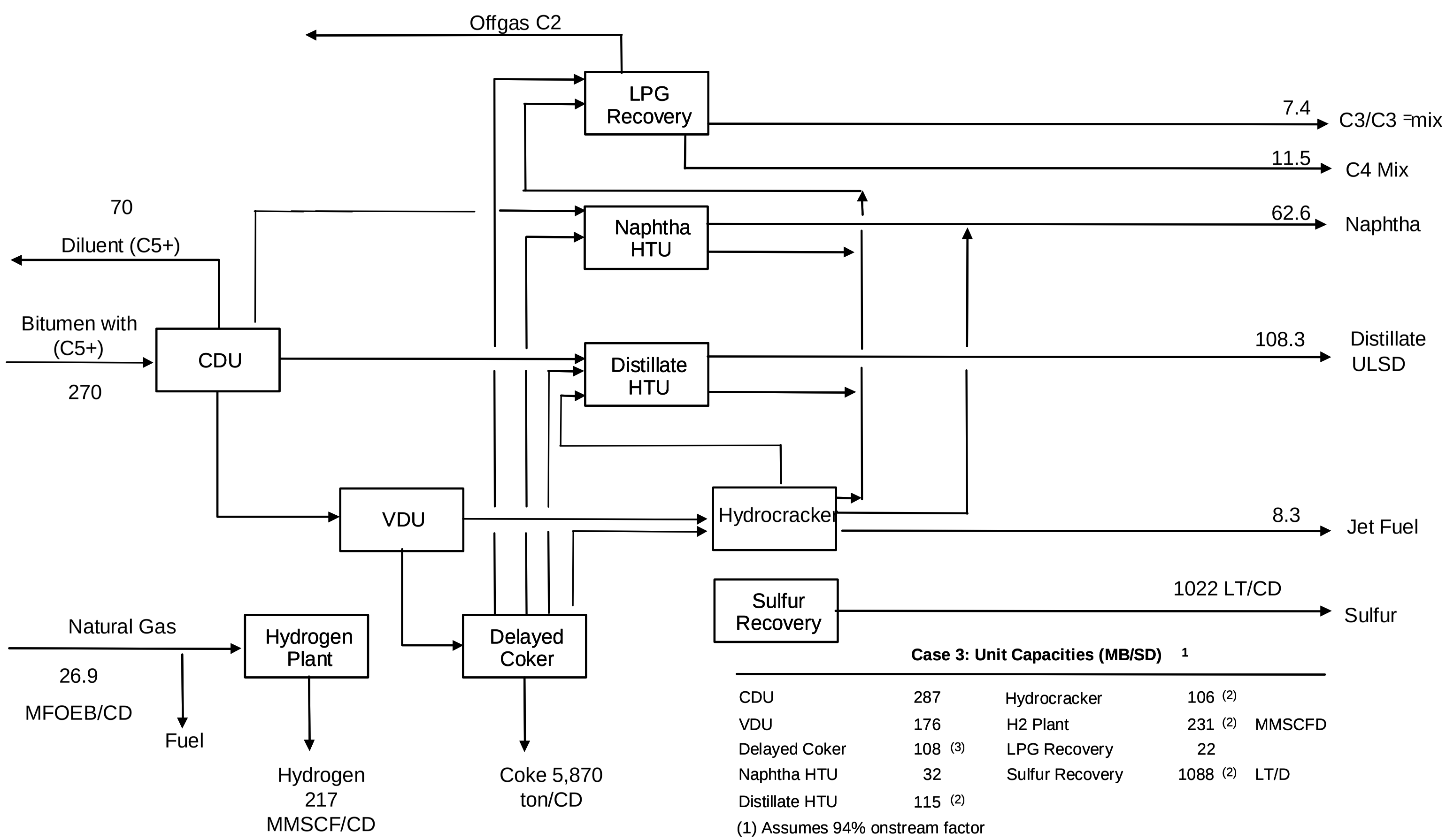


Case 1: Unit Capacities (MB/SD[1])

CDU	287	HGO HTU	106 (2)
VDU	177	H2 Plant	206 (2) MMSCFD
Delayed Coker	109 (3)	LPG Recovery	13
Naphtha HTU	32	Sulfur Recovery	1087 (2) LT/D
Distillate HTU	47		

(1) Assumes 94% onstream factor
(2) 2 Trains
(3) 6 Drums

FIGURE III-2
CASE 3: UPGRADER USING HYDROCRACKER FOR DILUENT & DISTILLATES (MB/CD UNLESS NOTED)



Case 3: Unit Capacities (MB/SD) [1]

CDU	287	Hydrocracker	106 (2)	
VDU	176	H2 Plant	231 (2)	MMSCFD
Delayed Coker	108 (3)	LPG Recovery	22	
Naphtha HTU	32	Sulfur Recovery	1088 (2)	LT/D
Distillate HTU	115 (2)			

(1) Assumes 94% onstream factor
(2) 2 Trains
(3) 6 Drums

The distillate hydrotreater unit and the heavy gas oil hydrocracker each have two trains because of the large capacity requirements, which also increases the capital cost. A detailed breakdown of the capital cost for Case 3 is provided in Table III-2. The capital cost for this case is $95 million higher than Case 1.

The remaining cases produce refined products for either the U.S. Midwest market or the California market. The difference in refined product specifications and demand preference in each market required different process unit configurations and costs. The California product cases are discussed later.

Case 4a(1): Upgrading to Refined Products

Case 4a(1) is similar to Case 3 with the addition of catalytic reforming and Isomerization units. This case resembles a traditional hydrocracking refinery with the production of conventional gasoline as illustrated in Figure III–3. The catalytic reformer unit also provides hydrogen for the hydrocracker and hydrotreater units and therefore reduces the size of the hydrogen plant that was used in Case 1 and Case 3.

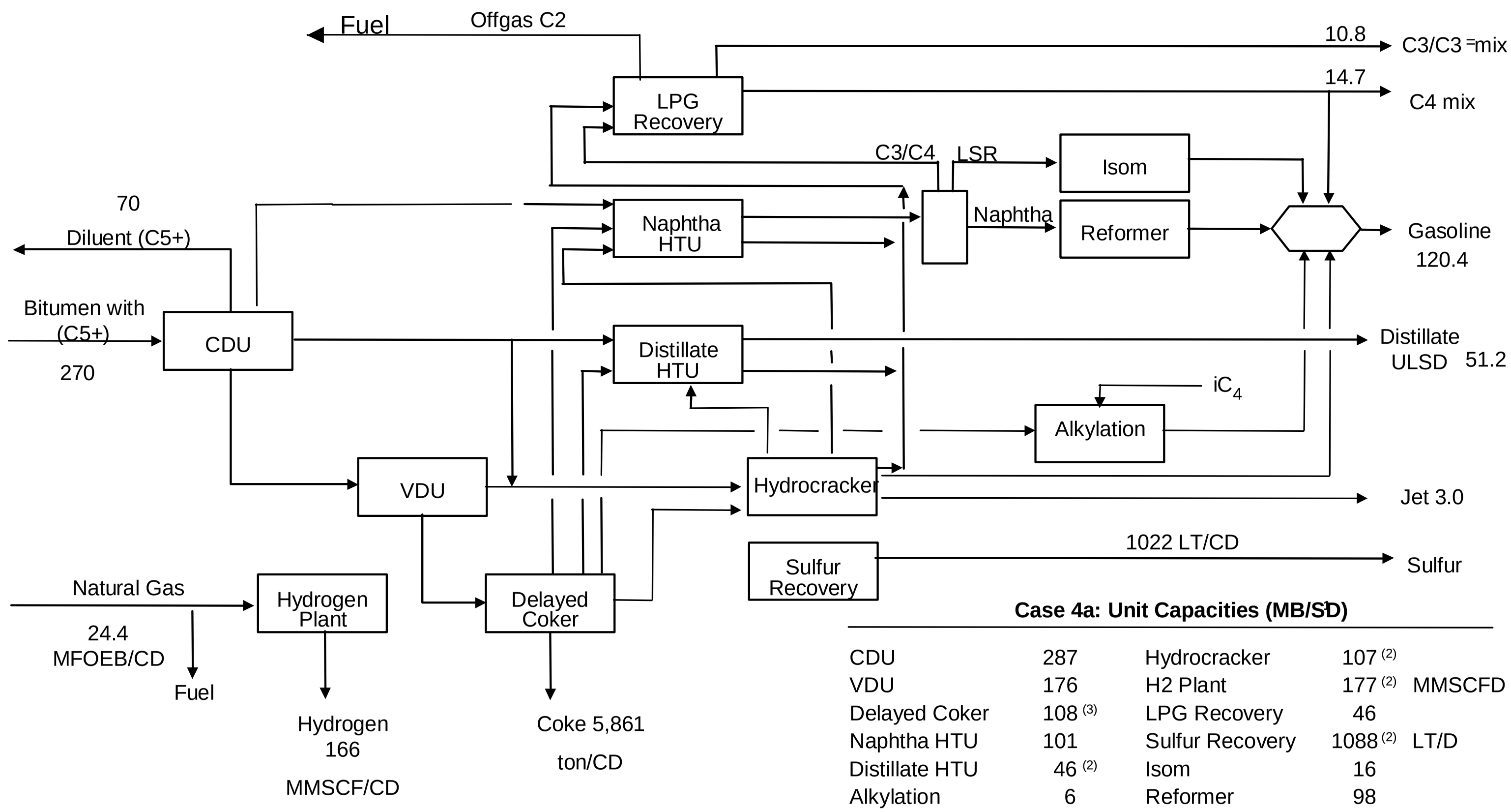
Gasoline produced from this case meets low sulphur requirements of 30 ppm, and includes both conventional gasoline and RFG. The RFG product produced is RBOB, and will require the purchase of 2,300 B/D of ethanol in the Midwest market to produce finished RFG. Since the catalytic reformer unit is susceptible to small amounts of sulphur and nitrogen contaminants, the hydrocracker naphtha needs to be reprocessed through the naphtha hydrotreater unit to meet the less than one ppm sulphur and nitrogen specification. This results in a much larger naphtha hydrotreater for this case compared to Case 3.

Butane recovered is used in the blending of gasoline, with excess butane sold in the market. Jet fuel production is slightly lower in this case than Case 3 since gasoline has a higher value than jet fuel resulting in the hydrocracker naphtha being directed to the reformer unit to produce gasoline at the expense of jet fuel. A capital cost summary for this case is provided in Table III-3.

Case 5a(1): Upgrading to Refined Products and Petrochemicals

This case is similar to Case 4a(1), but includes the addition of an aromatics chemical complex. This complex consists of a Sulfolane plant to remove benzene, toluene and some of the xylene from the reformate stream, with the raffinate and C9 aromatic stream sent to gasoline blending. The toluene is further processed in a hydro-dealkylation (HDA) unit to convert the toluene to benzene, which is then processed in the styrene production facility with ethylene. Figure III-4 shows the unit configuration for this facility.

FIGURE III-3
CASE 4A(1): MIDWEST REFINED PRODUCTS WITH VGO HYDROCRACKING (MB/CD UNLESS NOTED)

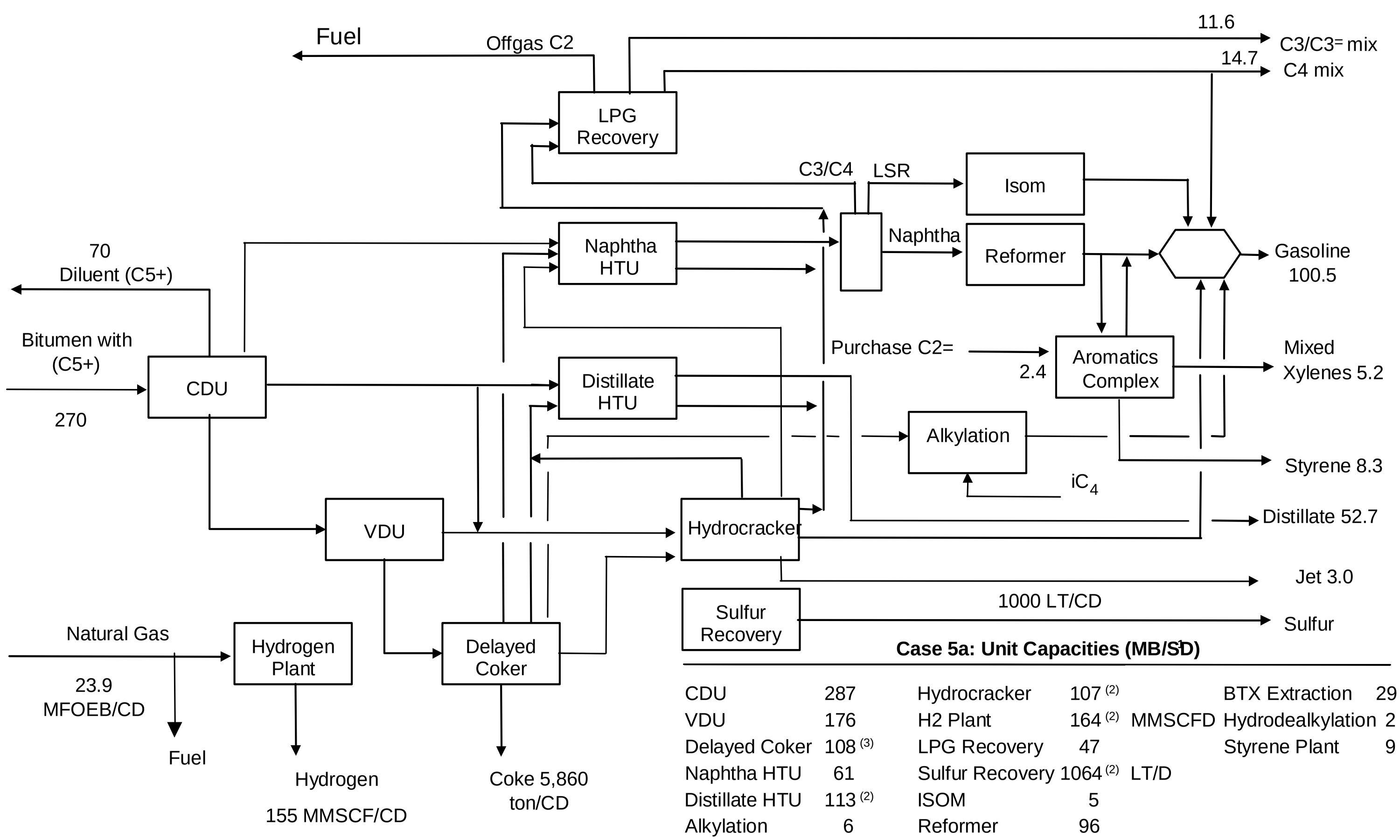


Case 4a: Unit Capacities (MB/SD)

CDU	287	Hydrocracker	107 (2)	
VDU	176	H2 Plant	177 (2)	MMSCFD
Delayed Coker	108 (3)	LPG Recovery	46	
Naphtha HTU	101	Sulfur Recovery	1088 (2)	LT/D
Distillate HTU	46 (2)	Isom	16	
Alkylation	6	Reformer	98	

(1) Assumes 94% onstream factor
(2) 2 Trains
(3) 6 Drums

FIGURE III-4
CASE 5A(1): MIDWEST REFINED PRODUCTS WITH VGO HYDROCRACKING AND STYRENE & XYLENE PRODUCTION (MB/CD UNLESS NOTED)



Case 5a: Unit Capacities (MB/SD)[1]

CDU	287	Hydrocracker	107 [2]		BTX Extraction	29
VDU	176	H2 Plant	164 [2]	MMSCFD	Hydrodealkylation	2
Delayed Coker	108 [3]	LPG Recovery	47		Styrene Plant	9
Naphtha HTU	61	Sulfur Recovery	1064 [2]	LT/D		
Distillate HTU	113 [2]	ISOM	5			
Alkylation	6	Reformer	96			

(1) Assumes 94% onstream factor
(2) 2 Trains
(3) 6 Drums

Approximately 8,300 B/D of styrene is produced which is equivalent to 436,000 tonnes per year. This is considered to be a world-class size for a styrene plant. To make this volume of styrene, almost all the toluene extracted is converted in an HDA unit, which adds to the capital and operating cost, but is justified based on the economic value added from the production of styrene. The extraction of xylene was also limited based the North America market's ability to absorb up to an incremental 100,000 tonnes/year of xylene production without having to send the product offshore. The remaining xylene was blended into gasoline. A more detailed discussion of petrochemical product pricing is located in Section VII.

The economics of producing cumene from benzene and propylene was also evaluated. Since both cumene and styrene compete for the benzene feed, increasing production of one product reduces the production of the other. The price forecast for cumene is considerably lower than for styrene resulting in a lower per pound contribution margin for cumene versus styrene. Thus, the economics support the production of styrene over cumene. The capital cost for the styrene plant is also higher than for the cumene plant on a per pound basis. Therefore, the styrene plant benefits from improved economies of scale if styrene production is maximized. For these reasons, cumene production was not included further in our analysis. Refer to Section VII for the price forecast for styrene and cumene.

The production of gasoline is lower in this case compared to Case 4a(1) because of the aromatics extraction process. The removal of benzene, toluene and xylene from the gasoline pool requires a higher reformer severity operation to meet the octane specification. However, there are insufficient high octane blend components to produce premium gasoline so the average market value of the gasoline slate is also lower. A detailed capital cost breakdown for this case is located in Table III-4.

SUMMARY OF YIELDS FOR MIDWEST CASES

The product yields for each case, where the refined products are destined to the U.S. Midwest market, are shown in Table III-5. Operating costs and capital costs are compared in Section IX.

CASES WHERE REFINED PRODUCTS ARE DESTINED TO CALIFORNIA

The following four cases were developed with the California region as the target market. As mentioned, the California market differentiates from the Midwest market due to differences in gasoline and diesel qualities. The significant difference in diesel quality between California and the Midwest is cetane, with California having a 47 - 55 cetane specification, and Midwest diesel at 40 cetane. However, California refiners can trade off diesel specifications such as total aromatics with sulphur content and cetane number and typical produce a diesel cetane number between 50 and 57. Cetane improver is also extensively used in California to provide some additional cetane boost of 1 to 8 cetane numbers if cetane quality is marginal.

Selected specifications for the gasoline in the California market are outlined in the following table.

COMPARISON OF SELECTED GASOLINE SPECIFICATIONS	Sulfur wppm	RVP (psi)	Olefins Max. Vol. %	Aromatics Max. Vol. %	Benzene Max. Vol. %
California, CARB, Phase 3	30.0	7.2	10.0	37.0	1.1
Midwest (Conventional)	30.0	10.3	32.0	45.0	5.0

As mentioned previously, the Midwest market quality specifications were based on non-RFG conventional gasoline production, which represents most of the gasoline sold in the region. The California gasoline quality specifications are more stringent than for the Midwest and result in higher capital and operating costs. These quality differences account for some of the changes in unit configurations developed for the California market when compared to the Midwest. One significant difference between the two configurations is the need for additional depentanizer capacity because of the low RVP requirements in California. Additionally, the low benzene specification requires some additional removal and saturation of benzene and benzene precursors from the reformer feed.

California gasoline also requires the addition of ethanol to provide oxygen into the gasoline. A "CARBOB" gasoline blend needs to be formulated which when blended with ethanol produces finished CARB gasoline.

In this analysis, the gasoline production of CARBOB needs to be blended with ethanol in California in a ratio of 94% CARBOB and 6% ethanol. As a result, the component concentrations can be higher to allow for dilution, but the octane can be lower because ethanol has a road octane value of 117.

Another significant difference between the California and Midwest market is the high ratio of gasoline demand relative to diesel demand in California. The diesel demand in PADD V, which includes California, Oregon, Washington and Arizona, is projected to be under 500,000 B/D. The PADD V market currently exports 30,000 B/D of distillate and therefore does not require significant incremental distillate imports. As a result, the California cases were developed with a high level of gasoline to distillate production to meet the market demands.

The quality differences and demand preferences between the regions had the most significant influences on changes to plant configurations for the California market. Some of the main differences between the two regional upgrader configurations included:

1. Processing of coker distillate in the California cases was done through the hydrocracker to make hydrocracker jet and naphtha rather than the distillate hydrotreater unit in the Midwest case. This was done to balance the gasoline to distillate ratio and to meet the higher cetane specification for distillate in California since coker distillate has a very poor cetane quality.

2. A high-pressure aromatics saturation unit or additional hydrocracking capacity is needed to increase the cetane in the diesel pool for the California case whereas the Midwest case only requires a milder hydrotreating process to remove sulphur.

3. The aromatics content for the gasoline in California is a difficult specification to meet. However refiners can trade-off aromatics with sulphur. As a result refiners in California typically run to a lower sulphur content in their gasoline, which allows them to trade-off some portion of aromatics using a complex model formula.

4. The California cases produce more butane because of the more severe hydrocracking and reformer operations compared to the Midwest cases.

5. The heavy distillate from the coker and crude units, produced in the California models for Case 4a, is transferred to the gas oil stream and is fed to the FCC and DCC units. This is necessary in order to meet diesel and gasoline specifications and results in a larger capacity for the FCC unit.

Case 4a(2): Upgrading to Refined Products

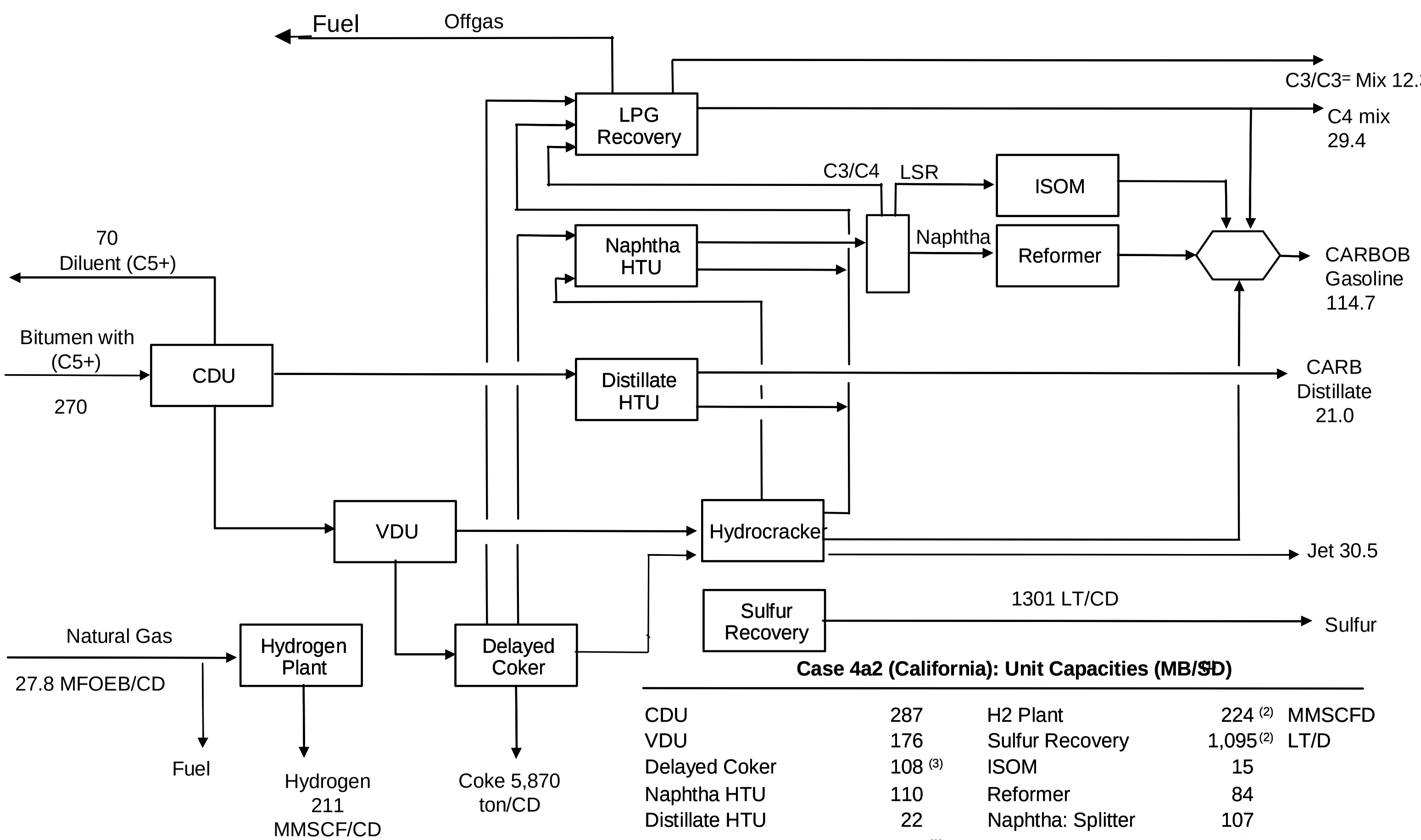
This case is similar to the Case 4a(1) for the Midwest market, with the inclusion of a high severity hydrocracker which converts 100% of the gas oil into jet fuel, light hydrocrackate, hydrocracker naphtha, and LPG's as indicated in Figure III-5. As a result, the naphtha hydrotreater unit and the reformer unit are larger in this case as is the production of gasoline. The jet fuel make is 30,000 B/D, which is higher than the diesel production, however jet fuel has a higher demand than on-road diesel in the California market.

As a result of these differences, the capital costs are higher for this case (Table III-6) than the Midwest case. The capital costs are also higher because of the naphtha splitter and depentanizer, although the net production of pentanes is zero. This case represents an annual average. Seasonal changes in the gasoline RVP results in a high amount of pentanes being produced in the summer, which could be stored and blended back into the gasoline in the winter, if such sufficient storage is available. Alternatively, since the upgrader would be built in Alberta, any excess pentanes could also be sold as diluent; this is reflected in the economic results in Section IX.

Case 5a(2): Upgrading to Refined Products and Petrochemicals

This case is similar to the U.S. Midwest case Case 5a(1), with the objective of producing a styrene product using a similar aromatics complex configuration including BTX extraction, hydro-dealkylation of some of the toluene and conversion of the benzene and ethylene into styrene. This case favours a high styrene production rate because of the high production of reformate which feeds the aromatics complex. The flow diagram for this case is shown in Figure III-6.

FIGURE III-5
CASE 4A(2):CALIFORNIA REFINED PRODUCTS WITH VGO HYDROCRACKING (MB/CD UNLESS NOTED)

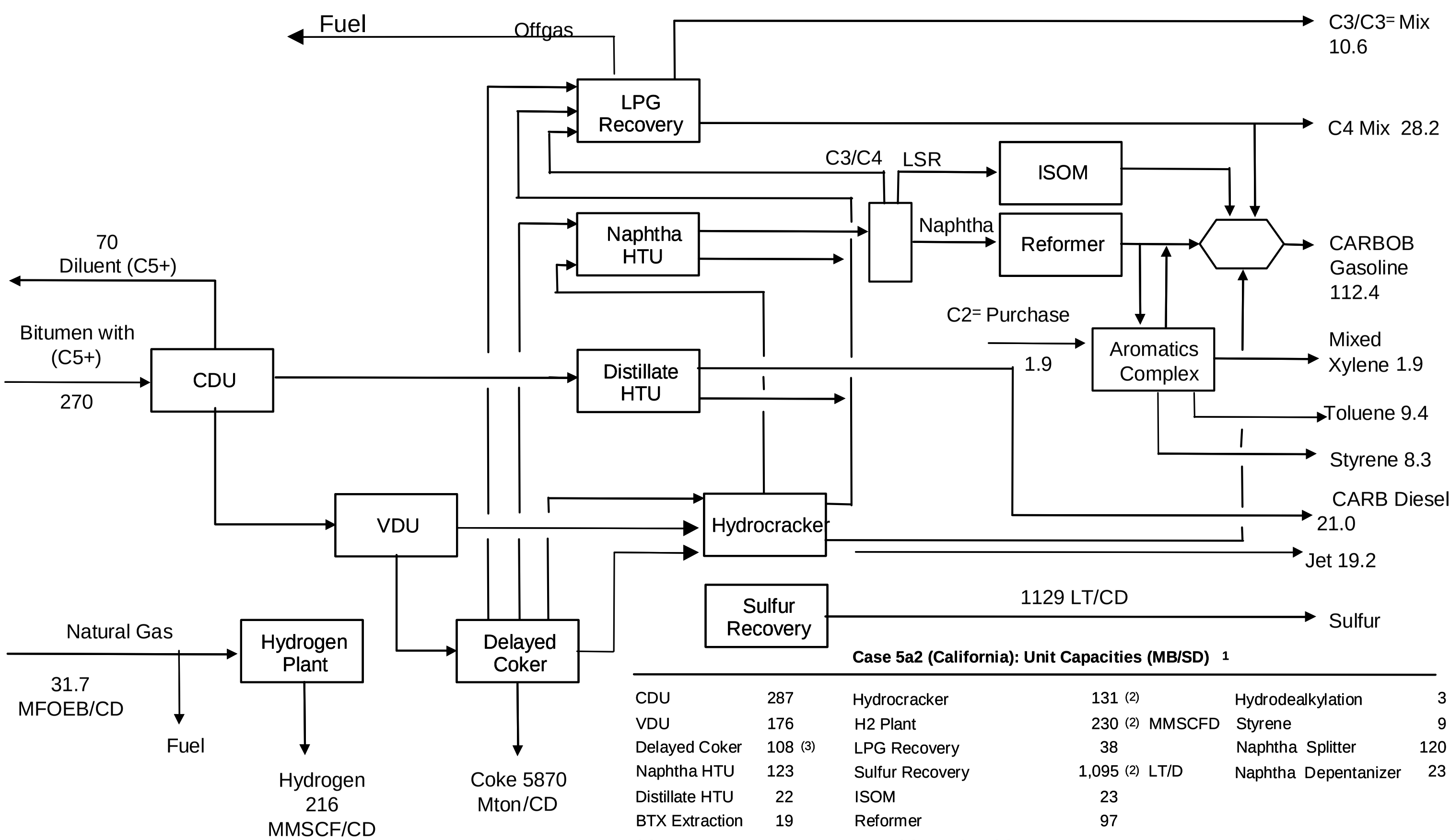


Case 4a2 (California): Unit Capacities (MB/SD) (1)

CDU	287	H2 Plant	224 (2)	MMSCFD
VDU	176	Sulfur Recovery	1,095 (2)	LT/D
Delayed Coker	108 (3)	ISOM	15	
Naphtha HTU	110	Reformer	84	
Distillate HTU	22	Naphtha: Splitter	107	
Hydrocracker	131 (2)	Naphtha: Depentanizer	8	
LPG Recovery	40			

(1) Assumes 94% onstream factor, **(2)** 2 Trains, **(3)** 6 Drums

FIGURE III-6
CASE 5A(2): CALIFORNIA REFINED PRODUCTS WITH VGO HYDROCRACKING AND STYRENE PRODUCTION (MB/CD)



Case 5a2 (California): Unit Capacities (MB/SD) [1]

CDU	287	Hydrocracker	131 (2)		Hydrodealkylation	3
VDU	176	H2 Plant	230 (2)	MMSCFD	Styrene	9
Delayed Coker	108 (3)	LPG Recovery	38		Naphtha Splitter	120
Naphtha HTU	123	Sulfur Recovery	1,095 (2)	LT/D	Naphtha Depentanizer	23
Distillate HTU	22	ISOM	23			
BTX Extraction	19	Reformer	97			

(1) Assumes 94% onstream factor, **(2)** 2 Trains, **(3)** 6 Drums

The total amount of styrene that could be produced from this case is almost double the amount produced for the Midwest Case 5a(1). However, the total amount of styrene has been limited to 8,300 B/D, which is equivalent to 436,000 tonnes per year. It was assumed that this would be the market limit for an additional styrene production facility in North America that would maintain the price of styrene. Our price forecast for styrene is included in Section V. Although most of the toluene could be blended into gasoline, some would have to be extracted and sold because of aromatics limitations in the gasoline pool, resulting in net toluene sales. It was assumed that the clearing market for this toluene would be the U.S. Gulf Coast. Additional ethylene purchases (36,000 tonnes per year) are required and was assumed to be purchased from current ethylene producers.

For this configuration, no net pentanes would have to be sold into the diluent market on an annual average, but would be required in the summer due to lower gasoline RVP. As previously mentioned, this product would be a good diluent blend component and would have a lower viscosity and gravity compared to C5+ diluent. The capital cost for this case is shown in Table III-7.

Case 4a(2): Upgrading to Refined Products with ISO-Octane

This case is similar to Case 4a(2), except that it was assumed that the refinery upgrader could purchase around 3,200 B/D of iso-octane at Edmonton. This product is a high octane blending component with a low RVP which is sent to California, and is valuable in blending ethanol into gasoline. We considered the impact of blending this into the CARBOB product at the refinery, and it enabled an increase in gasoline of 8,300 B/D over Case 4a(2).

The capital cost for this case is shown in Table III-8. It is only about 0.3% less than the capital cost for Case 4a(2). The primary benefit for this case is the higher yield of gasoline, and capturing the uplift of purchasing the iso-octane at Edmonton.

SUMMARY OF YIELDS FOR CALIFORNIA

The product yields for each case are shown in Table III-9.

U.S. REFINERY CASES

In addition to the projects examined in Alberta, potential refinery upgrades/expansions were also studied for the U.S. markets to compare relative economics between the two. In this task the capital costs and overall project economics were estimated for surrogate refineries located in the California and U.S. Midwest markets considering upgrading existing facilities to process bitumen blends (SynBit, SynSynBit and neat SCO). The surrogate refinery in the Midwest is a light to medium sour cracking refinery with access to Southern Illinois crude/product logistics as well as refined product markets. The overall capacity of the facility is 200,000 B/CD and the current configuration allows no vacuum resid upgrading capability as residual material is sold as either asphalt or blended to fuel oil. In the California market, the surrogate facility is a 250,000 B/CD medium sour coking facility with access to waterborne crude oils and the Southern California product market. The facility is a full conversion refinery with all vacuum residual material processed in the existing delayed coker. In the U.S. Mid-continent, a 50,000 B/D sweet crude/sour crude cracking facility is the surrogate facility. A table summarizing the critical processing units of each facility is shown below.

U.S. REFINERY CONFIGURATION FOR ANALYSIS
(Thousand Barrels per Calendar Day Unless Noted)

Refinery Process Units	U.S. Midwest	California	U.S. Mid-Continent
Atmospheric Distillation	200	250	50
Vacuum Distillation	84	115	16
Delayed Coking	-	55	-
Fluid Catalytic Cracking	54	89	13
Hydrocracking	12	29	-
Alkylation	13	19	3
Catalytic Reforming	50	47	14
Distillate Hydrotreating	42	40	11
Hydrogen Plant (MMSCF/D)	10	132	-
Sulfur Plant (LT/D)	228	426	11

Four separate cases were developed for the U.S. refineries. These cases are numbered consecutively from the other Alberta refinery cases. The case numbers and brief descriptions of each are outlined below.

U.S. REFINERY UPGRADING CASES

Case No.	Refining Market	Description of Case
Case 6	USMW	Project to allow 100,000 B/D of Synbit processing, maintaining current asphalt production.
Case 7	USMW	Project to allow processing of Synsynbit blend without expansion of distillation units (Hydrocracking expansion).
Case 8	California	Project to allow 100,000 B/D of Synbit processing.
Case 9	U.S. Mid-Continent	Project to replace sweet crude with neat SCO (25,000 B/D).

The two U.S. Midwest refinery projects involve upgrading the existing refinery to process either SynBit (Case 6) or Synsynbit (Case 7). In Case 6, asphalt manufacturing was maintained thereby the delayed coker's capacity is sized only to eliminate the fuel oil production. The heavier crude slate requires expansion of many of the refinery processing units, including a large hydrocracking expansion necessary to maintain the gasoline / distillate ratios for the market given SynBit's higher percentage of gas oil material versus other conventional crude oils. In Case 7, a Synsynbit blend is constructed to mimic a similar API gravity crude slate that the facility is currently processing. The blend is approximately 80/20 synthetic crude oil to bitumen, which corresponds to an API gravity of nearly 29 °API and 1.2 wt. % sulphur. The custom blend eliminates the need for expansion of vacuum distillation capacity and reduces the expansion in other downstream units, except for the hydrocracker. No residual upgrading is considered in the project as asphalt and fuel oil production are maintained.

The California refinery project involves the upgrading and/or expansion of an existing facility to process 100,000 B/D of SynBit. The increase in residual production requires expansion of most of the upgrading units, including the need for increased hydrocracking capacity to maintain market gasoline to distillate ratios. The sour crude processed and hydrogen addition necessary also requires expansion of auxiliary units including sulphur handling and hydrogen manufacturing.

The Mid-continent refinery considers the processing of neat SCO replacing the sweet crude slate. The increased distillate and VGO production requires a grassroots hydrocracker and significant expansion of the existing FCCU. Asphalt production is maintained through continued processing of sour crude albeit at a lower rate than the base case.

EXPANSION PROJECT DESIGN/CAPITAL COSTS

In the development of each upgrading case, Purvin & Gertz utilized its proprietary linear program (LP) model to represent each of the base refinery configurations, crude slate and resulting refined product mix. The LP helps determine the required increase in capacity necessary for various downstream units to process the bitumen blend in order to maintain product quality and production volumes to meet market demand. The LP model also provides material and energy balances which provides input to Purvin & Gertz' functional cost estimating tool that utilizes cost estimating curves to determine the installed cost of each processing unit, as well as the associated operating costs.

Each case's project economics are determined as a build up of refinery capital costs, assuming each unit that requires capacity expansion can be accomplished at a capital cost equal to the difference between pre- and post-project unit capacities. New units costs are calculated as grassroots construction. Total capital includes ISBL and OSBL, licensor fees, owner's costs, escalation and contingency (15 percent of total equipment costs). In addition to the project costs described above additional project costs related to acquiring environmental permits, location factors versus the USGC and conducting work within an operating facility were included in the overall project costs. These costs are estimated at 15 percent of the total project costs for the U.S. Midwest and 25 percent for California.

Case 6: U.S. Midwest Refinery SynBit Coker Project

In this case an existing medium sour cracking refinery with a nominal 200,000 B/D capacity is upgraded to process 100,000 B/D of SynBit. Foreign light sour and existing heavy Canadian crude oils were replaced with equal volumes of SynBit, with the remaining crude being domestic light sour. Gasoline to distillate ratios were held constant to the base refinery. Reformulated versus conventional gasoline production was also held in constant ratios to the base case. Base gasoline production was assumed to meet the 30 ppm sulphur specification and all diesel production, although segregated between on-road and off-road grades, meets a 15 ppm sulphur specification. In this case, asphalt production is held constant at 25,000 B/CD with SynBit assumed to meet asphalt production quality requirements.

The heavier crude slate requires a 16,000 B/SD expansion of the existing vacuum unit and a new 25,000 B/SD delayed coker to process vacuum residual in excess of asphalt production. Given the fixed gasoline to distillate ratio, excess gas oil produced from the new delayed coker as well as from the SynBit processing, requires a 28,000 B/D hydrocracker to be constructed, which converts the material to naphtha for further processing. The additional hydrocracker naphtha production requires the material to be reformed to meet finished gasoline specifications and a resulting 11,000 B/D expansion of the existing catalytic reforming unit is required. The additional sulphur from the SynBit processing requires significant sulphur handling capacity additions of approximately 200 LT/D. In addition, new hydrocracking capacity necessitates significant hydrogen production capacity of approximately 45 MMSCF/D.

Fixed operating costs increase with the addition of the new hydrocracker and delayed coker, both of which have relatively high levels of maintenance requirements. Variable operating costs are also affected by the addition of the two new units and expansion of several others. Catalyst costs per barrel increase with the new hydrocracker and large increases in the hydrogen plant capacity. The major increase in natural gas consumption is required as feed stock for hydrogen manufacturing. Table III-10 summarizes the charge/yield statements for the base refinery and the SynBit project as well as the estimated operating expenses for each. Table III-11 provides the estimated capacity expansions and/or upgrades for the project and the cost detail for the project.

Case 7: U.S. Midwest Refinery Synsynbit Hydrocracking Project

In Case 7, a blend of synthetic crude oil and bitumen is produced which provides a similar API gravity as the base refinery. This eliminates the need for expansion/upgrade of the existing refinery's distillation capacity. The refinery continues to produce asphalt and fuel oil as a means to convert vacuum residual material. As with Case 6, gasoline to distillate ratios and reformulated versus conventional gasoline production is held constant to the base case. The Synsynbit is substituted in place of the foreign light sour and the existing Canadian heavy sour crude.

The fixed gasoline to distillate ratios and the Synsynbit's large gas oil yield requires investment in a new hydrocracker to produce naphtha for gasoline manufacturing. The resulting naphtha goes to catalytic reforming (requiring 9,000 B/D expansion) before being blended to the gasoline pool. The resulting Synsynbit blend does not increase the overall sulphur level to the refinery; therefore existing sulphur handling capacity is sufficient. The new hydrocracker requires an additional 21 MMSCF/D of hydrogen. Fixed and variable operating costs increase proportionately with the addition of the new hydrocracker and catalytic reformer expansion. Table III-10 and III-11 provides similar detail as Case 6 for charge/yield statements, operating costs and project investments.

Case 8: California Refinery SynBit Coker Project

Case 8 upgrades an existing 250,000 B/D California medium sour coking facility to process 100,000 B/D of SynBit. The base crude slate is a mixture of waterborne medium sour crudes including Middle East medium sour and Alaskan North Slope (ANS) crude oils. The SynBit replaces equal volumes of the foreign and domestic light sour streams; while the small amount of local heavy sour (Thums) is left unchanged between cases. All CARB specification gasoline and diesel products are produced and ethanol is used as the oxygenate for gasoline.

The addition of SynBit increases the refinery's overall gas oil, vacuum residual and sulphur yields. To maintain gasoline to distillate ratios, delayed coking, FCCU and hydrocracking capacity expansion is necessary. No corresponding expansion of catalytic reforming capacity is needed, since virgin naphtha volumes are reduced with the addition of SynBit, creating spare capacity for the incremental hydrocracker naphtha production. The increased coker gas oil production and higher sulphur levels in the gas oil stream also requires expansion of the existing FCCU feed hydrotreater (VGO hydrotreater) to meet specifications for CARB products. Table III-12 summarizes the charge/yield statements for the base refinery and the SynBit project as well as the estimated operating expenses for each. Table III-13 provides the estimated capacity expansions and/or upgrades for the project and the cost detail for the project.

Case 9: Mid-Continent SCO Hydrocracker

Case 9 upgrades an existing 50,000 B/D Mid-continent sweet/sour crude cracking refinery to process 50% neat SCO. The base crude slate is 25,000 B/D of WTI and 25,000 B/D of WTS. The base refinery also produces a small amount of finished asphalt. No reformulated gasoline is produced by the facility. Although this case is modelled as a standalone refinery, it could also represent incremental cracking capacity within a larger facility.

The replacement of 25,000 B/D of WTI with neat SCO increases the refinery's overall VGO and distillate yields, while reducing the production of vacuum distillation unit hydraulics could severely impair the current heat balance for the unit, since typically feed preheat trains are typically integrated with vacuum bottoms streams. For purposes of this analysis, it is assumed the cost for such modifications are covered in this level of estimate.

To maintain gasoline to distillate ratios a new hydrocracking unit is necessary as well as significant expansion to the existing FCCU. The new hydrocracker results in the need to construct a hydrogen plant as well. Table III-14 summarizes the charge/yield statements for the base refinery and the neat SCO project as well as the estimated operating expenses for each. Table III-15 provides the estimated capacity expansions and/or upgrades for the project and the corresponding estimated capital cost.

TABLE III-1
UPGRADER BASE CASE 1: CAPITAL COST ESTIMATE
(Constant 2004 U.S. Dollars)

Unit	Capacity MB/SD		Capital Cost[1] $Million
Crude Distillation Unit	287		166.2
Vacuum Distillation Unit	177		110.7
Delayed Coker	109		515.2
Naphtha Hydrotreater	32		27.4
Distillate Hydrotreater	47		80.8
HGO Hydrotreater[2][8]	106		309.6
Hydrogen Plant[8]	206	MMSCFD	149.8
LPG Recovery	13		15.7
Sulphur Recovery[8]	1,087	LT/D	157.5
Total Onsite			1,532.9
Total Offsite[3]			778.8
Total Refinery			**2,311.7**
Licensor Costs[4]			**98.2**
Owner's Costs[5]			**328.3**
Escalation[6]			**176.0**
Contingency[7]			**437.1**
Grand Total			**3,351.3**

Notes: (1) Process units are inside battery line and (ISBL) Costs. All costs have been increased based on 1.3 location factor adjustment relative to U.S. Gulf Coast.
(2) HGO HTU is a mild hydrocracker.
(3) Offsites cost include tank farm, piping, power distribution, steam generating and distribution, water treating and cooling water.
(4) Licensor costs include fees, engineering and initial catalyst fill.
(5) Owners costs include project management, startup and commissioning, taxes and insurance, project development, etc.
(6) Escalation is 3%.
(7) Contingency is 15%.
(8) Two trains

TABLE III-2
CASE 3: CAPITAL COSTS
UPGRADER PRODUCING DILUENT AND DIESEL FUEL
(Constant 2004 U.S. Dollars)

Unit	Capacity MB/SD		Capital Cost[1] $Million
Crude Distillaiton Unit	287		166.2
Vacuum Distillaiton Unit	176		110.5
Delayed Coker	108		514.4
Naphtha Hydrotreater	32		27.4
Distillate Hydrotreater[7]	115		185.2
Hydrocracker[7])	106		740.4
Hydrogen Plant[7]	231	MMSCFD	160.6
LPG Recovery	22		22.4
Sulphur Recovery[7]	1,088	LT/D	157.6
Total Onsite			2,084.8
Total Offsite[2]			916.3
Total Refinery			**3,001.0**
Licensor Costs[3]			**127.5**
Owner's Costs[4]			**426.1**
Escalation[5]			**228.5**
Contingency[6]			**567.5**
Grand Total			**4,350.7**

Notes: (1) Process units are inside battery line and (ISBL) Costs. All costs have been increased based on 1.3 location factor adjustment relative to U.S. Gulf Coast.
(2) Offsites cost include tank farm, piping, power distribution, steam generating and distribution, water treating and cooling water.
(3) Licensor costs include fees, engineering and initial catalyst fill.
(4) Owners costs include project management, startup and commissioning, taxes and insurance, project development, etc.
(5) Escalation is 3%.
(6) Contingency is 15%.
(7) Two trains

TABLE III-3
CASE 4a(1): CAPITAL COSTS
REFINED PRODUCTS TO U.S. MIDWEST
(Constant 2004 U.S. Dollars)

Unit	Capacity MB/SD	Capital Cost[1] $Million
Crude Distillation Unit	287	166.2
Vacuum Distillation Unit	176	110.5
Delayed Coker	108	514.4
Naphtha Hydrotreater	112	64.9
Distillate Hydrotreater and Aromatics Desat [7]	47	109.1
Hydrocracker [7]	107	743.9
Hydrogen Plant [7]	177 MMSCFD	136.4
LPG Recovery	44	36.2
Sulphur Recovery [7]	1,088 LT/D	157.6
Alkylation	6	41.1
ISOM Unit	16	23.4
Reformer	98	130.4
Total Onsite		2,234.0
Total Offsite[2]		1,008.0
Total Refinery		**3,242.1**
Licensor Costs[3]		**137.8**
Owner's Costs[4]		**460.4**
Escalation[5]		**246.8**
Contingency[6]		**613.1**
Grand Total		**4,700.1**

Notes: (1) Process units are inside battery line and (ISBL) Costs. All costs have been increased based on 1.3 location factor adjustment relative to U.S. Gulf Coast.
(2) Offsites cost include tank farm, piping, power distribution, steam generating and distribution, water treating and cooling water.
(3) Licensor costs include fees, engineering and initial catalyst fill.
(4) Owners costs include project management, startup and commissioning, taxes and insurance, project development, etc.
(5) Escalation is 3%.
(6) Contingency is 15%.
(7) Two trains

TABLE III-4
CASE 5a(1): CAPITAL COSTS
REFINED PRODUCTS TO U.S. MIDWEST, PETROCHEMICALS
(Constant 2004 U.S. Dollars)

Unit	Capacity MB/SD		Capital Cost[1] $Million
Crude Distillation Unit	287		166.2
Vacuum Distillation Unit	176		110.5
Delayed Coker	108		514.4
Naphtha Hydrotreater	89		55.6
Distillate Hydrotreater and Aromatics Sat[7]	40		89.7
Hydrocracker [7]	107		743.9
Hydrogen Plant [7]	166	MMSCFD	131.2
LPG Recovery	45		36.5
Sulphur Recovery[7]	1,064	LT/D	155.2
ISOM	0		0.0
Reformer	89		124.6
Alkylation	6		41.1
BTX Extraction	29		76.6
Hydrodealkylaton	2		19.0
Styrene	9		350.0
Total Onsite			2,614.5
Total Offsite[2]			1,084.7
Total Refinery			**3,699.2**
Licensor Costs[3]			**157.2**
Owner's Costs[4]			**525.3**
Escalation[5]			**281.6**
Contingency[6]			**699.5**
Grand Total			**5,362.8**

Notes: (1) Process units are inside battery line and (ISBL) Costs. All costs have been increased based on 1.3 location factor adjustment relative to U.S. Gulf Coast.
(2) Offsites cost include tank farm, piping, power distribution, steam generating and distribution, water treating and cooling water.
(3) Licensor costs include fees, engineering and initial catalyst fill.
(4) Owners costs include project management, startup and commissioning, taxes and insurance, project development, etc.
(5) Escalation is 3%.
(6) Contingency is 15%.
(7) Two trains

TABLE III-5
SUMMARY: PRODUCT YIELDS MIDWEST CASES
(Thousand Barrels per Calendar Day)

		Case 1	Case 3	Case 4a(1)	Case 5a(1) Styrene(1)	Case 5a(1) Benzene(2)
Feed						
Bitumen		200.0	200.0	200.0	200.0	200.0
Field Butane						
Natural Gas (MFOEB/CD)		20.8	26.9	24.4	23.9	21.9
Total		220.8	226.9	224.4	223.9	221.9
Products						
Ethylene Purchases		0.0	0.0	0.0	-2.4	0.0
Propane/Propylene		5.5	7.3	10.8	11.6	11.5
Propylene High Production		0.0	0.0	0.0	0.0	0.0
Butane		1.5	11.5	14.7	14.7	14.4
RFG RBOB				46.4	40.1	33.8
Regular Unleaded Gasoline 30 ppm S		0.0	0.0	66.6	54.4	58.7
Premium Gasoline 30 ppm S		0.0	0.0	7.4	6.0	6.5
Jet/Kerosene		0.0	8.3	3.0	3.0	3.0
Diesel 15 ppm S		0.0	108.3	51.2	52.7	52.7
Subtotal: Refined Products		0.0	116.6	174.5	156.2	154.8
Benzene		0.0	0.0	0.0	0.0	4.9
Synthetic Crude		177.6	0.0	0.0	0.0	0.0
Naphtha/Diluent		0.0	62.6	0.0	0.0	0.0
Mixed Xylenes		0.0	0.0	0.0	5.2	5.2
Styrene(1)		0.0	0.0	0.0	8.3	0.0
Total		184.6	198.0	200.0	193.6	190.8
Fuel Grade Coke	tonne/day	5,873	5,861	5,861	5,861	5,861
Sulphur	LT/Day	1,021	1,022	1,022	1,000	1,023

Notes: (1) Styrene production equivalent to 436,000 tonnes per year
(2) Benzene is sold instead of producing styrene.

TABLE III-6
CASE 4a(2): CAPITAL COSTS
REFINED PRODUCTS TO CALIFORNIA
(Constant 2004 U.S. Dollars)

Unit	Capacity MB/SD		Capital Cost[1] $Million
Crude Distillation Unit	287		166.2
Vacuum Distillation Unit	176		110.5
Delayed Coker	108		514.4
Naphtha Hydrotreater[8]	110		80.0
Distillate Hydrotreater	22		77.3
Hydrocracker [7][8]	131		860.1
Hydrogen Plant [8]	224	MMSCFD	157.7
LPG Recovery	40		33.5
Sulphur Recovery [8]	1,095	LT/D	158.3
ISOM	15		24.3
Reformer	84		120.3
Naphtha: Splitter	107		29.8
Naphtha: Depentanizer	8		4.8
Total Onsite			2,337.3
Total Offsite[2]			1,002.3
Total Refinery			**3,339.7**
Licensor Costs[3]			**141.9**
Owner's Costs[4]			**474.2**
Escalation[5]			**254.2**
Contingency[6]			**631.5**
Grand Total			**4,841.6**

Notes: (1) Process units are inside battery line and (ISBL) Costs. All costs have been increased based on 1.3 location factor adjustment relative to U.S. Gulf Coast.
(2) Offsites cost include tank farm, piping, power distribution, steam generating and distribution, water treating and cooling water.
(3) Licensor costs include fees, engineering and initial catalyst fill.
(4) Owners costs include project management, startup and commissioning, taxes and insurance, project development, etc.
(5) Escalation is 3%.
(6) Contingency is 15%.
(7) Includes cracked distillate and VGO
(8) Two Trains

TABLE III-7
CASE 5a(2): CAPITAL COSTS
REFINED PRODUCTS TO CALIFORNIA, PETROCHEMICALS
(Constant 2004 U.S. Dollars)

Unit	Capacity MB/SD		Capital Cost[1] $Million
Crude Distillation Unit	287		166.2
Vacuum Distillation Unit	176		110.5
Delayed Coker	108		514.4
Naphtha Hydrotreater	123		86.2
Distillate Hydrotreater	22		77.3
Hydrocracker [7][8]	131		860.1
Hydrogen Plant [8]	230	MMSCFD	160.1
LPG Recovery	38		32.5
Sulphur Recovery [8]	1,095	LT/D	158.3
ISOM	23		31.0
Reformer	97		129.7
BTX Extraction	19		40.5
Hydrodealkylaton	3		28.7
Styrene	9		352.0
Naphtha: Splitter	120		32.3
Naphtha: Depentanizer	23		10.2
Total Onsite			2,790.0
Total Offsite[2]			1,124.4
Total Refinery			**3,914.3**
Licensor Costs[3]			**166.4**
Owner's Costs[4]			**555.8**
Escalation[5]			**298.0**
Contingency[6]			**740.2**
Grand Total			**5,674.7**

Notes:
(1) Process units are inside battery line and (ISBL) Costs. All costs have been increased based on 1.3 location factor adjustment relative to U.S. Gulf Coast.
(2) Offsites cost include tank farm, piping, power distribution, steam generating and distribution, water treating and cooling water.
(3) Licensor costs include fees, engineering and initial catalyst fill.
(4) Owners costs include project management, startup and commissioning, taxes and insurance, project development, etc.
(5) Escalation is 3%.
(6) Contingency is 15%.
(7) Includes cracked distillate and VGO
(8) Two Trains

TABLE III-8
CASE 4a(2) WITH ISO-OCTANE: CAPITAL COSTS
REFINED PRODUCTS TO CALIFORNIA
(Constant 2004 U.S. Dollars)

Unit	Capacity MB/SD		Capital Cost[1] $Million
Crude Distillation Unit	287		166.2
Vacuum Distillation Unit	176		110.5
Delayed Coker	108		514.4
Naphtha Hydrotreater	110		79.8
Distillate Hydrotreater	22		77.3
Hydrocracker [7][8]	131		860.1
Hydrogen Plant [8]	224	MMSCFD	157.8
LPG Recovery	40		32.0
Sulphur Recovery [8]	1,095	LT/D	158.3
ISOM	15		18.6
Reformer	84		119.9
Naphtha: Splitter	107		29.7
Naphtha: Depentanizer	8		7.0
Total Onsite			2,331.6
Total Offsite[2]			999.2
Total Refinery			**3,330.8**
Licensor Costs[3]			**141.6**
Owner's Costs[4]			**473.0**
Escalation[5]			**253.6**
Contingency[6]			**629.8**
Grand Total			**4,828.8**

Notes: (1) Process units are inside battery line and (ISBL) Costs. All costs have been increased based on 1.3 location factor adjustment relative to U.S. Gulf Coast.
(2) Offsites cost include tank farm, piping, power distribution, steam generating and distribution, water treating and cooling water.
(3) Licensor costs include fees, engineering and initial catalyst fill.
(4) Owners costs include project management, startup and commissioning, taxes and insurance, project development, etc.
(5) Escalation is 3%.
(6) Contingency is 15%.
(7) Includes cracked distillate and VGO
(8) Two Trains

TABLE III-9
SUMMARY: PRODUCT YIELDS CALIFORNIA CASES
(Thousand Barrels per Calendar Day)

		Case 4a(2)	Case 5a(2)	Case 4a(2) With Iso-octane
Feed				
Bitumen		200.0	200.0	200.0
Field Butane				
Natural Gas (MFOEB/CD)		27.7	31.8	27.6
Ethylene			2.4 (1)	
Total		227.7	234.3	227.6
Products				
Ethane/Ethylene (2)				
Propane/Propylene		12.3	10.5	11.5
Propylene High Production				
Butane		29.4	28.2	27.3
Regular Unleaded Gasoline CARBOB		90.4	112.5	97.0
Premium Gasoline CARBOB		24.4		26.1
Jet/Kerosene		30.5	18.4	31.0
Diesel CARB		21.0	21.0	21.0
Subtotal: Refined Products		166.2	151.8	175.0
Toluene			9.4	
Mixed Xylene			1.9	
Styrene			8.3 (2)	
Total		207.9	210.3	213.7
Fuel Grade Coke	tonne/day	5,861	5,861	5,861
Sulphur	LT/Day	1,161	1,046	1,165

Notes: (1) Only Ethane is produced in Case 5a with Ethylene purchased for Styrene Plant
(2) Styrene production equivalent to 436,000 tonnes per year

TABLE III-10
U.S. MIDWEST REFINERY UPGRADING PROJECTS CHARGE/YIELD & OPERATING COSTS
(Thousand of Barrels per Calendar Day Unless Noted)

Feedstocks / Products / Costs	Base Refinery	SynBit Coker Project (Case 6)	Synsynbit Hydrocracker Project (Case 7)
Feedstocks/Crude Oil			
Arab Extra Light	38	-	-
WTS	125	100	125
Cold Lake Blend	38	-	-
Athabasca Bitumen	-	52	15
Synthetic Crude Oil	-	48	60
Iso-Butane	3	1	1
Normal Butane	-	-	-
Ethanol	1	1	1
Total Feedstocks	204	202	202
Products			
Own-Produced Fuel (MBFOE/D)	6	8	7
Propanes	5	7	6
Butanes	0	1	1
RFG Regular Gasoline	19	21	21
RFG Premium Gasoline	2	2	2
Conventional Regular Gasoline	75	85	82
Conventional Premium Gasoline	8	9	8
Jet Fuel	12	12	12
On-Road Diesel	26	29	29
Off-Road Diesel	5	5	5
BTX	2	2	2
Fuel Oil	23	-	10
Slurry Oil	-	2	-
Asphalt	25	25	25
Coke - Fuel (ST/D)	-	1,239	-
Sulphur (LT/D)	228	416	223
Total Liquid Product	201	200	203
Total Liquid Yield (% of Feedstocks)	98.5%	99.1%	100.4%
Fixed Operating Costs ($MM/yr)			
Labor (excl. Maintenance)	31	39	34
Maintenance (incl. Labour)	35	51	42
Taxes & Insurance	9	12	10
Miscellaneous + G&A	11	13	12
Total Fixed Costs ($MM/yr)	87	116	98
Total Fixed Costs ($/Bbl Crude)	1.19	1.58	1.34
Variable Operating Costs			
Natural Gas (BFOE/Bbl Crude)	0.04	0.06	0.05
Electricity (kWh/Bbl Crude)	6.35	8.42	7.47
Water + Steam ($/Bbl Crude)	0.03	0.04	0.04
Catalyst + Chemicals ($/Bbl Crude)	0.28	0.33	0.30

TABLE III-11
U.S. MIDWEST REFINERY UPGRADING PROJECTS CAPITAL COSTS
(Capacities in Barrels per Stream Day, Costs in Constant 2004 U.S. Million Dollars)

Major Process Units / Project Capital	Base Refinery	SynBit Coker Project (Case 6)	Synsynbit Hydrocracker Project (Case 7)
		Incremental Capacity Expansion	
Crude Distillation Unit	211	-	-
Vacuum Distillation Unit	88	16	-
Delayed Coking Unit	-	25	-
Catalytic Reforming Unit	54	11	9
Fluid Catalytic Cracking Unit	59	3	2
Hydrocracking Unit	13	28	18
VGO Hydrotreating Unit	-	-	-
Distillate Hydrotreating Unit	46	-	-
Naphtha Hydrotreating Unit	54	11	9
FCC Gasoline Hydrotreating Unit	33	1	2
Alkylation Unit	14	1	-
Sulphur Plant (LT/D)	248	204	-
Hydrogen Plant (MMSCF/D)	11	45	21
Project Capital Cost Estimates			
Total On-Site (1)		338	140
Total Off-Site (2)		84	28
Total Refinery		422	167
Licensor Costs (3)		18	7
Owner's Costs (4)		60	24
Escalation (5)		32	13
Contingency (6)		80	32
Total Project excl. Other Costs		612	243
Other Project Costs (7)		92	36
Total Project Costs		704	279

Notes:
(1) Process units are included in on-site costs (ISBL).
(2) Offsite costs include tanks, inter-unit piping, power distribution and associated utilities.
(3) Licensor costs include fees, engineering, and initial catalyst fill.
(4) Owner's costs include project management, start-up and commissioning, taxes and insurance during construction, and project development costs.
(5) Escalation is 3 percent.
(6) Contingency is 15 percent.
(7) Other project costs is 15 percent and includes environmental permit work, location factor versus the USGC, project work in operating refinery, etc.

TABLE III-12
CALIFORNIA REFINERY PROJECT CHARGE/YIELD & OPERATING COSTS
(Thousand of Barrels per Calendar Day Unless Noted)

Feedstocks / Products / Costs	Base Refinery	SynBit Coker Project (Case 8)
Feedstocks/Crude Oil		
ANS	115	65
Athabasca Bitumen	-	52
SCO	-	48
Arab Light	30	-
Arab Medium	85	65
Thums	20	20
Normal Butane	-	1
Ethanol	9	9
Total Feedstocks	259	260
Products		
Own-Produced Fuel Gas (MBFOE/D)	12	12
Propane	7	7
Propylene	2	2
N-Butane	0	-
I-Pentanes	5	5
Regular CARB Gasoline	133	133
Premium CARB Gasoline	33	33
Jet Fuel	31	27
CARB Diesel	38	41
Slurry Oil	5	6
Coke - Fuel (ST/D)	2,018	2,258
Sulphur (LT/D)	426	588
Total Liquid Product	254	255
Total Liquid Yield (% of Feedstocks)	98.1%	97.9%
Fixed Operating Costs ($MM/yr)		
Labor (excl. Maintenance)	46	48
Maintenance (incl. Labour)	72	80
Taxes & Insurance	17	18
Miscellaneous + G&A	15	16
Total Fixed Costs ($MM/yr)	150	161
Total Fixed Costs ($/Bbl Crude)	1.65	1.77
Variable Operating Costs		
Natural Gas (BFOE/Bbl Crude)	0.07	0.08
Electricity (kWh/Bbl Crude)	9.50	10.89
Water + Steam ($/Bbl Crude)	0.05	0.05
Catalyst + Chemicals ($/Bbl Crude)	0.34	0.34

TABLE III-13
CALIFORNIA REFINERY UPGRADING PROJECT CAPITAL COSTS
(Capacities in Barrels / Stream Day, Costs in Constant 2004 US Million $)

Major Process Units / Project Capital	Base Refinery	SynBit Coker Project (Case 8)
		Incr. Expansion
Crude Distillation Unit	263	-
Vacuum Distillation Unit	121	16
Delayed Coking Unit	60	7
Catalytic Reforming Unit	51	-
Fluid Catalytic Cracking Unit	97	15
Hydrocracking Unit	31	10
VGO Hydrotreating Unit	95	14
Distillate Hydrotreating Unit	43	4
Naphtha Hydrotreating Unit	97	-
FCC Gasoline Hydrotreating Unit	62	3
Alkylation Unit	21	1
C_4 Isomerization Unit	3	-
C_5/C_6 Isomerization Unit	22	-
Sulphur Plant (LT/D)	463	176
Hydrogen Plant (MMSCF/D)	143	31
Project Capital Cost Estimates		
Total On-Site (1)		169
Total Off-Site (2)		29
Total Refinery		198
Licensor Costs (3)		8
Owner's Costs (4)		28
Escalation (5)		15
Contingency (6)		38
Total Project excl. Other Costs		288
Other Project Costs (7)		72
Total Project Costs		359

Notes:
(1) Process units are included in on-site costs (ISBL).
(2) Offsite costs include tanks, inter-unit piping, power distribution and associated utilities.
(3) Licensor costs include fees, engineering, and initial catalyst fill.
(4) Owner's costs include project management, start-up and commissioning, taxes and insurance during construction, and project development costs.
(5) Escalation is 3 percent.
(6) Contingency is 15 percent.
(7) Other project costs is 25 percent and includes environmental permit work, location actor versus the USGC, project work in operating refinery, etc.

TABLE III-14
MID-CONTINENT REFINERY PROJECT CHARGE/YIELD & OPERATING COSTS
(Thousand of Barrels per Calendar Day Unless Noted)

Feedstocks / Products / Costs	Base Refinery	SCO Hydrocracker (Case 9)
Feedstocks/Crude Oil		
WTI	25	-
WTS	25	25
SCO	-	25
Iso-Butane	1	1
Normal Butane	0	0
Total Feedstocks	52	51
Products		
Own-Produced Fuel Gas	2	2
Propanes	1	1
Butanes	-	-
Conv. Regular Gasoline	24	26
Conv. Premium Gasoline	3	3
Jet Fuel	4	4
On-Road Diesel	10	10
Off-Road Diesel	2	2
Fuel Oil	-	-
Slurry Oil	1	1
Asphalt	6	4
Sulphur (LT/D)	36	34
Total Liquid Product	50	51
Total Liquid Yield (% of Feedstocks)	97.5%	99.2%
Fixed Operating Costs ($MM/yr)		
Labor (excl. Maintenance)	14	16
Maintenance (incl. Labor)	11	14
Taxes & Insurance	3	3
Miscellaneous + G&A	5	6
Total Fixed Costs ($MM/yr)	32	39
Total Fixed Costs ($/Bbl Crude)	1.78	2.14
Variable Operating Costs		
Natural Gas (BFOE/Bbl Crude)	0.03	0.03
Electricity (kWh/Bbl Crude)	5.49	6.75
Water + Steam ($/Bbl Crude)	0.03	0.04
Catalyst + Chemicals ($/Bbl Crude)	0.28	0.32

TABLE III-15
MID-CONTINENT REFINERY UPGRADING PROJECT CAPITAL COSTS
(Capacities in Barrels / Stream Day, Costs in Constant 2004 US Million $)

Major Process Units / Project Capital	**Base Refinery**	**SCO Hydrocracker Project (Case 9)**
		Incr. Expansion
Crude Distillation Unit	53	-
Vacuum Distillation Unit	19	-
Catalytic Reforming Unit	14	-
Fluid Catalytic Cracking Unit	15	4
Hydrocracking Unit	-	4
Distillate Hydrotreating Unit	14	-
Naphtha Hydrotreating Unit	14	-
FCC Gasoline Hydrotreating Unit	9	2
Alkylation Unit	4	-
Sulphur Plant (LT/D)	39	-
Hydrogen Plant (MMSCF/D)	-	6
Project Capital Cost Estimates		
Total On-Site (1)		60
Total Off-Site (2)		12
Total Refinery		72
Licensor Costs (3)		3
Owner's Costs (4)		10
Escalation (5)		5
Contingency (6)		14
Total Project excl. Other Costs		104
Other Project Costs (7)		16
Total Project Costs		120

Notes: (1) Process units are included in on-site costs (ISBL).
(2) Offsite costs include tanks, inter-unit piping, power distribution and associated utilities.
(3) Licensor costs include fees, engineering, and initial catalyst fill.
(4) Owner's costs include project management, start-up and commissioning, taxes and insurance during construction, and project development costs.
(5) Escalation is 3%.
(6) Contingency is 15%.
(7) Other project costs is 15% and includes environmental permit work, location factor versus the USGC, project work in operating refinery, etc.

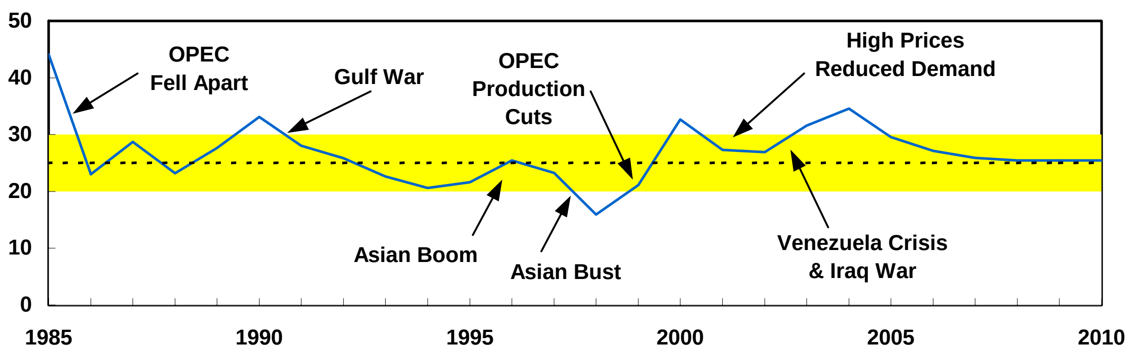
IV. U.S. PETROLEUM MARKET OVERVIEW AND PRICING

WORLD PETROLEUM SUPPLY/DEMAND TRENDS

WORLD DEMAND

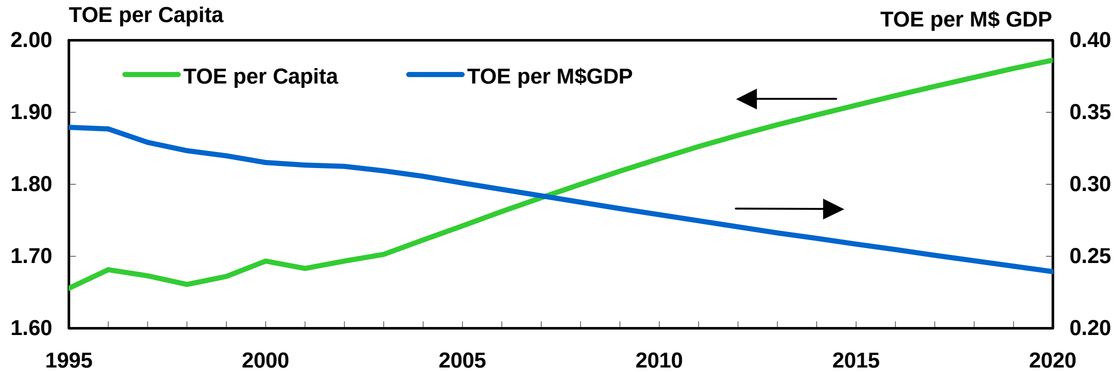
Global economic conditions and population have a very significant influence on consumption of petroleum products. While energy usage on a per capita or GDP basis varies from country to country based on a number of factors, it varies with the economic cycle to a significant degree. Petroleum demand has a somewhat low elasticity to price over broad ranges, since many of the uses of petroleum (transportation and home heating, for example) have a base level of need that consumers do not consider discretionary and for which other forms energy sources have limited availability for substitution. This inelasticity explains the ability for the underlying energy commodity, crude oil, to have the ability to experience very large price swings with relatively low short-term demand response. The figure below relates the historic price of crude oil to major events that have driven the price from a range consistent with the cost of production.

FIGURE IV-1
CRUDE OIL PRICE: WTI CUSHING
(Constant 2004 Dollars per Barrel)



On a long-term basis, however, steady reductions have been made in energy demand due to price rises and perception of the limited nature of the fuel commodities, as the U.S., for example reduced the energy use per dollar of GDP by over 40 percent since the crude embargo period of the 1970's. Such reductions have come from increased transportation fleet mileage per unit of fuel and from various improvements in thermal efficiency in many heating, commercial and industrial applications, as well as exportation of a portion of the country's manufacturing base. The developed countries making up the OECD have similar trends in energy efficiency and, therefore, a relatively low growth rate in demand with economic growth. The emerging economies, on the other hand, are experiencing large increases in per capita consumption as their economic base grows, in spite of the availability of modern, efficient technology, as new consumer demand exceeds the trends in efficiency of energy use.

FIGURE IV-2
ENERGY CONSUMPTION INDICES



Consistent with an outlook for world economic growth rates of about 3.0 percent for the 2004-2020, our outlook for world petroleum demand growth is at an approximately 1.8 percent rate until 2010 falling off to a rate of demand growth of just over 1 percent by 2020 due to effects of lesser petroleum demand from GDP dollars.

WORLD CRUDE OIL SUPPLY

World crude supply has increased adequately to meet demand throughout the recent historical period. While many of the large traditional oil producing countries are subject to production caps under OPEC quotas, much of the growth in production has been from non-OPEC sources such as the North Sea, West Africa, Asia, the Former Soviet Union, Latin America, and the U.S. Gulf of Mexico.

WORLD PETROLEUM SUPPLY
(Million B/D)

	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
OPEC	24.95	27.72	26.85	24.09	25.29	26.44	26.15	26.99	31.24	35.71
Non-OPEC	36.68	39.66	40.60	42.20	43.20	44.45	45.25	49.47	50.67	51.23
Total	61.63	67.38	67.45	66.29	68.48	70.88	71.39	76.46	81.91	86.94
Annual Change	0.4	1.8	0.1	-1.7	3.3	3.5	0.7	1.4	1.4	1.2

WORLD PRODUCT SUPPLY TRENDS

With the changing profile of production, differences in crude quality are occurring which have resulted in need for investment in the refining industry to compensate for a trend toward heavier crudes with higher impurity levels. Concurrently, the general world trend toward cleaner fuels has required massive investment in the industry.

World gasoline demand has grown at an average rate of about 1.4 percent since 1995. Consumption is growing in all regions but Europe, where dieselization of the motor fleet is being encouraged by tax incentives. Gasoline quality is trending towards cleaner burning specifications worldwide. While the U.S. and Europe are mature in the first steps, such as lead removal and oxygenate addition, the developing economies are still trending toward octane enhancement. Reduction of sulphur and aromatics is proceeding in the developed countries, and with some degree of delay, will spread to most markets.

World diesel/distillate heating oil demand is increasing faster than gasoline, with a global rate of 2.2 percent since 1995. Outside the U.S., diesel comprises a much larger part of motor fuel demand. Diesel quality is improving throughout the world with mandatory sulphur reduction in most markets. The U.S. and Europe are both mandating an ultra low sulphur diesel specification (15 ppm and less) in this decade. Other quality trends include cetane or other burning performance index enhancement via control of aromatics and/or use of additives.

The only major petroleum fuel that is not generally growing with economic development is residual fuel oil. In much of the world the residual fuel oil market is being displaced by natural gas. Fuel oil use is being subjected to ever tightening limits on site emissions of sulphur. Demand is essentially flat, but since the natural occurrence of residual fuel components is increasing due to a trend towards heavier crude production, there has been a significant recent increase in bottom of the barrel processing capacity.

WORLD REFINED PRODUCT DEMAND
(Thousand Barrels per Day)

	1985	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Gasoline	15,020	16,958	18,252	19,580	19,824	20,201	20,398	20,797	21,141	22,949	24,171	24,994
Naphtha	2,206	3,476	4,499	5,909	5,819	5,897	5,994	6,136	6,297	7,160	7,819	8,459
Kerosene/Jet fuel	4,356	5,081	5,254	5,965	5,801	5,644	5,646	5,735	5,835	6,342	6,802	7,260
Diesel/#2	14,333	16,015	17,538	19,749	20,315	20,346	20,949	21,515	22,083	25,028	27,486	29,920
Residual Fuel	11,410	11,164	9,626	8,764	8,464	8,117	8,170	8,176	8,101	7,798	7,614	7,494
Total	47,325	52,693	55,168	59,966	60,223	60,205	61,156	62,360	63,457	69,276	73,893	78,128
Annual % Change		2.2	0.9	1.7	0.4	0.0	1.6	2.0	1.8	1.8	1.3	1.1

U.S. PETROLEUM SUPPLY/DEMAND TRENDS

In the U.S., petroleum is the dominant energy source and has maintained its market share of nearly 40 percent over the past decade. Since the U.S. economy is so highly developed, shifts from one energy source to another occur very slowly. Gas and solid fuels each have 20 to 25 percent of the energy market. Gas has been regaining market share lost during the 1970s and 1980s when it was precluded from being used in new large boilers, but recent availability and price issues are expected to slow its growth. Nuclear power is limited by regulations and financial problems, but it continues to increase slowly and accounts for 8 percent of the total. Hydropower's share is only about 3 percent, with little potential growth remaining. Residual fuel oil and thermal distillate use have already been reduced to practical minimums, thus gas for heating will increase as demand grows.

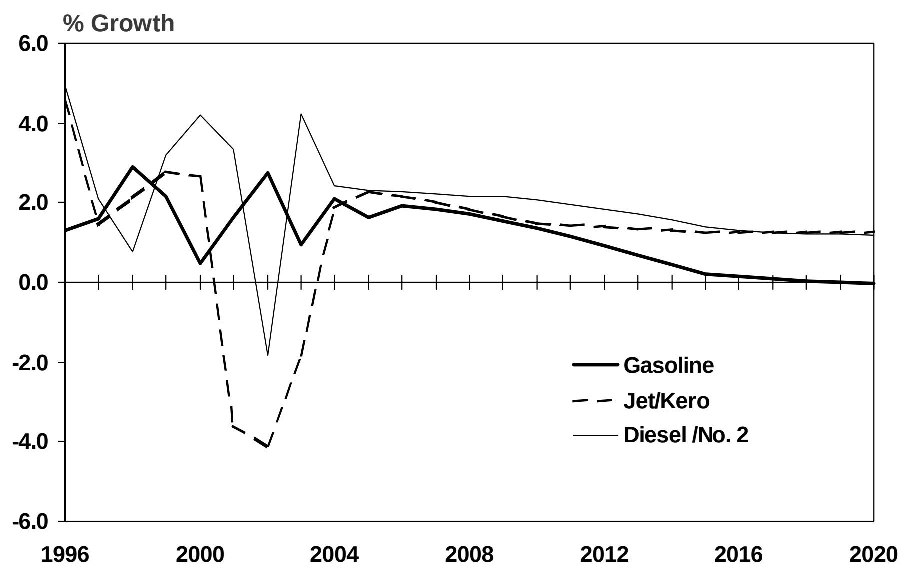
Demand for refined products grew at an average rate of over 2 percent from 1995 through 2000, but demand declined by 0.5 percent in 2001 as the economy slowed, particularly following the attacks of September 11. Growth resumed in 2002 at low rates, as declining jet fuel demand was offset by strong gasoline growth. Growth has continued at higher than average rates in 2003 and 2004, as economic recovery has occurred, but growth is expected.

U. S.REFINED PRODUCTS DEMAND
(Million Barrels per Day)

	1985	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Motor Gasoline	6,855	7,259	7,810	8,492	8,629	8,866	8,950	9,139	9,288	10,091	10,439	10,463
Kerosene/Jet Fuel	1,343	1,564	1,568	1,793	1,728	1,657	1,627	1,657	1,695	1,855	1,983	2,110
Distillate	2,866	3,020	3,207	3,722	3,847	3,776	3,936	4,031	4,124	4,594	4,995	5,311
Residual Fuel Oil+Asphalt	1,626	1,712	1,338	1,434	1,330	1,212	1,275	1,324	1,344	1,405	1,437	1,458
Other Products	2,306	3,630	3,962	4,468	4,159	4,317	4,241	4,334	4,408	4,641	4,813	4,896
Total Demand	14,996	17,186	17,885	19,908	19,693	19,828	20,029	20,484	20,859	22,587	23,667	24,237
Annual % Change		2.8	0.8	2.2	(1.1)	0.7	1.0	2.3	1.8	1.6	0.9	0.5

Product demand growth by product for major motor fuels is illustrated in the figure below, and discussed in the following paragraphs.

FIGURE IV-3
U.S. PRODUCT DEMAND GROWTH RATE



U.S. GASOLINE DEMAND

Gasoline demand had been growing sharply after the early 1990s recession. In 1996, strong overall petroleum demand tightened the market, causing prices to rise. Counterbalancing some of the increases in prices were consumer spending increases as well as a pronounced move towards larger, less efficient SUVs versus smaller passenger cars. The price collapse in 1998, in addition to some data adjustments, elevated demand growth to 3 percent. The higher prices in late 1999 and in 2000 caused demand to show very little growth in 2000, with an increase of only 1.7 percent in 2001. Part of the year-to-year fluctuations result from inventory shifts between primary and secondary storage which distort true consumption patterns.

Following the events of September 11, 2001, the economic slowdown and extended high prices would be expected to hurt gasoline demand growth. However, demand growth is estimated at 2.7 percent in 2002 resulting in consumption of almost 8.9 million B/D. Much of this demand strength is believed to stem from a shift from air travel to automobile travel, as also evidenced by the ongoing weakness in jet fuel demand. This substitution effect is projected to decline over the near term.

In the longer term future, gasoline demand growth is expected to slowly decline reaching a growth rate approaching zero after 2015, as higher efficiency vehicles increase in the fleet population. This includes growth of currently available hybrid types and direct injection technology which can be implemented in the ultra low sulphur specification environment after 2006.

DIESEL/NO. 2 FUEL OIL

Consumption trends for diesel have not been subject to the trends in vehicle efficiency that have influenced gasoline demand, but are much more closely tied to economic activity. The bulk of diesel fuel demand is used in commercial transportation which moves directly with strength in the economy. Demand for distillate fuel oil in the residential/commercial sectors moves with short-term temperature trends, but has been subject to long-term encroachment by natural gas.

Demand growth in 1996 averaged close to 5 percent with strong gains in diesel as well as heating oil. In 1997, the winter was significantly milder, resulting in an increase of only 2 percent. In 1998 the mild weather caused by El Niño effects resulted in demand rising only 0.8 percent. A strong recovery to 3.2 percent and 4.2 percent occurred in 1999 and 2000, respectively, mostly due to strong low sulphur diesel gains of over 5 percent, driven by a robust economy.

Growth slowed in 2001 along with the economy but overall demand held up better than expected due to the very cold 2000/2001 winters. The weak economy and a warm winter resulted in a 2.0 percent demand decline in 2002.

Distillate fuel oil market growth in the future will come mostly from increases in transportation consumption. Diesel penetration of the U.S. personal automobile fleet will be negligible. However, continued economic growth will increase the need for trucking and, therefore, diesel fuel. Bunker use of distillate has not changed much over the last five years.

Whereas distillate used for transportation has been growing rapidly, market shares of distillate in most other sectors have declined. The loss of market for distillate fuel oil has been particularly noticeable in the residential sector. Consumption of natural gas and electricity has pushed out demand for distillate. Longer term, we expect modest declines in this sector. Consumption of distillate in the industrial sector (combining industrial, oil company and electric utility) dropped to about 224,000 B/D in 1993, and has remained below 250,000 B/D since then. This compares to a high of 460,000 B/D in 1979. The drop has been primarily due to fuel substitution. The use of distillate fuel oil in the commercial sector also declined through the early 1990s. It has continued to fall to less than 200,000 B/D in 1998 and 1999 but recovered to 220,000 B/D in 2000/2001. Consumption in the farm and military sectors has also declined in recent years, and only little growth is anticipated. Off-highway has been the fastest growing sector but the use is relatively small (160,000 B/D).

In October 1993, refiners began to produce diesel fuel with a much lower sulphur content for the on-highway market. These fuels are required to contain 0.05 percent sulphur or less. Only about 60 percent of the distillate pool is required currently to meet these more stringent specifications. Even so, many refiners are able to produce 100 percent lower sulphur material. Low sulphur diesel has penetrated other sectors that consume diesel fuel, such as the farming and off-highway sectors, as a result of logistic constraints as well as strong marketing. Total U.S. low sulphur diesel demand exceeded 70 percent of distillate use in 2002 while the on-highway portion is only 59 percent of total consumption.

U.S. AVIATION FUELS

Growth in demand for aviation fuels has been one of the strongest among the refined products, led by commercial kerosene-type jet fuel. Aviation gasoline usage trends are extremely volatile, but consumption typically averages only about 20,000 B/D.

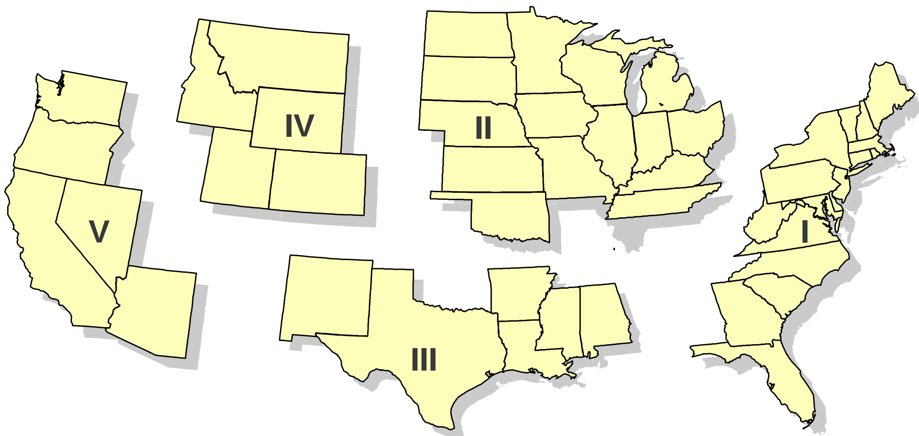
Kerosene-type jet fuel demand grew from about 800,000 B/D in the early 1980s to 1.34 million B/D in 1990, representing average growth in excess of 5 percent. Growth continued through the 1990s, with demand exceeding 1.7 million B/D in 2000. The September 11th attacks severely disrupted the airline industry late in 2001 and air travel has still not fully recovered. As a result, consumption dropped back to 1.65 million B/D in 2001 and dropped further in 2002, and 2003 before a recovery trend began. Recovery to pre-9/11 levels is expected in 2005. Longer term, a return to growth rates of 2 percent in the short term and 1.4 percent in the longer term is forecast.

Kerosene for burning is quite small in the U.S. (about 60,000 B/D) and there is minimal trade.

PRODUCT IMPORTS

Product imports patterns in the U.S. are extremely variable by region. Petroleum statistics are reported by the U.S. government for subdivision into Petroleum Allocation for Defense Distribution (PADDs). Subsequent sections of this report will focus on the market characteristics of target markets for Alberta products in the Midwest (PADD II) and the West Coast (PADD V).

FIGURE IV-4
PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICT (PADD)



The U.S. product market is primarily supplied from domestic refining. Total imports make up less than 10 percent of supply, and this is concentrated in PADD I, the U.S. East Coast. PADD III, the Gulf Coast region, has roughly 45 percent of U.S. refining capacity and 22 percent of U.S. product demand, and is a major net supplier to the larger PADD I and II markets via extensive pipeline systems.

U.S. PRODUCT SUPPLY BY PADD - 2003

PADD	Refinery Production	Imports	Exports	PADD Transfer	Supply Adjustment	Total Supply
I	2,047	1,202	53	2,933	7	6,136
II	3,623	107	26	1,064	78	4,846
III	7,978	336	631	(4,056)	424	4,051
IV	550	17	1	-36	92	622
V	2,873	111	227	95	29	2,881
	17,071	1,773	938	0	630	18,536

The following table show imports by PADD. For major motor fuel pipeline product grades such as would be supplied by the Alberta upgrades.

U.S. IMPORTS OF REFINED PRODUCTS BY PADD 2003
(Thousand BPD)

	PADD I	II	III	IV	V	U.S. TOTAL
Finished Gasoline	487	2	6	1	22	518
Gasoline Blendstock	294	0	41	0	32	367
Kero/Jet	74	1	1	0	41	115
Diesel/#2	311	7	3	8	6	335

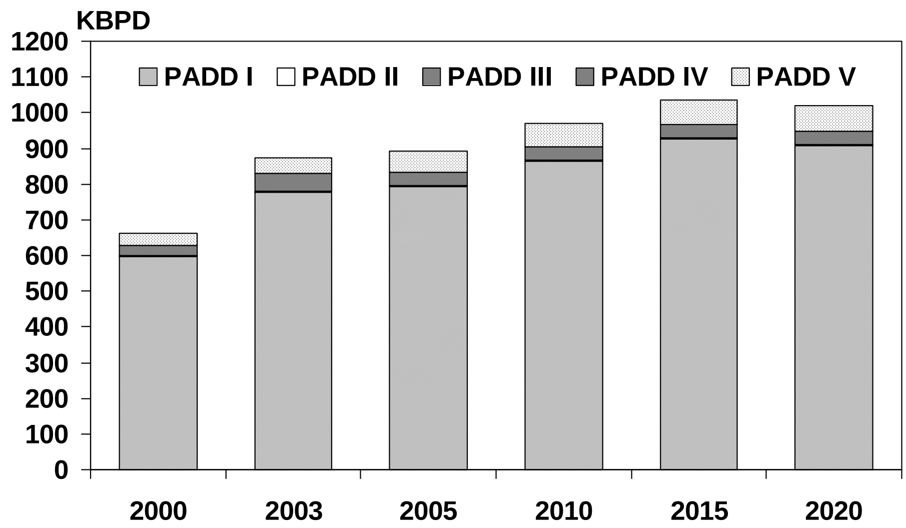
Existing U.S. imports from Canada are almost entirely to PADD I from the Maritimes and Quebec. Although total imports to PADD's II and IV are very low, they are 100 percent from Canada and primarily distillate trucked across the border. In PADD V the primary export volumes to the U.S. are gasoline component, delivered by pipeline into the Pacific Northwest.

U.S. IMPORTS OF REFINED PRODUCTS FROM CANADA 2003
(Thousand BPD)

	PADD I	II	III	IV	V	U.S. TOTAL
Finished Gasoline	155	2	--	1	1	159
Gasoline Blendstock	14	0	1	--	14	29
Kero/Jet	6	1	--	--	--	7
Diesel/#2	108	7	--	8	4	128

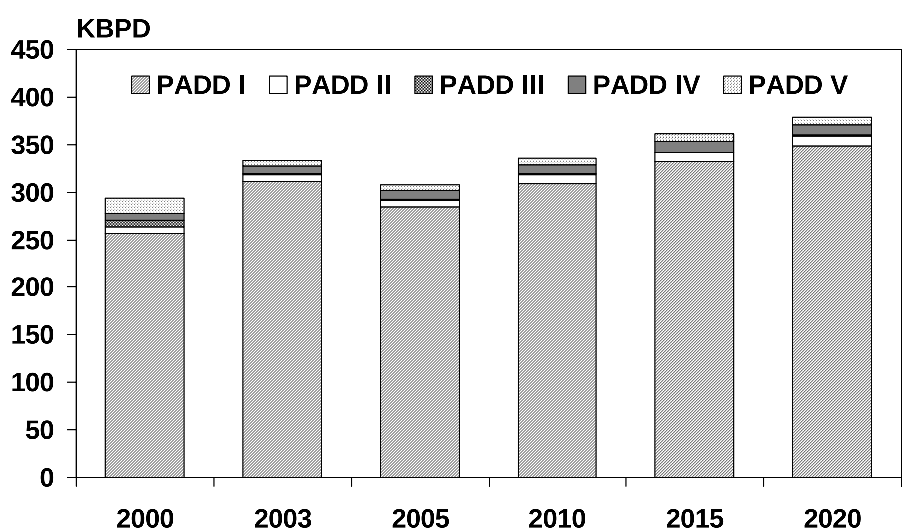
Imports are expected to increase in the future. The slow growth in demand coupled with expectations of typical refinery capacity creep rates of 1 percent per annum result in an expectation of growth of imports including blendstocks to exceed 1 million B/D 2015, before declining as gasoline growth approaches zero. The rapid growth of gasoline imports between 2000 and 2003 has reflected the surplus of gasoline; produced in Europe as refineries run to maximize diesel output for that market. The tightening of U.S. specifications is expected to be an impediment to gasoline import growth rates from 2005 forward, as some suppliers will struggle to meet the ultra low sulphur specification.

FIGURE IV-5
U.S. GASOLINE IMPORTS



Diesel imports are expected to grow moderately from the 2003 levels, with the new ultra low sulphur specification impeding growth in imports from Latin America and the local high demand preventing growth in imports from Europe in the period between 2005 and 2010.

FIGURE IV-6
U.S. DIESEL / #2 IMPORTS



U.S. MARKET SPECIFICATIONS

There are currently four major specification issues which create evolutionary changes over time or create limitations in regional marketing based on specification differences.

- National required phase-in of Ultra low sulphur (ULSD) specification
- Reformulated and oxygenated gasoline regional requirements
- Future of oxygenate requirements
- Boutique fuel issues

ULTRA LOW SULPHUR GASOLINE REQUIREMENTS

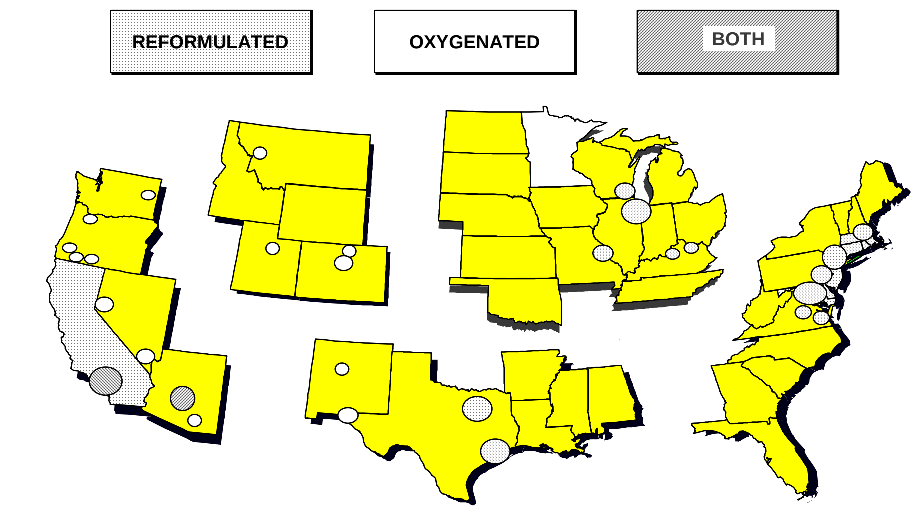
The EPA has mandated that the U.S. gasoline sulphur specification will be reduced to 30 ppm over a period from January 2004 to 2006. In 2004, the first year of the phase-in, the requirement is 130 ppm pool average. A system of credits is available to allow refiners to use their prior records of manufacture below required levels or purchase of credits from others to allow conformance with the law, offsetting credits against higher current levels as long as credits remain available. Schedule waivers have been received by some refiners that are pursuing approved plans for attainment that can't meet the deadline, and regional and small refiner waivers exist. For the Rocky Mountain region and refiners meeting several small refiner qualifications based on capacity or number of employees, an extension of the schedule to 2011 is possible, dependent on interaction with plans to meet the Ultra Low Sulfur Diesel (ULSD) specification.

Due to the phase-in being underway, the refiners have already determined their approach to meeting the specification, and where projects for desulphurization are needed, they are in advanced stages of development. Any new entrant, including importers must meet the current specifications. With a start-up date assumed of 2011, the Alberta Upgrader must design at the 30 ppm specification.

REFORMULATED AND OXYGENATED GASOLINE REQUIREMENTS

Current about 30 percent of U.S. gasoline is reformulated, and an additional 11 percent oxygenated. Reformulated gasoline is required in metropolitan areas that do not meet ambient air requirements adopted by the EPA, and some opt-in areas where local governments rather than the EPA have initiated the limitations. In some regions, particularly in the Northeast, distribution systems limitations create a need to deliver reformulated where it is not mandated. The map below shows location of mandatory oxygenated gasoline specification areas including reformulated and oxygenated requirements in the Continental U.S.

FIGURE IV-7
CURRENT REFORMULATED AND MANDATORY OXYGENATED GASOLINE AREAS



Of most interest to an Alberta upgrader, the target markets of California and the Milwaukee to Chicago region are reformulated markets, so a significant percentage of Alberta upgrader product must be planned to be reformulated. Ethanol is the oxygenate predominantly used in the region. Ethanolated gasoline is not pipeline transportable, so ethanol is added at distribution terminals, and refiners ship an oxygenate free base blendstock called R-Bob.

FUTURE TRENDS IN OXYGENATE REQUIREMENTS

In the longer term, the specification of reformulated and conventional gasoline may tend to merge. The ULSG specification brings conventional much closer to reformulated specifications and some of the economic barriers to merging the grades may be weakening. This would indicate that a new grassroots refinery should not be allowed to build in any significant impediments to future expansion of the reformulated grade.

Led by the California Carb III initiative, MTBE is under attack as the primary oxygenate in U.S. gasoline. MTBE has not been permitted in California gasoline since January 2004, due to its toxicity and its water solubility, which have caused a number of water contamination incidents. Other states, primarily in the Northeast, have announced an MTBE ban and are at varying stages of implementation.

Ethanol is the replacement for MTBE, but it has several disadvantages including lower hydrocarbon volume contribution at required oxygen content levels, poorer blend characteristics including greater volatility and less octane contribution, and poorer overall economics due to the cost relative to the beneficial contribution to the gasoline volume and quality.

In California, the California Air Resources Board (CARB) is advocating alternative reformulated gasoline blending without oxygenate, based on performance blending. This has not gotten EPA support, but represents potential for future change in gasoline specification.

BOUTIQUE FUELS

In addition to the reformulated/conventional issue, there are numerous local gasoline specification requirements.

- Mandatory ethanol content. Referring back to Figure IV-7, a number of urban areas primarily in the West have mandatory ethanol content. These locations have winter season minimum oxygen content from ethanol specifications due to concentration of ozone caused by risk of air stagnation and temperature inversions in their primarily mountainous environments.

- In the Corn Belt, ethanol use is generally promoted by tax benefits, such that while not mandatory, in a Corn Belt state such as Iowa, ethanolated gasoline is nearly 100 percent of year round supply. In Minnesota the use of ethanol in gasoline is mandated year round.

- Local performance formulations. All of California and Maricopa County, Arizona have local performance requirements for gasoline. Any gasoline sold in these markets must meet emissions performance guidelines approved by local authorities. California CARB III gasoline has specific ranges of sulphur, aromatics, volatility and oxygen requirements. The Arizona specification is slightly less stringent than the Carb specification.

- RVP limitations. Numerous localities have RVP limits in place to reduce gasoline volatility. These include major markets, such as: Atlanta, Portland, Salt Lake City, Kansas City, Baton Rouge, Detroit, Pittsburgh, Miami. These specifications primarily affect blend economics and logistics rather than manufacturing constraints.

DIESEL FUEL

The major diesel fuel regulation affecting the U.S. market is the ULSD specification which is a phase-down of on-road diesel specifications from 500 to 15 ppm sulphur in 2006. Small refiners and Rocky Mountain refiners have the ability to postpone the requirement until 2011 if they have implemented gasoline projects on schedule and 80 percent of regional on-road diesel meets the specification. The Alberta upgrader must plan to meet the specification.

The EPA has announced a plan for off-road diesel phase-down to 15 ppm between 2007 and 2010, but this does not yet have the force of law. At present, 30 percent of the U.S. diesel/#2 market is produced at sulphur levels over the current 500 ppm on-road specification either as off-road diesel, or heating oil.

In California and the major markets in Texas, local performance based blend requirements exist due to local NOx concentrations in the ambient air. These require emission performance in diesel engines equivalent to less than 10 percent aromatics, low sulphur, and cetane levels of 48-50.

There are no national initiatives to improve cetane in diesel fuel, and this restricts utilization of European high performance passenger car diesels. Without a change in this area penetration of diesel into the passenger care market will remain inhibited.

U.S. GULF COAST PRICES AND MARGINS

CRUDE OIL PRICE FORECAST

The long-term level of crude oil prices is set by the cost of finding, developing and producing required new sources of production. If prices are too high, supplies will increase because economics favor developing new reserves or producing existing reserves at higher rates. At the same time, demand is decreased by use of alternative fuels such as coal, natural gas, or nuclear energy, and by conservation efforts. The resulting imbalance of supply versus demand forces prices back down. If prices are too low, demand is stimulated, alternative energy supply development is constrained, new reserve additions become less economical, and natural decline rates quickly reduce production capacity. Ultimately, low prices cause demand to approach capacity limits on production, and the resulting competition for supply drives prices back up.

Most new non-OPEC reserves will be in hostile environments such as deepwater or Arctic areas, or will have high operating costs such as synthetic crudes. Technological improvements have been sufficient to contain costs, but recent trends indicate rising finding and development costs. Due to the inherent unpredictability of new discoveries and demand shocks, we have not attempted to forecast the timing of cycles, except the movement of the current cycle towards levels consistent with the long-term cost trend.

Short term trends can vary distinctly from the long range, and have recently been influenced by political events. The sudden weakening of world crude market fundamentals in late 2001 resulted in a sharp decline in world prices. Mideast tensions, the unsettled Venezuelan situation, and aggressive OPEC supply management resulted in a sharp price recovery in early 2002, which was sustained throughout the year. Prices reached the highest levels since the Gulf War period in February-March 2003 as tensions over Iraq mounted, and as the build-up toward war continued. Prices eased rapidly after the war started and uncertainty regarding the length and severity of the crisis began to resolve.

Beginning in mid-2003, prices reversed their decline and reached new peaks above $40 in May-June 2004. Strong demand, continuing export disruptions in Iraq, and terrorist attacks in Saudi Arabia and elsewhere contributed to price strength. However, these high price levels are not sustainable and have already begun to erode. OPEC has responded with quota increases and inventories have started to rise. Demand pressures may be softening. Prices are now expected to continue easing down through 2004 and 2005, approaching the upper end of OPEC's target price level by late 2005. As non-OPEC production grows, prices are projected to move towards the long-term forecast level.

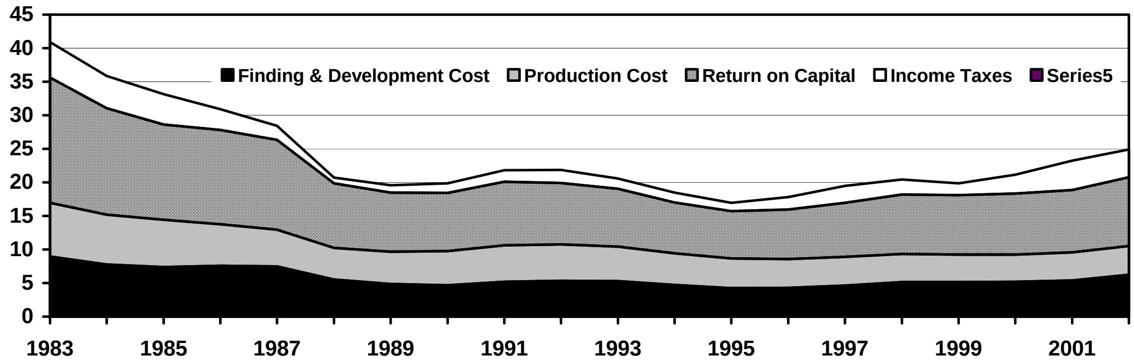
COST OF REPLACING AND PRODUCING RESERVES

The cost of developing and producing crude oil is an important benchmark in understanding the sustainable level of prices. These costs effectively establish a floor price for crude oil. If crude oil prices fall below this level and remain there for a sustained period of time, supplies will not be adequate to meet demand and prices will be driven upward. Likewise, if prices exceed costs by a large margin, excess supplies are likely to be developed, forcing prices back down.

Since a barrel of crude oil reserves can only be produced one time, companies must continually replace their production with additions to reserves, or else suffer liquidation through depletion. Thus, the forecast of crude oil must include not only the direct costs of sustaining production operations, but must also include the costs of finding and developing the reserves necessary to replace the oil produced. Costs must also include an adequate return on capital in order to sustain continued reinvestment. Publicly reported data for a survey of public companies with worldwide operations can be used to compile industry average costs. A single year's data can be misleading since exploration expenses and reserve additions may occur for several years before production of the reserves begins. Therefore, we show the costs as three year moving averages.

Data is compiled annually by the U.S. Department of Energy through its Financial Reporting System, and is consistent with that reported in SEC filings for the companies. The exploration and production (E&P) operations of the companies included in the survey span the globe. Their E&P activities occur in countries that allow private ownership of reserves and so exclude most OPEC production. In general, OPEC oil production is the lowest-cost source of supply. The operations of these shareholder-owned companies thus represent the marginal source of crude oil, and their marginal costs should be closely related to world crude oil prices. The historical cost of producing and replacing reserves is shown in Figure IV-8 below.

FIGURE IV-8
COST OF PRODUCTION AND RESERVE REPLACEMENT
(Dollars per Barrel Oil Equivalent - 3 Year Rolling Average)



Costs were pushed to very high levels by the energy crisis of the 1970s and the anticipation of ever-increasing prices. The price crash in 1985-86 caused write downs of reserves and the rolling average costs stayed high until this process was complete. Since then, costs have been in the range of $20 per barrel, falling some in the early to mid-1990s but rising in recent years. The costs include both oil and gas (expressed as oil equivalents). Since 2000, costs have trended upward more strongly. This analysis indicates that the cost of finding, developing, and producing crude oil and natural gas is in the mid $20 per BOE per barrel range.

In Figure IV-8, the Finding and Development Cost is the cost of property acquisition, exploration expenses (including dry hole costs and geological and geophysical costs), and development costs divided by the reserves added during each year. Because the costs must be recovered over the life of the reserves, additional return is needed for the companies to recover their cost of capital. This added return is indicated by the return on capital in Figure IV-8, and is based on a typical production profile. Production (or lifting costs) are the cash costs of production experienced by the companies for the year.

As prices increase, costs also tend to increase. Service companies are able to raise rates, leasing costs increase, and governments find new ways to tax. Conversely, when prices weaken, costs are squeezed. Income tax varies with the price of oil and gas, and is a significant cost for production operations.

LONG TERM FORECAST

The analysis of the cost of finding, developing and producing new reserves shows that oil prices in the mid $20 range are needed to support the development of new reserves. Most new non-OPEC reserves will be in hostile environments such as deepwater or Arctic areas, or will have high operating costs such as synthetic crudes. In recent years technological improvements have been sufficient to keep costs from increasing substantially. We expect this trend to continue, and costs to remain in the current range after adjustment for inflation.

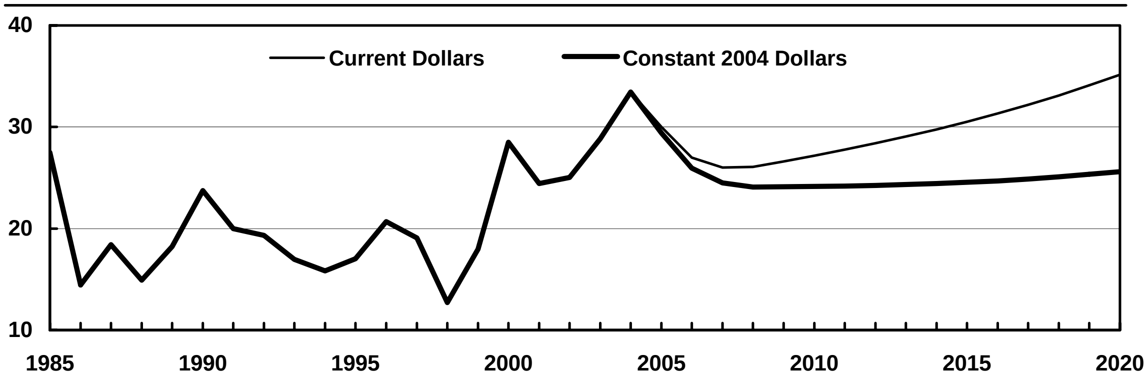
Later in the forecast period, a moderate increase in real prices is projected to begin, reflecting the tighter balance between demand and supply and the continuing need to develop new and alternative energy supplies. The magnitude of these future price increases will depend on the success of technology development to supplement traditional energy supplies, and to increase the efficiency of energy consumption. Based on the success of technology development over the past several decades, we anticipate that only small real increases in world energy prices will be required. If significant technological breakthroughs are achieved, energy prices could remain flat or even decline in real terms. However, if technological advancement slows, much larger increases in energy prices would be required in order to induce the necessary investments in energy conservation and development.

The forecast light crude oil prices outlined in Table IV-1 are based on parity with LLS on the U.S. Gulf Coast, adjusted for quality. The African crudes are also generally in parity. Price formulas are indexed to Brent, but the formula adjustment factors are set to keep these crudes in parity with Gulf Coast delivery. The steep backwardation in crude markets which prevailed over most of 1999-2002, along with the greater speculative activity in the Brent market, contributed to a relatively high apparent premium for Brent versus U.S. Gulf Coast crudes. More stable future market conditions are expected to result in maintenance of parity over the forecast period.

Brent and WTI continue to be the most actively traded spot crude oils in both the physical and paper markets. In the U.S. market, Light Louisiana Sweet (LLS) is an important Gulf Coast crude oil although the volume of trade (physical and paper) is much less than for WTI. Isthmus and Maya are used as indicators of Gulf Coast sour crude and heavy crude values, respectively, although their contract pricing structure can result in short-term price anomalies.

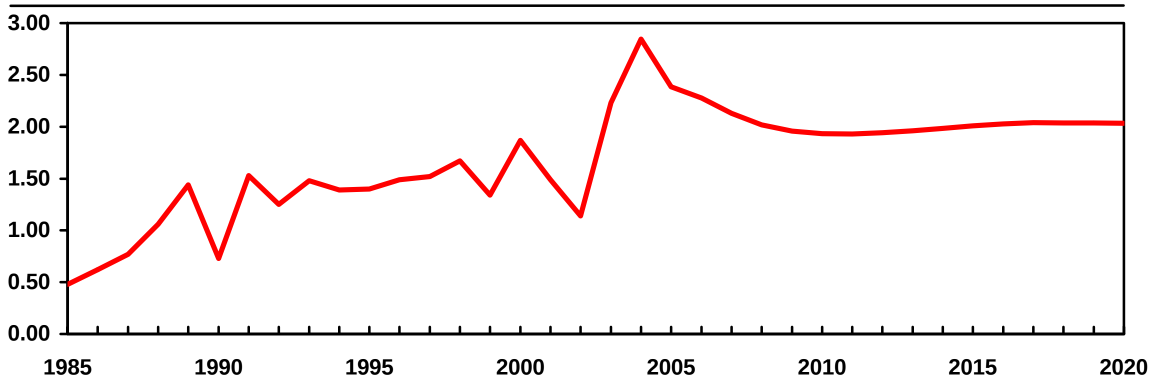
Brent serves North American as well as European markets and competes directly with the Middle Eastern and African crude oils that serve all major markets. The analysis of the cost of finding, developing and producing new reserves shows that a price of Brent in the mid $20 dollar per barrel range is needed to support the development of new reserves.

FIGURE IV-9
BRENT CRUDE OIL PRICE FORECAST
(Dollars per Barrel)



WTI is the most widely traded crude oil in the world and thus has importance well beyond its physical volume. The traded volume is many times the physical volume, but futures transactions values are tied to physical deliveries. Local market conditions in the U.S. Midcontinent determine the differential of WTI relative to domestic and international crude oils from the Gulf Coast. The pricing of WTI is quite complex as it depends on the direction of marginal crude flows within the inland region, and thus reflects the declining volume of WTI, changes in pipeline capacities, flows from the Gulf Coast and from Western Canada, and many other factors. The forecast WTI premium relative to Gulf Coast crude oils grows as crude supply in the inland region tightens and increased shipments of Gulf Coast-sourced crudes are required to balance inland markets.

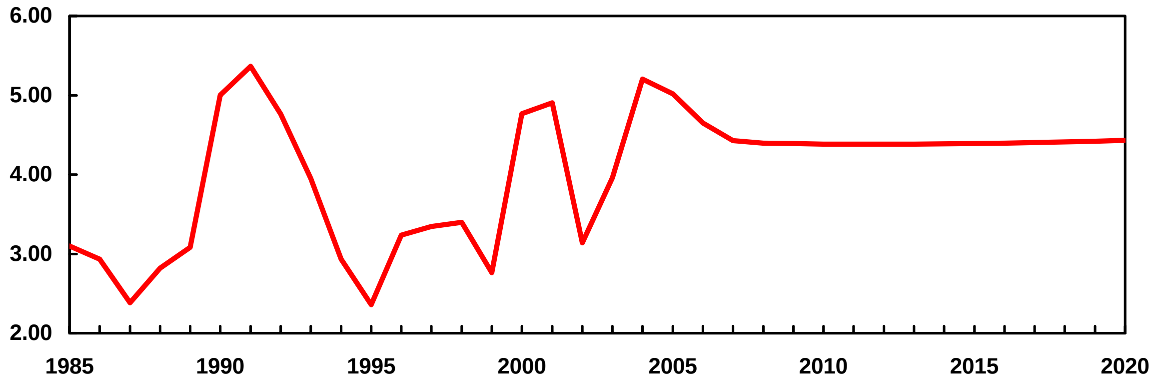
FIGURE IV-10
WTI, CUSHING/BRENT, FOB DIFFERENTIAL
(Forecast in Constant 2004 Dollars per Barrel)



Isthmus/Maya

Maya crude oil is used as an indicator for heavy, high sulphur crude oil on the U. S. Gulf Coast. The price of Maya is developed by analyzing the differential versus Isthmus. The OPEC crude production cutbacks in 1999 resulted in strong heavy crude prices through early 2000, but light/heavy differentials widened dramatically in mid-2000 through 2001. The startup of several new refinery conversion projects and the cutbacks in Venezuelan production kept differentials low during 2002. A sharp recovery in early 2003 was followed by a sharp decline in mid-year. The strong U.S. gasoline market in 2003-2004 increased light/heavy spreads to very high levels. We expect the spread to ease back towards equilibrium levels.

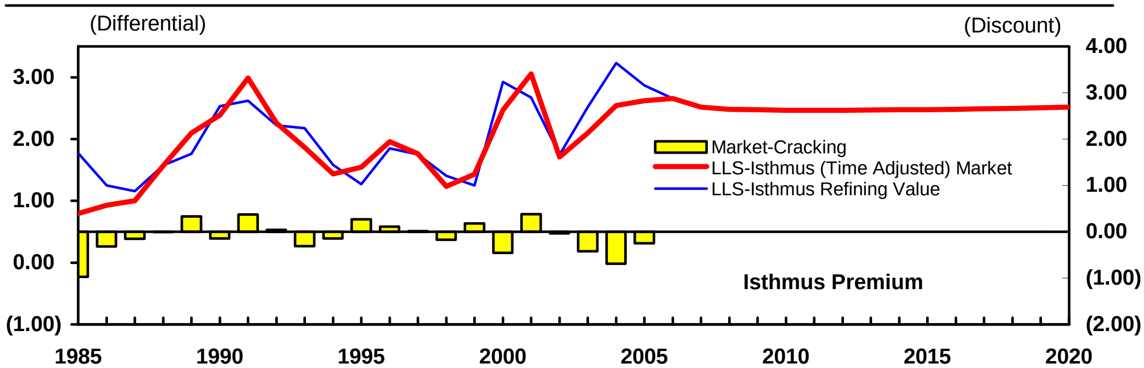
FIGURE IV-11
ISTHMUS/MAYA DIFFERENTIAL, USGC
(Forecast in Constant 2004 Dollars per Barrel)



U.S. SWEET/SOUR DIFFERENTIALS

The differential between sweet and sour crude oils is a function of the refining value of the crudes and the respective supply/demand pressures. Figure IV-12 shows that the differential between U.S. light sweet (LLS) and light sour (Isthmus) crude oils has closely tracked the U.S. Gulf Coast refining value differential. Periodically, temporary supply/demand imbalances cause price spreads to diverge from cracking values, but they always return toward equilibrium refining values. Future differentials between domestic sweet and sour crudes are based on cracking values and, therefore, depend on product prices and refining costs.

FIGURE IV-12
LLS/ISTHMUS DIFFERENTIAL, USGC
(Forecast in Constant 2004 Dollars per Barrel)

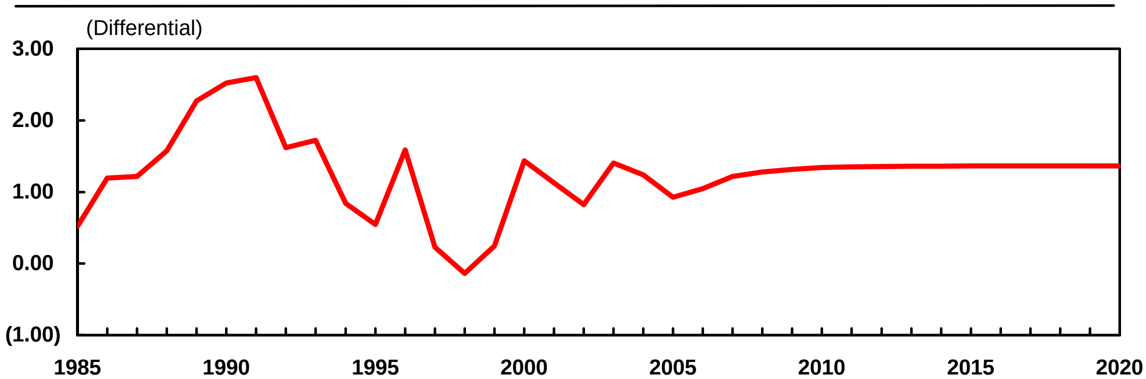


The LLS/Isthmus spreads are affected by the market timing structure, because the LLS price is for forward delivery whereas Isthmus is priced at delivery. The differential in the future is expected to be a function of the light/heavy differential and the price difference between low sulphur and high sulphur fuel oil, which explains the strong differential in 2000-2001 and 2003-

2004, as well as the comparative weakness in 2002. The forecast trends in the light/heavy differential are discussed in detail later in this section. Historical LLS/Isthmus price differentials closely follow marginal cracking refinery economics because sweet crude oil supplies have exceeded the demand required to meet low sulphur fuel oil demand and supply captive sweet crude refineries.

Another traditional international trading relationship monitored is the Brent/Dubai spread illustrated in Figure IV-13. The Brent/Dubai spread includes several elements in addition to the basic sweet/sour spread. Brent is refined in the Atlantic Basin while Dubai is used primarily in Asia. Thus, the East-West differential discussed above is an element in the differential. Market timing can also be an issue because of differences in delivery times. Our forecast, shown in Figure IV-13 and Table IV-1, includes these elements.

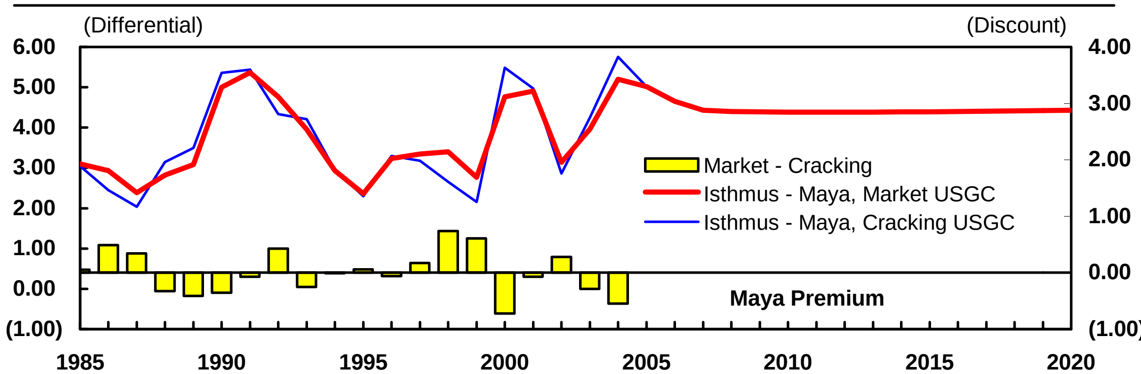
FIGURE IV-13
BRENT/DUBAI DIFFERENTIAL, FOB
(Forecast in Constant 2004 Dollars per Barrel)



U.S. GULF COAST LIGHT/HEAVY DIFFERENTIALS

Maya crude oil is used as an indicator for heavy, high sulphur crude oil on the U.S. Gulf Coast. The price of Maya is developed by analyzing the differential versus Isthmus. The historical Maya/Isthmus differential along with the cracking value differential is shown in Figure IV-14. As seen, the cracking value difference agrees well with historical differentials. The Maya/Isthmus differential is determined almost entirely by the light/heavy relationship. The OPEC crude production cutbacks in 1999 resulted in strong heavy crude prices and contributed to the narrow light/heavy differential. Rapid production increases in Venezuelan and Mexican heavy crude supplies resulted in a rapid widening of the light/heavy differential in 2000, which persisted through most of 2001. The startup of several residue conversion projects in the Western Hemisphere and the cutbacks in heavy Venezuelan production reversed this trend, and resulted in weak light/heavy differentials in 2002. A sharp recovery occurred in early 2003, but faltered in mid-year. Tight gasoline markets and weak fuel oil prices then produced wider differentials in late 2003, persisting into 2004. Long term, the differential is expected to remain at levels sufficient to justify expansion of conversion facilities. The discussion of light/heavy differentials later in this section describes the rationale for this forecast.

FIGURE IV-14
ISTHMUS/MAYA DIFFERENTIAL, USGC
(Forecast in Constant 2004 Dollars per Barrel)



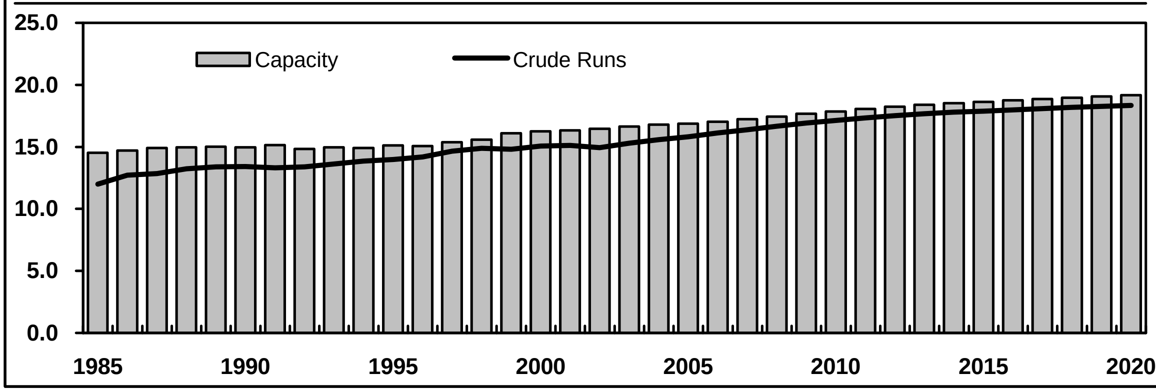
U.S. GULF COAST REFINING MARGINS

U.S. Gulf Coast refining margins have moved through several cycles over the past twenty years. Margins were very low for most of the 1980s due to the overhang of excess capacity. By the late 1980s, capacity had been largely rationalized, demand was growing strongly, and margins strengthened considerably. The 1990s were a period of high volatility, moving from the 1990 Gulf War peak to extremely low levels in 1999. This decade began with a strong recovery in 2000-2001, followed by a collapse in 2002. Margins recovered sharply through mid 2003. A number of factors then combined to propel margins to record high levels in early 2004, including product quality changes, low inventories, and tight capacity. In the near term, refining margins will continue to be influenced by these factors, with the outlook for long-term margins depending on trends in product demand, refining capacity, and light/heavy relationships.

REFINERY OPERATIONS

Increasing demand for petroleum products in the U.S. is expected to fuel growth in crude runs of about 1.3 percent annually through 2015. Crude oil runs are expected to increase from 15.3 million B/D in 2003 to 17.1 million B/D by 2010 and to 17.9 million B/D by 2015, as illustrated in Figure IV-15.

FIGURE IV-15
U.S. REFINERY OPERATIONS
(Million Barrels per Day)



Current operable refinery crude capacity is about 17.0 million B/D. Refinery operating rates have averaged about 90 percent over the past five years. Utilization is expected to remain in the 90-95 percent range. Capacity expansion over the last five years has been dramatic, with an increase of over 1.5 million B/D since 1996. Average expansion of about 1 percent over the forecast period will keep capacity in line with demand growth, though utilization will increase modestly under this scenario. This level of expansion can be achieved by debottlenecking, technology improvements and modest expansions which typically occur with product quality changes or general refinery revamping.

REFINING MARGINS

Refining margins are driven primarily by supply/demand pressures. Capacity utilization and capital expenditures are the major supply factors.

The near-term outlook for refining margins now appears quite positive. Utilization is high, capacity additions have slowed, demand growth is strong, and product quality changes will tend to restrict import availability and create an environment susceptible to supply disruptions. This picture stands in sharp contrast to the conditions prevailing through much of the 1990s, when capacity creep and expansions more than kept pace with demand growth. At the same time, site closures were rare. Instead, companies sold refining assets at low prices to competitors rather than rationalizing capacity, leading to continued or increased margin pressures. Even the wave of mergers resulted in only minimal capacity closures.

These positive conditions are likely to trigger the changes which will move margins down from the recent high levels. Expansion projects are now beginning to appear and the ultra-low sulphur fuel investment programs may bring additional capacity. In addition, one of the incentives for the tighter fuel specifications is to enable new high-efficiency engine technology to enter the fleet. Along with potential actions to address the threat of global climate change due to greenhouse gas emissions, demand growth is expected to slow markedly toward the end of the decade. These trends are evident in the European market, which has seen flat to declining gasoline demand in recent years. Europe's gasoline surplus will sustain imports to the East Coast, acting to restrain U. S. Gulf Coast refining margins.

MARGINAL REFINERY

The marginal U.S. Gulf Coast refinery has continually become more efficient and has reduced the output of its lowest value product — residual fuel oil. Production of residual fuel oil by U.S. Gulf Coast refineries have now fallen to 4 percent of crude runs. Operating costs have steadily been reduced. Our analysis shows that virtually all U.S. Gulf Coast refineries have some form of residue upgrading (resid destruction), ranging from direct catalytic cracking of "clean" resids to hydroprocessing and coking. In the late 1980s, the marginal refinery had no residue upgrading and long-term margins needed to support full cost economics of the cracking refinery (FCC with no residue upgrading). Today, the cracking configuration represents the marginally available capacity in a more complex facility, and so must only recover variable costs plus an incentive element. We monitor margins for cracking of Light Louisiana Sweet (LLS) crude oil, which is perhaps the best indicator of crude values on the Gulf Coast. This margin indicator closely follows trends in other measures, such as the various versions of the light products-versus-crude crack spread.

Annual average margins after variable costs for the LLS cracking refinery are shown in Figure IV-16. The margin forecast incorporates the impact of ultra-low sulphur gasoline and diesel production in 2005 and 2007, respectively, as well as the expected restrictions on MTBE use. During the late 1980s, these margins were sufficient to cover fixed cash costs and generate sufficient funds to meet sustaining capital requirements. As the industry has become more efficient, variable cost margins for LLS cracking have fallen to levels which recover only a portion of fixed cash costs and sustaining capital.

The short-term cyclic behavior of margins was discussed in the Global Overview section. Margins were fairly strong in 1997 and 1998, but fell sharply in 1999. A strong recovery in 2000 continued into mid-2001, due in part to low inventories and the effects of reformulated gasoline (RFG) specification changes. Following the September 11 attacks, the recession and weak demand resulted in poor profitability in 2002. Product prices and margins spiked upwards in late 2002 through 2003 assisted by cold weather and high distillate prices. High natural gas prices also resulted in higher prices for low sulphur fuel oil (LSFO), as produced by the LLS cracking configuration. Early 2004 maintained the 2003 margin momentum, but a combination of factors resulted in extraordinarily high margins in the second quarter. Continuing low product inventories, strong demand, and high levels of speculative activity in future markets resulted in very strong gasoline prices. In addition, the MTBE bans in New York and Connecticut reduced supply and tightened supplies of high quality blending components, while the initial phase of the gasoline sulphur reduction program reduced import availability. The factors will continue to affect margins for the next few years, although margins are expected to fall from the very high 2004 level. By the end of the decade, slowing demand growth and expected capacity additions should ease supply tightness, with margins falling towards the long-term cycle-average levels.

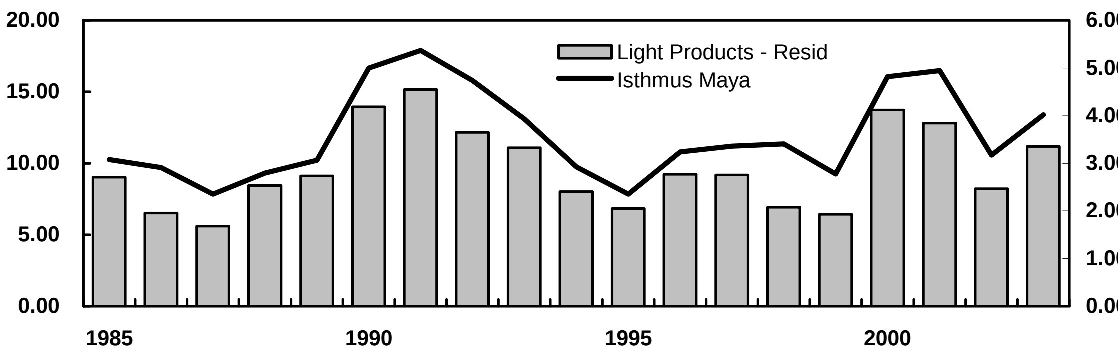
FIGURE IV-16
USGC LLS CRACKING MARGIN AFTER VARIABLE COSTS
(Forecast in Constant 2004 Dollars per Barrel)

LIGHT/HEAVY RELATIONSHIPS

While base cracking margins are a key determinant of refining profitability, the economics of converting residual fuel oil to light products have become an increasingly important component. Conversion capacity is defined as all of the refinery process units that transform the bottom-of-the-barrel residual components into light products, including processes such as fluid catalytic cracking (FCC and RFCC units), coking, and hydrocracking. These conversion units are generally the major margin contributors for U.S. refiners.

Conversion economics are typically measured by differences between light and heavy product prices or light and heavy crude oil prices. Heavy crude oils contain a higher proportion of residual components, and thus require higher-conversion refineries to process them fully to light products. Figure IV-17 illustrates historical light-heavy differentials in the Gulf Coast market. In the figure, the price spread between gasoline/diesel and residual fuel oil is compared to the spread between Isthmus (light) and Maya (heavy) crude oils.

FIGURE IV-17
LIGHT/HEAVY DIFFERENTIALS
(Light Products - Resid $/Bbl)
(Isthmus-Maya, $/Bbl)



Light/heavy differentials are the result of a complex balance of a number of factors, including:

- Demand for light products,
- Demand for light products relative to demand for heavy products and
- Supply of heavy feedstock to be upgraded and the corresponding need for conversion capacity.

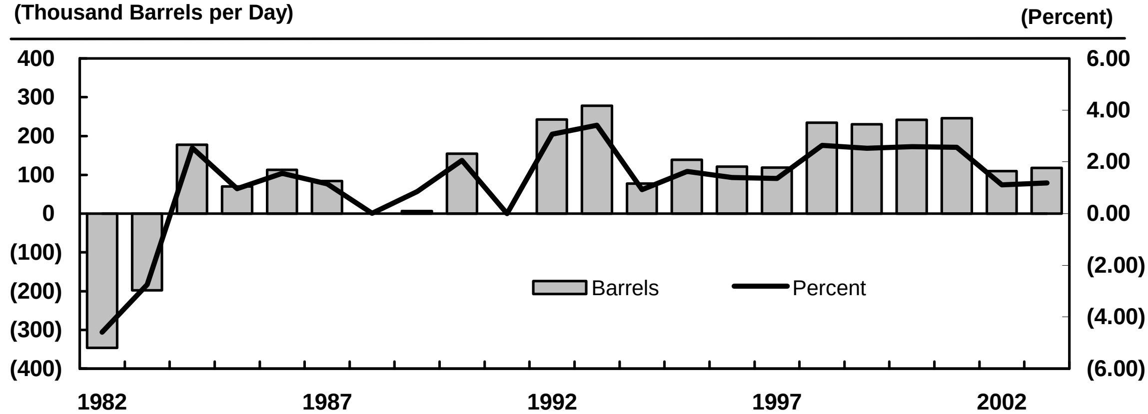
In the late 1980s, the balance between conversion capacity and heavy feedstocks was tight, with little or no excess capacity. As a result, returns on investment to refiners were sufficient to motivate new investments in capacity. By the early 1990s, the rate of addition of conversion capacity considerably exceeded the needed level. Many producers added this capacity with the intention of processing heavy crude into low sulphur diesel and reformulated gasoline. Many refiners found the most economic way of accomplishing this was to combine various refinery modifications made in response to regulatory changes with expansions of conversion capacity. Since conversion capacity is generally the most profitable increment of refining, many refiners believed that increasing it was the most effective way to maximize returns on product quality improvement investments. However, because so many refiners recognized the potential benefit of increasing conversion capacity, an overbuilding of such capacity resulted. The overabundance of conversion capacity drove up demand for heavy feedstocks and resulted in a narrowing of the light-heavy differential through 1995. A modest recovery in the light-heavy differential occurred in 1996 through 1998 driven mainly by the rising output of heavy crudes in the Western Hemisphere, but reduced production resulted in very weak differentials in 1999.

In 2000, increasing heavy crude production from Mexico and Venezuela, as well as increased OPEC production overall, resulted in a strong increase in the light/heavy differential. The light/heavy differential remained wide through the middle of 2001, but fell sharply and remained low through 2002. A number of coker projects came on stream in 2001 and 2002.

The disruptions in Venezuelan crude production also contributed to low differentials in 2002. Tight product markets resulted in a sharp increase in differentials in late 2002, continuing into early 2003. Differentials moderated in mid-year, but recovered late in the year. The same conditions that created the high margin environment in 2004 have contributed to strong light/heavy differentials as well. High freight rates have reduced netbacks for fuel oil shipments out of the Atlantic Basin, and production of heavier OPEC grades has increased residual availability. As crude oil and gasoline price pressures ease, light/heavy differentials are expected to fall towards long-term equilibrium levels.

Although the rate of increase in conversion capacity fell sharply in the mid-1990s, several major projects have recently been completed, and more are underway. Most of these projects were linked to supplies of heavy crude from Venezuela and Mexico and absorbed increases in heavy crude production. Net additions to total conversion capacity (adjusted for process type) in recent years have been at a rate of about 2 percent in the U.S. as outlined in Figure IV-18.

FIGURE IV-18
U.S. CONVERSION CAPACITY CHANGES
(Thousand Barrels per Day)



MARGIN OUTLOOK

Margins for various refinery complexity and configuration/crude supply combinations are presented in Figures IV-19 and IV-20 and shown in Tables IV-1 through IV-4. Capital intensive heavy crude operations show the highest margins. The forecast for light/heavy differentials and light crude cracking margins sets the stage for relatively weak heavy crude refining margins over the next two years before recovering.

The margin figures and tables incorporate the impact of ultra-low sulphur gasoline and diesel production. Ultra-low sulphur gasoline production is incorporated in 2005, with diesel in 2007. The price forecasts for both products are based on cash operating costs with a low level of capital recovery. Thus, these products result in a limited impact on projected refining margins.

Refining economics are analyzed in terms of both net margin (margin after variable and fixed cash costs) and "Capital Recovery Factor" (CRF) which is a measure of a simple financial return on replacement cost. The use of CRF provides an inflation-adjusted measure of refining profitability. Simple financial returns are also measured on the difference in margin and replacement cost between two types of notional refineries, referred to as incremental CRF. For example, the incremental CRF between catalytic cracking and coking gives an indication of the simple return for the upgrading investment of adding coking capability to a cracking refinery.

FIGURE IV-19
USGC LLS REFINING MARGINS
(Forecast in Constant 2004 Dollars per Barrel)

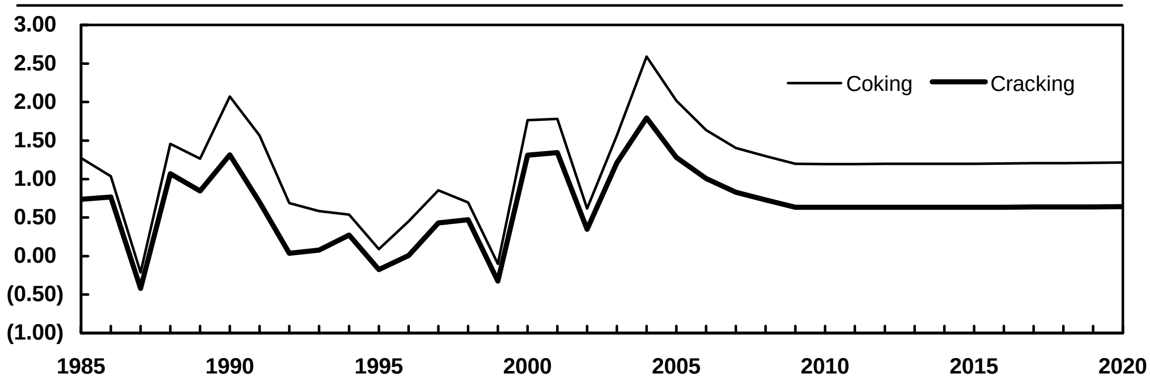


FIGURE IV-20
USGC SOUR CRUDE REFINING MARGINS
(Forecast in Constant 2004 Dollars per Barrel)

We expect margins to return to levels above the depressed levels of most of the 1990s but below the 2000-2004 average. The gasoline sulphur reduction program and reductions in MTBE use will tend to tighten supply, providing support for stronger margins over the next few years. Longer term, expansions in crude and conversion capacity are expected to ease supply/demand pressures.

Light/heavy differentials reached high levels in 2000-2001, but fell sharply in mid-2001 through 2002. Spreads increased in 2003, and have reached very high levels in 2004. Differentials are projected to move toward cycle-average levels over the next few years, but to remain at levels that support continuing conversion investment. The Isthmus incremental coking return in Figure IV-21 closely tracks the light/heavy differential.

FIGURE IV-21
ISTHMUS INCREMENTAL COKING RETURN
(Percent CRF)

REFINED PRODUCT PRICES

FORECAST METHODOLOGY

Refined product prices are a function of feedstock costs and the projected level of refinery profitability. Refinery profitability is related to operating rates and supply/demand factors. The prices of individual light products are a function of supply/demand factors and refining economics. The relationship between light and heavy products is related to global trends in conversion utilization as well as local factors.

Product prices in the U.S. are determined in an iterative fashion. Two key variables -- refining margins for a cracking refinery, and the incremental coking return at the U.S. Gulf Coast for a light sour crude refinery -- are input to the pricing models, along with the crude oil price forecast. The model then iteratively adjusts light product prices and residual fuel oil prices until converging on the single set of prices for these products that satisfies the input economic variables that have been derived through projected local and global fundamentals. Prices of other light products, including various grades of gasoline, are related to conventional unleaded regular gasoline based on refining economics and trends in supply requirements. Likewise, the prices of fuel oils of other grades are calculated to be consistent with these same factors.

The forecasts for U.S. Gulf Coast product prices in current and constant dollars are shown in Tables 5 and 6. The prices are spot pipeline prices for light products and waterborne prices for residual fuel oil. All prices are the mean of the high-low quotations. These prices are developed through an iterative procedure from the forecast margins discussed above and product price relationships discussed below.

The outlook for refined product prices in the U.S. Gulf Coast market will be influenced significantly in this decade by changing product specifications. An overview of product quality trends is provided in this section followed by the price forecasts by product type.

GASOLINE

The relationship among the gasoline grades and the pricing of conventional and reformulated gasolines through the forecast are important to the economics of capacity additions and modifications necessary for the industry to be able to supply these changing fuels.

The prices presented in this report represent a “phaseout” forecast for the use of MTBE in U.S. gasoline. MTBE use in New York, California, and Connecticut ended on January 1, 2004, and a number of other states are following. It is assumed that the Federal oxygen mandate for RFG is eliminated in 2005, and that MTBE use is prohibited in the U.S. outside California by 2012. As a result, octane values, gasoline prices, and refining margins are increased. Octane values remain higher than they would be if MTBE were to remain in use.

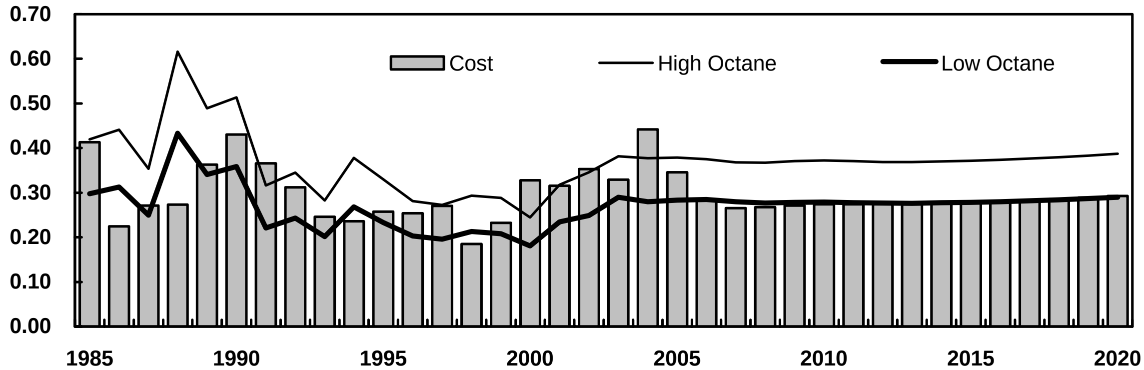
While this scenario requires the passage of significant new Federal legislation and other changes in regulations, it now appears to represent the most probable course of events. However, the timing and outcome of these future political battles is still subject to considerable uncertainty.

Conventional Gasoline Prices

Conventional gasolines remain a large part of the pool through the forecast. The relationships among the conventional grades have changed as reformulated fuels have been introduced. Octane values were affected by the addition of substantial quantities of MTBE and other oxygenates, and future octane relationships will be influenced by the MTBE phaseout. The structure of future regulations to reduce the sulphur content of conventional gasoline is in place. Forecasts are presented for gasoline of current quality, as well as for future low sulphur gasoline.

The pricing of different grades of conventional gasoline is a function of the value of octane and marketing factors. The value of octane, illustrated in Figure IV-22, is determined by the cost of manufacture. Our calculations are based on incremental reforming and other refining cost and yield factors. Higher octane operation results in lower yields of gasoline, higher proportions of less valuable by-products and additional operating costs.

FIGURE IV-22
USGC OCTANE COST-VALUE RELATIONSHIP
(Forecast in Constant 2004 Dollars per Octane Number-Barrel)



We compute "low" and "high" octane blending values. The low octane value represents the value per octane barrel for components with octane below regular gasoline (87 R+M/2), while high octane values represent levels above regular gasoline. The high octane market value is based on the differential between unleaded regular and premium gasolines. Historically there have been substantial market premiums above cost for premium gasoline. We expect premium gasoline to reflect a modest market add-on versus our estimated manufacturing cost, particularly as octane values increase due to the MTBE phaseout.

Reformulated Gasoline Prices

With the introduction of reformulated gasoline, the basis of all octane values shifted due to the net effects of addition of MTBE and modified processing. Addition of MTBE to even a portion of the gasoline pool resulted in reduced severity of operations to meet total octane requirements. This applied to the conventional grade gasoline that is still manufactured and sold in non-reformulated areas, as well as to the reformulated grades.

FIGURE IV-23
USGC SPOT GASOLINE DIFFERENTIALS
(Cents per Gallon)

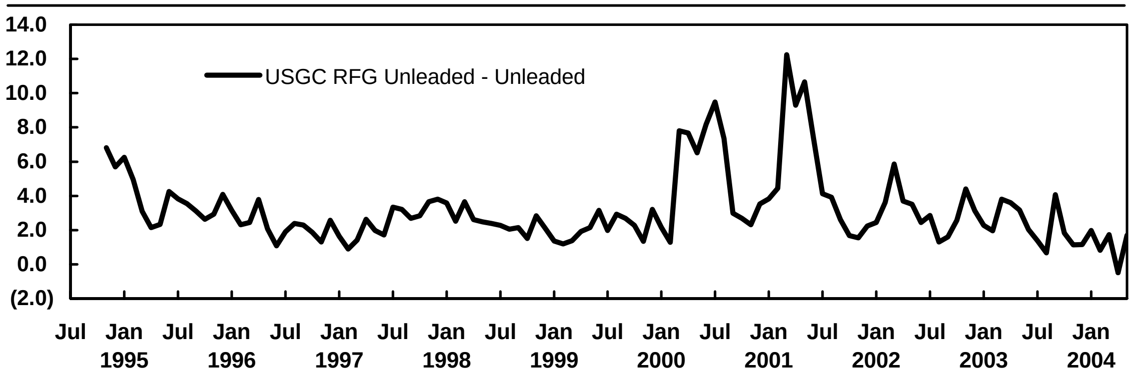


Figure IV-23 presents recent historical differentials for Phase I and II Federal RFG. Prior to the introduction of Phase I RFG in January 1995, concerns over tight supplies resulted in differentials nearing 7 cents per gallon. The premium soon fell to the 2 cent range, but bounced up due to the influence of very high methanol and MTBE prices. As oxygenate price relationships returned to normal, the differential fell back toward levels consistent with our estimates of incremental refining costs. Over the 1995 through 1999 period, the differential averaged 2.6 cents per gallon which is near calculated variable costs, covering operating costs, oxygenate costs, and yield effects.

Phase II reformulated gasoline was expected to show premiums averaging about 3.0 cents per gallon versus conventional gasoline. Some additional refinery investment was needed to reduce olefins, aromatics, and to meet distillation requirements. However, the primary goal of both capital investment and operating changes has been to reduce sulphur and vapor pressure. Most refiners are relying heavily on vapor pressure reductions to achieve the Phase II targets. Both butane and pentane/pentylene blending are being reduced to meet the need for gasoline RVP in the 6.5 to 6.9 psi. In early 2000, difficulties in adjusting to the new specifications, along with general gasoline supply tightness, resulted in very strong reformulated versus conventional differentials. The differentials increased to the 6 to 10 cent per gallon range during this period. Differentials declined in the fall but increased sharply in early 2001 due to tight MTBE supplies and continuing manufacturing difficulties. However, the seasonal transitions in 2002 and 2003 showed lower differentials due to experience gained in Phase II manufacturing. Differentials for Gulf Coast RFG, which contains MTBE, have been quite low in 2003 and 2004 due to weak MTBE pricing. MTBE has been trading at prices below its gasoline blending value, reducing the cost to produce RFG.

Differentials in the 3 cent per gallon range are projected. This level covers cash operating costs and can provide some limited capital recovery, depending on the technology used to reduce gasoline sulphur.

Ultra Low Sulphur Gasoline Prices

Over the past few years, a number of process technology licensors have announced new processes to reduce gasoline sulphur while minimizing the octane loss which occurs in conventional desulphurization. These new processes appear to be performing as expected allowing refiners to meet the new specifications at relatively low cost. Based on the new technology, production of ultra-low sulphur (30 ppm) gasoline is expected to result in higher fixed and variable costs of approximately 0.5 to 1.0 cents per gallon. With an anticipated modest level of capital recovery, prices for ultra-low sulphur gasoline are projected to increase by about 1.0 cent per gallon versus today's fuel.

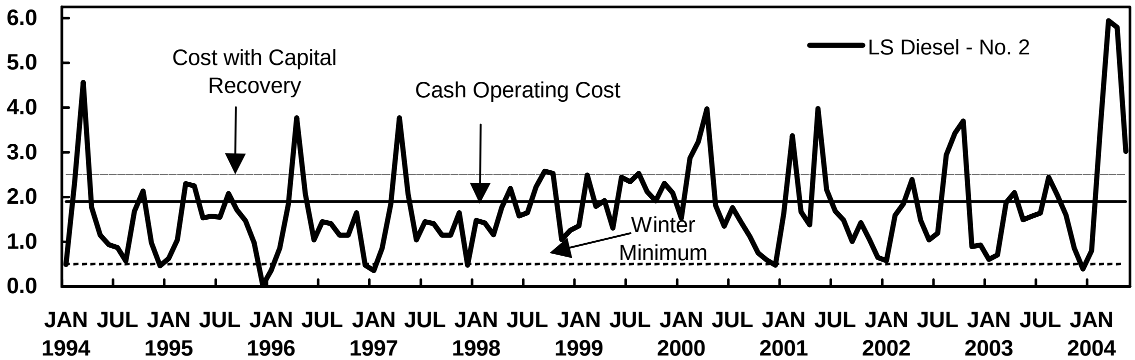
DISTILLATE FUELS

Standard Distillate

In this discussion we will refer to typical specification, heating oil/diesel fuel as "standard distillate," while the 0.05 percent sulphur diesel fuel introduced in 1993 will be referred to as "low sulphur" diesel. Distillate fuel oil prices are projected based on a relationship versus unleaded regular conventional gasoline. Distillate price differentials are somewhat more difficult to calculate on a strict refining economics basis due to the seasonal nature of price trends. Typically, the summer differentials will rise to a level that more than supports the maximized conversion of this material to gasoline through revised cutpoints for FCCU charge. At maximum utilization of cracking capacity the differential often rises above balanced levels. Our forecasts are based on a summertime (second and third quarter) distillate discount averaging in the 5 cent per gallon range, though peaks well over this level are typical.

Wintertime balances can be erratic and the typical premium on distillate during the winter season is both a function of the distillate balance, the weather conditions and the relative strength or weakness of the gasoline balance. Under typical conditions we estimate the wintertime premium (first and last quarters of the year) to be near zero. Often the strongest distillate period is just prior to the winter as inventories are being added to meet peak winter requirements. The combination of the expected averages yields a long-term forecast for a 3.5 cent discount for standard distillates relative to conventional gasoline (high sulphur) on an annual average basis, or about 4.5 cents versus ultra low sulphur gasoline.

FIGURE IV-24
USGC SPOT DIESEL DIFFERENTIALS
(Cents per Gallon)



Low sulphur diesel pricing has typically reflected the incremental operating costs required to manufacture the fuel, but is heavily influenced by seasonal factors. Figure IV-24 illustrates the historical spot differential between low sulphur diesel and No. 2 fuel oil (standard distillate) on the U.S. Gulf Coast. Tight supplies in October 1993, when the fuel was introduced, produced a spike in the differential. The tightness and price spikes were particularly pronounced in PADD II. The winter of 1993-94, however, was particularly cold. High residential/commercial demand drew low sulphur material into the heating oil pool, reducing the differential from the 4 cents per gallon (October, 1993 level) to 0.5 cents per gallon in January 1994. The high winter demand drew both low and high sulphur stocks down to low levels, resulting in another supply-induced price spike in spring 1994. Since then, expanded industry capabilities have resulted in a smoother price relationship, with annual average differentials very close to calculated cash costs for the marginal refiner. The differential has a strong seasonal component due to winter heating oil demand, which drives the differential down to around 0.5 cents per gallon. The price spikes early in a number of years generally resulted from low inventories following a severe winter and abnormal inventory time risk factors.

As shown below, the annual price differential of 1.5 to 2.0 cents per gallon is consistent with the cash operating cost for marginal sour crude cracking operations. Variable costs include both refinery operating cost elements and yield impacts. To produce the lower sulphur fuel, this plant must install high pressure, high severity hydrotreating capacity, even though the increase in total desulphurization throughput is relatively moderate.

LOW SULFUR DIESEL INCREMENTAL PRODUCTION COST: 1998-2003 AVERAGE
(U.S. Cents per Gallon Low Sulfur Diesel)

Variable	1.6
Fixed Cost	0.5
Total	2.1
Capital Charge at 10%	1.3

Simulations of refinery operations by PADD have indicated that the capacity to produce low sulphur diesel is in excess of market requirements. Thus, low sulphur diesel prices are not expected to provide any capital recovery for the high-cost producer. Instead, the cash costs for the high-cost producers tend to set the level of the low sulphur versus high sulphur differential, and differentials only exceed full cost levels during supply disruptions. Under the current regulations, the price differential should remain close to manufacturing costs, resulting in differentials of about 2.0 cents per gallon for low sulphur diesel relative to standard diesel. However, the introduction of ultra low sulphur diesel in 2006 is expected to have a significant impact on low sulphur diesel prices.

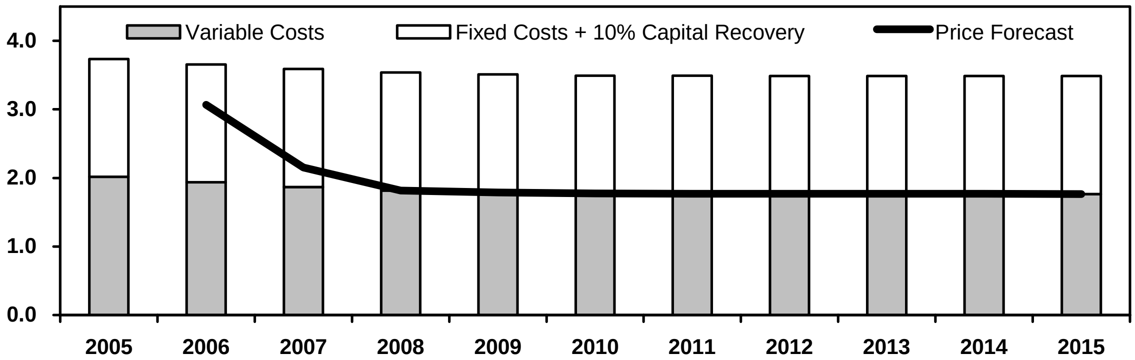
Ultra Low Sulphur Diesel

Production costs for 15 ppm ULSD diesel are estimated at 2.5 to 3 cents per gallon over the 500 ppm product. Variable and yield costs account for the majority of the price premium. Capital recovery accounts for slightly less than 1 cent per gallon. These costs cover the desulphurization only, as cetane and other properties are not expected to be constraining.

At the retail level, ULSD and LSD are likely to be priced identically. When ULSD is introduced, the only vehicles required to use it are the 2007 model year vehicles. These will comprise a very small portion of the fleet. However, at least 80 percent of the fuel available will be ULSD. Therefore, most vehicles not requiring ULSD will still have to fuel with it. Although it is possible that some smaller outlets may offer LSD at a slight discount to capture markets, we generally expect the price will be the same at major outlets. The question then becomes whether refiners or marketers will capture the difference in production costs.

Initial production of ULSD will be well above the minimum 80 percent level. A recent survey by the EPA showed that 96 percent of on-highway diesel production would be ULSD by 2006. Our informal survey indicates that most refiners will install facilities to make 100 percent of their diesel requirements (both on-road and off-road) to meet the ULSD standard. Some multi-refinery companies may elect to phase the investments by using credits at one facility to delay capital investments at another. The principal mode of compliance will be through revamp of units currently used to produce LSD. Since the same facilities will be used to produce both products, we expect the long-term differential between ULSD and LSD to merely reflect the variable cost avoided by producing LSD instead of ULSD of about 1.6 cents per gallon. The differential will likely exceed this level in the introductory period of 2006-2007, but is then expected to fall rapidly.

FIGURE IV-25
15 PPM VERSUS 500 PPM DIESEL COST AND PRICE RELATIONSHIP
(Forecast in Constant 2004 Cents per Gallon)

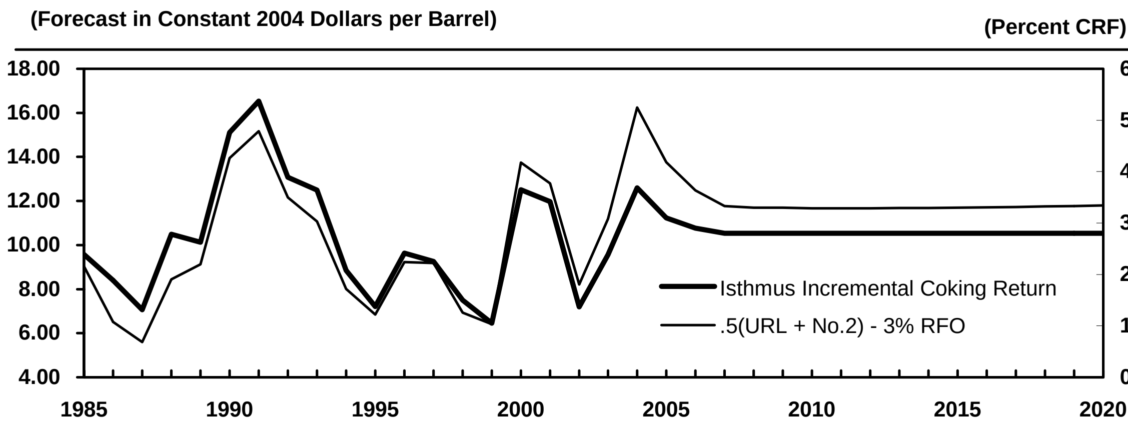


No. 2 fuel oil is expected to be in ample supply both internationally and domestically. As a result, we expect the differential between ULSD and No. 2 fuel oil to reflect the full cost of desulphurization, estimated at about 4.0 cents per gallon. The net effect of this market transition will thus increase the differential between No. 2 fuel oil and low sulphur diesel by 0.5 – 1.0 cents per gallon.

RESIDUAL FUEL OIL

The prices for high sulphur residual fuel oil are determined in a convergence calculation that satisfies the input incremental coking return on light sour crude, cracking refinery margins and the crude price at a particular point in time. Figure IV-26 shows the resulting projection of the light/heavy spread as reflected in the differential between an average of conventional unleaded regular gasoline and standard distillate minus 3 percent sulphur fuel oil on the U. S. Gulf Coast.

FIGURE IV-26
LIGHT/HEAVY RELATIONSHIPS
(Forecast in Constant 2004 Dollars per Barrel)



The light/heavy spread has oscillated over a wide range. A steady downward trend occurred through the first half of the 1980s as petroleum demand dropped, freeing up additional conversion capacity. At the same time, substantial project additions came on stream in 1984, while a coal strike in Europe pushed the spreads even narrower as residual fuel oil demand rose.

This downward trend reversed through the late 1980s and the Iraqi conflict in 1990 resulted in a sharp widening of the spread due to heavy crude oversupply and depressed residual fuel oil prices, particularly in the Western Hemisphere. The change in crude slates, and particularly the added conversion capacity from 1991 to 1995, reversed the trend. Residual fuel oil prices and light/heavy spreads narrowed during this period to levels that represent an excess of conversion capacity.

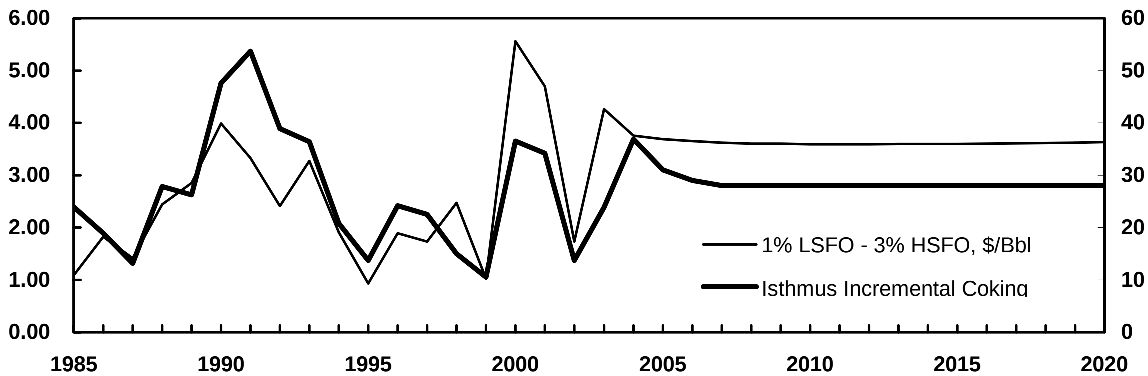
Light-heavy spreads widened in 1996-1998 as the previous overbuilding was absorbed by growing demand and increased heavy crude production. By late 1998, however, worldwide production cutbacks in the wake of the Asian financial crisis reduced residual availability and led to very low differentials in 1999. A sharp reversal occurred in 2000-2001 due to tight markets for light products, and growth in heavy crude production. These factors reversed in late 2001 and kept differentials low for most of 2002. The margin recovery in late 2002-early 2003 brought differentials to higher levels. Moderate differentials were experienced in 2003, but differentials have been very high in 2004. Differentials are projected to move towards long-term equilibrium levels over the next few years.

Grade Differentials

We do not envision shortages of low sulphur crude oils in the international market, and expect that low sulphur fuel oil will continue to be made from low sulphur crude residue and indirect desulphurization/blending. We do not expect the demand for low sulphur residual fuel oil to be high enough to require desulphurizing sour vacuum residue to produce low sulphur fuel oil in most markets. Consequently, the differential will be set by the alternative of additional processing to produce light products rather than fuel oil. This processing requires significant desulphurization investment and higher operating costs for sour residual fuels versus low sulphur residual fuels. Thus, the differential between high and low sulphur fuel oil closely follows trends in conversion returns. When conversion capacity is slack and returns are low, refiners will maximize income by preferentially processing the lower cost high sulphur feedstocks, reducing the sweet-sour differential. However, when capacity is tight, processing low sulphur material can effectively increase capacity due to its high yields, and so the differential between high and low sulphur residual widens.

The longer term forecast differential is based on continuation of the observed relationship with the conversion return as outlined in Figure IV-27. However, the 2000 to 2001 differentials rose to unprecedented levels. These aberrations were a result of high gas prices, resulting in dramatic fuel substitution effects. Residual fuel oil demand grew by almost 10 percent in 2000, and was fully concentrated in the lower sulphur fuels. As gas prices climbed in late 2002 and throughout 2003, the LSFO-HSFO differential again rose to higher levels, but dropped as seasonal demand pressures eased. Similar behavior has raised the LSFO-HSFO differential in 2004. Long-term differentials in the $3.50 per barrel range are projected.

FIGURE IV-27
FUEL OIL SULPHUR DIFFERENTIALS
(Forecast in Constant 2004 Dollars per Barrel) **(Percent CRF)**



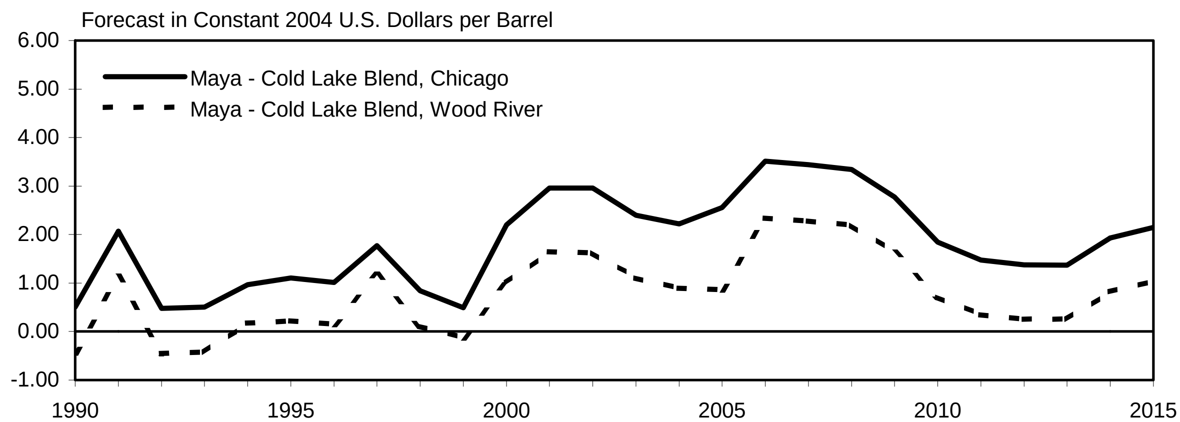
CANADIAN HEAVY CRUDE PRICING

Canadian heavy crude oil competes in the Midwest with Latin American heavy crude streams, although nearly all of this market is captured by Canadian crude. Our analysis uses competition versus Maya in the Midwest as the basic pricing mechanism for Canadian heavy crude and bitumen blend. Based on refinery economic analyses, we find that Canadian heavy crudes are valued based on their value to a refiner, relative to alternative feedstocks such as Maya, less a discount. The delivered cost of Mexican Maya crude is determined at Wood River based on the U.S. Gulf Coast price plus transportation via Seaway pipeline. Cold Lake Blend has a refining value which is close to Maya, but its price has historically been discounted to Maya to protect its market in the Midwest.

The price netbacks of Canadian heavy crude oils normally depends on how deeply they must penetrate into the Midwest market to move all the available supply. If Canadian heavy crude supplies are relatively short, they do not need to penetrate the U.S. market beyond the Chicago area. As a result, they would be overpriced for delivery to the Wood River area.

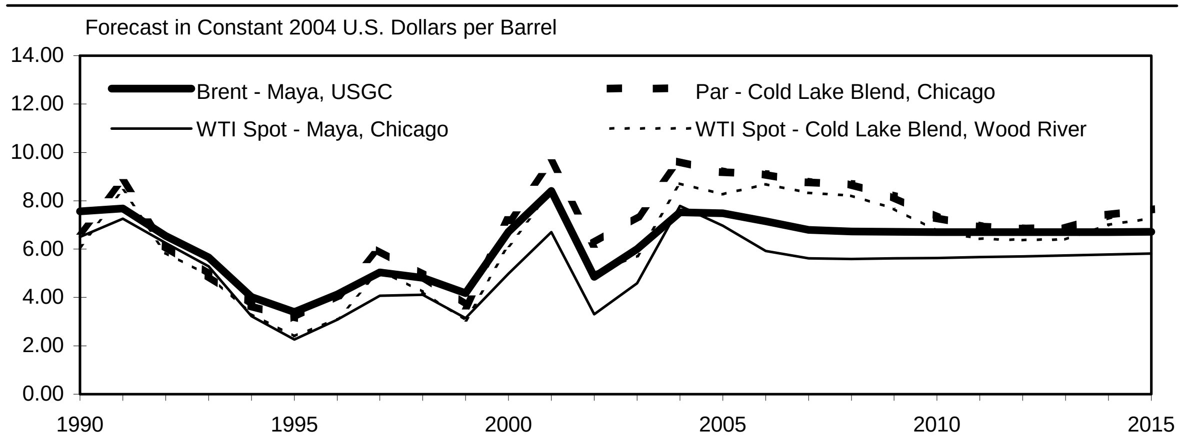
Supplies are projected to increase steadily throughout this decade. Our forecast for heavy crude supplies indicates that Canadian heavy crude will need to clear the market further south and must be competitively priced in the Wood River area in order to clear that market. Over the long-term, Cold Lake Blend price is forecast to be slightly below Maya price at Wood River (Figure IV-28), so Cold Lake Blend will remain an attractive refinery feedstock in Chicago. The discount shown in Figure IV-28 beyond 2005 provides a sufficiently attractive return to refiners if they add new coking capacity to process more heavy crude. If bitumen supplies come on stream at a much higher rate than expected, the resulting market discounts could be larger than experienced historically and than what was developed in our price forecasts.

FIGURE IV-28
HEAVY CRUDE PRICING



Since Canadian heavy crude is generally priced lower than Maya at Chicago, the Par/Cold Lake Blend differential is wider than the WTI/Maya differential, as well as the Gulf Coast Brent/Maya differential. World light/heavy differentials have widened relative to 2002, and the Canadian Par/Cold Lake Blend differential at Chicago has also widened (Figure IV-29), and is forecast to remain wider than the historical average. This should allow upgrading projects at existing refineries, particularly in the Chicago vicinity, to become economic, and result in growth in Midwest heavy crude runs. Similar incentives should be available for refineries in Canada, but only to a limited extent at Wood River where the light/heavy differential will remain lower than desired to justify significant new conversion investments.

FIGURE IV-29
LIGHT/HEAVY DIFFERENTIALS



Canadian crude prices netted back from Chicago to Western Canada are reported in Tables IV-9 and IV-10 in current and constant 2004 dollars respectively. Canadian light sweet crude (MSW) is forecast to average over $36.00 (U.S.) per barrel at Edmonton in 2004. Prices have moved higher in the past two years in response to global market trends. Light crude prices (WTI at Cushing) are forecast to be around $26.00 per barrel (constant 2004 U.S.$) by 2010, with gradual strengthening in real terms longer term.

For Canadian heavy grades, light/heavy differentials narrowed in 2002 but widened again in 2003 and 2004. We expect the differentials to narrow from the wide 2004 levels as overall crude prices decline, but still remain at higher levels than experienced through much of the 1990s. Our outlook for Canadian heavy/light differentials is based on increasing heavy supplies entering the market, which will require the refining industry to increase its capability to process more heavy feedstock. The refining industry is currently preoccupied with adding investments to reduce sulphur in gasoline and diesel fuel, and they need to be complete by 2006. Some refineries, when they add increased desulphurization capabilities to produce low sulphur diesel, will also make improvements in being able to process higher sulphur feedstocks. Therefore, we expect a lag will occur in the market's capability to readily use more heavy crude until after 2006. From 2006 onward, we expect differentials should hold at a level sufficient to encourage refiners to add further capabilities to process heavy crude.

The expected differentials for heavy crudes are as outlined below. Post 2005, Lloydminster Blend prices at Hardisty are expected to be in a range of $8.00 to 9.50 U.S. per barrel below WTI prices at Cushing.

LIGHT/HEAVY PRICE DIFFERENTIALS
(Forecast is in Constant 2004 Dollars (U.S.) Per Barrel)

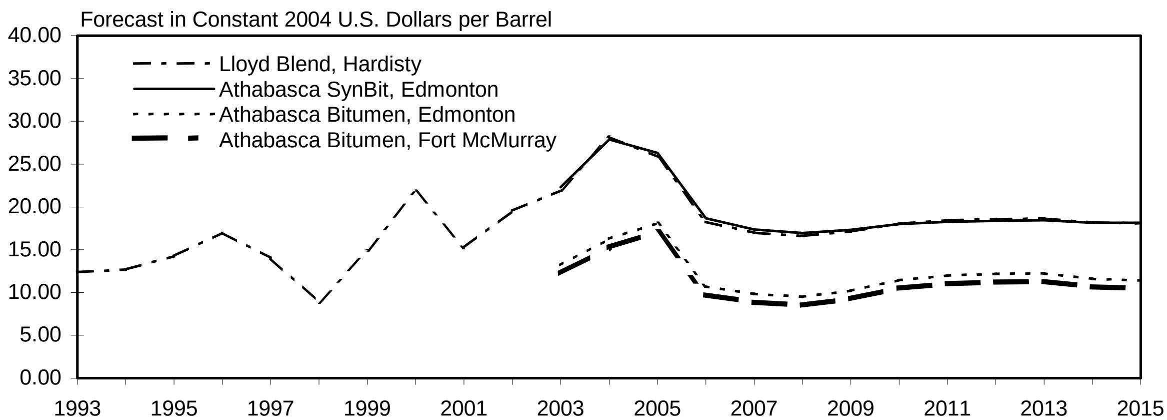
	2002	2005	2007	2010	2015
Brent-Maya, USGC	4.86	7.48	6.80	6.70	6.72
WTI at Cushing minus Lloydminster Blend at Hardisty	6.63	10.49	9.57	7.94	8.49

Athabasca bitumen netback prices were developed in this analysis. Future bitumen blend supplies to the market will include growing supplies of Cold Lake bitumen, but Athabasca bitumen blends will also begin to increase significantly as such new projects are developed. Athabasca bitumen blends will have higher sulphur content, higher metals, and higher TAN content (total acid number) than Cold Lake Blend. The higher TAN levels require refineries to have sufficient metallurgy to accommodate the more corrosive nature of Athabasca blends. Thus, Athabasca blends will likely experience a TAN penalty that will not apply to Cold Lake Blends.

Netback prices are quite dependent on the volume of diluent used to dilute the heavy crude for pipeline shipment, and the cost of that diluent. Both condensate and synthetic crude are used as diluents, although synthetic crude has just begun to be used. Condensate supplies are expected to decline slowly as natural gas production in Alberta declines. Because a large quantity of synthetic crude in northern Alberta is being transported past bitumen projects that require diluent, we expect synthetic crude to become an increasingly significant source of diluent going forward, and the resulting synthetic/bitumen (SynBit) blends will become major heavy crude streams entering the crude oil market. We believe that the price of SynBit blends will be the primary price determinant of Athabasca bitumen prices over the long-term.

Athabasca Blend (SynBit) at Edmonton (Table IV-10) is forecast to be $27.87 U.S. per barrel in 2005, and $17.85 U.S. per barrel in 2010 (both in constant 2004 dollars). We assumed that the Athabasca Blend experienced a $0.80 U.S. per barrel discount for its high TAN content. Athabasca bitumen at Edmonton is estimated to be at $11.37 U.S. per barrel in 2010 (in constant 2004 dollars). The netbacks are compared below in Figure IV-30.

FIGURE IV-30
CANADIAN HEAVY CRUDE OIL NETBACK PRICES



Our outlook for synthetic crude prices in Tables IV-9 and IV-10 reflects some softening in prices in the 2005-2006 timeframe. This is due to the expected large increases in synthetic crude production, and the need to expand markets for synthetic crude. If synthetic crude is used as a diluent, its price as a diluent should be more attractive than today. With significant growth in synthetic supplies expected, it is possible that synthetic crude may experience higher discounts in order to access new markets. If this occurs, it will become more attractive as a diluent, and provide higher bitumen netback prices.

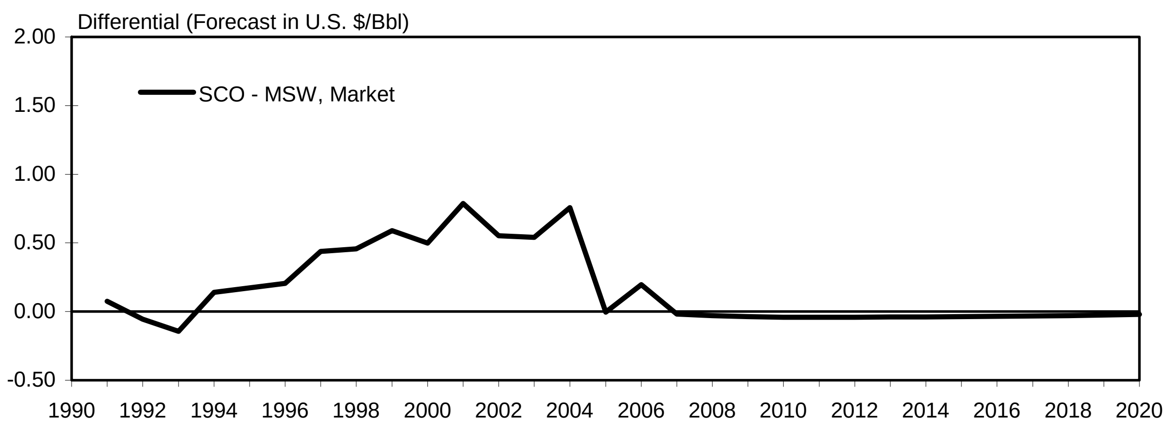
This analysis was based on WTI at around $26.00 per barrel. It WTI prices should drop below $18.00 per barrel on a sustained basis, the resulting bitumen netbacks would provide only a marginal return to a bitumen producer. As absolute crude prices drop, differentials between light and heavy crudes also narrow, although not linearly.

SYNTHETIC CRUDE OIL (SCO)

Synthetic crude oil is characterized as heavy crude upgraded to a light, sweet crude with an absence of resid content. The four main producers are Syncrude Canada and Suncor at Ft.

McMurray, Husky near Lloydminster and Newgrade in Regina. SCO competes directly with light sweet crudes such as MSW, LLS and other offshore crudes. As shown in Figure IV-31, the price of SCO over the past ten years has averaged at a small premium over MSW.

FIGURE IV-31
SWEET SYNTHETIC PRICE COMPARISON



In the early 1990s, the market value of SCO was lower than MSW, but since 1996, it has been US$0.40 to US$0.80 per barrel higher. SCO market premiums to MSW are supported by cracking economics. The last several years have seen strong pricing for Western Canadian light crudes, as they are attractive supplies to U.S. refiners compared to the alternative of importing long haul supplies from the North Sea or Africa. Synthetic crude has also received similar strong pricing support.

SCO experienced some price discounting in the early 1990s following Syncrude's Capital Expansion Project and start-up of the Husky upgrader, both resulting in a significant increase in synthetic crude supplies. Synthetic crude processing in the U.S. Midwest expanded, and exports of synthetic more than doubled from 53,000 B/D in 1990 to 117,000 B/D in 1993. Exports declined somewhat through 1996, but have gradually been increasing since.

The volume increase in exports over the last few years has been minor, and it has not affected the price during this time. However, the extent of exports which have begun to occur are substantial. SCO supplies have doubled between 2000 and 2004. By 2005 and thereafter, SCO production is expected to increase substantially, with potential market implications. Some synthetic crude will need to replace light sour crude, and will likely be mixed with heavy sour crude to be suitable, both technically and economically, for light sour crude refineries. Most refineries that run light sour crude in the traditional markets for Canadian crude do so for asphalt production or coking. SCO contains no resid and must be combined with a crude that is high in resid content to ensure asphalt demand can be met and coker utilization remains high. Usually, light sour substitution results in a lower value for SCO than if it replaced only light sweet crude. Also, synthetic crude results in a higher yield of distillate relative to gasoline yield than the market requires. A refiner can place a small amount of synthetic crude into its feedstock slate without a substantial impact on product yields. However, as the percentage of SCO in the crude slate increases, disposing of surplus distillate and VGO can create limitations that result in further reductions in its value to a refiner.

The PADD II market has a relatively high gasoline to distillate demand ratio. Rebalancing this ratio as more synthetic crude is run in the region will require some SCO price discounting to export distillate in excess of demands or reduce imports from PADD III. With the large increase in exports destined to PADD II, there will be increasing pressure to modify refineries in this region to better accommodate the synthetic crude. Synthetic crude prices will need to adjust to provide the necessary incentives for such modifications.

Our SCO price forecast reflects a higher quality SCO starting in 2006, which should help offset the negative price impact as production levels increase. In addition, Enbridge's proposed Spearhead Pipeline project, which will reverse the Cushing-to-Chicago (CTC) pipeline, will allow for an expansion of Canadian crudes sales into less traditional markets. The expansion should also provide for lower transportation costs into these markets and improve crude netback prices at Edmonton. We have assumed that the transportation cost from Chicago to Cushing would be about $0.35 per barrel. Enbridge has also announced that they intend to construct a new pipeline from Superior to Wood River to service both the Southern Midwest region and connect with the Spearhead pipeline. We assumed that the tariff from Edmonton to Wood River on this new pipeline would be similar to the tariff from Edmonton to Cushing. Our price forecast reflects this new pipeline alternative.

Based on current prices and the tariffs discussed above, Cushing would provide the lowest netback for SCO in 2006 when the Spearhead pipeline becomes available. Before 2012, we expect that the SCO can be absorbed in the traditional markets in Canada and Northern Midwest plus the Southern Midwest (Patoka hub) without shipping large volumes to Cushing. Cushing volumes of SCO could materialize with shipper support on Spearhead pipeline or if the tariff to Wood River remains higher than forecast. The forecast differential over the longer term (Figure IV-31) is expected to be close to MSW pricing. SCO prices are shown in Tables IV-9 and IV-10.

TABLE IV-1
INTERNATIONAL CRUDE OIL PRICES
(Current Dollars per Barrel)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Sweet Crude Oil Prices											
Brent, FOB	23.73	17.02	28.50	24.44	25.02	28.83	33.45	30.00	27.19	30.52	35.14
Brent, USGC	25.17	18.36	30.58	26.30	26.39	31.11	36.08	32.17	28.84	32.26	37.06
LLS, St. James	24.85	18.60	30.38	25.89	26.29	31.16	36.30	32.36	29.05	32.50	37.35
WTI Spot, USGC	24.97	18.63	30.31	25.91	26.23	31.10	36.29	32.33	29.23	32.90	37.84
WTI Spot, Cushing	24.46	18.42	30.37	25.93	26.16	31.06	36.30	32.43	29.36	33.02	37.94
WTI Spot, Midland	24.43	18.30	30.12	25.67	25.95	30.81	36.00	32.07	28.96	32.62	37.54
Sour Crude Oil Prices											
Isthmus, FOB	21.87	16.74	27.88	22.11	24.14	28.23	32.89	28.95	25.68	28.80	33.21
Isthmus, USGC	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.66	26.23	29.37	33.84
Maya, FOB	16.87	14.39	23.07	17.16	20.97	24.22	27.64	23.80	20.71	23.30	27.08
Maya, USGC	17.61	14.97	23.86	17.89	21.54	25.12	28.57	24.54	21.30	23.91	27.75
WTS Spot, Midland	22.57	17.42	28.20	23.12	24.80	28.32	33.29	29.31	26.34	29.72	34.31
WTS Spot, USGC	23.12	17.76	28.39	23.37	25.08	28.61	33.59	29.58	26.62	30.01	34.62
ANS, USWC	21.77	16.93	28.26	23.19	24.76	29.61	34.44	30.05	26.33	29.48	33.96
Dubai, FOB	20.50	16.09	26.24	22.80	23.85	26.76	31.36	28.32	25.04	28.12	32.46
Dubai, USGC	22.65	17.81	29.14	25.17	25.57	29.71	34.84	31.23	27.33	30.57	35.19
Oman, FOB	21.03	16.32	26.52	22.86	23.95	27.13	31.68	28.63	25.25	28.35	32.73

TABLE IV-2
INTERNATIONAL CRUDE OIL PRICES
(Forecast in Constant 2004 Dollars per Barrel)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Sweet Crude Oil Prices											
Brent, FOB	23.73	17.02	28.50	24.44	25.02	28.83	33.45	29.41	24.14	24.55	25.60
Brent, USGC	25.17	18.36	30.58	26.30	26.39	31.11	36.08	31.54	25.61	25.95	27.00
LLS, St. James	24.85	18.60	30.38	25.89	26.29	31.16	36.30	31.72	25.79	26.14	27.21
WTI Spot, USGC	24.97	18.63	30.31	25.91	26.23	31.10	36.29	31.70	25.96	26.46	27.56
WTI Spot, Cushing	24.46	18.42	30.37	25.93	26.16	31.06	36.30	31.80	26.07	26.55	27.63
WTI Spot, Midland	24.43	18.30	30.12	25.67	25.95	30.81	36.00	31.44	25.72	26.23	27.34
Sour Crude Oil Prices											
Isthmus, FOB	21.87	16.74	27.88	22.11	24.14	28.23	32.89	28.39	22.81	23.16	24.19
Isthmus, USGC	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.08	23.29	23.62	24.65
Maya, FOB	16.87	14.39	23.07	17.16	20.97	24.22	27.64	23.33	18.39	18.74	19.73
Maya, USGC	17.61	14.97	23.86	17.89	21.54	25.12	28.57	24.06	18.91	19.23	20.22
WTS Spot, Midland	22.57	17.42	28.20	23.12	24.80	28.32	33.29	28.74	23.39	23.90	24.99
WTS Spot, USGC	23.12	17.76	28.39	23.37	25.08	28.61	33.59	29.00	23.63	24.13	25.22
ANS, USWC	21.77	16.93	28.26	23.19	24.76	29.61	34.44	29.46	23.38	23.71	24.74
Dubai, FOB	20.50	16.09	26.24	22.80	23.85	26.76	31.36	27.76	22.23	22.62	23.65
Dubai, USGC	22.65	17.81	29.14	25.17	25.57	29.71	34.84	30.61	24.27	24.59	25.63
Oman, FOB	21.03	16.32	26.52	22.86	23.95	27.13	31.68	28.06	22.42	22.80	23.84

TABLE IV-3
U.S. GULF COAST LIGHT SWEET CRUDE MARGINS
(Current Dollars per Barrel)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Light Sweet Hydroskimming Refinery											
Product Sales Realization	24.92	18.45	31.45	26.83	26.25	32.06	36.46	32.99	29.85	33.37	38.26
Crude Cost	24.89	18.65	30.26	25.85	26.30	31.18	36.31	32.33	29.01	32.45	37.29
Gross Margin	0.03	(0.20)	1.19	0.99	(0.05)	0.89	0.15	0.66	0.84	0.92	0.97
Variable Costs	0.29	0.34	0.67	0.66	0.56	0.81	0.87	0.90	0.93	1.03	1.15
Fixed Costs	0.49	0.65	0.68	0.65	0.64	0.64	0.68	0.71	0.80	0.88	0.97
Net Refining Margin	(0.76)	(1.19)	(0.15)	(0.33)	(1.25)	(0.56)	(1.39)	(0.95)	(0.89)	(1.00)	(1.16)
Interest on Working Capital	0.20	0.13	0.24	0.15	0.10	0.11	0.13	0.15	0.16	0.18	0.20
Return, % of Replacement Cost	(14.23)	(16.06)	(4.51)	(5.64)	(15.81)	(7.70)	(16.11)	(10.91)	(9.16)	(9.27)	(9.73)
Light Sweet Cracking Refinery											
Product Sales Realization	27.64	20.10	33.45	29.04	28.39	34.31	40.15	35.91	32.28	36.07	41.29
Crude Cost	24.89	18.65	30.26	25.85	26.30	31.18	36.31	32.33	29.01	32.45	37.29
Gross Margin	2.75	1.45	3.19	3.20	2.09	3.13	3.83	3.58	3.27	3.61	4.00
Variable Costs	0.40	0.45	0.70	0.72	0.64	0.81	0.86	0.99	1.12	1.23	1.36
Fixed Costs	1.04	1.17	1.18	1.14	1.11	1.11	1.18	1.28	1.44	1.59	1.76
Net Refining Margin	1.31	(0.17)	1.31	1.34	0.35	1.21	1.79	1.31	0.71	0.79	0.88
Interest on Working Capital	0.22	0.14	0.25	0.16	0.11	0.11	0.13	0.16	0.17	0.19	0.21
Return, % of Replacement Cost	7.81	(2.06)	6.72	7.44	1.52	6.81	9.45	6.00	2.50	2.50	2.50
Light Sweet Coking Refinery											
Product Sales Realization	28.66	20.68	34.27	29.85	29.00	35.05	41.35	37.01	33.31	37.20	42.56
Crude Cost	24.89	18.65	30.26	25.85	26.30	31.18	36.31	32.33	29.01	32.45	37.29
Gross Margin	3.76	2.03	4.01	4.00	2.70	3.87	5.04	4.68	4.30	4.75	5.27
Variable Costs	0.44	0.51	0.81	0.83	0.73	0.95	1.01	1.10	1.25	1.37	1.52
Fixed Costs	1.25	1.43	1.43	1.39	1.35	1.36	1.44	1.52	1.71	1.88	2.08
Net Refining Margin	2.07	0.09	1.76	1.78	0.62	1.57	2.59	2.06	1.35	1.49	1.67
Interest on Working Capital	0.23	0.15	0.25	0.16	0.11	0.11	0.14	0.16	0.17	0.19	0.22
Return, % of Replacement Cost	11.07	(0.30)	7.89	8.44	2.64	7.44	11.53	8.45	4.62	4.63	4.67
Light Sweet Incremental Capital Recovery Factors (%)											
Hydroskimming/Cracking	28.60	14.30	19.89	22.74	21.70	23.72	39.21	24.81	15.48	15.60	16.10
Cracking/Coking	28.47	8.13	13.59	13.25	7.98	10.47	21.47	22.90	17.38	17.46	17.75

Note: Margin projections incorporate production of ultra-low sulphur gasoline (30 ppm) in 2005 and ultra-low sulphur diesel (15 ppm) in 2007

TABLE IV-4
U.S. GULF COAST LIGHT SWEET CRUDE MARGINS
(Forecast in Constant 2004 Dollars per Barrel)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Inflation Index (2004=1)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.02	1.13	1.24	1.37
Light Sweet Hydroskimming Refinery											
Product Sales Realization	24.92	18.45	31.45	26.83	26.25	32.06	36.46	32.35	26.51	26.84	27.87
Crude Cost	24.89	18.65	30.26	25.85	26.30	31.18	36.31	31.70	25.76	26.10	27.16
Gross Margin	0.03	(0.20)	1.19	0.99	(0.05)	0.89	0.15	0.65	0.75	0.74	0.71
Variable Costs	0.29	0.34	0.67	0.66	0.56	0.81	0.87	0.88	0.83	0.83	0.84
Fixed Costs	0.49	0.65	0.68	0.65	0.64	0.64	0.68	0.70	0.71	0.71	0.71
Net Refining Margin	(0.76)	(1.19)	(0.15)	(0.33)	(1.25)	(0.56)	(1.39)	(0.93)	(0.79)	(0.80)	(0.84)
Interest on Working Capital	0.20	0.13	0.24	0.15	0.10	0.11	0.13	0.15	0.14	0.14	0.15
Return, % of Replacement Cost	(14.23)	(16.06)	(4.51)	(5.64)	(15.81)	(7.70)	(16.11)	(10.91)	(9.16)	(9.27)	(9.73)
Light Sweet Cracking Refinery											
Product Sales Realization	27.64	20.10	33.45	29.04	28.39	34.31	40.15	35.21	28.66	29.01	30.08
Crude Cost	24.89	18.65	30.26	25.85	26.30	31.18	36.31	31.70	25.76	26.10	27.16
Gross Margin	2.75	1.45	3.19	3.20	2.09	3.13	3.83	3.51	2.91	2.91	2.91
Variable Costs	0.40	0.45	0.70	0.72	0.64	0.81	0.86	0.97	0.99	0.99	0.99
Fixed Costs	1.04	1.17	1.18	1.14	1.11	1.11	1.18	1.26	1.28	1.28	1.28
Net Refining Margin	1.31	(0.17)	1.31	1.34	0.35	1.21	1.79	1.28	0.63	0.63	0.64
Interest on Working Capital	0.22	0.14	0.25	0.16	0.11	0.11	0.13	0.15	0.15	0.15	0.16
Return, % of Replacement Cost	7.81	(2.06)	6.72	7.44	1.52	6.81	9.45	6.00	2.50	2.50	2.50
Light Sweet Coking Refinery											
Product Sales Realization	28.66	20.68	34.27	29.85	29.00	35.05	41.35	36.29	29.57	29.92	31.00
Crude Cost	24.89	18.65	30.26	25.85	26.30	31.18	36.31	31.70	25.76	26.10	27.16
Gross Margin	3.76	2.03	4.01	4.00	2.70	3.87	5.04	4.59	3.82	3.82	3.84
Variable Costs	0.44	0.51	0.81	0.83	0.73	0.95	1.01	1.08	1.11	1.10	1.11
Fixed Costs	1.25	1.43	1.43	1.39	1.35	1.36	1.44	1.49	1.52	1.52	1.52
Net Refining Margin	2.07	0.09	1.76	1.78	0.62	1.57	2.59	2.02	1.19	1.20	1.21
Interest on Working Capital	0.23	0.15	0.25	0.16	0.11	0.11	0.14	0.16	0.15	0.15	0.16
Return, % of Replacement Cost	11.07	(0.30)	7.89	8.44	2.64	7.44	11.53	8.45	4.62	4.63	4.67
Light Sweet Incremental Capital Recovery Factors (%)											
Hydroskimming/Cracking	28.60	14.30	19.89	22.74	21.70	23.72	39.21	24.81	15.48	15.60	16.10
Cracking/Coking	28.47	8.13	13.59	13.25	7.98	10.47	21.47	22.90	17.38	17.46	17.75

Note: Margin projections incorporate production of ultra-low sulphur gasoline (30 ppm) in 2005 and ultra-low sulphur diesel (15 ppm) in 2007

TABLE IV-5
U.S. GULF COAST SOUR CRUDE MARGINS
(Current Dollars per Barrel)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Light Sour Hydroskimming Refinery											
Product Sales Realization	21.98	17.22	28.07	23.86	24.70	29.51	33.41	30.11	26.87	30.07	34.57
Crude Cost	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.66	26.23	29.37	33.84
Gross Margin	(0.63)	(0.10)	(0.56)	1.07	0.02	0.44	(0.36)	0.45	0.63	0.70	0.73
Variable Costs	0.35	0.38	0.76	0.75	0.64	0.92	0.99	0.95	0.97	1.07	1.19
Fixed Costs	0.51	0.57	0.57	0.55	0.54	0.54	0.57	0.59	0.66	0.73	0.81
Net Refining Margin	(1.49)	(1.05)	(1.89)	(0.23)	(1.16)	(1.03)	(1.93)	(1.08)	(0.99)	(1.10)	(1.26)
Interest on Working Capital	0.18	0.13	0.21	0.13	0.09	0.10	0.12	0.14	0.14	0.16	0.18
Return, % of Replacement Cost	(21.75)	(13.84)	(23.98)	(4.18)	(14.26)	(12.65)	(21.02)	(12.25)	(10.06)	(10.12)	(10.52)
Light Sour Cracking Refinery											
Product Sales Realization	25.12	18.87	30.78	26.58	26.83	32.17	37.21	33.29	29.68	33.18	38.07
Crude Cost	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.66	26.23	29.37	33.84
Gross Margin	2.51	1.54	2.15	3.79	2.16	3.09	3.44	3.63	3.45	3.81	4.23
Variable Costs	0.58	0.60	1.10	1.10	0.95	1.31	1.40	1.46	1.44	1.59	1.77
Fixed Costs	1.03	1.13	1.11	1.08	1.05	1.05	1.12	1.19	1.33	1.47	1.62
Net Refining Margin	0.89	(0.19)	(0.06)	1.62	0.16	0.73	0.92	0.98	0.67	0.75	0.83
Interest on Working Capital	0.20	0.13	0.23	0.14	0.10	0.11	0.12	0.15	0.15	0.17	0.20
Return, % of Replacement Cost	4.66	(2.02)	(1.72)	8.88	0.34	3.70	4.31	4.27	2.36	2.37	2.38
Light Sour Coking Refinery											
Product Sales Realization	27.81	20.07	33.25	28.92	28.01	33.92	39.92	35.71	32.24	36.01	41.18
Crude Cost	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.66	26.23	29.37	33.84
Gross Margin	5.20	2.75	4.62	6.13	3.33	4.84	6.15	6.05	6.01	6.63	7.34
Variable Costs	0.61	0.67	1.14	1.16	1.01	1.34	1.43	1.51	1.57	1.73	1.92
Fixed Costs	1.36	1.51	1.47	1.42	1.39	1.39	1.48	1.56	1.74	1.93	2.13
Net Refining Margin	3.23	0.56	2.01	3.55	0.94	2.10	3.23	2.98	2.69	2.97	3.29
Interest on Working Capital	0.21	0.14	0.24	0.15	0.10	0.11	0.13	0.15	0.16	0.18	0.21
Return, % of Replacement Cost	15.20	1.96	7.96	15.28	3.73	8.82	12.58	10.86	8.66	8.66	8.67
Heavy Sour Coking Refinery											
Product Sales Realization	27.43	19.77	32.42	28.26	27.42	33.28	39.24	34.98	31.37	35.04	40.07
Crude Cost	17.61	14.97	23.86	17.89	21.54	25.12	28.57	24.54	21.30	23.91	27.75
Gross Margin	9.82	4.80	8.56	10.37	5.89	8.17	10.67	10.44	10.08	11.13	12.31
Variable Costs	1.02	1.06	1.90	1.91	1.65	2.27	2.43	2.49	2.36	2.60	2.89
Fixed Costs	1.86	2.04	1.95	1.89	1.84	1.85	1.96	2.06	2.28	2.52	2.78
Net Refining Margin	6.94	1.71	4.71	6.58	2.39	4.05	6.29	5.89	5.44	6.01	6.64
Interest on Working Capital	0.20	0.13	0.22	0.14	0.10	0.10	0.12	0.14	0.15	0.17	0.19
Return, % of Replacement Cost	24.53	5.35	14.75	21.16	7.53	12.78	18.30	16.25	13.48	13.49	13.48
Light Sour Incremental Capital Recovery Factors (%)											
Hydroskimming/Cracking	33.12	11.37	23.46	23.69	16.81	22.15	32.88	21.23	15.53	15.61	16.06
Cracking/Coking	47.59	13.72	36.49	34.16	13.70	23.84	36.87	31.00	28.00	28.00	28.00
Maya Coking/Coking	48.38	14.49	33.06	37.05	17.82	23.50	33.80	31.31	27.36	27.37	27.33

Note: Margin projections incorporate production of ultra-low sulphur gasoline (30 ppm) in 2005 and ultra-low sulphur diesel (15 ppm) in 2007

TABLE IV-6
U.S. GULF COAST SOUR CRUDE MARGINS
(Forecast in Constant 2004 Dollars per Barrel)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Inflation Index (2004=1)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.02	1.13	1.24	1.37
Light Sour Hydroskimming Refinery											
Product Sales Realization	21.98	17.22	28.07	23.86	24.70	29.51	33.41	29.52	23.86	24.19	25.18
Crude Cost	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.08	23.29	23.62	24.65
Gross Margin	(0.63)	(0.10)	(0.56)	1.07	0.02	0.44	(0.36)	0.44	0.56	0.56	0.53
Variable Costs	0.35	0.38	0.76	0.75	0.64	0.92	0.99	0.93	0.86	0.86	0.87
Fixed Costs	0.51	0.57	0.57	0.55	0.54	0.54	0.57	0.57	0.59	0.59	0.59
Net Refining Margin	(1.49)	(1.05)	(1.89)	(0.23)	(1.16)	(1.03)	(1.93)	(1.06)	(0.88)	(0.89)	(0.92)
Interest on Working Capital	0.18	0.13	0.21	0.13	0.09	0.10	0.12	0.13	0.13	0.13	0.13
Return, % of Replacement Cost	(21.75)	(13.84)	(23.98)	(4.18)	(14.26)	(12.65)	(21.02)	(12.25)	(10.06)	(10.12)	(10.52)
Light Sour Cracking Refinery											
Product Sales Realization	25.12	18.87	30.78	26.58	26.83	32.17	37.21	32.64	26.35	26.69	27.73
Crude Cost	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.08	23.29	23.62	24.65
Gross Margin	2.51	1.54	2.15	3.79	2.16	3.09	3.44	3.56	3.06	3.06	3.08
Variable Costs	0.58	0.60	1.10	1.10	0.95	1.31	1.40	1.43	1.28	1.28	1.29
Fixed Costs	1.03	1.13	1.11	1.08	1.05	1.05	1.12	1.17	1.18	1.18	1.18
Net Refining Margin	0.89	(0.19)	(0.06)	1.62	0.16	0.73	0.92	0.96	0.60	0.60	0.61
Interest on Working Capital	0.20	0.13	0.23	0.14	0.10	0.11	0.12	0.14	0.14	0.14	0.14
Return, % of Replacement Cost	4.66	(2.02)	(1.72)	8.88	0.34	3.70	4.31	4.27	2.36	2.37	2.38
Light Sour Coking Refinery											
Product Sales Realization	27.81	20.07	33.25	28.92	28.01	33.92	39.92	35.01	28.63	28.96	30.00
Crude Cost	22.61	17.32	28.63	22.79	24.68	29.08	33.77	29.08	23.29	23.62	24.65
Gross Margin	5.20	2.75	4.62	6.13	3.33	4.84	6.15	5.93	5.33	5.33	5.35
Variable Costs	0.61	0.67	1.14	1.16	1.01	1.34	1.43	1.48	1.40	1.39	1.40
Fixed Costs	1.36	1.51	1.47	1.42	1.39	1.39	1.48	1.53	1.55	1.55	1.55
Net Refining Margin	3.23	0.56	2.01	3.55	0.94	2.10	3.23	2.93	2.39	2.39	2.40
Interest on Working Capital	0.21	0.14	0.24	0.15	0.10	0.11	0.13	0.15	0.14	0.15	0.15
Return, % of Replacement Cost	15.20	1.96	7.96	15.28	3.73	8.82	12.58	10.86	8.66	8.66	8.67
Heavy Sour Coking Refinery											
Product Sales Realization	27.43	19.77	32.42	28.26	27.42	33.28	39.24	34.29	27.86	28.19	29.19
Crude Cost	17.61	14.97	23.86	17.89	21.54	25.12	28.57	24.06	18.91	19.23	20.22
Gross Margin	9.82	4.80	8.56	10.37	5.89	8.17	10.67	10.24	8.95	8.95	8.97
Variable Costs	1.02	1.06	1.90	1.91	1.65	2.27	2.43	2.44	2.09	2.09	2.10
Fixed Costs	1.86	2.04	1.95	1.89	1.84	1.85	1.96	2.02	2.03	2.03	2.03
Net Refining Margin	6.94	1.71	4.71	6.58	2.39	4.05	6.29	5.77	4.83	4.84	4.84
Interest on Working Capital	0.20	0.13	0.22	0.14	0.10	0.10	0.12	0.14	0.13	0.13	0.14
Return, % of Replacement Cost	24.53	5.35	14.75	21.16	7.53	12.78	18.30	16.25	13.48	13.49	13.48
Light Sour Incremental Capital Recovery Factors (%)											
Hydroskimming/Cracking	33.12	11.37	23.46	23.69	16.81	22.15	32.88	21.23	15.53	15.61	16.06
Cracking/Coking	47.59	13.72	36.49	34.16	13.70	23.84	36.87	31.00	28.00	28.00	28.00
Maya Coking/Coking	48.38	14.49	33.06	37.05	17.82	23.50	33.80	31.31	27.36	27.37	27.33

Note: Margin projections incorporate production of ultra-low sulphur gasoline (30 ppm) in 2005 and ultra-low sulphur diesel (15 ppm) in 2007

TABLE IV-7
U.S. GULF COAST PRODUCT PRICES
(Current Dollars)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Gulf Coast Product Prices,(¢/Gal.)											
Propane	34.75	32.03	57.93	46.90	41.03	56.89	65.36	59.94	53.73	59.88	67.24
Isobutane	49.60	40.58	68.11	56.87	54.17	68.82	75.97	70.98	64.43	71.96	81.67
Normal Butane	42.35	37.01	64.69	51.48	47.85	65.20	74.35	67.61	60.35	67.43	76.58
Natural Gasoline	53.61	41.10	73.11	59.16	58.05	72.74	85.39	77.51	65.43	73.30	83.73
Premium Unleaded Gasoline (Current Quality)	76.69	55.66	87.02	78.20	77.16	92.57	109.73	96.61	86.03	96.01	109.87
Mid-grade Unleaded Gasoline (Current Quality)	73.22	52.39	85.60	76.38	74.21	89.30	106.20	92.93	82.04	91.62	104.80
Regular Unleaded Gasoline (Current Quality)	70.57	50.95	83.53	73.66	72.22	87.12	104.35	91.09	80.05	89.42	102.27
Jet/Kerosene	72.76	49.45	84.76	72.09	68.69	82.32	97.44	88.29	79.62	88.96	101.79
Diesel/No. 2 Fuel Oil	65.41	47.20	80.84	68.85	65.80	80.43	92.46	83.95	76.11	85.07	97.47
0.05% S Diesel		48.64	82.58	70.66	67.66	81.89	94.92	86.35	79.12	88.41	101.18
1% Sulphur Residual Fuel Oil ($/Bbl.)	18.60	14.70	26.34	21.82	22.50	28.26	28.84	26.48	23.69	26.57	30.73
3% Sulphur Residual Fuel Oil ($/Bbl.)	14.61	13.77	20.78	17.12	20.77	24.00	25.08	22.72	19.65	22.10	25.74
Reformulated Gasoline (¢/Gal.)											
Phase I 1996-1999, Phase II 2000-2015											
Premium Unleaded Gasoline (Current Quality)	---------	59.13	92.34	83.56	80.09	94.31	110.77	98.14	88.41	99.64	113.96
Mid-grade Unleaded Gasoline (Current Quality)	---------	55.94	90.60	81.76	77.23	91.36	107.33	94.57	84.42	95.24	108.90
Regular Unleaded Gasoline (Current Quality)	---------	54.53	88.75	79.08	75.32	89.39	105.60	92.78	82.42	93.04	106.36
Low Sulphur (30 ppm) Conventional Gasoline (¢/Gal.)											
Premium Unleaded Gasoline	---------	---------	---------	---------	---------	---------	---------	97.79	87.22	97.33	111.32
Mid-grade Unleaded Gasoline	---------	---------	---------	---------	---------	---------	---------	94.11	83.23	92.93	106.26
Regular Unleaded Gasoline	---------	---------	---------	---------	---------	---------	---------	92.27	81.23	90.73	103.73
Low Sulphur (30 ppm) Reformulated Gasoline (¢/Gal.)											
Premium Unleaded Gasoline	---------	---------	---------	---------	---------	---------	---------	99.31	89.60	100.95	115.42
Mid-grade Unleaded Gasoline	---------	---------	---------	---------	---------	---------	---------	95.74	85.60	96.56	110.35
Regular Unleaded Gasoline	---------	---------	---------	---------	---------	---------	---------	93.96	83.61	94.36	107.82
Ultra - Low Sulphur (15 ppm) Diesel		---------	---------	---------	---------	---------	---------	---------	81.12	90.60	103.61

TABLE IV-8
U.S. GULF COAST PRODUCT PRICES
(Forecast in Constant 2004 Dollars)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Inflation Index (2004=1)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.02	1.13	1.24	1.37
Gulf Coast Product Prices,(¢/Gal.)											
Propane	34.75	32.03	57.93	46.90	41.03	56.89	65.36	58.77	47.71	48.16	48.98
Isobutane	49.60	40.58	68.11	56.87	54.17	68.82	75.97	69.59	57.21	57.88	59.50
Normal Butane	42.35	37.01	64.69	51.48	47.85	65.20	74.35	66.28	53.59	54.23	55.79
Natural Gasoline	53.61	41.10	73.11	59.16	58.05	72.74	85.39	75.99	58.10	58.95	60.99
Premium Unleaded Gasoline (Current Quality)	76.69	55.66	87.02	78.20	77.16	92.57	109.73	94.72	76.40	77.22	80.03
Mid-grade Unleaded Gasoline (Current Quality)	73.22	52.39	85.60	76.38	74.21	89.30	106.20	91.11	72.85	73.68	76.34
Regular Unleaded Gasoline (Current Quality)	70.57	50.95	83.53	73.66	72.22	87.12	104.35	89.31	71.08	71.92	74.50
Jet/Kerosene	72.76	49.45	84.76	72.09	68.69	82.32	97.44	86.56	70.70	71.54	74.15
Diesel/No. 2 Fuel Oil	65.41	47.20	80.84	68.85	65.80	80.43	92.46	82.31	67.58	68.42	71.00
0.05% S Diesel	------	48.64	82.58	70.66	67.66	81.89	94.92	84.65	70.26	71.10	73.70
1% Sulphur Residual Fuel Oil ($/Bbl.)	18.60	14.70	26.34	21.82	22.50	28.26	28.84	25.96	21.04	21.37	22.38
3% Sulphur Residual Fuel Oil ($/Bbl.)	14.61	13.77	20.78	17.12	20.77	24.00	25.08	22.27	17.45	17.77	18.75
Reformulated Gasoline (¢/Gal.)											
Phase I 1996-1999, Phase II 2000-2015											
Premium Unleaded Gasoline (Current Quality)	------	59.13	92.34	83.56	80.09	94.31	110.77	96.21	78.50	80.14	83.01
Mid-grade Unleaded Gasoline (Current Quality)	------	55.94	90.60	81.76	77.23	91.36	107.33	92.71	74.96	76.60	79.32
Regular Unleaded Gasoline (Current Quality)	------	54.53	88.75	79.08	75.32	89.39	105.60	90.96	73.19	74.83	77.48
Low Sulphur (30 ppm) Conventional Gasoline (¢/Gal.)											
Premium Unleaded Gasoline	------	------	------	------	------	------	------	95.87	77.45	78.28	81.09
Mid-grade Unleaded Gasoline	------	------	------	------	------	------	------	92.26	73.90	74.74	77.41
Regular Unleaded Gasoline	------	------	------	------	------	------	------	90.46	72.13	72.97	75.56
Low Sulphur (30 ppm) Reformulated Gasoline (¢/Gal.)											
Premium Unleaded Gasoline	------	------	------	------	------	------	------	97.37	79.56	81.19	84.08
Mid-grade Unleaded Gasoline	------	------	------	------	------	------	------	93.87	76.01	77.66	80.39
Regular Unleaded Gasoline	------	------	------	------	------	------	------	92.12	74.24	75.89	78.54
Ultra-Low Sulphur (15 ppm) Diesel		------	------	------	------	------	------	------	72.03	72.87	75.47

TABLE IV-9
CANADA NETBACK CRUDE AND NATURAL GAS PRICES
(Current U.S. Dollars per Barrel, Unless Noted)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Inflation, %	3.90	2.18	1.93	1.95	1.25	1.50	2.10	2.40	1.10	1.79	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Inflation Factor (2001 = 1.0)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24
Exchange Rate	0.86	0.73	0.73	0.72	0.67	0.67	0.67	0.65	0.64	0.72	0.75	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
Western Canada																						
Par, Edmonton [1]	23.70	17.65	21.56	20.13	13.76	18.68	29.96	25.50	25.73	31.13	40.22	29.64	28.73	27.59	27.62	28.18	28.81	29.40	30.05	30.74	31.47	32.25
MSW, Edmonton	23.50	17.46	21.41	19.96	13.60	18.46	29.79	25.25	25.48	30.68	39.66	29.12	28.23	27.10	27.12	27.67	28.28	28.87	29.50	30.18	30.90	31.67
Pentanes Plus, Edmonton	23.75	17.60	21.72	22.10	14.77	18.66	31.14	27.48	26.00	31.44	40.68	30.72	34.32	30.89	31.19	32.10	32.53	33.78	34.52	35.31	36.15	37.06
Synthetic Crude, Edmonton	23.16	17.63	21.62	20.40	14.06	19.06	30.29	26.04	26.03	31.22	34.44	29.18	28.38	27.03	27.04	27.59	28.19	28.78	29.41	30.09	30.81	31.58
Bow River, Hardisty	18.37	15.12	18.40	15.27	9.85	15.85	23.21	17.77	20.20	23.06	29.49	21.70	19.87	18.89	18.84	19.71	20.86	21.59	22.16	22.69	22.77	23.18
Hardisty Light, Hardisty	20.28	15.73	19.67	17.73	11.25	17.05	26.86	20.47	22.48	26.95	34.98	25.57	24.43	23.40	23.39	23.88	24.43	24.94	25.49	26.08	26.72	27.40
Lloydminster Blend, Hardisty	17.61	14.26	17.00	14.04	8.85	14.91	21.85	15.22	19.53	22.15	28.37	20.48	18.88	17.92	17.86	18.91	20.33	21.18	21.76	22.29	22.15	22.46
SynBit Basis[2]																						
- Athabasca Blend, Edmonton											28.14	20.67	18.82	17.84	17.76	18.62	19.75	20.46	21.01	21.52	21.59	21.98
- Athabasca Bitumen, Edmonton											21.74	12.82	10.00	9.35	9.20	10.34	11.95	12.78	13.25	13.61	13.07	13.11
- Athabasca Bitumen, Fort McMurray											20.61	11.73	8.91	8.26	8.09	9.22	10.82	11.64	12.09	12.44	11.88	11.91
Natural Gas (AECO), $US/MMBtu	1.12	0.84	1.02	1.33	1.37	1.97	3.42	4.01	2.58	4.76	4.88	4.44	4.40	4.37	4.36	4.43	4.51	4.59	4.69	4.91	5.08	5.20
US																						
WTI, Cushing	24.46	18.42	22.16	20.61	14.39	19.31	30.37	25.93	26.16	31.08	40.81	36.95	29.37	28.26	28.25	28.78	29.36	30.00	30.69	31.41	32.19	33.02
Brent, USGC	25.17	18.36	22.03	20.58	13.99	19.09	30.58	26.30	26.39	31.11	36.08	32.17	29.00	27.85	27.81	28.29	28.84	29.43	30.07	30.76	31.48	32.26
Isthmus, USGC	22.61	17.32	21.15	18.88	12.57	17.67	28.63	22.79	24.68	29.08	33.77	29.66	26.40	25.33	25.28	25.72	26.23	26.77	27.36	27.98	28.66	29.37
Maya, USGC	17.61	14.97	17.91	15.54	9.17	14.91	23.86	17.89	21.54	25.12	28.57	24.54	21.56	20.63	20.52	20.87	21.30	21.74	22.22	22.74	23.31	23.91
Natural Gas Henry Hub, $US/MMBtu	1.70	1.80	2.76	2.57	2.08	2.25	4.23	4.06	3.34	5.62	5.88	5.48	5.11	5.09	5.09	5.18	5.27	5.37	5.48	5.60	5.72	5.86

Notes: (1) Forecast for par crude (40 API) assumes market price based on (WTI - MSW) cracking value.
(2) Based on Synthetic Crude used as a diluent. Includes a $0.70 (US) per barrel TAN penalty.

TABLE IV-10
CANADA NETBACK CRUDE AND NATURAL GAS PRICES
(Constant 2004 U.S. Dollars per Barrel, Unless Noted)

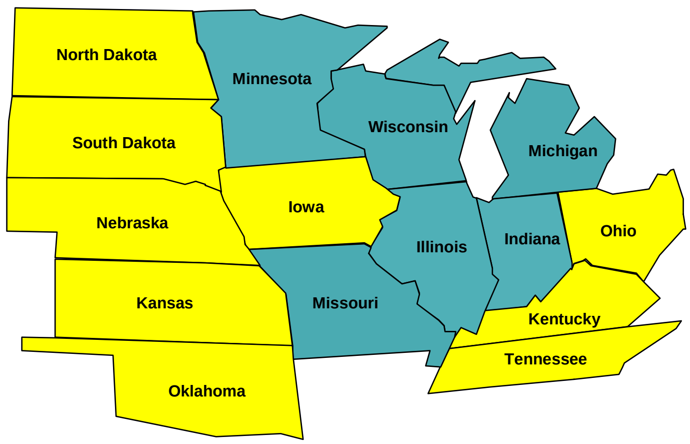
	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Inflation, %	3.90	2.00	1.90	1.70	1.10	1.40	2.20	2.40	1.70	1.80	2.98	2.50	2.20	2.10	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Inflation Factor (2001 = 1.0)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24
Exchange Rate	0.86	0.73	0.73	0.72	0.67	0.67	0.67	0.65	0.64	0.72	0.75	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
Western Canada																						
Par, Edmonton [1]	23.70	17.65	21.56	20.13	13.76	18.68	29.96	25.50	25.73	31.13	40.22	29.05	27.62	26.00	25.52	25.53	25.58	25.60	25.65	25.72	25.82	25.94
MSW, Edmonton	23.50	17.46	21.41	19.96	13.60	18.46	29.79	25.25	25.48	30.68	39.66	28.55	27.13	25.53	25.05	25.06	25.12	25.13	25.18	25.25	25.35	25.47
Pentanes Plus, Edmonton	23.75	17.60	21.72	22.10	14.77	18.66	31.14	27.48	26.00	31.44	40.68	30.12	32.99	29.11	28.81	29.07	28.88	29.41	29.46	29.55	29.66	29.80
Synthetic Crude, Edmonton	23.16	17.63	21.62	20.40	14.06	19.06	30.29	26.04	26.03	31.22	34.44	28.61	27.28	25.47	24.98	24.99	25.04	25.06	25.11	25.18	25.28	25.40
Bow River, Hardisty	18.37	15.12	18.40	15.27	9.85	15.85	23.21	17.77	20.20	23.06	29.49	21.28	19.10	17.80	17.40	17.85	18.52	18.80	18.91	18.98	18.68	18.64
Hardisty Light, Hardisty	20.28	15.73	19.67	17.73	11.25	17.05	26.86	20.47	22.48	26.95	34.98	25.07	23.49	22.05	21.61	21.63	21.69	21.71	21.76	21.83	21.92	22.04
Lloydminster Blend, Hardisty	17.61	14.26	17.00	14.04	8.85	14.91	21.85	15.22	19.53	22.15	28.37	20.08	18.15	16.89	16.50	17.13	18.05	18.44	18.57	18.65	18.17	18.06
SynBit Basis [2]																						
- Athabasca Blend, Edmonton											28.14	20.27	18.09	16.81	16.41	16.86	17.53	17.81	17.93	18.01	17.71	17.68
- Athabasca Bitumen, Edmonton											21.74	12.56	9.61	8.81	8.50	9.37	10.61	11.13	11.31	11.39	10.72	10.55
- Athabasca Bitumen, Fort McMurray											20.61	11.50	8.57	7.78	7.48	8.35	9.61	10.13	10.32	10.41	9.75	9.58
Natural Gas (AECO), $US/MMBtu	1.12	0.84	1.02	1.33	1.37	1.97	3.42	4.01	2.58	4.76	4.88	4.35	4.23	4.11	4.03	4.01	4.00	4.00	4.00	4.11	4.17	4.18
US																						
WTI, Cushing	24.46	18.42	22.16	20.61	14.39	19.31	30.37	25.93	26.16	31.08	40.81	36.22	28.23	26.63	26.10	26.06	26.07	26.12	26.19	26.29	26.41	26.55
Brent, USGC	25.17	18.36	22.03	20.58	13.99	19.09	30.58	26.30	26.39	31.11	36.08	31.54	27.87	26.25	25.69	25.63	25.61	25.62	25.67	25.74	25.83	25.95
Isthmus, USGC	22.61	17.32	21.15	18.88	12.57	17.67	28.63	22.79	24.68	29.08	33.77	29.08	25.37	23.87	23.35	23.30	23.29	23.31	23.35	23.42	23.51	23.62
Maya, USGC	17.61	14.97	17.91	15.54	9.17	14.91	23.86	17.89	21.54	25.12	28.57	24.06	20.72	19.44	18.95	18.91	18.91	18.93	18.97	19.03	19.12	19.23
Natural Gas Henry Hub, $US/MMBtu	1.70	1.80	2.76	2.57	2.08	2.25	4.23	4.06	3.34	5.62	5.88	5.37	4.91	4.80	4.71	4.69	4.68	4.68	4.68	4.69	4.70	4.71

Notes: (1) Forecast for par crude (40 API) assumes market price based on (WTI - MSW) cracking value.
(2) Based on Synthetic Crude used as a diluent. Includes a $0.70 (US) per barrel TAN penalty.

V. MIDWEST MARKETS

PADD II in the United States consists of the fifteen states located in the upper midsection of the country:

FIGURE V-1
PADD II STATES



In the following section, a "Midwest" region is analyzed. This region is defined as the states of Illinois, Indiana, Michigan, Wisconsin, Missouri, and Minnesota for purposes of this study. It is the "heart" of the market that could reasonably be served if Canadian product imports came into this region.

PADD II MARKET CHARACTERISTICS

- PADD II is a large petroleum market – 4 million B/D in 2003, or 28 percent of the U.S. total – with demand concentrated in the states surrounding the Great Lakes.
- The region is highly dependent on PADD III refineries (U.S.GC) for one-third of its product supply. The pipeline supply system is geared to move products from south to the north, with production from local PADD II regional pipelines radiating outward from centers in Tulsa, St Louis and Chicago and other major cities.

- Imported petroleum product volumes, all from Canada, are negligible.
- Total light product demand is expected to grow on average by 1.1 percent per year for the period 2004-2020. Gasoline demand growth rate is expected to decline toward the end of the forecast period. Gasoline demand is currently 64 percent of total light product demand, and would drop to 60 percent by 2020 based on our forecast. Currently the gasoline-to-diesel ratio is 2.25 in PADD II, but is forecast to be 1.9 in 2020. In the upper Midwest, where demand for all products is concentrated, the ratios are 2.5 currently, trending to 2.25 in 2020.
- A significant supply logistics issue in PADD II is the multiplicity of gasoline specifications. There are four programs in twelve states restricting gasoline RVP during certain seasons of the year, requirements for Northern and Southern RFG in five metropolitan areas, and a state that requires oxygenated gasoline year-round. Jet fuel and diesel products are manufactured to normal commercial specifications, with no special programs for PADD II.
- The extensive use of ethanol in gasoline is a striking PADD II attribute. Most of the U.S. ethanol production is also in PADD II, using locally grown corn as feedstock. Ethanol is used to provide the oxygen content required in RFG, to satisfy conventional oxygenated gasoline requirements, and simply to provide octane and volume in conventional gasoline.
- RFG is required in metro areas of Chicago, Milwaukee, St Louis, Cincinnati and Louisville. RFG currently makes up 14 percent of total gasoline demand.
- Premium gasoline currently makes up 9 percent of total gasoline.

PADD II LIGHT PRODUCT DEMAND

GENERAL

PADD II gasoline, jet fuel and diesel product demand was 4.0 million B/D in 2003, or 28 percent of the U.S. total. Of this, 2.8 million B/D was manufactured within the region, and 1.2 million B/D came from the PADD III region via the pipelines described. Figure V-2 provides a summary description of light product demand. Table V-1 provides detailed demand forecasts by state.

FIGURE V-2
PADD II LIGHT PRODUCT DEMAND
(Thousand Barrels Per Day)

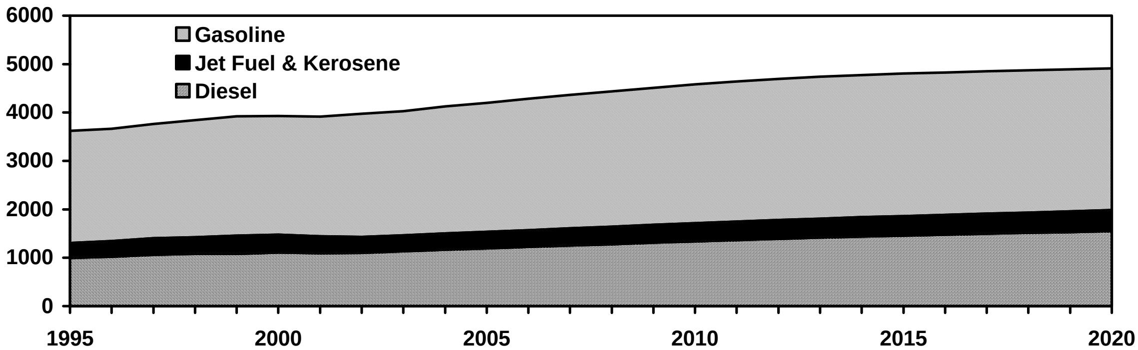
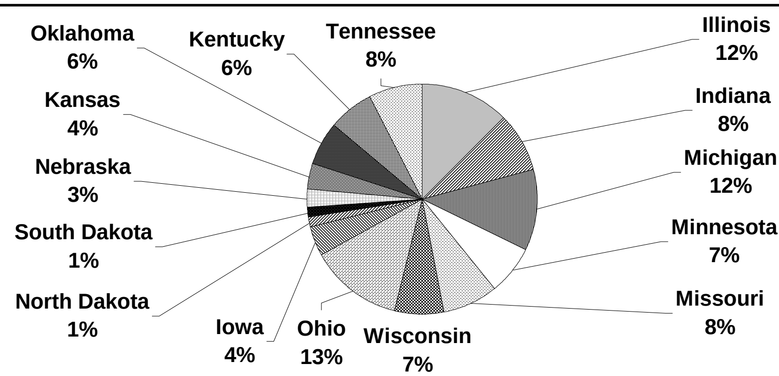


Figure V-3, a snapshot of 2003 demand, shows the light product demand distribution to the states in PADD II. The largest concentration of demand is in the upper Midwest in the seven states surrounding Illinois.

FIGURE V- 3
PADD II LIGHT PRODUCT DEMAND DISTRIBUTION IN 2003
(Percent)



DEMAND GROWTH

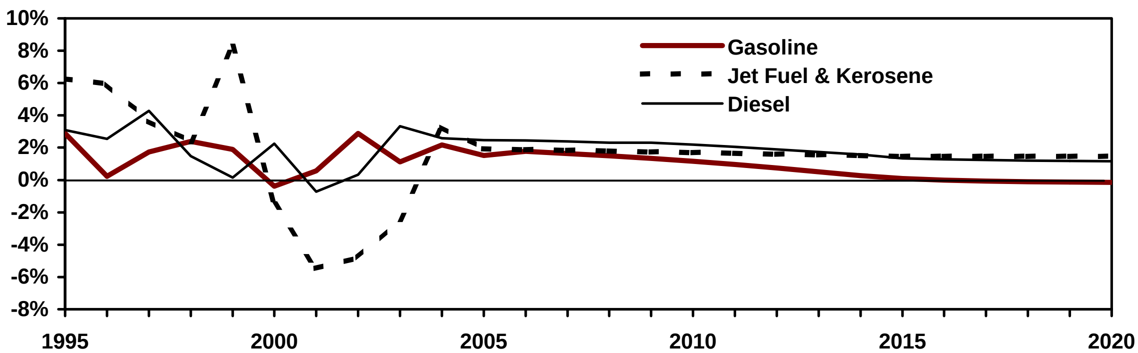
Total light product demand grew by 400,000 B/D from 1995 through 2003, approximately 1.4 percent per annum. It is expected to grow at approximately 1.1 percent annually from 2004 to 2020, although growth rates are expected to be lower later in the forecast.

PADD II LIGHT PRODUCT DEMAND GROWTH RATES

	2004	2010	2020
Gasoline	2.2%	1.2%	0.0%
Jet/Kerosene	3.3%	1.7%	1.5%
Diesel	2.6%	2.2%	1.7%

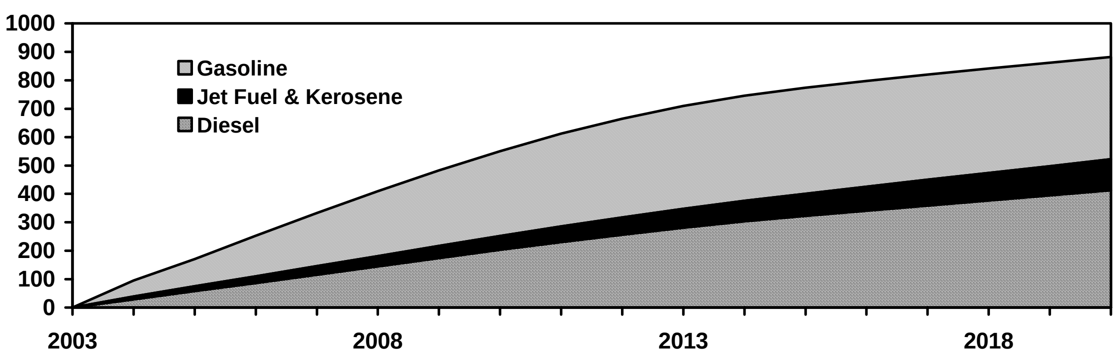
As the figure below indicates, demand growth is forecast to be higher for jet and diesel fuels than for gasoline, at least equaling population growth rates.

FIGURE V-4
PADD II LIGHT PRODUCT ANNUAL DEMAND GROWTH
(% Per Year)



The significant growth, in percentage terms, is expected to occur in jet fuel and diesel products. Gasoline growth, following national trends, will have a diminishing growth rate as more efficient vehicles increase in the fleet population, as illustrated in Figure V-5.

FIGURE V-5
PADD II LIGHT PRODUCT DEMAND VOLUME GROWTH FROM 2003
(Thousand Barrels Per Day)



PRODUCT MIX

The average product mix in PADD II over the forecast period is expected to be 62 percent gasoline, 8 percent kerosene and jet fuel, and 30 percent diesel fuel. Gasoline demand, currently 64 percent of the total, will decline to 60 percent by the end of the period. Gasoline demand, by states, is shown in Table V-2.

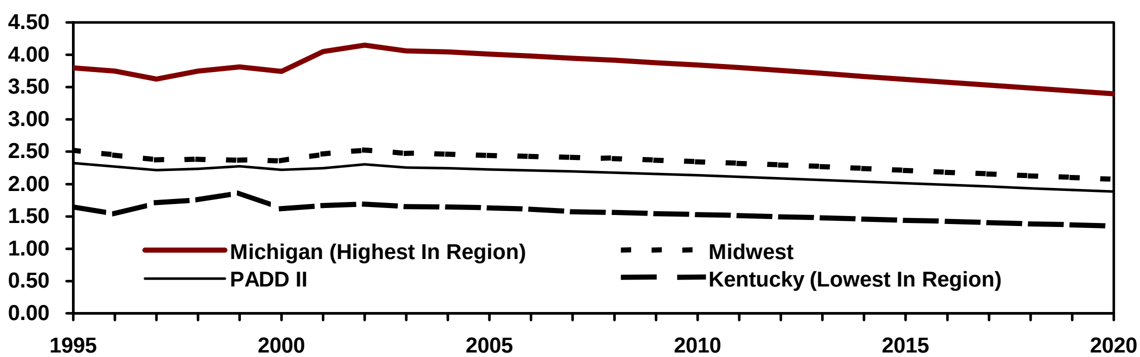
LIGHT PRODUCT DEMAND MIX
Percent

	2004	2010	2020
Gasoline	63.6	62.6	59.6
Jet/Kerosene	8.1	8.2	8.8
Diesel	28.3	29.3	31.6

GASOLINE-DIESEL RATIO

The ratio of gasoline to diesel fuel demand is of importance in the conceptual design of an upgrader refinery in Alberta. In 2003, there was a wide variation over the various states in PADD II, from a high of 4.0 in Michigan, to a low of 1.5 in Kentucky, with the overall PADD II average being 2.5. Because of the higher rate of demand growth for diesel compared to gasoline, the ratio declines over time (Figure V-6); also see Table V-3.

FIGURE V-6
PADD II GASOLINE / DISTILLATE RATIO



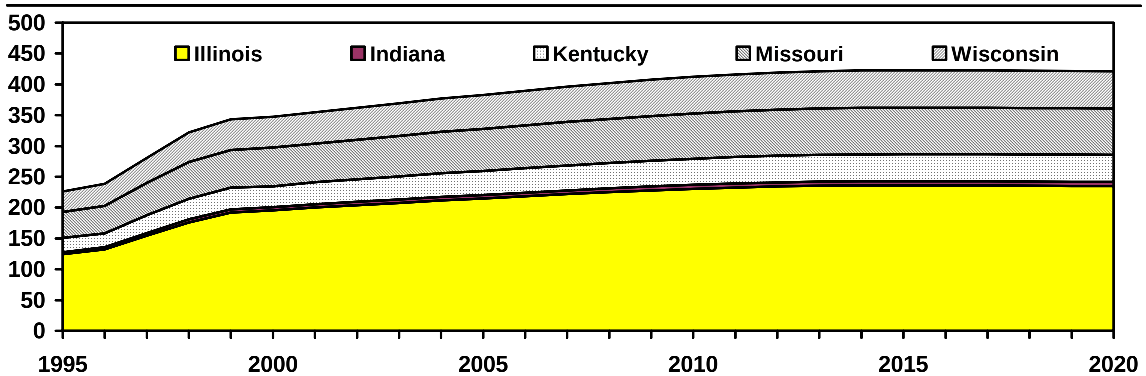
REFORMULATED GASOLINE DEMAND (RFG)

RFG is required by federal EPA regulations in the Chicago and Milwaukee metropolitan areas. In addition, Kentucky has established regulations requiring RFG on the Kentucky side of the Ohio River in the Louisville and Cincinnati areas, under the EPA's opt-in regulations. This was done to arrest declining air quality in those areas. Kentucky officials chose to implement federal EPA RFG requirements rather than a state program on account of ease of administration. Instead of having to establish administrative and operational procedures for a unique Kentucky program, they simply used the EPA RFG procedures. On the Indiana side of the Ohio in the Louisville area, a low-RVP gasoline program was adopted. There is no Ohio special gasoline quality program at Cincinnati even though the bulk of the Cincinnati metro area population is on the Ohio side of the River. On the Kentucky side, RFG is required for several counties.

Missouri state officials on the Missouri side of the Mississippi River at St Louis also opted-in to the federal EPA RFG program. Low RVP gasoline is required on the Illinois side.

In 2003, PADD II RFG demand was 377,000 B/D, or 14 percent of the total PADD II gasoline, Table V-4. As shown in Figure V-7, Illinois-Indiana (Chicago metro) RFG demand dominates the PADD II overall requirement:

FIGURE V-7
PADD II RFG Demand
(Thousand Barrels Per Day)



Essentially all RFG in PADD II uses ethanol as the oxygenate, except for some relatively small volumes of RFG supplied to St Louis. Because of the high solubility of ethanol in water, which is present to some degree in all product pipelines, blends of finished ethanol RFG cannot be shipped by pipeline. The hydrocarbon component of the RFG, referred to as "RBOB" (Reformulated Before Oxygenate Blending), is shipped instead, and is blended with ethanol directly into the transport trucks that deliver gasoline from wholesale terminals to retail outlets. All ethanol RFG in PADD II contains about 10 percent ethanol by volume.

OXYGENATED GASOLINE DEMAND

Oxygenated gasoline (10 percent ethanol) is required in Minnesota on a year-round basis. In addition, the state of Iowa has a gasoline tax program that provides very strong incentives to sell similar oxygenated gasoline product in that state. In addition to those states most of the upper PADD II states consume substantial volumes of ethanol-oxygenated gasoline, driven by the U.S. federal excise tax incentive and proximity of local ethanol supply. In 2002, the consumption of oxygenated gasoline, including RFG, in PADD II is estimated to have been 915,000 B/D, or 36 percent of total gasoline consumption, see Table V-5.

The proposed renewable fuels provisions of the proposed National Energy Policy require that 5.0 billion gallons per year of renewable fuels be produced and sold. If this ultimately becomes law, a likely scenario would be for ethanol use in the PADD II region to increase to a practical maximum, or the order of 8 percent of gasoline. Based on estimated 2010 gasoline consumption, this would increase ethanol use from 92,000 B/D to 229,000 B/D, or an increase of 137,000 B/D. Demand for the hydrocarbon portion of such gasoline would be reduced by the same amount.

DISTILLATE DEMAND

The forecast demand for diesel fuel in PADD II is shown in Table V-6. The annual average growth rate between 2004 and 2020 is 1.8 percent. Currently, diesel growth rates are strong, averaging between 2 and 3 percent since 2001.

Close to 80 percent of diesel fuel in PADD II is low sulphur fuel. We forecast that level to increase to 90 percent by 2008, and it is possible that it could increase further if off-road diesel is required to meet the future ultra-low specification of 15 ppm sulphur content.

Demand for jet fuel/kerosene is shown in Table V-7. Nearly all of this demand is for jet fuel. Demand growth is forecast to average 1.8 percent annually until 2010, and at 1.5 percent annually between 2010 and 2020.

PADD II FUELS SPECIFICATIONS

GASOLINE

The PADD II gasoline market is characterized by its multiplicity of specifications. As Figure 8 indicates, there is a challenging array of regional and local specifications which must be complied with.

FIGURE V-8
PADD II GASOLINE SPECIFICATIONS

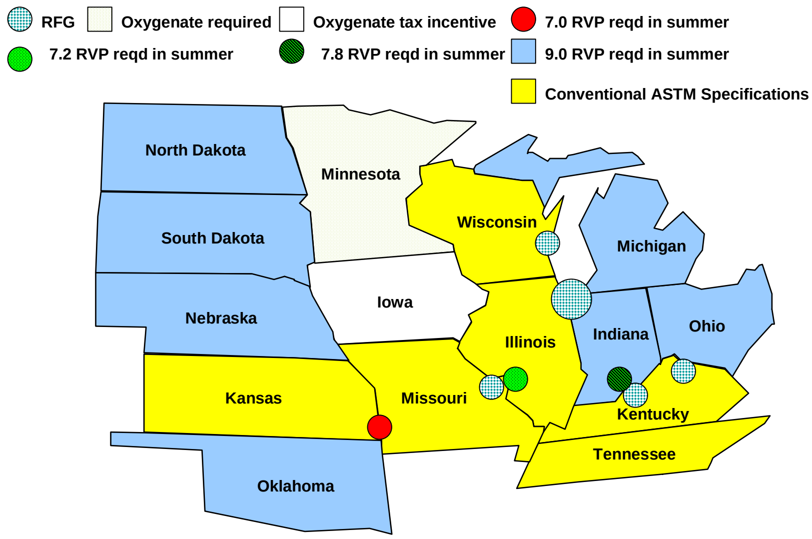


Table V-8 provides more detail on the regional gasoline specification requirements. These are certainly challenging from a supply perspective, but less so now than it was in the past. Until the recent expansions of the TEPPCO and Explorer pipelines, and the startup of the Centennial pipeline, all of which transport products from PADD III to PADD II, supply and product inventory management was complicated by occasions when the product lines were running at capacity, giving no leeway to react to local shortages, supply problems or imbalances. The problems in 2000 and 2001 were severe. The major disruption occurred when there was an outage in the Explorer pipeline operation at a time when seasonal gasoline specifications were changing. At such times inventories are reduced to minimum levels to avoid "trapping" product that does not conform to the then-current seasonal specifications. When the pipeline went down, there was neither inventory nor fresh supply and there were severe price spikes. This has not occurred since the 2002-2003 expansions of the pipelines.

From the perspective of a new Canadian product supply source, in selection of a physical supply point it should be borne in mind that the current supply infrastructure accommodates the multiplicity of product specifications, and so the supply point should be chosen so as to be as harmonious as possible with existing systems.

As with the rest of the U.S., a specification conversion is underway for gasoline, that will by 2006 require that sulphur content in gasoline not exceed 30 ppm. An Alberta upgrader would have to be designed to produce this low sulphur gasoline product, but the transition will be complete and adjustments made as required to the manufacturing, transportation and logistics facilities operations long before the Alberta plant could be constructed and come on stream.

DISTILLATE PRODUCT SPECIFICATIONS

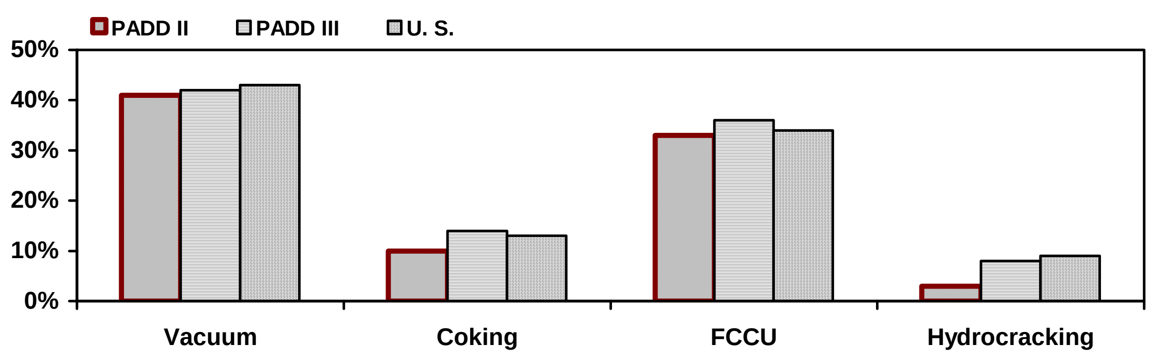
There are no regulatory-driven product specifications for distillate fuels in PADD II except for the EPA low sulphur regulations for on-road diesel fuel. A program is underway to reduce sulphur level in on-road diesel fuel to 15 ppm by 2006. Rulemaking is not complete for off-road diesel fuel, but the proposed rulemaking is for a reduction to 15 ppm to be in place by 2010. The Alberta upgrader would likely have to be able to produce 100 percent 15 ppm diesel fuel for the PADD II market, since it is assumed to come on-stream around 2011. There are no specification changes currently envisioned for jet fuel.

PADD II LIGHT PRODUCT SUPPLY

PADD II REFINERIES

There are 26 operating refineries in PADD II, ranging in crude processing size from 6,000 B/D to 410,000 B/D in size, with a total capability of 3.5 million B/D. The average refinery size is 135,000 B/D. The size, ownership and configuration of these refineries are provided in Table V-9. The configuration of PADD II refineries is compared to the U.S. as a whole in summary fashion in the following Figure V-9.

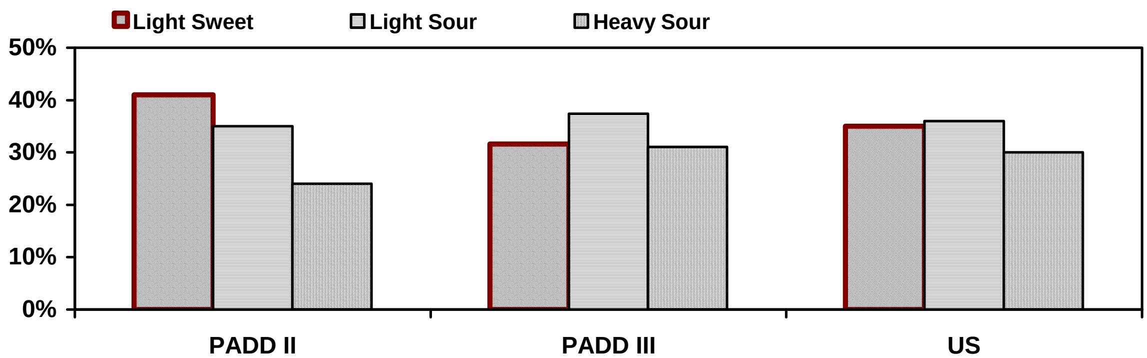
FIGURE V-9
REFINERY CONFIGURATION - SIZE OF CONVERSION UNITS
(Percent of Crude Capacity)



The smaller vacuum distillation and conversion unit sizes relative to crude capacity indicates processing of a somewhat lighter crude oil than the U.S. as a whole, with a lower level of bottoms (vacuum residual) conversion. Many PADD II refineries have significant asphalt businesses, because regional asphalt demand and pricing provide an acceptable alternate to residual conversion.

PADD II refineries process a lighter, sweeter crude mix than does PADD III and the U.S. as a whole, Figure V-10.

FIGURE V-10
REFINERY CRUDE SLATES
(Percent of Crude Runs)



As lighter crude availability and economics of processing decline, it is expected that PADD II refineries will adapt to more closely resemble PADD III facilities.

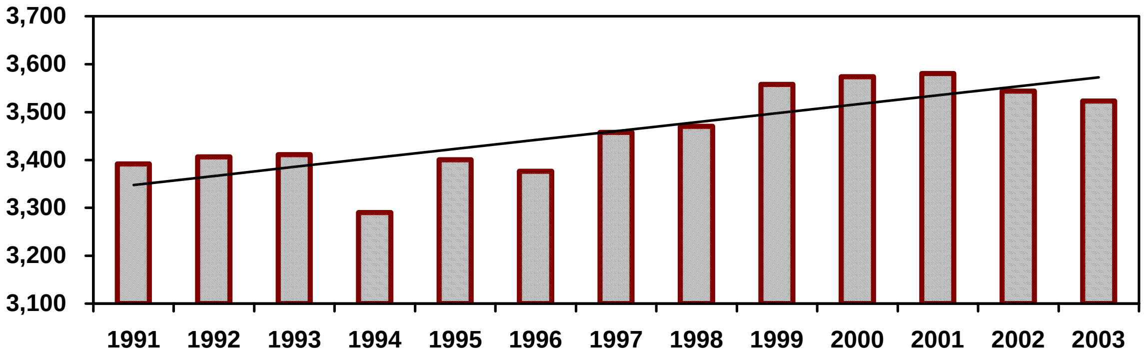
REFINERY YIELDS

Table V-10 provides estimates of the current light product supply capabilities of PADD II refineries. Table V-11 provides a light products supply-balance for 2003. These estimates were based on individual refinery configuration and estimated crude slates. As shown in Table V-11, in 2003 PADD II light products demand exceeded supply of refinery products and blendstocks by almost 1.0 million B/D.

REFINERY CAPACITY CREEP

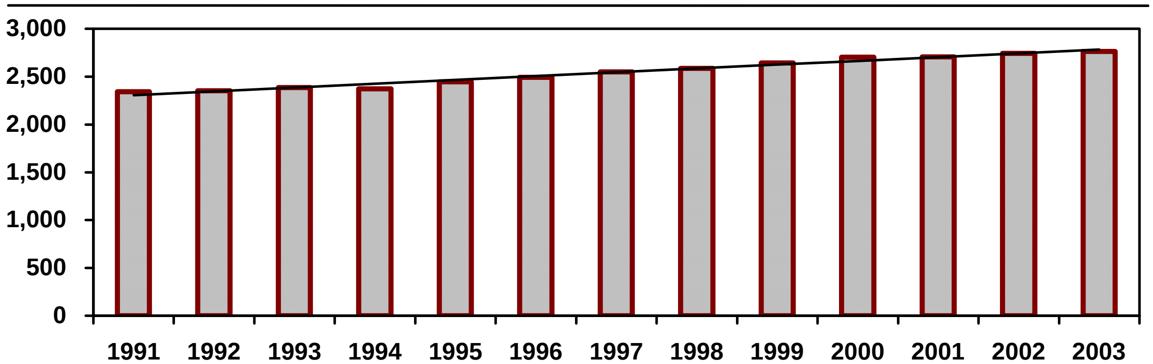
As is typical of refineries in general, PADD II refineries expand incrementally as operations are optimized and plants are shaken down after ongoing capital projects. As Figure V-11 shows, capacity creep from 1991 to 2003 in PADD II overall has been modest, amounting to 0.5 percent of capacity per year.

FIGURE V-11
PADD II REFINERY CAPACITY CREEP
(Thousand Barrels Per Day)



However, in the Midwest where demand is concentrated and the market in which the Alberta upgrader would compete, creep capacity addition has been somewhat higher, at 0.7 percent per year. This creep rate is made up of two components; a number of refineries expanding at the typical creep rates of 1 percent or more, and a smaller number of plants which have been shut down. A more telling analysis is the creep capacity addition of the refineries in operation in 2003, Figure V-12. Over the same 1991-2003 period, these plants were expanded 1.6 percent per year, about the same as the increase in demand, indicating that the refineries now in operation in the Midwest have on average maintained their share of the market demand.

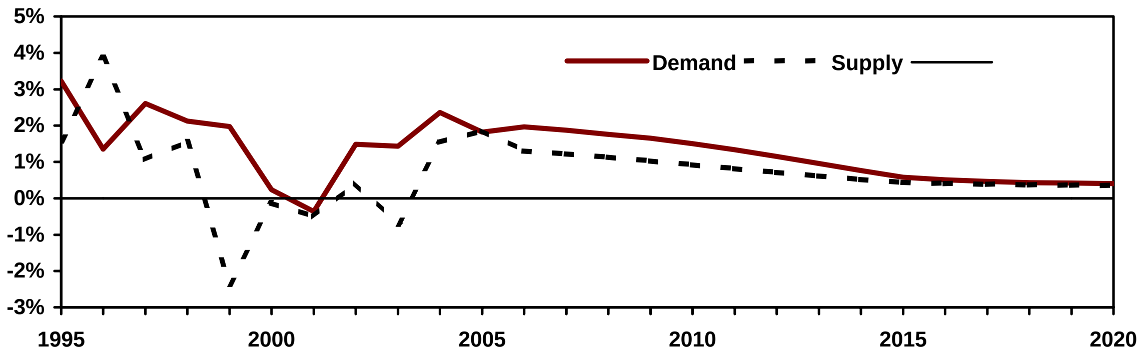
FIGURE V-12
MIDWEST 2003 OPERATING REFINERY CAPACITY CREEP
(Thousand Barrels Per Day)



SUPPLY-DEMAND GROWTH COMPARISON

A more direct comparison of local supply capability to demand over the longer term is provided in Figure V-13. Demand growth is expected to exceed regional supply growth over much of the forecast period.

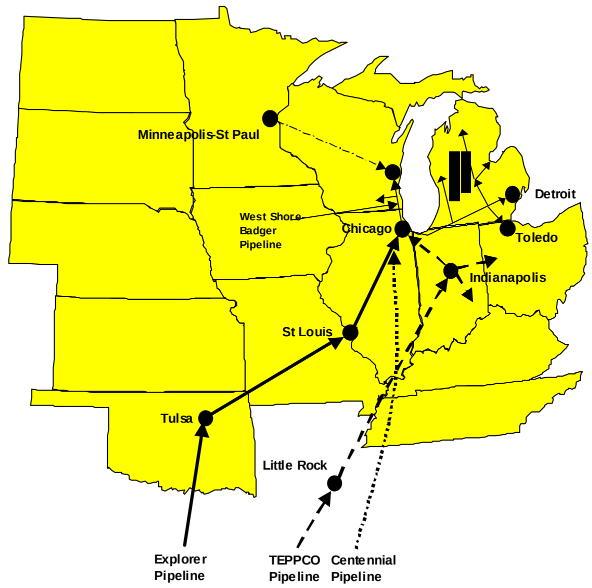
FIGURE V-13
PADD II LIGHT PRODUCT DEMAND & REFINERY SUPPLY GROWTH
(% Per Year)



PADD II SUPPLY PIPELINES

Foreign imports to PADD II, whether from Canada or from offshore via PADD III, are negligible in volume. Transfers from PADD III to PADD II are very substantial, however. In total, pipelines from PADD III to PADD II delivered almost 1.2 million B/D of light products in 2003, 29 percent of total product demand (and expected to rise to 33 percent of demand by 2020).

FIGURE V-14
MAJOR PIPELINES FROM PADD III TO PADD II



As shown in Figure V-14, there are three major pipelines moving light products from PADD III to PADD II, the Explorer, TEPPCO, and the Centennial systems. All three of these systems deliver product to Illinois, and with Ohio deliveries available on the TEPPCO line also. Regional pipelines radiate out from the major cities served, St Louis, Chicago, and Indianapolis.

MAJOR PADD III TO PADD II PIPELINES

System	Capacity, MB/D
Explorer	700
TEPPCO	450
Centennial	210 (Expandable to 320 MB/D)

Explorer Pipeline Company is a closely-held corporation owned by Shell, MAP, ChevronTexaco, Sun, CITGO, and ConocoPhillips. Centennial Pipeline LLC is a joint venture between Marathon Ashland Petroleum LLC and TE Products Pipeline Company, Limited Partnership (TEPPCO). TEPPCO is the operator. Operations personnel at TEPPCO describe the Centennial system as effectively an augmentation of the original TEPPCO system, in that essentially the same origination and delivery points are available on either line.

Other pipelines delivering product from PADD III include the Magellan, Phillips, and Kaneb systems.

Magellan is the petroleum products pipeline business acquired from Williams by a company now called Magellan Midstream Partners, L P. Historically, the origination point was in Oklahoma, with deliveries to the “Group” or “Group 3”, the states from Oklahoma to North Dakota and Missouri to Minnesota. The company expects to close the acquisition of the Chase and Orion pipeline assets before the end of 2004. Chase runs from Tulsa to western Kansas and Denver. The Orion system originates at Galena Park, Texas, running to Dallas and then splitting into a west line to Odessa, Texas, with a smaller line going on to El Paso, and a north line running to Wichita Falls, Texas and on into Oklahoma where there is a tie-in to the existing Magellan lines.

The Phillips pipeline originates in the Texas panhandle at the ConocoPhillips Borger refinery, serving Kansas City, St Louis, and Chicago.

The Kaneb pipeline serves the western areas of the states from Oklahoma to North Dakota.

PADD II SUPPLY SUBREGIONS

In the context of this study, the PADD II markets are best studied in accordance with the supply mechanisms that exist in the sub regions. The five states Oklahoma, Kansas, Nebraska, South Dakota and North Dakota are supplied by refineries in Oklahoma and Kansas using primarily the Kaneb and Magellan (ex-Williams) pipelines, and this area is largely self-sufficient in terms of supply-demand for petroleum products. The Magellan system also supplies the western areas of Minnesota, Iowa, and Missouri. Large pipelines from PADD III, the U.S. Gulf Coast region, enter PADD II through Missouri and Tennessee. A refinery in Memphis and the Gulf Coast pipelines supplies eastern Tennessee. Products for eastern Tennessee come from the pipelines that supply the southeastern and eastern regions of the U.S. from PADD III. Eastern Missouri supply comes from a refinery in the St Louis area and a Gulf Coast pipeline.

Kentucky derives its supply from refineries in Illinois, Indiana, and Ohio and has no indigenous supply.

The populous Ohio area has four refineries as well as pipelines coming the west and north, but is effectively in balance in respect of supply and demand for products. Eastern Iowa supply comes primarily from Chicago area refineries via pipelines.

Eastern Minnesota supply is from two refineries in the Minneapolis-St Paul area and pipelines from Chicago. Product from eastern Wisconsin comes both from the Minneapolis-St Paul refineries and from Chicago. Illinois, Wisconsin, Indiana and Michigan supply comes from Chicago area refineries and from the Gulf.

PADD II LIGHT PRODUCT SUPPLY-DEMAND BALANCES

In order to determine the long term and short term impact on product prices that would be caused by introduction of an Alberta project's product into the region, the upgrader volumes must be compared to the total supply picture. The change in supply that would be expected on introduction of the new volume from the upgrader is expected to occur in the volume of transfers from outside PADD II – i.e. the size of the accessible market is the difference between regional demand and product manufactured within PADD II. In this analysis we compare the potential Alberta supplies to overall PADD II transfers, to Chicago, to transfers to the upper Midwest, and to Detroit.

PADD II SUPPLY SOURCES

An important attribute of PADD II supply is the lack of foreign imports. Although there is a large volume transferred to the region from PADD III, from the U.S. Gulf Coast refineries, imports form a miniscule volume by comparison. This is illustrated in Figures V-15, V-16 and V-17 for gasoline, jet fuel and diesel supply sources, and detailed in Table V-12.

PADD II MARKET PENETRATION

The Enbridge crude oil pipeline system currently has lines that enter the U.S. south of Gretna, Manitoba, proceeding to Superior, Wisconsin. The system splits there and one leg proceeds east, above Lake Michigan and then south to Marysville and Sarnia. The other leg of the split proceeds south to Chicago. A number of these lines have been looped with parallel lines in capacity expansions. Discussions with Enbridge indicate that supply points are possible at Chicago, Detroit, and possibly, St Louis, given that the looping configuration makes conversion of part of the system to products possible without massive new investment. Based on the discussions, the product volumes from the upgrader project are apparently adequate to allow the necessary change of service and to pay back the capital improvements to allow handling and transfer of products.

For Chicago, the existing Enbridge crude oil system delivers to Griffith, immediately south and east of the urban center. A new products storage terminal would be required here, or, preferably, at Hammond to the north. As will be discussed later, the Hammond option would require nine miles of new pipeline. The Detroit delivery point is at Marysville, to the north of the city. A new products terminal would be required here to receive products if crude oil deliveries would continue. There is no Enbridge pipeline to St Louis, but Enbridge has proposed a new crude oil system called "Southern Access", which would run from Superior to Wood River, Illinois, immediately across the Mississippi from St Louis. Wood River is the center of the oil pipeline and terminal connections for the metropolitan area.

FIGURE V-15
PADD II GASOLINE SUPPLY SOURCES
(Thousand Barrels Per Day)

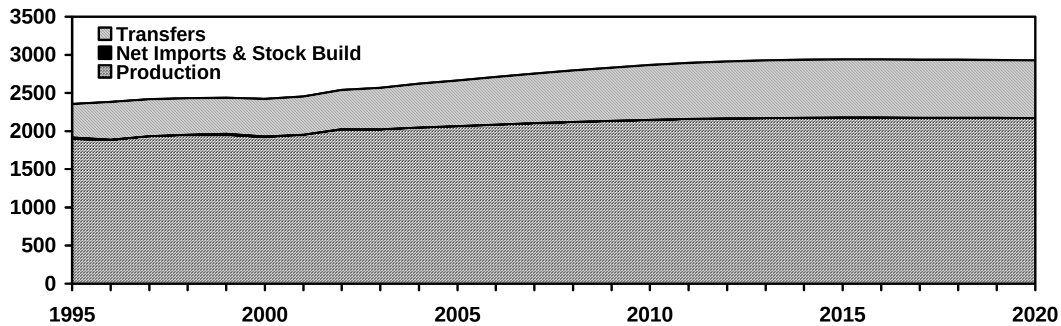


FIGURE V-16
PADD II JET FUEL & KEROSENE SUPPLY SOURCES
(Thousand Barrels Per Day)

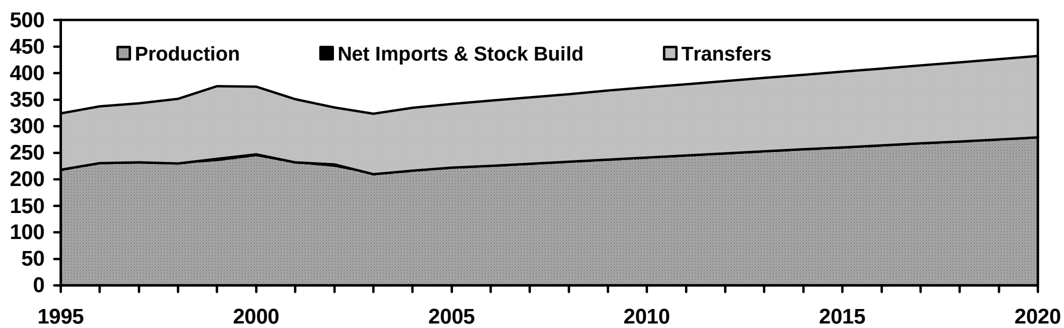
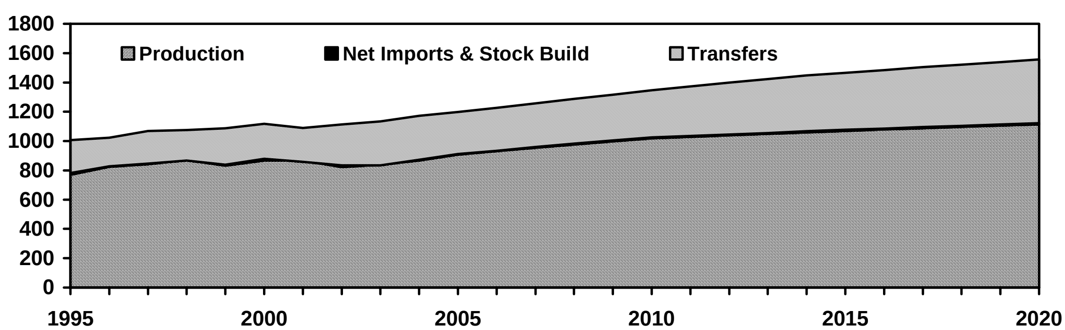


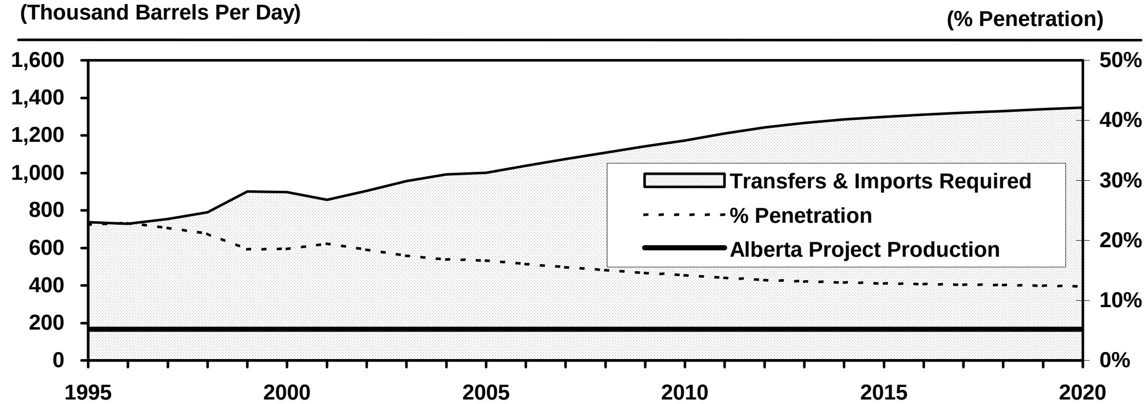
FIGURE V-17
PADD II DIESEL SUPPLY SOURCES
(Thousand Barrels Per Day)



The Enbridge "Mustang" pipeline delivers crude oil from Chicago to Patoka, in south central Illinois. Patoka is the northern terminus of the Capline crude oil pipeline, and a number of lines radiate outward from there. Another option that might be available to Enbridge if a St Louis product entry point is desired would be to convert the Mustang line to product service and add a line from Patoka to Wood River, a distance of 50 miles.

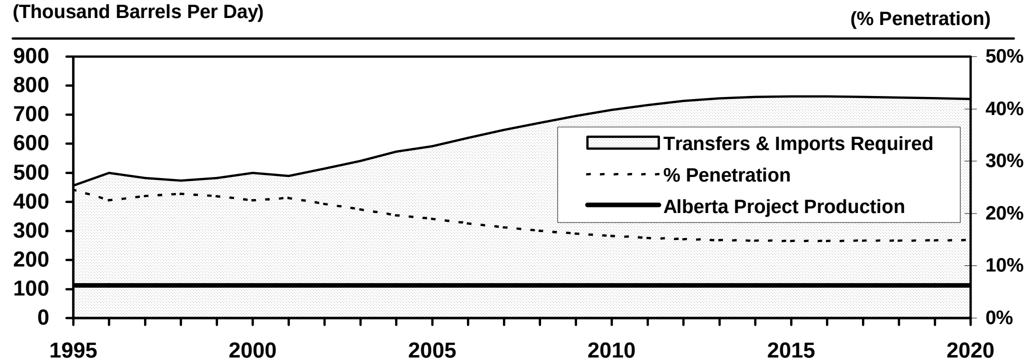
Overall, the proposed Alberta project volumes would have a small impact on the PADD II supply-demand balance, and would represent 20 percent of current transfers into the region and 17 percent by 2010. Figure V-18 shows the magnitude of the current transfers into the market, the expected production from the Alberta upgrader, and the percentage of the accessible market that the Alberta production represents:

FIGURE V-18
PADD II LIGHT PRODUCT MARKET PENETRATION
(Thousand Barrels Per Day)



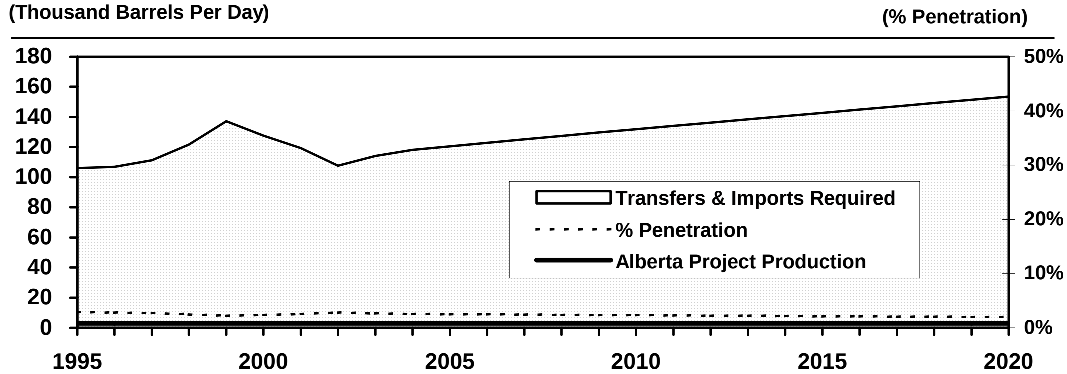
For gasoline, the balance is slightly more favorable for project volumes, which would require 16 percent penetration of transfer volumes BY 2010, Figure V-19.

FIGURE V-19
PADD II GASOLINE MARKET PENETRATION
(Thousand Barrels Per Day)



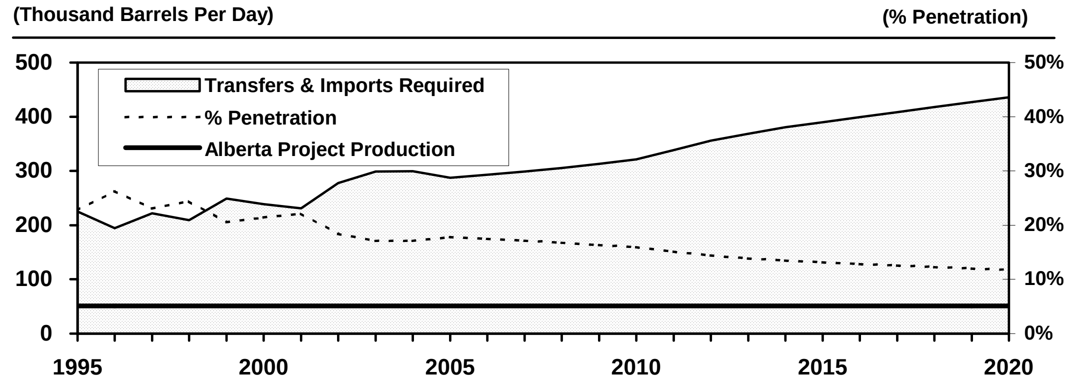
For jet fuel and kerosene, the projected 3,000 B/D from the Alberta project represent only 2 percent of expected 2010 transfers to PADD II, Figure V-20. This market should be able to readily absorb more jet fuel than was estimated to be produced from the Alberta refinery project.

FIGURE V-20
PADD II JET FUEL AND KEROSENE MARKET PENETRATION
(Thousand Barrels Per Day)



Diesel fuel from the Alberta project, around 50,000 B/D, would require a larger penetration of the volumes transferred into the region compared to gasoline or jet fuel, since the projected gasoline-diesel ration for the project output is set to match the longer term value of 2:1, as compared to the current 2.5:1. A penetration equal to 16 percent of expected 2010 transfers would be required to absorb the upgrader diesel output, Figure V-21.

FIGURE V-21
PADD II DIESEL MARKET PENETRATION
(Thousand Barrels Per Day)



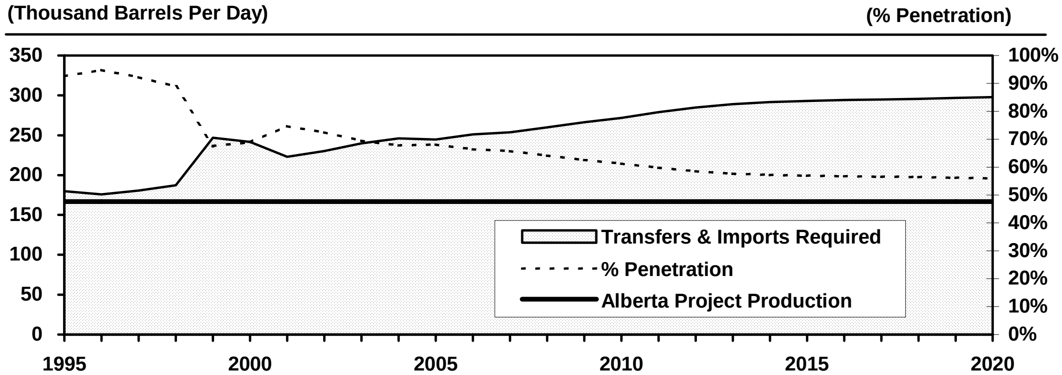
Details of the above market penetration analyses are provided in Table V-13.

CHICAGO ENTRY POINT MARKET PENETRATION

Although it is clear that the PADD II market can easily absorb the output from an Alberta project, the total region is not reasonably accessible unless the supply point is somewhere in the Houston-Lake Charles corridor. Based on the considerations outlined above on supply sub-regions, it can be concluded that the upper Midwest offers the best combination of large markets, a reasonable opportunity to compete in terms of large volumes of product imported from other regions, and reasonable access to existing supply pipelines from Western Canada. Given the existing pipeline network in this region, Chicago was chosen as the best potential injection point for upgrader product. To confirm this, penetration analyses were made for this market area. Local demand and supply were analyzed for this sub-region, comprised of northern Illinois, northwestern Indiana, eastern Wisconsin, and Michigan. Physical supply of this area can be accomplished from Chicago.

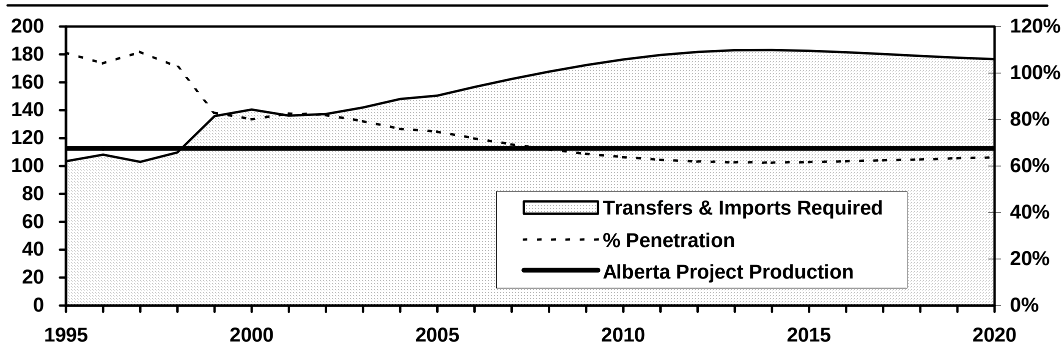
Overall, a light products penetration of 61 percent would be required by 2010, when the upgrader would come on stream, Figure V-22. This is detailed in Table V-14.

FIGURE V-22
CHICAGO HUB LIGHT PRODUCT MARKET PENETRATION
(Thousand Barrels Per Day)



The penetration required for gasoline is around 64 percent (Figure V-23). This is higher than the market can readily absorb, and would require some price discounting or distribution beyond Chicago to a larger market area.

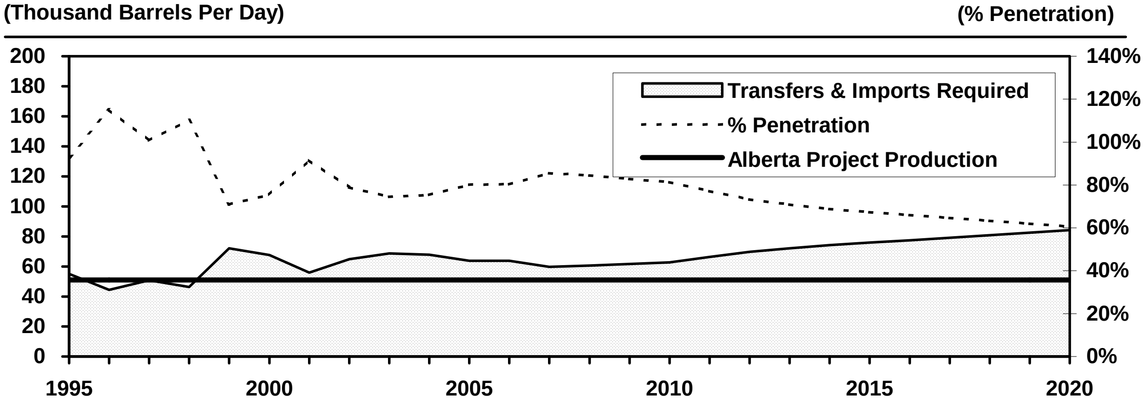
FIGURE V-23
CHICAGO HUB GASOLINE MARKET PENETRATION
(Thousand Barrels Per Day)



For jet fuel, the region is nearly in balance, which Table V-14 indicates. Going forward, around 30,000 B/D of jet fuel transfers are expected, so it should be possible to place the 3,000 B/D of upgrader product in the region.

The diesel penetration required would be a significant percentage of transfers into the region, around 80 percent in 2010. Since these upgrader diesel volumes would not be in head-to-head competition with structural barrels, those manufactured in refineries within the region, we believe that this level of penetration could be achieved with price discounting and using some combination of commercial discounts and exchange agreements. This much new volume of diesel fuel, though, would likely seek outlets beyond the immediate Chicago area if the product could be moved further.

FIGURE V-24
CHICAGO HUB DIESEL MARKET PENETRATION
(Thousand Barrels Per Day)

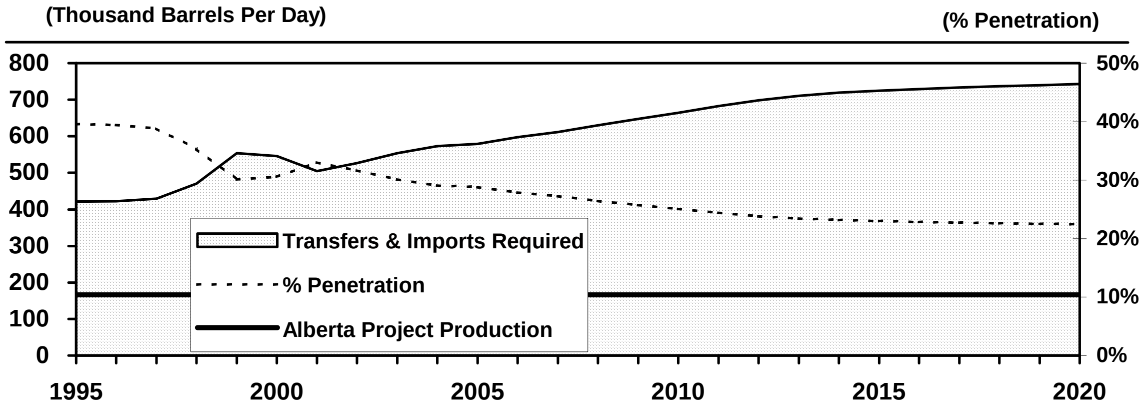


MIDWEST MARKET PENETRATION

Access to a larger market can be obtained if the upgrader product is introduced south of Chicago, but this would incur higher delivery costs for the Alberta product. The penetration analysis was repeated for the six-state region of PADD II that includes the states Illinois, Indiana, Minnesota, Wisconsin, Missouri and Michigan. This region is the competitive marketplace for introduction of upgrader product at St Louis or some nearby location that provides physical pipeline access to the six states.

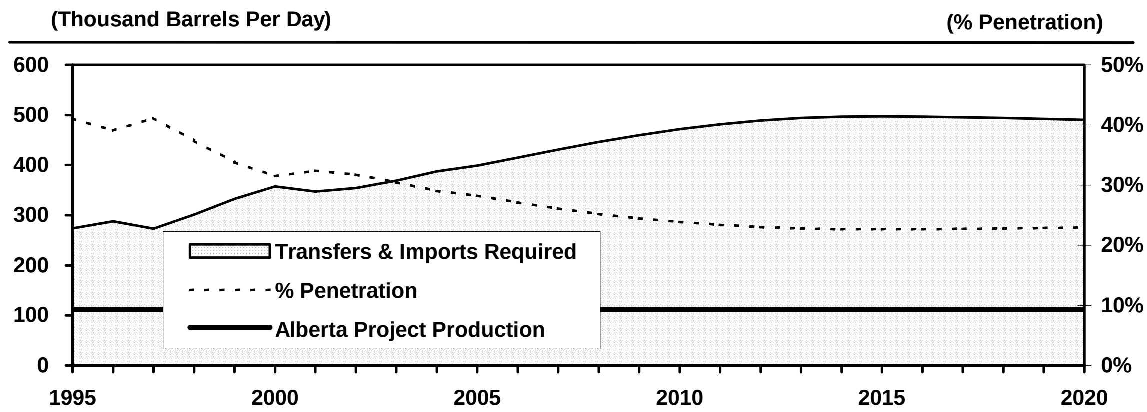
As expected, the impact of the Alberta supply on this market would be less substantial than was the case for a Chicago entry point. The new supply would be 25 percent of total light product transfers to this sub-region for 2010, Table V-15. Pricing for the Alberta upgrader economic evaluation in this report is based on the Chicago market penetration, since we believe that it is adequate to clear the market. Product introduction at St Louis-Wood River is viewed as a potential risk reduction option, that would come at increased capital cost for a new pipeline to extend from Chicago to Wood River, and other facilities, and a resultant lower netback price realization for the upgrader.

FIGURE V-25
MIDWEST LIGHT PRODUCT MARKET PENETRATION
(Thousand Barrels Per Day)



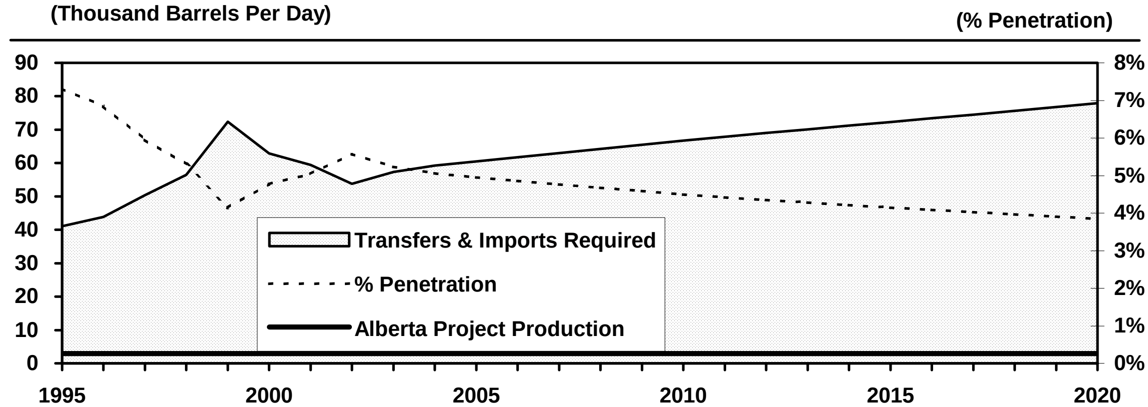
For gasoline, the impact is less, but still substantial, at 24 percent of transfers at 2010 rates, as shown below in Figure V-26.

FIGURE V-26
MIDWEST GASOLINE MARKET PENETRATION
(Thousand Barrels Per Day)



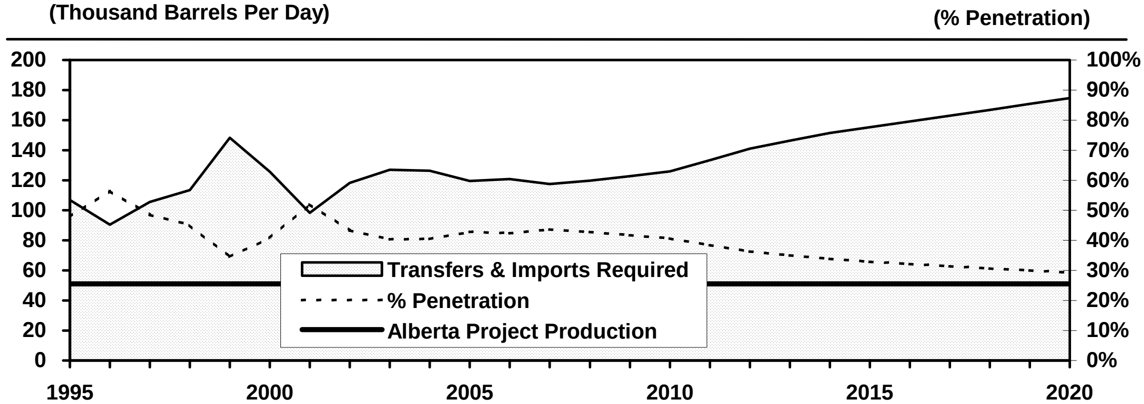
The supply-demand balance for jet fuel suggests that this market could absorb more jet fuel. It may warrant producing less diesel fuel and more jet fuel than was used in this study. As shown in Figure V-27, the assumed jet fuel volumes only fill a small portion of the market.

FIGURE V-27
MIDWEST JET FUEL AND KEROSENE MARKET PENETRATION
(Thousand Barrels Per Day)



The penetration required for the diesel fuel output from the Alberta project is large, at 41 percent of transfers at 2010 rates. At those levels, however, the sales of the product should be manageable within reasonable ranges of commercial discounts and exchange agreements.

FIGURE V-28
MIDWEST DIESEL MARKET PENETRATION
(Thousand Barrels Per Day)



DETROIT METRO MARKET PENETRATION

Since the Enbridge pipeline system could deliver product to Marysville, just north of Detroit, this location was considered in the Phase I report. On the basis of this more detailed market study, Detroit would not be a preferred delivery location because output volume of the Alberta project would be larger than the local market demand, as detailed in Table V-16. Michigan is supplied by the MAP refinery in Detroit and by pipelines, principally the Wolverine and BP systems. As will be shown in the pricing analysis to follow, Detroit wholesale prices are higher than those in Chicago, by amounts close to, but somewhat less than the pipeline charges required to move the product from Chicago to Detroit. Introduction of Alberta product at Detroit would convert the region from an importer of product to an exporter. As an export market, prices at Detroit would be equivalent to Chicago less most of the transportation cost to move product between them. Chicago is in any case a much larger market and based on the reversal of the pricing mechanism from import parity to export parity, the netback prices to the Alberta project business would be better in Chicago.

CHICAGO ENTRY POINT MARKET PRICE

PHYSICAL ENTRY POINT

It is our understanding that the Enbridge pipeline system can be modified at moderate cost to deliver refined products to Griffith, Indiana. At Griffith there is access to the Marathon and Buckeye systems. However, the best point of introduction of the upgrader product would be near Hammond, Indiana, about nine miles north of the Enbridge Griffith terminal. There is a large complex of terminals that can be accessed at Hammond, as well as access to the Wolverine, West Shore, Badger, BP and Buckeye pipelines. A number of product pipelines run from south to north immediately west of Griffith, in a corridor leading to Hammond.

Hammond is the location for which spot product is quoted in the OPIS and Platts publications, and is the usual point of reference for Chicago spot transactions.

CHICAGO PRODUCT PRICES

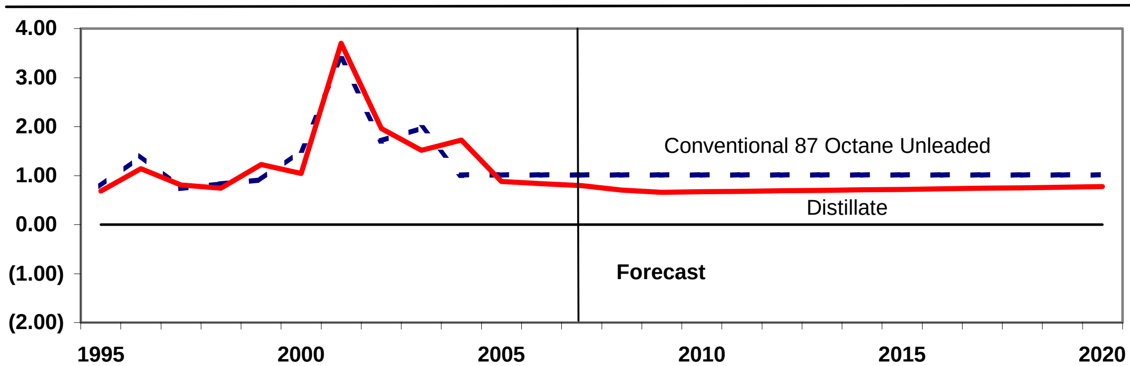
Because of the large volume of physical supply to PADD II and to the Chicago area, the product prices are closely related to the U.S. Gulf Coast prices plus the cost of transportation from PADD III. The current Explorer Pipeline tariff for the U.S. Gulf Coast to Chicago is 2.87 cents per gallon. For gasoline, the historical average Chicago price is 2.77 cents per gallon over the U.S. Gulf Coast value. Diesel fuel does not recover the full tariff cost; the historical price differential is 2.42 cents per gallon between Chicago and the U.S. Gulf Coast.

Going forward, the forecast price differentials for both gasoline and distillate prices have been lowered somewhat below historical values, on account of the recent elimination of PADD III to PADD II pipeline capacity bottlenecks. For gasoline, a price differential of U.S. Gulf Coast plus 2.4 cents per gallon was used for future prices, roughly 0.5 cents per gallon below that suggested by the U.S. Gulf Coast cost plus transportation, Figure V-29.

For diesel fuel, a price differential was used such that it was close to the historical averages for 2005, then gradually declining. The average price differential that was used was U.S. Gulf Coast plus about 1.8 cents per gallon, or roughly 1.0 cents per gallon below that suggested by the U.S. Gulf Coast cost plus transportation, Figure V-29. The decline in the initial forecast years is related to the increased penetration of Canadian synthetic crudes into PADD II. The higher distillate yields for these crudes as compared to conventional supplies places is expected to increase supply pressure on transfers from the U.S. Gulf Coast.

Tables V-17 and V-18 provide Purvin & Gertz' PADD II region refined product price forecasts (excluding any market discounts).

FIGURE V-29
CHICAGO vs USGC REFINED PRODUCT PRICES
(Constant 2004 U.S. Dollars per Barrel)



REGIONAL PRICES RELATIVE TO CHICAGO

The price model for estimation of a netback price for the Alberta upgrader was assumed to be the Chicago price, adjusted for the differences in prices for the region relative to Chicago, and, finally, an adjustment to account for the penetration of this market by the new product source.

The adjustment for the regional prices relative to Chicago was assumed to be the volumetric weighted average of Milwaukee, Chicago and Detroit wholesale rack prices relative to Chicago rack prices for construction of a netback to a Chicago delivery point.

For Milwaukee, the historical wholesale rack price differences with Chicago were somewhat greater than the pipeline tariff:

MILWAUKEE PRICES RELATIVE TO CHICAGO

	Cents per Gallon
Badger Pipeline Tariff	0.77
Gasoline (RFG) Rack Price Differential	1.46
No.2/Diesel Rack Price Differential	1.26

The price differential to Chicago was assumed to be the pipeline tariff of 0.77 cents per gallon, taking no credit for rack marketing margins, which would be to the customer's rather than the supplier's account.

In Detroit, the historical price differentials relative to Chicago are slightly less than the Wolverine tariff for movements from Chicago to Detroit, averaging 0.25 cents per gallon less than the tariff. This indicates that products supplied to this market provide the supplier with a netback price below the source market price in Chicago.

DETROIT PRICES RELATIVE TO CHICAGO

	Cents per Gallon
Wolverine Pipeline Tariff	1.88
Gasoline Rack Price Differential	1.64
No.2/Diesel Rack Price Differential	1.61

For gasoline and jet fuel sold in the "Chicago Hub" sub-region described above, product volumes from the Alberta Upgrader would be less than the range of 30-40 percent of transfers at which substantial price discounts would be required to break structural relationships as well as providing a lowest cost tier. For these products, a typical commercial discount appropriate to contract sales of large volumes of product should be assumed, of the order of 0.25 cents per gallon. Table V-19 illustrates the generation of the total discount to Chicago spot prices of 0.35 cents per gallon by including the weighting of the prices of the Michigan percentage of Chicago hub demand at the Detroit price discount level.

In Table V-20, a regional volumetrically weighted average price discount relative to Chicago is computed. This presumes that for product at the 30 percent of total regional transfer level, a nominal level of contractual discount of 0.25 cents per gallon will displace non-structural transfers that represent true spot market behavior. Above this level, a significant amount of transfers from the USGC are structural, such as integration of regional retail supply to related company refining operations at the USGC. The discount applied to create incentive adequate to move the product is based on shifting the breakeven netback point for shipments from the USGC fall in southern rather than northern Illinois. This characterization of two tiered pricing may represent levels associated with the economic needs of different types of contract customers, or tiered prices for increasing volume consumption within a given sales contract.

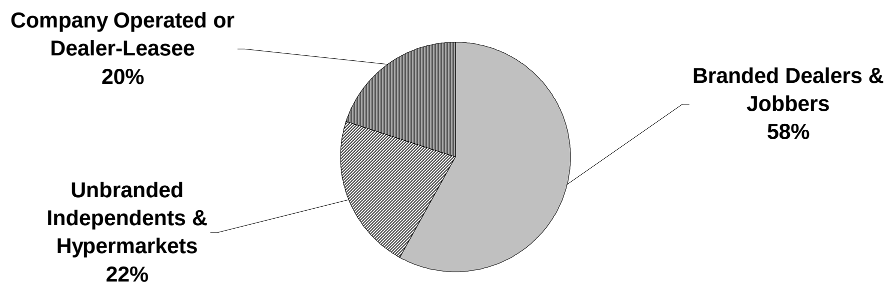
For diesel fuel, the penetration required is from over 70 percent of transfers currently, declining to around 60 percent at the end of the forecast period. As shown in Table IV-20, a commercial discount for diesel was estimated to be 0.25 cents per gallon for the increment of product equal to 30 percent of transfers into the region, and an additional 0.7 cents per gallon for the remainder. The weighted average is approximately 0.7 cents per gallon for 2010, declining to 0.62 cents per gallon in 2020. This assumes having volume tiered contracts with multiple suppliers.

MIDWEST RETAIL MARKET CHARACTERISTICS

RETAILER TYPE DISTRIBUTION

By far the majority of retail outlets in the Midwest are branded dealers and jobbers, who own the real estate and improvements, at 58 percent of the total. Company operated or lessee-dealer outlets are 20 percent of the total. Unbranded dealers and hypermarketers are estimated at 22 percent of total outlets, although the rapid growth in hypermarketer outlets makes this component difficult to estimate. The latest information available, for 2002, put hypermarketers at 5 percent of the market, with almost 50 percent growth rate.

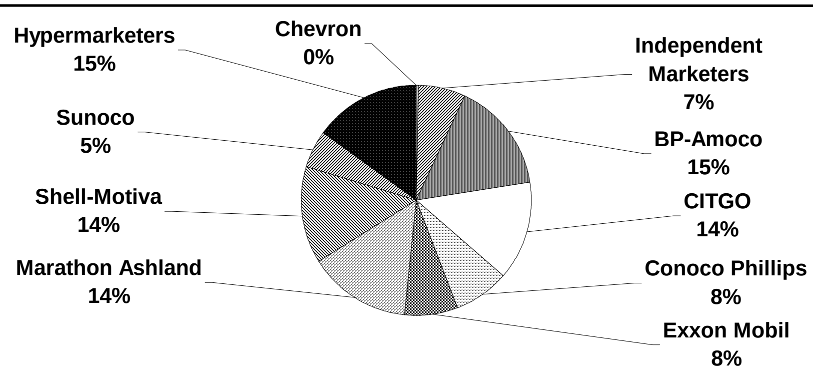
FIGURE V-30
PADD II RETAILER TYPE DISTRIBUTION
(Percent)



RETAIL MARKET SHARE

An estimate of retail market share was prepared based on retail outlet count available in the publication National Petroleum News, and similar sources, Figure V-31. The same caveat applies here in respect to hypermarketer market share, which is the most uncertain element in the analysis.

FIGURE V-31
ESTIMATE OF PADD II RETAIL MARKET SHARE
(Percent)



A supply-demand balance at the retail level was prepared. The latest year for which NPN data was available was 2002, but the retail share percentages derived from this were applied to 2003 state demand volumes. As Table V-21 indicates, a number of the larger retail marketers are short of product in the region, net of their local refinery production, and overall the shortage is 703,000 B/D.

ANALYSIS OF GASOLINE MARKET SHARE AND SELF-SUFFICIENCY OF SUPPLY (2002 Retail Outlet Count and 2003 State Demand Estimates)

Company	Estimated Retail Outlets	Market Share	Gasoline Sales, MB/D	Produced	Long/ (Short)
Company A	2,738	15.7%	296	277	(19)
Company B	29	0.2%	3	-	(3)
Company C	2,429	13.9%	262	83	(179)
Company D	1,348	7.7%	146	112	(34)
Company E	1,332	7.6%	144	121	(23)
Company F	2,468	14.2%	267	270	3
Company G	2,402	13.8%	259	-	(259)
Company H	899	5.2%	97	62	(35)
Hypermarketers	2,615	15.0%	282	-	(282)
Independent Marketers	1,172	6.7%	127	-	(127)
Total	17,433	100%	1882	924	(958)
Other Regional Refinery Output				255	(703)

MARKET ENTRY STRATEGY – OPTIONS AND RECOMMENDATIONS

Because of the volume of product that would be produced by the Alberta upgrader, an independent wholesale market operation is not likely to penetrate the market at a satisfactory rate while providing a satisfactory netback price for products. The size of the upgrader is necessary to achieve world-scale manufacturing economics and to utilize the available pipeline capacity to an acceptable level, however.

A better strategy would be to negotiate with the larger regional net buyers of product for term contract supplies, preferably with two or more such buyers, of course. Several of the large retailers are large net buyers of product according to their Form 10-K filings with the U.S. Securities and Exchange Commission. Many U.S. companies view the upstream sector as offering higher returns on capital, and may view the supply relationship as a useful partnership.

Tiered pricing that allows the buyer to obtain progressively lower priced supply with increased volumes is an effective mechanism for providing an incentive for retail marketing contract partners to maximize their takes under the agreements.

The hypermarketers represent a large and growing segment of the market. These offer an opportunity to contract for sales of large volumes of gasoline, more than likely at the penalty of a lower price, given the nature of the host businesses for these outlets.

Product exchanges rather than outright purchase may be offered. It may be necessary to do some of this type of business in order to gain market entry, but the further south the product is sent, the less of a market niche it possesses. Exchanges between upgrader product at Chicago for product in St Louis may be advantageous to the upgrader business, by providing access to a larger PADD II market. In the extreme, however, in an exchange between Chicago and the U.S. Gulf Coast the product could become, in effect, spot material in a very competitive and transparent market.

As discussed, Chicago is recommended as the physical delivery point, on account of there being existing Enbridge pipeline systems delivering there, and because of the large market offering reasonable opportunities to compete. Adding the stub pipeline from Griffith to Hammond is essential in order to provide the largest number of physical delivery options.

Delivery to St Louis would be expected to provide a lower netback price at the upgrader than would Chicago. However, this location offers access to the 130,000 B/D St Louis metro light product market, to markets in eastern and northern Missouri, to Iowa, and to the Ohio River Valley markets. As the penetration analysis showed, the upgrader product volumes are a materially lower percentage of competing supply volumes and thus this point of delivery would provide a lower risk but less profitable marketing strategy.

The proposed Alberta upgrader is configured to produce a small amount of jet fuel. The airlines that purchase this product represent a much smaller customer base than is the case for other products. Fuel represents a large percentage of their operating costs and they negotiate very hard for the lowest price and related terms. For that reason the upgrader should be configured to be able to either produce the jet fuel and diesel product as we have indicated in the upgrader product balances, or as 100 percent diesel product. There is no material capital cost to do this as we have configured the upgrader process sequence. The business operation could then start up producing 100 percent diesel product and, if and when a more attractive jet fuel sales opportunity presents itself, this could be given consideration. The properties of this stream as we have configured the upgrader will allow blending either as jet fuel or as diesel products.

TABLE V-1
PADD II LIGHT PRODUCT DEMAND
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Illinois	449	497	493	499	503	512	518	527	537	544	552	558	576	580
Indiana	315	347	326	330	334	342	347	354	361	367	373	378	396	404
Iowa	157	165	166	166	168	172	174	177	176	178	181	183	188	189
Kentucky	225	235	242	247	251	258	263	269	276	282	287	292	310	321
Michigan	419	457	452	459	464	474	482	491	500	508	516	523	543	550
Missouri	277	305	301	308	313	321	327	334	343	350	356	362	380	390
Ohio	477	517	513	521	528	538	547	556	569	577	586	593	615	624
Wisconsin	245	271	277	277	281	289	295	300	298	303	308	313	329	337
Regional Total	2,564	2,795	2,770	2,808	2,843	2,906	2,954	3,008	3,060	3,110	3,158	3,202	3,338	3,395
Minnesota	240	267	267	272	277	285	293	299	304	310	317	322	343	354
North Dakota	53	52	54	54	54	55	56	57	56	57	58	58	61	62
South Dakota	51	52	52	52	53	54	55	56	55	56	57	58	61	63
Nebraska	104	107	104	104	105	108	110	111	111	113	115	116	121	124
Kansas	148	145	141	142	143	147	149	152	152	155	157	159	166	169
Oklahoma	186	218	236	243	249	256	262	269	281	287	293	298	318	330
Regional Total	542	574	587	594	604	619	632	645	656	668	680	690	727	747
Tennessee	275	295	291	299	306	315	322	331	344	352	359	367	396	415
Total PADD II	3,620	3,930	3,915	3,973	4,030	4,126	4,201	4,283	4,363	4,440	4,513	4,581	4,804	4,912

TABLE V-2
PADD II TOTAL GASOLINE DEMAND
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Illinois	305	329	332	340	342	347	350	355	360	364	368	371	375	369
Indiana	192	203	206	212	214	218	221	225	229	232	235	237	244	242
Iowa	94	101	101	104	104	106	108	109	111	112	113	114	115	113
Kentucky	132	134	141	145	147	150	153	156	158	161	163	166	172	172
Michigan	303	324	328	336	340	347	352	358	364	369	374	378	386	384
Missouri	189	203	199	205	208	212	216	220	224	227	230	233	240	240
Ohio	319	333	333	342	344	351	355	360	365	370	374	378	383	379
Wisconsin	152	160	162	167	170	174	177	181	184	187	190	192	198	197
Regional Total	1,688	1,786	1,802	1,850	1,868	1,906	1,932	1,964	1,994	2,022	2,047	2,069	2,113	2,096
Minnesota	149	168	171	177	180	185	190	194	198	202	205	209	218	219
North Dakota	24	23	23	24	24	25	25	26	26	27	27	27	28	27
South Dakota	28	28	28	29	29	30	30	31	31	32	32	33	33	33
Nebraska	53	56	56	58	58	60	61	62	63	63	64	65	66	65
Kansas	81	88	84	86	87	89	90	92	93	95	96	97	99	98
Oklahoma	117	116	118	122	124	127	129	132	134	136	138	140	144	144
Regional Total	302	312	309	319	323	330	336	342	347	353	357	361	370	368
Tennessee	179	189	188	194	197	203	207	211	216	220	225	229	241	246
Total PADD II	2,317	2,455	2,469	2,540	2,569	2,624	2,664	2,711	2,756	2,797	2,834	2,867	2,942	2,928

TABLE V-3
PADD II GASOLINE-DIESEL RATIO DEMAND
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Illinois	2.96	2.74	2.87	2.92	2.84	2.83	2.81	2.78	2.71	2.69	2.67	2.64	2.49	2.33
Indiana	1.98	1.79	2.28	2.34	2.29	2.28	2.26	2.25	2.23	2.21	2.19	2.17	2.04	1.92
Iowa	1.82	1.87	1.83	1.93	1.91	1.91	1.89	1.90	2.00	1.98	1.97	1.95	1.85	1.74
Kentucky	1.65	1.62	1.67	1.69	1.65	1.65	1.63	1.61	1.57	1.56	1.55	1.53	1.44	1.35
Michigan	3.80	3.74	4.05	4.15	4.06	4.04	4.01	3.98	3.95	3.92	3.88	3.84	3.62	3.40
Missouri	2.70	2.49	2.42	2.45	2.39	2.38	2.35	2.33	2.25	2.23	2.21	2.19	2.06	1.93
Ohio	2.73	2.42	2.46	2.48	2.42	2.41	2.39	2.36	2.29	2.27	2.25	2.23	2.10	1.96
Wisconsin	2.21	1.96	1.86	2.00	1.99	1.98	1.97	1.99	2.17	2.15	2.14	2.12	2.01	1.90
Regional Aggregate	2.53	2.36	2.46	2.53	2.47	2.46	2.44	2.43	2.41	2.39	2.37	2.35	2.21	2.07
Minnesota	2.21	2.41	2.49	2.60	2.56	2.55	2.53	2.53	2.60	2.58	2.56	2.54	2.40	2.25
North Dakota	1.01	1.08	0.96	1.03	1.03	1.02	1.02	1.03	1.13	1.12	1.12	1.11	1.05	0.99
South Dakota	1.50	1.68	1.62	1.72	1.71	1.70	1.69	1.70	1.82	1.81	1.79	1.78	1.68	1.59
Nebraska	1.24	1.35	1.44	1.52	1.50	1.49	1.48	1.49	1.56	1.55	1.53	1.52	1.44	1.35
Kansas	1.51	2.11	1.95	2.05	2.03	2.02	2.01	2.01	2.10	2.08	2.07	2.05	1.94	1.82
Oklahoma	2.40	1.47	1.22	1.21	1.17	1.16	1.15	1.13	1.06	1.05	1.04	1.03	0.97	0.90
Regional Aggregate	1.62	1.55	1.40	1.44	1.41	1.41	1.39	1.39	1.38	1.37	1.36	1.34	1.27	1.19
Tennessee	2.37	2.39	2.39	2.39	2.31	2.30	2.28	2.25	2.13	2.11	2.09	2.07	1.94	1.82
Total PADD II	2.32	2.22	2.25	2.30	2.25	2.25	2.23	2.21	2.19	2.18	2.16	2.14	2.01	1.89

TABLE V-4
PADD II RFG DEMAND
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2004	2005	2010	2011	2012	2013	2014	2015	2020
Illinois	124	195	200	204	208	212	215	230	233	234	235	236	236	235
Indiana	3	5	5	5	6	6	6	6	7	7	7	7	7	7
Kentucky	23	34	36	37	37	38	39	42	43	43	44	44	44	44
Missouri	42	63	63	64	66	67	68	74	74	75	75	75	76	75
Wisconsin	33	50	51	52	53	54	55	59	60	60	61	61	61	60
Total	226	347	355	362	369	377	383	412	416	419	421	423	423	421

TABLE V-5
2002 PADD II ETHANOL RFG AND OXYGENATED GASOLINE CONSUMPTION
(Thousand Barrels Per Day)

State	Total Gasoline Demand	RFG or Oxygenated Gasoline Demand
Illinois	339	201
Indiana	212	80
Iowa	103	61
Kentucky	145	16
Michigan	336	75
Missouri	205	45
Ohio	341	124
Wisconsin	166	85
Regional Total	1,847	686
Minnesota	177	169
North Dakota	24	6
South Dakota	29	15
Nebraska	58	21
Kansas	85	18
Oklahoma	122	-
Regional Total	317	60
Tennessee	194	-
Total PADD II	2,535	915

TABLE V-6
PADD II TOTAL DIESEL DEMAND
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Illinois	103	120	116	116	120	122	125	128	132	135	138	140	151	158
Indiana	97	113	90	90	93	96	98	100	103	105	107	109	119	126
Iowa	52	54	55	53	55	56	57	58	55	56	57	58	62	65
Kentucky	80	83	84	85	89	91	93	96	101	103	106	108	119	127
Michigan	80	87	81	81	84	86	88	90	92	94	96	98	107	113
Missouri	70	81	82	84	87	89	92	94	99	102	104	106	116	124
Ohio	117	137	136	137	142	145	148	152	159	163	166	169	183	193
Wisconsin	68	81	87	83	85	87	90	91	85	86	88	90	98	104
Regional Total	666	756	730	731	754	772	790	808	826	844	863	881	954	1,010
Minnesota	67	69	68	68	70	72	75	76	76	78	80	82	91	97
North Dakota	23	22	24	23	24	24	25	25	23	23	24	24	26	27
South Dakota	18	17	17	17	17	17	18	18	17	18	18	18	20	21
Nebraska	43	42	39	38	39	40	41	41	40	41	42	42	46	48
Kansas	53	41	43	42	43	44	45	45	44	45	46	47	51	53
Oklahoma	48	79	97	101	106	109	112	116	126	129	132	135	149	159
Regional Total	186	200	220	220	228	234	240	246	250	256	262	267	291	308
Tennessee	75	79	78	81	85	88	90	94	101	104	107	110	124	135
Total PADD II	994	1,105	1,097	1,101	1,137	1,166	1,195	1,224	1,253	1,282	1,312	1,340	1,459	1,550
% Low Sulphur	69%	75%	72%	77%	79%	79%	79%	81%	89%	90%	90%	90%	91%	91%

TABLE V-7
PADD II JET FUEL AND KEROSENE DEMAND
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Illinois	40	48	45	43	42	43	43	44	45	45	46	47	50	53
Indiana	26	31	29	28	27	28	28	29	29	30	30	31	33	36
Iowa	10	10	10	9	9	9	10	10	10	10	10	10	11	11
Kentucky	14	18	17	16	16	16	17	17	17	18	18	18	20	22
Michigan	36	47	44	41	40	42	42	43	44	45	46	46	50	53
Missouri	18	22	20	20	19	20	20	20	21	21	22	22	24	26
Ohio	41	47	44	42	41	42	43	44	44	45	46	46	49	53
Wisconsin	25	30	28	27	26	27	28	29	29	30	30	31	34	36
Regional Total	210	252	238	227	221	228	232	236	240	244	248	252	270	290
Minnesota	23	29	28	27	27	28	28	29	30	30	31	32	35	38
North Dakota	5	7	7	6	6	6	6	6	7	7	7	7	7	8
South Dakota	6	7	7	6	6	6	7	7	7	7	7	7	8	8
Nebraska	8	9	9	8	8	8	8	9	9	9	9	9	10	10
Kansas	13	15	15	14	13	14	14	14	15	15	15	15	17	18
Oklahoma	21	22	21	20	20	20	21	21	22	22	22	23	25	27
Regional Total	53	61	58	55	53	55	56	57	59	60	61	62	67	72
Tennessee	21	27	25	24	24	24	25	26	26	27	27	28	31	34
Total PADD II	308	369	349	332	324	335	341	348	354	360	367	373	403	433

TABLE V-8
RFG, OXYGENATED, AND LOW RVP GASOLINE PROGRAMS

State	7.0 RVP	7.2 RVP	7.8 RVP	9.0 RVP	Southern RFG	Northern RFG	Oxygenated	Ethanol Blended
Illinois		St Louis metro Jun1 - Sep15				Chicago metro		
Indiana			Louisville metro Jun1 - Sep15	All counties except Louisville & Gary metro May1 - Sep15		Gary metro		
Iowa								Tax credit
Kentucky						Louisville, Cincinnati metro		
Michigan		Detroit metro Jun1 - Sep15		All counties except Detroit metro May1 - Sep15				
Missouri	Kansas City metro Jun1 - Sep15				St Louis metro			
Ohio				All counties May1 - Sep15				
Wisconsin						Milwaukee metro		
Minnesota				May1- Sep15			Required year round	
North Dakota				All counties May1 - Sep15				
South Dakota				All counties May1 - Sep15				
Nebraska				All counties May1 - Sep15				
Kansas	Kansas City metro Jun1 - Sep15							
Oklahoma			Voluntary for Tulsa metro	Required all counties in summer				
Tennessee			Nashville, Memphis metro areas	All other counties May1 - Sep15				

TABLE V-9
CONFIGURATION OF PADD II REFINERIES - 2003
(Thousand Barrels Per Day)

Company	Location	State	Crude	Vacuum	Coking	FCC	Reforming	Hydro-cracking	Naphtha-Gasoline Hydro-treating	Distillate Hydro-treating	VGO & Misc Hydro-treating	Alkylation & Poly	Isom-erization	Asphalt
BP	Whiting	IN	410	242	34	157	86	0	87	96	117	34	25	60
BP	Toledo	OH	152	66	34	57	41	29	38	14	38	11	0	9
CITGO	Lemont	IL	159	71	46	60	28	0	54	50	6	19	0	39
ConocoPhillips	Wood River	IL	286	107	0	90	85	29	82	71	26	21	0	40
ConocoPhillips	Ponca City	OK	190	69	24	59	47	0	45	56	21	17	8	0
Cooperative Refining LLC	Coffeyville	KS	110	50	17	29	17	0	36	24	0	7	9	0
Cooperative Refining LLC	McPherson	KS	79	32	20	21	21	11	32	35	0	6	14	0
Countrymark Cooperative, Inc.	Mt. Vernon	IN	24	7	0	8	7	0	10	0	0	2	2	0
Exxon Mobil	Joliet	IL	238	113	56	93	42	0	92	85	0	27	0	11
Flint Hills Resources	Rosemount	MN	271	171	61	77	44	0	81	97	95	15	16	23
Frontier Oil & Ref.	El Dorado	KS	110	39	18	37	30	0	42	36	45	13	13	0
Gary-Williams Energy Corp.	Wynnewood	OK	53	16	0	19	13	5	12	0	0	5	4	5
Marathon Ashland	Robinson	IL	192	62	28	50	74	26	57	67	0	12	13	0
Marathon Ashland	Catlettsburg	KY	222	91	0	96	46	0	59	86	50	12	13	22
Marathon Ashland	Detroit	MI	74	36	0	29	20	0	16	18	17	4	0	21
Marathon Ashland	St. Paul Park	MN	70	30	0	25	20	0	21	26	25	5	9	11
Marathon Ashland	Canton	OH	73	34	0	25	20	0	25	10	24	8	5	11
Murphy Oil	Superior	WI	33	20	0	10	7	0	8	7	6	1	2	7
Premcor Refining Group	Lima	OH	165	52	23	40	57	26	63	0	0	0	19	0
Sinclair Oil	Tulsa	OK	50	25	0	16	11	0	11	16	0	3	5	2
Somerset Refinery	Somerset	KY	6	0	0	0	2	0	2	0	0	0	0	0
Sunoco Inc.	Toledo	OH	140	30	0	60	46	28	48	0	0	12	0	0
Sunoco Inc.	Tulsa	OK	85	30	9	0	18	0	24	0	11	0	0	0
Tesoro West Coast	Mandan	ND	58	0	0	25	12	0	12	0	0	5	5	0
Valero Energy Corp.	Ardmore	OK	85	32	0	28	20	0	26	33	31	6	7	10
Williams (Mapco)	Memphis	TN	190	0	0	68	36	0	60	53	0	16	4	0
Total PADD II			3,523	1,425	369	1,177	845	153	1,040	879	509	261	171	270
Percent Of Crude Capacity			100%	40%	10%	33%	24%	4%	30%	25%	14%	7%	5%	8%

TABLE V-10
PADD II LIGHT PRODUCT SUPPLY CAPABILITY - 2003
(Thousand Barrels Per Day)

Company	Location	State	PADD	Crude	Conventional Gasoline				Distillates			Total Light[1]
					Regular	Premium	Total	Jet/Kero	Diesel	LS Diesel	Total Diesel	Products
BP	Toledo	OH	II	138	61	15	77	14	12	28	40	130
BP	Whiting	IN	II	372	160	40	200	37	33	78	111	348
CITGO	Lemont	IL	II	144	66	17	83	14	10	24	34	131
ConocoPhillips	Wood River	IL	II	260	88	23	112	24	13	31	44	179
Exxon Mobil	Joliet	IL	II	216	97	24	121	22	17	39	56	199
Countrymark Cooperative, Inc.	Mt. Vernon	IN	II	21	8	2	10	2	2	5	7	19
Marathon Ashland	Canton	OH	II	66	24	6	31	6	5	11	16	53
Marathon Ashland	Catlettsburg	KY	II	201	71	18	89	20	12	27	39	148
Marathon Ashland	Detroit	MI	II	67	24	7	31	6	5	11	16	52
Marathon Ashland	Robinson	IL	II	174	72	18	90	17	18	43	61	169
Marathon Ashland	St. Paul Park	MN	II	63	23	6	29	6	5	11	16	51
Premcor Refining Group	Lima	OH	II	150	63	16	79	15	16	37	53	147
Sunoco Inc.	Toledo	OH	II	127	50	12	62	13	12	27	39	114
Murphy Oil	Superior	WI	II	30	10	3	13	3	2	4	6	22
Flint Hills Resources	Rosemount	MN	II	263	122	31	153	25	16	38	54	231
Coffeyville Resources Refining & Marketing LLC	Coffeyville	KS	II	100	44	11	55	10	8	20	28	93
Cooperative Refining LLC	McPherson	KS	II	72	30	7	37	7	7	17	24	68
Frontier Oil & Ref.	El Dorado	KS	II	100	40	10	51	10	10	24	34	94
ConocoPhillips	Ponca City	OK	II	172	71	18	89	17	18	41	59	165
Gary-Williams Energy Corp.	Wynnewood	OK	II	48	19	5	23	5	4	10	15	43
Sinclair Oil	Tulsa	OK	II	45	16	4	21	4	3	7	10	35
Tesoro West Coast	Mandan	ND	II	53	21	5	26	5	5	11	16	47
Valero Energy Corp.	Ardmore	OK	II	77	28	7	35	8	5	13	18	61
Williams (Mapco)	Memphis	TN	II	172	68	17	85	17	16	37	53	155
				3,130	**1,279**	**323**	**1,602**	**306**	**254**	**593**	**848**	**2,755**

1) Estimate of current supply capability excluding ethanol.

TABLE V-11
2003 PADD II LIGHT PRODUCT SUPPLY/DEMAND BALANCE
(Thousand Barrels Per Day)

State	Demand	Refinery Supply	Blendstock Supply	Total Supply	Long (Short)
Illinois	503	734	20	754	250
Indiana	334	397	8	405	70
Iowa	168	-	6	7	(161)
Kentucky	251	160	2	161	(90)
Michigan	464	57	8	64	(400)
Missouri	313	-	4	5	(309)
Ohio	528	481	12	493	(34)
Wisconsin	281	24	8	33	(248)
	2,843	1,851	69	1,921	(923)
Minnesota	277	306	17	323	46
North Dakota	54	51	1	52	(2)
South Dakota	53	-	2	2	(51)
Nebraska	105	-	2	2	(103)
Kansas	143	277	2	279	136
Oklahoma	249	328	-	328	79
	604	656	6	663	59
Tennessee	306	168	-	168	(138)
Total PADD II	4,030	2,981	92	3,074	(956)

TABLE V-12
PADD II LIGHT PRODUCT SUPPLY SOURCES
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2005	2010	2015	2020
Gasoline Production	1,858	1,953	1,978	2,023	2,025	2,070	2,148	2,176	2,171
Transfers	436	490	499	511	544	594	716	761	752
Net Imports + Stock Change	20	10	(10)	3	(3)	(2)	0	2	2
Gasoline (%)									
Production	80%	80%	80%	80%	79%	78%	75%	74%	74%
Transfers	19%	20%	20%	20%	21%	22%	25%	26%	26%
Net Imports + Stock Change	1%	0%	0%	0%	0%	0%	0%	0%	0%
Jet Fuel and Kerosene Production	204	242	230	225	210	221	241	260	279
Transfers	103	126	120	105	116	122	133	144	155
Net Imports + Stock Change	1	1	(1)	2	(2)	(1)	(1)	(1)	(1)
Jet Fuel and Kerosene (%)									
Production	66%	65%	66%	68%	65%	65%	65%	65%	65%
Transfers	33%	34%	34%	32%	36%	36%	36%	36%	36%
Net Imports + Stock Change	0%	0%	0%	1%	-1%	0%	0%	0%	0%
Diesel Production	770	871	848	823	838	908	1019	1069	1114
Transfers	213	221	256	266	302	284	316	383	429
Net Imports + Stock Change	12	12	(7)	12	(3)	3	5	7	8
Diesel (%)									
Production	77%	79%	77%	75%	74%	76%	76%	73%	72%
Transfers	21%	20%	23%	24%	27%	24%	24%	26%	28%
Net Imports + Stock Change	1%	1%	-1%	1%	0%	0%	0%	0%	0%

TABLE V-13
PADD II LIGHT PRODUCT MARKET PENETRATION BY CANADIAN PRODUCT
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2005	2010	2015	2020
Total Light Product Demand									
Regional Total	3,635	3,933	3,918	3,974	4,032	4,202	4,582	4,805	4,913
Regional Production									
Total Regional Production	2,792	2,942	2,970	2,977	2,982	3,107	3,314	3,410	3,469
Ethanol & Other Blendstocks	90	90	89	93	92	92	94	95	94
Net Imports Required	753	902	858	904	958	1,003	1,174	1,300	1,349
Alberta Upgrader Yields	167	167	167	167	167	167	167	167	167
% Penetration Required	22%	18%	19%	18%	17%	17%	14%	13%	12%
Gasoline Demand									
Regional Total	2317	2455	2469	2540	2569	2664	2867	2942	2928
Regional Production									
Total Regional Production	1806	1831	1872	1929	1932	1976	2052	2079	2075
Ethanol & Other Blendstocks	90	90	89	93	92	92	94	95	94
Net Imports Required	421	535	508	519	545	595	721	767	759
Alberta Upgrader Yields	113	113	113	113	113	113	113	113	113
% Penetration Required	27%	21%	22%	22%	21%	19%	16%	15%	15%
Jet Fuel and Kerosene Demand									
Regional Total	323	373	352	333	326	343	374	404	434
Regional Production									
Total Regional Production	217	246	232	226	212	223	242	261	280
Net Imports Required	106	128	119	108	114	121	132	143	154
Alberta Upgrader Yields	3	3	3	3	3	3	3	3	3
% Penetration Required	3%	2%	3%	3%	3%	2%	2%	2%	2%
Diesel Demand									
Regional Total	994	1105	1097	1101	1137	1195	1340	1459	1550
Regional Production									
Total Regional Production	769	866	866	823	838	908	1019	1069	1114
Net Imports Required	225	239	231	278	299	287	321	390	436
Alberta Upgrader Yields	51	51	51	51	51	51	51	51	51
% Penetration Required	23%	21%	22%	18%	17%	18%	16%	13%	12%

TABLE V-14
CHICAGO HUB LIGHT PRODUCTS MARKET PENETRATION BY CANADIAN PRODUCT
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2005	2010	2015	2020
Total Light Products Regional Demands									
Total	1,057	1,165	1,157	1,170	1,183	1,227	1,320	1,370	1,389
Regional Production									
Total Regional Production	742	781	789	791	793	825	879	904	919
Ethanol & Other Blendstocks	22	24	24	25	25	26	27	28	28
Net Imports Required	180	242	223	230	240	245	272	293	298
Alberta Upgrader Yields	167	167	167	167	167	167	167	167	167
% Penetration Required	93%	69%	75%	72%	70%	68%	61%	57%	56%
Gasoline Regional Demands									
Total	728	780	789	809	817	844	902	920	912
Regional Production									
Total Regional Production	490	497	508	523	524	536	557	564	563
Ethanol & Other Blendstocks	22	24	24	25	25	26	27	28	28
Net Imports Required	103	140	136	137	142	151	176	182	177
Alberta Upgrader Yields	113	113	113	113	113	113	113	113	113
% Penetration Required	109%	80%	83%	82%	79%	75%	64%	62%	64%
Jet Fuel and Kerosene Regional Demands									
Total	77	96	91	86	84	87	95	102	109
Regional Production									
Total Regional Production	56	63	60	58	54	57	62	67	72
Transfers	22	33	31	28	29	30	33	35	37
Project Volume	3	3	3	3	3	3	3	3	3
% Of Transfers	14%	9%	10%	11%	10%	10%	9%	9%	8%
Diesel Regional Demands									
Total	252	289	277	275	283	296	323	349	369
Regional Production									
Total Regional Production	197	221	221	210	214	232	260	273	285
Transfers	55	68	56	65	69	64	63	76	84
Project Volume	51	51	51	51	51	51	51	51	51
% Of Transfers	93%	76%	92%	79%	74%	80%	81%	67%	61%

TABLE V-15
MIDWEST LIGHT PRODUCT MARKET PENETRATION BY CANADIAN PRODUCT
(Thousand Barrels Per Day)

State	1995	2000	2001	2002	2003	2005	2010	2015	2020
Total Light Product Demand									
Regional Total	1,941	2,142	2,115	2,143	2,171	2,261	2,453	2,564	2,613
Regional Production	-	-	-	-	-	-	-	-	-
Total Regional Production	1,455	1,532	1,546	1,551	1,552	1,616	1,722	1,772	1,803
Ethanol & Other Blendstocks	65	64	64	66	65	66	67	68	68
Net Imports Required	422	546	505	526	553	579	664	725	743
Alberta Upgrader Yields	167	167	167	167	167	167	167	167	167
% Penetration Required	40%	31%	33%	32%	30%	29%	25%	23%	22%
Gasoline Demand									
Regional Total	1288	1384	1396	1435	1451	1504	1618	1658	1649
Regional Production									
Total Regional Production	950	963	985	1014	1016	1039	1079	1094	1091
Ethanol & Other Blendstocks	65	64	64	66	65	66	67	68	68
Net Imports Required	274	357	347	354	369	399	471	497	491
Alberta Upgrader Yields	113	113	113	113	113	113	113	113	113
% Penetration Required	41%	31%	32%	32%	30%	28%	24%	23%	23%
Jet Fuel/Kerosene									
Regional Total	168	207	195	186	181	191	208	225	242
Regional Production	0	0	0	0	0	0	0	0	0
Total Regional Production	127	144	136	132	124	130	142	153	164
Net Imports Required	41	63	59	54	57	61	67	72	78
Alberta Upgrader Yields	3	3	3	3	3	3	3	3	3
% Penetration Required	7%	5%	5%	6%	5%	5%	4%	4%	4%
Diesel Demand	-	-	-	-	-	-	-	-	-
Regional Total	485	551	524	523	539	566	627	681	722
Regional Production									
Total Regional Production	378	426	426	404	412	446	501	526	548
Net Imports Required	107	126	98	118	127	120	126	155	175
Alberta Upgrader Yields	51	51	51	51	51	51	51	51	51
% Penetration Required	48%	41%	52%	43%	40%	43%	41%	33%	29%

TABLE V-16
DETROIT LIGHT PRODUCT MARKET PENETRATION BY CANADIAN PRODUCT
(Thousand Barrels Per Day)

County	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Total Light Product										
Detroit Metropolitan Counties	177	187	185	186	188	191	193	205	210	211
Detroit Production	50	52	52	52	51	52	52	53	54	54
Net Imports Required	127	135	133	135	136	139	141	152	156	157
Alberta Upgrader Yields	167	167	167	167	167	167	167	167	167	167
% Penetration Required	131%	123%	125%	124%	122%	120%	118%	110%	107%	106%
Gasoline Demand										
Detroit Metropolitan Counties	128	133	134	137	137	140	141	148	149	147
Detroit Production	30	30	30	31	30	30	30	31	31	31
Net Imports Required	98	103	104	106	107	109	110	117	118	116
Alberta Upgrader Yields	113	113	113	113	113	113	113	113	113	113
% Penetration Required	115%	109%	108%	106%	105%	103%	102%	96%	95%	97%
Jet Fuel and Kerosene Demand										
Detroit Metropolitan Counties	15	19	18	17	16	17	17	18	19	21
Detroit Production	6	7	6	6	6	6	6	6	7	8
Net Imports Required	9	13	12	11	11	11	11	12	12	13
Alberta Upgrader Yields	3	3	3	3	3	3	3	3	3	3
% Penetration Required	32%	24%	26%	28%	28%	27%	27%	26%	24%	23%
Diesel Demand										
Detroit Metropolitan Counties	34	35	33	33	34	34	35	39	41	43
Detroit Production	14	16	16	15	16	16	16	16	16	16
Net Imports Required	19	19	17	18	18	19	20	23	26	28
Alberta Upgrader Yields	51	51	51	51	51	51	51	51	51	51
% Penetration Required	263%	263%	301%	289%	279%	270%	261%	222%	199%	184%

TABLE V-17
MIDWEST PRODUCT PRICES
(Current Cents per Gallon)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Chicago (Cents per Gallon)											
Propane	38.43	34.81	59.83	54.19	42.78	63.35	67.09	63.16	56.86	63.23	70.85
Isobutane	48.54	43.66	71.88	67.76	62.17	76.78	81.09	76.94	69.62	77.55	87.71
Normal Butane	39.65	39.93	65.10	53.71	51.08	67.80	76.17	70.05	61.92	69.14	78.42
Regular Unleaded Gasoline	71.05	52.81	87.14	81.72	76.15	91.82	106.79	94.13	83.80	93.49	106.70
Premium Unleaded Gasoline	75.89	57.41	91.71	87.15	81.56	97.27	112.17	99.64	89.79	100.08	114.29
Jet/Kerosene	75.15	52.01	88.18	78.74	72.29	86.94	102.63	91.43	82.40	92.07	105.30
Diesel/No. 2 Fuel Oil	65.88	48.83	83.33	77.66	70.41	84.05	96.63	86.08	77.81	87.03	99.74
Low S Diesel	-------	50.29	85.78	79.42	70.94	85.51	99.09	88.48	82.83	92.57	105.88
1% Sulphur Residual Fuel Oil ($/Bbl.)	20.31	16.30	28.46	23.96	24.76	30.74	31.44	29.02	26.35	29.51	34.01
3% Sulphur Residual Fuel Oil ($/Bbl.)	12.90	12.17	18.66	14.98	18.51	21.52	22.48	20.18	17.00	19.16	22.47
30 ppm S RFG Gasoline	-------	-------	-------	-------	-------	-------	-------	95.81	86.17	97.11	110.79
30 ppm S Premium RFG Gasoline	-------	-------	-------	-------	-------	-------	-------	101.17	92.16	103.71	118.38
Group 3 (Cents per Gallon)											
Propane	35.45	31.83	56.63	50.99	39.58	60.15	63.84	59.90	53.44	59.56	66.89
Isobutane	45.48	40.60	68.68	64.56	58.97	73.58	77.84	73.68	66.20	73.88	83.76
Normal Butane	36.59	36.87	61.90	50.51	47.88	64.60	72.92	66.79	58.50	65.47	74.47
Regular Unleaded Gasoline	70.68	53.15	86.84	81.80	75.56	91.73	106.47	94.18	83.86	93.55	106.77
Premium Unleaded Gasoline	75.67	56.89	90.30	86.68	81.01	97.18	111.86	99.70	89.85	100.15	114.36
Jet/Kerosene	-------	52.10	88.33	78.03	70.30	86.92	101.93	90.89	81.75	91.24	104.25
Diesel/No. 2 Fuel Oil	66.35	50.46	84.21	76.19	69.23	85.03	96.94	86.55	78.23	87.35	99.93
Low S Diesel	-------	51.48	86.36	79.07	70.94	86.49	99.40	88.95	83.25	92.89	106.07
1% Sulphur Residual Fuel Oil ($/Bbl.)	16.89	13.10	24.22	19.68	20.24	25.78	26.24	23.94	21.04	23.64	27.45
3% Sulphur Residual Fuel Oil ($/Bbl.)	12.90	12.17	18.66	14.98	18.51	21.52	22.48	20.18	17.00	19.16	22.47

TABLE V-18
MIDWEST PRODUCT PRICES
(Forecast in Constant 2004 Dollars per Barrel)

	1990	1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Inflation Index (2004=1)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.02	1.13	1.24	1.37
Chicago (Cents per Gallon)											
Propane	38.43	34.81	59.83	54.19	42.78	63.35	67.09	61.92	50.49	50.85	51.61
Isobutane	48.54	43.66	71.88	67.76	62.17	76.78	81.09	75.43	61.82	62.37	63.89
Normal Butane	39.65	39.93	65.10	53.71	51.08	67.80	76.17	68.67	54.98	55.61	57.13
Regular Unleaded Gasoline	71.05	52.81	87.14	81.72	76.15	91.82	106.79	92.28	74.41	75.19	77.72
Premium Unleaded Gasoline	75.89	57.41	91.71	87.15	81.56	97.27	112.17	97.69	79.73	80.49	83.26
Jet/Kerosene	75.15	52.01	88.18	78.74	72.29	86.94	102.63	89.64	73.17	74.05	76.70
Diesel/No. 2 Fuel Oil	65.88	48.83	83.33	77.66	70.41	84.05	96.63	84.39	69.09	70.00	72.66
Low S Diesel	-------	50.29	85.78	79.42	70.94	85.51	99.09	86.74	73.55	74.45	77.13
1% Sulphur Residual Fuel Oil ($/Bbl.)	20.31	16.30	28.46	23.96	24.76	30.74	31.44	28.45	23.39	23.74	24.77
3% Sulphur Residual Fuel Oil ($/Bbl.)	12.90	12.17	18.66	14.98	18.51	21.52	22.48	19.78	15.09	15.41	16.37
30 ppm S RFG Gasoline	-------	-------	-------	-------	-------	-------	-------	93.94	76.52	78.10	80.70
30 ppm S Premium RFG Gasoline	-------	-------	-------	-------	-------	-------	-------	99.18	81.84	83.41	86.23
Group 3 (Cents per Gallon)											
Propane	35.45	31.83	56.63	50.99	39.58	60.15	63.84	58.73	47.45	47.90	48.73
Isobutane	45.48	40.60	68.68	64.56	58.97	73.58	77.84	72.24	58.79	59.42	61.01
Normal Butane	36.59	36.87	61.90	50.51	47.88	64.60	72.92	65.48	51.94	52.65	54.25
Regular Unleaded Gasoline	70.68	53.15	86.84	81.80	75.56	91.73	106.47	92.33	74.47	75.24	77.77
Premium Unleaded Gasoline	75.67	56.89	90.30	86.68	81.01	97.18	111.86	97.74	79.78	80.54	83.30
Jet/Kerosene	-------	52.10	88.33	78.03	70.30	86.92	101.93	89.11	72.59	73.38	75.94
Diesel/No. 2 Fuel Oil	66.35	50.46	84.21	76.19	69.23	85.03	96.94	84.86	69.47	70.25	72.79
Low S Diesel	-------	51.48	86.36	79.07	70.94	86.49	99.40	87.20	73.92	74.71	77.27
1% Sulphur Residual Fuel Oil ($/Bbl.)	16.89	13.10	24.22	19.68	20.24	25.78	26.24	23.47	18.68	19.01	20.00
3% Sulphur Residual Fuel Oil ($/Bbl.)	12.90	12.17	18.66	14.98	18.51	21.52	22.48	19.78	15.09	15.41	16.37

TABLE V-19
WEIGHT FACTOR FOR REGIONAL VERSUS CHICAGO GASOLINE PRICING
(Thousand Barrels Per Day, except as noted)

State	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
Regional Demands													
Northern Illinois	272	274	281	282	287	289	293	297	301	304	306	311	307
NW Indiana	63	65	66	67	68	69	70	71	72	73	74	75	74
Eastern Wisconsin	121	123	126	128	131	133	136	138	140	142	144	148	147
Michigan	324	327	336	340	347	352	358	364	369	374	378	386	384
Total	780	789	809	817	833	844	857	870	882	893	902	920	912
Percentages													
Michigan	42%	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%
Non-Michigan	58%	59%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%	58%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Base Chicago Discount, ¢/Gallon													
Michigan Penalty, ¢/Gallon													
Wtd Detroit Adjustment, ¢/Gallon	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11
Total Discount ¢/Gallon	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.36

TABLE V-20
DIESEL PRICE DISCOUNTING TO PENETRATE MARKET
(Thousand Barrels Per Day)

State		1995	2000	2001	2002	2003	2004	2005	2010	2015	2020
Regional Demands		252	289	277	275	283	289	296	323	349	369
Total Regional Production		199	224	224	213	217	224	235	263	276	288
Transfers		53	65	53	62	66	65	61	60	73	81
Project Volume		51	51	51	51	51	51	51	51	51	51
30% of Transfers		16	20	16	19	20	20	18	18	22	24
Balance		35	32	35	32	31	32	33	33	29	27
		51	51	51	51	51	51	51	51	51	51
Discounts											
1st Tranche	0.25										
2nd Tranche	0.95										
Total ¢ Per Gallon		0.73	0.68	0.73	0.69	0.68	0.68	0.70	0.70	0.65	0.62

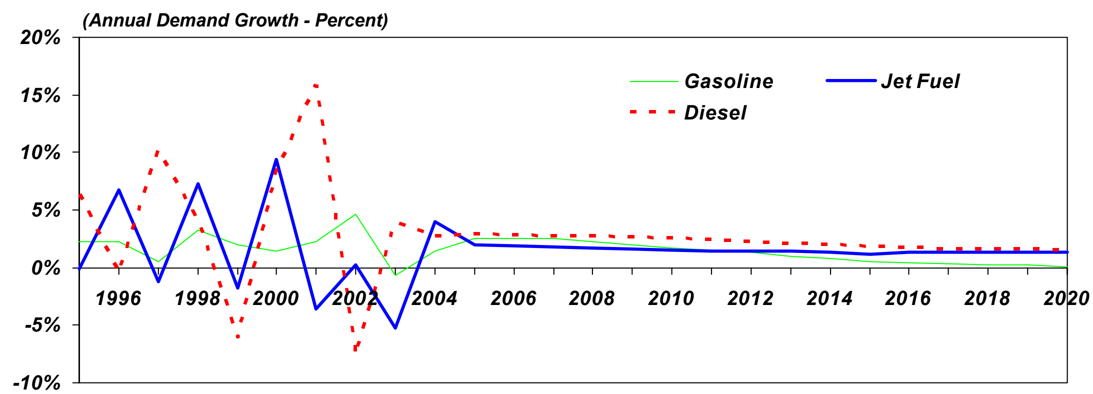
VI. U.S. WEST COAST MARKET ANALYSIS

The U.S. West Coast is a distinct petroleum product market due to its relative geographic isolation and stringent petroleum product specifications. Unless otherwise noted, the U.S. West Coast refers to PADD V, which includes the states of Arizona, Nevada, California, Oregon, Washington, Hawaii, and Alaska. The West Coast is fairly self-sufficient with respect to product supply, although eastern Arizona and Washington receive pipeline supplies from PADDs III and IV, respectively. In recent years, the West Coast has been importing and receiving slightly higher volumes of domestic gasoline, high-valued gasoline blending components, and jet fuel. Other products tend to enter on an opportunistic basis or when refinery outages cause short-term supply disruptions.

PADD V LIGHT PRODUCT DEMAND

Product demand grew rapidly on the West Coast through the 1980s, but consumption increases slowed to about 1.3 percent per year over the past decade. Diesel was particularly hard hit by the recession in 1991-92. Diesel demand has recovered to about 500,000 B/D in 2003, and long term growth is expected to be around 2.5 percent driven by on-road diesel fuel use. Jet fuel showed strong in the 1990s as it captured military demand and travel to the Far East increased. Of course, jet fuel consumption declined in 2001-03 period, as a result of the reduction in travel from the events of September 11th and the coinciding economic slowdown. Gasoline has shown steady increases in demand throughout the historical period and makes up approximately two-thirds of the total transportation fuel consumption in the region. Table VI-1 at the end of this section provides the forecast for total light product consumption in PADD V by state. Figure VI-1 below shows the outlook for demand growth by each major product.

FIGURE VI-1
LIGHT PRODUCT ANNUAL DEMAND GROWTH

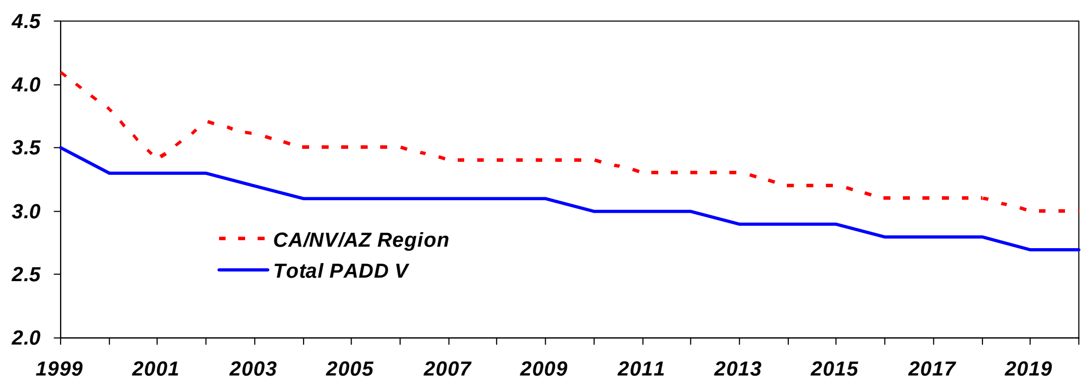


HISTORICAL PADD V LIGHT PRODUCT DEMAND
(Thousand Barrels Per Day)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003
Gasoline	1,260	1,337	1,369	1,376	1,422	1,450	1,470	1,504	1,573	1,563
Jet Fuel	374	414	442	437	469	460	504	485	486	461
Diesel	436	383	381	421	437	410	444	515	476	494
Total PADD V	2,070	2,134	2,192	2,233	2,328	2,321	2,418	2,505	2,535	2,518
Annual Demand Growth - %		2.5%	2.7%	1.9%	4.2%	-0.3%	4.2%	3.6%	1.2%	-0.7%

Nearly 60 percent of the total demand for light refined product is in the state of California, followed by Washington and Arizona at approximately 12 percent and 11 percent, respectively. Given its outlook for continued strong growth, Arizona is expected to surpass Washington in total light product demand by 2006. Gasoline and diesel demand are highly seasonal within Alaska, with winter sales approximately 50 percent lower than sales from June through August.

FIGURE VI-2
GASOLINE / DIESEL DEMAND RATIO



The region is heavily dependent on gasoline as its main transportation fuel as seen by the gasoline to diesel ratios in the figure above. Continued movement towards diesel powered engines in personal automobiles is anticipated reduce this ratio to near 2.5:1 by 2020.

PADD V GASOLINE

Gasoline consumption has grown rapidly over the past four years (2.4 percent per year) to around 1.6 million B/D currently. The outlook for PADD V is for continued growth in demand. Lower growth rates are expected in the outer years as the influence of increasing efficiency, higher prices for reformulated fuels, and growth in alternative fuels begins to influence gasoline demand negatively. Nearly two-thirds of the gasoline consumption for the region takes place in California at approximately 1 million B/D. Table VI-2 at the end of this section provides the forecast for gasoline consumption in PADD V by state.

Historically, premium unleaded gasoline demand has generally exceeded that in the rest of the U.S., except for PADD I, due to the stronger economy, vehicle preferences, and correspondingly higher discretionary premium purchases. Declines in premium demand observed in other regions were also observed in PADD V. In 2000/01, premium was down to about 13.5 percent from a peak of over 21 percent in the early 1990s. Sales have recovered to over 14 percent. Mid-grade appears to have peaked in 1995 at nearly 14 percent and is now down to 7.5 percent.

PADD V GASOLINE GRADE DISTRIBUTION
(Percent)

	1990	1995	1996	1997	1998	1999	2000	2001	2002	2003
Regular Leaded	15.3	-	-	-	-	-	-	-	-	-
Regular Unleaded	61.9	67.7	71.2	72.4	71.7	74.0	76.6	77.1	76.1	78.2
Mid-Grade Unleaded	1.7	13.7	13.4	12.7	12.3	11.1	10.1	9.5	9.5	7.3
Premium Unleaded	21.1	18.5	15.4	14.9	16.0	14.8	13.3	13.4	14.4	14.4

GASOLINE SPECIFICATIONS

All states along the West Coast are subject to the federal ultra-low sulphur (Tier 2) gasoline standard beginning in 2004. Alaska is included in the Geographic Phase-in Area (GPA) which allows deferring the production of ultra-low sulphur gasoline until 2007. In addition, the PADD V market maintains a fragmented number of individual state, county and city boutique specifications for gasoline. The table below summarizes the various gasoline regulations for areas within PADD V. The most stringent of these gasoline specifications is the California Air Resource Board's (CARB) Phase III Reformulated Gasoline Program.

PADD V GASOLINE STANDARDS BY AREA

Region	Gasoline Specifications
California	CARB Ph. III RFG
Maricopa County, AZ	CBG Gasoline (1); Winter Oxy
Clark County, NV	CBG Gasoline (2); Winter Oxy
Tucson, AZ	Winter Oxy
Washoe, NV	Winter Oxy
Oregon (Select Counties)	Winter Oxy
Spokane County, WA	Winter Oxy
Anchorage, AK	Winter Oxy

(1) AZ CBG provides regulations similar to CARB or Federal RFG requirements.
(2) NV CBG limits sulfur and aromatics maximum and average concentrations.

CARB PHASE III REFORMULATED GASOLINE

The Phase III Reformulated Gasoline regulations were adopted in 1999 and were originally scheduled to take effect January 1, 2003, but were delayed until January 1, 2004. However, several major California refiner/marketers voluntarily eliminated the use of MTBE in early 2003, as per the original schedule. Much of the impetus for the Phase III regulation stems from the California MTBE Ban. Outside of the MTBE Ban requirements, Phase III regulations are not substantially more stringent than the Phase II regulations. The MTBE Ban was initiated by Governor Davis with his Executive Order in early 1999. California also pursued a waiver of the Federal oxygenate requirement through two channels. CARB formally requested a waiver of the requirement from EPA on the grounds that CARB Phase III gasoline without oxygen exceeds Federal standards, but the waiver request was denied by the EPA in June 2001. The state subsequently sued the EPA over the decision but no quick resolution of the suit is anticipated. While energy legislation considered in the Congress in 2003 and 2004 would eliminate the RFG oxygen mandate, no bill has yet been passed.

As no relief from the oxygenate mandate is expected in 2004, gasoline produced for Federal ozone non-attainment areas in California will need an oxygen content of at least 2 wt.% percent using ethanol since MTBE is no longer allowed. Ethanol has a very high blending RVP, making it very difficult to use during the summer blending season when CARB specifications call for an RVP of less than 7.0 psi.

PADD V DIESEL

Distillate consumption in PADD V accounts for about 13 percent of the U.S. total. The major reason for the low consumption rate relative to the population and level of economic activity is that there is very little distillate used for heating due to the relatively mild weather in the region. The consumption of distillate on the West Coast is heavily weighted toward transportation fuels. Therefore, growth in distillate consumption will depend primarily on demand for transportation fuels. This dictates the quality requirements, since on-highway diesel must meet low sulphur and reformulated diesel requirements. Heating fuel and diesel fuel for bunkers, railroads, farms, and off-highway use have less stringent specifications currently, but are subject to increased sulphur removal beginning in the 2007 – 2010 time frame. Table VI-3 provides the diesel fuel consumption forecast for PADD V by state.

DIESEL SPECIFICATIONS

All states within PADD V are subject to the ultra-low sulphur diesel standard in 2006, with the exception of Alaska. The state of Alaska has been exempt from meeting the current 500 ppm sulphur specification for on-road diesel and was given the option of developing its own plan to transition to the new ultra-low sulphur (15 ppm), including extending the current national deadline. Alaska has chosen to meet the current national plan of 15 ppm sulphur diesel by 2006 for all urban communities along the Alaska road system connected to the contiguous states and the larger communities served by the marine highway system. Rural Alaskan communities are given a choice to meet the national standards at any time between 2006 and a final deadline of June 2010.

CARB REFORMULATED DIESEL

The reformulated diesel program was adopted in 1988 and implemented statewide in October 1993. The CARB regulations were based on the EPA diesel fuel requirements, which limited diesel fuel sulphur to a maximum 0.05 weight percent. CARB took those requirements one step further by placing a restriction on the allowable aromatics content of the fuel. The basic regulation limited the aromatic content of diesel marketed in California to a maximum of 10 percent while retaining the EPA sulphur limit. Provisions allowed alternative fuel formulations that did not meet the 10 percent limit to be sold if emissions could be shown to be better than those of a 10 percent aromatic fuel based on engine testing results. Most of the complying diesel is manufactured under an approved alternative formulation or under the special small or independent refiner provisions.

PADD V JET FUEL/KEROSENE

Aviation fuels demand in PADD V grew at almost 3.0 percent per year in the past decade. Jet fuel demand is expected to grow at an annual rate of about 2.0 percent through the forecast. Consumption for kerosene for uses other than jet fuel are currently about 3,500 B/D for the entire region and a slow decline is forecast. Table VI-4 provides the jet fuel/kerosene consumption forecast for PADD V by state.

Distribution of demand among the states within PADD V is somewhat different for jet fuel than other light products. This is due to a high level of jet fuel demand that has developed in Alaska as the Anchorage airport has become a very large air cargo fueling hub. Cargo flights between the U.S., Europe, and Asia generally follow great-circle routings that take them over Alaska. The economics of air cargo operations, which seek to maximize the cargo weight carried on any particular flight, encourage operators to minimize fuel carried at the expense of aircraft range, since time enroute is less critical for cargo relative to passengers. Thus, a mid-route refueling stop is generally in economic interest of cargo operators. In addition to the economic advantage of refueling, Anchorage has become a transfer and consolidation center for several cargo carriers.

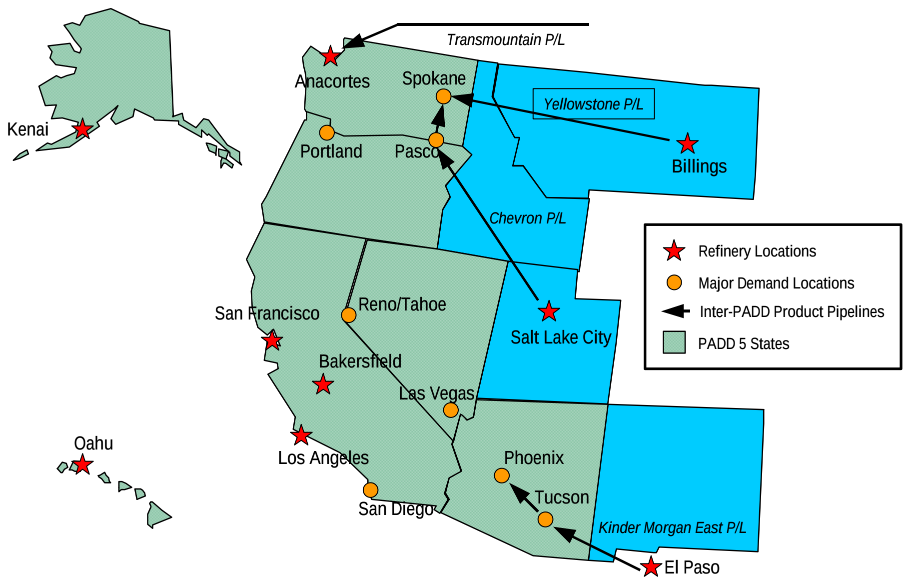
PADD V LIGHT PRODUCT SUPPLY

Given its relative geographic isolation, PADD V has remained fairly self-sufficient with respect to light product supply. Inter-PADD transfers from pipelines and waterborne trade as well as foreign imports provide the balance of supply to the region; however non-indigenous product historically has averaged less than 15 percent of the total supply.

PIPELINE SUPPLY SOURCES

Pipeline supply into PADD V originates from three different refined product sources; Billings, Montana (PADD IV), Salt Lake City, Utah (PADD IV), and El Paso, Texas (PADD III). The figure below illustrates the inter-connection with the various pipelines in the region. In the case of the Yellowstone and Chevron Pipelines from PADD IV, product is supplied to the western Washington area and originates from refining centers located in Billings and Salt Lake City. The Kinder Morgan East Line originates in El Paso, Texas where there is one refinery operating. However, El Paso serves as an inter-connection point for several other pipelines that bring product from the Texas Panhandle refineries, West Texas refineries, and the Gulf Coast refineries as well as refineries in New Mexico. The Kinder Morgan line runs to Tucson, Arizona with a reversible portion of the pipeline running between Tucson and Phoenix.

FIGURE VI-3
INTER-PADD PRODUCT PIPELINE INTERCONNECTIONS



Together these three pipelines have provided approximately 5 – 6 percent of the total light product supply to the PADD V region. Because of the growth of the Arizona market and the relative difficulty in expanding economic supply from California, the Kinder Morgan East Line now operates at 100 percent of capacity year round and requires a proration policy for shippers. Kinder Morgan has studied an expansion of the East Line and estimated a project of approximately $200 million would be necessary to increase the capacity to Phoenix by 44,000 B/D (the pipeline currently delivers approximately 55,000 B/D to Phoenix). A favorable order from the Federal Energy Regulatory Committee (FERC) has prompted Kinder Morgan to move forward with the project at an estimated completion and start-up by the first quarter of 2006. It is assumed that the majority of this capacity increase will be filled by gasoline shipments. There are no other future plans for expansions of existing pipelines or construction of grassroots pipelines for the PADD V region. During the forecast period it is assumed the Kinder Morgan expansion will help boost inter-regional pipeline supply to PADD V to approximately 9 percent by 2010.

SUPPLY OF FOREIGN IMPORTS

Similar to pipeline deliveries, foreign imports have averaged less than 7 percent of total light product supply historically. Total refined product foreign imports have averaged approximately 160,000 B/D during the last five years. The largest volume of product imported into the region is jet fuel, accounting for roughly 40 percent of the total product imports. The majority of the jet fuel imports are sourced from Asia, brought about by a rapid expansion of refining capacity and a corresponding decrease in demand from the region's financial troubles in the mid-1990s.

PADD V REFINED PRODUCT FOREIGN IMPORTS
(Thousand of Barrels per Day)

	1999	2000	2001	2002	2003
Finished Gasoline	23	16	24	16	21
Gasoline Components	8	4	12	13	32
Oxygenates	50	66	61	52	22
Jet Fuel / Kerosene	61	101	75	59	41
Diesel Fuel	10	16	12	4	6
Total Product Imports	152	202	185	143	121

As the phase-out of MTBE from California gasoline started in 2003, component imports replaced oxygenate (MTBE) imports. This trend is expected to continue in 2004 as the majority of ethanol used in producing CARB gasoline is supplied from the U.S. Midwest, and demand for clean gasoline components, alkylate and iso-octane primarily, will continue. Other finished products imports, gasoline and diesel, are relatively sporadic and entry to PADD V is typically done on an opportunistic basis and this trend is expected to continue through the forecast period.

PADD V REFINED PRODUCT FOREIGN IMPORTS BY SOURCE
(Thousand of Barrels per Day)

	1999	2000	2001	2002	2003
Canada	27	37	27	21	20
Asia	56	79	83	64	47
Middle East	31	47	43	35	32
Latin America	22	38	24	18	17
Other	15	1	9	6	6
Total Product Imports	152	202	185	143	121

Sources of foreign imports into PADD V primarily originate in Asia or the Middle East. Asia's imports are primarily finished jet fuel and the Middle East imports have been primarily oxygenates and other gasoline components. Canada supplies roughly 25,000 B/D of finished product primarily to Washington and Alaska. Canadian imports reach the U.S. West Coast via the Trans Mountain Pipeline system. Foreign imports of finished refined product are expected to increase by approximately 1.3 percent per year during the forecast period, although gasoline oxygenates will continue to be replaced by increases in component imports. Total light product foreign imports are expected to average approximately 180,000 B/D by 2020, accounting for roughly 6 percent of the total light product supply for the region. Given a continued outlook for tight supply/demand balances for the region, swings in import levels will likely continue when refinery outages cause supply shortfalls and the resulting price increase creates sufficient arbitrage to cover the cost of freight.

REGIONAL REFINERY SUPPLY

Total crude oil refining capacity in PADD V is just over 3,000,000 B/D, making it the third largest refining region within the U.S., behind the U.S. Gulf Coast and Midwest. The refining industry is characterized by large (>100,000 B/D), complex refineries that are located in proximity to the major regional product markets in large coastal cities. The major refining regions on the West Coast are the Los Angeles, San Francisco, and Puget Sound areas. Small clusters of refineries are located in the San Joaquin Valley of California near Bakersfield, Honolulu, and a few facilities in Alaska. Nearly 85 percent of the region's refining capacity is located in California and Washington.

PADD V REFINERY CAPACITY BY STATE

State	Capacity (BPCD) (1)
Alaska	386,500 (2)
Arizona	-
California	1,936,058
Hawaii	147,700
Nevada	-
Oregon	-
Washington	606,947
Total PADD V	3,077,205

(1) Based on 2003 OGJ Worldwide Refining Survey
(2) Total crude capacity not reflective of product output due to processing scheme.

There are two dominant types of refineries on the West Coast: waterborne light sour crude coking refineries and California heavy crude coking refineries. Variations do exist in terms of both crude supply and complexity. Some refiners process a combination of the two types of crude oil and some refiners in the Pacific Northwest process a combination of Canadian crude oil and some Asian light sweet imports. The complexity of West Coast refiners has advanced appreciably in the last decade both by the addition of conversion capacity and the closure of facilities. Excess capacity, weak refining margins, and the introduction of more stringent CARB product specifications in the mid-1990s resulted in the closure of many simpler refineries and consolidation of capacity into larger coking facilities. These recent changes recent changes and the overall quality of the region's indigenous crude oils, have resulted in the West Coast (California particularly) maintaining some of the most complex refining facilities in the world. The table below summarizes the size and complexity of the refineries in California.

CALIFORNIA REFINING INDUSTRY [1]

	California Heavy Sour Coking	Waterborne Light Sour Coking	U.S. Coking Average (w/o Calif.)
Total Capacity (BPD)	963,300	646,500	9,059,000
Avg. Refinery Capacity (BPD)	120,400	215,500	205,900
Upgrading Capacity as % Total Crude Capacity			
Vacuum Distillation	75%	50%	45%
Coking	37%	23%	19%
Catalytic Cracking	45%	34%	33%
Hydrocracking	24%	18%	6%

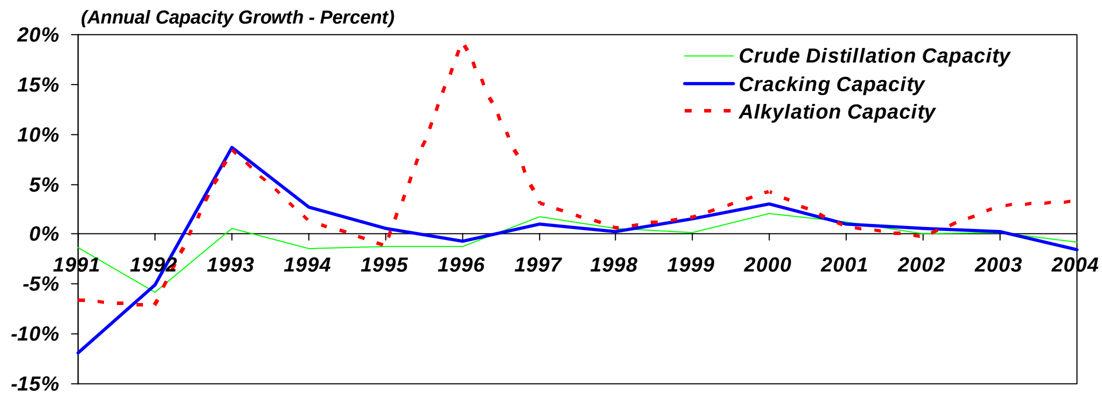
(1) Based on 2003 OGJ Worldwide Refining Survey.

As seen from the table above, the California heavy crude coking refineries have a large ratio of vacuum distillation, catalytic cracking and coking capacity as compared to other coking refineries in the U.S. This is due to the quality of crude oils that these facilities were designed to process, which have a high concentration of vacuum gas oil and vacuum residuum. In addition, these facilities also have rather large capacity hydrocracking units as a result of the strict specifications for CARB refined products, which require sulphur removal and aromatic saturation. The waterborne light sour facilities are similar in configuration to a "typical" U.S. coking facility; however delayed coking and hydrocracking capacities exceed the overall average.

REGIONAL CAPACITY CREEP

Although PADD V has seen some level of capacity rationalization in recent years, the region has shown its ability to creep capacity near typical levels for the overall U.S. refining average. The chart below shows the overall crude capacity expansion of PADD V during the last fifteen years. The chart excludes the state of Alaska refinery capacities, since the highly seasonal demand patterns and processing schemes employed by the local facilities do not represent an accurate reflection of total product output capability.

FIGURE VI-4
PADD V CAPACITY CREEP

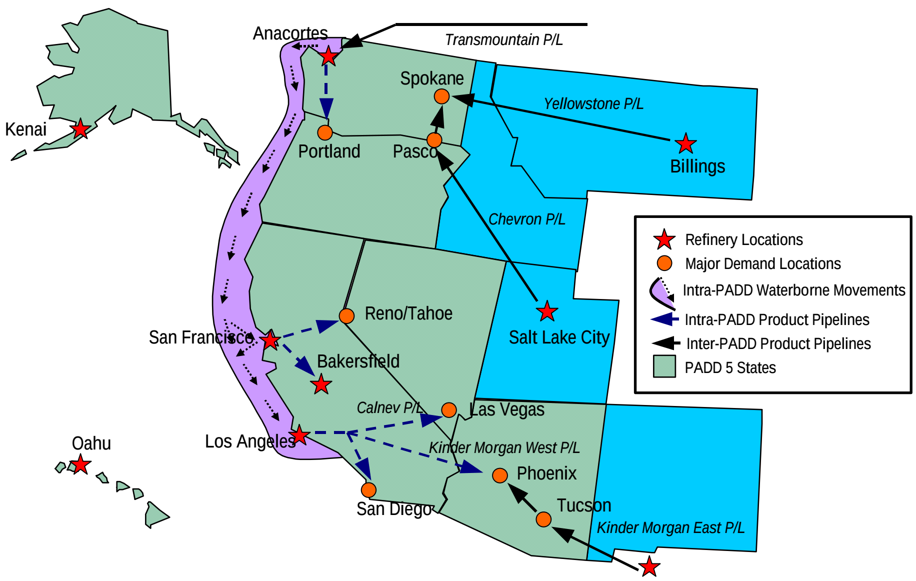


Since 1996 PADD V crude capacity has expanded by approximately 0.5 percent per year. The low period of 1996 corresponds to the CARB Phase II gasoline requirements which led to the closure of a number of less sophisticated refining facilities in California. During the same time period cracking (both fluid catalytic and hydrogen) as well as alkylation have expanded similarly at 0.8 percent and 2.0 percent per annum, respectively. These conversion unit increases have increased the region's ability to supply light product beyond that achievable by crude capacity expansions alone. Recently capacity expansions in the region have slowed, including a slight contraction in 2003-2004 as some refiners lost economic capacity as a result of tougher CARB Phase III gasoline requirements. It is anticipated that in the near-term (2005 – 2010) refined product production in PADD V will increase to meet growing demand (1.5 – 2 percent per annum) before reaching approximately 1 percent per year annual growth longer term. The outlook for the PADD V light product supply/demand balance is shown in Table VI-5 at the end of this section.

PADD V PRODUCT SUPPLY REGIONS

PADD V can be further segregated into regional supply centers, where refinery concentration of capacity and regional pipelines dictate how product is distributed to demand centers. The figure below illustrates the three major supply areas within PADD V.

FIGURE VI-5
PADD V REFINED PRODUCT SUPPLY REGIONS



Alaska and Hawaii operate primarily in a self-sufficient manner although some imports and intra-PADD trade does exist. The Washington/Oregon region is nearly balanced with respect to light product supply/demand, with excess production in Washington supplying northern Oregon as well as component trade to California. Net waterborne movements from the region flow south into California, although some finished gasoline moves from Northern California to the Oregon coast. The California/Nevada/Arizona (CA/NV/AZ) region encompasses the largest production and consumption region within PADD V, accounting for over 70 percent of the PADD V totals. This region can be further defined by Northern and Southern California sections, Northern California section covering the Bay Area, Fresno and northern Nevada (primarily Reno and Lake Tahoe) while Southern California includes the major markets of Los Angeles, San Diego, Las Vegas and Phoenix. Demand splits for this region are roughly 35 percent Northern California and 65 percent Southern California. There is also net waterborne traffic of product trade south from the Bay Area to Los Angeles. The table below estimates the supply/demand balances for light product in 2003 based upon the supply regions outlined above.

PADD V REGIONAL SUPPLY/DEMAND BALANCES
(Thousand of Barrels per Day)

Regional Supply Center	Refinery Prod.	Net Receipts (1)	Stock Change	Exports	Total Demand
California/Nevada/Arizona	1,607	303	18	(36)	1,892
Washington/Oregon	468	21	5	(13)	480
Alaska/Hawaii	179	(29)	1	(6)	146
Total PADD V	2,254	294	24	(55)	2,518

(1) Net receipts include foreign imports, inter-PADD transfers and intra-PADD transfers.

The supply region requiring the largest amount of net receipts is the CA/NV/AV region. Given net movements within this region (i.e. San Francisco to Los Angeles), the logical location for delivering product to PADD V would be the Los Angeles area, which is the major product manufacturing location has the capability of receiving product through waterborne means of transportation.

PADD V PRODUCT PRICING MECHANISMS

West Coast product prices are determined by a combination of local factors and interaction with other major refining markets. During normal times, product prices trend toward levels dictated by local supply/demand economics. However, the West Coast will occasionally shift out of balance and require shipments into or out of PADD V to reestablish the balance. During such times, prices are dictated by the cost of competitive supplies from external locations. It is instructive to analyze West Coast product prices in terms of four operating modes: Surplus Supply, Balanced, Direct Shipment, and Supply Disruption.

Over-Supply: In this mode the West Coast has excess product and shipments to the U.S. Gulf Coast or other locations take place. Prices are determined by export economics. Although surplus product supplies can be "relieved" through shipments to Latin America or the Pacific Rim, West Coast product prices may fall as low as 6 cents per gallon under the U.S. Gulf Coast product prices, in the extreme, while in this mode.

Balanced: In this mode the West Coast is balanced and prices are set by local supply/demand factors and refinery economics. While operating in this mode prices may range from 0 to 6 cents per gallon over the U.S. Gulf Coast, but tend to average close to a 5 cent per gallon premium.

Direct Shipment: In this mode the West Coast refinery system is short and supplies arrive fairly ratably from the U.S. Gulf Coast or other locations. Prices are determined by the economics of bringing cargoes from the U.S. Gulf Coast and most often range between 7 and 15 cents per gallon over the U.S. Gulf Coast depending on the cost of transportation, availability of supplies meeting California specifications, and other factors.

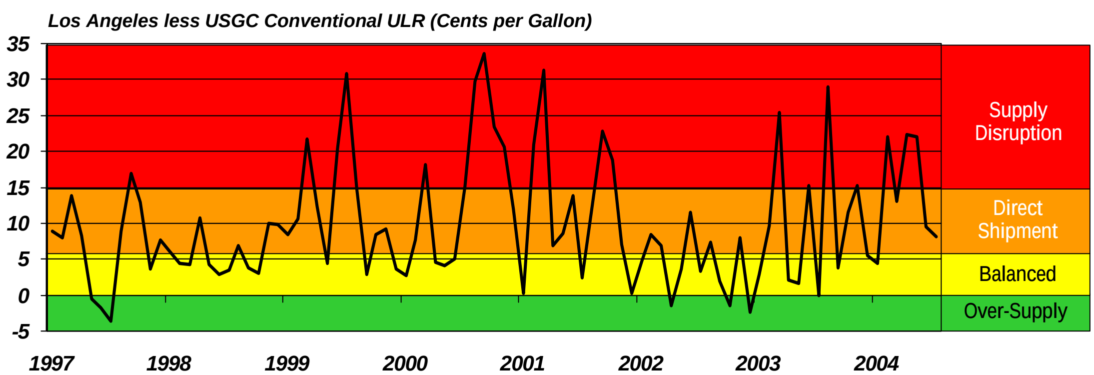
Supply Disruption: In this mode the West Coast has experienced a substantial supply disruption that can only be accommodated by large-scale imports from foreign sources. Prices have reached 50 cents per gallon over the U.S. Gulf Coast in severe cases for short periods.

The West Coast refining system may operate in all four modes during any given year with the frequency of operation in any particular mode determined largely by the overall supply/demand balance.

The West Coast refining system has tightened considerably over the last decade. Growing regional demand for petroleum products, combined with refinery closures has tightened the product balance. In addition, the refining system lost a degree of supply flexibility with the introduction of CARB specification products in the mid-1990s. The tighter specifications make it much more difficult for local refiners to blend around operational problems or produce incremental product during times of shortfall. When fuel specifications were simpler, refineries had more ways to manufacture products without violating critical specifications. Tighter specifications also introduce barriers to product supplies from outside the region. The supply barriers result because specific blends must be produced for shipment or highly valued blending components such as alkylates must be supplied to the geographically isolated California market.

As a result, the West Coast refining system has operated much more frequently in the Direct Shipment and Supply Disruption mode since the introduction of CARB reformulated gasoline, leading to higher product prices and higher refining margins over time. The figure below illustrates the frequency of operation in the various modes over the last several years. Whereas it used to take significant world events to drive West Coast prices into the Supply Disruption mode, now any moderate refinery upset can drive the system into the Supply Disruption mode in the post-CARB gasoline era.

FIGURE VI-6
U.S. WEST COAST GASOLINE PRICING MECHANISM

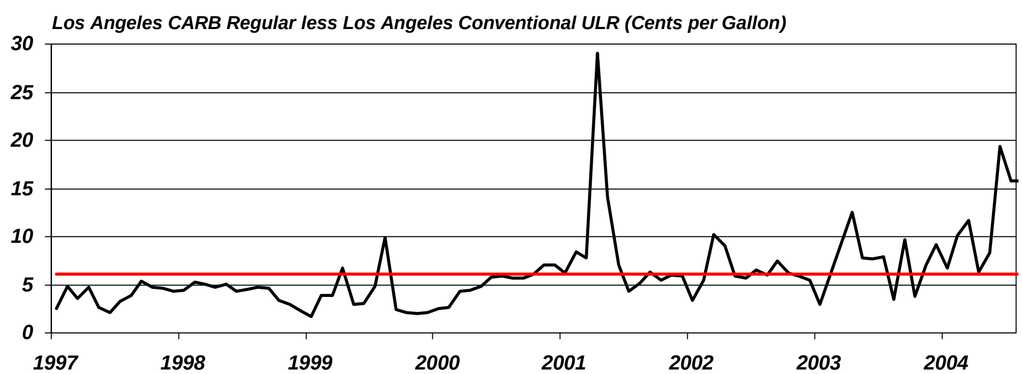


We expect the West Coast refining system to continue to experience occasional supply disruptions over the next five years. The result will be a continuation of strong refining margins on an average annual basis with periods of extreme upward price volatility over any particular year as the system moves in and out of the various operating modes. We expect the Direct Shipment mode to dominate West Coast product price determination until the current market tightness is relieved. Longer-term, the combination of the expected startup of the Longhorn pipeline and more routine shipments of CARB gasoline and blending components will likely result in a tighter relationship with U.S. Gulf Coast product prices and may reduce the frequency of upward price volatility for West Coast product prices.

CALIFORNIA GASOLINE PRICES

The differential for CARB Phase II gasoline versus conventional gasoline since 1997 is shown in the figure below. Although volatility continues to exist, the differential between CARB and conventional unleaded gasoline generally has ranged from 2 to 6 cents per gallon. In spite of the sharp spike in early 2001, the differential averaged about 6 cents per gallon over the 1997-2004 period.

FIGURE VI-7
HISTORICAL CALIFORNIA GASOLINE PRICES



Conventional gasoline is being phased out of the market and is losing relevance to refinery economics in the region. Currently, conventional gasoline manufactured in California is still supplied to Nevada and small portions of Arizona. However, these markets are expected to diminish in coming years. Both Phoenix, Arizona and Las Vegas, Nevada have introduced their own grades of reformulated gasoline known as “Cleaner Burning Gasoline” (CBG). Pacific Northwest refiners still produce the majority of their gasoline as conventional, but supply some volumes of CARB gasoline and components to California.

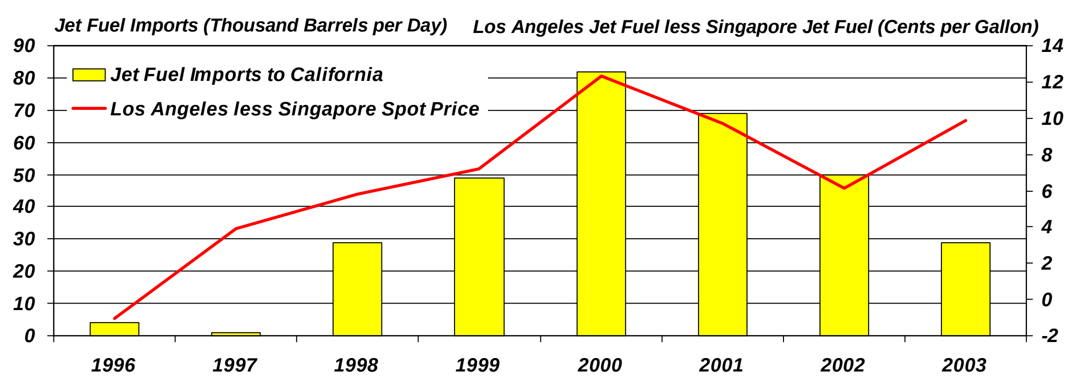
The differential between CARB and conventional gasoline prices should not be interpreted in terms of refinery profitability on CARB investments. Because conventional gasoline has very limited markets and many California refineries can produce 100 percent CARB gasoline, conventional gasoline sells at the CARB price less the variable operating cost of production. This variable cost difference does not necessarily imply that the refiner is not making a return on the CARB investment because the alternative of making large quantities of conventional gasoline does not exist. Thus, the price of conventional in the post-CARB period is not the same as it would have been had CARB gasoline not been introduced.

In developing our gasoline price forecast, Purvin & Gertz has assumed the RFG oxygenate requirement will be lifted in 2005. MTBE use ceased completely in California in 2004. Following these assumptions, incremental operating costs have been estimated at 3 to 4 cents per gallon. If the oxygen mandate remains in place, higher costs will come from the cost of ethanol, but also from the costs of pentane rejection and other changes made to accommodate the ethanol. The impact of a portion of the industry moving away from MTBE in 2003 resulted in pressure on gasoline supplies, and produced a sharp increase in the CARB-conventional differential as the transition to summer-grade CARB occurred in early 2003. In early 2004, with the full implementation of the MTBE ban and gasoline markets tight throughout the U.S., the differential spiked again.

CALIFORNIA JET FUEL PRICES

The U.S. West Coast has a very large relative demand for jet fuel due to the presence of several major international and transcontinental transportation hubs. The high proportion of jet fuel typically requires incremental jet fuel to be made through hydrocracking at the expense of gasoline rather than diesel, the norm in most other markets. However, with the increasing pressure to supply gasoline in the California market in recent years, imports of jet fuel have increased as jet fuel is a more fungible fuel than CARB gasoline. The figure below illustrates the level of jet fuel imports to California, with reductions recently related to lower overall demand.

FIGURE VI-8
HISTORICAL CALIFORNIA JET FUEL FOREIGN IMPORTS



The figure above also illustrates the spot price difference for jet fuel between Los Angeles and Singapore. During periods of high import levels the Los Angeles price responds to import parity levels, as differentials above 6 – 8 cpg allow sufficient recovery of transportation costs between the Far East and the U.S. West Coast.

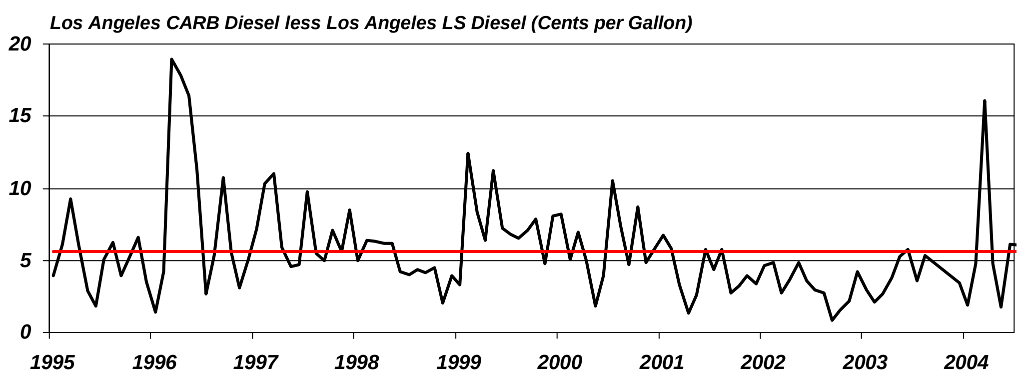
The differential between gasoline and jet fuel is very volatile depending on the local supply/demand situation. In the low gasoline demand season, jet fuel typically becomes more expensive than even CARB unleaded gasoline. Conversely, during the strong gasoline season, gasoline prices can reach 10 to 15 cents per gallon higher than jet fuel prices. On an annual average basis, we forecast jet fuel to be 9 to 12 cents per gallon less than regular CARB gasoline.

CALIFORNIA DIESEL PRICES

Most refiners in California now have the capability to produce substantial volumes of CARB reformulated diesel. CARB diesel is produced under alternative formulation rules rather than meeting the absolute 10 percent aromatics specifications. In many cases, these alternative formulations allow aromatics content in the 20 percent to 25 percent range, but require very low sulphur and nitrogen content. Individual alternative formulations are generally trade secrets and therefore each refining company produces CARB diesel to a different set of specifications.

EPA low sulphur diesel is manufactured for adjacent regional markets and a small volume of high sulphur international grade is produced and exported. Export cargo prices are linked to international prices. However, the CARB grade product is dependent only on local supply/demand factors. As a result, the differential between CARB diesel and conventional low sulphur diesel varies considerably. The figure below illustrates the historical differential between CARB diesel and low sulphur diesel in Los Angeles. Our forecast is based on an annual average differential of 4.5 cents per gallon for the Los Angeles market. Forecast prices for light products in California are shown in Table VI-6 at the end of this section.

FIGURE VI-9
HISTORICAL CALIFORNIA DIESEL PRICES

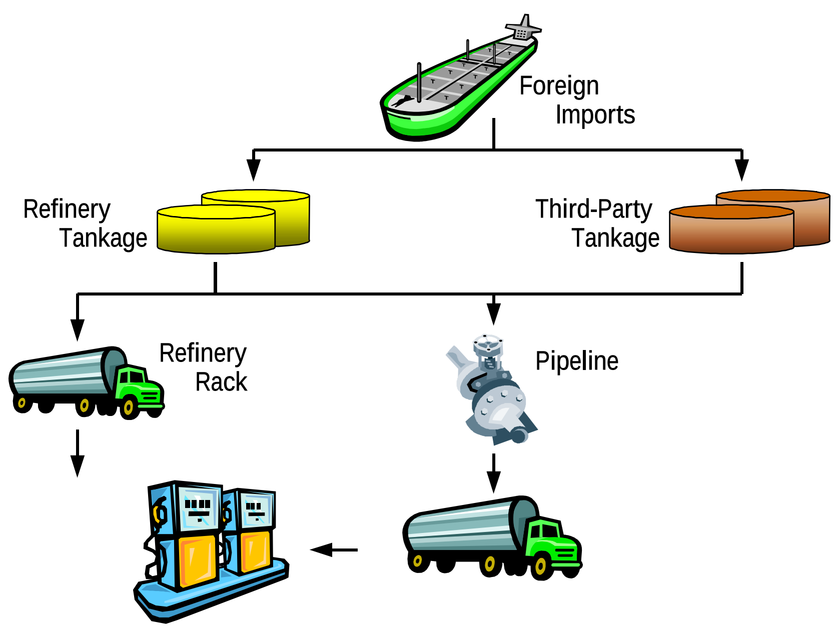


ALBERTA PROJECT IMPACT ON PRICES

The Alberta refinery case for California grade products has a design basis to produce 112,500 B/D of Regular CARBOB (California Reformulated Non-Oxygenated Gasoline Blendstock), 18,400 B/D of jet fuel and 21,000 B/D of CARB Diesel. Purvin & Gertz has determined what the corresponding pricing effect for each product would be if this level of production were delivered to the CA/NV/AZ supply region, assuming the material would enter the region through the Los Angeles refining center. The pricing impact is based upon the anticipated volume of each product from the Alberta project and to what level or class of supply it penetrates.

There is an underlying discount of similar magnitude for each product based upon the cost to transport product from a waterborne delivery to a marketable site (pipeline or rack location). This cost represents typical logistic mechanisms for delivery of foreign imports, which include utilization of dock and wharfage facilities, intermediate storage, and harbor to inland location pipeline tariffs. The cost of such services ranges from 1 – 1.5 cpg. The figure below provides an illustration of this mechanism.

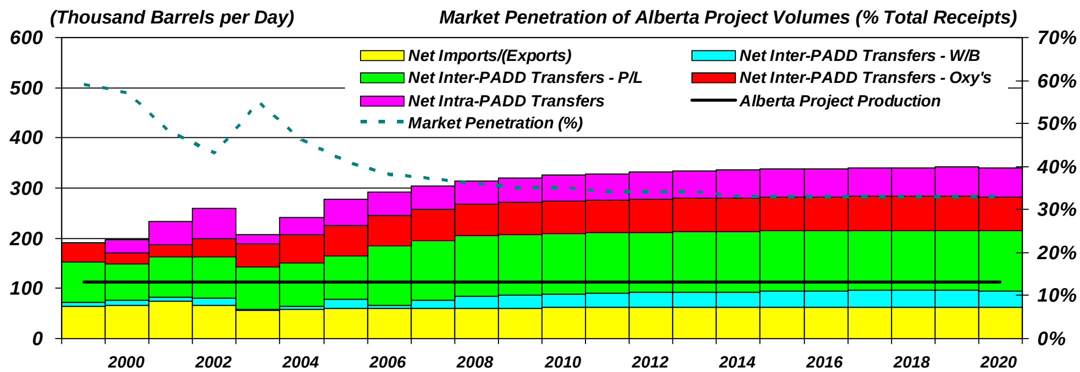
FIGURE VI-10
LOGISTIC STRUCTURE FOR IMPORTED GASOLINE VOLUMES



ALBERTA PROJECT GASOLINE PRICE DISCOUNTS

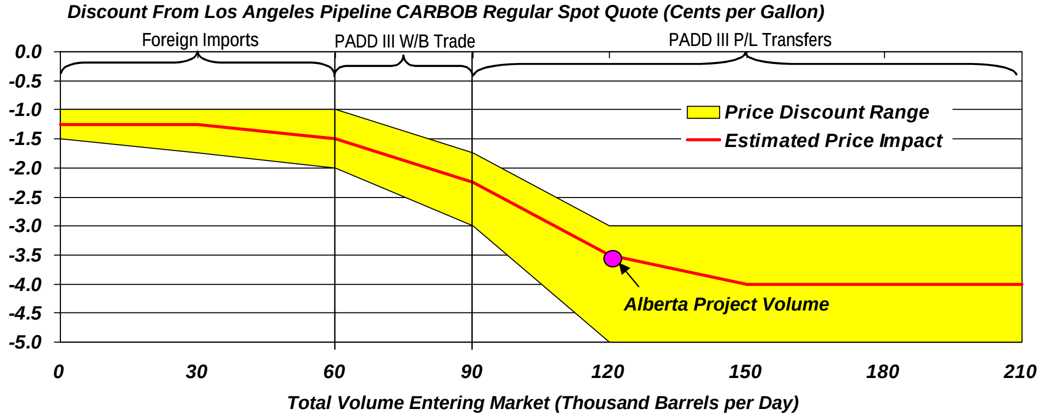
Based upon the forecast supply/demand balance for gasoline in the CA/NV/AZ supply region, incremental non-indigenous supply of gasoline and gasoline components will come from foreign imports (~ 60,000 B/D), Inter-PADD waterborne movements (~ 30,000 B/D) as well as from PADD III pipeline supply (Kinder Morgan East Line), see Figure VI-11 below. In order for the Alberta Project to place the entire 112,500 B/D of product it will be required to displace an equal volume of these incremental supply modes.

FIGURE VI-11
GASOLINE MARKET PENETRATION – CA/NV/AZ SUPPLY REGION



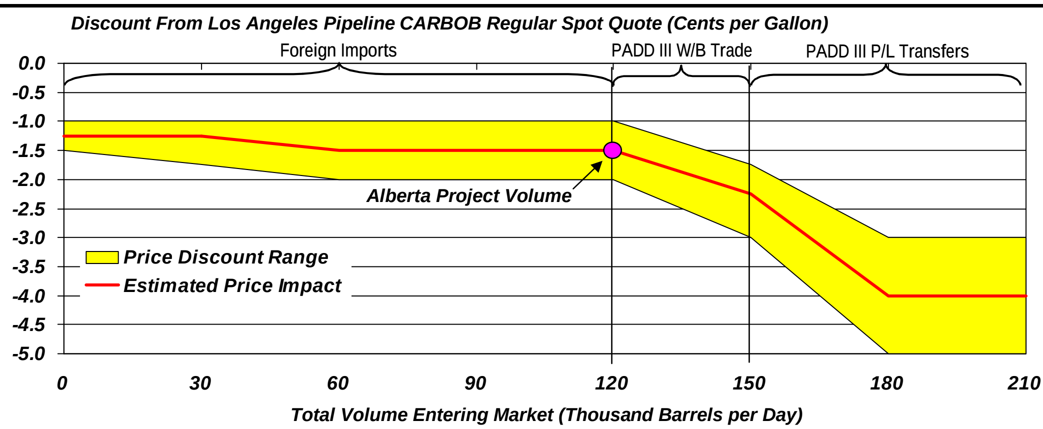
Foreign imports would be the first tier to displace as they are most sensitive to price changes in the market. In order to enter the market with volumes required to displace the majority of foreign imports, sufficient incentives would be required to discourage opportunistic imports. While price indexation mechanics present a difficulty unlike the Midwest where products can be marked off the Gulf Coast, we believe that a continuous presence at price levels averaging 0.5 – 1.0 cpg below the forecast level would provide sufficient disincentive for most offshore imports. The next supply mode is waterborne transfers of product (primarily PADD III). This level of supply is typically intra-company related and is movement of primarily components from one company's facility along the U.S. Gulf Coast to its refinery on the U.S. West Coast. This level of movement is typically made due to manufacturing synergies within a refining system and therefore would require incremental pricing discounts to discourage this level of movement. For purposes of this analysis we believe price reductions in the range of 1 – 3 cpg would eliminate the benefit of integration of remote locations for these types of movements. The last level of supply penetrated by the Alberta Project would be pipeline transfers from East Texas into Arizona. In this case, incremental Alberta Project volumes require refineries that supply this pipeline to reduce crude runs and/or divert product to other locations if logistically possible. In this case price discounts would have to reach level that incremental crude runs are uneconomical or alternative markets become attractive. This would require higher discounts in the range of 3-5 cpg. Given the potential for a wide-range of potential discounts, the mid-point (3.3 cpg) of the range is used to establish a base case discount for the Alberta Project gasoline supplied to the market. The figure below illustrates the methodology described.

FIGURE VI-12
EXPECTED MARKET RESPONSE TO ALBERTA PROJECT GASOLINE VOLUMES



As a sensitivity to the forecast basis for refinery production increases, we have also prepared a pricing impact case should capacity creep average only 1 percent per year on average. In this case a larger volume of foreign imports would be required into the region in order to meet demand levels. Therefore, discounts would be of a lower magnitude since the Alberta project volume would be penetrating less severe market supply modes.

FIGURE VI-13
MARKET RESPONSE TO ALBERTA PROJECT GASOLINE VOLUMES – 1% CREEP CASE



ALBERTA PROJECT DIESEL PRICE DISCOUNTS

Utilizing similar methodology to estimate price discounts associated with gasoline volumes, diesel price discounts were determined. The U.S. West Coast market is a net exporter of diesel, and therefore increased volumes brought into the market would exacerbate this imbalance. CARB diesel produced and delivered to the West Coast as part of the Alberta

Project would require penetration into more efficient modes of supply, thereby increasing the potential discount.

FIGURE VI-14
DIESEL MARKET PENETRATION – CA/NV/AZ SUPPLY REGION

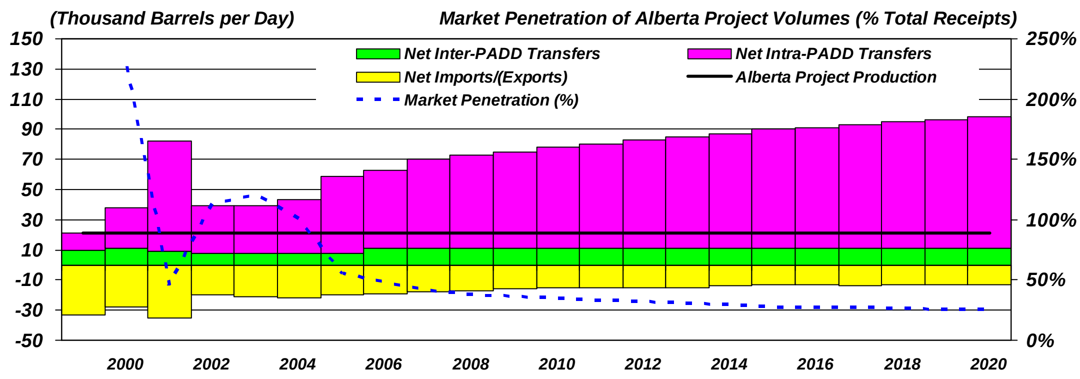
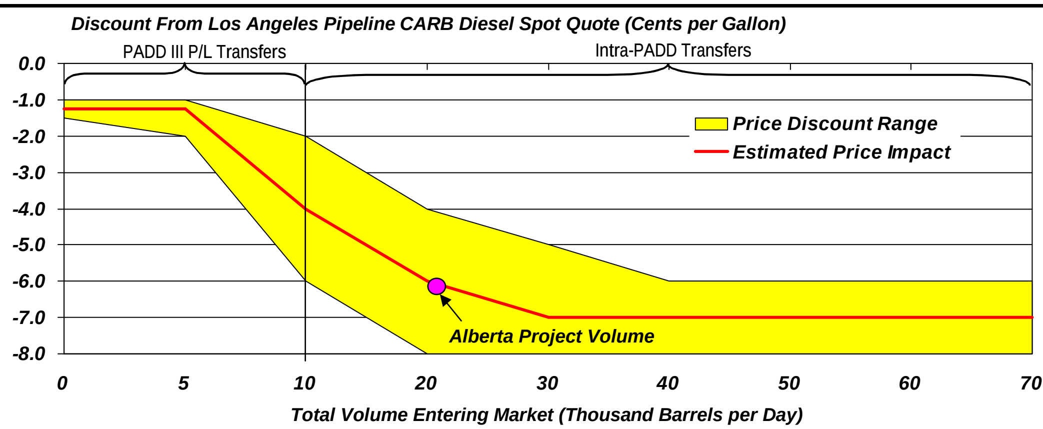


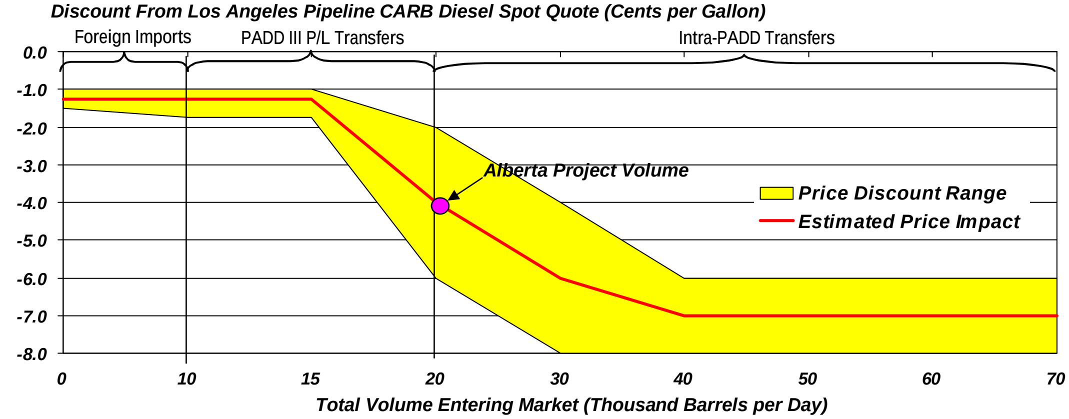
FIGURE VI-15
EXPECTED MARKET RESPONSE TO ALBERTA PROJECT DIESEL VOLUMES



The first level of market penetration would be pipeline transfers from PADD III, given diesel's position as a net export product. This volume would have similar discounts to the gasoline market, requiring a magnitude large enough to discourage incremental crude runs or diverting material to alternative markets. The second level of supply would be intra-PADD transfers. These represent primarily intra-company movements of CARB diesel and/or CARB diesel blending components (i.e. hydrocracker diesel) from Washington refineries to California facilities. Given the efficient nature of such movements, the discounts associated with this level of supply would have to be large enough to discourage production of CARB diesel from these refineries. This level of discount is estimated to be roughly 4 – 8 cpg, with a mid-point of 6.3 cpg used for base case analysis.

Similar to gasoline, a sensitivity case was constructed recalculating supply/demand balances for the region if refinery production were to grow at 1 percent per annum. The price impact is mitigated in this case since foreign imports would become necessary to meet demand.

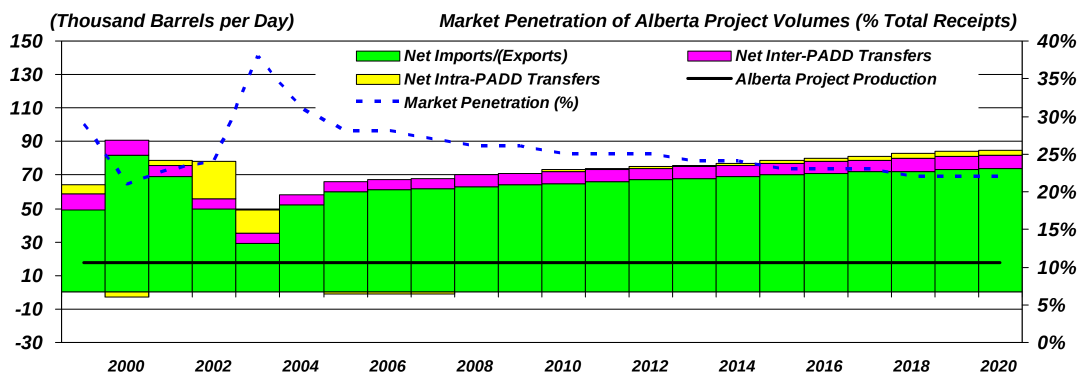
FIGURE VI-16
MARKET RESPONSE TO ALBERTA PROJECT DIESEL VOLUMES – 1% CREEP CASE



ALBERTA PROJECT JET FUEL PRICE DISCOUNTS

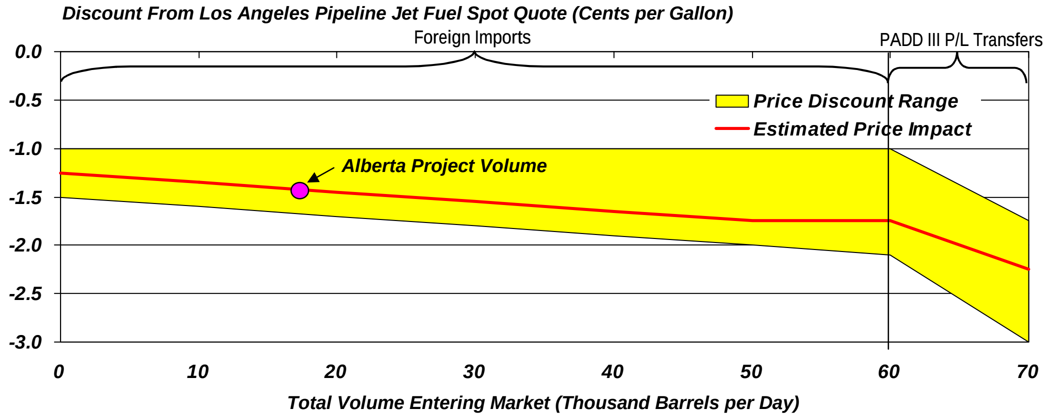
Unlike gasoline and diesel, the West Coast imports a significant amount of jet fuel to balance demand. The Alberta Project design basis calls for a relatively small volume of finished jet fuel, thus the anticipated pricing discounts are lower.

FIGURE VI-17
JET FUEL MARKET PENETRATION – CA/NV/AZ SUPPLY REGION



Forecast supply/demand balances assume approximately 60,000 B/D of jet fuel imports for the CA/NV/AZ market requirements, which exceeds the Alberta Project jet fuel volume by nearly three times. Therefore, discounts are only of the magnitude to discourage distant foreign imports to the market. For purposes of this analysis it is assumed jet fuel would require discounts of 1.4 cpg versus the quoted market price.

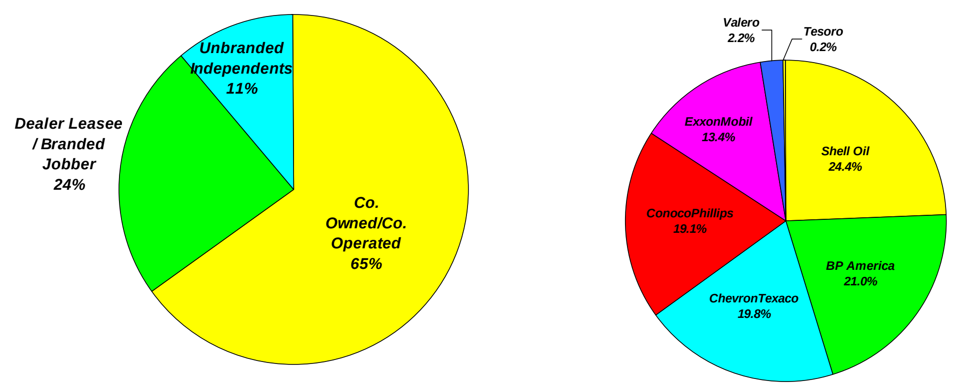
FIGURE VI-18
EXPECTED MARKET RESPONSE TO ALBERTA PROJECT JET FUEL VOLUMES



CALIFORNIA RETAIL MARKETING

The retail gasoline market in California is highly concentrated among a finite number of companies. These companies, which also operate refineries in the region, account for approximately 90 percent market share through company-owned/company-operated, dealer lease or branded jobber retail marketing structures. Based on information gathered from public sources some level of retail market share for California can be determined. The left pie chart shows a breakdown by company of the company-owned/company-operated stores in California. Information is incomplete on dealer lease and branded jobber retail outlets, therefore a full market share by company is not attainable.

FIGURE VI-19
CALIFORNIA GASOLINE RETAIL MARKET SHARE



Supply of gasoline in the market follows a similar market structure as seen in the table below.

CALIFORNIA RETAIL MARKETING STRUCTURE

Company	Gasoline Supply Market Share (1)	Retail Structure	Gasoline Retail Market Share (2)
BP America	20.2%	Co-Op/Dealer Leasee	65.0%
ChevronTexaco	18.1%	Branded Dealers/Jobbers	24.0%
Shell Oil Co.	15.0%		
ConocoPhillips	14.5%		
Valero	10.1%		
ExxonMobil	6.8%		
Tesoro	4.8%		
Total CA Refiners	89.5%	Total CA Refiners	89.0%
Other Suppliers	10.5%	Unbranded Independents	11.0%

(1) Based on 2003 Board of Equalization data.
(2) Based on 2004 California State Assembly Hearing data.

As seen by the balances between retail gasoline supply and retail market share some companies require net purchases of material from either other local market participants or independent sources. These imbalances have become more frequent given the high level of merger and acquisition activity along the West Coast in recent years. Two large independent gasoline suppliers, Valero and Tesoro, have emerged in the market without significant integrated retail sites. Therefore these companies provide a large percentage of the merchant supply in the area to other refining companies, independents and hypermarkets.

STRATEGY FOR ENTERING CALIFORNIA MARKET

In the case of gasoline sales, the structure of the current market minimizes the level of spot trade that occurs between market participants. In addition, independent or third-party logistic structures for delivery of waterborne imports is limited, making it necessary to utilize some amount of assets owned/operated by the major market players. Successful entry into the market would require some level of advanced negotiations with current market participant. Those marketers who are currently in need of additional supply are engaged in longer-term contracts given the low availability of spot volume. This would require Alberta Project developers to seek long-term arrangements in advance of actual completion of construction for the facility.

Independent entry for jet fuel and diesel is likely less restrictive. Major airlines and cargo carriers are large consumers of jet fuel along the U.S. West Coast. The international carriers have the ability to purchase imported barrels and enter them into Customs bonded storage. These “bonded” imports can be withdrawn from storage duty free when used for fuel on aircraft destined on international flights. A much larger wholesale market is available for fuel, as large trucking or commercial operations purchase fuel in this manner. Independent suppliers such as Petro-Diamond and Itochu have larger wholesale diesel market shares versus the larger integrated marketers/refiners.

TABLE VI-1
PADD V LIGHT PRODUCT DEMAND FORECAST
(Thousand Barrels Per Day)

State	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Alaska	76	68	72	64	70	80	85	86	93	84	89	95	89	89	92	95
Arizona	188	189	193	205	213	224	239	240	260	268	278	289	297	298	308	319
California	1,275	1,230	1,253	1,219	1,247	1,269	1,284	1,317	1,356	1,364	1,421	1,472	1,496	1,481	1,506	1,536
Hawaii	57	58	54	52	55	55	54	54	54	54	58	63	59	58	59	60
Nevada	75	75	79	82	87	90	99	101	107	104	109	113	115	116	120	125
Oregon	157	154	151	153	156	159	164	163	175	170	176	179	179	179	182	187
Washington	250	245	246	245	260	264	272	278	288	286	295	301	305	304	311	319
Total PADD V	2,078	2,019	2,047	2,019	2,088	2,141	2,198	2,240	2,334	2,328	2,426	2,511	2,541	2,524	2,577	2,641
Annual Demand Growth - %		-2.9%	1.4%	-1.4%	3.4%	2.5%	2.7%	1.9%	4.2%	-0.3%	4.2%	3.5%	1.2%	-0.7%	2.1%	2.5%

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Alaska	97	97	99	101	103	105	107	108	110	111	112	114	115	116	117
Arizona	330	342	352	363	373	382	392	400	409	417	423	430	436	441	447
California	1,571	1,609	1,642	1,671	1,699	1,723	1,745	1,763	1,777	1,788	1,799	1,809	1,818	1,826	1,834
Hawaii	61	60	61	62	62	63	64	64	65	65	65	66	66	66	66
Nevada	129	133	137	141	145	149	152	156	159	162	164	166	168	170	172
Oregon	191	194	198	202	205	208	211	213	215	217	218	220	221	222	223
Washington	328	335	343	350	356	362	368	373	377	380	384	387	390	393	396
Total PADD V	2,705	2,770	2,832	2,889	2,943	2,992	3,037	3,077	3,111	3,140	3,166	3,190	3,213	3,235	3,255
Annual Demand Growth - %	2.4%	2.4%	2.2%	2.0%	1.9%	1.7%	1.5%	1.3%	1.1%	0.9%	0.8%	0.8%	0.7%	0.7%	0.6%

TABLE VI-2
PADD V GASOLINE DEMAND FORECAST
(Thousand Barrels Per Day)

State	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Alaska	16	14	16	16	18	20	18	17	18	18	19	17	19	19	19	20
Arizona	108	111	114	118	124	129	135	134	144	150	155	160	170	170	175	181
California	838	818	865	846	843	859	872	885	904	925	939	964	1,005	995	1,005	1,026
Hawaii	24	25	24	25	26	26	26	26	26	25	25	27	28	27	28	28
Nevada	41	42	44	44	47	49	52	55	60	59	60	63	67	67	69	72
Oregon	87	88	87	92	93	93	96	92	100	100	99	99	103	103	104	107
Washington	146	149	151	157	157	161	169	168	169	173	173	174	182	182	185	190
Total PADD V	1,260	1,247	1,302	1,298	1,308	1,337	1,369	1,376	1,422	1,450	1,470	1,504	1,573	1,563	1,584	1,624
Annual Demand Growth - %		-1.1%	4.4%	-0.2%	0.7%	2.3%	2.3%	0.5%	3.3%	2.0%	1.4%	2.3%	4.6%	-0.7%	1.4%	2.5%

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Alaska	20	21	22	22	22	23	23	23	24	24	24	24	24	24	24
Arizona	187	194	200	206	212	216	221	226	229	233	236	238	240	242	244
California	1,050	1,074	1,096	1,115	1,132	1,147	1,159	1,169	1,175	1,178	1,181	1,183	1,184	1,184	1,184
Hawaii	29	29	30	30	30	31	31	31	31	31	31	31	31	31	31
Nevada	74	77	79	81	84	86	87	89	90	92	93	94	94	95	95
Oregon	109	111	114	116	117	119	120	121	122	122	123	123	123	123	122
Washington	195	200	204	208	212	215	218	220	222	223	224	225	226	226	227
Total PADD V	1,664	1,705	1,744	1,778	1,809	1,837	1,860	1,879	1,894	1,904	1,912	1,917	1,922	1,926	1,927
Annual Demand Growth - %	2.5%	2.5%	2.3%	2.0%	1.7%	1.5%	1.3%	1.0%	0.8%	0.5%	0.4%	0.3%	0.2%	0.2%	0.1%

TABLE VI-3
PADD V DIESEL DEMAND FORECAST
(Thousand Barrels Per Day)

State	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Alaska	32	27	29	26	22	28	23	27	30	23	22	32	25	26	27	28
Arizona	33	28	31	37	36	40	45	47	52	52	51	59	57	60	62	65
California	226	207	184	162	178	188	185	208	217	205	231	267	252	260	266	273
Hawaii	19	20	15	13	14	14	12	12	12	12	12	17	12	12	13	13
Nevada	20	19	20	21	21	21	26	25	25	23	24	26	24	26	27	28
Oregon	47	44	42	39	38	40	39	42	44	41	44	48	44	45	47	48
Washington	60	55	51	42	52	52	52	59	59	56	59	66	61	64	66	68
Total PADD V	436	400	372	340	360	383	381	421	437	410	444	515	476	494	508	522
Annual Demand Growth - %		-8.3%	-7.1%	-8.6%	6.0%	6.4%	-0.5%	10.2%	4.0%	-6.2%	8.3%	15.9%	-7.6%	3.9%	2.7%	2.9%

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Alaska	28	26	27	28	28	29	30	30	31	31	32	32	33	33	34
Arizona	67	71	74	76	79	81	84	87	89	92	94	96	98	100	103
California	280	291	298	305	313	319	326	332	338	343	348	353	358	363	368
Hawaii	13	11	11	12	12	12	12	12	13	13	13	13	13	13	13
Nevada	29	30	31	32	33	34	35	36	37	38	39	40	41	41	42
Oregon	49	50	51	52	53	55	56	57	58	59	60	60	61	62	63
Washington	70	72	74	76	77	79	81	83	85	86	88	89	91	92	93
Total PADD V	537	551	566	581	596	610	624	637	650	662	673	684	695	706	716
Annual Demand Growth - %	2.8%	2.7%	2.7%	2.6%	2.5%	2.4%	2.3%	2.1%	2.0%	1.8%	1.7%	1.6%	1.6%	1.6%	1.5%

TABLE VI-4
PADD V JET FUEL/KEROSENE DEMAND FORECAST
(Thousand Barrels Per Day)

State	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Alaska	27	26	26	21	29	31	43	41	45	42	46	44	45	43	45	47
Arizona	47	49	48	49	53	54	59	58	63	65	71	69	70	67	70	72
California	207	201	201	209	224	219	225	222	232	231	247	238	237	224	231	235
Hawaii	14	13	13	13	15	15	16	16	17	17	20	19	19	18	19	19
Nevada	14	13	14	16	19	20	21	21	22	21	24	23	24	23	24	25
Oregon	23	21	22	22	25	25	28	28	31	28	32	31	31	29	30	31
Washington	43	40	43	44	50	50	50	51	59	56	63	60	60	57	60	61
Total PADD V	374	364	366	375	414	414	442	437	469	460	504	485	486	461	479	489
Annual Demand Growth - %		-2.7%	0.8%	2.3%	10.6%	-0.1%	6.7%	-1.2%	7.3%	-1.8%	9.4%	-3.6%	0.2%	-5.2%	4.0%	2.0%

State	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Alaska	48	49	50	51	51	52	53	54	54	55	56	57	57	58	59
Arizona	74	76	78	80	82	84	86	87	89	91	93	95	97	98	100
California	238	242	245	248	251	254	257	260	262	265	268	270	273	276	279
Hawaii	19	19	19	20	20	20	20	20	21	21	21	21	21	21	22
Nevada	26	26	27	28	28	29	29	30	31	31	32	32	33	34	34
Oregon	31	32	32	33	33	33	34	34	34	35	35	35	36	36	36
Washington	62	63	64	65	66	67	68	69	70	71	71	72	73	74	75
Total PADD V	498	507	516	524	532	540	547	554	562	569	576	583	590	598	605
Annual Demand Growth - %	1.9%	1.8%	1.7%	1.6%	1.5%	1.4%	1.4%	1.4%	1.3%	1.2%	1.3%	1.3%	1.3%	1.3%	1.3%

TABLE VI-5
PADD V LIGHT PRODUCT SUPPLY/DEMAND BALANCE
(Thousand Barrels Per Day)

Product	Flow	1999	2000	2001	2002	2003	2004	2005	2010	2015	2020
Total Light Product	Refinery Production	2,041	2,135	2,175	2,242	2,254	2,284	2,316	2,545	2,716	2,820
Total Light Product	Inter-PADD Transfers	176	162	160	181	173	196	216	270	285	290
Total Light Product	Foreign Imports	173	201	193	147	121	148	158	168	176	183
Total Light Product	Exports	(77)	(74)	(94)	(46)	(55)	(56)	(53)	(46)	(44)	(44)
Total Light Product	Supply Adjustments	2	(6)	2	9	24	(2)	(4)	(3)	(2)	(1)
Total Light Product	Consumption	2,315	2,419	2,436	2,534	2,518	2,569	2,633	2,935	3,132	3,247
Motor Gasoline	Refinery Production	1,208	1,261	1,279	1,334	1,318	1,340	1,362	1,498	1,582	1,603
Motor Gasoline	Inter-PADD Transfers	146	134	137	161	155	174	191	239	247	249
Motor Gasoline	Foreign Imports	90	86	100	81	75	77	77	80	81	81
Motor Gasoline	Exports	(7)	(8)	(17)	(9)	(7)	(7)	(7)	(8)	(8)	(8)
Motor Gasoline	Supply Adjustments	2	0	(0)	5	21	(1)	(1)	(1)	(0)	(0)
Motor Gasoline	Consumption	1,439	1,473	1,498	1,572	1,562	1,583	1,622	1,808	1,902	1,926
Diesel	Refinery Production	446	467	489	492	514	526	537	595	651	703
Diesel	Inter-PADD Transfers	17	18	15	13	12	15	18	24	30	32
Diesel	Foreign Imports	16	16	17	6	6	6	6	7	8	8
Diesel	Exports	(63)	(57)	(69)	(36)	(39)	(40)	(37)	(29)	(26)	(27)
Diesel	Supply Adjustments	(0)	(2)	1	1	2	0	(3)	(1)	(1)	(1)
Diesel	Consumption	415	442	452	476	495	508	522	596	662	716
Jet Fuel / Kerosene	Refinery Production	387	407	407	416	422	418	417	452	483	514
Jet Fuel / Kerosene	Inter-PADD Transfers	13	10	8	7	6	7	7	7	8	9
Jet Fuel / Kerosene	Foreign Imports	67	100	76	60	41	65	75	82	87	93
Jet Fuel / Kerosene	Exports	(7)	(9)	(8)	-	(9)	(9)	(9)	(9)	(9)	(9)
Jet Fuel / Kerosene	Supply Adjustments	0	(4)	2	4	1	(1)	(1)	(0)	(0)	(0)
Jet Fuel / Kerosene	Consumption	460	504	485	486	461	479	489	532	569	605

TABLE VI-6
CALIFORNIA LIGHT PRODUCT PRICE FORECAST[1]
(Current Cents per Gallon)

State	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Inflation Factor (2004 = 1.0)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20
Regular CARB Phase II Gasoline	72.92	69.79	51.89	68.58	103.50	94.81	83.22	105.03	--	--	--	--	--	--	--	--	--	--
Premium CARB Phase II Gasoline	77.70	73.89	56.61	74.09	110.30	101.42	89.00	112.39	--	--	--	--	--	--	--	--	--	--
Regular CARBOB Phase III	--	--	--	--	--	--	--	--	129.75	111.44	99.40	94.15	93.27	94.65	96.53	98.49	100.59	102.81
Premium CARBOB Phase III	--	--	--	--	--	--	--	--	137.36	118.47	106.11	100.85	100.10	101.67	103.72	105.80	108.01	110.38
CARB Diesel	73.07	67.69	48.62	63.07	97.73	81.29	74.94	91.35	116.81	101.25	92.02	88.41	88.03	89.26	90.97	92.83	94.81	96.92
Jet Fuel	66.56	63.08	44.69	58.45	94.06	77.00	72.94	88.36	113.31	97.68	88.38	84.70	84.25	85.40	87.03	88.81	90.71	92.74

State	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Inflation Factor (2004 = 1.0)	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49	1.52	1.55	1.58	1.61	1.64	1.67
Regular CARB Phase II Gasoline	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Premium CARB Phase II Gasoline	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Regular CARBOB Phase III	105.17	107.63	110.25	113.04	116.01	119.15	122.46	125.91	129.44	133.01	136.60	140.16	143.67	147.14	150.57	153.95	157.32
Premium CARBOB Phase III	112.91	115.56	118.38	121.39	124.60	128.01	131.59	135.32	139.14	143.01	146.89	150.74	154.53	158.25	161.93	165.56	169.16
CARB Diesel	99.15	101.53	104.06	106.75	109.62	112.66	115.85	119.17	122.57	126.02	129.47	132.91	136.30	139.65	142.97	146.25	149.51
Jet Fuel	94.88	97.17	99.62	102.22	105.00	107.95	111.05	114.27	117.57	120.92	124.27	127.60	130.89	134.13	137.34	140.50	143.65

Note: (1) Excludes market entry discounts that could face a new Alberta export refinery.

VII. PETROCHEMICAL PRODUCTS MARKET ANALYSIS

The primary petrochemical products that were proposed to be produced from the Alberta refinery/petrochemical complex were styrene, benzene, and mixed xylenes. This section of the report describes the markets for such products, and the likely implications in the market if a substantial new supply of these products enter the market.

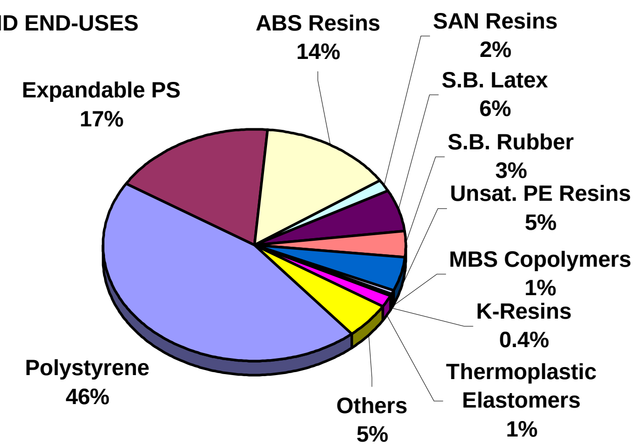
This section of the report was prepared by CMAI.

STYRENE

GLOBAL OVERVIEW

By 2010, the approximate startup date for any Bitumen-based styrene production in Western Canada, the world market for styrene is estimated to be 30.3 million tons. Of this total, nearly 45 percent is for the production of polystyrene. If expanded polystyrene is included, this figure climbs to greater than 62 percent.

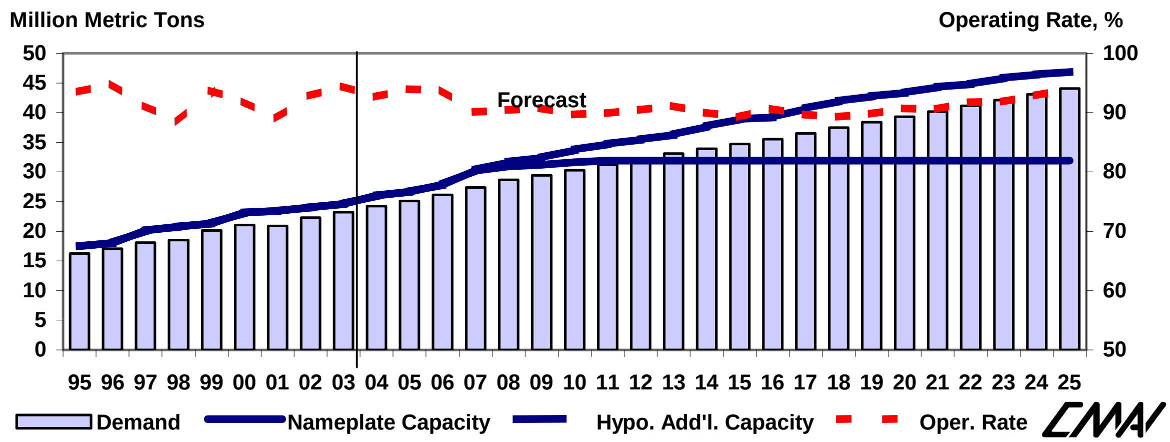
FIGURE VII-1
2010 WORLD STYRENE DEMAND END-USES



2010 Demand = 30.3 Million Metric Tons

In the period between now and 2010, the demand growth for styrene is expected to approximate GDP growth worldwide, an average annual rate of 3.9 percent while supply is a fairly evenly matched 4.0 percent. This global demand growth will require an additional 2.1 million metric tons of capacity to be built by 2010 to keep operating rates at a reasonable level.

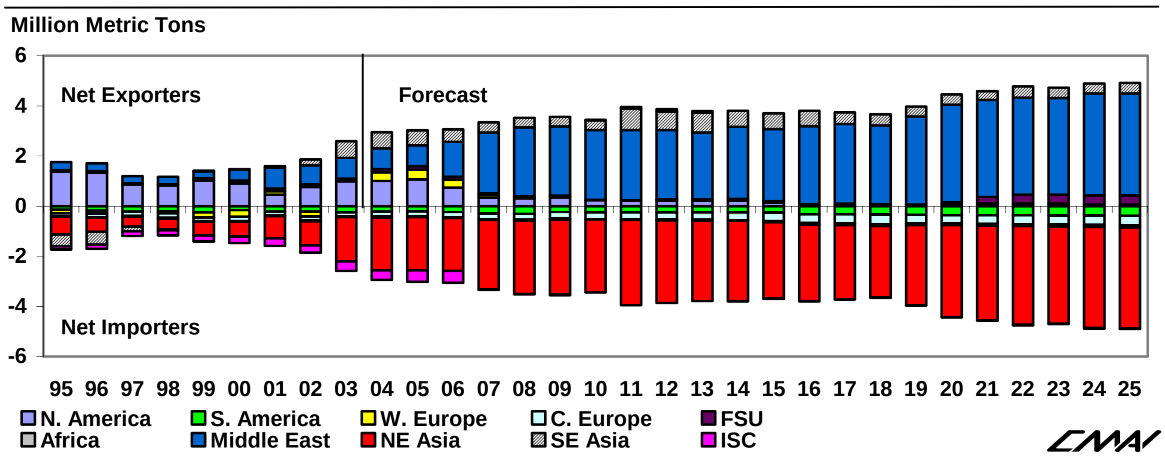
FIGURE VII-2
WORLD STYRENE SUPPLY & DEMAND



Generally speaking, the Asian markets and China in particular, represent the fastest growing markets for styrene. The older and more mature economies of the U.S. and West Europe have lower growth rates on large market sizes.

International trade in styrene and in its derivatives is also expected to grow over the period as capacity is added in lower cost regions such as the Middle East to satisfy Far Eastern demand. Global trade as a percent of total supply remains fairly steady at 15 to 20 percent throughout the forecast period.

FIGURE VII-3
WORLD STYRENE NET TRADE



NORTH AMERICA STYRENE

North America appears to be making the transition from a true global supplier to a more localized industry due largely to the increase in natural gas costs and its large requirement for imported benzene. Contributing to this is lower cost capacity being added in other parts of the world.

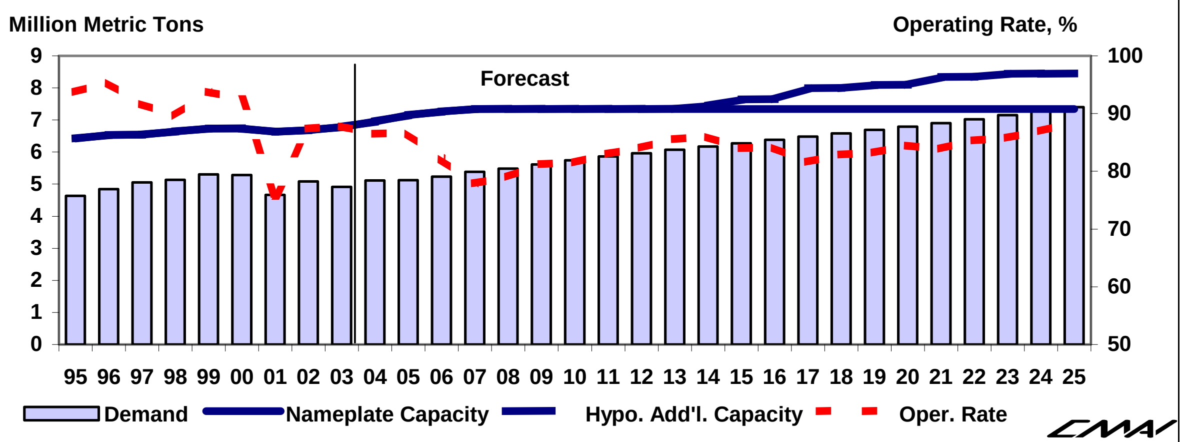
Net exports should remain relatively healthy and grow in the next couple of years before falling due to new capacity in other parts of the world.

North America styrene demand growth waffled along in the early 2000's but is forecasted to resume 1.5 percent per annum average growth between now and 2010.

No major additional capacity is forecasted for the region over the next several years. In fact, CMAI does not foresee the need for any capacity additions until the 2009 – 2010 timeframe.

Imports of finished goods – mostly durable goods – continue to pour in, primarily from China, hurting downstream demand.

FIGURE VII-4
NORTH AMERICA STYRENE SUPPLY & DEMAND



North America net styrene exports in 2004 are forecast to be slightly higher than in 2003 at just over 1.0 million tons. This is welcome news considering that in 2001 this level was as low as 458,000 tons. The majority of the improvement has been with flows to Asia.

The last capacity addition was ChevronPhillips with 180,000 tons late in 2002. Cosmar expanded capacity in 2004 while Nova and Pemex have expansions planned for the later in the forecast period.

FIGURE VII-5
CANADA STYRENE SUPPLY & DEMAND

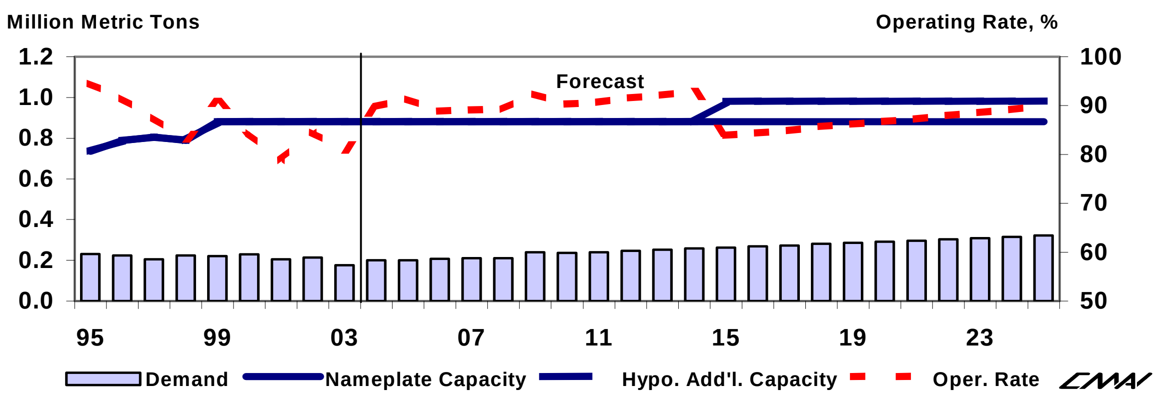


FIGURE VII-6
UNITED STATES STYRENE SUPPLY & DEMAND

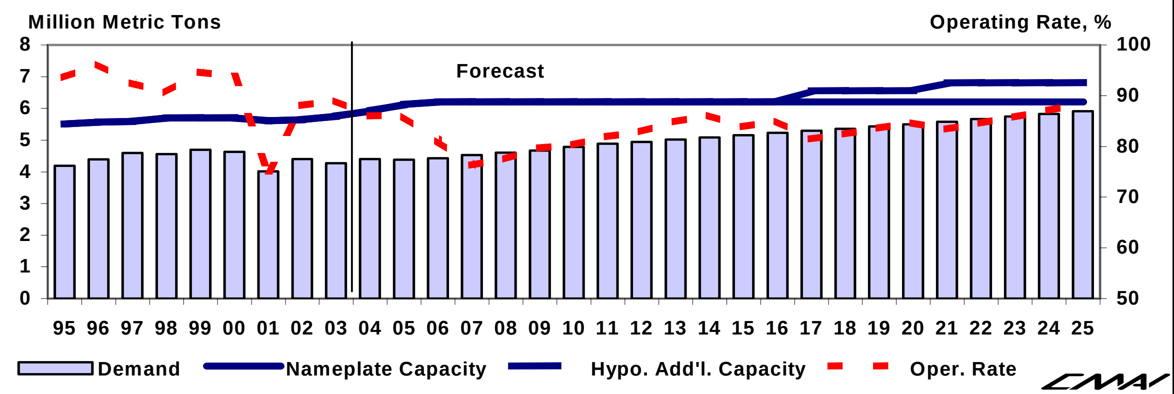
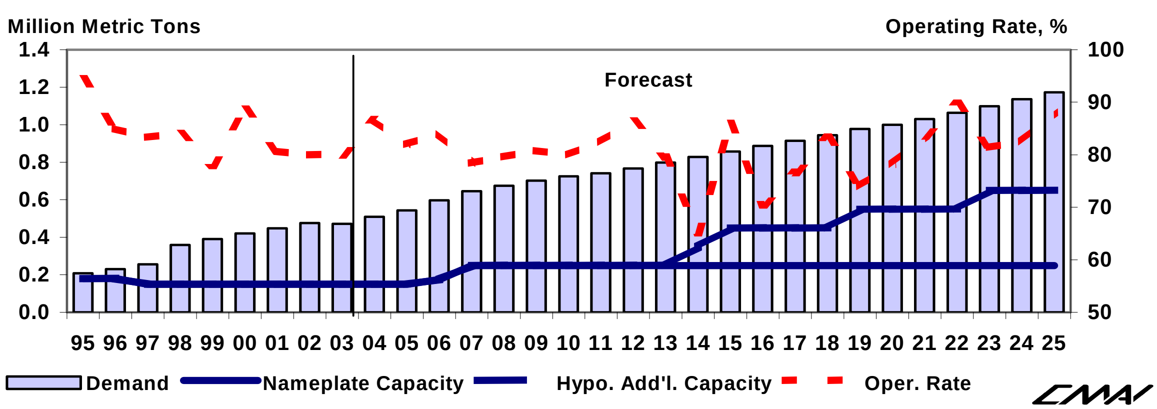


FIGURE VII-7
MEXICO STYRENE SUPPLY & DEMAND



The region should see its production rise through 2005 before retreating as net exports fall due to major capacity additions in other parts of the world. There is more than ample capacity projected for the region and operating rates will not return to the glory years barring capacity rationalization or much better demand growth than forecast. The forecast assumes that exports will fall and domestic demand growth will be met via reduced exports.

The majority of the imports are from within the region. In other words, product moves within the three countries and the total regional balance adds all three. There is little product that comes from outside the region and it tends to be intermittent.

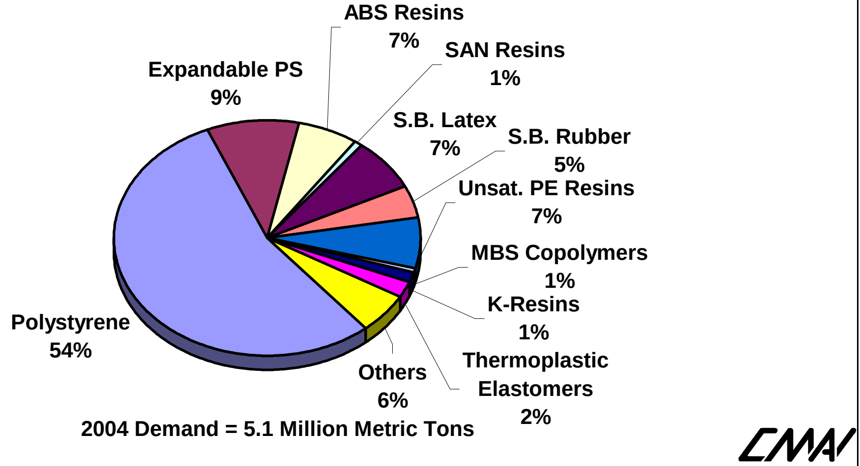
There are some imports that do not physically enter the region because they are done via location swap agreements. One player may provide product in North America to receive it in Asia. It is worth noting that we do expect some volumes from Europe to enter the East Coast of the U.S. when the arbitrage allows it, in fact, n 2004 there have already been a series of shipments from Europe to the U.S.

Over the years the high EB content in imported styrene has hurt imports. The region is mostly accustomed to EB content of less than 100 parts per million (PPM) while imports tend to be 200 – 300 PPM. A large portion of the new European styrene capacity is PO/SM based which tends to have the required EB content for North America. Imports into the U.S. from deep sea cargoes are also hindered by the notion that a large part of the consumers are in the mid-West of the U.S. Therefore, product would have to be transloaded onto barges or railcars which would add to the cost.

North American styrene demand is not expected to once again suffer as badly as the last three out of four years. However, our forecast calls for demand to grow fairly slowly at around 1.9 percent per year through 2010. Relative to fairly decent forecast economic growth the forecast growth rate is below GDP rates. Furthermore, considering that styrene demand actually declined slightly during 1999 – 2004 it is welcome news.

The PS styrene demand sector continues to be the largest by far at over 50 percent. Its share has not changed very much as most styrene derivatives are having a hard time finding strong growth. EPS is showing some of the best growth of the sizable derivatives (3.3 AAGR through 2010). The majority of EPS growth is for the construction market as it has excellent insulation properties and pre-form applications.

FIGURE VII-8
2004 NORTH AMERICA STYRENE DEMAND END-USES



Limited styrene derivative capacity additions are partly at fault for the fairly slow growth. The reason being is that downstream converters/OEMs continue to move production overseas where costs are lower. Therefore, finished goods imports keep growing, especially for durable goods, at the expense of styrene and styrene derivative demand. For example, electronics and appliances will barely grow in the region. Only Mexico will see decent growth in electronics as the U.S. market will continue to decline and Canada will not see any change. The packaging sector for EPS also suffers from the lack of electronics being built in North America.

Downstream it appears that the trend for PS growth in the coming years will be mostly for products that have high margins and for products that do not travel well. High-end electronics, medical or other applications as such should have sufficient margin to pay any rise in resin costs. Products that do not travel well such as light finished goods that take up space should be okay.

ABS demand also suffers from the electronics and appliances now being produced in other parts of the world. ABS demand is expected to grow at an average annual rate of 2.2 percent through 2010. The automotive sector continues to battle with PP and other products. SBR battles natural rubber imports and imported tires.

North America's net trade position is expected to go through some major ups and downs in the coming years. The last five years or so has seen major fluctuations from a high of over one million tons of net exports to a low of 458,000 tons. Going forward, CMAI forecasts net trade to fall to the 225,000 ton level by 2010. The competitiveness of the North American region is largely tied to the relationship of natural gas to crude oil. Not only for styrene but downstream as well. As gas prices have moved higher relative to oil, export opportunities have dropped. In addition, the region is a net importer of benzene.

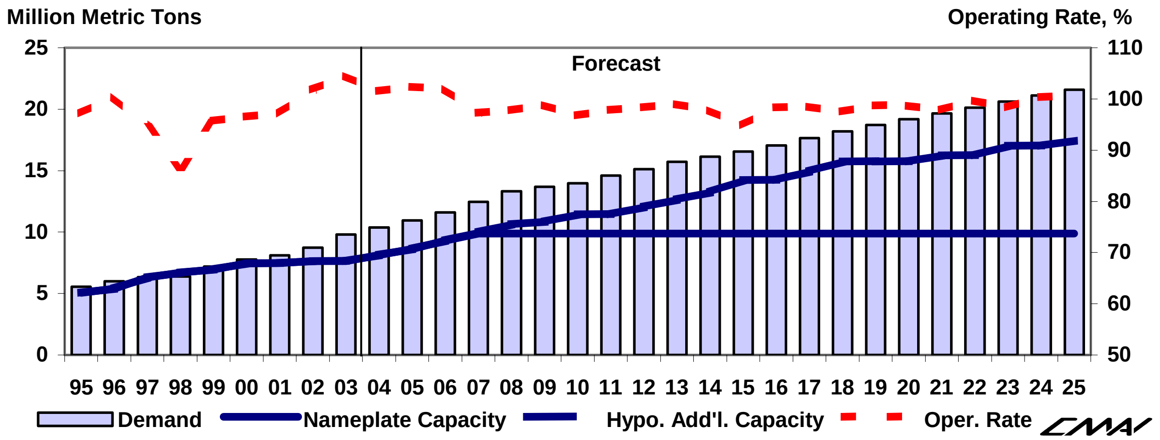
Styrene operating rates in North America should remain relatively low compared to historical levels unless some capacity rationalization takes place. Over the years, rates under 90 percent would equal terrible margins. However, producers have learned that managing production is much easier than demand. The latter is up to the market and too many variables exist. This has helped styrene margins improve relative to operating rates.

Overall, styrene demand should continue to grow but at relatively slow rates.

NORTHEAST ASIA STYRENE

There has been no significant capacity growth for three years while demand has grown over the same period faster than anywhere else in the world. As a result, local operating rates are very high, well above the world average and the region's trade deficit has grown to its largest volume ever. Despite comprising two of the world's largest styrene exporting countries (Japan and Korea), China's import growth has resulted in a 2004 regional (Northeast Asia) net import of around 2.1 million tons. Net import volume will continue to increase as demand growth is forecast to be relatively strong (less in percentage terms than capacity but demand is larger) and operating rates are forecast to remain very high.

FIGURE VII-9
NORTHEAST ASIA STYRENE SUPPLY & DEMAND



Additions to capacity further into the forecast are mainly those in China that have been known about for some years, but Taiwan's FCFC is also adding a recently-announced unit as part of its third cracker project. This is expected on line by mid-2006. In the short term, Korea's LG and Japan's Asahi will add about 450,000 ton/year of capacity between them. Margins have been so good, and promise to be good for two-to-three years, that Asahi has postponed the planned closure of its old 150,000 ton/year unit. The only probable locally driven Chinese styrene expansion is by Qilu, with 100,000 tons planned by 2005. This will make it the largest producer in China until Shell and BP (with their respective partners) come on line.

Merger activity in Korea will affect merchant styrene flows and potential investment in new capacity. Atofina's purchase of half of Samsung General will give the Europeans major access to about 40 percent of Samsung's styrene supply. The general expectation is that SGC will focus on the domestic market, including its affiliate Cheil Industries, while Atofina will use its supply for captive use and merchant sales. It has consumption in China and Singapore and may also ship from Europe. The company has long had plans to expand PS capacity in China, but there are still no concrete details. There is also the possibility that Samsung Atofina will expand the capacity of the Daesan complex, including the styrene units. The styrene capacity of Hyundai Petrochemical will in due course fall under the effective control of LG since that company together with Honam is taking over the Daesan-based producer. LG's derivative expansions in Korea and China (and possibly India) will ultimately account for a large part of HPC's 480,000 ton/year capacity. HPC is currently a large merchant seller with a significant surplus for spot exports. There will be displacement of supply from other suppliers to LG currently, but there will be a net reduction in spot liquidity. The industry in Northeast Asia enjoys average industry operating rates of over 100 percent. This is to be expected from the regional deficit, high margins recently and the competitive advantages arising from cheaper utility costs and ethylene. Lower rates are forecast, but the decline is not significant in the nearer term. A more pronounced fall later in the forecast period is highly dependent on the competitive Middle East supply actually being on stream and flowing into China at that time.

Given the pace of projected demand growth, CMAI has added hypothetical capacity for styrene. Other than debottlenecks, we consider there is the possibility for another world scale unit (perhaps in China, though time is running out for start up before 2008 considering the usual pace of progress) or smaller units in Korea and/or Japan.

Through 2010 the increase in production of almost 2.67 million tons (over 2004) will require approximately 2 million tons of benzene. The three world scale styrene projects in the region (bp, Shell and FCFC) have benzene consumption in excess of that available from the associated crackers. The region's current slight benzene surplus will erode significantly, potentially turning into a deficit without increased production, and (more) benzene will be shipped into Northeast Asia as styrene from the Middle East, Europe and the U.S. Gulf.

Regional net trade will turn increasingly negative. By 2010 net imports are forecast to increase by roughly .8 million tons over 2004 levels to 2.9 million tons. China of course dominates the region in terms of demand and trade. Its capacity lags way behind demand, being only 22 percent of annual demand in 2004. The deficit is of course larger if Hong Kong is included. China capacity represents 11 percent of the market in Northeast Asia in 2004, but it will account for 40 percent of the demand in 2004. By 2010, the demand share grows to greater than 56 percent while capacity share grows to 22 percent of the regional total.

In 2004, styrene production will be just under 8.3 million tons, with 768,000 tons of this from the region's two POSM units. The addition of the PO-only unit in Japan (and the Ellba Eastern unit in Singapore in 2002) has not depressed the operation rate of POSM plants in Northeast Asia.

Operating rates remain near the highest on record since the industry reached its recent scale - at 102 percent of nameplate capacity. All four industries in Japan, Korea, China and Taiwan are estimated to be at or above 100 percent utilization, despite some cutbacks during the SARS scare. However, many official company capacities are understated. Nevertheless production is effectively at maximum in the region. These high rates keep the fixed cost per unit of production very competitive.

The expansions by LG and Asahi are the first significant regional increases in capacity since FCFC's second unit in Taiwan in 2000.

The vast majority of the growth is in China where there is more consumption and consumption growth in higher value derivatives (EPS, ABS, UPEs, etc., rather than PS) compared with the typical average. Demand growth in China in 2004 is expected to be greater than total Northeast Asian demand growth, implying demand in the rest of the region has declined.

Growth will be strongest in EPS (average annual growth rate, AAGR, of 7.7 percent through 2010) and ABS (5.8 percent). Consumption in PS will grow by only 4.9 percent.

In China, EPS consumes almost as much styrene as polystyrene in 2004 (about 32 and 28 percent of total demand respectively) and China is the only country to show such a consumption distribution. This trend is expected to continue.

Exports from countries within the region go mainly to China. Exports to other regions (India, South East Asia and occasionally Europe) have continued, but the volumes have reduced as Northeast Asia's deficit increases and the other regions move further into surplus (other than India).

Future growth in production is, as with PS and the other major derivatives, where the demand growth is – in China. Japan and Korea will see some modest short term increases, but there are no world scale investment plans. Due to displacement by projected Middle East supply, production in these countries is forecast to decline slightly through 2010. The continued growth of the Formosa giant in Taiwan is the one exception to this rule. The company will have over 1.0 million tons of styrene capacity by mid 2006. At this scale, and with the integration involved, this capacity should run quite hard, probably at the expense of the other two producers in Taiwan. A portion of the styrene will be consumed in (exported to) the company's derivative capacity expansions in China. Otherwise the production increase is dominated by the new supply from Secco (bp) and Shell, plus some potential further unannounced capacity expansion in China.

China is the major net importer in the region. Hong Kong imports all of its needs, while Taiwan's import volume has decreased. Net imports are forecast to increase by 2010 by over 1.0 million tons to about 4.2 million tons. Most of this increase in the later years of the forecast period will be moving from the competitive styrene capacity expansions in the Middle East (mainly Saudi Arabia and Iran).

Northeast Asian SM consumption is forecast to grow at an average annual rate of 5.7 percent to 2010, compared with an average rate of 7.6 percent in the last five years. NEA is a "two-speed" region with the migration of derivative production to China resulting in high growth in this country and minimal growth in the more mature markets of Japan, Korea and Taiwan. The world average annual growth rate to 2010 is forecast at 3.9 percent. The forecast growth rate for

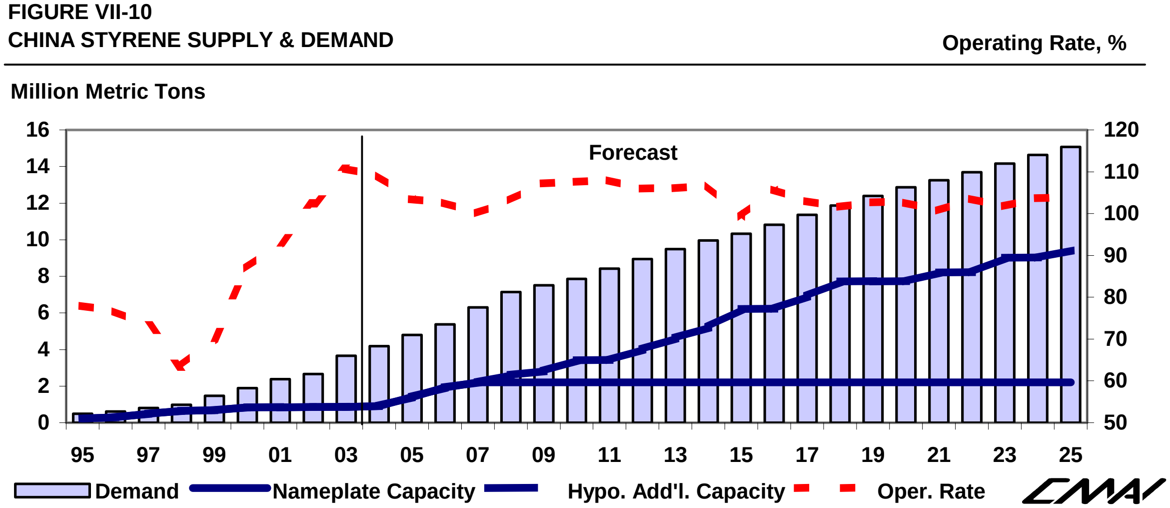
Chinese SM consumption is 12.4 percent, which seems high but is arguably conservative relative to average annual growth in the last five years of 23.2 percent.

The Northeast Asian styrene industry is in a relative blessed position. It is in the highest growth market in the world, runs at over 100 percent utilization on average, has competitive feedstock supply and doesn't run its utilities on natural gas. Thanks to China's import growth and lagging self sufficiency development, it will remain in a sold out position until competitive pressures increase due to the export oriented styrene coming on stream in the Middle East. The market can easily accommodate the three world scale projects planned in China and Taiwan.

The major unknown and the major threat to regional (and global) styrene profitability is the planned new supply in the Middle East. Experience has shown that many such projects do not meet their planned start up targets. CMAI has undertaken diligent research to form an accurate assessment of realistic start up dates of Middle East projects. This new supply is the key to the balances in Northeast Asia in the period 2006-2010. However, there are many variables that may alter the supply of styrene from these sources at this time.

Considering that China's styrene consumption is forecast to almost double by 2010 (to over 7.8 million tons) and its import requirement is forecast to expand to over 4.1 million tons, we have added some capacity creep in the Chinese industry and another world scale in China in 2008 (hypothetical capacity). This is quite a presumption and not CMAI's normal practice, but if another world scale plant is going to be built anywhere in the world, China is one of the two likely places (the Middle East the other). There are several local plans to build capacity in China that could aggregate up to a world scale unit. There are no major MNC proponents of capacity at this stage (Dow's project is looking to have slipped well after 2008), but BASF (with YPC) could be one potential plant constructor. Ideally the unit would be part of a cracker project, but after Secco and Shell there is nothing grass roots looking likely at this stage.

FIGURE VII-10
CHINA STYRENE SUPPLY & DEMAND



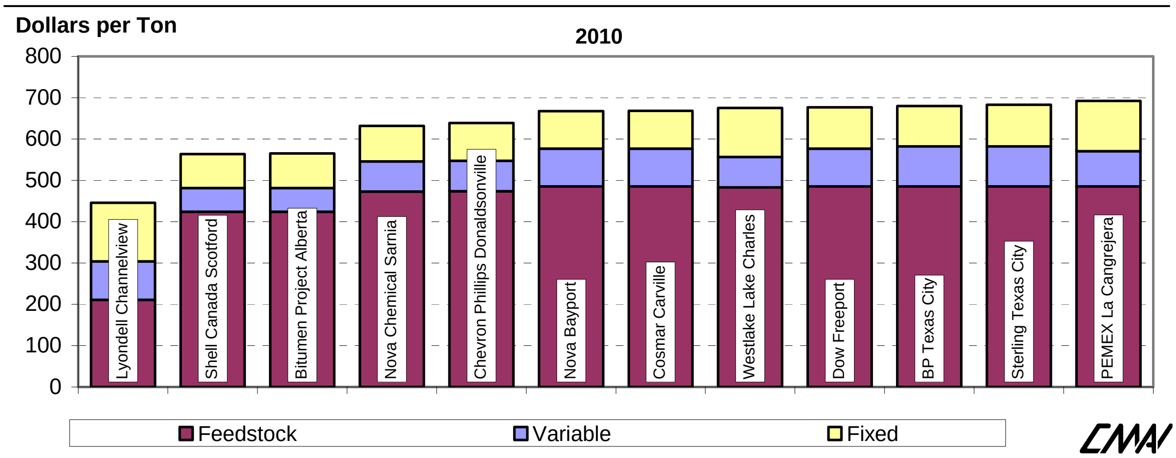
STYRENE COST COMPETITIVENESS

CMAI has examined the forecasted cash production costs for the North American styrene producers and generated a comparison. This analysis uses market pricing for ethylene and benzene since these two commodities have ready alternate value in the North American market. If we were examining a remote production site (such as an export-oriented facility in the Middle East for example), transferring these feedstocks at cash cost may be more appropriate to accurately gauge the lowest styrene production cost. Since the Bitumen Project has yet to be built and all options are still open concerning production, sales or purchases of ethylene and benzene, this is an appropriate method of analysis in CMAI's opinion. To see the effect of transferring raw materials at cash cost, the same analysis is provided at the end of this section. **No proprietary information has been used in this analysis. CMAI's analysis is based on in-house models and publicly available data. Cash production costs are calculated based upon plant sizes, estimations of cracker feedslates and the extent of producer integration. CMAI's opinion of the relative cost position of these producer should in no way be considered a recommendation of a specific rationalization candidate.**

As can be seen in the graphic below, the two Western Canadian styrene producers, Shell and the proposed Bitumen Project, are projected to have costs lower than all but the Lyondell PO/SM unit. This is attributable to the lower market values of the ethylene and benzene in Western Canada.

Styrene is priced on an FOB plant basis. Much of the consumption in North America is found in the U.S. Midwest. CMAI estimates that the freight costs from the Western Alberta producers are comparable to those from the U.S.G.C. producers when shipping to the Midwest. As a result, the delivered cost position for these producers would not materially change.

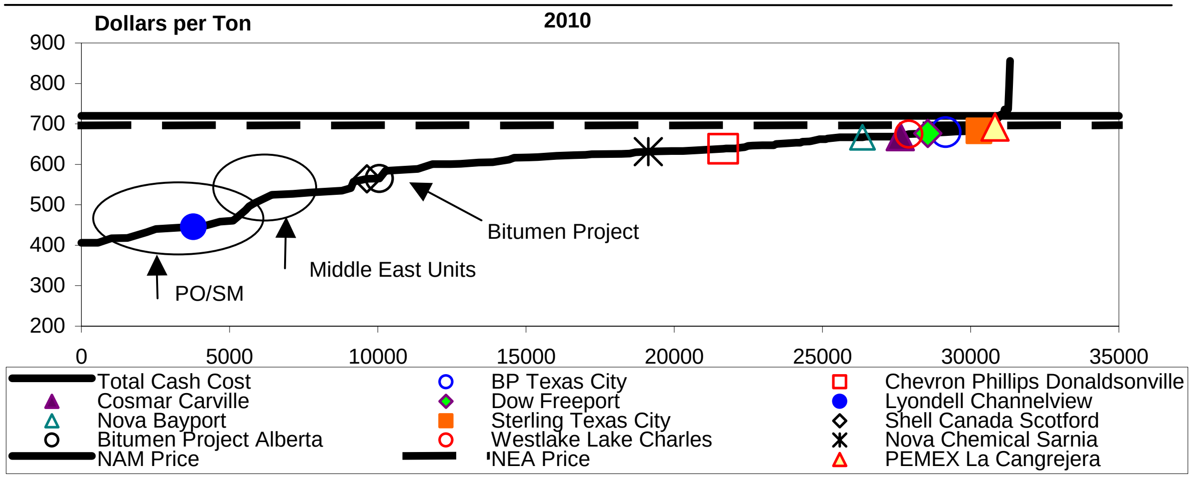
FIGURE VII-11
NORTH AMERICAN STYRENE PRODUCTION COSTS



If this cost information is presented along with cumulative production capacity, a cost curve is generated. With global demand estimated at just over 31 million tons in 2010, it appears that the

Bitumen Project is well positioned from a cost point of view. This must be examined within the context of demand however, and this is examined in the Styrene Market Study section of this report. CMAI's regional price forecasts are overlaid on this graphic to visualize the available margins between price and production cost.

FIGURE VII-12
GLOBAL STYRENE CASH COSTS BY SITE

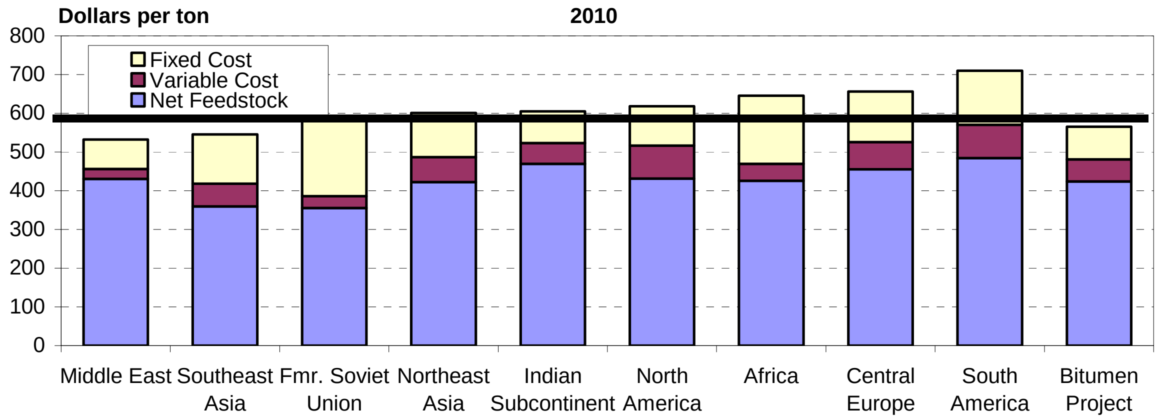


CMAI, while not expert in international freight costs, understands the freight rates from Vancouver to South China to be on the order of $60 per metric ton (10,000 ton lots), more for smaller parcels. In addition to this ocean freight a Western Canadian producer must initially rail the styrene to the port. This is estimated to add another $40 or so per ton, resulting in a 2004 cost of $100 to export styrene to China.

It can be seen that the PO/SM units and the Middle Eastern producers enjoy the lower end of the cost curve, and consequently, have the greatest flexibility in terms of markets. Three Northeast Asian producers are in this group; Shell/CNOOC in China with 560 ktpa, SK Evertec in Korea with 350 ktpa, and Nihon Oxirane in Japan with 420 ktpa. Two Singapore producers account for another 465 ktpa of styrene production in this group.

If we examine the global picture for styrene production costs, we must concentrate on three areas; the Bitumen Project, the Asian producers and the low cost Middle East producers. The supply and demand section described China's hunger for styrene that will need to be satisfied by both domestic production and imports. A comparison of the production costs of the various regions of the world indicates that the weighted average cost of the Northeast Asian producers are about $35 per ton higher than the Bitumen Project. When the $100 shipping costs are included, the Bitumen Project is at a distinct disadvantage.

FIGURE VII-13
REGIONAL STYRENE CASH COSTS



Since the Middle East is on track to be a major exporter of styrene to the Chinese market, the costs of such are of great importance to the competitiveness of the Bitumen Project. With cash costs in the $536 per ton range compared to the $565 or so for Western Canada, an immediate $30 of advantage is enjoyed by the Middle East. Significant volumes of petrochemicals trading between the Middle East and China will likely result in good shipping rates, on top of the savings of not having to transport by rail to the load port. Southeast Asia's costs of $546 per ton are also lower than the Bitumen Project and the freight considerably lower. It should be pointed out that CMAI has assigned a market price that is related to other regions (that have more transparent markets) to the ethylene in the Middle East. This results in very handsome returns to the crackers which of course could be pared back to lower the ethylene price into the styrene units even lower.

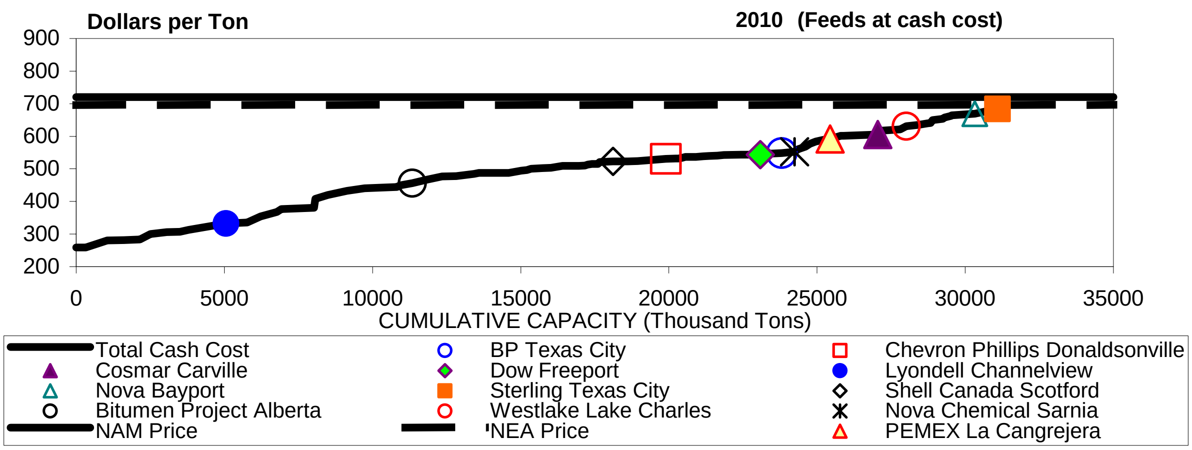
In light of this cost information, it is considered unlikely that the proposed Bitumen plant would wish to principally target the Asian market. It does however show an opportunity to participate in the North American market, at least from a cost point of view.

MARKET VALUE OF FEEDSTOCK VS. CASH COST

Of the North American producers, all but three sites also include ethylene production. These three are Shell Canada, Nova in Bayport and Sterling in Texas City. Several of the other sites consume ethylene that is made by the same company and pipelined to the styrene unit such as Dow's Freeport styrene plant and Chevron Phillips Donaldsonville.

As mentioned at the beginning of this section, cost curves can be run a market prices for the feedstocks or at cash cost (or any point in between for that matter).

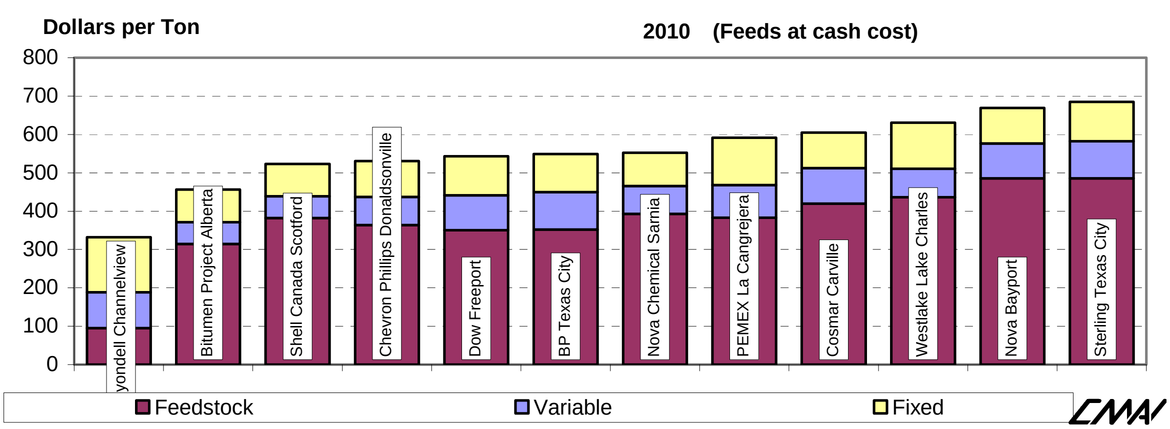
FIGURE VII-14
GLOBAL STYRENE CASH COSTS BY SITE



The most notable change is evident for the Bitumen Project. Purvin and Gertz have estimated the cash costs of the ethylene and benzene into the styrene unit at a cost of $312 and $306 per ton, respectively. While the benzene price is not a significant advantage, the ethylene price is. This advantaged ethylene price does not include any volumes that would need to be purchased (at market) to make up any shortfall in ethylene requirements to the styrene unit. Therefore the Bitumen Project position on this curve is the best case scenario.

The other producers on the curve do not have materially different ethylene cost structures from each other (except for those non-integrated producers) and any differentiation is further dampened by the fact that the styrene molecule is only ~26 percent ethylene.

FIGURE VII-15
NORTH AMERICAN STYRENE PRODUCTION COSTS



The Lyondell PO/SM unit occupies the lowest cost position of the North American producers, both on raw materials at market and cash cost bases. As a byproduct of propylene oxide production, the styrene “cost” from this unit incorporates the credit from propylene oxide sales as well as costs of propylene and oxygen.

The findings of these cost analyses have been used in the preparation of the Market Penetration section of this report.

STYRENE MARKET PENETRATION

The Cost Competitive section of this report detailed the proposed Bitumen project’s cash cost for styrene production and identified the North American market as the most likely target market. Unfortunately, the growth in styrene demand within this mature region is slow and new capacity is not required for to approximately ten years.

This section will examine where to market the proposed 425,000 metric tons of capacity if the plant were to startup in 2010.

With a $100 to $120 per ton cost advantage over the higher cost units in North America, the new Bitumen project can afford to be price aggressive if necessary to “buy in”. The degree to which this would be necessary however is dictated by the nature of the project participant; existing North American producer or newcomer. This will be discussed shortly.

CMAI’s price forecast for styrene in 2010 is $720 per ton (average price paid) in the U.S.G.C. The Bitumen project’s cash cost in 2010 is estimated to be $566. The 3 highest cost North American styrene producers’ total capacity is 427,000 tons and their lowest cash production costs are $685 per ton. An additional 1.2 million tons can be rationalized at a cost of $680 or lower. These represent full cash cost (feedstock, variable and fixed costs) but no return on investment. On a short-term basis these producers would certainly run if they could cover variable costs, but longer term full costs must be covered. Fixed costs are estimated to be in the $100 to $120 per ton range for these units.

To rationalize these units CMAI estimates that a price (in 2010 dollars) in the range of $680 per ton on a long-term basis will be required. Initially, the price may need to be lower still, closer to the variable cost of the targets, under $600 per ton.

Judging from the very flat nature of the cost structure in the North American market (see Figure VII-15), many producers will experience the same pressure if the price were lowered. Consequently, it bears examination of the individual producers to seek out the most likely rationalization candidate(s).

- **PEMEX – LA CANGREJERA, MEXICO** –150,000 tons of capacity with a 100,000 ton expansion scheduled for 2006. The two smallest units in North America and the highest cost. PEMEX has no downstream derivative demand of its own but is supplier to many different companies in Mexico.

- **STERLING – TEXAS CITY, TX, USA** – Two styrene trains with only one EB unit and one purification section, combined capacity of 772,000 tons. Sterling is understood to be actively selling in the Asian markets through swap arrangements. Sterling is not integrated downstream or upstream.

- **DOW – FREEPORT, TX, USA** – 467,000 and 177,000 tons of capacity. Dow's U.S. integration includes ABS, polystyrene, SBL and UPE at multiple sites. Dow also has polystyrene, SBL and UPE derivatives in Canada.

- **BP – TEXAS CITY, TX, USA** – 453,000 tons of capacity. Only plant BP has in North America. BP has no downstream integration.

- **WESTLAKE – LAKE CHARLES, LA, USA** – 205,000 tons of capacity. Only plant Westlake has in North America. Ethylene is sourced from 100 percent ethane-fed cracker, believed to be vulnerable due to high gas costs. Westlake has no styrene derivatives businesses and looks at styrene as a means of moving ethylene to market.

- **COSMAR – CARVILLE, LA, USA** – Two units, each of 575,000 tons per year. This is a joint venture between Atofina and GE. Atofina produces polystyrene at Carville, while GE has ABS, SAN and polystyrene production at various locations in the U.S.

- **NOVA – BAYPORT, TX, USA** – 771,000 ton unit. Nova's U.S integration includes EPS and polystyrene in multiple locations.

- **NOVA – SARNIA, ONT, CANADA** – 431,000 ton unit. This unit is believed cost advantaged due to the consumption of dilute ethylene and a logistical advantage to the large Midwest consuming area. Nova has polystyrene capacity in Montreal.

- **CHEVRON PHILLIPS – DONALDSONVILLE, LA, USA** – 499,000 and 454,000 ton units. These units are understood to have an advantaged benzene position and thus have a lower overall cash cost. Believed to be an active exporter to Asian markets. CPC produces polystyrene as well as K-resin (styrene butadiene copolymer).

- **SHELL CANADA – SCOTFORD, ALB. CANADA** – 450,000 ton unit. Like the proposed Bitumen plant, Shell's plant enjoys the benefit of lower priced ethylene, benzene and natural gas that its U.S.G.C. competition. Active in the export market to Asia through swaps in the U.S.G.C. Shell has no downstream styrene integration in Canada or the U.S.

- **LYONDELL – CHANNELVIEW, TX, USA** – 635,000 and 624,000 units, both SM/PO, the only ones in North America. Believed to be an active exporter to the Asian markets. Lyondell has no downstream derivative demand for styrene. Operating rates are a function of PO demand/economics rather than styrene demand.

Of course, lowering the price of styrene in order to penetrate the market would have a material impact on the economics of the project. This approach may be the only viable one for a new styrene producer to enter the North American market. The North American market is very mature and there is little need for new styrene derivative capacity. Downstream investment to consume the styrene monomer is therefore not considered a very good option. There may be the opportunity to acquire a merchant buyer of styrene (such as Huntsman's 84,000 ton EPS unit in Peru, Illinois), but these opportunities are few.

If the Bitumen project partner were one of the existing North American styrene marketers however, a more orderly introduction of the volumes into the market could take place through coordinated plant operations, pre-arranged exports (either direct or via swap) or other pre-marketing arrangements. Multiple producers or large consumers may even be able to participate in the project through some form of "condo" scenario where the unit would be shared.

In either case it is reasonable to presume that some quantities will need to be exported to Asia while the domestic market slowly grows to demand the extra styrene capacity. While the volume opportunity has been shown to exist in China as can be seen in the table below, the cost structure of both the Middle Eastern and Southeast Asian producers has been shown to be lower on both a production and delivered basis.

CHINA PROJECTED STYRENE NET TRADE (000 mtons)	
2004	-3,163
2005	-3,340
2006	-3,394
2007	-4,090
2008	-4,440
2009	-4,490
2010	-4,190
2011	-4,740
2012	-4,690
2013	-4,590
2014	-4,390
2015	-4,158

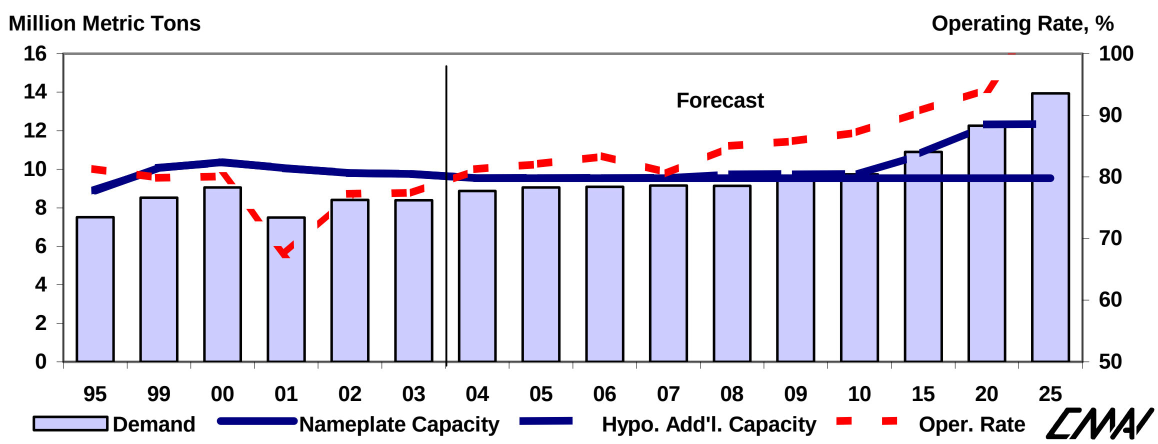
Should the Bitumen project be able to reduce the cost of exporting to Asia by either swapping with a U.S. Gulf Coast producer (thus eliminating the rail cost to export port) or by some means of reducing the total freight cost (rail plus ocean) from Canada directly, the netbacks of shipping to China can be improved.

The current price forecast of $696 per ton in Northeast Asia would only result in a margin of $31 for the Bitumen project in 2010. ($696 - $100 shipping - $565 production cash cost). Any future marketing plan would therefore seek to minimize the volumes into this market in favor of the North American market.

BENZENE

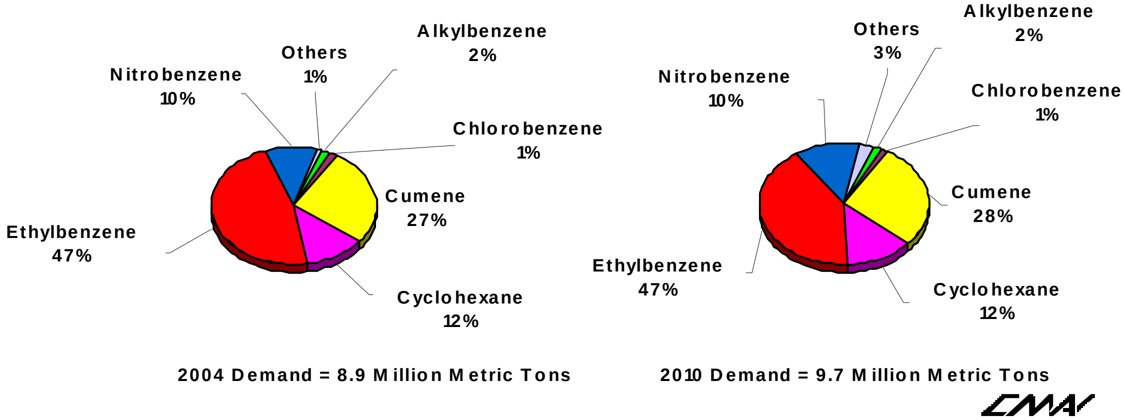
As an alternative to producing styrene, the Bitumen Project could instead market benzene. While this has not been examined as a formal case per se, the opportunity exists since the benzene produced could easily be exported down to the United States, a sizeable net importer.

FIGURE VII-16
UNITED STATES BENZENE SUPPLY & DEMAND



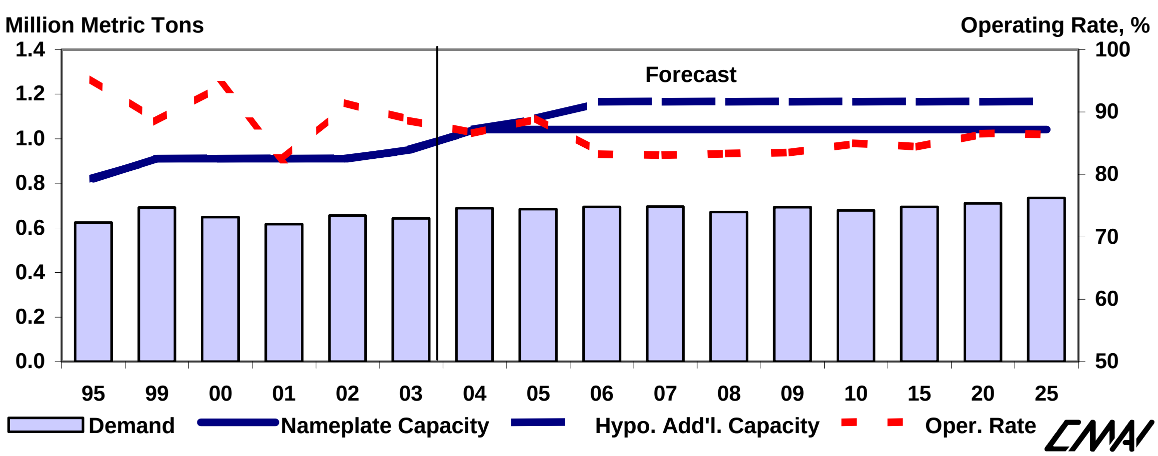
In 2010 the United States is forecasted to have net imports on the order of 1.3 million tons or roughly 13 percent of total domestic demand. In 2004 benzene demand in the United States is dominated by ethylbenzene (for styrene) followed by cumene (for phenol and acetone production) and cyclohexane. All other uses combined consume only slightly more than consumed for cyclohexane. As can be seen in the following comparison between 2004 and 2010, the consumption of benzene into ethylbenzene remains the dominant end use, but the actual percentage drops a little bit.

FIGURE VII-17
UNITED STATES BENZENE DEMAND AND END USE



Canada is already a supplier of benzene to the U.S. In 2004 net exports are forecasted at just over 200,000 tons, all but a very little bit of it (to Europe) is exported to the U.S. CMAI forecasts this trend to continue over the foreseeable future.

FIGURE VII-18
CANADA BENZENE SUPPLY & DEMAND

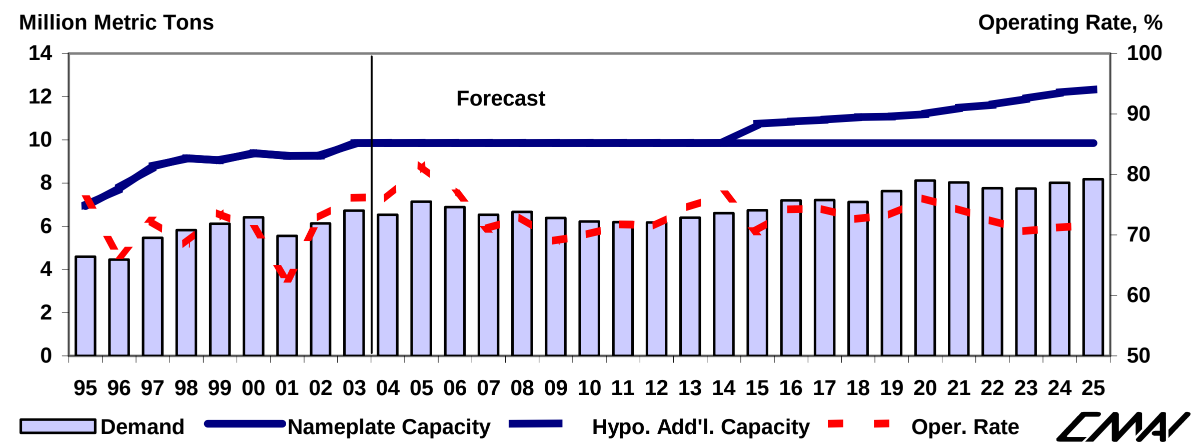


As described previously in the price forecast section, benzene pricing in Canada is forecasted as the U.S.G.C. price minus freight.

MIXED XYLENES – ISOMER GRADE

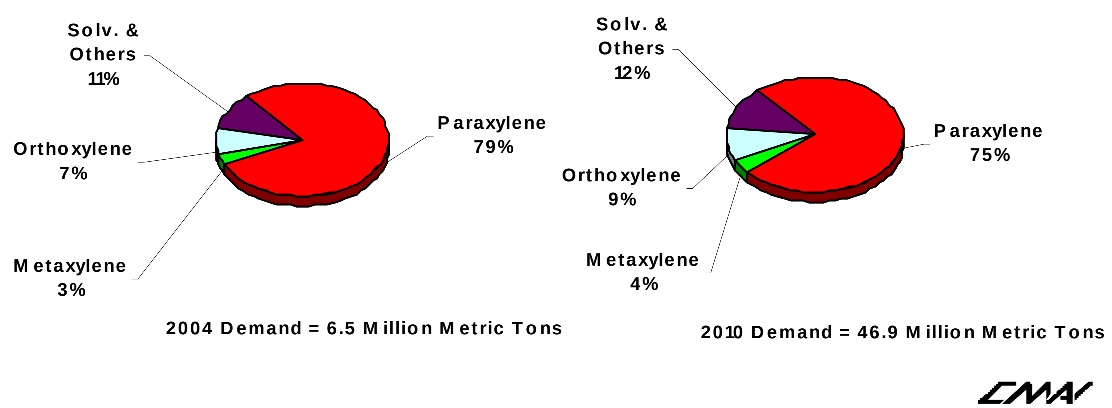
Unlike the situation with benzene, mixed xylenes are net long in the United States and in 2010 the U.S. is forecasted to net export 687,000 metric tons.

FIGURE VII-19
UNITED STATES MIXED XYLENES SUPPLY & DEMAND



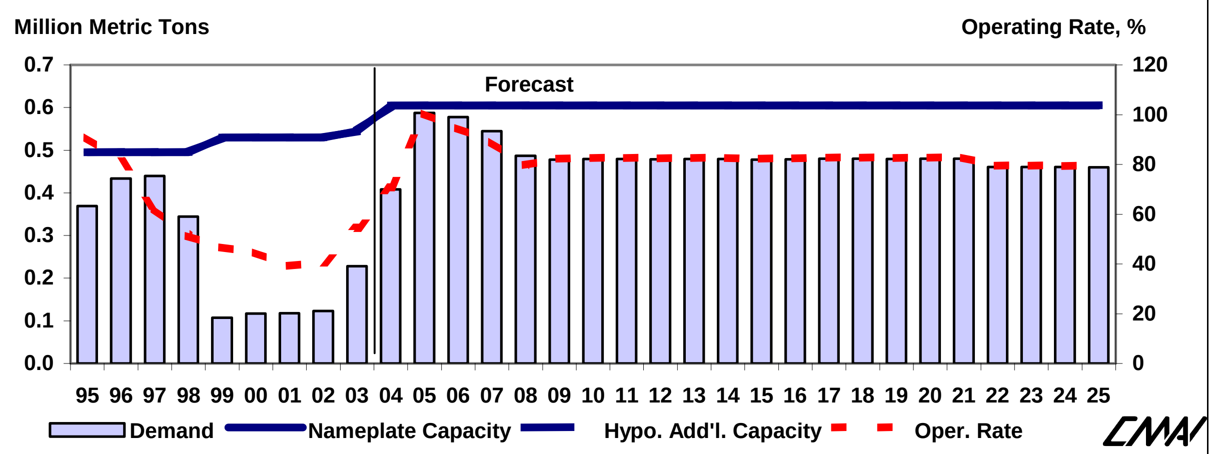
As expected, demand is heavily dominated by paraxylene for the polyester chain. This is not expected to change with time.

FIGURE VII-20
UNITED STATES MIXED XYLENES DEMAND AND END USE



The Canadian market is both very small and well balanced with net exports of ~20,000 metric tons anticipated in 2010. Operating rates peak in the 2005 timeframe as the El Paso Refining paraxylene unit in Montreal expands capacity from 165,000 mtons per year to 350,000 mtons per year, but retreat as incremental mixed xylene capacity is added (selective TDP and reformate distillation).

FIGURE VII-21
CANADA MIXED XYLENES SUPPLY & DEMAND



Much of the xylenes that are exported from the U.S. are destined for Northeast Asia; a rapidly growing region in the production of polyesters. Although the region is forecasted to add sufficient capacity to satisfy the demand growth, the largest consumer in the area, China, will remain a net importer and thus a potential target for the Bitumen Project mixed xylene production.

FIGURE VII-22
NORTHEAST ASIA MIXED XYLENES SUPPLY & DEMAND

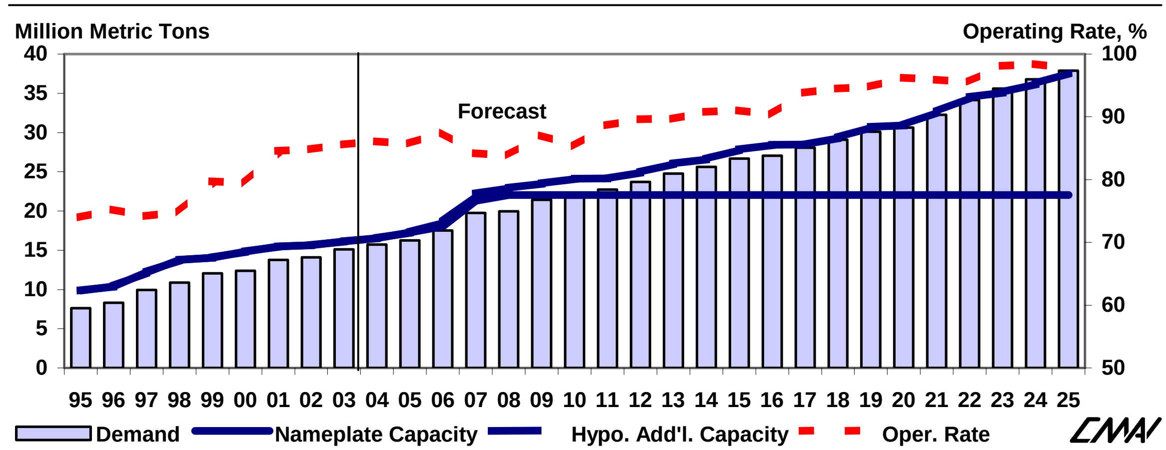
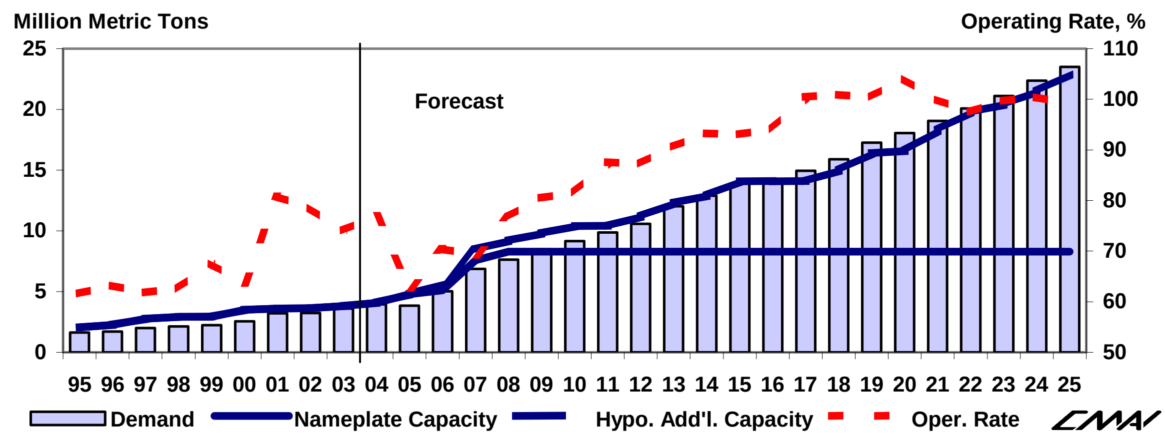


FIGURE VII-23
CHINA MIXED XYLENES SUPPLY & DEMAND



VIII. LOGISTICS AND NETBACK PRICES

Whether bitumen is marketed as a blend, or is converted into high value products, both will require the resulting products to be exported from Canada. Therefore, the logistics associated with such exports is an important aspect in the feasibility of the various cases studied in this report.

REFINED PRODUCTS LOGISTICS

The proposed upgrader cases would process 200,000 B/D of bitumen and produce up to 185,000 B/D of refined products. Depending on the upgrader configuration and product objectives, refined product output could range from as 116,000 B/D up to 185,000 B/D of refined products. For this study, we have focused on two export markets, the Midwest and California.

Based on feedback from both Enbridge and Terasen, it would be preferable to keep the volume of refined products above 100,000 B/D in order to justify the facilities to keep such products shipped in a dedicated pipeline. Therefore, we have viewed this analysis as shipping refined products to either the U.S. Midwest, or to California, but not to both markets at the same time.

Pipelines are generally used for overland shipments of large quantities of petroleum. Refined products have quality specifications which require segregation, or careful batch sequencing in pipelines, or product cleanup facilities at the destination. As sulphur limits on gasoline and diesel become lower in 2005/06, it will be more difficult to pipeline these products without segregation. Most of the pipelines leaving Edmonton carry crude oil so pipeline changes will be needed to handle an additional 185,000 B/D of clean fuels.

Although not examined in this study, smaller volumes could be shipped in crude oil pipelines with high quality streams such as synthetic crude oil and NGL mixes. Likely, some form of cleanup would be required to eliminate any sulphur that might have been picked up from these other streams. Such clean up adds costs, but could be a viable option in the early stages of bringing production on stream, or if it was decided to spread the output from the Alberta refinery to several markets.

At present, the Edmonton area refiners ship refined products on three pipelines; 1) the Enbridge pipeline as far east as Gretna, Manitoba for further shipment to Winnipeg, 2) Terasen's Trans Mountain Pipeline (TMPL) to Burnaby, B.C., and 3) the APPL line, operated by Petro-Canada, to Calgary, Alberta. These systems adequately supply the existing markets for refined products in Western Canada, so volumes equivalent to the upgrader output would have to be exported through expanded pipelines.

FIGURE VIII-1
LOGISTICAL ROUTES FOR EXPORT OF REFINED PRODUCTS

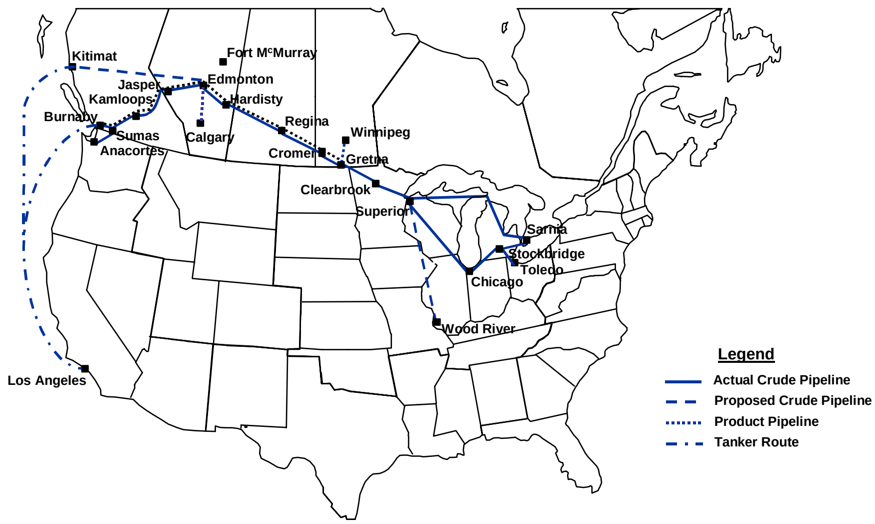
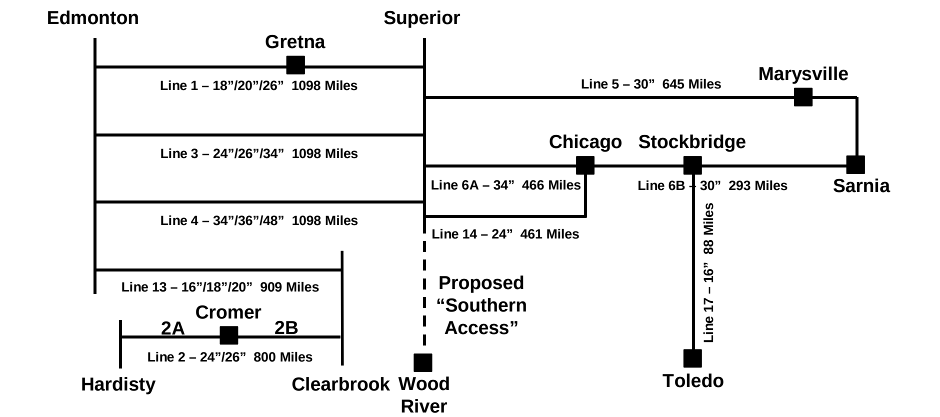


Figure VIII-1 shows the major pipeline infrastructure for pipelines leaving Edmonton. Most of the pipeline capacity is for crude oil. The Enbridge pipeline and TMPL systems are discussed further as either may have an opportunity to ship up to 185,000 B/D of refined products to the export market.

ENBRIDGE

The Enbridge system from Edmonton to Sarnia, Ontario is shown schematically in Figure VIII-2. The Canadian system is owned by Enbridge Inc. while the U.S. system is owned by Enbridge Energy Partners LP, except Line 17 to Toledo. Enbridge has four lines leaving Edmonton, three for crude oils exclusively. Line 1 carries refined products as well as NGL's, condensate and synthetic crude oil (SCO) and has a capacity of 260,000 B/D on an annualized basis. In 2003, Enbridge shipped 83,000 B/D of refined products and 113,000 B/D of NGL's, leaving 64,000 B/D for condensate and SCO. The refined products are delivered from Edmonton to Regina, Saskatchewan and Gretna, whereas the NGL's are shipped to Superior, Wisconsin and then on Line 5 to Marysville, Michigan and Sarnia, Ontario. Line 5 has a capacity of 491,000 B/D and also carries condensate, SCO and conventional light sweet crudes to Sarnia.

FIGURE VIII-2
ENBRIDGE PIPELINE SYSTEM CONFIGURATION, EDMONTON TO SARNIA



Line Commodities and Annual Capacities in 2003 (KB/D)

Line 1	Line 2	Line 3	Line 4	Line 5	Line 6	Line 13	Line 14	Line 17	Proposed
• NGL • Synthetics • Ref. Products (to Gretna)	• Heavy Crudes	• Light Crudes • Med. Crudes • Synthetics • Condensate	• Heavy Crudes	• NGL • Light Crudes • Synthetics • Condenstate	• Heavy Crudes • Med. Crudes • Light Crudes • Condensate	• Synthetics	• Heavy Crudes • Med. Crudes • Light Crudes • Synthetics	• Heavy Crudes	• Light Crudes • Med. Crudes • Heavy Crudes • Synthetics
260.4	2A: 339.6 2B: 408.8	465.4	678.0	491.2	6A: 662.3 6B: 290.6	174.9	434.0	80.0	250.0

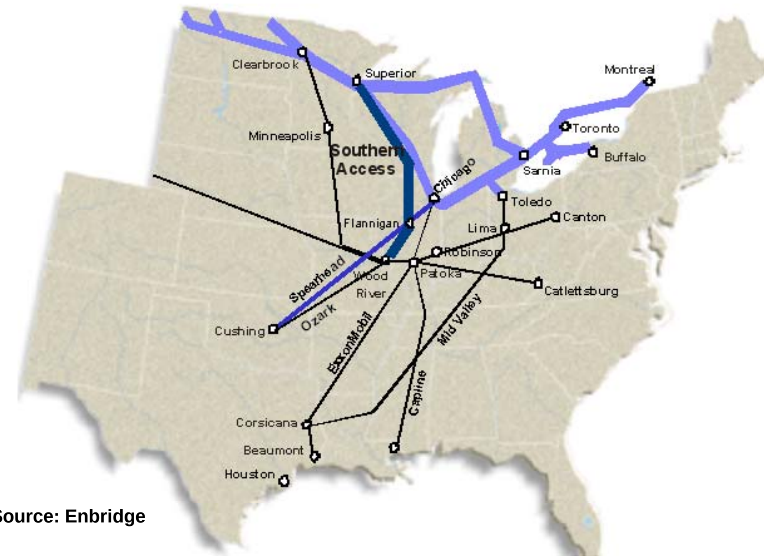
Source of information - Enbridge

Line 1 would not have capacity for an additional 185,000 B/D of refined product although it might have as much as 147,000 B/D of capacity from Gretna to Superior. Line 3, with a capacity of 465,000 B/D, carries SCO as well as light and medium crudes from Edmonton to Clearbrook and Superior. Line 13 (175,000 B/D) carries SCO only. In order to accommodate another 185,000 B/D of refined product for Superior, line services might have to be re-arranged. Thus, major changes between Edmonton and Superior will likely be required, but this might be accommodated when new crude capacity is needed between Edmonton and Superior.

Line 5 is already in clean crude/NGL service. If conventional crudes could be shipped south of Superior via Chicago, leaving only SCO, condensate and NGL's in the system, refined products might be shipped to Marysville for the Michigan market. A new terminal would likely be needed, or a new line to existing terminals in Detroit. However, as discussed in Section V, this is a less preferable option than going to Chicago.

From Superior, there are two crude lines to Chicago, Lines 6 and 14, with capacities of 662,000 B/D and 434,000 B/D respectively. In late 2003, Enbridge proposed to construct a "Southern Access" line from Superior to Wood River, Illinois south of Chicago, Figure VIII-3. It could start up around 2007 with a crude capacity of 250,000 B/D, and expand in phases through a combination of loops along Line 14 and adding pumping capacity. It would also intersect the Spearhead pipeline which Enbridge has acquired, and these lines could also supply Chicago. If there was strong support to move refined products to Chicago, then Line 14 would need to be fully looped such that the existing 24-inch Line 14 could be used to transport refined products and clean crudes such as SCO to Chicago, or Line 14 would need to be switched to products and more capacity added in the Southern Access line.

FIGURE VIII-3
PIPELINES TO MID-CONTINENT

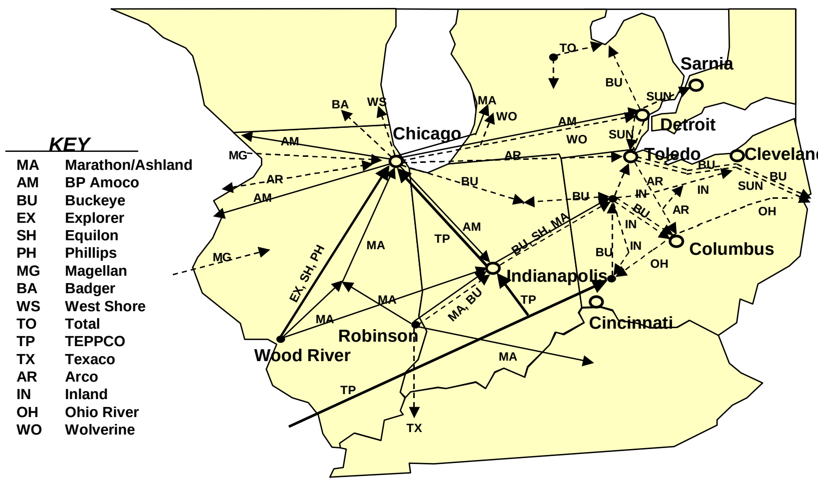


Source: Enbridge

Assuming that Enbridge's Line 14 can be made available to deliver refined products to the U.S. Midwest, products would arrive at its Griffith, Indiana terminal, Figure VIII-4. At Griffith, we believe the most logical means to get into the extensive product distribution system in that area is by constructing a new 9-mile line to Hammond. There are a significant number of large terminals near Hammond. This location would have access to the Wolverine, West Shore, Badger, BP and Buckeye pipelines. The Marathon and Buckeye systems could also be accessed at Griffith.

As shown in Figure VIII-4, product delivered into Chicago will be able to serve the Chicago market as well as markets north, west, and east of Chicago. The ability to deliver products south of Chicago are more limited, as most of the lines south of Chicago are flowing north, as shown in Figure VIII-4. The BP line to Indianapolis might provide southern access if capacity was available.

FIGURE VIII-4
MIDWEST PRODUCT PIPELINE SYSTEMS



The Enbridge companies have Canadian and U.S. tariffs to ship crudes from Edmonton to Chicago, Marysville and Sarnia. For refined products within the Prairies, the tariff for diesel is the same as light crude. The tariff for gasoline was assumed to be 6 percent lower. For the future tariff, Enbridge has not assumed major facilities upstream of Superior. To integrate the Spearhead and Southern Access systems, Enbridge has proposed a rolled-in tariff structure for its existing system; and we have used this increase in the estimated Enbridge shipping costs.[1] We understand that this would add about 5 cents per barrel to the existing tariff and would affect crude, including SCO, as well as products. We have not added other pipeline costs to ship products to Chicago; assuming that future changes in the pipeline system could accommodate products, if shipper commitments are made. We used a terminal cost and new pipeline extension charge of $0.25 (US) per barrel to deliver the refined products to Hammond. Using a pipeline escalation of 1 percent per year and a foreign exchange rate of $0.74 U.S. Dollars per Canadian Dollar, the transportation costs are estimated as follows:

[1] As of October/November of 2004, Enbridge and the industry are examining a number of options regarding future tolls. The assumptions utilized in this study may require updating in the near future when resolutions are reached.

TRANSPORTATION COSTS ESTIMATED FROM EDMONTON, 2015(1)		
	Current U.S. $/B To Chicago	Constant 2004 U.S. $/B To Chicago
SCO	1.85	1.44
Diesel	2.15	1.68
Gasoline	2.04	1.59

Note: (1) Pipeline plus receiving terminal for refined products.

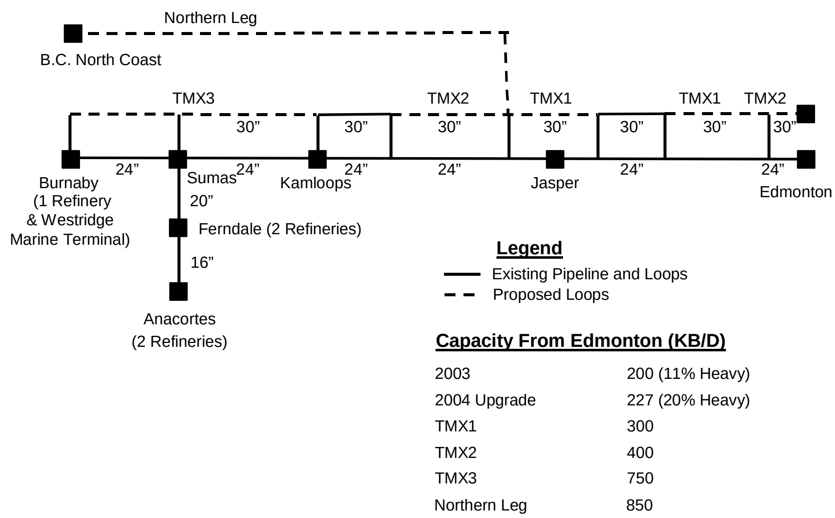
Depending on the rate of growth in oil sands production, shipments of bitumen blends and SCO are expected to rise. The production of refined products from bitumen could replace some crudes or be supplemental to the production of other oil sands crudes. Enbridge may have to expand or reconfigure its system further. They should have flexibility to design for 185,000 B/D of refined products if they have suitable shipper support.

Enbridge is also proposing a 400,000 B/D Gateway pipeline to deliver oil sands crudes from Edmonton or Fort McMurray to Kitimat or Prince Rupert, B.C. for export to California or Asia around 2010. Although there are no current plans for refined products, the project is still being developed, so perhaps the plans could be adjusted to accommodate refined products if there is sufficient commercial support.

TERASEN

The TMPL line to Burnaby carries refined products and a variety of crudes from Edmonton in a single line. TMPL's configuration is shown schematically in Figure VIII-5. The current capacity depends in part on the proportion of heavy crudes in the line; with 11% heavy crudes, the capacity is 200,000 B/D. This also assumes shipments of refined products to be 94,000 B/D. TMPL is expanding by 25,000 B/D during 2004, expected to be in operation in the fourth quarter. In 2003, TMPL shipped 77,000 B/D of gasoline and distillates. The product volumes may be reduced if refiners stop shipping diesel when low sulphur specifications commence in 2006, although the industry is working on a clean-up solution that is expected to allow diesel shipments to continue in the pipeline. It is unlikely that TMPL could carry another 185,000 B/D of clean refined products in its current configuration without discontinuing crude oil shipments altogether.

FIGURE VIII-5
TMPL SYSTEM CONFIGURATION WITH EXPANSIONS



Source: Information received from Terasen

Terasen has recently proposed a phased expansion and refers to it as the TMX project. The first (TMXI) would add a loop to Jasper, Alberta and increase capacity by over 70,000 B/D. The second expansion (TMX2) would add a loop to Kamloops, B.C. and reach 400,000 B/D of capacity. It will still have a single line to Burnaby so shipping additional clean products without contamination from crudes would not likely be feasible. The third expansion (TMX3) would loop the line to Burnaby and provide up to 750,000 B/D of capacity. TMX3 could be available around 2010 or 2011. Under this scenario, the existing 24-inch line would have capacity to ship up to 250,000 B/D of light oil, and the new 30-inch section could carry up to 500,000 B/D of heavy crude. Thus, this system could handle all the refined products for an upgrader. Thus, TMX3 would be needed for the refined products from the possible upgrading/refining cases to be shipped to Vancouver.

In order for TMX3 to be carried out, it will require producer support to ship a substantial amount of bitumen blends to Vancouver for export sales. We understand that industry participants are examining the potential of markets in California, Puget Sound, and in Asia as possible new markets for bitumen blends and synthetic crude oil. If there is support for substantial volumes to be shipped to a new port on the northwest coast of B.C. (Kitimat or Prince Rupert), Terasen has proposed an alternative to TMX3 called the "Northern Leg". This alternative would provide for 550,000 B/D of heavy crude capacity to this port, and allow 250,000 B/D of light oil to be shipped to the Vancouver/Puget Sound area. Some cleanup might be required for refined petroleum products that would be shipped with light crude oil.

For export to California, product would be loaded onto marine tankers at the Westridge terminal at Burnaby. With TMX3, shipping 750,000 B/D of crude and products (mostly for export) to this area would require the marine terminal and dock to also be expanded.

The cost of moving refined products from Edmonton to Los Angeles would include pipeline, marine and terminal charges. For the pipeline and Westridge terminal, TMPL estimates that the tariff would not change in real terms from current tariffs as the extra volume would pay for the extra investment. Allowing for pipeline inflation of approximately 1 percent per year and an exchange rate of 0.74 U.S. Dollars per Canadian Dollar, the TMPL tariff, including the Westridge terminal fee, is estimated at $1.50 (US) per barrel for gasoline and diesel in 2015, or $1.21 (US) per barrel in 2004 constant dollars.

The maximum tanker size for the Burrard Inlet is approximately 100,000 dwt, a LR1 class vessel. We have used our forecast of a world scale foreign flag rate of $0.75 (US) per barrel from Vancouver to Los Angeles, for an LR1 tanker in clean products service. A terminalling fee is included in the price discount to allow products to be off-loaded and moved into the existing pipeline infrastructure at Los Angeles, as discussed in Section VI. The total transportation cost for gasoline in 2015 is estimated at $2.32 (US) per barrel or $1.87 per barrel in constant 2004 dollars.

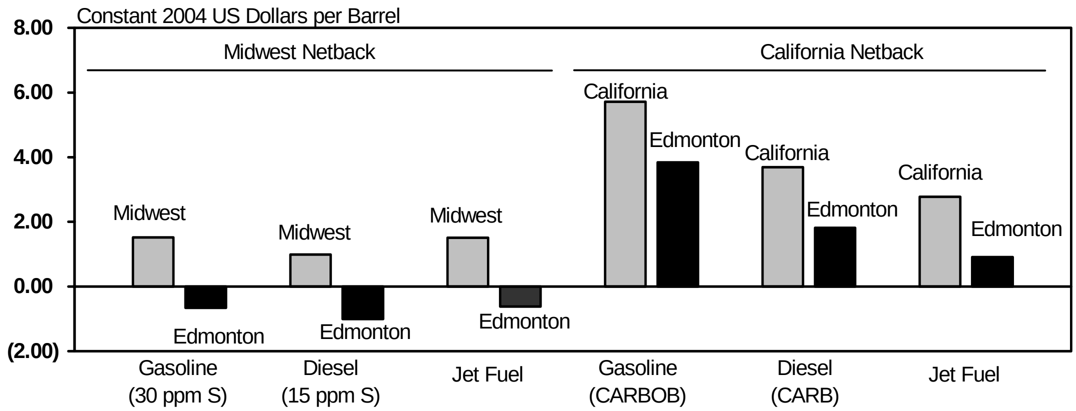
Terasen also controls the Express pipeline from Hardisty, Alberta to Casper, Wyoming. Terasen has considered the potential of a products pipeline along this route and onward to California. It is more costly than the TMPL expansions, but could be considered if the TMX3 or Northern Leg expansions do not occur.

REFINED PRODUCT PRICES

Similar to the Phase I analysis, we assumed that the refined products from an Edmonton upgrader would be sold either in the U.S. Midwest or in California. Transportation costs were deducted from the prices in these markets. Market prices in the Midwest and California were used as a basis, but were adjusted to reflect market entry discounts.

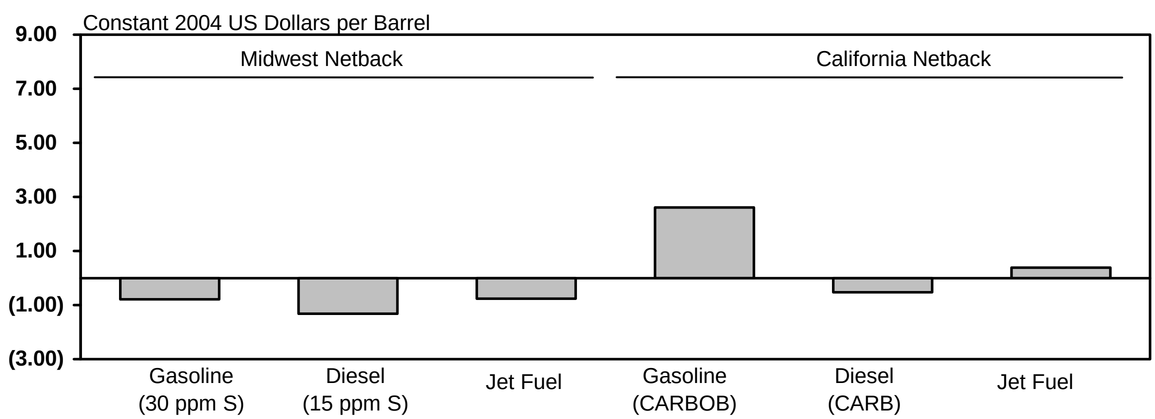
Crude pricing and forecast product margins establish product prices at the U.S. Gulf Coast. Product prices in the Midwest are related to U.S. Gulf Coast prices but they are higher (see Figure VIII-6). Refined products move by pipeline to the Midwest from U.S. Gulf Coast refineries. Netback prices for refined products are forecast based on the market prices in the Midwest less estimated transportation costs. The netback price at Edmonton, assuming there are no market discounts, for gasoline is about the same as the U.S. Gulf Coast price whereas the netbacks for diesel and jet fuel are less than the U.S. Gulf Coast prices, Figure VIII-6.

FIGURE VIII-6
PRODUCT PRICE DIFFERENTIAL ABOVE U.S. GULF COAST, 2015, WITHOUT MARKET ENTRY



Taking into account the market entry discounts that were developed in Section V for the U.S. Midwest, and in Section VI for California, the differentials at Edmonton relative to the U.S. Gulf Coast are lower, as shown in Figure VIII-7.

FIGURE VIII-7
PRODUCT PRICE DIFFERENTIAL ABOVE U.S. GULF COAST, 2015, INCLUDING MARKET ENTRY

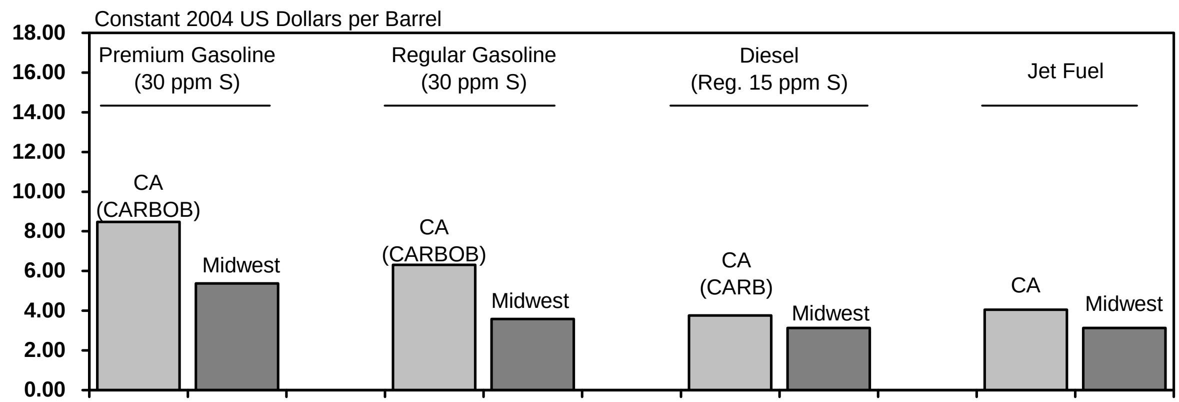


California products, both gasoline and diesel, have unique specifications, and are costly to produce. The California market is somewhat isolated from the U.S. Gulf Coast and crude slates are heavier on average, so refinery margins are higher than U.S. Gulf Coast margins, and product prices are much higher than the U.S. Gulf Coast or the Midwest prices, as discussed in Section VI. The resulting netback prices at Edmonton are higher than the U.S. Gulf Coast prices, despite higher transportation costs to the California market, and the higher discounts in that market.

The product netbacks from the Midwest and California including the market entry discounts, are compared in Figure VIII-8 versus the SCO price. The netback prices from

California are much higher for gasoline and diesel because of the higher market prices for these high quality products. For California gasoline, we have used CARBOB blendstock which will be blended with ethanol in California for finished product. For the Midwest, we have shown regular grade gasoline on the comparison below, but our analysis also assumes some RFG is produced for that market.

FIGURE VIII-8
REFINED PRODUCT NETBACK PRICES ABOVE SCO AT EDMONTON 2015, WITH MARKET DISCOUNTS



Netback prices at Edmonton for gasoline, diesel and jet fuel are all higher than the SCO price, so the revenue from refining bitumen will exceed the revenue from upgrading to SCO alone. Gasoline has a slightly higher netback than distillates. The price of diesel from the Midwest is similar to the jet fuel price. The price of CARB diesel for California is above jet fuel because of the diesel specifications, but demand for diesel in California is relatively low compared with other U.S. market regions.

TABLE VIII-1
TRANSPORTATION COSTS FOR PETROLEUM PRODUCTS
(U.S. Dollars per Barrel, Unless Noted)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inflation Index (2003=1)	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37
Current Dollars											
Edmonton to Chicago											
Diesel Transport	1.94	1.97	1.99	2.02	2.05	2.08	2.11	2.14	2.17	2.20	2.23
Gasoline Transport	1.84	1.86	1.89	1.92	1.94	1.97	2.00	2.03	2.06	2.09	2.12
Edmonton to Los Angeles											
Edmonton to Burnaby	1.40	1.42	1.44	1.46	1.48	1.50	1.52	1.54	1.56	1.59	1.61
Marine Plus Terminalling	0.77	0.78	0.79	0.80	0.81	0.82	0.84	0.85	0.86	0.87	0.88
Total	2.17	2.20	2.23	2.26	2.29	2.32	2.36	2.39	2.42	2.46	2.49
Constant 2004 Dollars											
Edmonton to Chicago											
Diesel Transport	1.72	1.71	1.70	1.68	1.68	1.68	1.66	1.66	1.64	1.63	1.63
Gasoline Transport	1.63	1.62	1.62	1.60	1.59	1.59	1.57	1.57	1.56	1.55	1.55
Edmonton to Los Angeles											
Edmonton to Burnaby	1.24	1.23	1.23	1.21	1.21	1.21	1.20	1.20	1.19	1.18	1.18
Marine Plus Terminalling	0.68	0.68	0.67	0.67	0.67	0.66	0.66	0.66	0.65	0.65	0.65
Total	1.92	1.91	1.90	1.88	1.88	1.87	1.86	1.85	1.84	1.82	1.82

TABLE VIII-2
CRUDE AND PRODUCT PRICES AT EDMONTON (UNLESS NOTED)
(U.S. Dollars per Barrel, Unless Noted)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Crude Oil											
WTI, Cushing	29.36	30.00	30.69	31.41	32.19	33.02	33.89	34.83	35.80	36.84	37.94
MSW at Edmonton	28.28	28.87	29.50	30.18	30.90	31.67	32.50	33.39	34.34	35.36	36.43
SCO at Edmonton	28.19	28.78	29.41	30.09	30.81	31.58	32.41	33.31	34.26	35.28	36.36
Naphtha/Diluent for Midwest	28.28	28.87	29.50	30.18	30.90	31.67	32.50	33.39	34.34	35.36	36.43
Natural Gas (US$/MMBTU)	4.51	4.59	4.69	4.91	5.08	5.20	5.33	5.46	5.61	5.78	5.95
Refined Products[1]											
Gasoline											
Low S Regular for Midwest	33.21	33.90	34.63	35.42	36.25	37.13	38.07	39.08	40.16	41.31	42.52
Low S Premium for Midwest	35.73	36.45	37.23	38.06	38.95	39.90	40.92	42.00	43.17	44.40	45.71
Low S Regular RFG for Midwest	34.25	34.95	36.10	36.92	37.78	38.70	39.68	40.73	41.85	43.04	44.29
Low S Premium RFG for Midwest	33.76	34.45	35.63	36.43	37.30	38.18	39.12	40.14	41.23	42.39	43.62
CARBOB Regular for California	36.99	37.76	38.58	39.45	40.38	41.35	42.39	43.49	44.68	45.93	47.25
CARBOB Premium for California	40.01	40.83	41.69	42.63	43.63	44.68	45.80	47.00	48.29	49.65	51.08
Distillates											
Low S Diesel for Midwest	32.50	33.18	33.92	34.70	35.53	36.41	37.36	38.37	39.45	40.60	41.81
CARB Diesel for California	33.40	34.09	34.84	35.64	36.49	37.40	38.37	39.41	40.52	41.70	42.94
Jet Fuel for Midwest	32.51	33.19	33.93	34.71	35.53	36.42	37.36	38.37	39.45	40.59	41.80
Jet Fuel for California	33.80	34.50	35.26	36.07	36.92	37.84	38.82	39.87	40.99	42.18	43.43
Gas Liquids											
$C2/C2^{=}$ Mix	15.87	16.16	16.47	17.15	17.69	18.07	18.48	18.92	19.40	19.93	20.46
$C3/C3^{=}$ Mix	23.33	23.83	24.36	24.91	25.50	26.12	26.78	27.48	28.22	29.00	29.82
C3 (Propane)	23.33	23.83	24.36	24.91	25.50	26.12	26.78	27.48	28.22	29.00	29.82
Field Butane	23.29	23.81	24.35	24.93	25.49	26.09	26.72	27.40	28.13	28.90	29.70
C4 Mix	23.29	23.81	24.35	24.93	25.49	26.09	26.72	27.40	28.13	28.90	29.70
Pentanes	28.28	28.87	29.50	30.18	30.90	31.67	32.50	33.39	34.34	35.36	36.43
Petrochemicals[1]											
Propylene Polymer Grade (c/lb)	19.26	20.00	21.11	21.50	21.94	22.42	22.95	23.51	24.09	24.74	25.41
Propylene Polymer Grade ($/bbl)	35.11	36.45	38.47	39.19	39.99	40.88	41.84	42.85	43.92	45.10	46.32
Styrene (c/lb)	28.03	31.03	32.92	34.69	35.35	36.08	36.85	37.65	38.49	39.36	40.27
Styrene ($/bbl)	88.72	98.23	104.21	109.81	111.90	114.21	116.65	119.18	121.85	124.59	127.46
Cumene (c/lb)	23.04	23.45	23.98	24.37	24.81	25.31	25.84	26.41	27.01	27.66	28.33
Cumene ($/bbl)	74.82	76.15	77.86	79.13	80.56	82.18	83.90	85.75	87.71	89.81	91.99
Mixed Xylenes ($/bbl)	41.22	42.46	43.98	45.38	46.43	47.57	48.79	50.07	51.48	52.98	54.52
Benzene ($/bbl)	51.68	52.54	53.45	54.45	55.55	56.88	58.30	59.83	61.45	63.19	65.01

Note: 1) Includes market entry discounts.

TABLE VIII-3
CRUDE AND PRODUCT PRICES AT EDMONTON (UNLESS NOTED)
(Forecast in Constant U.S. Dollars per Barrel, Unless Noted)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Inflation Index (2004=1)	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37
Crude Oil											
WTI, Cushing	26.07	26.12	26.19	26.29	26.41	26.55	26.72	26.92	27.13	27.37	27.63
MSW at Edmonton	25.12	25.13	25.18	25.25	25.35	25.47	25.63	25.81	26.03	26.27	26.54
SCO at Edmonton	25.04	25.06	25.11	25.18	25.28	25.40	25.56	25.75	25.97	26.21	26.48
Naphtha/Diluent for Midwest	25.12	25.13	25.18	25.25	25.35	25.47	25.63	25.81	26.03	26.27	26.54
Natural Gas (US$/MMBTU)	4.00	4.00	4.00	4.11	4.17	4.18	4.20	4.22	4.25	4.30	4.33
Refined Products[(1)]											
Gasoline											
Low S Regular for Midwest	29.49	29.51	29.56	29.64	29.73	29.86	30.02	30.21	30.44	30.69	30.97
Low S Premium for Midwest	31.72	31.73	31.77	31.85	31.95	32.09	32.26	32.47	32.72	32.99	33.29
Low S Regular RFG for Midwest	30.41	30.43	30.81	30.89	30.99	31.12	31.29	31.49	31.72	31.98	32.26
Low S Premium RFG for Midwest	29.98	29.99	30.41	30.49	30.60	30.70	30.85	31.03	31.25	31.50	31.77
CARBOB Regular for California	32.85	32.87	32.93	33.01	33.13	33.26	33.42	33.62	33.86	34.13	34.42
CARBOB Premium for California	35.53	35.54	35.59	35.67	35.79	35.94	36.11	36.33	36.59	36.89	37.21
Distillates											
Low S Diesel for Midwest	28.86	28.89	28.95	29.04	29.15	29.29	29.46	29.66	29.90	30.17	30.46
CARB Diesel for California	29.66	29.68	29.74	29.82	29.93	30.08	30.25	30.46	30.71	30.98	31.28
Jet Fuel for Midwest	28.87	28.90	28.96	29.04	29.15	29.29	29.46	29.66	29.90	30.16	30.45
Jet Fuel for California	30.01	30.04	30.09	30.18	30.29	30.43	30.61	30.82	31.06	31.34	31.64
Gas Liquids											
$C2/C2^=$ Mix	14.10	14.07	14.06	14.35	14.51	14.53	14.57	14.63	14.70	14.81	14.90
$C3/C3^=$ Mix	20.72	20.74	20.79	20.85	20.92	21.01	21.12	21.24	21.39	21.55	21.72
C3 (Propane)	20.72	20.74	20.79	20.85	20.92	21.01	21.12	21.24	21.39	21.55	21.72
Field Butane	20.68	20.73	20.79	20.86	20.91	20.98	21.07	21.18	21.32	21.47	21.64
C4 Mix	20.68	20.73	20.79	20.86	20.91	20.98	21.07	21.18	21.32	21.47	21.64
Pentanes	25.12	25.13	25.18	25.25	25.35	25.47	25.63	25.81	26.03	26.27	26.54
Petrochemicals[(1)]											
Propylene Polymer Grade (c/lb)	17.11	17.41	18.02	17.99	18.00	18.04	18.10	18.17	18.26	18.38	18.51
Propylene Polymer Grade ($/bbl)	31.18	31.73	32.84	32.79	32.80	32.87	32.99	33.12	33.28	33.51	33.74
Styrene (c/lb)	24.89	27.02	28.10	29.03	29.00	29.02	29.06	29.11	29.17	29.25	29.33
Styrene ($/bbl)	78.78	85.52	88.94	91.88	91.79	91.86	91.98	92.13	92.35	92.58	92.85
Cumene (c/lb)	20.46	20.41	20.46	20.39	20.35	20.35	20.37	20.41	20.47	20.55	20.64
Cumene ($/bbl)	66.44	66.29	66.45	66.22	66.09	66.09	66.15	66.29	66.48	66.73	67.01
Mixed Xylenes ($/bbl)	36.60	36.96	37.54	37.97	38.09	38.26	38.47	38.71	39.01	39.36	39.71
Benzene ($/bbl)	45.89	45.74	45.62	45.56	45.57	45.74	45.97	46.25	46.57	46.95	47.36

Note: 1) Includes market entry discounts.

IX. ECONOMIC RESULTS

This section of the report provides a detailed discussion of the assumptions, basis, and results for the economic evaluation. All cases were evaluated to determine a return on investment on the initial capital expenditure using a discounted cash flow analysis. The economic evaluation included all capital and operating costs, the price netted back for each product, and the feedstock costs. All returns are based on 100% equity, without considering the leverage potential of carrying some debt. Purvin & Gertz developed price forecasts for the SCO and refined products, and CMAI prepared a price forecast of the petrochemical products. These price forecasts and the product volumes were used in the discounted cash flow models. A sensitivity analysis was also undertaken to address the impact of changes in key variables.

ALBERTA UPGRADER CASES

ASSUMPTIONS AND BASIS

A cash flow model was developed to help assess the economic feasibility of constructing an upgrader/refining complex in Alberta. Cash flows for each of the California and Midwest cases were used to determine the financial viability of each scenario through the calculation of an Internal Rate of Return (IRR) and the calculation of a Net Present Value (NPV) based upon a Weighted Average Cost of Capital (WACC).

The following key assumptions were utilized in developing the cash flow model:

1. The sustaining capital needed to maintain the current operation was assumed to escalate during the life of the facility commencing in 2011 after the first year of operation. The rate was estimated to be 1.0% for the first five years, increasing to 1.5% in years 6 through 10, then 2% in years 11 to 15 and 2.5% after 15 years of operation. The sustaining capital was assumed to be an operating expense since it is not attributed to an expansion of the facility or any such betterment. As a result, the sustaining capital was expensed in the year it was spent.

2. The effective tax rate in Alberta is assumed to be 34.62 percent which is the current corporate tax rate.

3. The discount rate used to determine NPV in the DCF model was based on a weighted average cost of capital (WACC) of nine percent. This value is based on a typical long-term corporate bond yield and assumed expected return on equity by investors for this type of facility. Net present values of each case were prepared based on the 9% cost of capital.

4. Construction on the facility was assumed to commence in 2007 with capital being injected into the four year construction project in the following proportions:

    a. 2007 = 20% of capital expenditures

    b. 2008 = 25% of capital expenditures

    c. 2009 = 35% of capital expenditures

    d. 2010 = 20% of capital expenditures

5. The facility was assumed to commence operation in 2010 at 75% capacity, reaching 100% capacity in 2011.

6. Inflation is assumed to be approximately two percent per year.

7. The Capital Cost Allowance rate (CCA) for the facility is assumed to fall under the Class 10 category which equates to a CCA rate of 30% (the half-year conversion rule was applied).

8. Product prices for the economic evaluations are outlined as shown in Tables VIII-2 and VIII-3. These prices are based on Purvin & Gertz' long-term forecasts as of June, 2004.

DISCUSSION OF RESULTS

The economic analysis is presented using a simple determination of the annual recovery of the initial investment (Capital Recovery Factor) and a discounted cash flow analysis. The annual return was developed on a per barrel of bitumen processed. The IRR analysis was then prepared using a detailed 20-year cash flow analysis.

The economic analysis for Case 1 (standalone upgrading) is not related to any particular region and represents sales of SCO according to Purvin & Gertz' long-term price forecast for SCO. The economic results for Cases 3 to 5 are dependent on the region where the refined products are sold. The first analysis is centred on refined products destined to the Midwest market followed by the California analysis.

MIDWEST ANALYSIS

The gross margin for each of the cases is the difference between the product realization and the crude cost all in 2004 constant dollars according to the following table. The cost of bitumen feedstock is based on Purvin & Gertz' price forecast. The 2015 value for bitumen is $10.55 (US) per barrel at Edmonton in constant dollars (Table IV-10). This cost of bitumen is at the plant gate near Edmonton, so netback prices in the Athabasca oil sands would be around $9.60 (US) per barrel, in constant 2004 dollars. The economic results for the Alberta upgrading project cases for refined products destined to the U.S. Midwest market are outlined below.

ECONOMICS COMPARISON FOR MIDWEST CASES - 2015
(2004 Constant U.S. Dollars)

		Case 1	Case 3	Case 4a(1)	Case 5a(1)	Case 5a(1) Benzene
Total Capital	$ Million	**3,351**	**4,351**	**4,700**	**5,363**	**4,693**
Product Realization	$/Bbl Bitumen	23.77	27.62	29.41	31.18	28.55
Less Bitumen Cost (2015)		10.55	10.55	10.55	10.55	10.55
Gross Margin		13.23	17.07	18.86	20.64	18.00
Less Operating Costs						
Variable		3.18	4.19	4.02	3.94	3.64
Fixed		1.97	2.51	2.71	2.95	2.78
Subtotal		5.15	6.69	6.73	6.90	6.41
Net Refining Margin	$/Bbl Bitumen	8.07	10.38	12.13	13.74	11.59
Replacement Cost	$/yr Bbl	45.91	59.60	64.38	73.46	64.29
Annual Return(1)		17.6%	17.4%	18.8%	18.7%	18.0%
IRR		12.2%	12.3%	13.3%	13.2%	12.7%

Note: (1) Annual recovery of initial investment, or "Capital Recovery Factor"

The fixed and variable costs are subtracted to yield the net refining margin. The variable costs include those costs that are dependent on the crude charge such as fuel, electricity, catalyst, chemicals and water. The fixed costs consist of operations and maintenance costs including wages and salaries, property taxes and insurance, general overhead and other miscellaneous annual costs. To determine the annual return on the initial investment, the total capital cost for each case is divided by the annual throughput which is the annual replacement cost in $/yr-barrel. This net refining margin divided by the annual replacement cost provides a simple annual return on investment for each case, or capital recovery factor. This annual return value does not include any taxes or sustaining capital and only views the return on investment for one discrete year and does not account for the time value of money.

Case 1 yields an IRR of 12.2% based on the forecast prices of synthetic crude and bitumen. The netback price for bitumen at Edmonton is $10.55 (US) per barrel in 2015, in constant 2004 dollars. The economics of the upgrader are very susceptible to the price of bitumen and SCO. This price of bitumen represents a reasonable return for the bitumen producer, and still provides sufficient incentive for a refiner to invest in a conversion unit to upgrade the heavy crude as outlined later where we examine the economics of upgrading SynBit in a refinery. If the price of bitumen was lower, the merits of a stand-alone upgrader would improve. This will be discussed further in the sensitivity analysis. As well, one should not conclude from this assessment that upgraders are marginally uneconomic. Integration of upgrading with a SAGD operation, or a mining and extraction plant, could provide sufficient economics to warrant these types of projects, and any operating synergies would allow for reduced overall project capital and operating costs. If there are significant processing agreements in place, the upgrader likely could have significant debt financing, which would improve the return on equity above the levels shown.

Case 3 produces a finished diesel product as well as naphtha for sale as diluent. The volume of naphtha is large and could reduce the premium C5+ diluent is expected to have in the future as demand increases and bitumen production continues to rise. Even though we have reduced the price for the naphtha relative to current diluent prices, this case still yields an IRR of 12.3%, just slightly higher than Case 1. The incremental revenue from diesel and diluent is sufficient to overcome the higher capital and operating costs of the gas oil hydrocracker and additional hydrogen plant capacity that this upgrader requires to produce diluent and diesel fuel.

In this analysis, we developed market discounts that we estimate would likely be incurred if the market faced absorbing a significant supply of products. For the U.S. Midwest, we developed price discounts in Section V that include a discount of $0.15 (US) per barrel for gasoline, and a discount of $0.35 (US) per barrel on diesel fuel. These adjustments have been included in the netback pricing shown in Tables VIII-2 and VIII-3.

Case 4a(1) yields the highest return for products destined to the Midwest market, with an IRR of 13.3% based on the production of a mix of 75% conventional and 25% RFG gasoline. RBOB gasoline would be produced, and would be blended with ethanol in the market to produce finished RFG. In addition to a hydrocracker, this case includes a catalytic reformer unit and isomerization unit to improve the octane of the gasoline. The higher product realization gained from the sale of gasoline slightly offsets the higher capital costs needed, relative to Case 1, to produce the gasoline.

Case 5a(1), which adds the production of styrene, yields a return with an IRR of 13.2%. Case 5a(1) takes the Case 4a(1) configuration and adds an aromatics extraction process that removes the benzene, toluene and xylene from the reformate stream. An extra $663 million is required, and ethylene feedstock must be purchased. The benzene stream from the reformer at 4,900 B/D is fairly small, and the styrene economics based on only the natural benzene yield would be marginal because of the high capital cost to build a styrene plant. To help improve the styrene plant return, a small hydrodealkylation (HDA) plant was added to convert 2,000 B/D of toluene into benzene. This resulted in the production of 436,000 tonnes per year of styrene, which in size is a world-scale facility. We also considered a modified Case 5a(1) that exported benzene rather than producing styrene. Even though the capital cost decreased, the return dropped to 12.7%.

CALIFORNIA ANALYSIS

If refined products from the Alberta upgrader are destined to the California market, the quality of the products will be greater than that required for the Midwest market. The higher quality though, requires greater investments, mainly for more hydrogen addition. A summary of the economic results are shown in the following table.

Market entry discounts, though, will be higher in California than in the U.S. Midwest. As discussed in Section VI, we have included a differential of around 1.25 cents per gallon to allow product to be offloaded in the harbour and shipped into the product pipeline system in Los Angeles. In addition, we have included a market entry discount for gasoline of $0.40 (US) per barrel. For diesel fuel, the market entry discount is substantial at around $2.65 (US) per barrel.

ECONOMIC COMPARISON FOR CALIFORNIA CASES - 2015
(2004 Constant U.S. Dollars, unless noted)

		Case 4a(2)	Case 5a(2)	Case 4a(2) with IsoOctane(2)
Total Capital	$ Million	**4,842**	**5,675**	**4,829**
Product Realization	$/Bbl bitumen	32.32	35.12	33.48
Less Bitumen Cost		10.55	10.55	10.55
Less IsoOctane Cost				0.72
Gross Margin		21.77	24.57	22.21
Less Operating Costs				
Variable		4.38	4.97	4.35
Fixed		2.82	3.13	2.75
Subtotal		7.20	8.10	7.10
Net Refining Margin	$/Bbl bitumen	14.58	16.47	15.11
Replacement Cost	$/yr Bbl	66.32	77.74	66.15
Annual Return, %(1)		22.0%	21.2%	22.8%
IRR		15.4%	14.9%	**16.1%**

Notes: (1) Annual recovery of initial investment, or "Capital Recovery Factor"
(2) Assumes that IsoOctane is purchased in Edmonton.

The California market provides somewhat higher returns than occurred for the corresponding Midwest cases. In general, the higher expected refined product realizations in California help to improve the margin, even though capital costs increase as shown in the above table. The price discounts are significant, but the returns are still around 15%.

Case 4a(2) IRR increases to 15.4%, higher than the Midwest Case 4a(1) which has a 13.3% IRR, even though the capital cost increased by around $140 million. The improvement in margins can still be attributed to the higher product realization for CARB gasoline and diesel.

Case 5a(2) has a slightly lower IRR at 14.9% due to the cost of the styrene facility. Styrene production could have been higher in this case due to the higher volume of reformate produced. However, styrene production was limited to 430,000 tonnes per year, similar to the Midwest case because the North American market will likely be able to absorb only one new worldscale plant beyond 2010 (as discussed in Section VII).

A second refined products case, Case 4a(2), was prepared which examines the potential of purchasing iso-octane in Edmonton. Iso-octane is produced in Edmonton, and is a high octane component that is shipped to the West Coast of British Columbia by pipeline and rail, and then delivered to California refineries by marine tanker. As noted in the above table, it allows for a slight reduction in capital cost, and increases gasoline yield. This case generated a 16.1% return, which was the highest of all the California cases. A key assumption in this case is what would be a fair price for the iso-octane, which we estimated based on its high octane value and low RVP, both which are desirable characteristics to a California refinery. It may be necessary to pay a premium in order to bid the iso-octane supplies away from existing long-term contract users, which would reduce the return for this case.

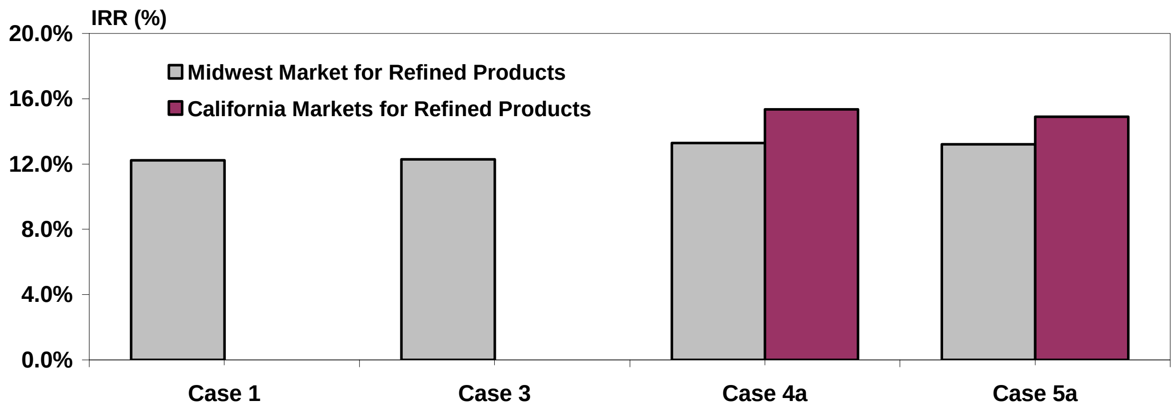
In conclusion, the higher value for CARB gasoline and diesel appears to provide for the higher returns in the California cases relative to the U.S. Midwest. The hydrocracker configuration provides for the highest economic value added, and confirms the conclusions in the Phase I study which also examined catalytic cracking of VGO as an alternative to hydrocracking. In fact, most refineries in California have a high level of hydrocracking capacity, which is a preferred refinery configuration for producing CARB specification product. Styrene production, Case 5a(2), slightly decreases the return relative to producing only refined products, Case 4a(2).

If Terasen is not able to provide a segregated product pipeline from Edmonton to Vancouver, the economics of supplying products to the California market become less attractive. If products were shipped in a batch mode within the crude pipeline, some contamination would occur, and a clean-up step would be required. We have not undertaken a thorough assessment of the potential to successfully clean up products, especially to levels as low as 10 – 15 ppm required for future diesel, but we understand that the Western Canadian refiners are working on such a solution to enable low sulphur diesel to be shipped from Edmonton to Vancouver on the Trans Mountain line by 2006. If the clean-up cost is as much as 3 cents (US) per gallon, the rate of return for Case 4a(2) would drop from 15.4% to 14.5%.

COMPARISON OF RETURNS

The resulting rates of returns for each of the Alberta upgrading cases are shown below in Figure IX-1.

FIGURE IX-1
COMPARISON OF CASES



The Base Case (Case 1) upgrader provides a return of 12.2% based on the bitumen price forecast shown in Tables IV-9 and IV-10. In 2015, we have a bitumen price of $13.11 in Edmonton in nominal dollars, and $10.55 per barrel (in 2015, in constant 2004 dollars). All of the other cases shown show higher returns. The production of refined products excluding petrochemicals from a hydrocracking refinery (Cases 4a) provided the highest returns. The refining and petrochemical cases, Case 5a, showed the next best returns.

Clearly, the California cases provide better returns than does the Midwest cases or the Base Case upgrader (Case 1). Although the market entry discounts are higher in California, the higher product prices in that market should continue to support the extra investments required to produce the CARB product qualities.

SENSITIVITY ANALYSIS

The analysis developed for the various cases represent our estimates of the most likely scenario for each case the economic evaluation. Even though this analysis represents the expected value based on our forecast for prices and costs, there remains some uncertainty as to the outcome of these price and cost relationships. As a minimum, a sensitivity analysis provides some insight into the effect of a deviation from those forecast and predicted values. This analysis is an assessment of certain key variables that affect case valuations. Our sensitivity analysis is not a substitute for a risk assessment since risk incorporates an estimate of the probability of each of the sensitivity trials. Instead, our analysis evaluated the impact of a change to each key economic driver with other values held constant. Tables IX-1 and IX-2 summarize the sensitivity results.

The most significant economic drivers that influence the IRR for most cases include capital cost, feedstock costs, product prices, and natural gas and NGL prices.

In most cases we assumed the sensitivity was distributed symmetrically above and below the base value.

Capital Cost

Capital cost is the most significant cost for each case and occurs early in the project, so the effect on return is pronounced. Our base case assumption, as discussed in Section III, was for a location factor of 1.3 and was developed using information from recently completed projects of this magnitude. There exists a chance that the capital cost could deviate from this base case assumption and that cost overruns are a distinct possibility. It is also possible that, for various reasons, costs could be lower than experienced in the apparent overheated labour market with capital costs deviating by as much as ±30%. Recent rises in the Canadian dollar relative to the U.S. dollar may put more pressure on the costs of such projects. Labour costs, which represent a significant portion of the total cost, are mainly in Canadian dollars.

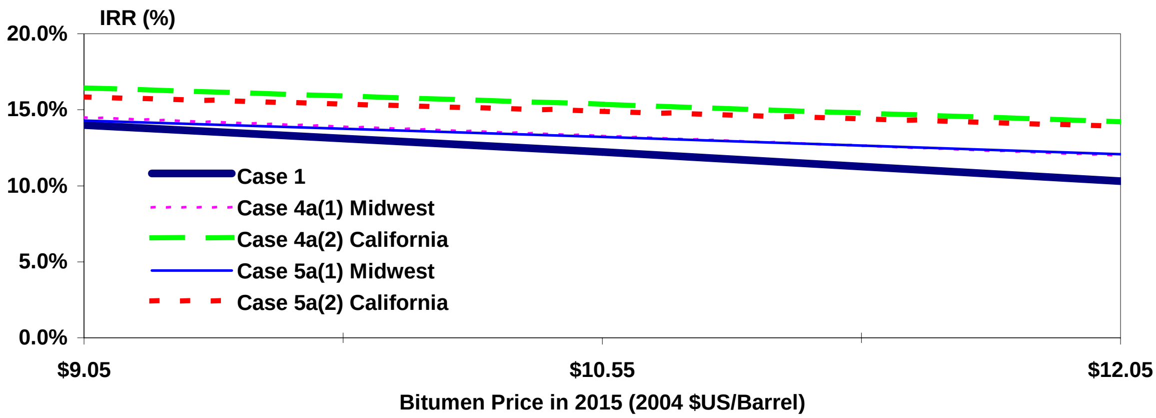
Product Prices

Products of significant volume produced from the upgrader include SCO, naphtha, gasoline, jet fuel, and diesel. Butane production may be significant and could be either a product or a feedstock (depending on the case). Lighter products such as ethane and propane are not produced in significant quantities, and these were included in the natural gas price sensitivity. Our assumption was that underlying changes to the overall price of crude would affect product prices equally. A $2.00 per barrel increase in WTI would result in an identical increase in SCO, naphtha, gasoline, jet fuel, diesel and butane price. Although this correlation is a simplification, our assumption should provide some directional price movement for the products. The impact of the market discounts are discussed later.

Bitumen

Our forecast for the bitumen price is based on a long-term light/heavy price differential that provides a reasonable return for a refiner to make an investment in additional upgrading capacity. The price forecast for bitumen is approximately $10.55 per barrel in 2004 constant dollars, which yields a 12.2% IRR for the upgrader base case (Case 1). It is possible that a producer may sell at a price lower than this and still achieve a reasonable return. To test this, the bitumen price was varied by $1.50 per barrel to evaluate the effect on case IRR. Figure IX-2 illustrates the IRR response of each case to changes in bitumen price and reveals that the economics for the standalone upgrader, Case 1, are more sensitive to bitumen prices than are the other cases.

FIGURE IX-2
IRR SENSITIVITY TO BITUMEN PRICE



Natural Gas and Related Liquids Price

Natural gas price is a large input cost to the upgrading facility as both a source of fuel and to provide feed for the steam-methane reformer to produce hydrogen for hydrocracking and hydrotreating. Natural gas prices have exhibited a high amount of volatility recently. However the relationship between natural gas and crude should prevail over the long-term within reasonable limits. We have assumed that the price deviation for natural gas would be similar to the deviation in crude price. As a result, the return for each case was tested at ± 11% of the base natural gas price, which is around $0.50 (US) per million Btu.

Since the price of ethane and propane is influenced by the price of natural gas, our sensitivity analysis of natural gas price also includes equivalent changes in ethane and propane prices. This sensitivity is not as significant because of the large volume of ethane and propane that is produced. We have assumed that ethane is used as fuel, and propane/propylene is sold as a mix. Similarly, the mixed C_4 stream is also assumed to be sold.

The results of these sensitivities are illustrated in the tornado diagrams Figures IX-3 to IX-9.

FIGURE IX-3
MIDWEST: CASE 1 SENSITIVITY

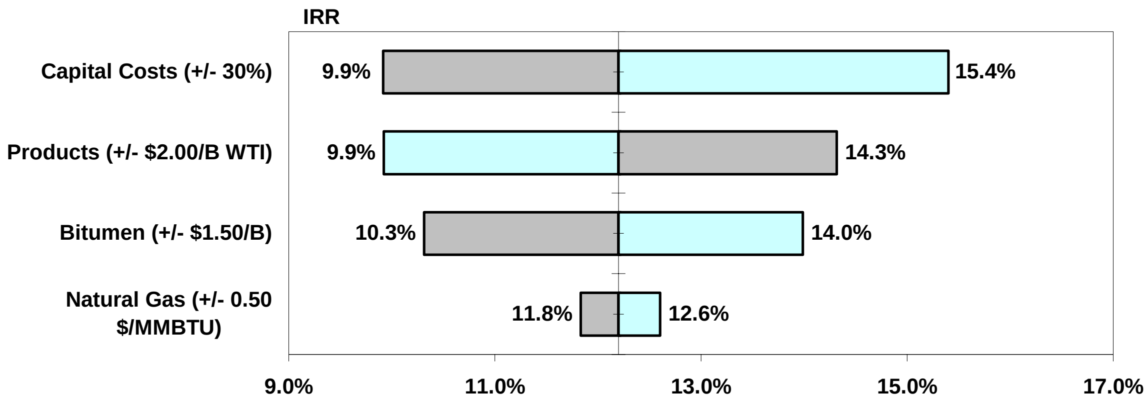


FIGURE IX-4
MIDWEST: CASE 3 SENSITIVITY

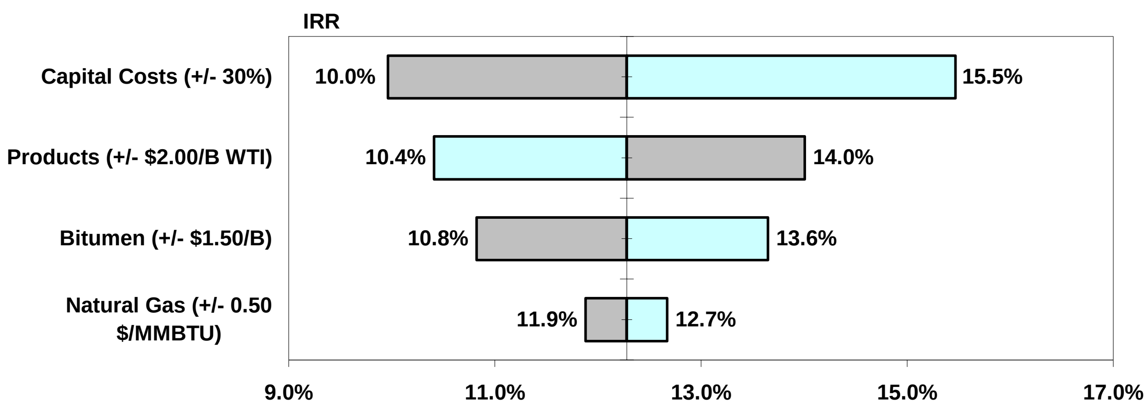


FIGURE IX-5
MIDWEST: CASE 4a SENSITIVITY

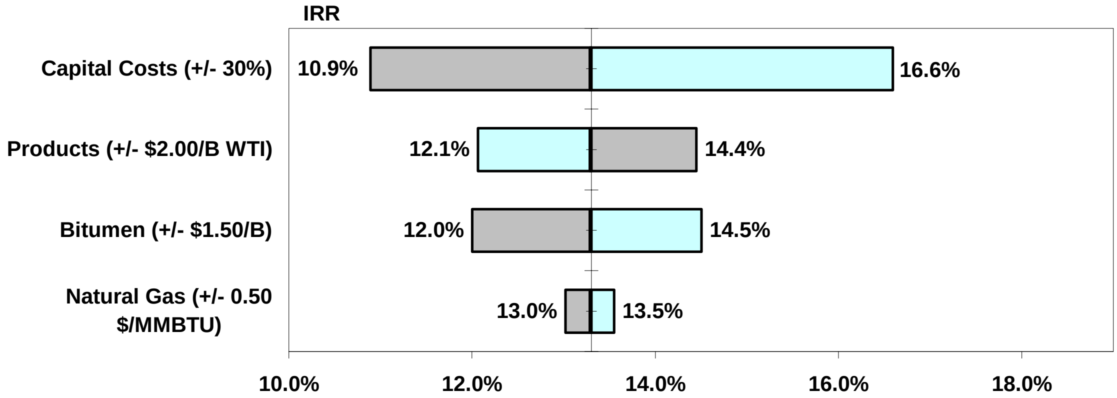


FIGURE IX-6
MIDWEST: CASE 5a SENSITIVITY

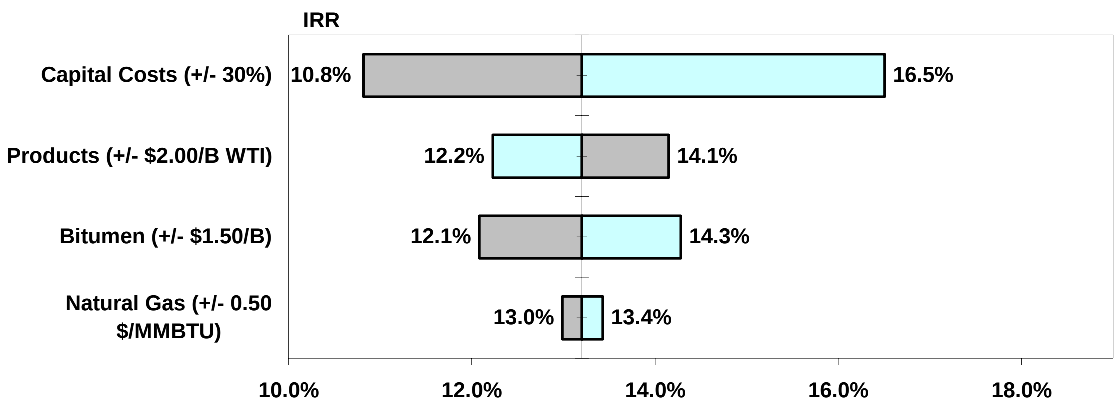


FIGURE IX-7
MIDWEST: CASE 5a BENZENE NO STYRENE SENSITIVITY

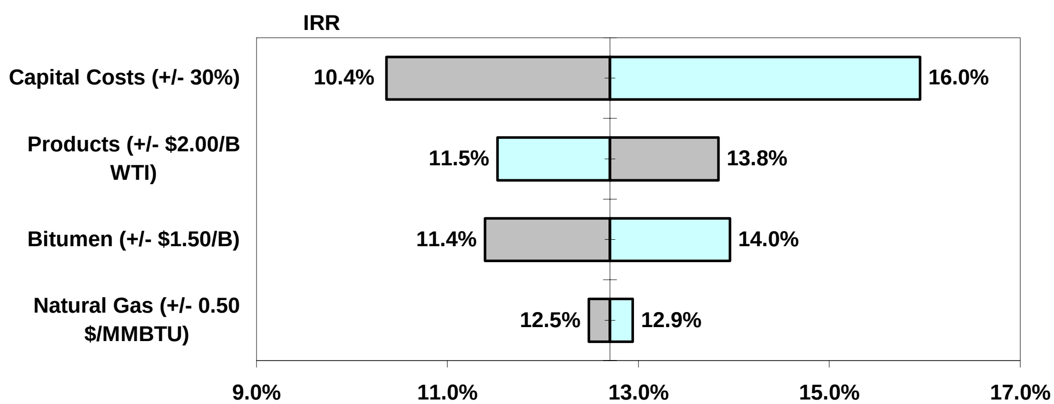


FIGURE IX-8
CALIFORNIA: CASE 4a SENSITIVITY

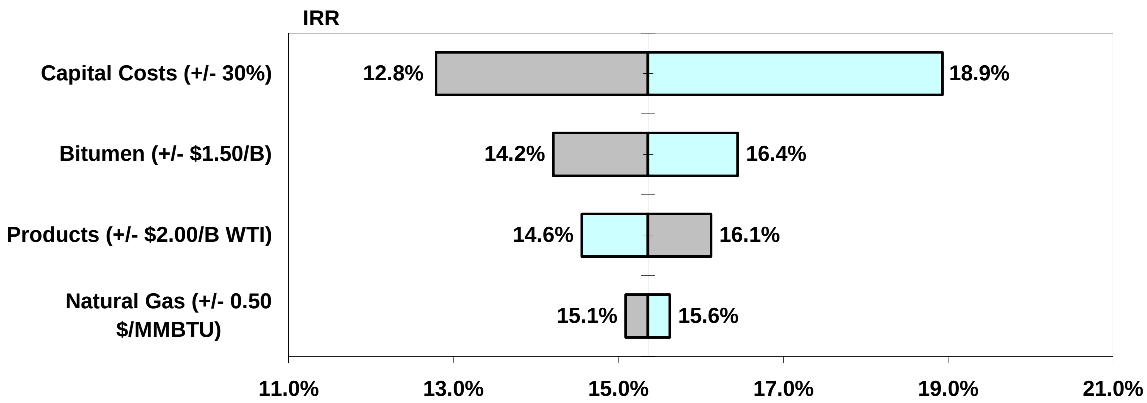


FIGURE IX-9
CALIFORNIA: CASE 5a SENSITIVITY

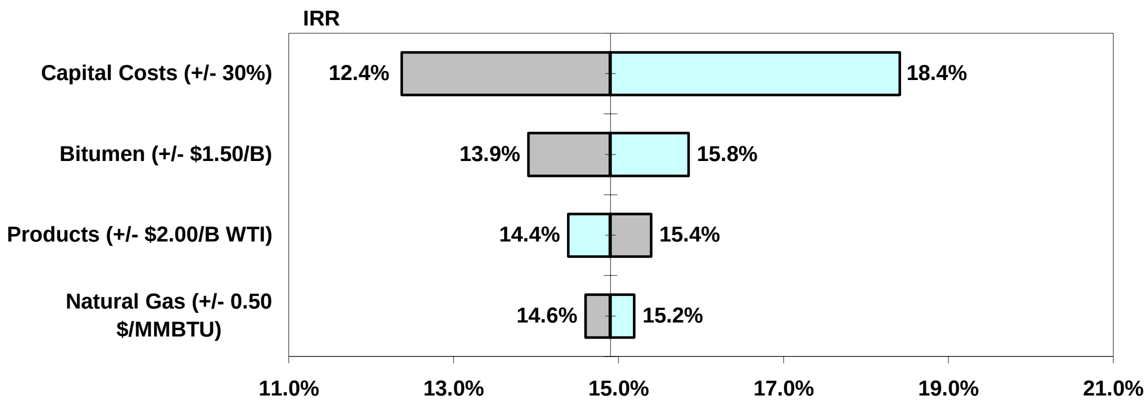
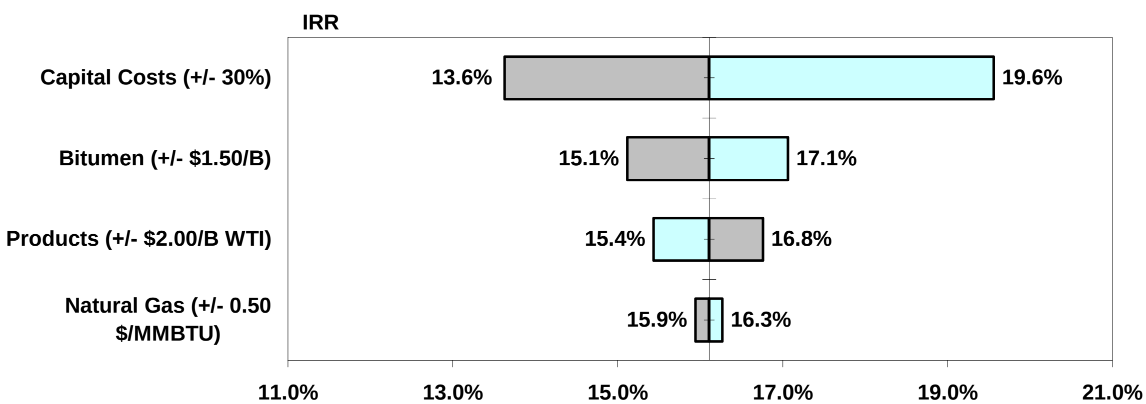


FIGURE IX-10
CALIFORNIA: CASE 4a (with iso-Octane) SENSITIVITY



INCREMENTAL ECONOMICS

As outlined earlier, this assignment also addresses the incremental potential to produce refined products and primary petrochemicals relative to stand-alone upgrading. This assumes that the bitumen producing industry will find a way to justify and support stand-alone upgrading.

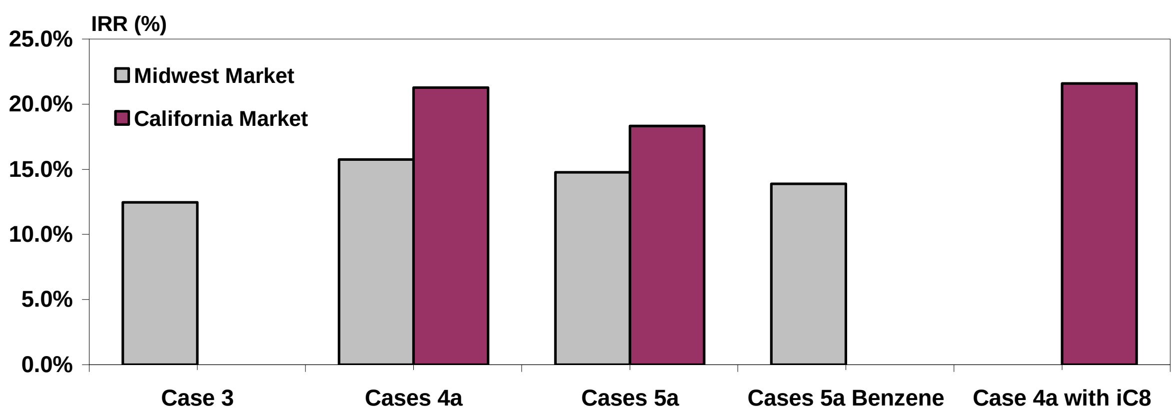
The incremental capital for each case is shown below, and detailed in Table IX-3.

INCREMENTAL CAPITAL COST
($Millions of U.S Dollars – 2004)

Cases	Capital Cost	Incremental Cost to Case 1
Case 1	3,351.3	-
Case 3	4,350.7	999
Case 4a(1)	4,526.3	1,175
Case 5a(1)	5,362.8	2,012
Case 4a(2)	4,841.6	1,490
Case 5a(2)	5,674.7	2,323

Figure IX-11 provides a comparison of the incremental returns of each of the cases relative to the Base Case upgrading project. The incremental IRR reveals the incentive to produce other products besides SCO from the upgrader. What is important to note is that the price of bitumen is irrelevant to this comparison because all cases assume the same price of bitumen as the Base Case (Case 1).

FIGURE IX-11
INCREMENTAL IRR COMPARISON RELATIVE TO CASE 1



The refined products only cases (Case 4a) show significant returns over the Base Case. The addition of petrochemical products, primarily styrene, reduces the economics slightly, as shown below, and described further in Table IX-3.

IMPROVEMENT IN RETURNS
(Incremental % Return Over Base Case)

	IRR(%)
Refining Only, Hydrocracking	
Case 4a(1)	15.7%
Case 4a(2)	21.3%
Addition of Petrochemicals	
Case 5a(1)	14.8%
Case 5a(2)	18.3%

It is clear from the above analysis that the California market should provide somewhat higher returns as compared to the Midwest market, due primarily to the stronger prices for CARB products. The petrochemical cases producing styrene, added to the hydrocracking refinery cases, actually reduces the returns in both markets slightly relative to producing only refined products.

IMPROVEMENT IN RETURNS FOR PETROCHEMICAL STEP

	Incremental Investment $ Million	Incremental IRR (%)
U.S. Midwest Cases		
Case 5a(1) relative to Case 4a(1)	663	12.7%
California Cases		
Case 5a(2) relative to Case 4a(2)	833	12.0%

In conclusion, the petrochemical steps, based on producing styrene, show IRR returns that are between 12 and 13%. Regardless to which market the refined products are destined, the petrochemical steps appear to provide slightly lower returns than do the projects that produce only refined products. The combined refined products/petrochemicals cases still generate greater returns than standalone upgrading. Possibly, if lower cost sources of benzene could be obtained, such as from local refiners, or a lower cost source of ethylene could be obtained, the petrochemical economics could be improved.

U.S. REFINERY CONVERSION CASES

U.S. REFINERY UPGRADING ECONOMIC ASSUMPTIONS

As outlined in Section III, four cases were evaluated to upgrade oil sands products in U.S. refineries. These cases are as follows:

U.S. REFINERY UPGRADING CASES

Case No.	Refining Market	Description of Case
Case 6	USMW	Project to allow 100,000 B/D of SynBit processing, maintaining current asphalt production.
Case 7	USMW	Project to allow processing of 100,000 B/D of SynSynBit blend without expansion of distillation units (Hydrocracking expansion).
Case 8	California	Project to allow 100,000 B/D of SynBit processing.
Case 9	U.S. Mid-Continent	Project to substitute 25,000 B/D of neat SCO for sweet crude.

Project cash flow models were developed to determine the economics of each of the U.S. refinery upgrading projects. Project start dates and IRR calculations presented herein are consistent with those produced for the Alberta projects. Other key assumptions utilized for the U.S. refinery projects are as follows:

1. Construction of the project was assumed to commence in 2007 with capital being spent during a four year construction period in the following proportions:
   a. 2007 = 20 percent of total project capital
   b. 2008 = 25 percent
   c. 2009 = 35 percent
   d. 2010 = remaining 20 percent
2. The new project was assumed to commence operation at the beginning of year 2010 at full capacity.
3. Additional annual sustaining capital associated with the project was assumed to be equal to 2 percent of the total project cost.
4. Depreciation consistent with U.S. tax laws for petroleum refining facilities and uses a 10-year ACRS schedule.
5. Federal income tax rate = 35 percent.
6. Synthetic crude oil and bitumen prices consistent with Alberta project economics (FOB Edmonton) and delivered to the each market using appropriate transportation costs.

DISCUSSION OF RESULTS

Table IX-4 summarizes the economics of each U.S. upgrading project. Economics are considered on an incremental basis versus the base case. The SynBit coker upgrading projects in the U.S. Midwest (Case 6) provides incremental gross margin by increasing product revenue due to the increase in higher value light product (gasoline and diesel) versus fuel oil production from the implementation of the coker as well as reducing feedstock costs by processing heavy sour crude oil versus the base case medium sour. In Case 7, the feedstock cost actually increases due to the high volume of synthetic crude oil processed, therefore incremental gross margin is obtained by an increase in product revenue from higher volumes of gasoline and diesel from the hydrocracker project. For the California project, project benefit is gained by a reduction in feedstock costs when moving 100,000 B/D of crude runs from a medium sour to heavy sour. Since the base refinery has an existing coker there is no incremental increase in product revenue. In Case 9, gross margin increases due to higher product revenue from reduced vacuum residual and increased distillate production. However, the majority of the gross margin improvement is offset by higher operating costs.

For each case the estimated fixed and variable costs are subtracted from the gross margin to yield net refining margins. Fixed expenses are those costs that are not dependent on the level of throughput processed at the facility and would be incurred even if the facility was not operating. These fixed costs include labor, maintenance and turnaround expenses, environmental costs, and miscellaneous expenses including business services, support services and corporate G&A. Variable expenses are costs that are associated with refinery throughput, including fuel, electricity and water. The annual return for the project is the net margin in $/barrel divided by the capital cost of the project in $/barrel-year. The IRR is determined from after-tax net cash flows assuming a 40-year project life.

Case 6 shows the largest return of the three U.S. upgrading projects, which is consistent with Purvin & Gertz' outlook for heavy sour coking economics in future years. The California SynBit coker case is slightly lower than Case 6 due in part to slightly higher capital costs as well as not benefiting from a full refinery upgrade converting sour crude cracking capacity to sour crude coking (i.e. medium sour coking to heavy sour coking). The SynSynBit hydrocracking economics suggest that the current price of synthetic crude oil provides approximately 10.4 percent capital recovery for a hydrocracker constructed to process the material. The neat SCO case does not provide sufficient net margin improvement to cover its capital cost and therefore the IRR for the project is zero.

The refinery conversion projects to process SynBit were characterized based on actual refineries that were most applicable to such applications. There are only a few such refineries, and they might not be available for such modifications due to their own plans. Other refineries could also be candidates, but they would be smaller and would likely result in lower returns. Each SynBit barrel contains 50% SCO, so a 100,000 B/D SynBit conversion results in an incremental market for only 50,000 B/D of bitumen. We believe that a few refineries will likely convert or be expanded to process more bitumen, but the extent of incremental bitumen markets that are developed in this way may still fall short of potential bitumen supplies.

SENSITIVITY ANALYSIS

A number of sensitivity cases are presented to reflect how changes in project capital costs, operating costs, or forecasted market conditions (i.e. price of crude oil or refinery gross margins) affect project returns. The following cases are intended to show the effect of a single variation from our base analysis or assumption. They are shown individually, but combinations and ranges outside those illustrated are possible.

Synthetic Crude Oil Price

The economics for the four U.S. refining cases are based on Purvin & Gertz' price outlook for SCO. Our view of SCO pricing (see Section IV) is based on the existing markets being able to absorb the incremental SCO production without any new investments required in refineries. However, as these markets become saturated, incremental supplies of SCO will need to find new markets. It is possible that SCO prices may experience further discounts simply by transporting new production to more distant markets.

As outlined in the four refining cases where new capacity is added to process SCO, either with bitumen or neat, the price of SCO is a very key variable. For upgrading SynBit, a reduction in the price of SCO by $1.00 per barrel provides a strong uplift in economics, but both SynBit cases should be viable based on the base SCO price forecast. (This assumes, however, that bitumen price remains unchanged if SCO prices change, which in reality might not be the case.) For the SynSynBit and neat SCO cases, though, the viability of these cases are very sensitive to the price of SCO. A discount of $1.00 per barrel is needed to bring the SynSynBit return from 10% to 16.9%. A discount of $2.00 per barrel on the SCO price in the Mid-continent neat SCO case provides a reasonable project return of approximately 15 percent IRR.

The results of the sensitivity analysis for each of the U.S. refinery upgrading cases are illustrated in the tornado diagrams Figures IX-11 to IX-13.

FIGURE IX-12
U.S. MIDWEST REFINERY UPGRADE: CASE 6 (SYNBIT COKER)

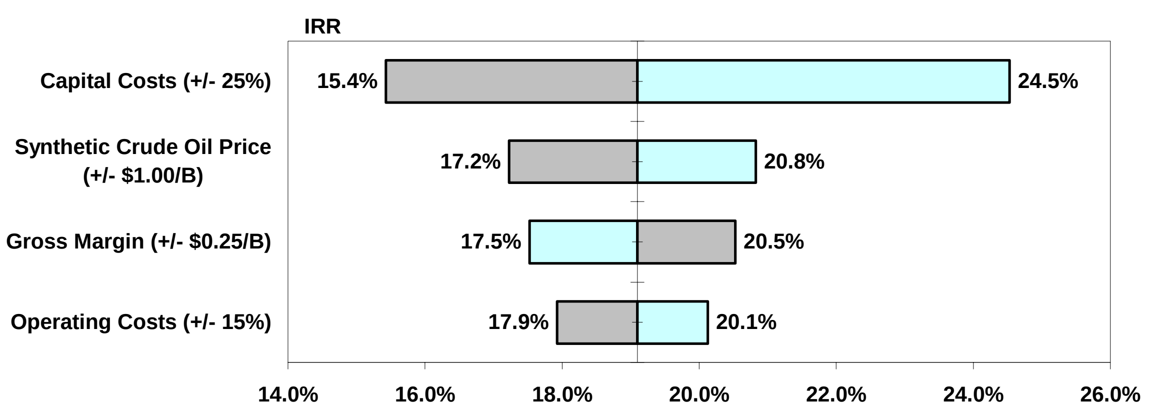


FIGURE IX-13
U.S. MIDWEST REFINERY UPGRADE: CASE 7 (SYNSYNBIT HYDROCRACKER)

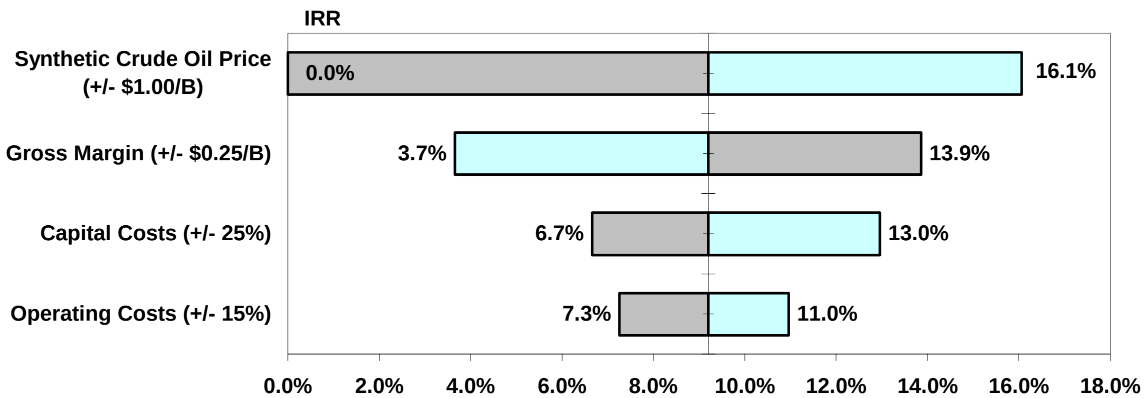
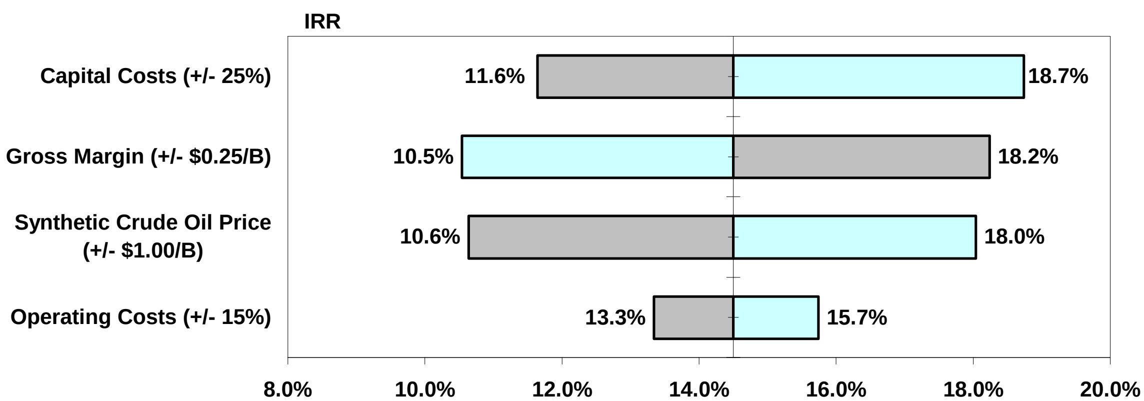


FIGURE IX-14
CALIFORNIA REFINERY UPGRADE: CASE 8 (SYNBIT COKER)



Capital Costs

Purvin & Gertz has estimated the capital costs for each project utilizing curve type estimates for refinery process units. The accuracy of cost estimates is dependent on the degree of engineering definition and the amount of engineering completed. For this analysis, hypothetical refinery configurations are being utilized and projects are conceptual only, therefore curve type capital estimates are sufficient for this level of cost estimate. The overall expected accuracy of this level of cost estimate is about +/- 35 percent.

In addition, these projects are anticipated to be executed in operating refineries. Additional time and cost is likely to acquire necessary permits and complete the work within an operating facility. A contingency of 15 percent has been included in the cost estimate to account for some these unknown factors in addition to a location adjusted "other project costs" of 15 – 25 percent. Given the large degree of variation in cost estimates that could result if a project was further pursued a sensitivity case was generated by deviating the overall project capital cost by +/- 25 percent to determine the change in project IRR.

Operating Costs

Given the volatility in the price of energy (electricity and natural gas) over the last several years, operating costs for a refining facility can vary widely from year to year. In addition, changes in project scope or an individual refinery's overall energy balance could have a substantial difference in the estimated operating costs used for project valuation. A sensitivity of +/- 15 percent on the total operating costs for each project was used to determine its effect on project IRR.

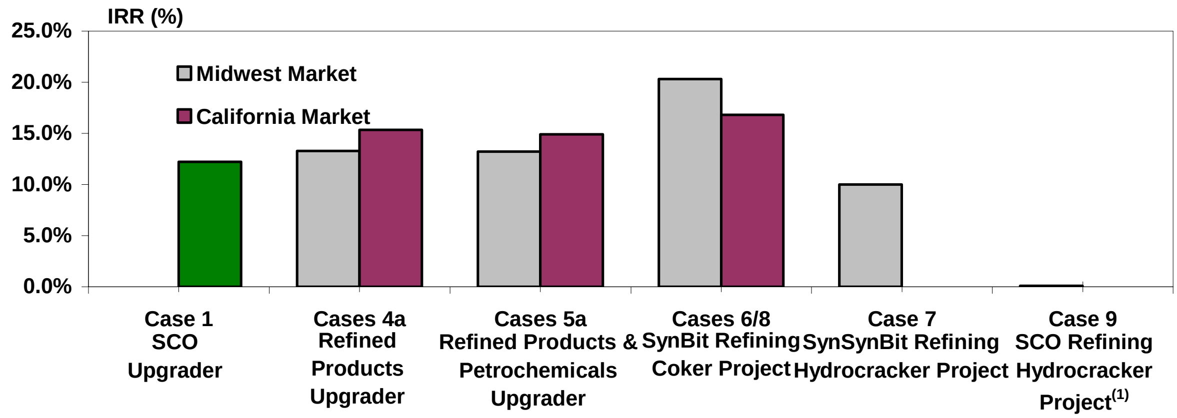
Gross Margin

The base analysis presented in the U.S. Refinery Market section represents Purvin & Gertz' assessment of the most likely future economic scenario and operating performance. Our forecast is an equilibrium forecast, which tends to identify the mid point around which the market fluctuates. When it is higher or lower, it should trend toward return to equilibrium, but the market will not reside at that point. To examine the effect of variances in gross margin outlooks on project economics, a $0.25 per barrel of crude throughput change was used as a sensitivity case.

COMPARISON OF ALL PROJECTS

From the assessment of both Alberta upgrading projects and U.S. refinery upgrading projects, the following Figure IX-15 shows the relative rates of return for the various projects.

FIGURE IX-15
OVERALL ECONOMIC COMPARISON OF PROJECTS



1) Return for a Mid-Continent location is 0%

Based on the above, upgrading refineries in California and the U.S. Midwest to process SynBit provided the highest returns. For an Alberta based refinery, the California market should provide slightly better returns than the Midwest market. Upgrading a Midwest refinery to process SynSynBit, or a Mid-continent refinery to process SCO, provided lower returns than the Alberta based projects.

Another conclusion that could be made regarding the cases that use SCO, is that our forecast price of SCO may be too high to encourage refiners to add investments to equip refiners to process more SCO. A lower SCO price would improve the economics of all the downstream refinery cases considered.

TABLE IX-1
MIDWEST CASES
INTERNAL RATE OF RETURN: SENSITIVITY ANALYSIS

	Low	High	Case 1			Case 3			Case 4a(1)			Case 5a(1)			Case 5a(1) Benzene no Styrene		
	IRR Case	IRR Case	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
Products Change (+/- $2.00 per barrel WTI)	$ (2.00)	$ 2.00	9.9%	12.2%	14.3%	10.4%	12.3%	14.0%	12.1%	13.3%	14.4%	12.2%	13.2%	14.1%	11.5%	12.7%	13.8%
Natural Gas (+/- 0.50 $/MMBTU)	$ 0.50	$ (0.50)	11.8%	12.2%	12.6%	11.9%	12.3%	12.7%	13.0%	13.3%	13.5%	13.0%	13.2%	13.4%	12.5%	12.7%	12.9%
Capex (+/- 30%)	0.30	(0.30)	9.9%	12.2%	15.4%	10.0%	12.3%	15.5%	10.9%	13.3%	16.6%	10.8%	13.2%	16.5%	10.4%	12.7%	16.0%
Bitumen (+/- $1.50 per barrel)	$ 1.50	$ (1.50)	10.3%	12.2%	14.0%	10.8%	12.3%	13.6%	12.0%	13.3%	14.5%	12.1%	13.2%	14.3%	11.4%	12.7%	14.0%

TABLE IX-2
CALIFORNIA CASES
INTERNAL RATE OF RETURN: SENSITIVITY ANALYSIS

	Low IRR Case	High IRR Case	Case 4a(2) Low	Case 4a(2) Base	Case 4a(2) High	Case 5a(2) Low	Case 5a(2) Base	Case 5a(2) High	Case 4a(2) with isoOctane		
Products Change (+/- $2.00 per barrel WTI)	$ (2.00)	$ 2.00	14.6%	15.4%	16.1%	14.4%	14.9%	15.4%	15.4%	16.1%	16.8%
Natural Gas (+/- 0.40 $/MMBTU)	$ 0.50	$ (0.50)	15.1%	15.4%	15.6%	14.6%	14.9%	15.2%	15.9%	16.1%	16.3%
Capex (+/- 30%)	0.30	(0.30)	12.8%	15.4%	18.9%	12.4%	14.9%	18.4%	13.6%	16.1%	19.6%
Bitumen (+/- $1.50 per barrel)	$ 1.50	$ (1.50)	14.2%	15.4%	16.4%	13.9%	14.9%	15.8%	15.1%	16.1%	17.1%

TABLE IX-3
INCREMENTAL CAPITAL RECOVERY AND IRR

		Midwest Refined Products				California Refined Products			
Base Case:	**1**	**1**	**1**	**1**	**4a(1)**	**1**	**1**	**1**	**4a(2)**
Incremental Case:	**3**	**4a(1)**	**5a(1)**	**5a(1) Benzene**	**5a(1)**	**4a(2)**	**5a(2)**	**4a(2) iC8**	**5a(2)**
Δ Capex ($Million)	999.4	1,348.8	2,011.5	1,341.6	662.7	1,490.3	2,323.4	1,477.5	833.1
Δ Capex ($/B/D)	4,997.1	6,744.1	10,057.7	6,708.1	3,313.6	7,451.5	11,617.0	7,387.6	4,165.5
Δ Margin ($/B)[(A)]	2.31	4.06	5.67	3.52	1.61	6.50	8.40	7.04	1.90
Incremental CRF (%)	16.8	22.0	20.6	19.1	17.8	31.9	26.4	34.8	16.6
Incremental IRR (%)	12.5	15.7	14.8	13.9	12.7	21.3	18.3	21.6	12.0

Note: (A) 2015 prices and costs in constant 2004 dollars.

TABLE IX-4

SUMMARY: ECONOMICS FOR CONVERSION OF U.S. REFINERIES
(2004 Constant U.S. Dollars)

		Case 6 USMW SynBit Coker			Case 7 USMW SynSynBit Hydrocracker			Case 8 California SynBit Coker			Case 9 Mid-Continent SCO Hydrocracker		
		Base Case	Post - Project	Diff.	Base Case	Post - Project	Diff.	Base Case	Post - Project	Diff.	Base Case	Post - Project	Diff.
Total Project Capital	$ Million			704			279			359			208
Product Realization	$/Bbl Crude	28.25	29.87	1.61	28.25	29.59	1.34	35.88	35.90	0.02	29.82	31.49	1.67
Less Feedstock Cost		24.38	22.71	(1.67)	24.38	24.85	0.47	26.45	25.30	(1.14)	27.49	28.01	0.52
Gross Margin		**3.87**	**7.15**	**3.28**	**3.87**	**4.74**	**0.87**	**9.43**	**10.59**	**1.17**	**2.33**	**3.48**	**1.15**
Variable Expenses		1.48	2.09	0.62	1.48	1.79	0.31	2.69	2.99	0.30	1.09	1.64	0.55
Fixed Expenses		1.19	1.58	0.39	1.19	1.34	0.16	1.65	1.77	0.12	1.72	2.27	0.55
Subtotal Operating Costs		**2.66**	**3.68**	**1.01**	**2.66**	**3.13**	**0.47**	**4.34**	**4.76**	**0.42**	**2.81**	**3.91**	**1.11**
Net Refining Margin	$/Bbl Crude	**1.21**	**3.47**	**2.26**	**1.21**	**1.61**	**0.40**	**5.09**	**5.84**	**0.75**	**(0.48)**	**(0.44)**	**0.05**
Replacement Cost	$/yr Bbl	23.97	33.60	9.64	23.97	27.79	3.82	35.98	39.92	3.94	27.84	39.25	11.41
Annual Return (1)		5.0%	10.3%	23.5%	5.0%	5.8%	10.4%	14.1%	14.6%	19.0%	-1.7%	-1.1%	0.4%
IRR				19.1%			9.2%			14.5%			0.0%

Note: (1) Average annual recovery of initial investment or "Capital Recovery Factor".

X. BENEFITS AND IMPACTS

The previous chapters of this report identify and compare a range of options regarding the upgrading of bitumen from the Alberta Oil Sands. They have shown that most of the options could be commercially viable given the right combination of industry sponsorship and project management, although some are more marginal than others. However, there are various degrees of risk associated with the options, and generally the risks increase as the project costs increase, and of course the increase in costs are associated with an increase in the level of upgrading.

The value added to the Province of Alberta, by increasing the amount of upgrading within the province, could be substantial as outlined further below. Creating new direct jobs and new supporting jobs, along with the associated economic spin-offs, should be valuable to the province as it seeks new sources of revenue (even if they are mainly derived through taxes) to replace revenue from declining oil and gas royalties. The province has enjoyed the revenue generated through royalties attributable to conventional oil and gas production for many years. This has encouraged strong economic growth in the province, and created many thousands of employment positions. Over the years, the economy has matured and broadened, and diversification into many other areas, such as petrochemicals, research and development, computer and Internet support, pharmaceuticals, and agricultural businesses. However, with the decline in oil and gas revenues, the oil sands will become a more and more important contributor to the Alberta economy. The oil sands also will continue to become more important given the growing demand for energy in North America, and the continuing decline of more conventional domestic supplies.

The vastness of the oil sands, in energy terms, is huge. Estimates range in the order of 300 billion barrels of ultimate potential recoverable oil. Forecast by industry experts vary, but suggest that oil sands production (bitumen or upgraded bitumen) could increase from 880,000 B/D in 2003 to 2.5 million to 3.0 million barrels per day by 2020. The Alberta Chamber of Resources, in its recent report[1] suggested a target of 5 million B/D of oil sands production by 2030 as reasonably plausible. For the next 50 to 100 years, it will likely be the primary focus for growth in Alberta's economy.

[1] Alberta Chamber of Resources, Oil Sands Technology Roadmap, January 30, 2004.

PETROCHEMICAL DEVELOPMENTS IN ALBERTA

In the early 1970s, the Province of Alberta encouraged a group of companies to work together to generate a new petrochemical business in Alberta. For a number of years prior to that time, natural gas was in a large surplus supply position and was available at attractive prices compared to major petrochemical centres such as the U.S. Gulf Coast. The Alberta petrochemical industry was built based on access to a long-term secure supply of natural gas feedstock, available at competitive pricing and with access to global markets. The Alberta petrochemical industry relies on natural gas liquids, mainly ethane, for feedstocks to produce ethylene. Ethylene is used to manufacture polyethylene, ethylene glycol, and styrene. The industry also produces numerous other products including fertilizer. By building infrastructure (gas processing plants, pipelines and storage), ethane is extracted from natural gas and used as a primary feedstock to produce ethylene. Currently, there are four ethane cracking plants in Alberta, including two of the world's largest, with a capacity to produce 8.6 billion pounds per year of ethylene. Most of the ethylene is upgraded into derivative products such as polyethylene, ethylene glycol and styrene. Styrene is used for many consumer products such as expend polystyrene cups and ethylene glycol is used for textiles and for anti-freeze. Many of these products are exported to market in the U.S. and elsewhere to be converted into finished consumer products. Although a small amount of petrochemical products is upgraded into consumer goods in the province, most of the production is exported as bulk commodities to downstream facilities that can manufacture a wide range of consumer products such as plastic wrap, molding, wire and cable, flooring, plastics, detergents, synthetic lubricants, PVC pipe and cable, automobile parts, etc.

The primary economic driver for an Alberta petrochemical industry was a natural gas price that was lower than other petrochemical industry centres. The favourable price of gas and efficient world scale facilities were able to more than offset the extra costs of being an inland industry that is forced to transport much of its production by rail to external markets.

Natural gas production in Western Canada is expected to peak over the next five to ten years. Although the gas supply resource base is still estimated to have extensive undeveloped reserves, much of it is located in environmentally sensitive areas such as in the Alberta foothills. The high cost and long lead times to obtain permits and drill expensive wells has slowed down the industry's ability to bring on new supplies. As a result, North American gas prices have risen substantially above the price levels enjoyed by the Alberta petrochemical industry in the 1970s-1980s. The development of pipeline capacity has kept Alberta gas prices at relatively small differentials to gas prices in the U.S. Gulf Coast. This has tightened margins for the petrochemical industry in Alberta relative to its competitors at the U.S. Gulf Coast.

New supplies of natural gas from the McKenzie Delta are expected to come onstream by around 2010, and will help meet market demands. After that time, we expect Alaskan gas supplies also to develop and be made available to U.S. markets. By that time, though, natural gas production from Western Canada will likely be in decline. As a result, the petrochemical industry in Alberta will not likely be able to continue to have the same advantage regarding natural gas prices as it has in the past. Although this industry will likely continue to operate for many years, it will not have the same opportunities to expand as it once did back in the 1970s-1980s when it did enjoy a natural gas pricing advantage.

This study has focused on generating petrochemicals from the oil sands, as well as refined products. As outlined earlier in this report, a substantial amount of natural gas will be required to produce the bitumen, and if it is upgraded within Alberta, to assist with the upgrading processes. As long as natural gas is used to help produce or upgrade bitumen, any bitumen related product, such as petrochemical feedstocks, will still be subject to natural gas prices.

We did not consider upgrading approaches that generated steam and hydrogen from the oil itself or from coal. If we had done this, it might have provided products that would not be as sensitive to natural gas prices. However, capital costs would have been higher, and likely greenhouse gas emissions would also have been higher. If refineries or petrochemical plants develop in the U.S. to use Canadian oil sands products as feedstock, they likely would use natural gas for energy and hydrogen. Thus, the comparison we have provided is much more valid if we assume natural gas is used as well for the upgrading cases within Alberta. Upgrading further to reduce or eliminate the use of natural gas would become an optimization step for a specific project, and likely should be considered as any such projects are developed further.

The petrochemical products that were considered in this study were primarily oil derived products, such as benzene, xylenes, and styrene (although styrene also requires ethylene). Styrene, therefore, is quite related to natural gas prices in Alberta, even when produced in a bitumen upgrading plant. The benzene and xylene products are less sensitive to natural gas prices except for the cost of hydrogen and fuel.

It is conceivable that as more upgrading facilities are built in Alberta, there will be available byproducts such as ethylene, propylene and butylenes that can support further downstream developments. The suggested 200,000 B/D upgrader discussed in Section III only generates around 10,000 tonnes per annum of ethylene, and 45,000 tonnes per annum of propylene. However, a number of such upgraders if built could produce sufficient byproducts to support world scale derivative developments. The value of such products would likely continue to be tied relative to natural gas prices, as upgraders could burn such products rather than burn natural gas. The main savings would be attributable to not requiring major investments in cracking facilities, and the synergism from being tied to large scale operations. This should in itself provide a strong reason to continue to produce petrochemicals in Alberta for decades to come.

Based on a recent report by T.J. McCann[2], it was identified that certain synthetic gas liquids (mainly ethylene, ethane, and propylene) could be extracted from the current oil sands operations near Fort McMurray. Further, as new upgraders come onstream, they could

[2] T.J. McCann and Associates Ltd., et al, Petrochemicals from Oil Sands, July 2002.

contribute to this total. Already, Suncor's propylene volumes are being recovered at the Williams Energy SGL plant at Suncor's site.

A new world scale ethylene derivative plant would take around 500,000 tonnes per year of ethylene. A world scale polypropylene plant would need about 500,000 tonnes per year of propylene as well. Currently, there is nearly enough propylene for a new world scale plant to be located in Alberta. Ethylene recovery from upgraders is more difficult however, because of the high cost of separation and compression. Possibly, it still could be utilized someday if the quantities become large enough to justify recovery.

As upgraders are added in Alberta, (most are expected to produce synthetic crude oil), the potential recovery of such feedstocks becomes closer to reality. This potential, however, will not materialize if all the upgrading capacity is built in the heart of the market, i.e., the U.S. Midwest, rather than in Alberta. Ideally, having the upgraders in close proximity could be beneficial for future petrochemical feedstock recovery.

MARKETING BITUMEN BLENDS

Since Imperial Oil commenced production of its Cold Lake bitumen in the late 1960s, bitumen blend has been exported. By 2003, approximately 300,000 B/D of bitumen from the Alberta oil sands was mixed with diluent, and most was exported. This has been a successful way for many years of growing oil sands production, similar to the success experienced with heavy crude oil. The resulting bitumen and heavy oil exports have resulted in Canada becoming a major crude oil exporter to the U.S.

We expect that bitumen blend exports will continue to grow. Although the export market for heavy is close to being saturated, it is not static; it will also likely grow. Some of the large heavy crude refineries in the U.S. Midwest (such as Flint Hills at Pine Bend, Exxon Mobil at Joliet, BP at Whiting and Toledo, Marathon Ashland at Catlettsburg, ConocoPhillips at Wood River) have grown in the past ten years, and are reported to be among the most successful refineries in the U.S. It is logical that they would continue to grow as more oil sands supplies, particularly bitumen supplies, become available.

In the last several years, the North American refining industry has been focusing on investments to produce low sulphur fuels. Some of these refineries are taking the opportunity to debottleneck their existing refineries at the same time, which may help them to process more heavy crude. Such investments could be in the category of refinery "creep", but some may be more extensive than that. The current round of investments for low sulphur fuels should be complete in 2006. After 2006, we expect the northern U.S. refining industry will be exploring investment opportunities to utilize more Canadian bitumen blends

Creep in refinery capacity should increase heavy crude runs. Over the years, capacity in more complex, modern refineries continued to grow at a measured pace. Small but successive investments and improvement steps have allowed this to occur. We expect this trend will continue. The current rounds of investments to produce low sulphur gasoline and diesel should result in some increased capability to process more heavy and/or higher sulphur crudes. Although likely to occur, the resulting creep in capability is still expected to be modest compared to the need for more heavy processing capacity.

At this current time, the following is known about new conversion projects that have been announced. Refiners currently are busy investing in facilities to produce low sulphur gasoline and distillate. However, we expect that some refiners will take this opportunity to undertake debottlenecking or improvement initiatives that will allow them to process more heavy crude.

In the U.S. Midwest, ConocoPhillips plans to reactivate the former Premcor Hartford coker, and integrate it with its Wood River refinery. This coker is sized at 18,000 B/D, but may be expanded to 20,000 B/D. It could be further expanded as the Wood River processes more Canadian heavy crude.

United Refining at Warren, Pennsylvania has received environmental approval for a new coker project. Timing of this project to be in place is expected by 2005 or 2006. United Refining has also been seeking to get some support from Canadian producers through an equity investment and/or a long-term crude supply arrangement.

We understand that Flint Hills is adding a hydrocracker and hydrogen plant at its Minnesota refinery to help it produce low sulphur diesel fuel. These changes will likely help the refinery to use more bitumen/synthetic blend (SynBit) as well as produce the required low sulphur diesel fuel.

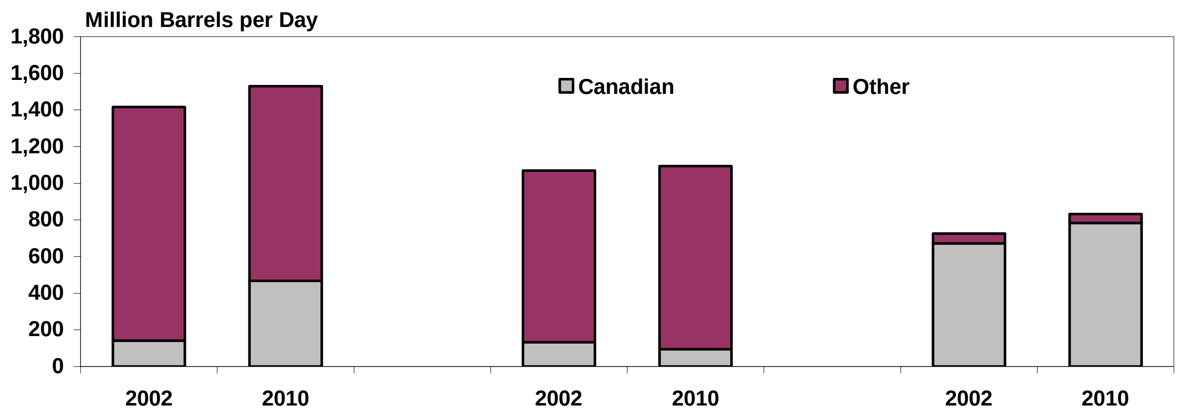
As outlined in Section III, we have identified several cases of converting refineries to run additional quantities of SynBit through a major conversion of the refinery to handle the additional residual material that is resident in the bitumen blend. The economics for such a development appear quite reasonable, showing fairly strong economic returns. For these reasons, we are quite confident that the market will see additional developments to process bitumen blends from Alberta.

UPGRADING TO SYNTHETIC CRUDE OIL

Since the startup of Suncor's oil sands operations in the late 1960s, producing and marketing a high quality synthetic crude oil has been considered the most logical way to develop a mining oil sands project. As compared to in-situ projects, which are better suited for staging in steps of say 10 to 20,000 B/D, mining projects are large scale operations, and today are considered to be in the range of 150,000 to 200,000 B/D to be a practical size. It is possible that mining projects could produce bitumen blends, but when they start up, the hurdles of putting that much bitumen blend into the marketplace is formidable, because it will need probably the same amount of diluent to allow the bitumen to be transported to the market, as each bitumen barrel must be accompanied by 0.35 to 1.0 barrel of diluent per barrel of bitumen to allow the oil to be transported to market. On the other hand, if the project produces sweet synthetic crude oil, its fungibility makes it fairly easy to ship SCO into the marketplace and have it utilized by many refineries. If a mining project were planning to produce bitumen and market a bitumen blend, it would likely require an associated bitumen refining project or projects to be developed in the markets so as to absorb the new production. With SCO, though, the market can grow just by existing refineries backing out their light crudes in favour of the new SCO supplies.

For oil sands projects to produce SCO and market SCO has worked well in the past, and should continue to work well for at least a few more projects. Currently as shown in Figure X-1, the heavy market in the U.S. Midwest is nearly saturated. The light sweet market has room to absorb more SCO. The amount of SCO that it might absorb is dependent upon the quality of the SCO, and whether any of these refineries might add capabilities to process more synthetic crude, and the price attractiveness of the SCO relative to their other light crude feedstocks.

FIGURE X-1
PADD II (MIDWEST) REFINERY CRUDE RUNS



The light sour market in the U.S. Midwest is quite large, as shown in Figure X-1, at around 32% of the total crude runs, and for the most part has not been tapped by oil sands products. Industry has been examining options to produce light sour SCO that could replace other light sour crudes and thus obtain a larger share of this market. Currently the industry is considering blends of synthetic crude and SynBit (SynSynBit) to try and capture a piece of this market. Several upgrading proponents are considering the production of sour SCO that could reach this market. However, there are challenges to produce a stream of adequate quality without spending a substantial investment in upgrading. This is being worked on by the industry, and may prove to be another route to expanding markets for SCO. In Section IX, we showed that for SynSynBit to be attractive to a light crude refinery such that it would add hydrocracking capacity to allow it to use a substantial quantity, it would require a lower price for the mix than our current forecast. A discount of approximately $1 per barrel on SCO improved the return to more acceptable levels.

However, before new capacity is needed to be added to process more SCO in the market, there is still a substantial market that can be developed albeit with possibly an erosion in SCO price as the quantity of SCO increases. Our work in this study was not supported by an

SCO market penetration study, as we intended to establish only the bounds if the market did require new investments to be made in order to absorb new SCO supplies. However, based on previous studies[3], we believe that the market still can absorb an additional 500,000 B/D of sweet SCO without incurring much of a discount. After reaching that level, refineries will need to take more than they would prefer without a discount in price, unless the quality is improved. Thus, there likely will be another accessible market traunch with only modest discounts. If SCO quality is improved further, such as being proposed by Opti/Nexen and possibly others, there may be further expansions in the market with little impact on price. Thus, it is not likely that we will see much new investment to process sweet SCO in the near future.

Another variable that must be considered is the amount of synthetic crude that will be used as diluent. If bitumen upgrading projects occur within U.S. refineries, demand for SCO as diluent will likely grow strongly, and this reduces the volume of SCO available to be marketed as a neat product.

UPGRADING TO REFINED PRODUCTS

When Suncor began producing synthetic crude oil from its oil sands plant in the late 1960s, some of the SCO was utilized in its Sarnia refinery, and in Sun Oil Company's Toledo refinery. Both of these refineries were modified with new hydrocrackers to allow them to better process the synthetic crude oil into a full compliment of high quality products. This was the first example of integration between producing oil sands products and producing refined products. These operations continue to process a substantial quantity of synthetic crude oil.

Since 1997, Suncor has been producing diesel fuel at its oil sands operation near Fort McMurray. It has grown to nearly 30,000 B/D, most of which we believe is sold in the Edmonton diesel market. We understand that Suncor may be considering to expand this further over time, especially if there is the opportunity to move volumes efficiently to more distant markets.

Shell produces all of its refined products at Edmonton utilizing synthetic crude derived from the oil sands. When it first developed its Scotford refinery, it had planned to tie it into its planned Alsands Oil Sands Project. High costs resulted in the cancellation of the Alsands Project but the Scotford refinery was built and it purchased SCO from both Suncor and Syncrude. In addition to producing high quality refined products, it also produced benzene and styrene in an adjacent petrochemical complex. It became one of the most successful refineries in Canada, because it was totally tailored to process SCO, while SCO prices were set (and they will likely continue to be set) by marginal refineries located in more distant markets.

In 2003, coincidental with the Albion Oil Sands Plant and new upgrader at Scotford, the Scotford refinery underwent sufficient changes to switch to the SCO output from the new oil

[3] Private studies for Purvin & Gertz' clients.

sands project. This allowed Shell to be fully integrated with its own oil sands production to refined products and petrochemical sales.

Imperial Oil, at its Edmonton refinery, has been processing SCO since the start of the Syncrude operation in 1977. It has an SCO processing train. It cannot readily use more SCO, though, without further changes to its refinery configuration.

Petro-Canada, at its Edmonton refinery, also has an SCO processing train, which allows it to process a significant quantity of SCO. Recently, Petro-Canada was developing plans to convert the refinery to process bitumen, but high construction costs forced it to pursue a less expensive option. Petro-Canada has now agreed to have Suncor process bitumen in its oil sands upgrader from Petro-Canada's oil sands project at McKay River, and it will receive a partially upgraded feedstock (essentially sour VGO with no bottoms) at its Edmonton refinery. Petro-Canada built a new VGO hydrotreater for its low sulphur diesel which will enable it to handle the partially upgraded product received from Suncor. By outsourcing some of this upgrading, this project has also enabled Petro-Canada to more fully integrate its oil sands and refining operations.

Consumer Co-operatives has also developed capacity at its Regina refinery to process a partially upgraded SCO stream from Suncor. This project allowed the refinery to be expanded from 55,000 B/D to 80,000 B/D in 2003. In some respects, this approach is very similar to the one developed by Petro-Canada, except Consumers Co-operatives does not have its own oil sands supply.

The concept of developing partially upgraded SCO in the oil sands and having associated downstream refineries make investments to process it has not been explored in this report. Our closest case, where a refinery makes a change to process SynSynBit, requires some of the same investments, but it includes bottoms that need to be processed. This option could open more markets, again targetting the light sour market (Figure X-1) that remains a relatively undeveloped target for future SCO developments.

By producing finished products such as gasoline and diesel fuel, as outlined in Cases 4 and 5, an oil sands producer could sell its output directly to end-use consumers, rather than to refineries. Domestic markets, though, such as in Western Canada, are well served by existing refineries that are among the most modern and efficient of any in North America. As discussed above, they have grown with the market and have an efficient product distribution infrastructure ranging from Vancouver to Winnipeg. A new refinery in the Edmonton area would need to export most, if not all, of its output. Herein lies the major challenge for a new export refinery. How can the products be efficiently transported to the export market and effectively marketed such that it becomes a reasonable business alternative to exporting SCO or bitumen blends?

As outlined earlier in this report, we have developed two export refinery scenarios, one to Chicago, and the other to Los Angeles. Both have merits as well as many hurdles. Exporting products to the U.S. Midwest ranks ahead of the California option primarily because the market is larger and easier to reach and penetrate, but it generates a lower return. The California option has a better economic return if it were possible to obtain a new product pipeline from Edmonton to Vancouver to ship refined products in a dedicated form, and to overcome the market entry discounts that we have forecast to persist for many years if a new traunch of imports comes from Canada into this market.

It will be difficult to assess how much the local Western Canadian refining industry might be impacted by a new export refinery. It will be very dependent on commercial arrangements and the ownership of the refinery. One logical way for a new project would be to sell term volumes of products to export customers, such as independent marketers or possibly even U.S. refineries. In such a case, the products would not likely even enter the Canadian market, and thus the effect would be minimal on the local market. However, at the other range of possibilities, if an independent group developed the refinery project in Alberta, with all the products sold on the open market, some sales into the Alberta market might be expected.

If an Alberta refinery project is developed to send supplies to the California or Midwest market, the availability of the export infrastructure would likely encourage increasing refined products production from existing Alberta refineries such that they could also be exported. Large refineries in Alberta would reap benefits in terms of economy of scale and efficiency. This would have the benefit of increasing markets for oil sands production, and allow Alberta to become an even larger and more significant North American refining centre.

The economic benefits to Alberta if refined products are produced to be exported will no doubt be as important as new bitumen projects themselves. Jobs from building and operating a new refinery will provide a boost to the economy. Creating a new (third) market for oil sands products would also further encourage the development of new oil sands projects. It would initiate a new market that could likely grow well beyond bitumen blend and SCO markets, a market that would be dependent on future consumer demand requirements rather than downstream refining preferences.