Chapter 2

CALIFORNIA PETROLEUM SUPPLY, TRANSPORTATION, REFINING AND MARKETING TRENDS

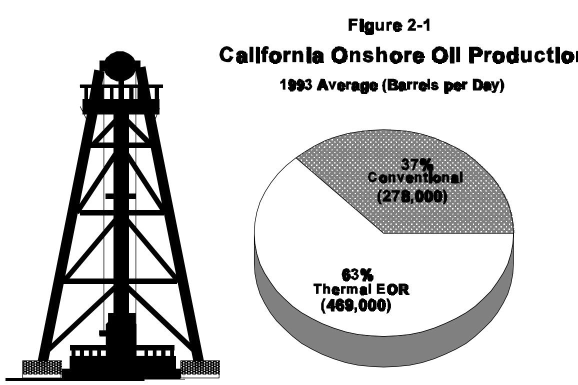
INTRODUCTION

California is an integral part of the world oil market as a world-scale petroleum consumer. Historically, about 50 percent of this petroleum came from in-state production, 45 percent from Alaska and 5 percent from foreign sources. This chapter discusses how these petroleum supply sources will change over the next 20 years. The percentage supplied from foreign sources will increase as both Alaska and California production decline. This will occur despite expectations of level petroleum fuel demand in California's transportation sector over the next 20 years (as discussed in Chapter 4). These findings are based on gradual increases in oil prices. It should be noted that more abrupt increases in oil prices would cost consumers more but also stimulate additional production and add to California's current proven reserves of 4 billion barrels.

This chapter also includes an overview of California's petroleum transportation system and discusses issues pertaining to California's refining and marketing sectors. Refining sector trends show cause for concern. Fewer refineries are now located in California and utilization rates are high. If this trend continues, product availability could become limited and prices would increase. The market would respond by importing more petroleum products to California, but time delays can be expected. This is because refiners outside California have not invested in producing California-specific fuel and shipments from the Gulf Coast or other regions require time.

ONSHORE OIL PRODUCTION

Onshore California oil is currently recovered by both conventional and enhanced extraction techniques. Conventional methods use the natural pressure of an oil field or, if the pressure is too low, water is injected to increase the pressure of the oil field to allow greater amounts of oil to be removed. Enhanced oil recovery uses more advanced techniques to extract oil from fields that have been nearly depleted using conventional methods.



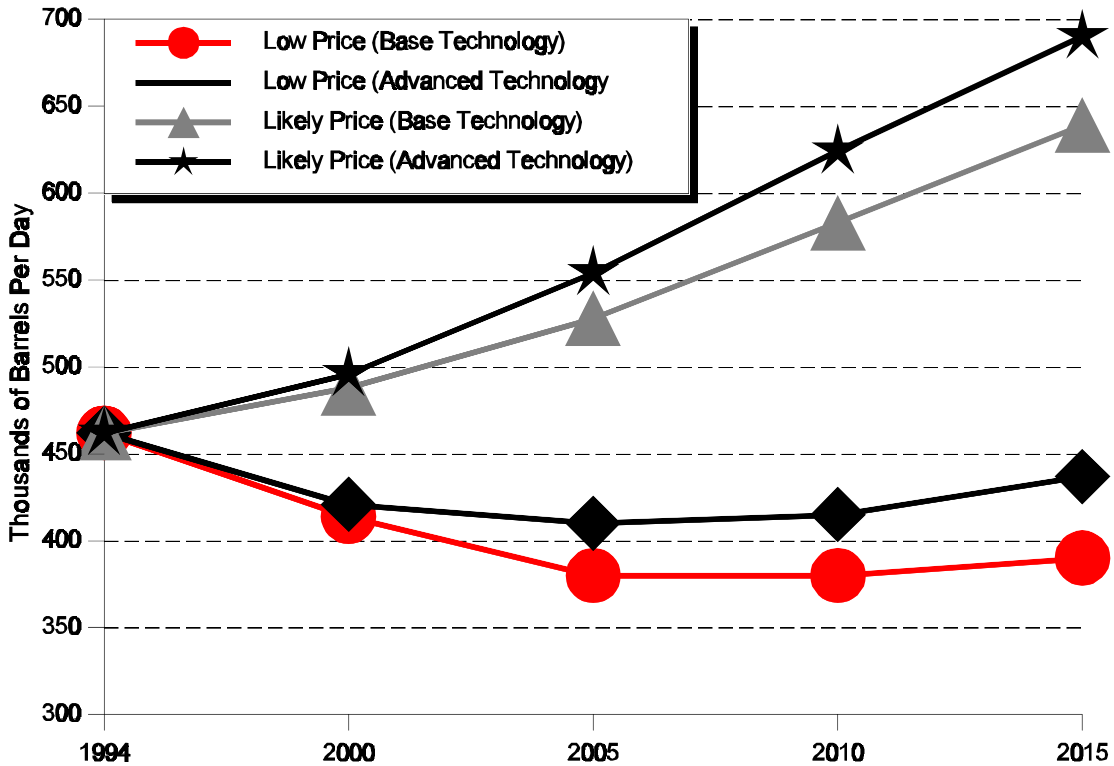
The principle of enhanced oil recovery is to inject some agent into the partially depleted underground oil reservoir to economically recover additional barrels of oil, which could no longer be obtained through traditional oil recovery methods. Carbon dioxide gas, hydrocarbon solutions, chemical polymers, and steam are types of agents injected into the reservoir. Steam injection, referred to as Thermally Enhanced Oil Recovery (TEOR), is important to California's total production since it represents about 63 percent of onshore production and is responsive to prevailing oil prices and technology advances (see Figure 2-1).[1] Furthermore, California TEOR production accounts for over 60 percent of total enhanced oil recovery production in the United States.

Onshore oil production has been declining since 1985 at an average annual rate of 3.4 percent.[2] In 1993, California onshore production averaged nearly 750,000 barrels per day or 79 percent of total California production. Statistical extrapolations from historical data produce a very broad range for California onshore production in the future. The range is so broad, varying between a 7.5 percent decline per year to a 1 percent increase per year, that it is not instructive to energy policymakers. To develop a more definitive forecast, the Energy Commission sponsored some modeling work to examine the effects of future oil prices on California's TEOR.[3]

The model used was the same as that developed for the Department of Energy analysis of lifting the Alaska North Slope (ANS) export ban. The low and most likely oil price paths from the Energy Commission's Delphi VII forecast were used and both "base and advanced" TEOR technology assumptions were considered. As shown in Figure 2-2, the results indicate that the TEOR production could represent

Figure 2-2

California TEOR Production



between 390,000 and 690,000 barrels per day by 2015.[4] Total onshore production in this case could then range between 433,000 barrels per day to 767,000 barrels per day by 2015. This assumes that TEOR production continues to represent an increasing proportion of total onshore production as shown by historical trends. At this growth rate, TEOR would represent about 90 percent of onshore production in 20 years, compared to 63 percent in 1993.

Based on initial responses to the current Delphi oil price survey, it appears unlikely that TEOR production could approach the upper range of 690,000 barrels per day shown by the modeling results. The current Delphi participants foresee still lower world oil prices than indicated in prior surveys. Furthermore, historical data on TEOR production has shown that production ranges between 400,000 and 500,000 barrels per day during periods of higher oil prices. This does not mean that California TEOR production could not meet or exceed the modeling result. As noted in Chapter 1, oil prices could follow a higher price path which would stimulate production while costing the consumer more.

If TEOR production follows the production path indicated by the low price, base or advanced technology modeling result, then TEOR production in 2015 becomes approximately 7 percent to 17 percent below 1993 production. Total onshore production would then range from 433,000 to 486,000 barrels per day by the end of the forecast period, about 35 percent to 42 percent less than 1993 onshore levels. This is equivalent to a 2 percent to 3 percent per year average decline. The Energy Commission believes this expectation is reasonable, but future oil prices could result in higher or lower production.

OFFSHORE OIL PRODUCTION

Offshore California oil is produced from fields that are located in both state and federal waters. State waters are those within three miles from shore and federal waters are those beyond three miles. Production from federal waters surpassed that of state waters in 1988 and now is nearly 2.5 times greater than state offshore production. Proven reserves in state waters are estimated at about 235 million barrels compared to 735 million barrels in federal waters.

Production in state waters has been declining since 1986. The September 1994 California ban on further offshore drilling in all state waters will lead to still fewer state resources contributing to the offshore total. Several platforms in the state waters of the Santa Barbara Channel are now being abandoned and removed because of uneconomical operating costs and reserve depletion.

Total long-term offshore oil production is expected to decline gradually. Proven reserves are near one billion barrels and the current production rate is about 200,000 barrels per day. A simple projection of historical trends indicates that production could decline an average of 0.2 to 4 percent per year reaching between 163,000 and 64,000 barrels per day by 2013.

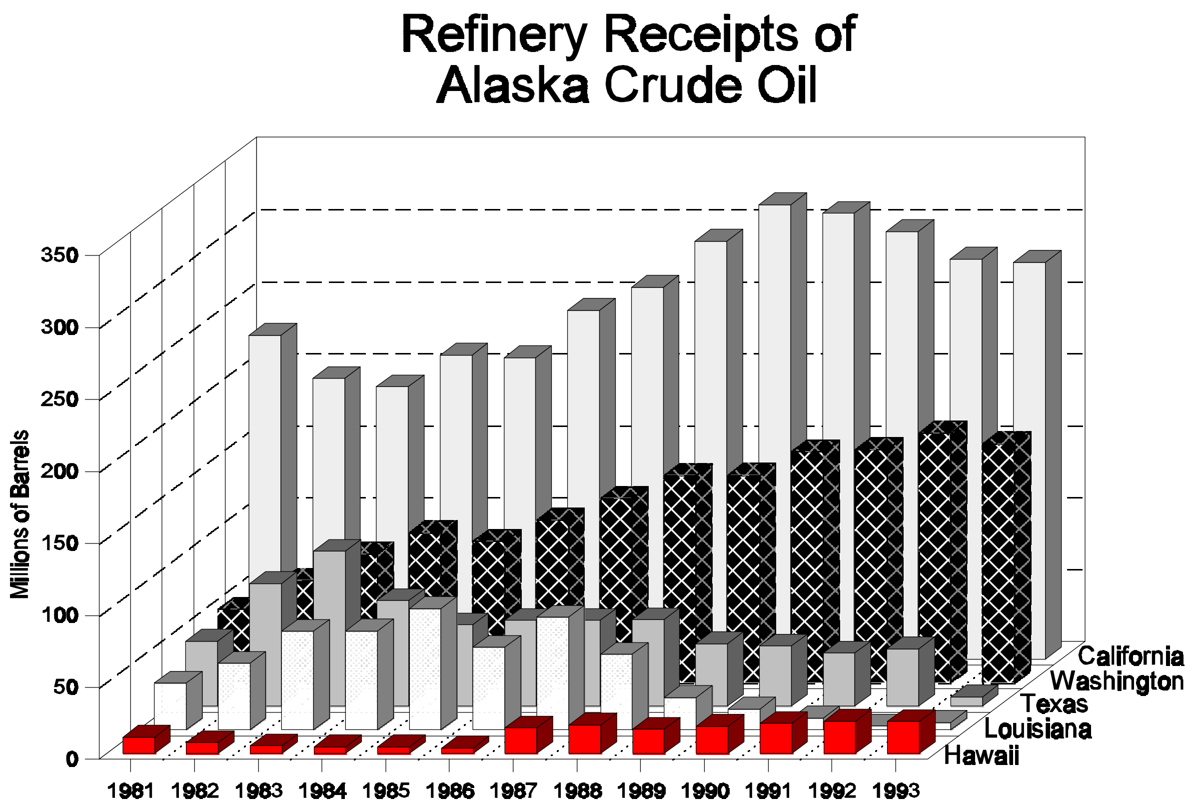
This does not reflect short-term expectations for a further increase in federal offshore production. Short-term forecasts offered by the Minerals Management Service and the Division of Oil, Gas and Geothermal Resources indicate the addition of about 50,000 barrels per day in the 1995 to 1998 timeframe. The addition is from waters in the Santa Maria Basin and Santa Barbara Channel.

In the long term, offshore production will occur primarily within federal waters and could represent between 10 percent and 33 percent of total California production by the end of the forecast period compared to 21 percent in 1993. Combined with onshore oil production, total California oil production levels are expected to range between 497,000 and 649,000 barrels per day. This represents a 31 percent to 47 percent decline from 1993 production.

PETROLEUM SUPPLIES FROM ALASKA

Although Alaska supplies petroleum to refineries in many states (including Washington, Hawaii, Texas, and Louisiana), California is Alaska's largest customer. Figure 2-3 shows the distribution of Alaskan North Slope (ANS) crude oil for the top five importers since 1981.[5] Supplies to California and Washington generally increased until 1990. Since 1990, however, declining Alaska production has gradually resulted in reduced supplies to California. This trend is expected to continue,

Figure 2-3



although California will remain a major market for ANS oil. For example, in 1993, California received 43 percent of its crude oil demand from Alaska.

An extrapolation of this trend indicates California continuing to receive lesser volumes of ANS oil and Washington continuing to receive increasing ANS volumes. Future supply conditions, however, are complicated by other factors in addition to declining Alaska production. Refinery ownership patterns and the potential for ANS oil exports are two examples.

Total Alaska petroleum production has been declining an average of 4 percent per year since 1989. Prudhoe Bay and Kuparuk are the number one and two producing North Slope fields, respectively, accounting for about 85 percent of total North Slope production. Prudhoe Bay production started declining in 1988. Production from Kuparuk is expected to remain fairly stable for five more years before declining. Kuparuk production is approximately one-third that of Prudhoe Bay. Cook Inlet production peaked at 83 million barrels in 1970 and has now declined to 15.5 million barrels per year.

Forecasts of total Alaska production by the Alaska Department of Natural Resources (ADNR) show that over the next 20 years production will decline an average of 12 percent per year.[6] As production declines further, the economic limit of the Trans Alaska Pipeline becomes a major factor. Some estimates indicate that once production falls to between 200,000 and 400,000 barrels per day, the pipeline will no longer technically or economically function.[7] Furthermore, this would leave 500 million to 1 billion barrels of "lost" recoverable liquids in the ground.

One caveat to these forecasts is that they do not reflect the influence of changes in government policy. An end to the ANS export ban appears to be imminent.[8] The study completed by the U.S. Department of Energy in June 1994 on lifting the ANS oil export ban indicated that permitting ANS oil exports could increase Alaska production.[9] Depending on the oil price path and the type of tankers used for transport, Alaska production could increase by approximately 55,000 to 70,000 barrels per day by 2000. The study findings also stated that permitting ANS oil exports could add 200 million to 400 million barrels to Alaska's reserves, about the same as those of the Endicott or Point McIntyre fields. Reserves are added because more resources become economic to produce as oil prices increase.

These findings on potential production increases would change the steepness of the production decline curves, but not the direction. This is because the production gains are smaller than the losses. The estimated increase in Alaska production by the end of 2000 from repealing the export ban is about one-third the volume of the total production decline that occurred between 1992 and 1993.

If restrictions on ANS exports to foreign countries are lifted, ANS petroleum demand in the Pacific Rim market could affect the supply to California. If current restrictions for transporting ANS crude by U.S. flagships only are lifted, ANS producers would be interested in shipping oil to Pacific Rim nations since the transportation cost for shipping by foreign vessels will be lower. Pacific Rim nations would purchase ANS oil because they are interested in secure supplies, their refinery configurations are compatible with ANS oil and it offers an opportunity to reduce trade deficits. On the other hand, OPEC suppliers, now providing countries like Japan with the bulk of their supplies, may compete vigorously with ANS suppliers resulting in lower levels of ANS shipments.

Despite the complexity, it is clear from production forecasts that California will be receiving significantly fewer barrels of oil from Alaska within the next six years. If history is any indicator, West Coast demand for crude oil, whether met by Alaska or another supplier, will increase gradually in the future if refinery capacity is expanded above current levels. The ADNR forecast shows Alaska demand for petroleum increasing 1.5 percent per year between 1995 and 2010. Historical Energy Information Administration data shows that Washington and Oregon petroleum product demand is also increasing.[10] Finally, California petroleum product demand has increased an average of 1.8 percent per year on average since 1976. However, the Commission expects this growth rate to slow and eventually level off over the next 20 years.

The longer term questions become: 1) what sources of supply will be used to fill the void between declining Alaska production and California demand? and 2) what are the effects on California from the range of oil supply possibilities?

FOREIGN PETROLEUM SUPPLY SOURCES

California relies on foreign oil for about 5 percent of its total petroleum demand. OPEC sources account for 1.5 percent of total demand with Indonesia providing slightly over half of the OPEC supply. NonOPEC petroleum accounts for the balance with Mexico providing a small fraction of this total.

Indonesia once supplied over 8 percent of California's petroleum deliveries.[11] These imports, however, have slowly been replaced by nonOPEC imports. Indonesia is expected to play less and less a role in California's petroleum supplies, although some isolated shipments may occur if the arrangements are profitable. Indonesia may itself become a net crude oil importer in the next few years as their production and consumption trends cross.

In the longer term, California can expect greater reliance on both OPEC and nonOPEC petroleum suppliers. Venezuela is a possible source of OPEC supply because of shorter transport distances and continuing additions to the country's reserve base, now estimated at 150 billion barrels. In 1992, Venezuela crude oil imports represented 23 percent of the nonArab OPEC crude imported to California.[12] Saudi Arabia is another expected future supplier because of its reserve base and capability to expand longer term market share. Middle East suppliers have provided crude oil to California in the past and will likely do so again.

California will also look to nonOPEC suppliers for petroleum. A larger volume of imports may come from Mexico where proven oil reserves are over 100 billion barrels. Imports from Canada may also continue, but Canada has a reserve to production ratio similar to the United States and will also import more oil in the long term. Imports from some South American countries, such as Argentina, are possible. Argentina is pursuing privatization of oil field development which is expected to increase production from that country.

These foreign oil supply possibilities illustrate that there are many potential suppliers of crude oil and that many more arrangements with foreign suppliers will be reached by California's petroleum refiners in the future. Some California refiners will need to make those arrangements sooner than others, particularly refiners without the upgrading equipment needed to minimize residual fuel oil yields from refining heavy crude oil. Increasing reliance on world oil market supplies does not guarantee economic havoc for California, but the value of pursuing energy conservation and fuel diversity policies would again become evident should disruptions in those supplies occur.

CRUDE OIL TRANSPORTATION

California relies on tankers from Alaska to deliver almost half of its petroleum supply, about 1 million barrels per day. Forty percent of this supply enters Northern California ports and 60 percent arrives in Southern California. The other half of California's petroleum supply is produced in-state and is primarily transported by pipeline to refineries in the San Francisco Bay area, the Los Angeles Basin and Bakersfield (see Figure 2-4). Pipelines are also used to bring offshore crude oil from state and federal

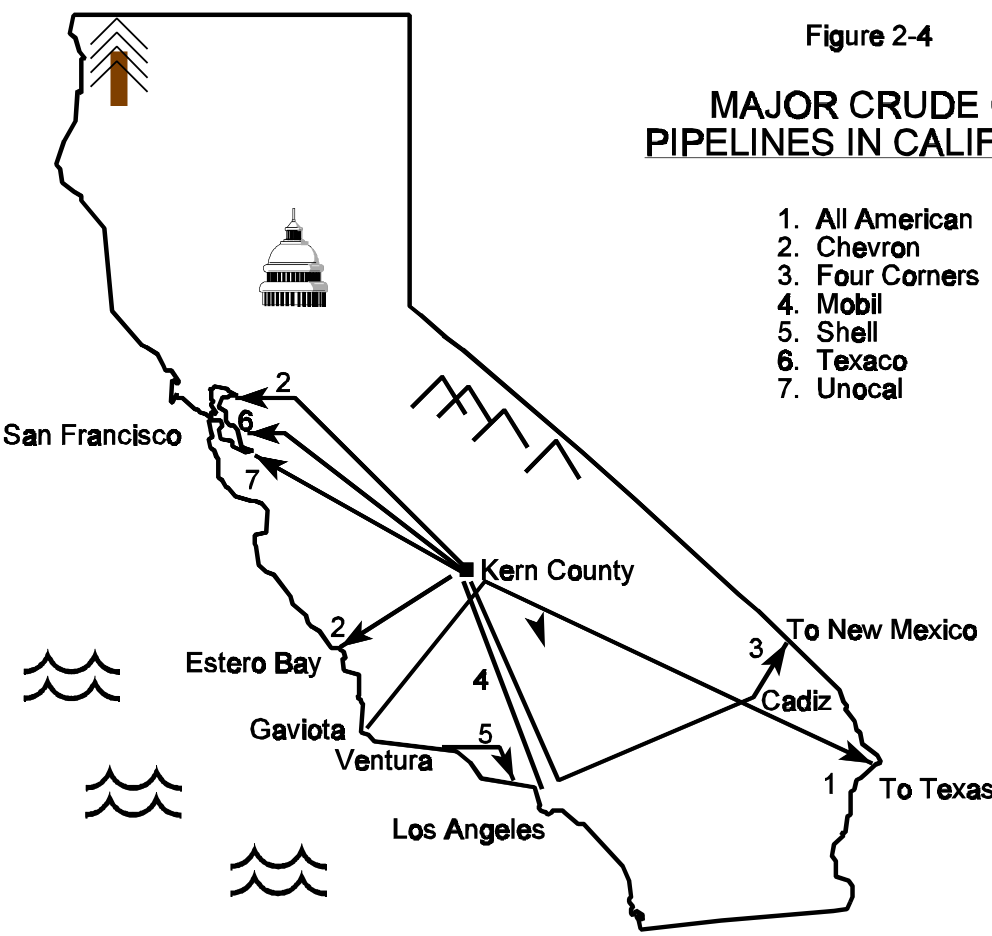


Figure 2-4

MAJOR CRUDE OIL PIPELINES IN CALIFORNIA

1. All American
2. Chevron
3. Four Corners
4. Mobil
5. Shell
6. Texaco
7. Unocal

waters onshore. Producers of both offshore and onshore oil also have the option of transporting their crude oil to the Gulf Coast via the All American pipeline, which has a maximum capacity of 300,000 barrels per day.

Crude oil from Kern County can be transported north to San Francisco by one of three pipelines owned respectively by Chevron, Texaco or Unocal. Kern crude oil can also be transported south to Los Angeles in either the Four Corners common carrier pipeline or Mobil's proprietary line. In addition, Chevron owns a pipeline going from Kern County west to Estero Bay where tankers then transport the crude oil to its refinery destination.

The Four Corners system from the San Joaquin Valley to Los Angeles (actually two parallel lines known as #1 and #63) has been operating at its capacity of 100,000 to 115,000 barrels a day.[13] This system has not been able to accommodate the total volume "nominated" by producers. When the volume nominated exceeds the pipeline capacity, all requests are prorated by a certain percentage. The Northridge earthquake on January 17, 1994, caused heavy damage to both the #1 and #63 lines, shutting down the system for nine days. Although the pipelines are currently operating, the damage has not been completely repaired and, consequently, the Four Corners pipeline continues to be over-nominated.

Part of the reason for the heavy demand on the Four Corners system is its use for transporting offshore oil from the Point Arguello field to Los Angeles refineries. Since there is no direct pipeline along the coast, producers of offshore oil use the All American Pipeline from Gaviota (just north of Santa Barbara) to its junction with Four Corners at Pentland. At this point, the heavy crude oil is blended with lighter San Joaquin Valley crude oil and transferred to the Los Angeles-bound pipeline. This blending procedure allows faster delivery rates. For environmental reasons, Santa Barbara County has required that offshore oil brought onshore at Gaviota must be transported by pipeline, not tanker.

Since the 1981 discovery of the Point Arguello field offshore Santa Barbara, several companies have proposed additional crude oil pipelines which could transport this oil from Gaviota to Los Angeles refineries. One proposal by Pacific Pipeline originally specified a route along the coast from Gaviota directly to Los Angeles. The current proposal would link with the All American pipeline in Kern County to Los Angeles, similar to the Four Corners route. The advantage of the new route is that it could transport up to 130,000 barrels per day of San Joaquin Valley crude oil as well as offshore crude oil to Los Angeles. This project continues to face opposition from local community groups and its construction remains uncertain.

Pipelines are also used to transport finished petroleum products from refineries to bulk terminals. Since California is a net exporter of finished petroleum products, pipelines are also used to deliver these products to terminals in Reno, Las Vegas and Phoenix. Chapter 3 discusses the anticipated concerns of transporting reformulated gasoline by pipeline.

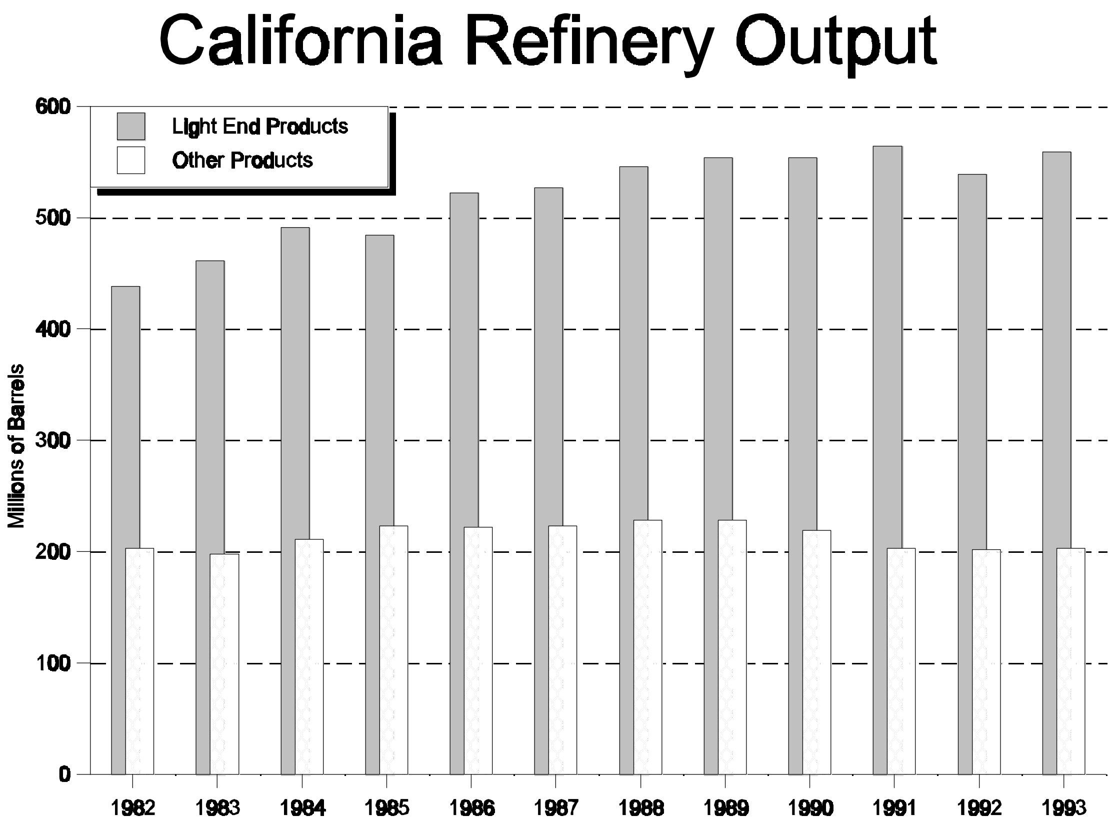
CALIFORNIA'S DECLINING REFINING CAPACITY

The major challenge facing the oil industry in California over the next decade will not be the availability of crude oil but the availability of refining capacity to make fuel to California's specifications, especially reformulated gasoline and diesel. Should any refinery experience an unscheduled outage, replacement supplies may be limited by a combination of factors: 1) fewer refineries in California and 2) the absence of refiners outside the state making the investments required to produce large quantities of reformulated fuels for the California market.

The refining industry in California has experienced a reduction in the number of operating refineries with a corresponding reduction in the statewide crude oil distillation capacity. Since 1982, the number of operating refineries in California has decreased from 44 to 24. This loss of 20 refineries represents a 23 percent loss in operable distillation capacity in the state, from 2.5 million to 1.9 million barrels per calendar day, a loss of 574 thousand barrels per calendar day.

Many of the refiners that ceased operation did so because they were unable to upgrade their facilities to produce the cleaner fuels, beginning with unleaded gasoline. Each refiner has had to decide

Figure 2-5



whether or not to make the substantial capital investment needed to meet CARB fuel specifications. Those refineries that cannot compete on a cost basis in California's clean fuel program may opt to close or to make fuel for markets outside the state.

This is the case for small independent refiners. Most have not been able to finance the investments to upgrade their facilities out of cash flow from present operations. Several small refiners found that the market would not accept the risk of financing such investments, so they have either shutdown, produce only heavy-end products such as asphalt, or have been converted to petroleum storage facilities. This is illustrated by the recent closures of Pacific Refining Company in Hercules and Powerine in Santa Fe Springs. For the remaining small refiners, the outlook is not encouraging if they are unable to generate the necessary volume to compete in gasoline markets outside California.

The refining industry has been able to compensate for the loss of refining capacity, during a time of growing demand, by increasing the refinery utilization rate from 71 percent in 1982 to 95 percent in 1993. This has enabled the industry to increase the production of petroleum products by 300 thousand barrels per day. This increase has been in response to an increase in the demand for light-end products, the most valuable of the refined products. The light-end products are motor gasoline, aviation fuels and distillates. The production of light-end products has increased 27 percent, going from 438 million barrels (1.2 million barrels per day) in 1982 to 559 million barrels (1.5 million barrels per day) in 1993. By contrast, the output of other products has remained constant (see Figure 2-5).[14]

In addition, the industry has improved the efficiency of its operations and has made improvements in refining process technology. However, with a utilization rate now at 95 percent, there is limited capability to increase product output on a sustained basis. Based on current information available from oil companies, California refineries have the ability to meet the demand for Phase 2 RFG in 1996, even under a high demand scenario. If California continues to lose refining capacity over the next decade and demand for refined products remains level or increases, then refiners have the option to either import additional volumes of finished products, import additional refined product blendstocks, or perform refinery modifications (such as debottlenecking).

In the short term, a major unscheduled outage may cause a temporary tight supply situation because of the high utilization rate. However, there are several options available which may help refiners to mitigate the tight supply. First, existing inventories of product and blendstock may be drawn down to meet demand. This option has been made more viable by increased storage capacity in the state as a whole. Second, refiners may seek a CARB variance to offset the volume of fuel lost by the outage. Third, additional refined products or blendstocks may be imported. However, such imports would involve a time delay for transportation from the U.S. Gulf Coast, the Northwest or the Pacific Rim, and would come at a higher cost. Because California is somewhat isolated from other major refining centers, the movement of products to the state could lead to a near-term tight supply situation. And since refiners outside the state may be reluctant to make the necessary investments to make large volumes of California-specific fuel, out-of-state refining capability may be limited. The unique fuel specifications for California's reformulated gasoline and diesel fuels could limit the availability of these fuels from outside California.

CHALLENGES FACING CALIFORNIA PETROLEUM FUEL MARKETERS

Finding a balance between environmental concerns, government revenue needs and business growth remains a substantial challenge confronting California. Conflicts between business and public interests are frequent. Petroleum product marketers have expressed several concerns with regulatory measures that have increased the cost of doing business in California. The following examples apply to underground storage tank replacements, fees for cleaning up fuel leaks, and tax collection policies.

In addition to CARB reformulated gasoline regulations which will further improve California air quality, regulations regarding fuel storage tanks are also protecting groundwater resources. The Public Health and Safety Code establishes requirements for underground storage of hazardous substances. As hazardous substances, petroleum fuels must be stored safely. The Code includes tougher standards that apply to underground petroleum fuel storage tanks built after January 1, 1984. Tanks constructed before 1984 must be upgraded or replaced by December 22, 1998. The regulations are intended to help ensure that groundwater supplies will be protected from contamination from all underground fuel tanks.

Petroleum product marketers cite the expense of tank replacement as an additional financial burden incurred by their business. The California Independent Oil Marketers Association estimates the cost of upgrading pre-1984 tanks to be $100,000 per tank. Low-interest loans are available for these upgrades provided the gross annual income of the company requesting the loan does not exceed 7 million dollars. Petroleum marketers are complying with the regulation, but foresee that some businesses may close as the deadline for compliance approaches.

The oil marketers association is also concerned with an upcoming increase in the fee collected to fund the cleanup of unauthorized releases of fuel, i.e., leaks. The Barry Keene Underground Storage Tank Cleanup Trust Fund Act of 1989 was established to make available the funds collected from the fee to see that corrective action is taken when leaks occur. The fee of 0.7 cents per gallon will increase to 1.2 cents per gallon in 1997. While the per gallon fee increase seems small, the large fuel volumes involved add up to a significant expense. Marketers will pay the increase up front, but consumers may likely see a corresponding small increase in per gallon fuel prices.

Changes in the way fuel excise taxes are collected and diesel storage requirements are also causing concern among fuel marketers. Before 1994, marketers were permitted 45 to 60 days after purchasing fuel to collect and pay federal and state excise taxes on the fuel. Effective January 1, 1994, for the federal tax and July 1, 1995, for the state tax, marketers must pay the tax at the time of purchase. These changes were instituted to eliminate tax fraud as well as nonpayment by marketers who may have gone out of business before the tax could be collected from their customers.

The change in tax collection presents an additional cash flow problem for some marketers. The additional operating capital needed to pay the tax up front by the marketer purchasing seven tankloads of fuel a day, for example, could amount to approximately $500,000 per month. While marketers now have a large incentive to recoup those funds by collecting promptly from their customers, it is an incentive they would rather do without.

A similarly motivated requirement for ensuring proper tax collection on diesel fuel went into effect January 1, 1994. Both off-road and on-road diesel fuel have the same chemical composition, but are identified differently for tax purposes. Off-road diesel is exempt from excise tax and is required to be dyed red to distinguish it from on-road diesel. "Clear" diesel for on-road use is taxed. The color difference requires that separate storage tanks be used to avoid commingling. The requirement makes the field auditor's job easier and helps assure proper tax collection. From the marketer's perspective, however, the expense of providing segregated storage in some cases has not warranted selling both red and clear diesel fuel. As a result, some marketers lost those customers who require the diesel fuel that the marketer no longer sells.

These examples demonstrate the trade-offs that can occur between environmental protection, government revenue needs and business growth. Smaller companies can be particularly affected by the expense of complying with environmental controls and have difficulty remaining competitive. On the other hand, government must act responsibly to protect public health and safety. In reducing the risk of environmental damage, consideration must always be given to the economic costs of regulatory measures.

ENDNOTES

1. Conservation Committee of California Oil and Gas Producers, ***Annual Review of California Oil and Gas Production 1993***, Table B-10a and M-1.

2. Conservation Committee of California Oil and Gas Producers, ***Annual Review of California Oil and Gas Production 1993***, Tables M-1 and M-4.

3. Testimony of Scott H. Stevens, Advanced Resources International, ***California Thermal Enhanced Oil Recovery (TEOR)***, 1995 Fuels Report Hearing, May 11, 1995.

4. Ibid.

5. Energy Information Administration, Form EIA-810.

6. Alaska Department of Natural Resources, ***Historical and Projected Oil and Gas Consumption***, March 1995.

7. Idaho National Engineering Laboratory for the U.S. DOE, ***Alaska North Slope National Energy Strategy Initiative, Analysis of Five Undeveloped Fields***, May 1993.

8. Both the Senate and the House of Representatives have approved legislation to lift the ban on exporting ANS crude oil. ANS oil could be traded on foreign markets early next year.

9. U.S. Department of Energy, ***Exporting Alaskan North Slope Crude Oil, Benefits and Costs***, June 1994.

10. Energy Information Administration, ***State Energy Data Report***, 1992.

11. Petroleum Industry Information Reporting Act (PIIRA) data has been collected since 1981 and includes information on refinery operations, petroleum and fuel stocks, imports and exports and petroleum fuel use.

12. Charles Greene Consultants, ***The Impact on California of Alaska's Crude Oil Production***, June 1993.

13. Throughput capacity varies depending on the gravity and viscosity of the crude oil being transported.

14. Submittals from oil companies under the Petroleum Industry Information Reporting Act.