S&T

# System Dynamics

## Petroleum Storage & Transportation

National Petroleum Council • April 1989

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William E. Swales, Chairman, Committee on Petroleum Storage & Transportation

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.


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VOLUME II

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# INTRODUCTION

In February 1987, the Secretary of Energy requested the National Petroleum Council (NPC) to determine the capacities of the nation's petroleum and gas storage and transportation facilities as part of the federal government's overall review of emergency preparedness planning. The Council has conducted similar studies at the request of the federal government since 1948. The most recent reports are the 1979 report entitled Petroleum Storage and Transportation Capacities and the 1984 report entitled Petroleum Inventories and Storage Capacity. In addition to updating the 1979 and 1984 reports, this study was to place more emphasis on describing the dynamics and interrelationships of the petroleum and natural gas delivery systems. Specifically, the Secretary requested that:

> Emphasis should be given to the re-examination of minimum operating inventory levels, the location of storage facilities, and availability of inventories in relation to local demand, and the capabilities of distribution networks to move products from refining centers to their point of consumption particularly during periods of stress.

(See Appendix A for the complete text of the Secretary's request letter and a description of the National Petroleum Council.)

To respond to the Secretary's request, the NPC established the Committee on Petroleum Storage & Transportation, chaired by William E. Swales, Vice Chairman - Energy, USX Corporation. The Honorable H. A. Merklein, Administrator, Energy Information Administration, served as Government Cochairman of the Committee. A Coordinating Subcommittee and four task groups were formed to assist the Committee. This volume was prepared by the System Dynamics Task Group, chaired by D. R. Hayward, Vice President, U.S. Supply, Marketing & Refining Division - U.S., Mobil Oil Corporation. Charles C. Heath, Director, Petroleum Supply Division, Energy Information Administration, served as Government Cochairman of the Task Group. (Rosters of the study groups responsible for this volume are contained in Appendix B.)

The Council's overall report, Petroleum Storage & Transportation, is being issued in five volumes:

- Volume I - Executive Summary
- Volume II - System Dynamics
- Volume III - Natural Gas Transportation
- Volume IV - Petroleum Inventories and Storage
- Volume V - Petroleum Liquids Transportation.

In addition, detailed profiles of the companies that participated in the natural gas transportation and petroleum pipeline surveys are available from the NPC.

## SYSTEM DYNAMICS

Volumes III, IV, and V provide detailed descriptions of and capacity data on the various sections of the petroleum and natural gas supply system. This volume builds on the information in those volumes, focusing on the dynamics of the overall system. It has a dual purpose:

- To examine the capability of the petroleum and natural gas supply system to respond to normal demands anticipated through 1992 and to respond to abnormal situations that may "stress" the system

- To explain in broad terms how the supply system operates in a competitive business environment.

For this purpose, the supply system includes refineries, petroleum and natural gas imports, and trading as well as transportation and storage facilities.

It is convenient to describe the supply system in monolithic statistics of capacity, throughput, and inventory; but in fact, the system is comprised of thousands of separate, individual companies in competition with each other. These companies make individual decisions and take independent actions in accord with their individual economic interest and incentives. System performance is the net result of those decisions and actions. Nevertheless, the system does respond rationally and predictably to economic incentives (or disincentives) that result from variations in supply and demand.

The logical response of the supply system to the economics of supply and demand is a recurrent theme of this volume. These economics shaped the major industry changes of the last decade, and they will be seen to be a primary factor in the operation of the system in normal times and in periods of stress.

This is not a statistical volume, but statistical data (largely from the Energy Information Administration) have been used to illustrate the dynamic operation of the supply system and its principal elements. It is believed that an understanding of the system dynamics provides support for the conclusion that the industry, if permitted, can meet future demands and can deal effectively with severe stress situations. Certainly, the history of recent years should provide credence to the assertion that the system adapts quickly and efficiently to change.

# EXECUTIVE SUMMARY

This summary provides a brief overview of the National Petroleum Council's examination of the dynamics of the oil and natural gas distribution system. While concern was focused on the U.S. distribution system and its changes, the NPC also dealt with international issues, because the United States is an integral part of the world supply system. This study examined comprehensively two types of changes that occur -- or might occur -- in the supply-demand system and the industry capacity to respond. These two types of changes include:

- Long-term economic trends that cause continuing -- but not sudden -- shifts in the distribution patterns of crude oil, finished products, and natural gas throughout the market.

- Short-term and sudden shifts or crises in either supply or consumption of crude oil, finished products, and natural gas. Such crises might include the sudden and complete disruption of a major pipeline or the unexpected upsurge in demand because of weather or some unusual, unpredictable event.

Events over time demonstrate that the system for the distribution of petroleum (crude and refined) and natural gas is both resilient and flexible. As demand and supply have ebbed and flowed and shifted geographically, the system has readjusted itself by fresh allocation or switching of investment to cope with the evolving changes and short-term operating adjustments. Most notable has been the ability of the system to readjust to compensate for the closing of over 100 U.S. refineries in the past seven years. The fact that this could be accomplished without product outages in the marketplace is testimony to both the resilience and flexibility of the system.

In addition, the system has the built-in flexibility and reserves to cope with a broad variety of sudden disruptions to either supply or demand. To test this capability, the NPC examined six possible disruption scenarios to determine how the system might respond. The scenarios represented a realistic mix of the "bad things" that might happen to disrupt the flow of crude oil, product, and natural gas or to significantly change demand. In each case, the system was found to be capable of repositioning supply and/or repairing the system in time to prevent any significant disruption of supply to consumers.

Three important overall conclusions about the petroleum distribution system emerged from this study:

- There is a built-in supply cushion or reserve that can be used to overcome possible disruptions, because the system supply lines are far-reaching both via ocean and pipeline. In addition, inventory storage cushions at strategic points along the way help absorb short-term fluctuations.

- Should a mechanical disruption occur in a pipeline, for example, the means exist in many cases to quickly fix the line or circumvent it. In part, the great strength of the petroleum distribution system lies in its interconnectability, and thus the availability in most cases of one or more alternative supply routes.

- As longer-term trends evolve, there are built-in financial incentives to invest capital to meet new and changing demands. Examples include: reversing the flow of a pipeline, looping a system (building a parallel line), building new pipelines, or developing a deep-water port. These are illustrations of how investment gets realigned or made fresh to meet changing conditions.

It is important to note that the driving force behind the system's capacity to readjust is the economic incentive of the free market. In a free market, as supply and demand ebb and flow, price also moves, encouraging either an increase in supply movement or a diminution in consumption.

The remainder of this summary consists of two parts. First, an examination of the longer-term trends the NPC has studied over the past decade to determine how, and with what success, the system has adjusted to cope with changing system requirements. Second, a brief look at each of the six hypothetical crisis scenarios designed to determine how the system reacts to violent, short-term shifts in either demand or supply.

## EXAMINING THE LONGER-TERM TRENDS

### Oil

It is important to establish at the outset that the domestic and international petroleum industries (which are inexorably intertwined) have experienced severe volatility and uncertainty in the past decade. Indeed, recent years have been difficult ones, and as a result the industry has experienced dramatic changes in its supply system.

Since 1979, the industry has passed through two significant periods. First, from a supply-and-demand high point in 1978-1979, the nation entered a period of great conservation with U.S. consumption falling off from a 1978 high of 18.8 million barrels per day (MMB/D) down to a low of 15.2 MMB/D in 1983 before gradually rising to 16.7 MMB/D in 1987. This was a frenzied period in which drastic price rises were anticipated, encouraging expensive searches for alternative energy sources. This also was the period of the Iranian oil cut-off when both oil and natural gas supplies were expected to be inadequate. That expectation was premature; West Texas sour crude oil prices hit a high of $36 per barrel in 1980 before plunging to a low of about $10 per barrel in 1986. The impact on U.S. exploration and production was harsh.

Despite the volatility of price, demand, and supply (particularly shifts in source), only minimum disruptions were felt by the consuming public or commercial enterprises. Perhaps the only consequences of note that many people remember were the gasoline lines for a brief period in 1979.

The second stage began in 1983-1984 with the gradual increase in petroleum demand, with a recovery to 16.7 MMB/D by 1987. Demand for petroleum products also rose gradually in the rest of the world. Prices during this period generally decreased. During this period, OPEC had a significant production surplus, which eventually appeared in the market. The price crash in 1986 badly hurt exploration and production in the United States. OPEC continues to be a significant factor, whose influence is unlikely to diminish soon. Again, this second stage, 1983-1987, was a period of uncertainty and volatility. One can hope for price stability at some reasonable level; but no one is willing to count on it.

Under these trying conditions, the petroleum (crude oil and product) distribution system performed remarkably well. There were no significant disruptions in petroleum supply to any part of the U.S. economy during this second stage.

During the period from 1979 to 1988, major changes took place in the petroleum supply system. These changes included:

- Regulation -- January 1981 marked the end of price and allocation regulations. These regulations, which had a stultifying effect on the industry, reduced both the benefits and risks of competition. However, in 1981 the industry went back to full-bore competition in a period when demand was dropping.

- Crude Oil Production and Imports -- Average annual crude oil production rose from a low of 8.1 MMB/D in 1976 to a high of 9 MMB/D in 1985, in large part because of the growth of Alaskan production. In 1987, it fell to 8.3 MMB/D and is still declining. However, U.S. demand is rising, resulting in increased imports of foreign crude oil.

- Change in Product Mix -- Both tightened environmental regulation and inter-fuel price competition have significantly changed the mix of products needed to serve consumers. One major swing has been a drop of over 1.75 MMB/D in the demand for residual fuel oil since 1978, even though a small recovery is projected for the future. This has been replaced by natural gas and even coal in some cases. In contrast, the demand for gasoline and distillates has risen by 0.9 MMB/D since 1983.

- <u>Refining Capacity</u> -- One of the most dramatic changes has been a significant reduction in crude oil refining capacity in the United States. Between 1981 and 1986, over 100 refineries were closed. In 1981, the industry had a refining capacity of more than 18 MMB/D. Current refining capacity is less than 16 MMB/D, but in general it is more efficient and more economical capacity. Because refining throughput and refinery location largely determine the movement of crude oil, these changes have had a substantial impact on the distribution system and its performance.

- <u>Petroleum Transportation and Inventory</u> -- Declining demand and lower domestic production altered demand on the U.S. pipeline system. For example, the Texoma and Seaway pipelines were switched from crude oil to gas. Also, the decline in crude oil price altered the expectations of future price improvement and thus changed the economics of carrying inventory. As a result, system inventories of crude oil and product went from a high of 1,300 million barrels to just below 1,000 million barrels in 1985.

## <u>Natural Gas</u>

Natural gas plays a vital role in our energy distribution system for two important reasons. First, gas fulfills some 23 percent of our energy needs primarily in residential and commercial heating and in industrial processing and electric generation. Second, depending on price and availability, some users switch back and forth between gas and residual fuel oil. Thus, the ability of the system to ensure gas availability is vital to our economy in itself but further affects increases or decreases in the demand for residual fuels.

The changes in the natural gas industry reflect a similar supply-demand cycle to that experienced in the oil industry -- i.e., increasing demand followed by a period of conservation and diminished demand. Gas consumption attained a high of nearly 22 trillion cubic feet (TCF) in 1972, driven by low regulated wellhead prices. In 1973, wellhead prices averaged $0.22 per thousand cubic feet (MCF). Such low prices led to a fall in proved natural gas reserves, from almost 300 TCF in 1967 to about 200 TCF by 1978. Following the passage of the Natural Gas Policy Act (1978), average wellhead gas prices reached $2 per MCF in 1981 and $2.50 in 1982, while prices of some deregulated categories of gas ran up to $10 per MCF at the time. Average U.S. consumer gas prices peaked in 1984 at $4.85 per MCF, when wellhead prices peaked at $2.66 per MCF.

Natural gas consumption declined during the late 1970s and early 1980s, reaching a low of about 16 TCF in 1986. Pipelines and other distribution facilities became significantly underutilized. Also, decreasing demand resulted in a substantial surplus of domestic production capacity (the so-called "gas bubble"). Competition resulted in gas prices falling below regulatory ceilings. Demand for natural gas has increased in recent years. In 1987, natural gas consumption rose 1 TCF and it appears to have exceeded 18 TCF in 1988.

These undulations in supply and demand put a strain on the distribution system. In addition, the problems associated with these changes were greatly aggravated by continued tight regulation by the federal government. Until 1978, the overall effect of this regulation was to hold gas prices at artificially low levels that did not support exploration and replacement of gas reserves. To attempt correction, the government phased through a series of regulations that have moved the gas industry closer to a competitive, market-oriented business. However, this transition has been painful for the industry. The transition continued in 1988; but most major problems were being resolved and most producers had some improved access to the market on competitive terms.

In addition to the federal government, state agencies such as public utility commissions continued to be dominant in natural gas and other energy matters. The utility commissions testify in federal rate case hearings, review the flow-through of costs on new supplies of natural gas, and survey the supplies of natural gas moving to the end-user. Consequently, the local distribution companies (LDCs) and interstate pipeline companies continue to be sensitive to the actions and needs of not only state utility agencies but also state and municipal environmental, archaeological, land use, and other agencies.

It is notable that throughout the turmoil of the past 10 years, a most creditable job was done in transmitting gas to end-users, particularly to preferred users such as residences, hospitals, schools, and other public institutions. An important lesson emerges from this experience. There is no perfect system, but it is clear that the supply stream functions more effectively when the incentives of the free market are in play.

## THE SUPPLY SYSTEM UNDER NORMAL CONDITIONS

One must recognize that the rapid changes in the oil industry over the past decade reflect the continuing business environment for the supply system. The successful supply performance is clear testimony to the response capability and adaptability of the system. As part of this study, the NPC also examined the ability of the system to handle industry growth through 1992.

To examine future supply capability, the study used the Department of Energy (DOE) forecast for 1992, as shown in Table 1. It is interesting to note that 1992 demands for crude oil and petroleum products are not projected to reach the

TABLE 1

U.S. OIL AND GAS DEMAND AND SUPPLY*

| | Actual 1979 | Actual 1987 | Projected 1992 |
|---|---|---|---|
| Oil Demand | (Thousands of Barrels per Day) | | |
| Gasoline | 7,034 | 7,206 | 7,330 |
| Distillate | 3,311 | 2,976 | 3,440 |
| Residual Fuel | 2,826 | 1,264 | 1,470 |
| Others§ | 5,342 | 5,219 | 5,480 |
| Total Oil Demand | 18,513 | 16,665 | 17,720 |
| Oil Supply | (Thousands of Barrels per Day) | | |
| Crude Petroleum | 8,552 | 8,349 | 6,870 |
| Crude Imports¶ | 6,519 | 4,674 | 7,060 |
| Product Imports | 1,937 | 2,004 | 2,300 |
| Other** | 1,505 | 1,638 | 1,490 |
| Total Oil Supply | 18,513 | 16,665 | 17,720 |
| Gas Demand | (Billion Cubic Feet) | | |
| Residential | 4,958 | 4,302 | 4,597 |
| Commercial | 2,770 | 2,392 | 2,672 |
| Industrial | 6,807 | 5,827 | 6,420 |
| Electric Utility | 3,462 | 2,814 | 3,228 |
| Subtotal | 17,997 | 15,335 | 16,917 |
| Lease and Plant Fuel | 1,486 | 1,033 | 956 |
| Pipeline Fuel | 600 | 517 | 527 |
| Total Gas Demand§§ | 20,084 | 16,885 | 18,400 |
| Gas Supply | (Billion Cubic Feet) | | |
| Dry Gas Production | 19,443 | 16,295 | 17,280 |
| Net Imports | 1,249 | 987 | 1,610 |
| Unaccounted/Inventory | (608) | (397) | (490) |
| Total Gas Supply§§ | 20,084 | 16,885 | 18,400 |

*Data and forecast from DOE Energy Information Administration.

§Includes LPG, jet fuel, kerosine, lubes, and other products.

¶Includes the Strategic Petroleum Reserve.

**LPG production, inventory flux, process gain, and other, less exports.

§§Totals may not equal the sum of components due to independent rounding.

peak-year 1979 requirements. Future demands were examined in total and by Petroleum Administration for Defense District (PADD) to identify the areas of principal change such as an increase in foreign crude oil to PADD II (the Midwest) and increased tanker deliveries in the U.S. Gulf.

In this volume, many energy statistics are compiled on a PADD basis. The five PADDs, shown in Figure 1, are consistent with the following broad geographic regions:

- PADD I - East Coast
- PADD II - Midwest
- PADD III - U.S. Gulf Coast
- PADD IV - Rocky Mountain
- PADD V - West Coast.


Figure 1. Petroleum Administration for Defense Districts (PADDs).

Gas supply and demand data are also presented in Table 1. Gas demand in the Lower-48 States is projected by the Energy Information Administration (EIA) to increase to 18.4 trillion cubic feet (TCF) per year by 1992, an increase of 1.5 TCF from 1987. This projected rate for 1992 is still about 1.7 TCF below the actual demand in 1979. Overall, this indicates surplus capacity in most of the transportation system. In addition, increased transmission facilities to serve the Northeast and California have been proposed and are awaiting regulatory approval. Additions to current capacity have also been proposed to serve the Florida markets. If these proposals for capacity additions are approved, there will clearly be adequate natural gas transmission capacity to fully cover expected demand through 1992.

This study examined many aspects of the supply system. They included the gathering of crude oil and its distribution to refineries by pipeline, barge, and ocean tanker and the distribution of product from refineries to consumers by pipeline, barge, tank truck, and rail tank car. Movement of product from foreign sources through the distribution system was also reviewed.

Finally, the changing supply needs of 1992 were compared with anticipated supply and transportation capacity. The supply system appears to have ample capacity and flexibility to handle projected growth in demand through 1992.

## THE SUPPLY SYSTEM UNDER STRESS

Satisfied that the system could handle distribution expeditiously under normal growth conditions, the NPC considered the possibility of a variety of sudden and severe crises. In other words, the Council sought to examine the capability of the U.S. distribution system to cope with unusual and unexpected stress.

It is important to mention that even under typical conditions, the system responds to a constant stream of minor stress such as refining down-time, missed pipeline deliveries, unexpected changes in weather, swings in sales, and the like. Occasionally, the system is faced with more serious stress conditions. A degree of stress is normal in the industry, but few stress situations result in serious supply problems. In fact, the consumer rarely feels the impact. The system can respond like a huge shock absorber to changes in demand or supply, because of a built-in level of inventory in storage, considerable product in transit, and of course the ability to move to alternative sources of supply. These features work to give the system its remarkable resilience and flexibility.

The purpose, then, became to test the supply system under conditions of severe or abnormal stress. To do so, six stress scenarios were designed to rigorously test the system's capacity to adapt to sudden and demanding changes in supply requirements. These were:

1. Oil Import Disruption (initiating an SPR drawdown)
2. Colder-Than-Normal Weather
3. Canadian Gas Import Disruption
4. Product Pipeline Disruption (PADD III to PADD II)
5. TAPS Disruption
6. Canadian Crude Oil Import Disruption.

For each of these scenarios, a critical evaluation was made of the system's ability to cope. This included carefully developed alternative ways to provide the crude oil, product, or natural gas to overcome the crisis situation. Each scenario is briefly described below, along with suggestions as to how the industry could effectively handle the situation.

Scenario 1: Oil Import Disruption

This scenario tests the system's ability to handle a 90-day disruption in foreign crude oil and product imports, totaling 3 MMB/D in 1987 and 4.5 MMB/D in 1992, as outlined in Table 2.

The capacity of the Strategic Petroleum Reserve and the enormous flexibility of the inventory and supply system are adequate to overcome even such an extensive loss of crude oil. The product loss could be made up from both domestic and foreign refineries.

As the scenario is designed, the crude oil loss would vary by region. The most serious supply problem would occur on the East Coast (PADD I). However, crude oil and product can be shifted to meet these needs. Free-market trading is vital to the efficient distribution of SPR oil.

TABLE 2

STRESS SCENARIO 1
ASSUMED IMPORT REDUCTIONS
(Thousands of Barrels per Day)

1987

| | Crude Oil | Product | Total |
|---|---|---|---|
| PADD I | 510 | 420 | 930 |
| PADD II | 270 | -- | 270 |
| PADD III | 1,450 | 210 | 1,660 |
| PADD V | 140 | -- | 140 |
| Total | 2,370 | 630 | 3,000 |

1992

| | Crude Oil | Product | Total |
|---|---|---|---|
| PADD I | 765 | 630 | 1,395 |
| PADD II | 405 | -- | 405 |
| PADD III | 2,175 | 315 | 2,490 |
| PADD V | 210 | -- | 210 |
| Total | 3,555 | 945 | 4,500 |

In brief, the combination of SPR inventory back-up and the ability of the system to shift product from other parts of the system permit coping with even such large crude oil losses.

Scenario 2: Colder-Than-Normal Weather

This scenario examines how the supply system might cope with an unusually severe winter with temperatures averaging either 10 percent colder than normal for 90 days or 20 percent colder than normal for 30 days throughout the nation. While we have experienced one or the other of these conditions on average once in every five years, these conditions have not been significantly exceeded in the last 50 years.

Both of these conditions could be handled by a combination of inventory drawdowns and a variety of resupply alternatives. This solution would hold both today and for the demand projected for 1992. The point of heaviest stress in this scenario is the deliverability of natural gas to the East Coast, with the area of greatest concern being New England. In that area, some dual-fuel boilers would shift from gas to oil. Construction projects have been proposed, however, to eliminate natural gas pipeline capacity bottlenecks.

In short, the current supply system with the improvements now in progress is fully capable of handling the severest weather conditions we have experienced in over 50 years.

Scenario 3: Canadian Gas Import Disruption

This scenario analyzes the effects of a 50 percent loss in gas imports for the month of January at each of the five entry points between Canada and the United States. The assumed reductions for purposes of this scenario are about 2.3 billion cubic feet per day, as detailed in Table 3.

TABLE 3

STRESS SCENARIO 3
DISRUPTION IN CANADIAN GAS IMPORTS
(Millions of Cubic Feet per Day)

| | Assumed Gas Reduction |
|---|---|
| PADD I (New England) | 25 |
| PADD I (Mid-Atlantic) | 100 |
| PADD II | 410 |
| PADD IV | 555 |
| PADD V (West Coast) | 1,235 |
| Total | 2,325 |

This gas loss would be met by calling upon the built-in cushion and flexibility in the system. First, the system inventory would be tapped to meet a large percentage of the shortfall. Second, some fuel switching would take place in the East Coast industrial and electric utility sectors, primarily by drawing on available inventories of residual fuel oil.

In brief, the system could weather the loss of 50 percent of the gas normally imported from Canada for 30 days without significant difficulty. However, the Canadian natural gas shut-off scenario may pose a temporary problem for the West Coast if sufficient natural gas is not in storage at the time of the shut-off. This scenario, therefore, emphasizes the important role of seasonal gas storage in meeting abnormal demands.

## Scenario 4: Product Pipeline Disruption (PADD III to PADD II)

This scenario tests supply system capability to respond to a major disruption in a products pipeline flow. For the purposes of this study, the NPC examined the consequences of Explorer pipeline being shut down for 30 days. This pipeline delivers about 360 thousand barrels per day (MB/D) to the Midwest (PADD II) from the U.S. Gulf Coast area (PADD III). This is an important product supply for a high-consumption area. This scenario represents an unlikely stress condition, because product pipelines are repaired quickly; normally only a few days of down time would be expected for a pipeline problem.

Available inventory is usually adequate to cover this assumed product loss. The assumed loss of pipeline deliveries for 30 days would amount to about 10.8 million barrels: roughly equivalent to three day's supply. This is less than the amount of inventory typically available above minimum operating inventory levels in this area, as shown in Table 4. In addition to drawing inventories, a number of alternative means exist to

TABLE 4

PADD II
AVAILABLE SYSTEM INVENTORY -- ABOVE MINIMUM*
(Days Supply)

| | Gasoline | Distillate | Jet Fuel |
|---|---|---|---|
| Primary Inventory | 4 | 1 | 8 |
| Secondary (jobbers, etc.) | 4 | 3 | - |
| Tertiary (consumers) | 6 | 21 | 6 |
| | 14 | 25 | 14 |

*Based on March 31, 1988 data and methodology outlined in Volume IV of this report, Petroleum Inventories and Storage.

increase product supply, including increased refining runs, use of spare capacity in other pipelines, and reduced shipments of product out of the area to regions that can receive product from other sources.

In summary, the loss of a single pipeline into the Midwest for a 30-day period could be handled by a combination of normal industry operating practices.

Scenario 5: TAPS Disruption

This scenario examines the shutdown of deliveries from the Trans-Alaska Pipeline System for 30 days. TAPS is the largest throughput crude oil pipeline in the United States, carrying an average of about 2 MMB/D for transshipment to the West Coast, Gulf Coast, the Virgin Islands, and Hawaii. This constitutes about 15 percent of the total U.S. crude oil demand.

The loss of 2 million barrels of production is a major disruption even in the world market; the loss of 2 million barrels of Alaskan crude oil is particularly difficult because most of the crude oil is consumed on the West Coast, remote from other major crude oil logistics systems. Given current levels of worldwide inventories and surplus foreign production capacity, acquisition of replacement supply for the West Coast should not be a major obstacle; the problem is to maintain continuity of supply until replacement crude oil supply can be delivered.

Replacement of the East-of-Rockies supply poses no major problem, but the situation on the West Coast would be more difficult. The West Coast crude oil loss could be managed by a combination of measures, including: drawdown of inventories, diversion of ships carrying Alaskan crude oil from their intended destinations, and increasing imports of crude oil and product.

Thus, while the disruption of TAPS would result in higher cost to the marketplace, essential supply needs would be met, assuming normal world crude oil supply availability, especially in a current disruption. However, the loss of TAPS supply for 30 days in 1992 could pose a substantially more serious problem, which would be felt by West Coast consumers for several weeks. The West Coast re-supply problem will become more difficult in later years as projected Alaskan production drops and West Coast consumption increases, leaving significantly less oil in transit to provide continuity in the early days of the cut-off.

Scenario 6: Canadian Crude Oil Import Disruption

The final stress scenario tests options available in case of a 30-day disruption of Canadian crude oil imports delivered via Inter-Provincial pipeline. This would result in a 500 MB/D crude oil loss in the Upper Midwest.

Supply to cover a 30-day Canadian crude oil disruption is normally available from primary crude oil inventories in the

Midwest and Gulf Coast. Pipeline capacity to move the crude oil to the affected areas is also available. Inventories would be replenished with increased non-Canadian imports later in the stress response cycle. The system also retains the flexibility to supply significant volumes of finished product into the affected areas. By 1992, projected growth in refinery crude oil demand will make replacement of the Canadian volume in kind more difficult. Incremental product supply and product inventory draw would be required to bridge a 30-day loss of Canadian crude oil.

For most of the Midwest, the lost Canadian crude oil could be replaced quickly except for the Twin Cities area.

## Summary

Designing and examining these six scenarios has served to highlight some important factors about our supply system:

- The system is very resilient and flexible, permitting it to adjust to and resolve a wide range of stress situations.

- This flexibility and adaptability depend heavily on built-in inventories that occur at key points in the system, and on the system's great capacity to obtain crude oil, product, or natural gas from alternative supply sources.

- The interconnectability of the individual parts of the system permits shifting and diverting product from many sources to virtually any point of ultimate consumption. In this sense, the U.S. and worldwide petroleum distribution networks are the most widespread of any logistic systems in the world.

It is important to recognize that these stress scenarios examined the ability of the system to move crude oil, product, and gas in abnormal conditions. In all the scenarios, supply was expected to be available in the system. Obviously, the system could not resolve situations in which there was not adequate supply available to the system. In this respect, the Stratetic Petroleum Reserve provides an important source of potential supply, if required.

Finally, the study has made it clear that economics and the free market drive this system. It is a simple but profound concept: as supply shortages develop, prices rise, encouraging a shift to rebalance the disposition of crude oil, product, or natural gas. When artificial constraints are placed on the system, the natural balancing, self-correcting process does not work.

Since the end of World War II, no serious petroleum shortages have occurred at the consumer level except gasoline lines and natural gas curtailments in the era of price and allocation controls. In recent years, however, there have been situations where the market felt particularly heavy pressure because of abnormal conditions. These included:

- Motor gasoline supply tightness in the summer of 1988
- The fuel-switching episode of 1986
- The Southwest freeze-up of 1983.

While these events had their economic cost and produced a high level of discomfort for oil and gas companies, they did not prove in any way disruptive -- convincing testimony to the flexibility and adaptability of our supply system.

# CHAPTER ONE

# BACKGROUND -- OVERVIEW OF CHANGES

## INTRODUCTION

The U.S. petroleum supply "system" consists of thousands of separate, independent entities, most of which are in direct competition with each other. Despite the disparate business and economic interests of the industry members, the aggregate system responds to economic incentives (and disincentives) in a rational and reasonable fashion; and analysis of the "system" capability and performance is a useful simplification.

Economic incentive is the driving mechanism of the supply system. It shapes the short-term response to problems and opportunities, and it triggers longer-term investment decisions.

It is convenient to discuss the capability and performance of the supply-system components as if they were monolithic entities. They are not. The performance of the system represents the net result of actions taken by a great many participants, each responding to its own economic interest and incentive. The interaction of the system components can be very complex. For example, a rise in local distillate prices could simultaneously trigger increased refinery production, attract increased imports and supply from other areas, induce flexible consumers to switch fuels, and cause inventory draw (or build, in some cases).

The supply system has changed dramatically since 1979, when the NPC issued its report, *Petroleum Storage and Transportation Capacities*. This volume describes some of the more significant changes. It also outlines the operation of current system components in terms of their flexibility and capability to meet present and future demands under "normal" economic and supply conditions.

The same economic dynamics that control the "normal" operation of the supply system apply to abnormal situations that "stress" the system. Chapter Three of this volume concerns the system response to some actual stress conditions and the system capability to respond to some hypothetical situations of very severe stress.

Measured by results, the supply system has worked well in periods of both shortage and surplus, and it is continuing to work well. The current system is efficient and economic; and it is again growing to meet economic requirements. Under "normal" operating conditions and prices, no significant problems are projected through 1992. Further, the system retains considerable flexibility to respond to quite unusual stress situations.

## INDUSTRY TRENDS

In 1979, when the NPC's last full report on petroleum storage and transportation was published, gasoline lines plagued some American motorists; petroleum demand averaged 18.5 MMB/D; imported crude oil prices averaged $22 per barrel and were rising; and net oil imports accounted for 43 percent of U.S. consumption. By 1982, new natural gas sales contracts with producers were being made at prices up to $10 per thousand cubic feet (MCF), as pipeline companies attempted to arrange long-term supplies to alleviate projected natural gas shortages.

Generally, the years since 1979 have been difficult ones for the industry. Shortages of crude oil and refined products turned to market gluts, and prices dropped precipitously. Surplus natural gas production and competition from cheap oil forced most gas prices below their regulated ceilings, resulting in fundamental changes in gas marketing. With the benefit of hindsight, the changes are perceived to be the predictable result of the classic economic laws of supply and demand, but the swiftness and vigor of the reaction were a surprise to almost everyone in the industry.

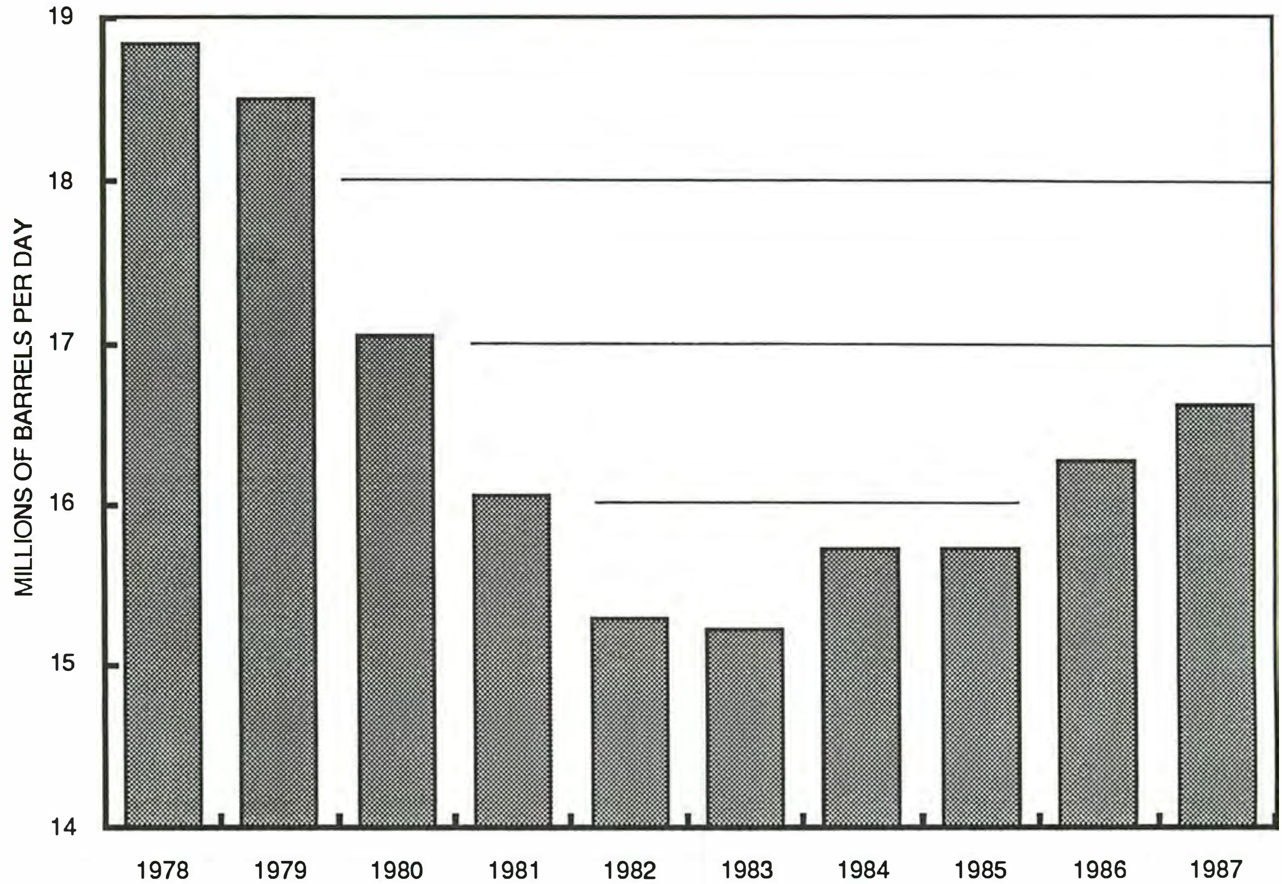
The U.S. supply system and the economic environment in which it operates have changed greatly since 1979. The changes that resulted in the present system occurred in two stages -- a decline stage and the current recovery stage.

### First Stage

In 1979, U.S. petroleum consumption and U.S. refinery runs were the second highest in history, only slightly below the prior year. The cutoff of Iranian crude oil had triggered a second round of shortages, of which gasoline lines were the most visible symptom. Natural gas supplies were projected to be inadequate, and in many areas new gas connections to residental and business consumers were banned.

The government and the financial experts were projecting energy costs to rise significantly faster than inflation through the decade; forecasts of $100 a barrel for crude oil in the 1990s were common. It was the kind of frenzied environment in which a project to generate gas from chicken droppings could receive serious consideration; but it was also an environment that attracted money and talent to more substantial energy supply projects.

However, it was the demand half of the supply-demand equation that first signaled a change. As shown in Figure 2, U.S. petroleum consumption began to decline in 1979 and dropped 3.6 MMB/D (about 19 percent) before bottoming out at about 15.2 MMB/D in 1983. Demand was also declining in the rest of the world; by 1984, free-world demand was down 6.4 MMB/D (about 13 percent) from 1978. Today the eventual effect of high prices on energy demand seems obvious, but it was not widely apparent in 1979.




SOURCE: EIA, Petroleum Supply Annual, 1987, Vol. 1, Table S1.

Figure 2. Total U.S. Product Demand.

High energy prices were also bringing new energy supplies to the market. The most significant element was the growth of non-OPEC oil supply. From 1978 through 1983, non-OPEC supply increased 4.5 MMB/D. This growth, coupled with reduced demand and competition from gas, coal, and nuclear energy, produced a classic "squeeze" on OPEC sales. The magnitude of this squeeze is illustrated in Table 5, which shows the changes in free-world supply and demand from 1978 through 1987. With demand down by 5.4 MMB/D and competing supply up by 6.5 MMB/D, OPEC sales had declined 11.9 MMB/D by 1983. Further, OPEC's market share had declined from about 60 percent of free-world demand in 1978 to 40 percent in 1983, representing a significant loss of control.

The impact of both shortage and surplus on domestic crude oil prices is illustrated in Figure 3, which shows typical posted prices for a sour (high sulfur) West Texas crude oil. (This crude oil is similar in quality to the average crude oil run in U.S. refineries and normally trades $0.75 to $1.25 per barrel below the more widely known West Texas intermediate crude oil.) In mid-1973, the wellhead price for West Texas sour crude oil was about $4 per barrel and rising. The Arab embargo, which began in October, quickly pushed prices to the $10 per barrel level by year end.

TABLE 5

FREE-WORLD SUPPLY AND DEMAND
(Millions of Barrels per Day)

| | 1978 | 1983 | 1987 |
|---|---|---|---|
| Demand | 50.3 | 44.9 | 47.5 |
| Supply | | | |
| OPEC | 30.3 | 18.4 | 19.0 |
| Non-OPEC | 18.6 | 23.1 | 25.3 |
| Other* | 1.4 | 3.4 | 3.2 |
| | 50.3 | 44.9 | 47.5 |

*Inventory flux, imports from Communist Bloc, etc.

Source: BP Statistical Review, June 1988.

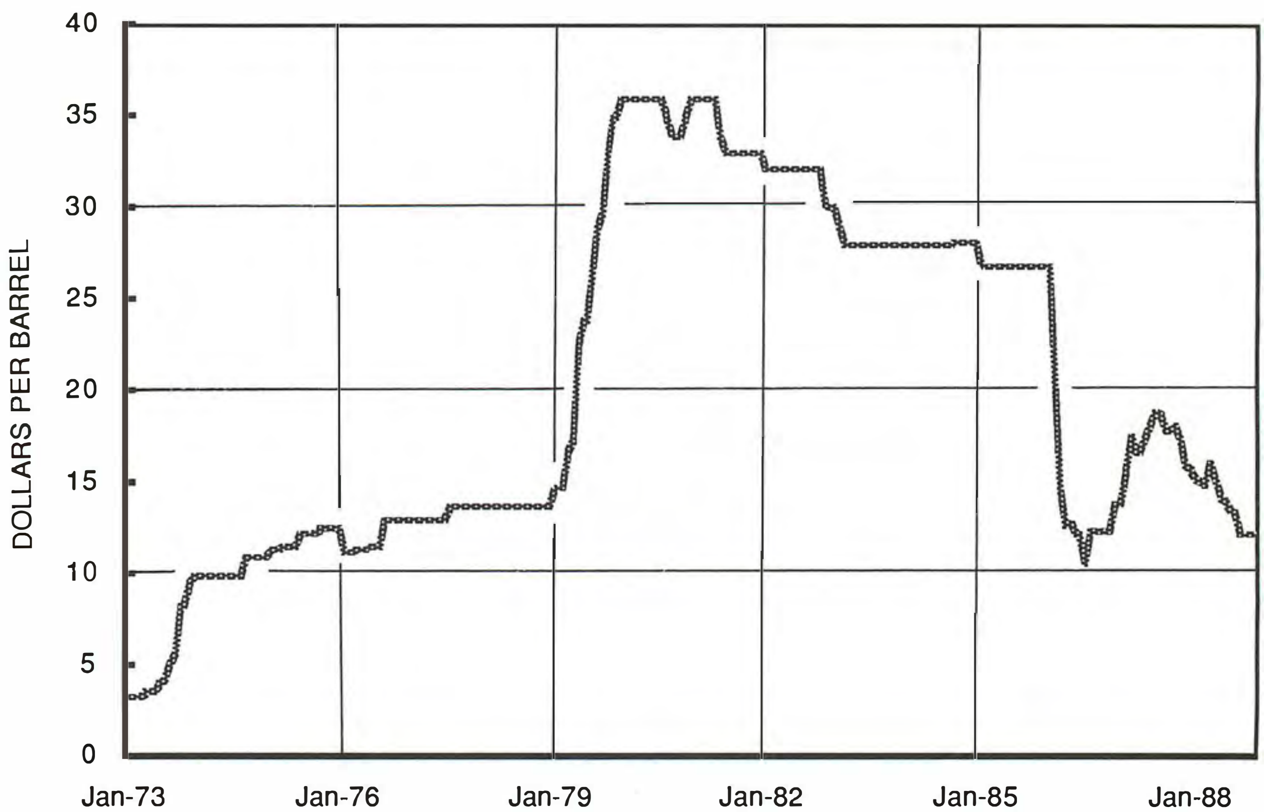



Figure 3. West Texas Sour Crude Oil Posted Prices.

The Iranian revolution cut world crude oil supply by almost 5 MMB/D at the end of 1978, and by early 1979 it became apparent that Iranian sales would not rebound soon. World prices rose quickly. In a calculated (and successful) attempt to run prices up further, Libya cut its crude oil exports. In the United States, sour crude oil postings (for crude oil which was not price controlled) rose to about $36 per barrel by early 1980.

Surplus production began to appear in 1980. Initially, the OPEC cartel tried to defend prices by acting as the "swing" supplier, with limited success. OPEC continued to raise their "official" prices to a peak "benchmark" level of $34 per barrel for Saudi crude oil in 1981, but cut-rate crude oil was beginning to appear in the spot market in significant quantities as individual OPEC members competed for a shrinking market. Crude oil prices drifted down.

The decline in OPEC sales fell disproportionately on Saudi Arabia; the combination of lower price and greatly reduced volume was adversely affecting internal development. In October 1985, the Saudis implemented a program to win back their former market share. Under the program, Saudi crude oil was priced on a "netback" formula tied to spot prices of refined products in the area where the crude oil was refined. It virtually guaranteed a refining profit, and it was an invitation to turn surplus crude oil into surplus product.

As shown in Figure 3, the effect on U.S. crude oil prices was severe. In the first half of 1986, posted prices dropped more than $16 a barrel to a low of about $10. The effect of the price crash on the exploration and production sector of the industry was also severe. Since both crude oil and product prices declined, refiners and marketers were relatively unaffected, though there were large reductions in inventory values.

Since late 1986, prices have fluctuated between $12 and $19 per barrel, largely in response to OPEC activity.

<u>Second Stage</u>

The second stage of changes in the U.S. supply system and the economic environment since 1979 is the recovery stage. Although crude oil prices continued to decline until 1986, the second stage really began in 1984, when petroleum demand again began to increase. As shown in Figure 2, overall U.S. petroleum demand in 1987 was 16.7 MMB/D, up 1.4 MMB/D from the low point. This represents a recovery of about 40 percent of the losses in the 1978-1983 period. The growth has been primarily in the lighter products (e.g., gasoline, distillate, and jet fuel); residual fuel consumption appears to have reached a low and is projected to grow modestly.

Growth has improved the business environment of the refining and marketing sector substantially. After a painful shake-out period in which many refineries became uncompetitive and were shut down, the refining sector is now operating at more efficient utilization levels. Investment in upgrading and debottlenecking of existing facilities is adding to capacity.

Petroleum demand in the rest of the free world has also been growing, as shown in Table 5. Total free-world demand in 1987 (excluding the so-called Centrally Planned Economies) was up 2.6 MMB/D from 1983, a 6 percent increase. However, most of this new demand was covered by increases in non-OPEC production, leaving OPEC with 1987 production of 19.0 MMB/D and unused production capacity estimated at 7 to 9 MMB/D.

Crude oil price uncertainty associated with the OPEC surplus continues to affect the U.S. exploration and production sector. Crude oil and natural gas prices have risen from their lows, and drilling is up modestly but still well below the pre-1986 levels. In the near term, the stability of the crude oil market will probably depend largely on OPEC production policy.

For the longer term, the EIA is forecasting that supply-demand pressure will push oil prices up. Real crude oil prices have dropped to a level that promotes demand growth. Moreover, in the United States price levels are insufficient to cover the replacement of oil reserves being consumed currently. Figure 4 is a plot of West Texas sour postings in constant 1973 dollars.

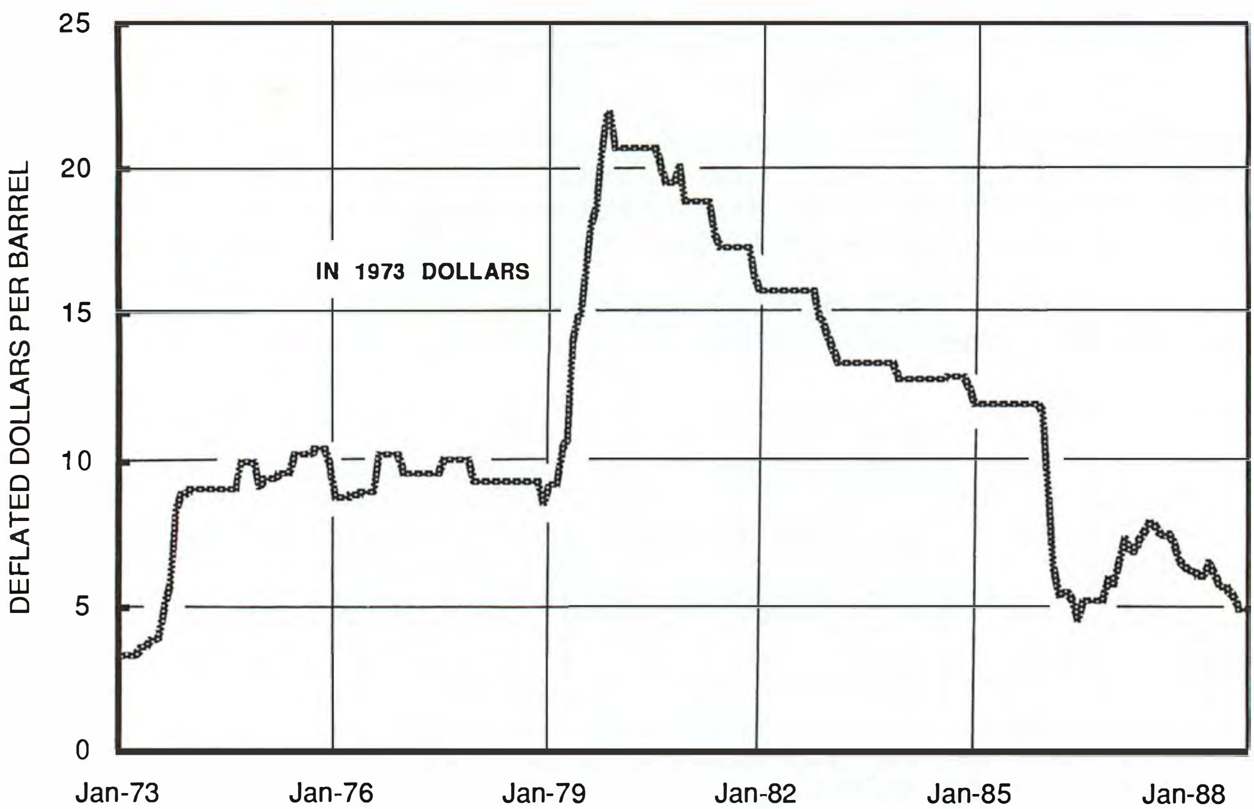



Figure 4. West Texas Sour Crude Oil Posted Prices -- Adjusted for Inflation.

These are the same postings shown on Figure 3, but prices have been adjusted for inflation to reflect the buying power of 1973 dollars. Inflation coupled with the 1986 price reduction has reduced real crude oil prices almost to the level of 1973 -- in effect closing the supply-demand cycle which began then. Consumers and producers both can hope that the next cycle will be more sedate.

## MAJOR SYSTEM CHANGES

The decline and partial recovery trends outlined above have resulted in some significant changes to elements of the supply system over the last 10 years. Some of the major changes are outlined below; the economic interactions that produced these changes are continuing to shape the present system.

### Regulations

The end of price and allocation regulations in January 1981 produced a major change in the way the system operates. The industry returned to full-bore competition in an environment of declining demand, surplus capacity, and the accumulated problems of eight years of controls. Table 6 lists some of the major regulations in effect in 1979 and gives some indication of the restriction on normal competitive operation that the regulations had imposed.

The regulatory environment significantly reduced both the benefits and risks of competition. Customers were "locked" to suppliers, making it difficult to use more or cheaper supply to win added market share. The normal competitive benefits of lower crude oil costs, transportation savings, or improved efficiency could not be realized; regulations required that these savings be "passed through" to consumers in the form of lower prices, or directly shared with competitors under the Mandatory Supply Program. Conversely, the burden of inefficient equipment and operations could also be passed on to semi-captive customers with little risk.

It has been said that government regulations were not designed to solve the supply problems of the time but to allocate the burdens uniformly. Unfortunately, by inhibiting the normal competitive and market incentives, regulations probably extended and exacerbated the burden. Further, by protecting and subsidizing inefficiency, the regulations made the eventual economic shake-out harsher and more painful.

None of the regulations remain, even in standby form. The effect of regulations on the system's ability to respond to supply problems is described in detail in the NPC's 1987 report entitled Factors Affecting U.S. Oil & Gas Outlook.

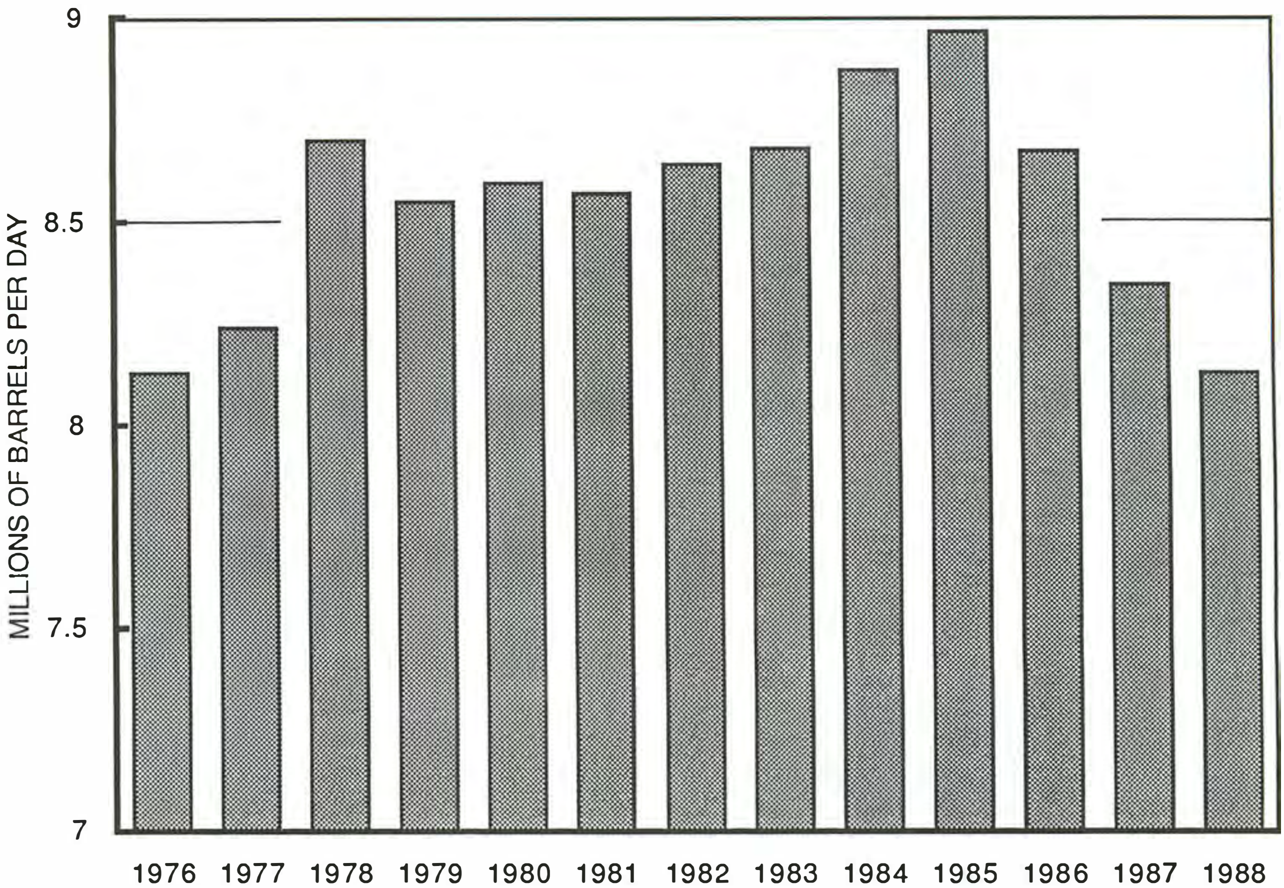
TABLE 6

MAJOR OIL REGULATIONS -- 1979

| | |
|---|---|
| Crude Oil Price Controls | Imposed multi-tiered ceiling prices on domestic crude oil prices. |
| Product Price Controls | Imposed effective ceilings on product margins. Product prices were pegged to a base-period price and escalated with increased costs over the base period. |
| Crude Oil Entitlement Program | Mandated the purchase of "entitlement" rights to refine price-controlled oil. The objective was to equalize crude oil costs among refiners and to subsidize small refiners, refiners suffering economic hardship, and various exotic energy projects. |
| Mandatory Supply Program | Mandated the sale of crude oil by major refiners to small refiners. |
| Supplier/Purchaser Rules | Mandated continuing supply to crude oil and product customers who bought in a designated base period, making it difficult for either supplier or customer to change. |
| Product Allocation | Required refiners and marketers to offer product to customers who purchased in an established base period in proportion to the customer's base-period purchases. |

## Crude Oil Production and Imports

Intense drilling, exploration, and enhanced oil recovery activity in the mid-1970s and early 1980s arrested the long-term decline in U.S. production and actually increased rates for some years. As shown in Figure 5, annual average U.S. production rose from a 20-year low of 8.1 MMB/D in 1976 to about 9 MMB/D in 1985.




SOURCE: EIA, Monthly Energy Review, August 1988.

Figure 5. U.S. Crude Oil Production.

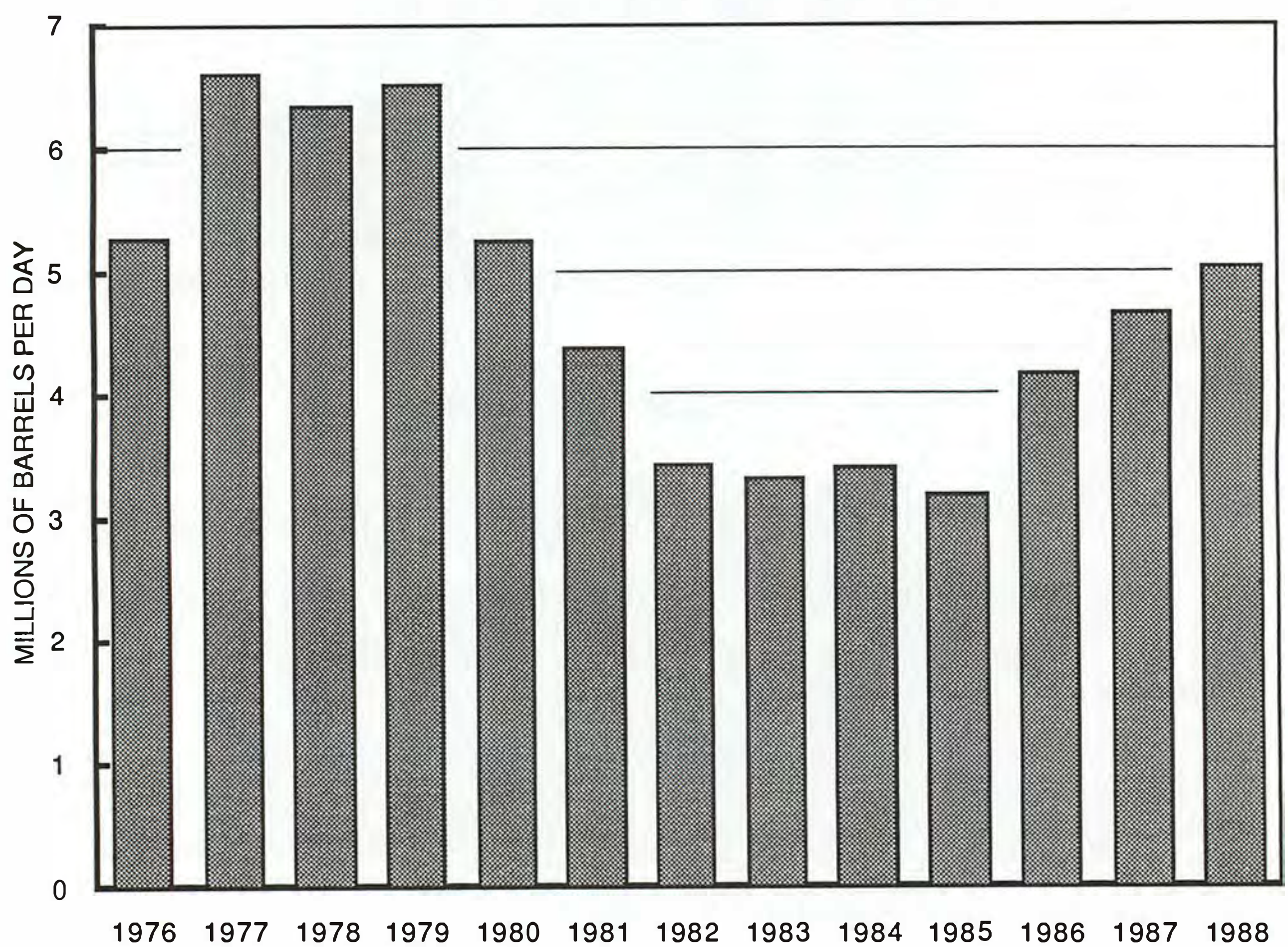
Much of this growth was from Alaska's North Slope, but stepped-up investment in the Lower-48 States made a sizable contribution.

On a percentage basis, the growth was not large; but it was a significant reversal of a long-term trend. It reflected a high level of industry activity fueled by the high level of then-current and expected prices in the period following the Iranian crisis. The precipitous price reductions of early 1986 cut off the cash flow needed to finance new projects, and within a few months, development activity was halved. The effect on production was almost instantaneous, as illustrated in Figure 5. Crude oil production declined an average of nearly 300 MB/D in 1986 -- all of which occurred in the last three quarters of the year. In 1988, production dropped to 8.1 MMB/D, and it is continuing to decline.

In the NPC's 1987 report, Factors Affecting U.S. Oil and Gas Outlook, the impact of the price collapse on various portions of the industry was described. The reaction was severe, but those firms remaining appear to be recovering. Companies have cut back outlays in line with lower revenues and are able to cope with the lower activity rates. Even the hard-hit oil service industry (e.g., drilling, geophysics, well service) seems to have returned to modest profitability.

Nevertheless, there is little prospect that industry activity will return to pre-1986 highs soon. Since many of the canceled projects were contingent on inflated crude oil prices, they would be economically wasteful at current values. Thus, for the near term, at least, further production decline seems certain.

With demand up and domestic crude oil production down, it is not surprising that imported crude oil volumes are again increasing. Figure 6 shows average crude oil import rates from 1976 through the first half of 1988. Imports bottomed out at 3.2 MMB/D in 1985 -- down more than 50 percent from the peak rate of 6.6 MMB/D in 1977. Since then, imports have increased steadily to an average rate of 5.0 MMB/D in 1988.




SOURCE: EIA, Monthly Energy Review, August 1988.

Figure 6. Crude Oil Imports.

## Product Mix

The mix of refined products in overall U.S. demand has changed in response to tightened environmental regulation and inter-fuel price competition. The most significant change has been the rapid decline in residual fuel demand. As shown below, residual fuel oil demand dropped 1.76 MMB/D between 1978 and 1987, and its share of total U.S. oil demand was halved.

U.S. RESIDUAL FUEL OIL DEMAND

| | 1978 | 1987 |
|---|---|---|
| Demand (MMB/D) | 3.02 | 1.26 |
| Percent of Total Oil Demand | 16% | 8% |

Residual fuel oil has been displaced by cheaper and/or cleaner fuels (natural gas, nuclear power, and coal) in the industrial-electric utility sector and by natural gas and distillate fuels in the commercial sector. Regulations limiting sulfur emissions and fuel sulfur content effectively eliminated much of the market for domestic residual fuel production and contributed to a significant change in the U.S. refinery configuration.

Other product changes have been less significant. Gasoline remains the principal product, accounting for about 43 percent of total U.S. petroleum consumption. The widely forecast shift to diesel-powered passenger cars failed to materialize. The phase-out of lead-based octane enhancers coupled with mandatory volatility reductions has pressed the industry's octane capacity, but price differentials between high and low octane stocks have supported octane capacity additions.

As shown below, gasoline consumption in 1987 was only slightly below the 1978 peak rate.

GASOLINE AND DISTILLATE DEMAND (MMB/D)

| | 1978 | 1983 | 1987 |
|---|---|---|---|
| Gasoline | 7.4 | 6.6 | 7.2 |
| Distillate | 3.4 | 2.7 | 3.0 |

The overall distillate demand figures mask a major shift from residential heating use to transportation (diesel) fuel. Currently, demand for residential heating accounts for only 16 percent of total distillate use. The most visible result of this change has been the reduction in inventory required to meet winter demand.

## Refinery Capacity

The sharp decline in petroleum product demand resulted in excess U.S. refinery capacity. Between 1979 and 1983, refinery input dropped more than 3 MMB/D. The end result was a vigorous, often brutal competition for the remaining market, which eventually shut down more than 3 MMB/D of uncompetitive refining capacity.

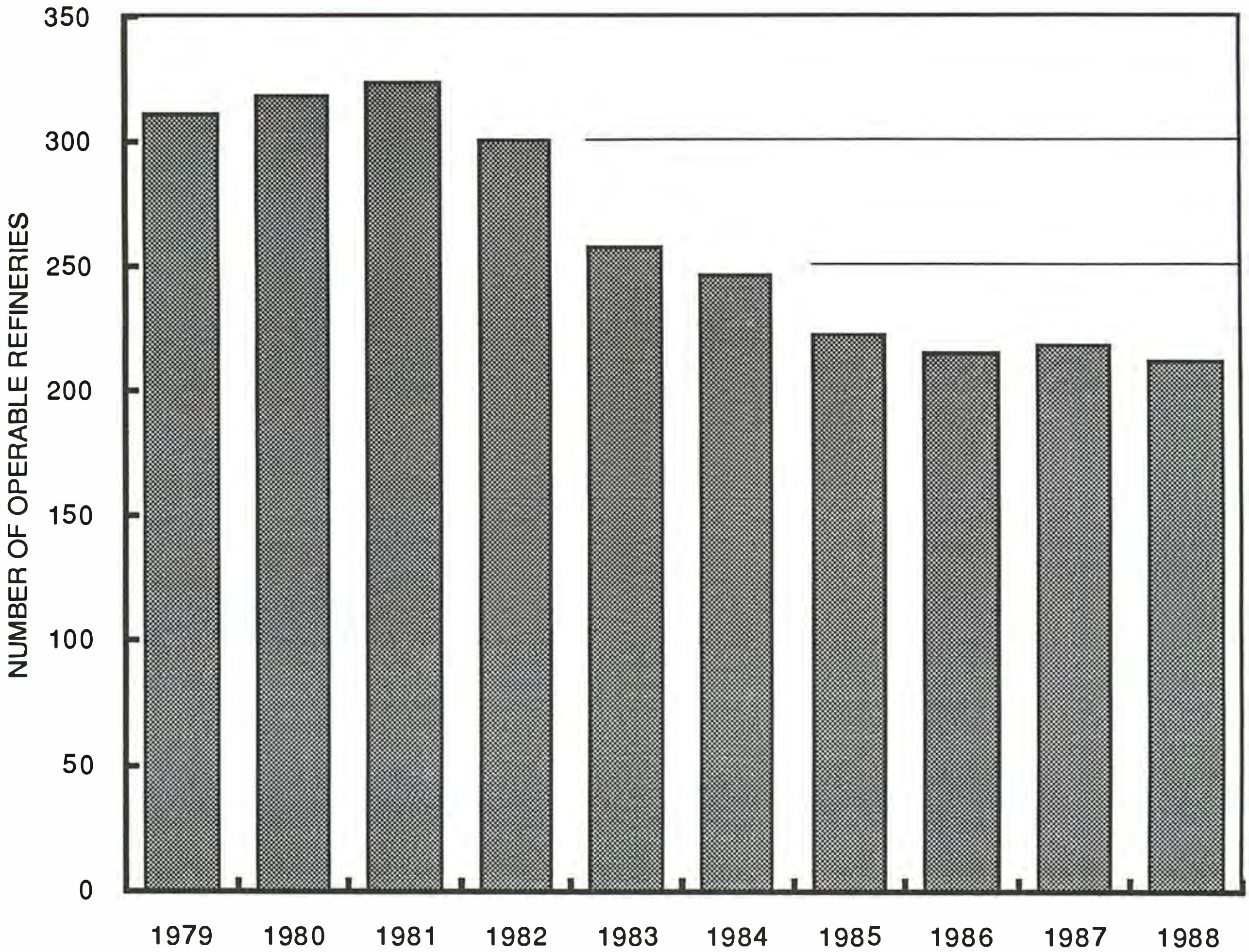
By 1981, declining demand had left almost a third of operable U.S. refining capacity idle. Refiners found it difficult to recover heavy fixed costs (capital, labor, taxes, etc.) at the lower throughput. Refinery margins were poor and would remain so for some years.

It is axiomatic that incremental product costs increase as a refinery becomes more fully loaded. But at reduced-run levels, many refiners found themselves with very low incremental or "next barrel" costs. The result was a paradoxical situation in which overall refining profits were poor, but the apparent margins on incremental or added production were very attractive. This situation invited the intense price competition that characterized the refining sector from 1980 through 1985.

Figures 7 and 8 show the results of that competition. Between the beginning of 1981 and 1986, a third of the refineries (over 100 plants) were permanently shut down. Basic distillation capacity was reduced about 17 percent in the same period.

Most of the idled plants were small and inefficient by current standards. Statistically, most were inland plants in PADDs II and III, although there were closures in every PADD. Inter-refinery competition was not the only element in the refinery shake-out. Many of the idled plants were originally designed to serve local markets that had changed significantly. Others were built to take advantage of price and allocation regulations. Stringent environmental regulations and declining residual fuel oil demand left some plants with product that was increasingly difficult to market. Further, high interest rates and unfavorable scale economics made it difficult for the smaller plants to justify new investment to remain competitive. (Not all the idled refineries were small; several plants in the 75 to 125 MB/D range were closed as well.)

By 1986, reduced capacity coupled with renewed demand growth raised refinery utilization above 80 percent, an economically efficient level. Capacity expansions began to appear in 1986, reflecting projections of improved profitability made earlier by some refiners. About 0.5 million barrels of net additional capacity were added during 1986 and 1987.




SOURCE: EIA, Petroleum Supply Annual, 1987.

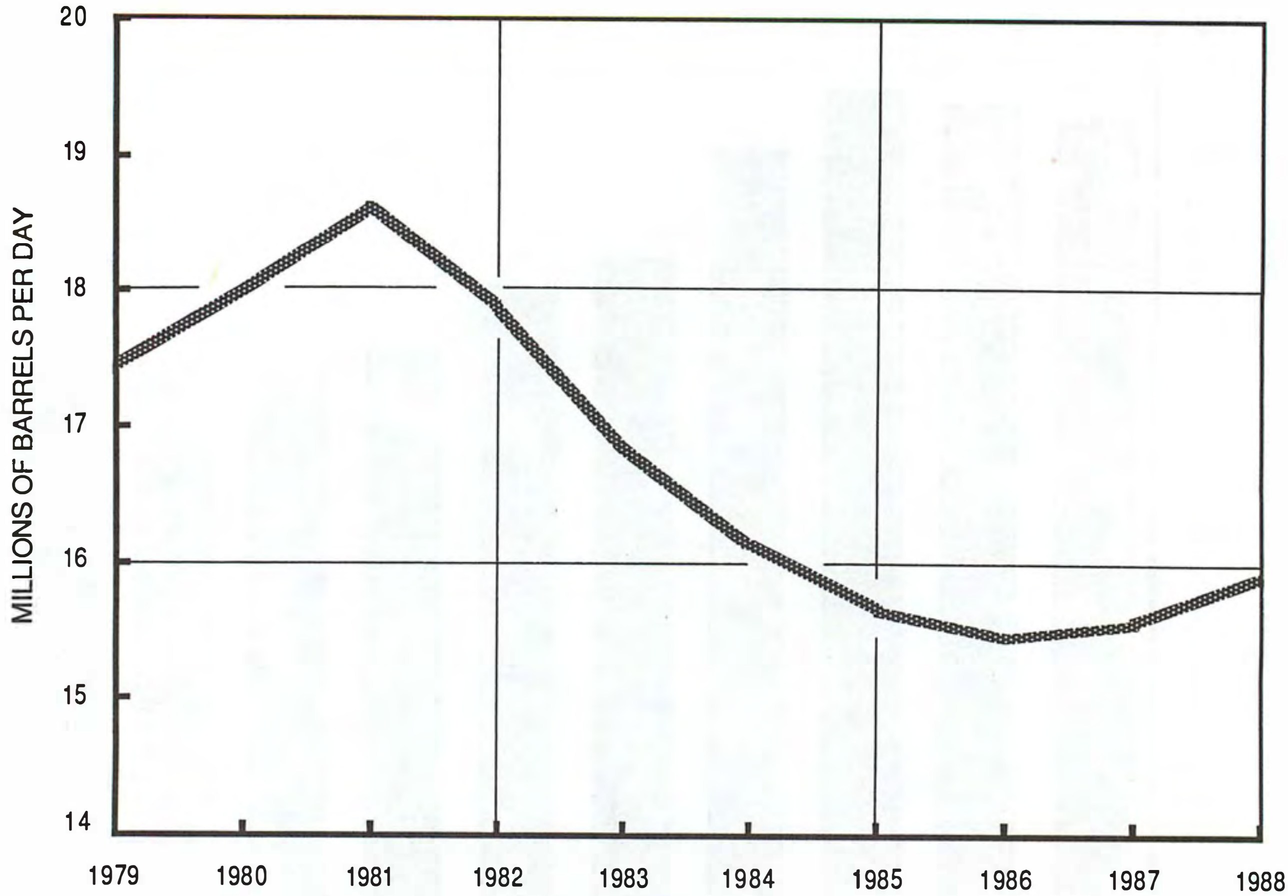
Figure 7. Number of Operable Refineries as of January 1.

The economic shake-out period was a difficult period for the refiners, but the net result is a more efficient and economical refinery system oriented to current product demands. The improvement in refinery margins has stimulated investment in new facilities, and further investment seems likely.

## Petroleum Transportation and Inventory

Declining demand and domestic production effectively unloaded most domestic crude oil and product pipelines, making some uneconomic. The Texoma and Seaway pipelines, which were built to bring imported crude oil from the Texas Gulf Coast to inland pipeline connections, became superfluous as imported crude oil volumes declined more than 3 MMB/D between 1979 and 1984. Both lines were converted to gas service by 1984.

The economic health of most product carriers has recovered with renewed growth in product demand, but the continued decline




SOURCE: EIA, Petroleum Supply Annual, 1987.

Figure 8. Operable Refinery Capacity -- 1979 to 1988.

in domestic crude oil production poses a longer-term problem for crude oil lines dedicated to moving field production to refineries.

The decline of crude oil and product prices after 1981 radically changed the perceived economics of inventory. Between 1973 and 1981, oil prices increased more than $30 per barrel -- an average of almost $4 per year. During this period, the value of oil in storage grew much faster than the carrying costs, making inventory a very good investment as well as a cushion against anticipated future supply shortages. As shown in Figure 9, total U.S. crude oil and product inventories increased by 27 percent between 1973 and year-end 1980.

The turnaround in crude oil prices beginning in 1981 and the growing crude oil surplus in the market reversed the economics of excess inventory. The industry "cashed" unnecessary inventory, bringing average volumes back to the level required to maintain efficient operation. As shown in Figure 9, overall inventory volumes have returned to the 1973-1974 level.

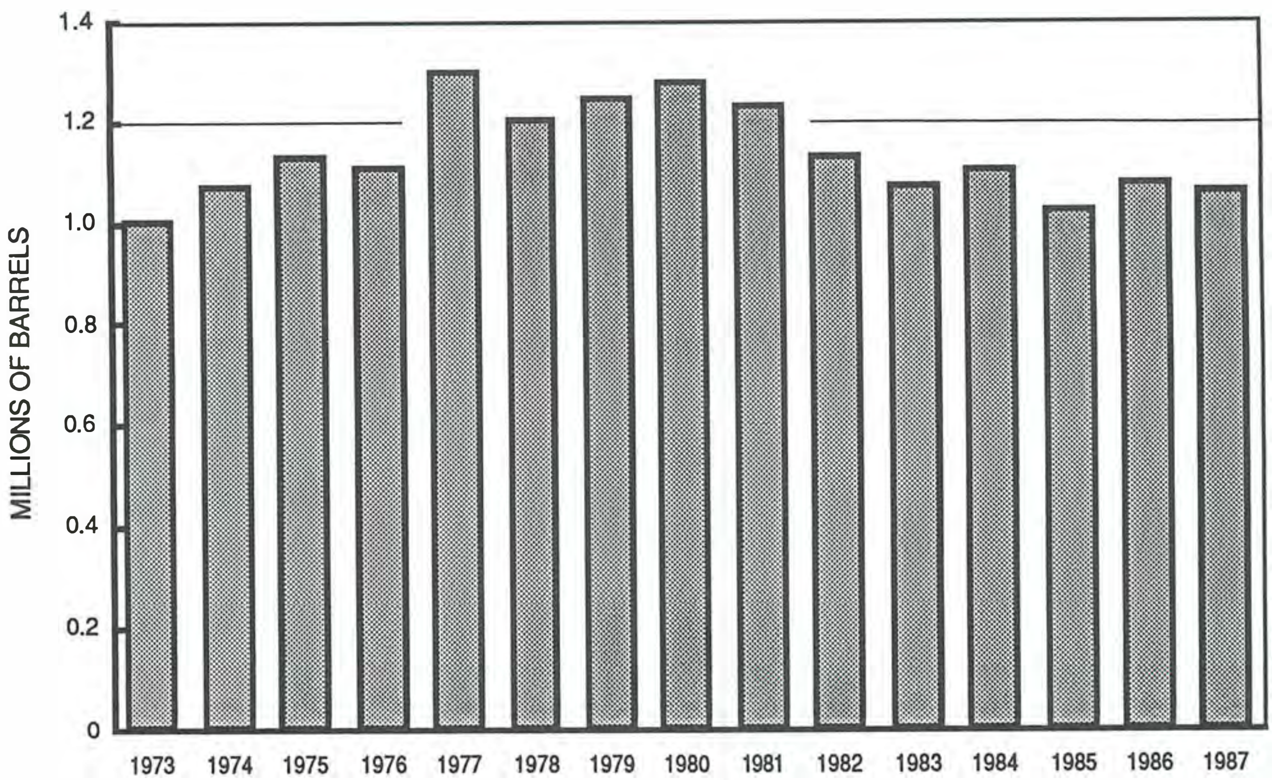
(In Volume IV of this study, Petroleum Inventories and Storage, and Volume V, Petroleum Liquids Transportation, changes in these system elements are reviewed in detail.)

## Natural Gas

The changes in the natural gas industry since 1979 reflect essentially the same supply-demand cycle as the oil business. However, the problems associated with change were aggravated by continued regulation.

In 1979, the dynamics of the natural gas system were almost entirely controlled by federal law and regulation. Prices for nearly all gas production were essentially fixed. With minor exceptions, gas pipeline companies were the sole purchasers of field gas production. Their tariffs and profit margins were also tightly regulated, but they were protected from competition in their allocated markets. There was competition among transmission companies for regulatory approval to serve new markets and for gas supply to support the proposed expansions, but in general, price was not a significant competitive element.

From 1938 through 1978, the interstate natural gas industry had been insulated from both the benefits and vicissitudes of inter-fuel competition and supply-demand pressures by the regulation of the Federal Power Commission and its successor, the




SOURCE: EIA, Petroleum Supply Annual, 1987.

Figure 9. U.S. Crude Oil and Product Inventory (Excluding Strategic Petroleum Reserve).

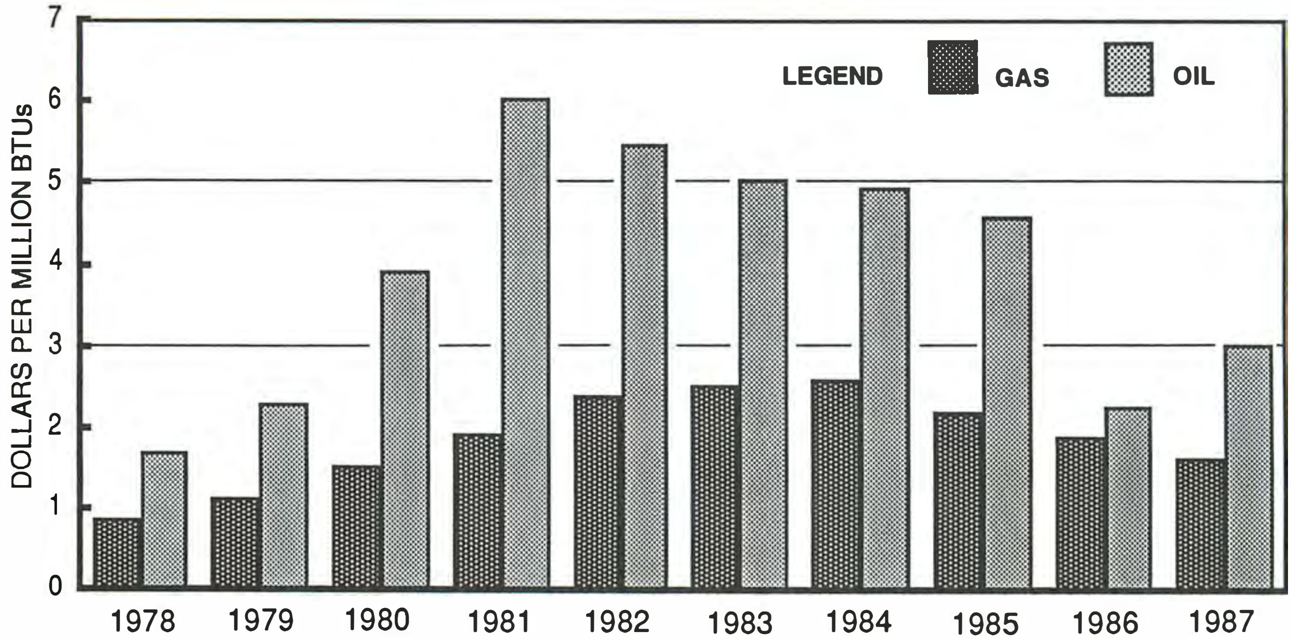
Federal Energy Regulatory Commission (FERC). The overall effect of regulation was to maintain gas prices at artificially low levels that did not support replacement of gas reserves. Gas shortages began to appear in the early 1970s, exacerbating U.S. energy problems resulting from both the Arab embargo and the Iranian revolution.

Legislation aimed at creating an incentive to find and produce additional gas reserves resulted in a maze of different controlled prices. By the early 1980s, gas of equivalent quality was being sold at wellhead prices ranging from $0.20 to $10 per million BTUs, depending on when and where it was discovered, the depth of the producing well, and whether it had first been sold in the interstate market. Further, with regulatory oversight, gas transmission companies were paying substantially more for certain gas supplies than they could sell them for at the delivery end of the pipeline. The rationale was that the high-priced gas could be "rolled in," or averaged, with very low-priced base volumes without raising the controlled consumer prices to a level where competition from alternative fuels would become a factor. As shown in Figure 10, average wellhead gas prices remained well below crude oil prices when measured on an equivalent energy basis (dollars per million BTUs).

Under the Natural Gas Policy Act of 1978 (NGPA), gas price ceilings were programmed to increase steadily with the addition of expensive new supplies, the escalation of some older gas prices at rates exceeding inflation, and the decontrol of various gas streams. In the past, wellhead gas prices paid by interstate transmission companies were nearly always at ceiling levels. As shown in Figure 10, wellhead gas prices continued to increase through 1984, although crude oil prices had been declining for three years; nevertheless, gas remained a bargain at the burner tip until 1986 when the sharp drop in crude oil prices closed the gap between gas and fuel oil suddenly and unexpectedly.

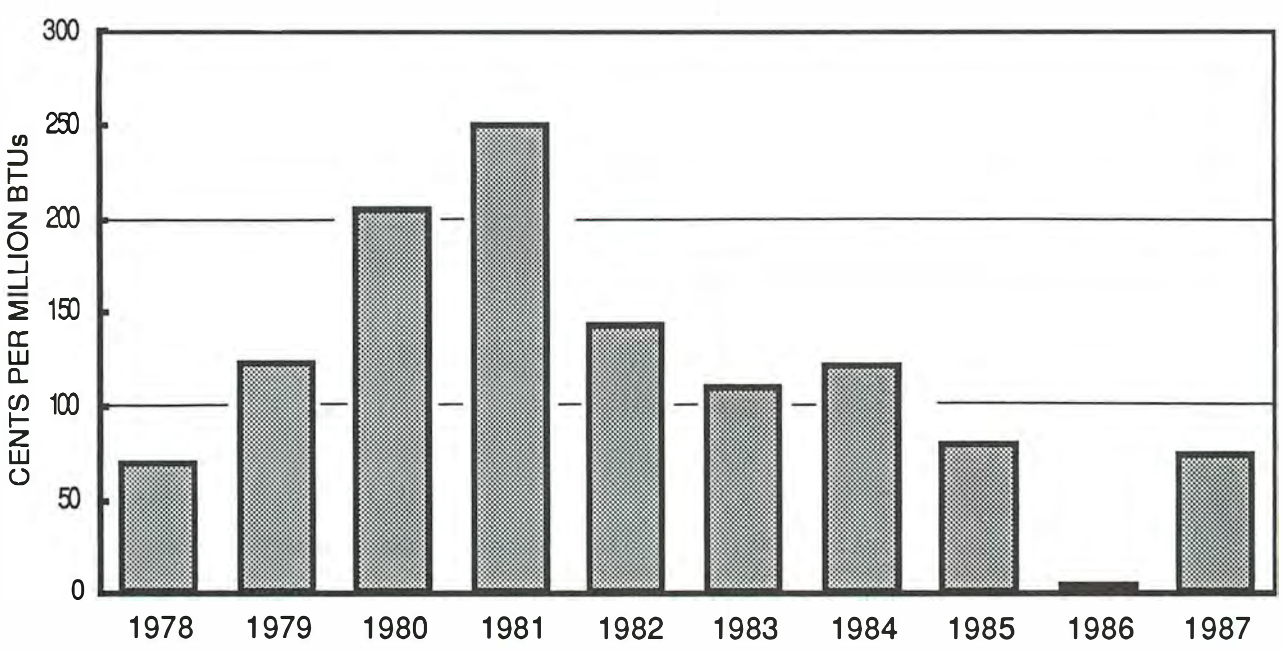
The magnitude of the price bargain is illustrated by Figure 11, which shows the average price advantage of natural gas over residual fuel in actual prices paid by electric utilities. In 1981, price regulations made gas prices an average of $2.50 per million BTUs cheaper than residual fuel. In view of the very large incentive for utilities to burn gas, it is not surprising that other regulations pursuant to the 1978 Fuel Use Act were required to restrict the use of gas by utilities.

The price increase permitted by the NGPA, and the psychology of shortage, caused burner tip prices to increase in the early 1980s. This led to increased conservation and a shift by some consumers to less expensive fuel. These changes coupled with the inability to price competitively to some classes of consumer resulted in an overall decline in gas demand roughly comparable to that experienced by oil, delayed by about two years. Figure 12 shows the decline of both oil and gas demand as a percentage of 1978 demand. By 1985, the gas consumption was about 12 percent below 1978.



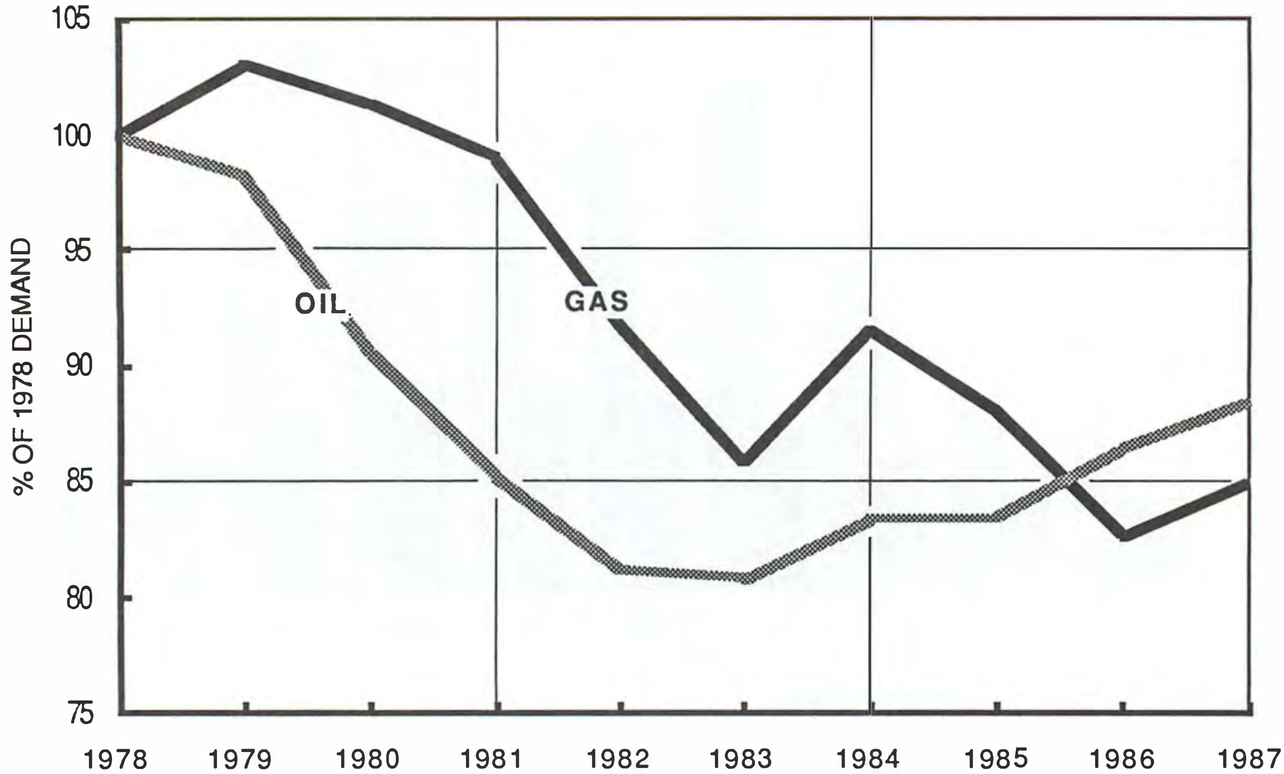

SOURCE: Energy Information Administration.

Figure 10. Average Crude Oil and Natural Gas Prices
at the Wellhead -- Excluding PADD V.




SOURCE: EIA, Monthly Energy Review, March 1988.

Figure 11. Incremental Price of Residual Fuel
Above Natural Gas to Electric Utilities.




SOURCE: EIA, Monthly Energy Review, March 1988, Tables 3.1a and 4.2.

Figure 12. Oil and Gas Demand as Percentage of 1987 Demand.

As gas demand decreased, gas supply kept increasing. In response to above-market prices offered to producers for new production, gas exploration and drilling surged; in 1981, new gas reserves exceeded annual production by a substantial amount for the first (and last) time since 1967. A rapidly increasing "bubble" of surplus gas appeared and began to affect the market.

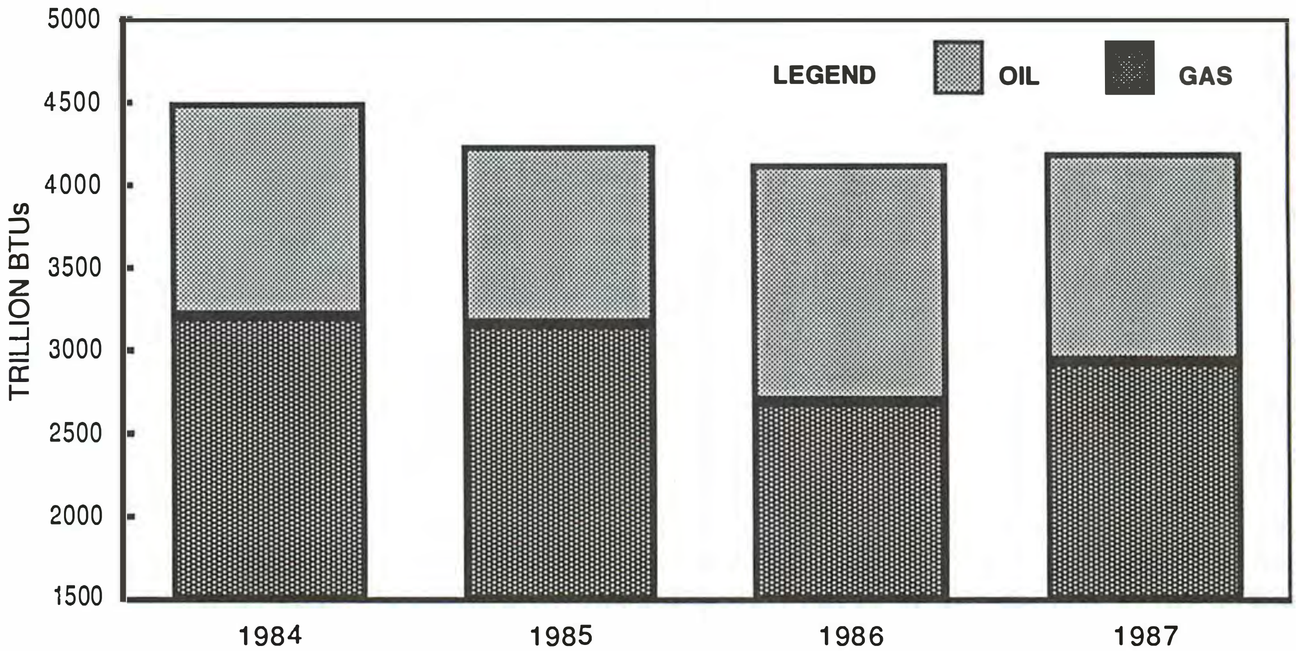
Despite the surplus, gas prices continued to rise; by 1985, the average consumer price was double that of 1979. It was recognized that rising prices in a shrinking market were eroding the competitive position of gas, but few in the industry anticipated the magnitude of the changes that would result.

The steep drop in oil prices in early 1986 reduced residual fuel prices by 50 percent in less than six months, and left gas uncompetitive with residual fuel in many industrial and utility markets. Despite regulatory inertia, gas companies acted quickly to cut gas prices and minimize the loss of sales volume. Gas prices to utilities were cut an average of $1 per million BTU in a nine-month period. Even so, there was a recognizable shift of utility demand to residual fuel, as shown in Figure 13. Much of the lost sales were recovered in 1987 as the result of responsive and innovative pricing by gas sellers.

The gas industry was thrust into the competitive market while still saddled with the burdens of previous regulatory miscalculations. Transmission companies found themselves with contractual obligations to take, or pay for, gas in excess of consumer demand and at fixed prices well above the levels their customers could or would pay. Some producers, particularly those with new production, discovered that they had no access to the market, even at deeply discounted prices. In an attempt to encourage competition, FERC issued orders relieving local gas distribution companies from certain contractual obligations to buy from interstate pipelines, but no comparable relief was offered to the pipelines. (Legislative and regulatory changes are described in detail in Volume III of this report, Natural Gas Transportation.)

The transition to a competitive, market-oriented business has been difficult and painful for producers and for gas transmission companies, but many of the problems are on the way to being resolved. Today, more producers have access to the market on a non-discriminatory basis. A substantial spot gas market has developed; and large users, including local distribution companies, routinely shop the market for bargains. Transmission companies compete vigorously with each other to supply gas or gas transportation.

The transition is continuing, but it is clear that the new gas system will be more responsive to market forces and more economically equitable to producers and consumers than in the past.




SOURCE: EIA, Monthly Energy Review, May 1988, Table 2.6.

Figure 13. Petroleum and Natural Gas Input to Electric Utilities.

The timing of the change is appropriate; gas demand is growing again, but producibility is continuing to decline. The gas "bubble" of surplus capacity is shrinking, and it appears that gas supply and demand are in better balance than they have been for many years. However, it is not certain when the "bubble" of surplus gas productivity will disappear. Ratification of the U.S.-Canada trade treaty substantially reduced regulatory barriers to gas imports on both sides of the border, and it is not yet clear whether U.S. gas supplies will be significantly affected.

## Electric Utility Generation Mix

In 1979, oil and natural gas provided 29 percent of the energy to generate electricity. At that time, this figure was already trending downward. Prior to 1973, it had been increasing. Since 1979, the volume of oil and gas consumed by electric generators has fallen precipitously. From the time of the first oil price shock in 1973-1974, electric utilities embarked on building programs to replace oil- and gas-fired electric generating capacity with nuclear and coal-fired capacity, due to the lower marginal cost of operation of coal and nuclear facilities. The second oil price shock of 1979-1980 only reinforced that trend, despite the simultaneous occurrence of the accident at Three Mile Island.

Electric utilities forecasted electricity demand to continue growing at a multiple of the rate of economic growth, as it had in the 1960-1973 period. Instead, the rate of growth dropped substantially, even relative to economic growth, as real electricity prices rose. (See Figure 14.) Utility projects, and especially coal and nuclear plants, take a long time to complete. As such plants were brought on stream in an environment of slower-than-expected electricity growth, they afforded even more opportunity to back out oil- and gas-fired generation.

The effect of this can be seen in the following graphs of oil, gas, coal, nuclear, and total energy consumed by electric utilities. (See Figures 15 and 16.)

Today, oil and gas play a marginal role in electricity generation, not just because the total amount of these fuels consumed is smaller, but because plants using these fuels often operate only in periods of high electricity demand. Due to very high fixed costs and low operating costs, coal, nuclear, hydropower, and geothermal plants are usually run as "base-load" plants -- that is, whenever they are not shut down for maintenance, they are operating to recover their fixed costs. Overly optimistic demand forecasts of the past left a glut of coal-fired generating capacity in certain areas such as the Midwest and the south-central United States. As a result, some coal-fired plants were relegated to use only in high demand periods. Generally, a utility does not desire this. Oil- and gas-fired generators typically have relatively high operating (i.e., fuel) costs, and

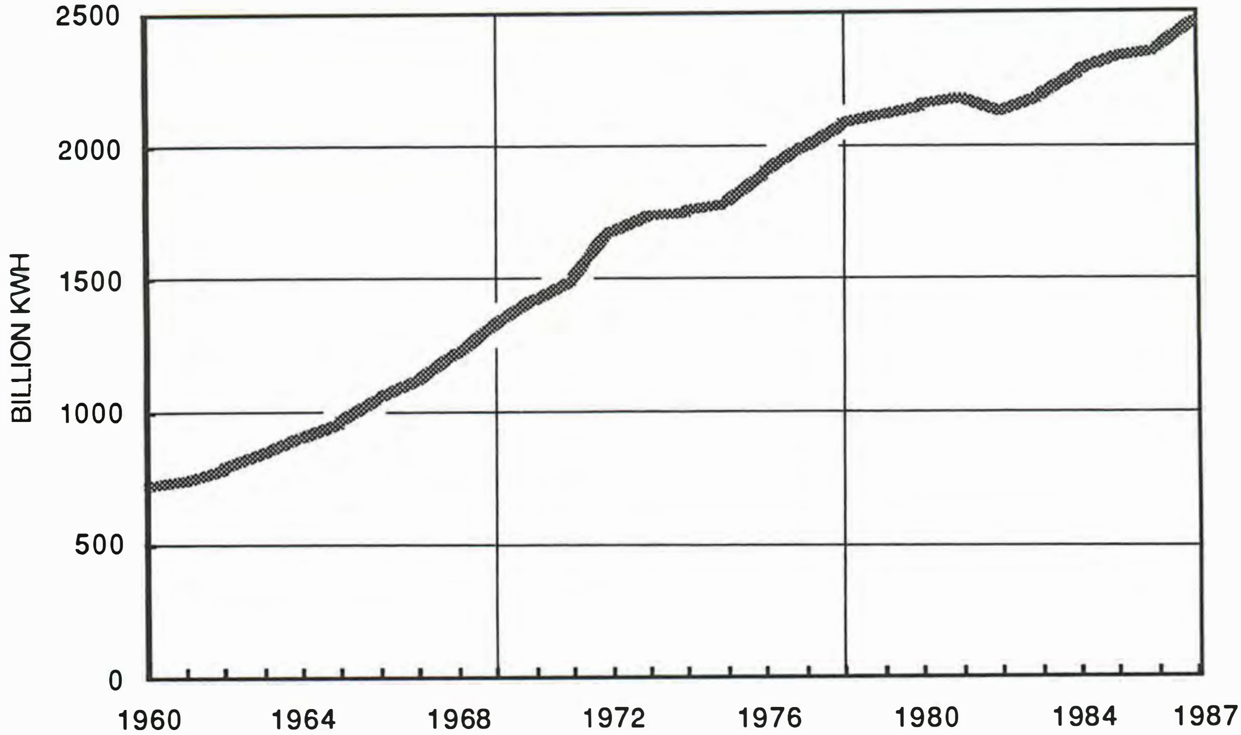



Figure 14. U.S. Electricity Sales.

low capital costs (near zero, in fact, for a fully amortized plant), and therefore tend to be operated for peaking purposes.

In recent years, utilities have again begun using natural gas for base load in new facilities. Several reasons for this are:

- Plans for "new" nuclear powerplants are non-existent, due to a combination of poor popular perceptions of nuclear safety, very high capital costs, cost overruns, and regulatory uncertainty. This has left some fast-growing areas concerned about imminent power shortages.

- Large decreases in gas prices, together with environmental advantages, have improved the competitiveness of gas versus coal in electric generation.

- Increasing construction of cogenerated power and other independent small powerplants is occurring, due to the 1978 Public Utilities Regulatory Practices Act (PURPA). These plants are considerably less capital intensive, and use fossil fuels, usually gas.

The course of future gas prices and availability will affect the future of this trend.

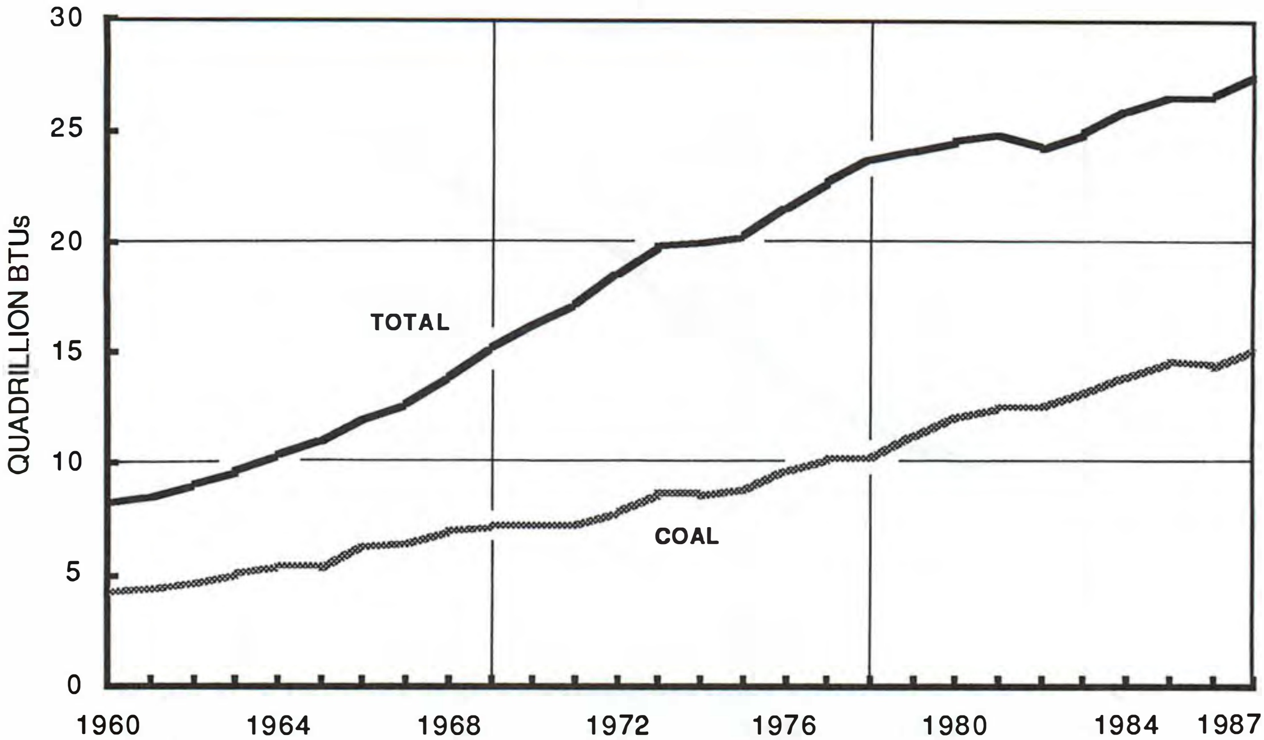



Figure 15. Energy Input to Electric Utilities.

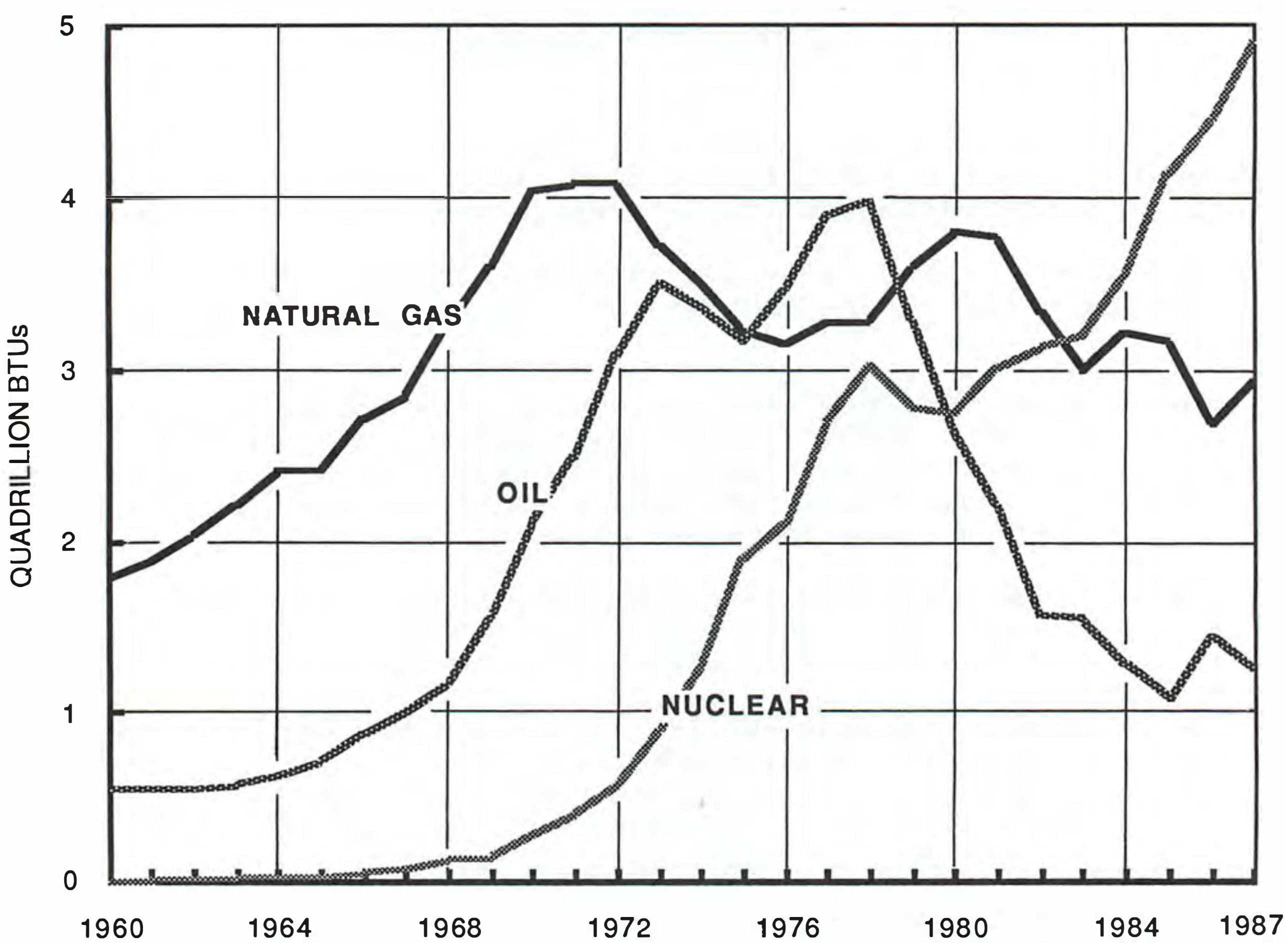



Figure 16. Energy Input to Electric Utilities.

OUTLOOK FOR THE FUTURE

The EIA is projecting no significant reversal of recent petroleum supply-demand trends. Table 7 shows EIA's forecast for 1992 along with historical data for comparison. Among the significant elements are:

- Continued modest growth in petroleum product demand. U.S. product requirements are projected to grow 1.1

TABLE 7

U.S. PETROLEUM DEMAND AND SUPPLY*
(Thousands of Barrels per Day)

| | 1979 | 1984 | 1987 | 1992 Proj. |
|---|---|---|---|---|
| Product Demand | | | | |
| Gasoline | 7,034 | 6,693 | 7,206 | 7,330 |
| Distillate | 3,311 | 2,845 | 2,976 | 3,440 |
| Residual Fuel | 2,826 | 1,369 | 1,264 | 1,470 |
| Other§ | 5,342 | 4,819 | 5,219 | 5,480 |
| Total Demand | 18,513 | 15,726 | 16,665 | 17,720 |
| Product Supply | | | | |
| Crude Production | 8,552 | 8,879 | 8,349 | 6,870 |
| Crude Imports¶ | 6,519 | 3,426 | 4,674 | 7,060 |
| Product Imports | 1,937 | 2,011 | 2,004 | 2,300 |
| Other** | 1,505 | 1,410 | 1,638 | 1,490 |
| Total Supply | 18,513 | 15,726 | 16,665 | 17,720 |
| Imports | 46% | 35% | 40% | 53% |

*Data and base case forecast from DOE Energy Information Administration.

§Includes LPG, jet fuel, kerosine, lubes, and other products.

¶Includes the Strategic Petroleum Reserve.

**LPG production, inventory flux, process gain, and other, less exports.

MMB/D between 1987 and 1992. This is equivalent to a 1.25 percent per year growth rate.

- Continued decline in domestic crude oil production. An overall decline averaging about 4 percent per year is forecast to reduce domestic crude oil supply by nearly 1.5 MMB/D between 1987 and 1992.

- Overall imported crude oil and product volume will be increased to about 53 percent of total demand by 1992, up from 40 percent in 1987.

TABLE 8

LOWER-48 STATES NATURAL GAS
HISTORICAL SUPPLY AND DEMAND
AND PROJECTED GROWTH
(Billion Cubic Feet)

| Demand | Actual 1979 | Actual 1987 | Projected 1992 |
|---|---|---|---|
| Residential | 4,958 | 4,302 | 4,597 |
| Commercial | 2,770 | 2,392 | 2,672 |
| Industrial | 6,807 | 5,827 | 6,420 |
| Electric Utility | 3,462 | 2,814 | 3,228 |
| Subtotal | 17,997 | 15,335 | 16,917 |
| Lease and Plant Fuel | 1,486 | 1,033 | 956 |
| Pipeline Fuel | 600 | 517 | 527 |
| Total* | 20,084 | 16,885 | 18,400 |
| Supply | | | |
| Dry Gas Production | 19,443 | 16,295 | 17,280 |
| Net Imports | 1,249 | 987 | 1,610 |
| Unaccounted/Inventory | (608) | (397) | (490) |
| Total* | 20,084 | 16,885 | 18,400 |
| Imports | 6% | 6% | 9% |

*Totals may not equal the sum of components due to independent rounding.

Source: EIA, Natural Gas Annual; EIA projection.

DOE projects crude oil prices will rise modestly with prices in the range of about $14.00 to $20.00 per barrel for 1992 in 1988 dollars. Obviously, demand growth would be influenced by where in this range future prices lie, but the price effect is not projected to be sufficient to alter projections significantly.

The forecast changes pose no substantial problems for the industry, but transportation of imported crude oil from tidewater to Midwest (PADD II) refineries may become a bottleneck. Crude oil import levels in 1992 are projected to be somewhat higher than in 1979, but two pipelines (Seaway and Texoma) that served this market were converted to natural gas service. The bottleneck, if it develops, is unlikely to be serious, as pipeline capacity can be expanded relatively quickly.

The modest growth poses no major strain on product transportation and distribution systems. Projected demand is not significantly greater than volumes handled in the past without difficulty.

Natural gas consumption in the Lower-48 States is projected to grow about 1.7 percent per year between 1987 and 1992 as shown in Table 8. Residential demand will grow at about 1.3 percent per year, and the aggregate of other demands at about 2 percent per year.

Growth at this level will be within the present system capacity, assuming approval of pending applications for pipeline expansion to the Northeast and to Florida and California.

# CHAPTER TWO

# THE SUPPLY SYSTEM UNDER NORMAL CONDITIONS

## OVERVIEW

The oil and gas industries have demonstrated a capability to respond rapidly to change. The physical flexibility of the manufacturing, transportation, and distribution systems is complemented by trading activities that effectively provide every part of the country with access to global supplies and world market prices. The system responds to economic incentive in both current operations and long-term investment.

The "system" is highly fragmented. Functional segments of the system (e.g., refiners, transporters, traders) operate independently and compete with other segments for a share of the overall profit margins, even within integrated companies. Within each function, companies compete vigorously for market share, for improved efficiency, and for higher earnings. Competing companies make independent decisions based on their own economics and their own views of the future.

Despite the enormous complexity of the system, it responds rapidly and predictably to economic incentive. Historically, the system has demonstrated that it can and will meet energy demands if it is physically possible and economically attractive.

This section reviews the principal elements of a system that has undergone substantial change over the last 10 years. Parts of the system are nearing the "capacity" estimates made only a few years ago; parts of the system are still underutilized and likely to remain so. Recent performance of the system indicates that there remains considerable flexibility within "normal" cost ranges.

## CRUDE OIL TRANSPORTATION AND STORAGE

The refining and marketing sector is a high-volume, low-margin business in which efficiency is essential to survival. Nowhere is that efficiency more evident than in the transportation of petroleum. Even with the basic efficiency of the physical system, transportation is a major cost for the industry, and a great deal of effort is directed to improving the competitive position of individual companies through investment, trades, and supply realignment.

This section outlines the physical and economic structure of the crude oil transportation system as it has changed over recent years.

## Principal Crude Oil Movements

Table 9 shows 1987 crude oil production and consumption by PADD. About 37 percent of U.S. crude oil production is from the oil fields of Alaska and California, in PADD V. The bulk of East-of-Rockies production is from Texas and Louisiana (PADD III) and from Oklahoma and Kansas in PADD II. (Table 10 shows similar data for 1979.)

Most domestic crude oil is refined in the same region in which it is produced. Table 9 indicates that inter-PADD movements of domestic crude oil totaled only 1,181 MB/D (about 14 percent of production) in 1987, and half of that volume reflected the movement of surplus Alaska and California offshore oil from PADD V.

TABLE 9

1987 CRUDE OIL SUPPLY AND DEMAND
(Thousands of Barrels per Day)

| | Total | PADD I | PADD II | PADD III | PADD IV | PADD V |
|---|---|---|---|---|---|---|
| **Supply** | | | | | | |
| Field Production | 8,349 | 41 | 865 | 3,827 | 561 | 3,055 |
| Imports* | 4,674 | 1,111 | 870 | 2,431 | 65 | 197 |
| Domestic Inter-PADD | - | 60 | 1,121 | (339) | (237) | (605) |
| Inventory/Other | 16 | 39 | 4 | (80) | 48 | 5 |
| Total§ | 13,039 | 1,251 | 2,860 | 5,839 | 437 | 2,652 |
| **Demand** | | | | | | |
| Refinery Input | 12,854 | 1,251 | 2,844 | 5,839 | 437 | 2,483 |
| Exports | 151 | - | 16 | - | - | 134 |
| Direct Use | 34 | - | - | - | - | 34 |
| Total§ | 13,039 | 1,251 | 2,860 | 5,839 | 437 | 2,652 |

*Imports include 73 MB/D to SPR in PADD III; imports are volumes refined in the PADD.

§Totals may not equal sum of components due to independent rounding.

Source: EIA, Petroleum Supply Annual, 1987.

TABLE 10

1979 CRUDE OIL SUPPLY AND DEMAND
(Thousands of Barrels per Day)

| | Total | PADD I | PADD II | PADD III | PADD IV | PADD V |
|---|---|---|---|---|---|---|
| Supply | | | | | | |
| Field Production | 8,552 | 146 | 871 | 4,556 | 608 | 2,371 |
| Imports* | 6,519 | 1,432 | 1,526 | 2,969 | 65 | 528 |
| Domestic Inter-PADD | - | 5 | 1,369 | (957) | (186) | (232) |
| Inventory/Other | (174) | 67 | 34 | (173) | (7) | (98) |
| Total§ | 14,897 | 1,650 | 3,800 | 6,395 | 480 | 2,569 |
| Demand | | | | | | |
| Refinery Input | 14,648 | 1,646 | 3,729 | 6,390 | 477 | 2,405 |
| Exports | 235 | 4 | 69 | - | 2 | 159 |
| Direct Use | 14 | - | 2 | 5 | 1 | 5 |
| Total§ | 14,897 | 1,650 | 3,800 | 6,395 | 480 | 2,569 |

*Imports include 67 MB/D to SPR in PADD III; imports are volumes refined in the PADD.

§Totals may not equal sum of components due to independent rounding.

Source: EIA, "Supply, Disposition, and Stocks of all Oils by PAD Districts and Imports into the United States, by Country, Final 1979," Energy Data Reports, February 1981.

## Intra-PADD Movements

For the bulk of East-of-Rockies production, transportation from the wellhead to a refinery is a two-step process:

- Gathering is the collection of crude oil from individual properties in small-diameter pipelines or by truck for input into a large-diameter pipeline.
- Mainline or trunkline transportation is the movement of the "gathered" oil to refineries.

Originally, most crude oil was gathered via pipeline networks connecting separate properties in an oilfield. Gathering systems were often owned by the mainline company to which they were connected and operated as regulated common carriers. The great bulk of domestic crude oil production was first purchased at the input to the gathering system (commonly, if not accurately, called a "wellhead" purchase) by refiners who paid all downstream gathering and transportation costs.

Crude oil production that was too small or too distant to justify a gathering pipeline connection was trucked to a mainline input point. Originally trucked volume was small, but volumes began to increase as pipeline companies found that their regulated tariff structure (based on long pipeline life and steady throughput) made it uneconomic to build to properties that were expected to have a high decline and short life.

As trucked volumes increased, crude oil resellers appeared to compete with regulated tariff haulers. Resellers buy crude oil at the wellhead and resell it at a mainline input point. Because they do not transport non-owned oil, resellers were not classified as public carriers; and thus they were able to provide effective truck transportation for less than the regulated tariffs. Their private-carrier status also permitted them to build pipeline gathering systems without the tariff restrictions that applied to common carriers.

Today it is estimated that resellers gather almost 25 percent of East-of-Rockies production -- mostly by truck. Resellers still act effectively as transporters for others, but they also buy substantial quantities of crude oil for their own accounts. They sell this crude oil at mainline points on both long- and short-term arrangements. At large pipeline hubs (e.g., Midland, Cushing, St. James) a significant secondary market has developed. Most domestic spot prices are quoted at these pipeline hubs. (For that reason, spot prices are not directly comparable to posted prices, which apply to wellhead sales.)

Gathering costs can range from a few cents per barrel to over $2 per barrel for crude oil trucked long distances. On average, gathering costs are larger than mainline transportation tariffs. Table 11 illustrates a typical range of costs to move crude oil from the Midland area of West Texas to the Beaumont/Port Arthur refinery center.

Not surprisingly, much of the crude oil transportation dynamics are centered on minimizing gathering costs. For example, refiners often negotiate exchanges that allow them to deliver their purchased crude oil to a nearby mainline and exchange it for crude oil more economic to their refineries. The effect is to minimize gathering expense without altering either exchange partner's overall crude oil supply.

Small volumes of crude oil are gathered and/or transported to refineries by barge.

In PADD V, California production of about 1.1 MMB/D is gathered and transported to local refineries in much the same

TABLE 11

TYPICAL CRUDE OIL TRANSPORTATION COSTS
WEST TEXAS TO BEAUMONT/PORT ARTHUR
(Dollars per Barrel)

| | Pipeline Gathering | Truck Gathering |
|---|---|---|
| Gathering | 0.10 to 0.60 | 0.50 to 1.40 |
| Mainline | 0.40 to 0.60 | 0.40 to 0.60 |
| Total | 0.50 to 1.20 | 0.90 to 2.00 |

fashion as East-of-Rockies production. Most ANS crude oil production of about 2 MMB/D is moved via the TAPS pipeline to the port of Valdez and then by American-flag tanker to the Puget Sound area of Washington and to California and Hawaii. About 600 MB/D is shipped to East-of-Rockies locations, and somewhat over 100 MB/D is moved to the Virgin Islands.

Because of the remote geographic location of ANS production and the widely disparate markets in which the crude oil is sold, it is impractical to establish a single wellhead price for the crude oil. Instead, the value of ANS crude oil is established separately for volumes sold in each major market area, and this value is "netted back" to the wellhead by subtracting transportation costs. The "net back" price is the basis for establishing state royalty and severance tax obligations. In effect, Alaska shares in the cost of transportation of ANS to market; this sharing has been and will continue to be a significant factor in the transportation dynamics of Alaskan crude oil.

### Imported Crude Oil and Inter-PADD Movements

Crude oil imports in 1987 averaged almost 4.7 MMB/D. Pipeline deliveries from Canada accounted for about 608 MB/D, but the bulk of imported crude oil was delivered by foreign-flag tank ships. Table 12 shows the geographic mix of crude oil imports in 1987.

The relatively long transit times for many foreign crude oils are a significant factor in crude oil supply planning and dynamics. As illustrated in Table 13, foreign crude oil may be in transit for up to 45 days after loading. For a refiner, long transit times mean reduced supply flexibility and higher levels of inventory and inventory cost. In the highly volatile market of recent years, long transit times also increased the risk of adverse market changes between purchase and delivery. To offset these disadvantages, some producers have sold long-haul crude oil from transshipping terminals in the Caribbean or priced it based on the market at or near the delivery date.

TABLE 12

PERCENTAGE OF MARINE DELIVERIES OF FOREIGN CRUDE OIL IN 1987
(By Region)

| | | |
|---|---|---|
| Latin America | 32% | |
| Middle East | 26% | |
| Africa | 23% | Total Marine |
| Europe | 9% | Deliveries of |
| S.E. Asia | 7% | Foreign Crude Oil |
| Other | 3% | 4,066 MB/D |

Source: EIA, Petroleum Supply Annual, 1987.

TABLE 13

VARIOUS TYPICAL DELIVERY PERIODS

| | Days |
|---|---|
| Mexico/Houston/St. James | 2 to 3 |
| Alaska to West Coast | 7 |
| Venezuela/Gulf Coast | 5 |
| North Sea/Gulf Coast | 17/20 |
| Middle East/Gulf Coast | 40/45 |
| Far East/Panama/Gulf Coast | 40/45 |
| Alaska/Panama Pipeline/Gulf Coast | 20 |
| West Africa/Gulf Coast | 20 |

More than 75 percent of foreign crude oil is consumed in PADDs I and III. Most of this crude oil is delivered directly by tanker to coastal refineries or to adjacent marine terminals. However, a significant volume of foreign crude oil is transported by pipeline into inland PADDs. Canadian crude oil is delivered into PADDs I, II, and IV. (PADDs III and V also received very minor volumes in 1987.) About 400 MB/D of waterborne foreign crude oil is received in PADD III and transported by pipeline to PADD II.

Long-haul crude oil movements on inter-PADD systems are relatively low cost, as indicated in Table 14. This cost has been a factor in the location and competitive position of inland refineries.

Inter-PADD crude oil movements have been the most volatile segment of the pipeline business in recent years and are likely

TABLE 14

TYPICAL CRUDE OIL PIPELINE TARIFFS*
(Dollars per Barrel)

| Route | Typical Tariff |
|---|---|
| Louisiana to Chicago | 0.50 |
| Midland, TX to Chicago | 0.70 |
| Cushing, OK to Chicago | 0.44 |

*Excludes gathering cost to mainline input; includes loss allowances.

to remain so. Figure 17 shows approximate inter-PADD crude oil flows in 1987. Figure 18 is a similar chart for 1979, which illustrates the major changes in inter-PADD volumes.

Crude oil movements from PADD III to PADD II have been the most affected. In 1979, pipeline shipments of foreign and domestic crude oil between PADD III and PADD II totaled more than 2.6 MMB/D. By 1987, a combination of lower demand and increased Canadian imports in PADD II had reduced the shipments to PADD I by more than 1.2 MMB/D (to 1.4 MMB/D). The decline left long-haul pipelines significantly underutilized. Two pipelines (Seaway and Texoma) were shut down and converted to gas service; these lines were built in the 1970s to bring crude oil from the Gulf Coast to connect to inland pipeline hubs in Texas and Oklahoma (PADD II). Despite these shutdowns, there is about 30 percent spare capacity in the remaining lines.

Crude oil movements from PADD III to PADD II are expected to increase in the next five years, as increasing demand and declining production increase the need for imported crude oil. By 1992, U.S. crude oil import volume is projected to be slightly above the 1979 level and more than 2 MMB/D higher than 1987.

Capacity in existing long-haul pipelines serving PADD II will be adequate to handle the projected demand, but a potential bottleneck could develop in capacity to transport crude oil to the inland origin points of some pipelines. It is expected that this bottleneck will be avoided by a combination of:

- Utilization of existing spare capacity

- Shifting inland domestic crude oil production to PADD II and replacing it with imported crude oil at coastal refineries in PADD III

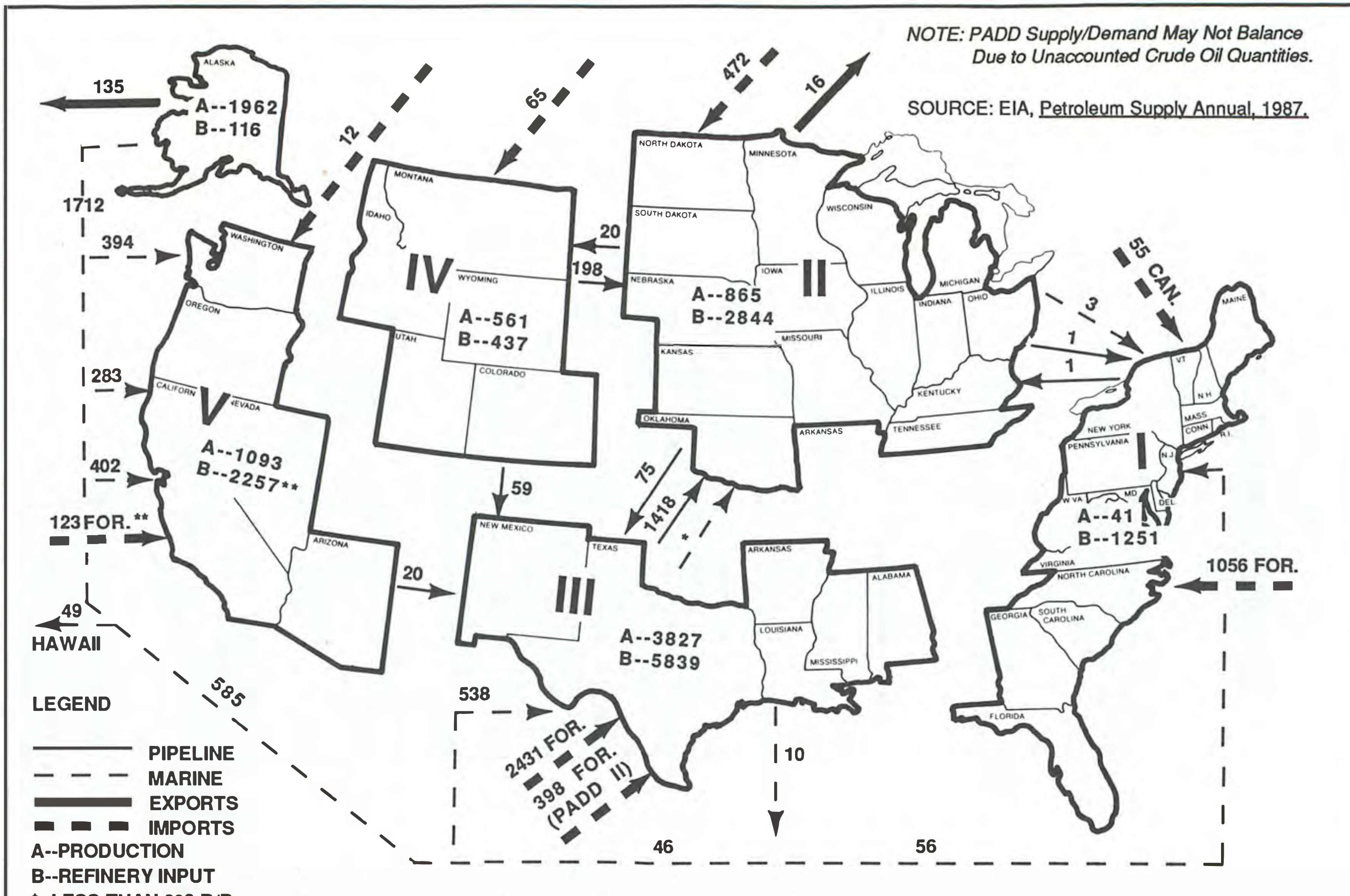



Figure 17. 1987 Inter-PADD Crude Oil Movement (Thousands of Barrels per Day).

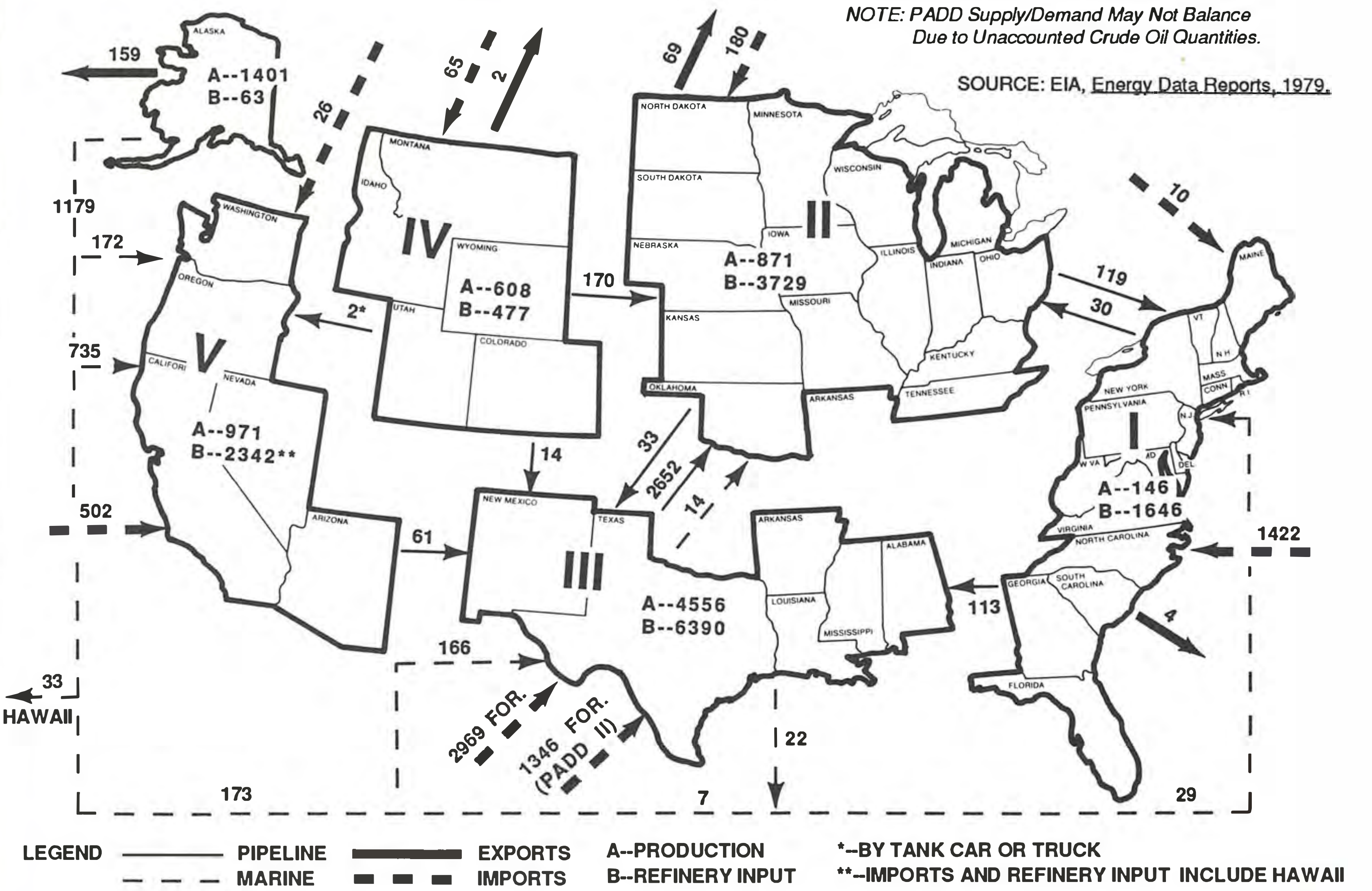



Figure 18. 1979 Inter-PADD Crude Oil Movement (Thousands of Barrels per Day).

- Construction or conversion of new capacity to deliver imported crude oil to inland centers already connected to long-haul pipelines serving PADD II.

Reversal of underutilized crude oil lines that now run from inland oil fields to coastal refineries may become attractive as production declines. One such reversal, an ARCO line between the Houston area and Oklahoma, has recently been completed.

Most other inter-PADD pipeline movements are projected to decline as local refineries consume a larger share of declining production. A possible exception may be shipments of California and Alaska crude oil to Texas on the new All-American pipeline system.

Figure 19 is a map of the major crude oil pipelines in the United States. A more detailed discussion of pipeline facilities by PADD is presented in Appendix C, which contains a map of crude oil pipelines in each PADD and a brief review of current capacity utilization.

## The Physical Systems

Within the United States, pipelines are the principal mode of crude oil transportation. This section presents data on other crude oil transportation modes of importance.

### Tank Ships

In 1987, the U.S. imported more than 4 MMB/D of foreign crude oil by tank ship. Essentially all of this volume moved in foreign-flag vessels. Currently, there is a substantial surplus of foreign flag vessels as illustrated in Table 15. This table lists both crude oil and product tankers by size range and identifies a surplus capacity of roughly 10 percent in ships that are presently idle. These figures do not include spare capacity in combined dry cargo-crude oil carriers. Further, a substantial increase in effective carrying capacity can be obtained from the active fleet by merely increasing ship speed. In periods of surplus tonnage and low charter rates, ship owners operate tankers well below design speed to reduce bunker fuel expense.

In view of the large additional carriage capacity that can be called up from the existing fleet with higher charter rates, it is unlikely that foreign-flag tankers will constrain crude oil supply in the next five years. However, world shipbuilding capacity remains substantially underutilized, and the world tanker fleet could be increased if economic demand were to develop.

The United States is not a major user of foreign tankers. Table 16 shows the movement of crude oil to the United States and the rest of the world. Excluding Canadian imports, which are delivered by pipeline, waterborne crude oil imports to the United States averaged only about 25 percent of worldwide volume, and much of that involved relative short-haul tanker voyages.

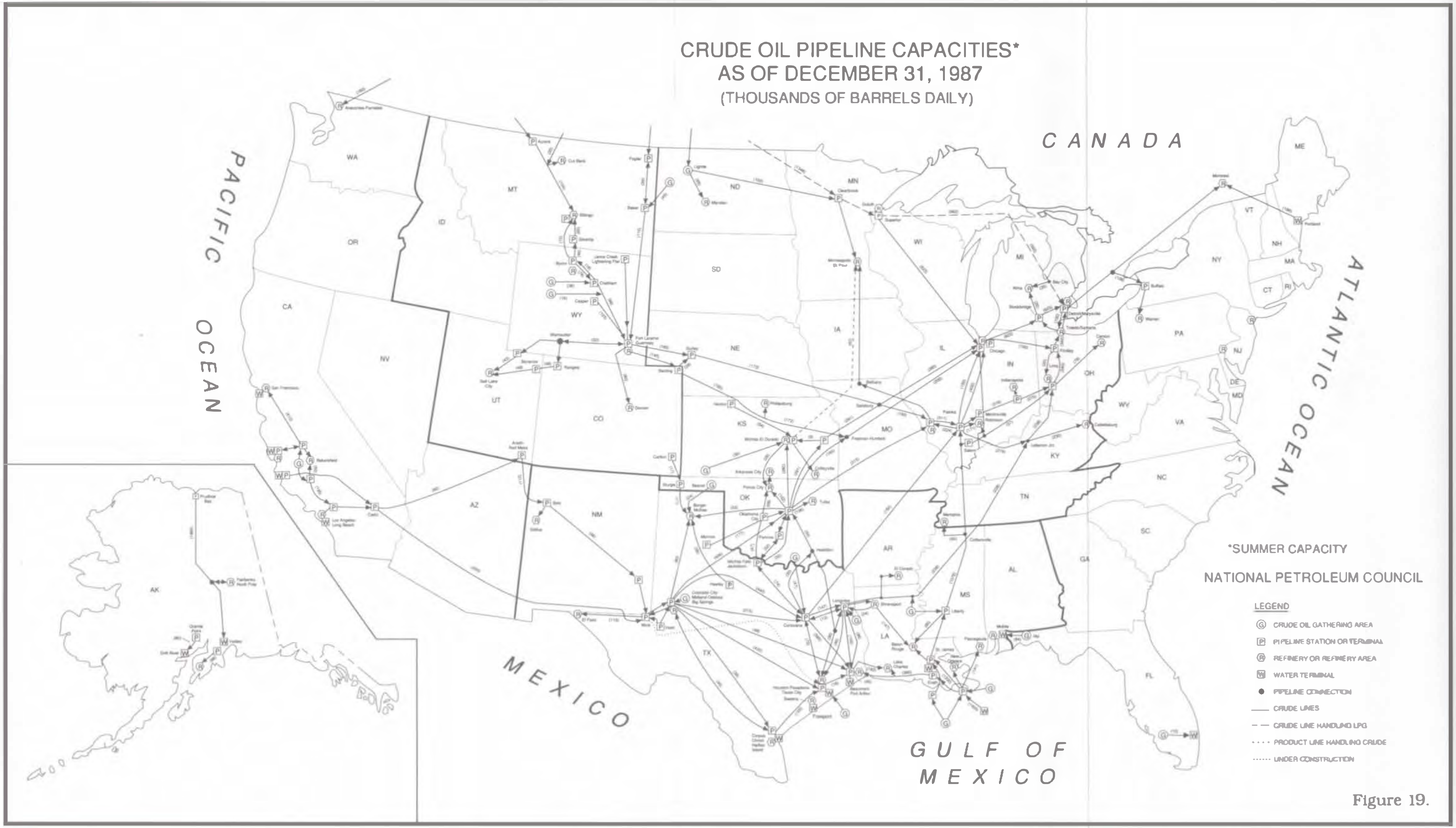

CRUDE OIL PIPELINE CAPACITIES*
AS OF DECEMBER 31, 1987
(THOUSANDS OF BARRELS DAILY)
CANADA
PACIFIC OCEAN
ATLANTIC OCEAN
MEXICO
GULF OF MEXICO
WA
OR
CA
NV
ID
MT
WY
UT
AZ
CO
NM
ND
SD
NE
KS
OK
TX
MN
IA
MO
AR
LA
WI
IL
MI
IN
OH
KY
TN
MS
AL
GA
FL
SC
NC
VA
WV
PA
NY
VT
NH
ME
MA
CT
RI
NJ
DE
MD
AK
*SUMMER CAPACITY
NATIONAL PETROLEUM COUNCIL
LEGEND
CRUDE OIL GATHERING AREA
PIPELINE STATION OR TERMINAL
REFINERY OR REFINERY AREA
WATER TERMINAL
PIPELINE CONNECTION
CRUDE LINES
CRUDE LINE HANDLING LPG
PRODUCT LINE HANDLING CRUDE
UNDER CONSTRUCTION

Figure 19.

TABLE 15

WORLD FLEET
SHIPPING STATISTICS AND ECONOMICS*
(Million Deadweight Tons)

| Vessel Size MDWT | Total | Active | Idle |
|---|---|---|---|
| 10-25 | 8.8 | 8.6 | 0.3 |
| 25-30 | 5.7 | 5.6 | 0.1 |
| 30-35 | 6.6 | 6.5 | 0.1 |
| 35-45 | 10.9 | 10.6 | 0.3 |
| 45-55 | 5.2 | 5.0 | 0.1 |
| 55-65 | 8.3 | 8.1 | 0.2 |
| 65-80 | 9.3 | 8.9 | 0.4 |
| 80-90 | 19.4 | 18.9 | 0.5 |
| 90-100 | 7.7 | 7.3 | 0.5 |
| 100-125 | 11.4 | 11.0 | 0.4 |
| 125-150 | 17.6 | 17.2 | 0.4 |
| 150-200 | 8.3 | 8.0 | 0.3 |
| 175-200 | 2.4 | 2.4 | - |
| 200-225 | 3.7 | 2.6 | 1.1 |
| 225-300 | 75.8 | 65.9 | 9.8 |
| 300+ | 30.1 | 20.7 | 9.5 |
| | 231.3 | 207.3 | 24 (10.4% idle) |

*Totals may not equal the sum of components due to independent rounding.

Source: Extracted from Drewry's Shipping Statistics and Economics #216, October 28, 1988.

Under the Jones Act, foreign-flag vessels may not trade between U.S. ports. Internal U.S. traffic is restricted to ships built in the United States and operated and manned by U.S. entities. This restriction protects American shipping from competition from foreign vessels, which are cheaper to build and less expensive to man.

The U.S. Maritime Administration (MARAD) indicates that there are 158 liquid-carrying vessels aggregating 10.3 million deadweight tons (MMDWT) licensed to trade under the Jones Act. Table 17 shows the size range of these ships. Not all these ships are in active service, and many are not available for the commercial movement of crude oil or petroleum products.

TABLE 16

1987 WORLD CRUDE OIL MOVEMENTS
(Thousands of Barrels per Day)

| | To | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| From | U.S. | Canada | Latin America | Western Europe | Africa | Southeast Asia | Japan | Austral-asia | Rest of World | Destin. Unknown* | Total Exports |
| United States | -- | 17 | 127 | 1 | -- | 2 | -- | 2 | -- | -- | 149 |
| Canada | 610 | -- | -- | 1 | -- | -- | 15 | -- | -- | -- | 626 |
| Latin America | 1,301 | 52 | -- | 240 | -- | 21 | 180 | -- | -- | 288 | 2,082 |
| Western Europe | 356 | 140 | 11 | -- | 24 | -- | -- | -- | -- | 18 | 549 |
| Middle East | 986 | 33 | 206 | 2,891 | 320 | 1,245 | 2,156 | 65 | 737 | -- | 8,639 |
| North Africa | 159 | -- | 11 | 1,322 | -- | 36 | 17 | -- | 394 | -- | 1,939 |
| West Africa | 819 | 26 | 62 | 822 | 40 | 2 | 2 | -- | 36 | -- | 1,809 |
| East and South Africa | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0 |
| South Asia | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0 |
| South East Asia | 278 | -- | 9 | -- | -- | -- | 572 | 53 | 4 | 55 | 971 |
| Japan | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 0 |
| Australasia | 49 | -- | -- | -- | -- | 32 | 7 | -- | -- | -- | 88 |
| USSR, E. Europe, & China | 69 | -- | 161 | 863 | 28 | 205 | 250 | -- | 1,531 | 57 | 3,164 |
| Total Imports | 4,627 | 268 | 587 | 6,140 | 412 | 1,543 | 3,199 | 120 | 2,702 | 418 | 20,016 |

*Includes in-transit losses and volume change, minor movements, and other.

Source: BP Statistical Review of World Energy.

TABLE 17

1988 JONES ACT TANKER FLEET*

| Vessel Size (MDWT) | No. of Ships |
|---|---|
| 15-30 | 21 |
| 30-50 | 72 |
| 50-80 | 27 |
| 80-100 | 11 |
| 100-150 | 10 |
| 170-270 | 17 |
| Total | 158 |

*Vessels include tankers in lay-up, worldwide and domestic service, clean product, crude oil, chemical, residual fuel oil, grain, military sealift command, and other service.

Source: U.S. Maritime Administration.

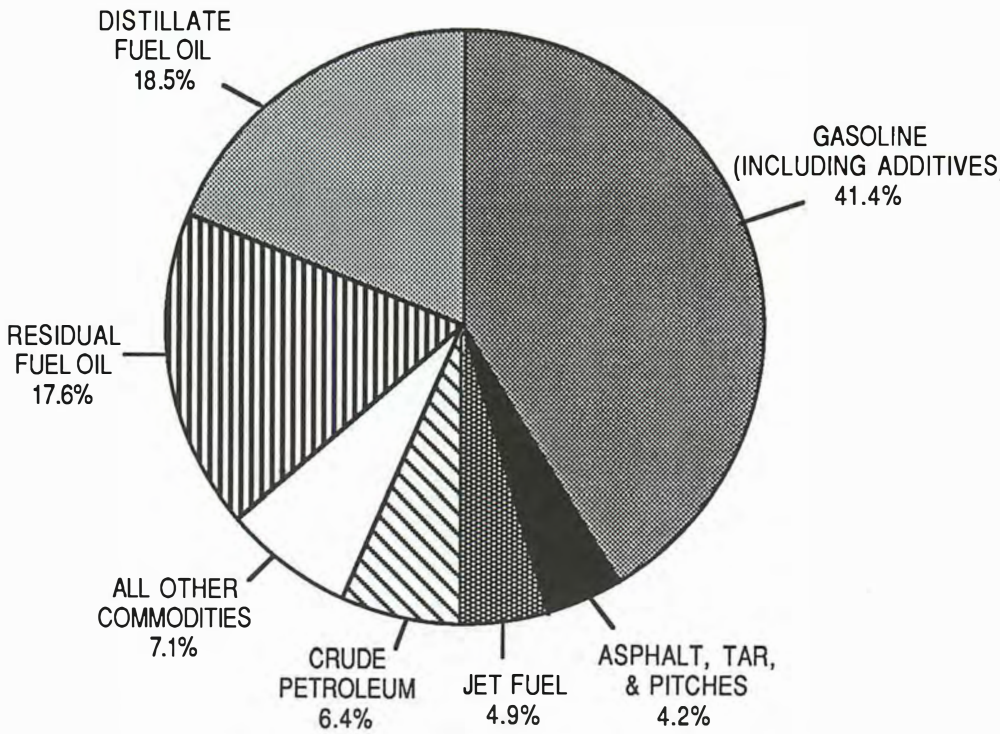
The bulk of the U.S.-flag crude oil carriers move ANS crude oil. Vessels from 30 to 270 thousand deadweight tons (MDWT) operate in the Pacific, moving crude oil from Valdez, Alaska, to West Coast refineries and to Panama, where it is pipelined across the Isthmus and transported to East-of-Rockies refineries. Most of the vessels in Gulf/Atlantic service are in the 50 to 80 MDWT range suitable for U.S. ports.

The capacity of the present Jones Act crude oil fleet is projected to be adequate to cover demands for the next five years. The decline of ANS crude oil volume and completion of a new pipeline from California to Texas should reduce overall U.S.-flag demand. However, the present fleet is aging and will have to be replaced eventually.

### Tank Barge Movements

At the end of 1987, the Coast Guard reported a total of 4,077 tank barges with a total capacity of 81.3 million barrels in various liquid carrying services. This is an increase of 106 units and 9.9 million barrels capacity over figures reported in the 1979 NPC report, Petroleum Storage and Transportation Capacities.

Most of the tank barge traffic between U.S. ports carries petroleum products, as illustrated in Figure 20; crude oil




SOURCE: U.S. Maritime Administration (MARAD), Domestic Waterborne Trade of the U.S., 1985.

Figure 20. Principal Commodities Carried Between U.S. Ports by Non-Self-Propelled Tank Barge in 1985 -- Percentage of Total.

accounts for only 6 percent of inter-port trade. However, a considerable fraction of crude oil barge movement is not between established ports. Barges gather crude oil from some coastal fields and transport it to refineries; and barges are often used to lighter (partially unload) foreign and domestic tankers within a port. Table 18 shows reported refinery receipts of crude oil by barge in 1987.

Crude oil barge capacity is adequate for current needs. No future capacity problems are expected under normal operating conditions as additional barges can be constructed in a relatively short period.

Marine Terminals

With the exception of the Louisiana Offshore Oil Port (LOOP), most marine terminal facilities on the East and Gulf Coasts are limited by water depth to tankers of 50 to 80 MDWT fully loaded. The facilities often receive larger ships that have been lightered to acceptable draft. In the mid-1970s, plans were developed to build deep-water oil port facilities in Texas and in Delaware Bay in addition to the LOOP facility, but declining demand for imported crude oil and declining tanker charter rates made these facilities unnecessary.

As shown in Table 19, the Maritime Administration lists 66 crude oil receiving facilities in the United States. Most of

TABLE 18

REFINERY CRUDE OIL RECEIPTS BY BARGE IN 1987*
(Thousands of Barrels per Day)

| | PADD I | PADD II | PADD III | PADD IV | PADD IV | Total |
|---|---|---|---|---|---|---|
| Domestic | 3 | 9 | 353 | 0 | 19 | 384 |
| Foreign | 45 | 1 | 20 | 0 | 3 | 68 |
| | 48 | 9 | 373 | 0 | 22 | 452 |

*Totals may not equal the sum of components due to independent rounding.

TABLE 19

U.S. SEAPORT TANKER AND BARGE TERMINALS
LIQUID BULK BERTHS

| Berth Type | Berth Total | North Atlantic | South Atlantic | Gulf Coast | South Pacific | North Pacific | Great Lakes |
|---|---|---|---|---|---|---|---|
| Crude Oil | 66 | 9 | 0 | 38 | 13 | 6 | 0 |
| Refined | 285 | 103 | 37 | 40 | 31 | 35 | 39 |
| Petroleum-crude/refined | 157 | 29 | 15 | 61 | 27 | 19 | 6 |
| LPG | 5 | 1 | 0 | 4 | 0 | 0 | 0 |
| LNG | 5 | 3 | 1 | 1 | 0 | 0 | 0 |
| Liquid Bulk - Other | 103 | 32 | 8 | 35 | 13 | 5 | 10 |
| Barge | 248 | 69 | 2 | 100 | 22 | 43 | 12 |
| Total* | 621 | 177 | 61 | 179 | 84 | 65 | 55 |

*Total is not the sum of components because of duplication of terminals handling both tankers and barges.

Source: Maritime Administration, Office of Port and Intermodal Development, Port Facility Inventory, and U.S. Army Corps of Engineers, Water Resources Support Center, Port Series.

these are in coastal area refineries, but there are commercial terminals that serve a number of users. LOOP is the largest of these facilities; it can receive the largest tankers currently in existence.

East and Gulf Coast refiners minimize the disadvantage of small ship receiving facilities by using VLCCs (Very Large Crude Carriers) in the 200 to 300 MDWT range for the initial transportation leg, and smaller ships for the final leg. The transfer from large ship to smaller may be made through transshipping terminals in the Caribbean or by direct lightering into ship or barge.

On the West Coast, the Alaskan Port of Valdez routinely loads VLCC-size ships with ANS crude oil. Ships of this size trade between Valdez and the Panama pipeline input or the Virgin Islands. Other West Coast ports cannot receive loaded VLCC-size ships; but a number of refineries can handle ships of 120 MDWT and larger.

Marine terminal capacity is expected to be adequate to handle growth through at least 1992. Marine deliveries of imported crude oil in 1992 are expected to be no higher than in 1979, but there have been a number of additions to marine terminal capacity, including completion of LOOP.

### Rail and Truck

Truck transportation of crude oil is limited largely to "gathering," the relatively short haul from the well to a mainline input. Overall truck volumes are substantial.

Overall rail movements of crude oil to refineries totaled only 57 MB/D, most of which reflected a unit train operation moving very heavy crude oil from California's San Joaquin Valley. In this case, a unit train operation offered a unique and cost-effective alternative to an expensive heated pipeline system.

## Crude Oil Inventory

At the end of 1987, privately owned crude oil inventories totaled almost 349 million barrels. Table 20 shows the location of these barrels in the system. Inventories at March 31, 1988 are also shown for comparison. The NPC estimates that about 300 million barrels of this inventory are required to maintain normal operation (e.g., line fill, tank bottoms, minimum working volume), leaving "available crude above minimums" at about four days' refinery consumption. A detailed presentation of crude oil and product inventory requirements is included in Volume IV of this report, Petroleum Inventories and Storage.

At recent price levels, average crude oil inventory would be worth well over $5 billion. Storage and carrying costs for crude oil inventory are obviously significant, with interest alone amounting to $0.5 billion per year.

Producers have little storage or inventory at the field level. As shown in Table 20, only 6 percent of inventory is at the lease (oil property) level.

TABLE 20

U.S. CRUDE OIL INVENTORIES
(Thousands of Barrels)

| Location | At 12/31/87 | At 3/31/88 |
|---|---|---|
| Lease | 21,177 | 21,235 |
| Pipelines & Tank Farm | 204,613 | 209,976 |
| Refinery | 95,851 | 100,803 |
| Alaskan In Transit | 27,354 | 21,611 |
| Total | 348,995 | 353,625 |

REFINED PRODUCT TRANSPORTATION AND STORAGE

The transportation and distribution system for petroleum products is efficient and cost-effective. Low pipeline and marine transportation costs allow foreign and domestic refineries to compete in distant markets, providing consumers with a wide choice of suppliers and the benefits of effective competition. For most refiners, efficient product distribution is a prerequisite for economic survival.

Product Supply and Major Movements

As shown in Table 21, domestic refineries produced more than 90 percent of U.S. finished product demand in 1987. Clearly, distribution of refinery output is the largest and most economically important product transportation element.

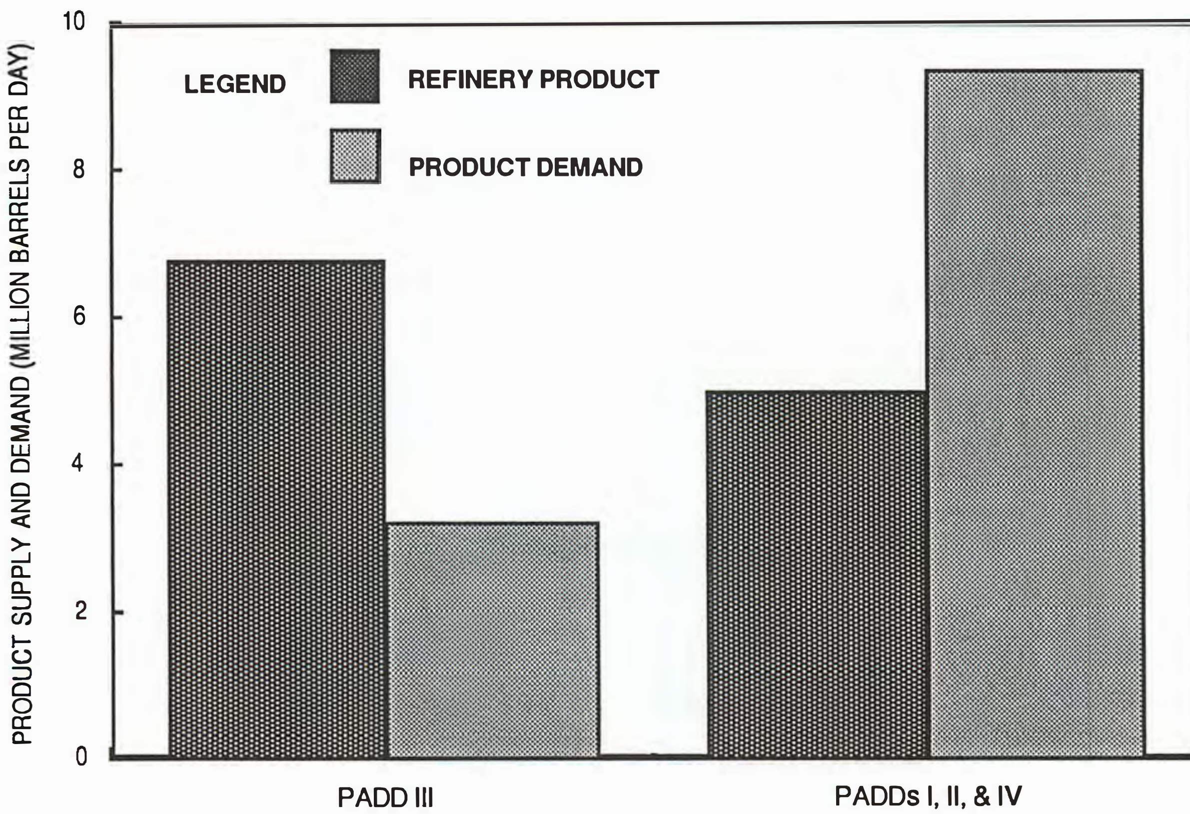
Most refinery production is consumed in the same area (PADD) in which it was produced. The exception is the Gulf Coast area of PADD III. This area is the refining hub of the United States, and its refineries provide "swing" or supplemental product to meet the needs of other East-of-Rockies areas. Figure 21 illustrates the surplus of refinery production in PADD III compared with the rest of the East-of-Rockies area (PADDs I, II, and IV).

TABLE 21

1987 U.S. FINISHED REFINERY PRODUCT SUPPLY AND DEMAND
(Millions of Barrels per Day)

| | |
|---|---|
| Demand | 15,119 |
| Supply | |
| Refinery | 14,178 |
| Imports* | 1,443 |
| Exports and Other | (502) |
| | 15,119 |

*Excludes unfinished and blend stocks normally processed in refineries.




SOURCE: EIA, Petroleum Supply Annual, 1987.

Figure 21. East-of-Rockies Product Supply and Demand.

Major pipeline networks have been developed to move finished gasoline, distillates, and jet fuel to the large population centers of PADDs I and II. As illustrated schematically in Figure 22, the primary transportation paths for Gulf Coast refineries resembles a giant "V." Product can be shifted to either the Midwest or East Coast leg of the "V" as dictated by economics. Pipeline deliveries from PADD III are supplemented by barge and tanker shipments to East Coast ports and by barge deliveries to PADD II ports on the Mississippi and tributary rivers.

Long-haul pipeline and marine transportation costs are low enough to permit Gulf Coast refineries to compete effectively with Midwest and East Coast refiners. For example, the cost to move gasoline from the Gulf Coast to Chicago is about 2¢ per gallon or 84¢ per barrel. This is not significantly higher than the 50¢ to 70¢ per barrel cost of bringing crude oil from PADD III to Chicago area refineries, and in many locations the small difference may be more than offset by other savings.

Long-haul movement is neither volumetrically nor economically the most important component of overall product transportation costs. However, it commands a disproportionate share of industry attention and analysis because the volume and economics of these movements vary. Local transportation and final distribution expenses account for the bulk of product transportation costs. These costs may include barge or pipeline delivery from a local refinery or long-haul pipeline terminus to a truck or rail terminal followed by final delivery to a consumer or retailer.

The cost per mile of transportation typically increases rapidly as the size and distance of the product shipment decreases. This cost increase is illustrated graphically in Figure 23 (and numerically in Table 22), which shows typical cost elements to deliver a gallon of gasoline from the U.S. Gulf Coast to a service station in Boston. In the illustration the transportation for 1,500 miles from the Gulf to New York Harbor is provided by a large-diameter pipeline at a cost of 2.2¢ -- roughly $.0015 per mile per gallon. The next leg from New York to Boston (250 miles) by barge costs three times as much per mile; and the final 40-mile truck delivery to the station costs 25 times as much per mile as the pipeline. Obviously, transportation cost is determined more by the mode of transportation than by the distance moved.

The large differences in cost per mile of various modes of product transportation provide ample incentive to continually adjust the system in response to seasonal or structural changes in demand or economics. For example, companies often negotiate agreements to exchange the use of truck terminals to reduce each party's average truck mileage per gallon of delivered product.

### Product Imports

As shown in Table 23, finished product imports into the United States totaled more than 1.4 MMB/D in 1987. This volume

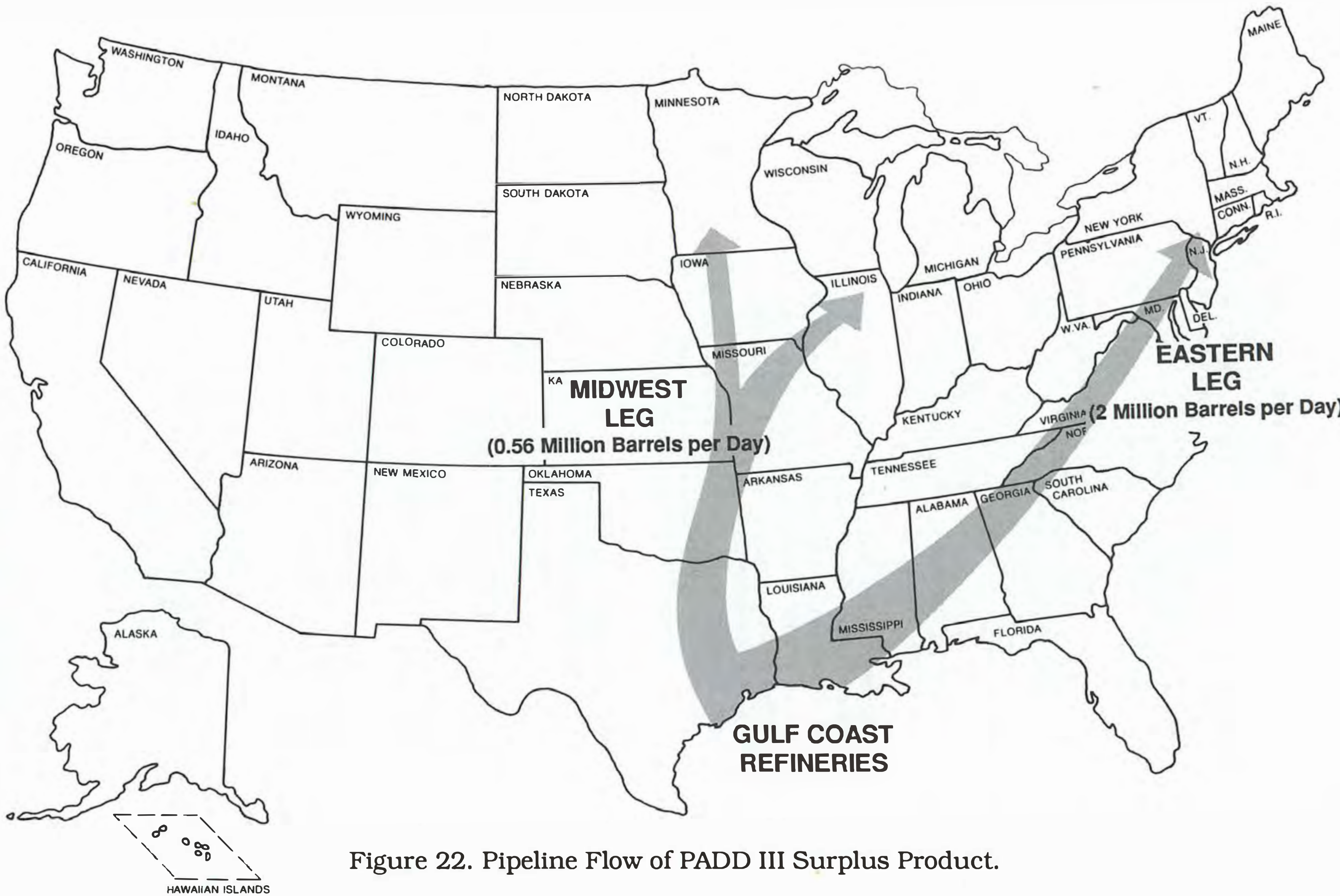



Figure 22. Pipeline Flow of PADD III Surplus Product.

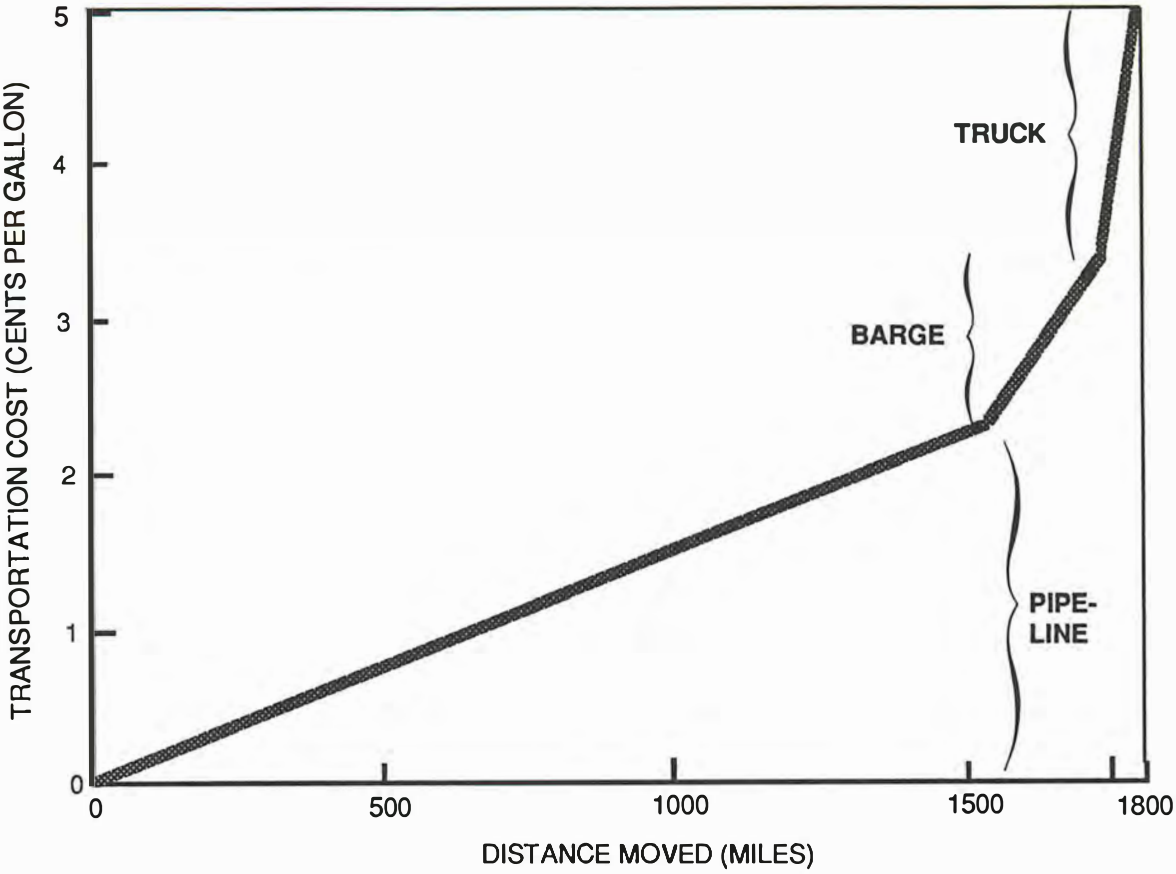



Figure 23. Illustrative Cost to Transport Gasoline from the U.S. Gulf Coast to a Boston Service Station.

TABLE 22

ILLUSTRATIVE
COST TO TRANSPORT GASOLINE FROM THE
U.S. GULF COAST TO A BOSTON SERVICE STATION

| Transport Segment | No. of Miles | Transport Cost: Cents Per Gallon | Transport Cost: Cents Per Mile-Gallon |
|---|---|---|---|
| Pipeline to N.Y. Harbor | 1,500 | 2.2 | 0.0015 |
| Terminal Cost (Increm.) | - | 0.1 | - |
| Barge to Boston | 250 | 1.1 | 0.0044 |
| Terminal Cost (Increm.) | - | 0.1 | - |
| Truck to Service Station | 40 | 1.5 | 0.0375 |
| Total | 1,790 | 5.0 | 0.0028 |

TABLE 23

1987 FINISHED PRODUCT IMPORTS*
(Thousands of Barrels per Day)

| | Finished Product Imports | | |
|---|---|---|---|
| | Canada | Other | Total |
| PADD I | 76 | 1,132 | 1,208 |
| PADD II | 23 | 5 | 28 |
| PADD III | 3 | 144 | 147 |
| PADD IV | 4 | - | 4 |
| East-of-Rockies§ | 106 | 1,281 | 1,387 |
| PADD V | 13 | 44 | 56 |
| Total U.S.§ | 118 | 1,325 | 1,443 |

*Excludes NGLs, unfinished oils, and motor gasoline blending components.

§Totals may not equal the sum of components due to independent rounding.

Source: EIA, Petroleum Supply Annual, 1987.

was about evenly split between conventional light products (gasoline, kerosine, distillates, and jet fuel) and heavy products such as residual fuel, asphalt, and lubricants. With the exception of Canadian deliveries, essentially all the imported products were transported by foreign-flag tanker.

More than 85 percent of the waterborne imported product was delivered to PADD I, predominantly in the New England and Mid-Atlantic regions. This delivery pattern is a direct reflection of transportation economics. It is obvious that Europe is closer to New England than to the U.S. Gulf Coast, but a closer look at a map will reveal that the Gulf Coast has little location advantage even for most Caribbean product supply sources. If the East-of-Rockies area requires imported gasoline or distillates, the lowest overall transportation cost will be obtained by directing the imports to PADD I and eliminating the cost of moving product from PADD III by pipeline.

Table 24 illustrates the magnitude of the cost advantage using typical ocean freight rates and pipeline costs. Transportation savings of 2¢ to 3¢ per gallon are more than enough to cause refiners to rearrange supply lines. For example, a refiner with a significant market in the Northeast may trade or sell his PADD III refinery production for use in the Midwest and replace it with product imported into the Northeast. By so doing, the refiner maintains the production of his PADD III refinery at optimum rates and minimizes the cost of supplying his PADD I market.

TABLE 24

ILLUSTRATION OF THE COST ADVANTAGE OF PADD I IMPORTS
(Cents Per Gallon)

| | Transportation Cost of Gasoline From | |
|---|---|---|
| | NW Europe | Venezuela |
| Import to PADD III | | |
| Ocean Freight | 4.2 | 1.7 |
| Pipeline to N.Y. | 2.2 | 2.2 |
| Total | 6.4 | 3.9 |
| Direct Imports to PADD I | | |
| Ocean Freight | 3.2 | 2.0 |
| Direct Import Advantage | 3.2 | 1.9 |

Obviously changes in import volume have a significant effect on domestic crude oil movements. Import volumes vary substantially with price and freight rate changes, making the economics of PADD I supply unusually dynamic.

Despite the preferential direction of product imports to PADD I, East Coast consumers are not significantly more exposed to an import disruption than the rest of the country. Capacity is available to redistribute domestic supplies and to replace lost imports. (See "Scenario 1: Oil Import Disruption," in Chapter Three.)

## Inter-PADD Movements

Figure 24 shows pipeline and waterborne movements of conventional light products between PADDs in 1987. The major product flow from the U.S. Gulf Coast area (PADD III) to the East Coast and Midwest is evident, but the map shows a number of other movements that appear to be counter to the primary flow direction or opposite in direction to other movements. For example, the map shows that 67 MB/D of product flowed into PADD IV from PADD II while 26 MB/D moved in the opposite direction.

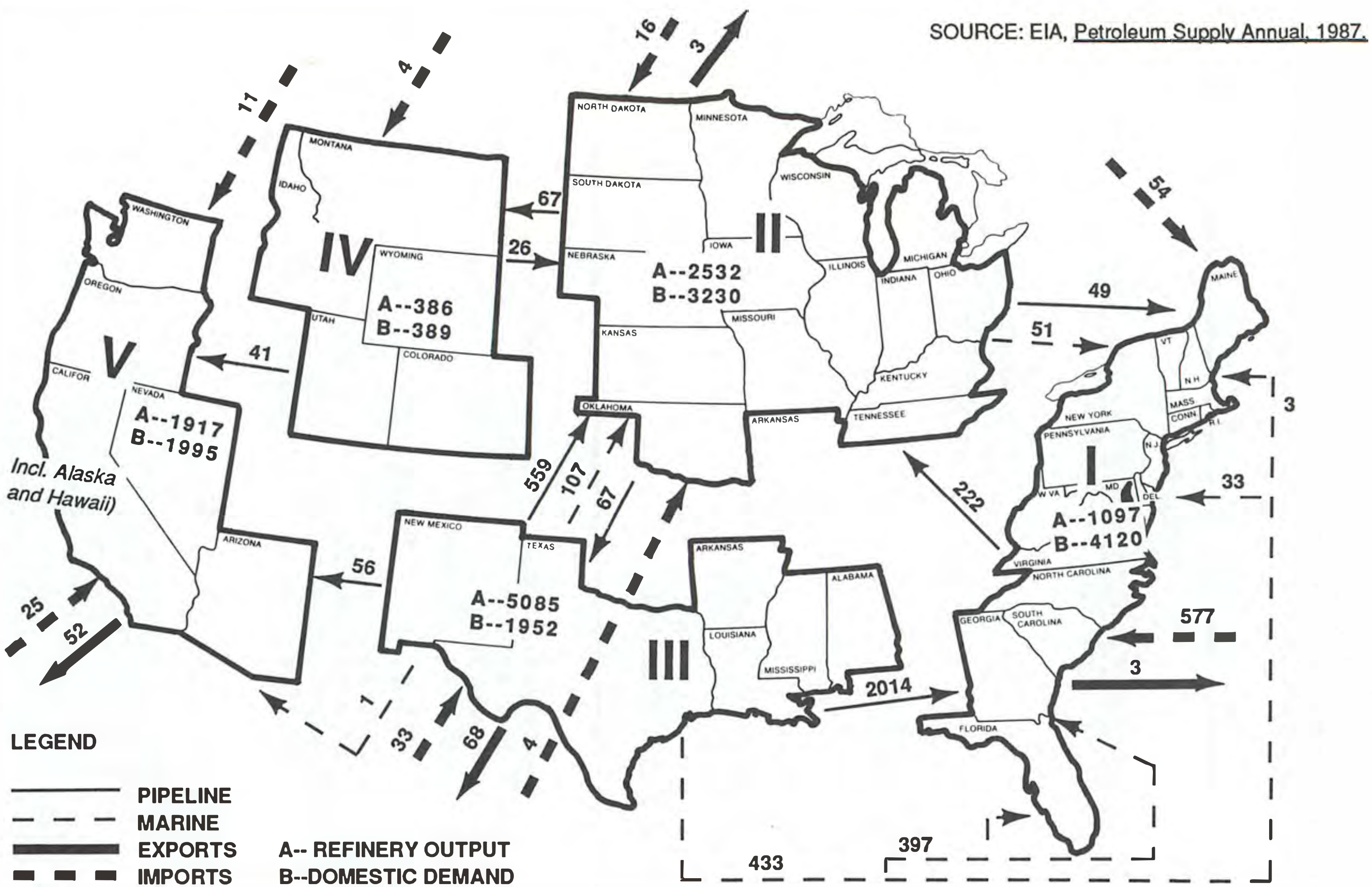



Figure 24. 1987 Gasoline and Distillate Inter-PADD Movement -- Including Jet Fuels and Kerosine (Thousands of Barrels per Day).

These movements illustrate the fact that transportation cost to a market is often more a function of its proximity to a primary transport terminal (e.g., pipeline terminal) than the absolute distance from a refinery. For example, it is less expensive to supply eastern Washington and Oregon from refineries in Montana and Wyoming than from much closer refineries in Washington, because these areas can be supplied by pipeline from PADD IV. Similarly, it is economic to supply the southeastern portion of PADD II with product from PADD I, because it can be delivered via a low-cost spur from the major Colonial and Plantation pipeline systems.

Transportation cost is only one of the elements determining product flow. Local demand and refining economics coupled with transport cost determine the "range" in which a refinery's output can be competitive with other sources. For example, product moves both up the Mississippi River (by barge) from PADD III and down the river from northern refineries in PADD II. The economic "interface" between these movements is determined by incremental refinery production cost in each area, as well as by barge costs. The initial location of the economic "interface" often varies for different refiners, but normally product trading soon eliminates wasteful crosshauling.

Figure 24 also shows the larger inter-PADD marine movements of gasoline and distillates (including kerosine and jet fuel). About 433 MB/D was moved from PADD III to PADD I (primarily to Florida and the Southeast) by seagoing barge and tankship in 1987. About 107 MB/D was shipped on the river system from PADD III to PADD II.

Figure 25 similarly shows inter-PADD product flow in 1979. There have been relatively few large changes between 1979 and 1987.

- Pipeline flow of products from PADD III to PADD II has increased more than 200 MB/D, reflecting the closure of PADD II refineries. This has improved the throughput of previously underutilized long-haul lines.

- Marine shipments from PADD III to Florida and the East Coast have declined about 400 MB/D, in part because of increased product imports. Most current marine movements are to the South Atlantic states and Florida.

In PADD V, refining centers in the Los Angeles, San Francisco Bay, and Puget Sound areas are near the major population centers they serve. There is little long-haul product movement.

## The Physical System

The facilities that transport refined product are much more diverse in size, type, and cost than comparable crude oil facilities. In this section, the various physical-transportation modes of current importance are briefly described.

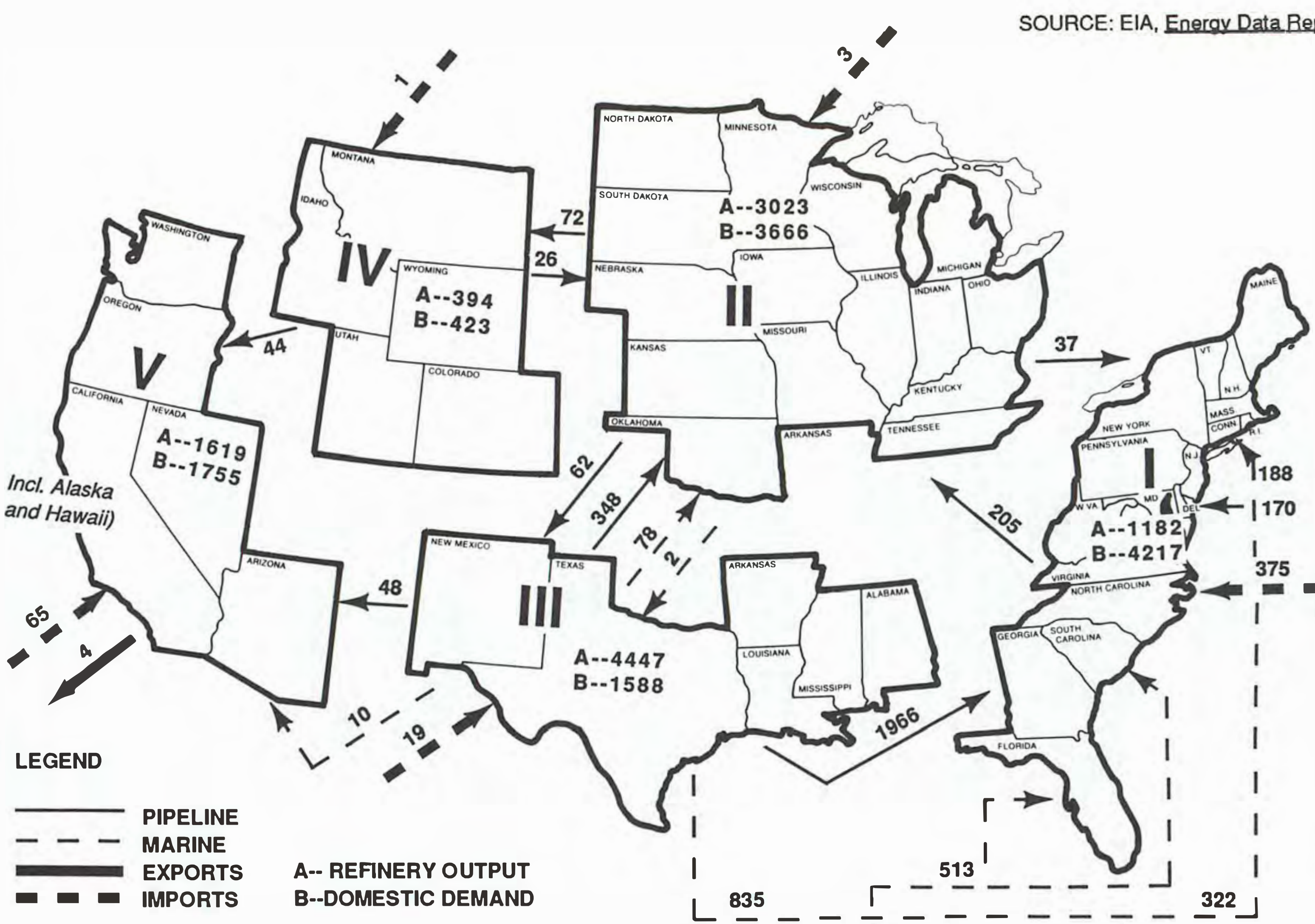



Figure 25. 1979 Gasoline and Distillate Inter-PADD Movement -- Including Jet Fuels and Kerosine (Thousands of Barrels per Day).

### Pipelines

In addition to the inter-PADD systems, there is a highly developed network of other (often smaller) lines to distribute product from local refineries or from delivery points on long-haul pipelines. Figure 26 shows the larger product pipelines in the United States. Appendix D contains further data on pipelines in each PADD and a review of the adequacy of these systems to meet probable demands through 1992. In general, capacity limitations of the present systems are not expected to pose significant problems.

### Marine Vessels

In 1987, finished and unfinished product imports (excluding LPG) delivered by foreign flag vessels amounted to more than 1.6 MMB/D. Gasoline and distillates were about 640 MB/D of this total, and residual fuel imports were more than 540 MB/D. The balance was finished specialty products (e.g., asphalt, lubricants) and unfinished oils.

Table 25 shows major world product movements by tanker for 1987. The total figure for U.S. imports is somewhat lower than data published by the Energy Information Administration, but the table is representative of U.S. supply sources. It shows a geographic mix of U.S. waterborne imports in 1987 as follows:

| | |
|---|---|
| Latin America | 54% |
| Western Europe | 14 |
| North Africa | 11 |
| Middle East | 8 |
| Southeast Asia | 3 |
| All Other | 10 |
| | 100% |

U.S. imports accounted for about 25 percent of the barrels moved in foreign trade in 1987; the percentage of ship tonnage used was smaller because of the large volume of imports from short-haul sources. As outlined in the Crude Oil Transportation and Storage section, there is little risk that product imports to the United States will be constrained by a shortage of product tankers.

Marine trade between U.S. ports is restricted by law to ships built in the United States and owned and manned by U.S. entities. Table 15 (in the Crude Oil Transportation and Storage section) shows the number and size of U.S.-flag ships currently licensed under the Jones Act to trade domestically. Most foreign and domestic product ships serving U.S. ports are in the 30 to 50 MDWT range, a size consonant with water depth and tankage limitations at most ports; however, product ships as small as 10 MDWT and as large as 90 MDWT also operate here.

Barge movements represent the largest volume of marine product movements. The U.S. Maritime Administration estimated

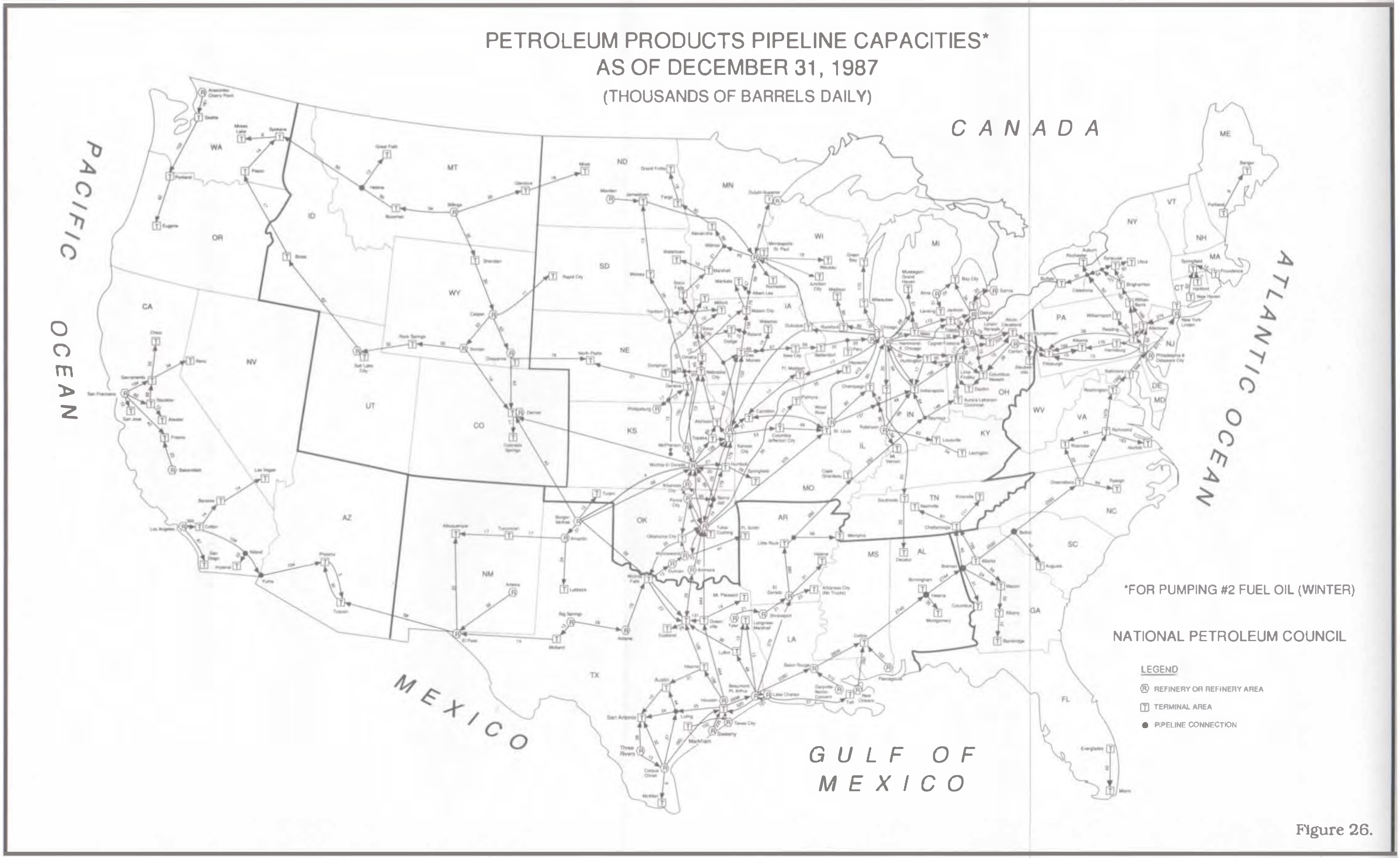

PETROLEUM PRODUCTS PIPELINE CAPACITIES*
AS OF DECEMBER 31, 1987
(THOUSANDS OF BARRELS DAILY)
CANADA
PACIFIC OCEAN
ATLANTIC OCEAN
MEXICO
GULF OF MEXICO
WA
OR
CA
ID
NV
MT
WY
UT
AZ
CO
NM
ND
SD
NE
KS
OK
TX
MN
IA
MO
AR
LA
WI
IL
MI
IN
OH
KY
TN
MS
AL
GA
FL
SC
NC
VA
WV
PA
NY
VT
NH
ME
MA
CT
NJ
DE
MD
*FOR PUMPING #2 FUEL OIL (WINTER)
NATIONAL PETROLEUM COUNCIL
LEGEND
REFINERY OR REFINERY AREA
TERMINAL AREA
PIPELINE CONNECTION

Figure 26.

TABLE 25

1987 WORLD PETROLEUM PRODUCT MOVEMENTS
(Thousands of Barrels per Day)

| | To | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| From | U.S. | Canada | Latin America | Western Europe | Africa | Southeast Asia | Japan | Austral-asia | Rest of World | Destin. Unknown* | Total Exports |
| United States | -- | 70 | 166 | 181 | 4 | 70 | 32 | 11 | 8 | 55 | 597 |
| Canada | -- | -- | -- | 3 | -- | -- | -- | -- | -- | -- | 3 |
| Latin America | 871 | -- | -- | 7 | -- | -- | 8 | 1 | -- | 66 | 953 |
| Western Europe | 230 | 8 | 14 | -- | 95 | 1 | -- | 1 | 37 | 115 | 501 |
| Middle East | 133 | -- | 49 | 486 | 10 | 372 | 554 | 46 | 24 | -- | 1,674 |
| North Africa | 181 | -- | -- | 281 | -- | -- | 22 | -- | 13 | -- | 497 |
| West Africa | 35 | -- | -- | 15 | 21 | -- | -- | -- | -- | -- | 71 |
| East & South Africa | -- | -- | -- | 5 | -- | -- | -- | -- | -- | -- | 5 |
| South Asia | 27 | -- | -- | 1 | -- | 7 | 16 | 1 | -- | -- | 52 |
| Southeast Asia | 52 | -- | 2 | 1 | -- | 2 | 255 | 29 | 44 | -- | 385 |
| Japan | 1 | -- | -- | -- | -- | 19 | -- | -- | 7 | 1 | 28 |
| Australasia | 7 | -- | -- | -- | -- | 20 | 26 | -- | 1 | -- | 54 |
| USSR, E. Europe, & China | 80 | -- | 185 | 786 | -- | 51 | 8 | -- | 158 | 45 | 1,313 |
| Total Imports | 1,617 | 78 | 416 | 1,766 | 130 | 542 | 921 | 89 | 292 | 282 | 6,133 |

*Includes in-transit losses and volume change, minor movements, and other.

Source: BP *Statistical Review of World Energy*.

that 1986 barge deliveries of both crude oil and product totaled more than 4 MMB/D. Table 26 shows the areas of barge activity. Major barge delivery areas are the Atlantic Coast, the Gulf Coast, and the Mississippi/Ohio river system, with less activity on the West Coast.

TABLE 26

1986 BARGE ACTIVITY BY LOCATION

| | MB/D | % |
|---|---|---|
| North Eastern | 743 | 17.5 |
| Atlantic Inland Waterways | 519 | 12.2 |
| Gulf Inland Waterways | 1,288 | 30.3 |
| Lower Mississippi | 789 | 18.5 |
| Upper Mississippi | 182 | 4.3 |
| Ohio and Trib. | 357 | 8.4 |
| California | 188 | 4.4 |
| Pacific N.W. | 138 | 3.2 |
| Great Lakes | 53 | 1.2 |

Source: U.S. Maritime Administration (MARAD), Domestic Waterborne Trade of the U.S., 1985, Table V-5, by receiving area.

Product movements account for the bulk of barge deliveries. Figure 27 shows the mix of liquid cargo carried between U.S. ports; the data are for 1985 but also reflect the current mix.

The cost of transporting products by barge varies greatly with the size of the movement and the distance traveled. Shipment on large barge tows can be competitive with even fairly large pipelines. A large barge tow can transport gasoline 1,000 miles up the Mississippi River system to Chicago for as little as 3.3¢ per gallon or 1,000 miles to eastern Florida for 2¢ per gallon. However, much of the barge volume is on smaller vessels providing secondary distribution of product from primary receiving points.

In recent years, large oceangoing barge arrays have replaced aging U.S.-flag tank ships in many areas. The low construction cost and low manpower requirements of the barges make them more economical than tank ships. The lower capital cost makes barge investment less risky as well in a rapidly changing supply environment.

Domestic marine product movements are not projected to grow overall. Increasing import volumes will undoubtedly replace domestic supply in some ports, and the capacity of the inland river system is becoming limited by lock capacity and water

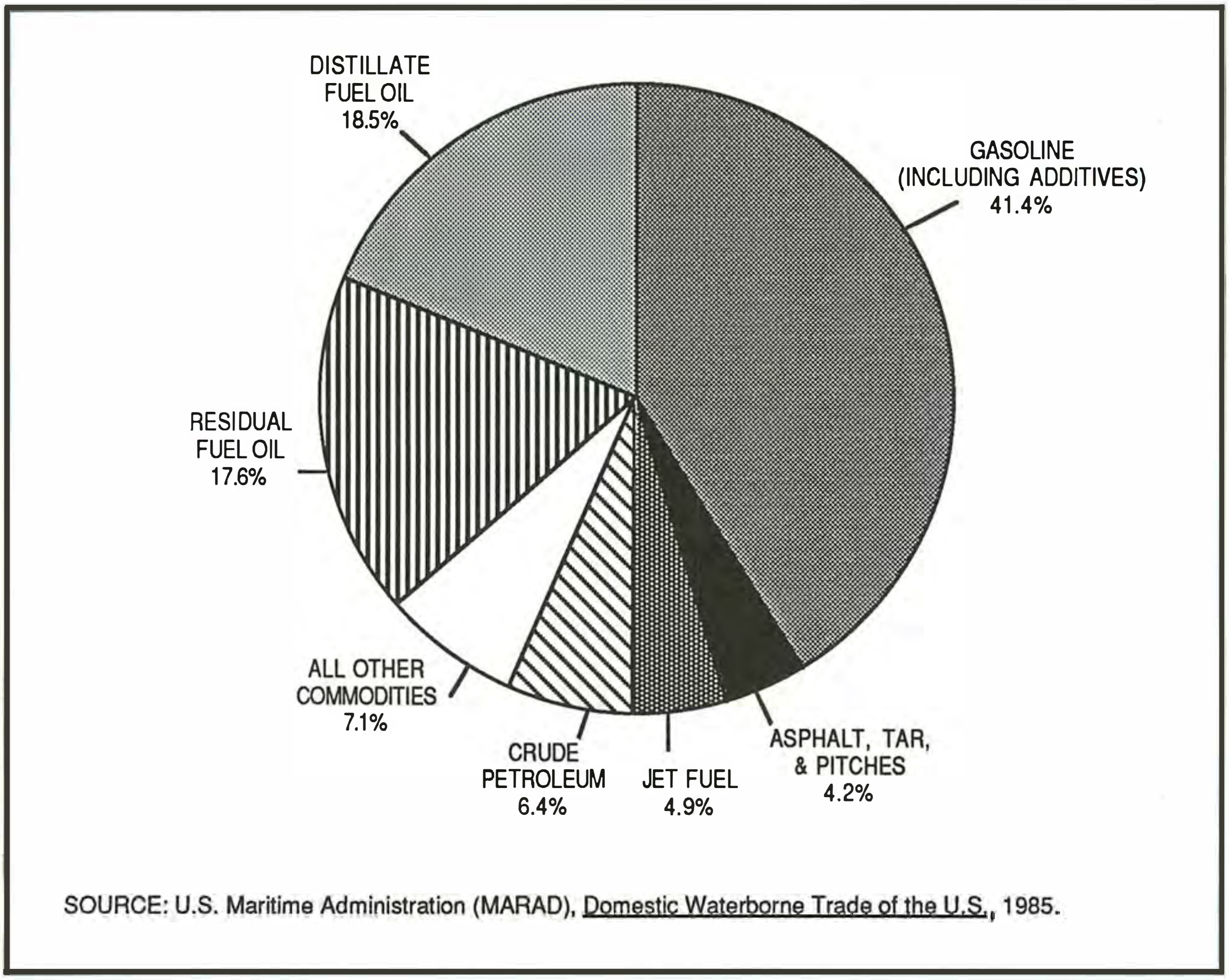



Figure 27. Principal Commodities Carried Between U.S. Ports by Non-Self-Propelled Tank Barge in 1985 -- Percentage of Total.

depths. Domestic ship and barge capacity is not expected to be a bottleneck for supply transportation through the early 1990s.

Rail Tank Cars

Products transported by rail are largely heavy products (asphalt, residual fuel, lubricants), as illustrated in Table 27. These products are not normally shipped by pipeline, and rail shipment is usually the most economic transportation mode to consumers not served by barge.

The relatively high cost of switching and loading rail cars makes rail movement uncompetitive with trucks for distances less than 100 miles, but for long trips rail costs are much more attractive. To illustrate, to move residual fuel 100 miles, truck transport may be cheaper than rail by more than a cent per gallon, but on a 1,000 mile delivery, rail cost could be over 30¢ per gallon less.

TABLE 27

1987 RAIL CAR PETROLEUM MOVEMENT
BY CLASS 1 CARRIERS

| Commodity | Carloads | MB/D |
|---|---|---|
| Asphalt | 30,842 | 41 |
| Residual Fuel Oil | 46,964 | 57 |
| Crude Petroleum and Natural Gasoline | 41,262 | 66 |
| Gasoline and Jet Fuel | 10,380 | 10 |
| Distillate Fuel Oil | 14,211 | 15 |
| Lubricating Oils | 25,517 | 32 |

The industry has reduced much of the tank car surplus that depressed car rentals in the mid-1980s, but there is little prospect of a car shortage. Past performance indicates that cars can be constructed very quickly when rental or purchase rates are attractive.

### Tank Trucks

The U.S. Department of Transportation estimates that over 102,000 tank trucks are in petroleum and chemical service, including 10,000 LPG carriers. Truck capacities normally vary from 100 to 200 barrels, but larger truck-trailer combinations operate where permitted by local regulation.

The high cost of truck transportation limits their use to relatively short-haul, low-volume deliveries to consumer and retailer tanks. A 100-mile delivery of gasoline by truck may cost about 2.6¢ per gallon -- 20 percent more than the cost to move a gallon of gasoline 1,500 miles on a major pipeline. Most oil companies continually analyze and adjust their truck traffic patterns to minimize overall truck miles.

Given the large number of trucks and their geographic dispersion, it is very unlikely that truck capacity could limit normal supply. However, additional truck capacity can be made available in emergency or stress situations by utilizing vehicles on extra shifts and overtime. The cost of such transportation is high.

### Residual Fuel Transportation

The physical characteristics of residual fuel make its transportation distinct from that of other products. Residual fuel is not normally moved by pipeline because of its high viscosity and tendency to become semi-solid at a low temperature. For the same reason, many of the marine vessels and tank cars carrying residual fuel are equipped with heating coils to maintain product fluidity.

The volume of residual fuel movements in the United States has changed radically since 1979 as illustrated by the maps in Figures 28 and 29. These maps show the inter-PADD flow of residual fuel in 1979 and 1987. The major differences are:

- A reduction in residual fuel imports from 1,151 MB/D in 1979 to 565 MB/D in 1987. This reflects a very large reduction in residual fuel consumption only partially offset by decreased refinery production.

- A reduction of more than 100 MB/D in marine movements from PADD III to PADD I.

- A shift of PADD V from a net importer to a large exporter of residual fuel.

Today, domestic movements of residual fuel are of little importance overall; that situation is unlikely to change in the next five years as growth in demand is expected to be met with added imports.

LPG Transportation

Most LPG transportation systems are dedicated exclusively to that service, although a few pipelines "batch" LPG with conventional product shipments. The high vapor pressure of LPG makes it necessary to maintain the product under pressure (or refrigeration) in pipelines and storage.

There is a dual pipeline system for LPG. "Raw mix" lines gather an unfractionated mix of products from field gas plants. The raw mix contains varying percentages of ethane, propane, butanes, and natural gasoline. Raw mix lines terminate in areas with underground storage and LPG fractionators. Pipelines frequently offer transportation and fractionation in a bundled deal. Figure 30 shows the lines that gather mixed LPG.

Fractionated (or purity) product is moved in a separate "delivery" system to consuming areas in the Midwest and South. Figure 31 shows the major delivery pipelines originating at Mount Belvieu and Borger, Texas, and at Conway, Kansas. Pipeline imports of fractionated LPG are received from Canada via the Interprovincial/Lakehead system and the Cochin pipeline.

Well over half the LPG demand in the United States is in PADD III; petrochemical plants in the Gulf Coast area are major consumers of LPG as feedstock, and Gulf Coast refiners have been large-scale users of butane for gasoline blending. Net inter-PADD movements of LPG are relatively small, as shown in Figure 32. Figure 33 shows that the distribution pattern for LPG has changed relatively little since 1979. A significant exception is the completion of a new line to bring LPG from the Overthrust Belt to West Texas.

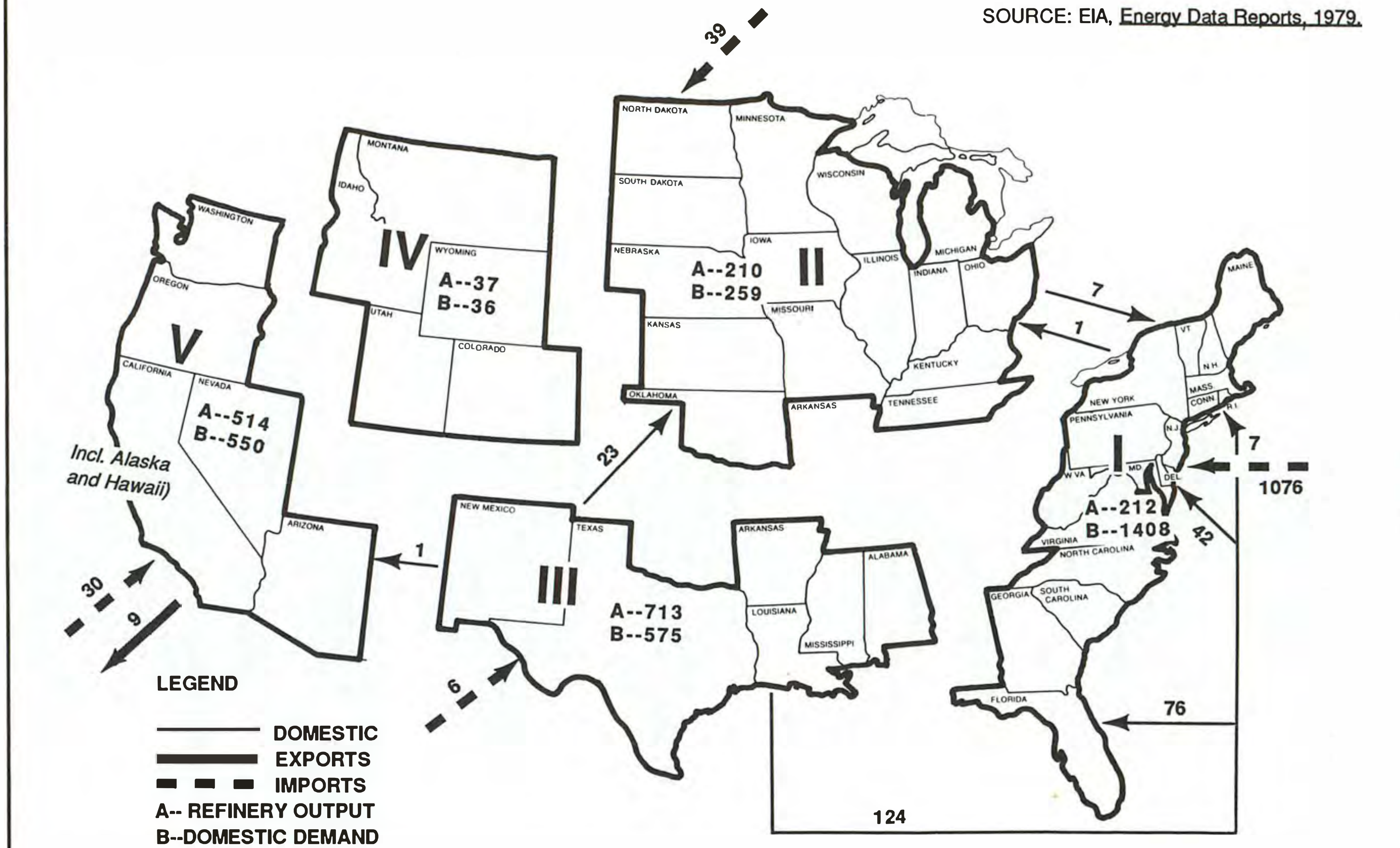



Figure 28. 1979 Residual Fuel Oil Marine Inter-PADD Movement (Thousands of Barrels per Day).

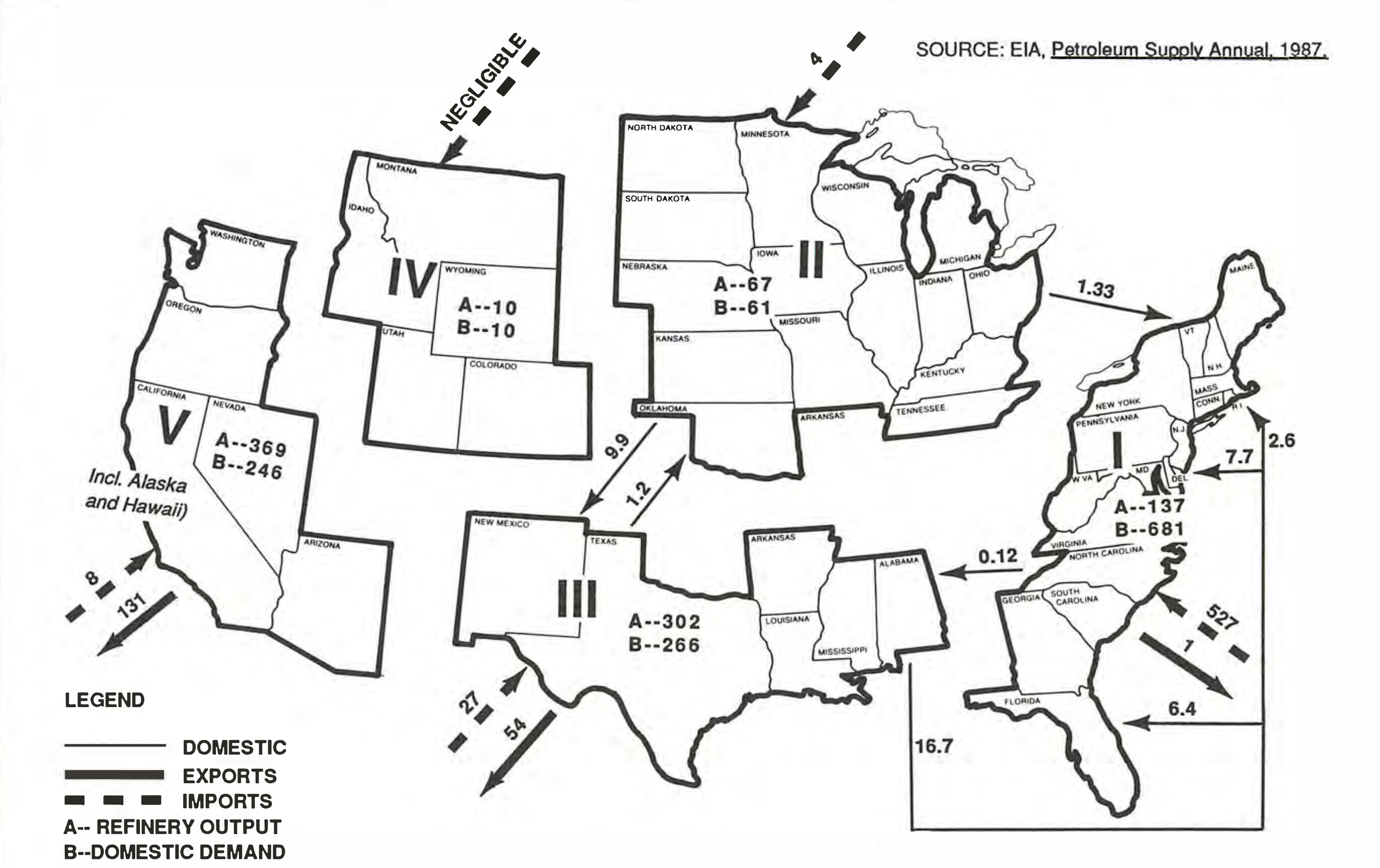



Figure 29. 1987 Residual Fuel Oil Marine Inter-PADD Movement
(Thousands of Barrels per Day).

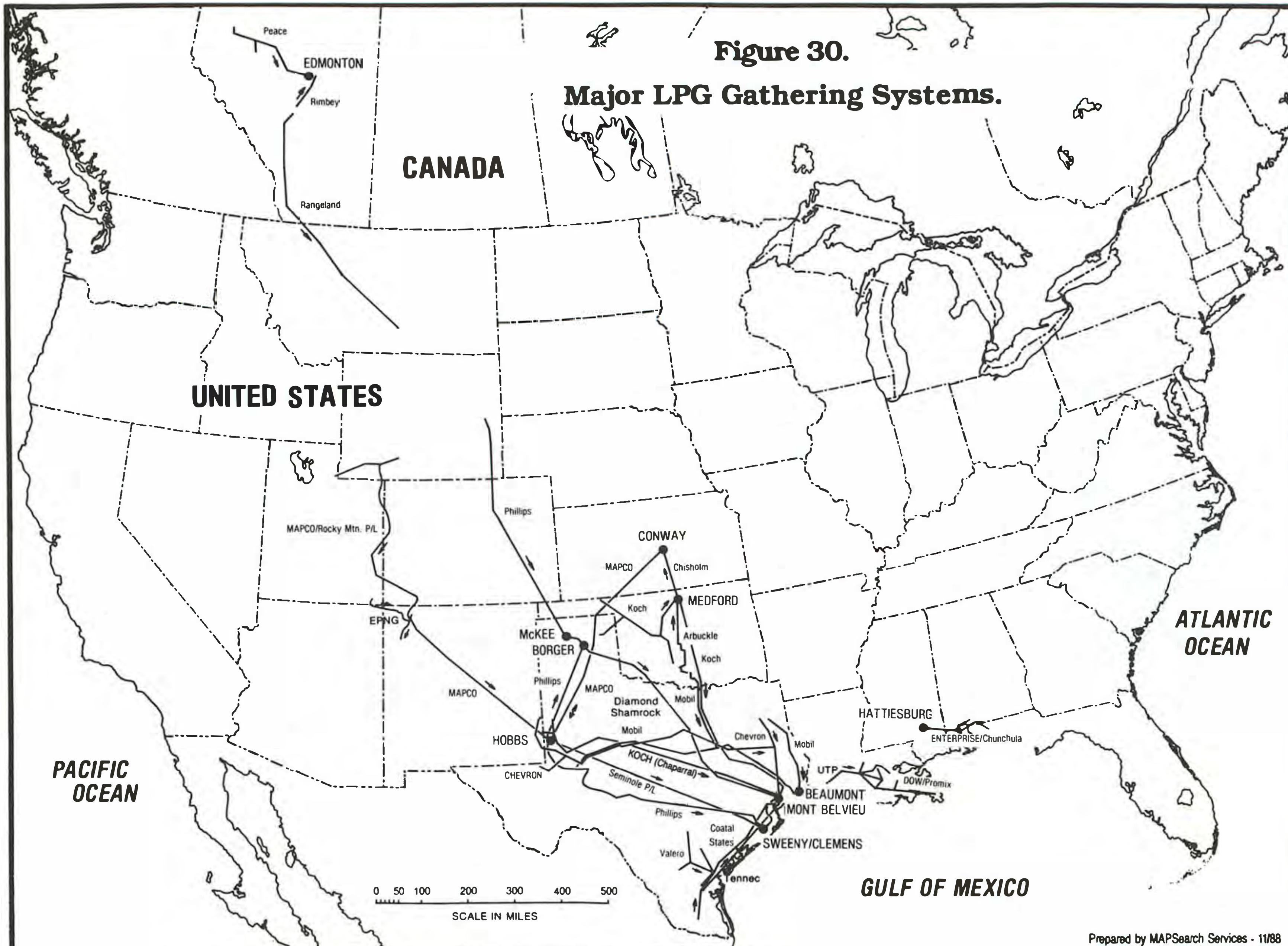



**Figure 30. Major LPG Gathering Systems.**

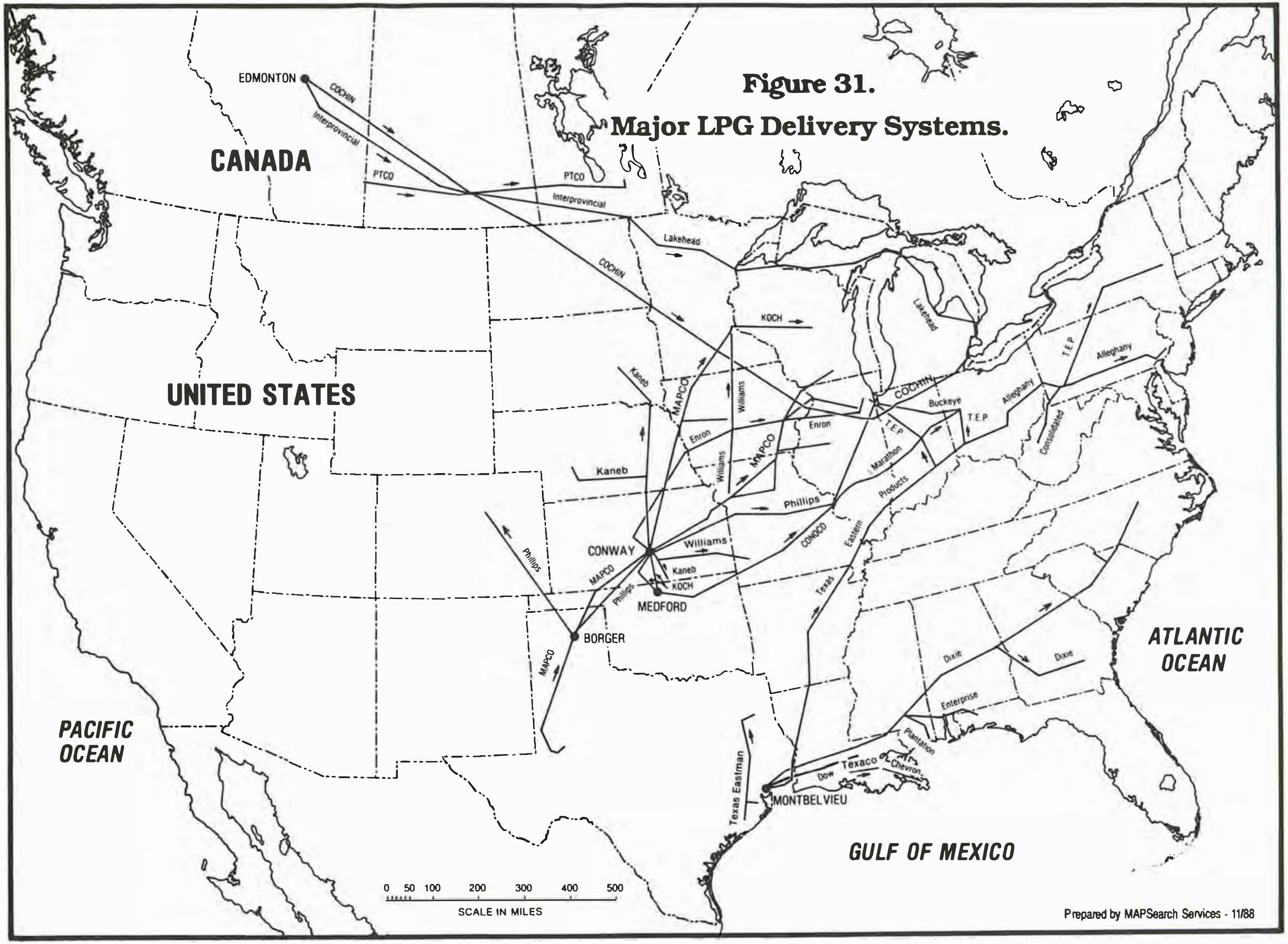



**Figure 31. Major LPG Delivery Systems.**

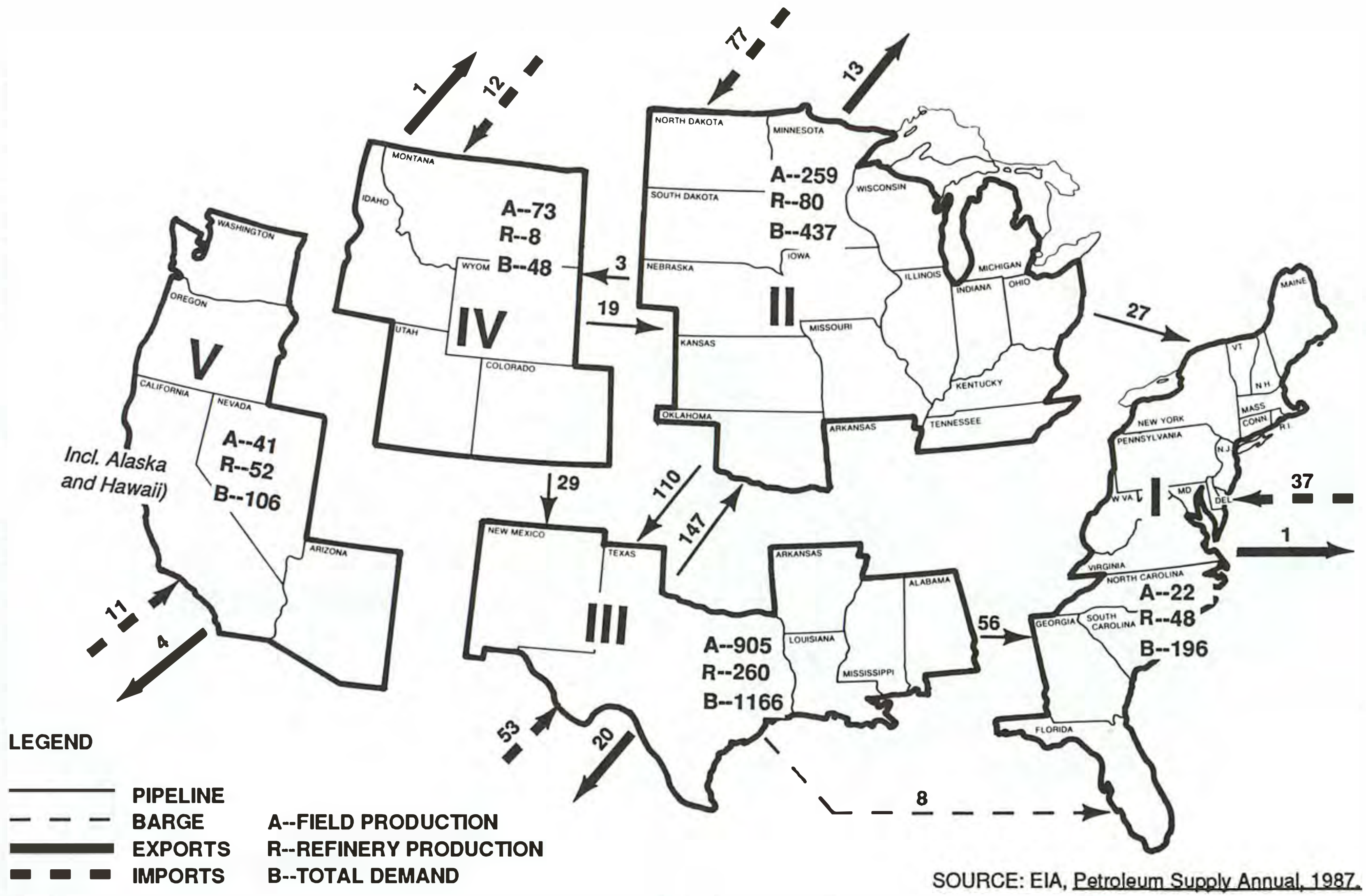



Figure 32. 1987 Inter-PADD LPG Movement (Thousands of Barrels per Day).

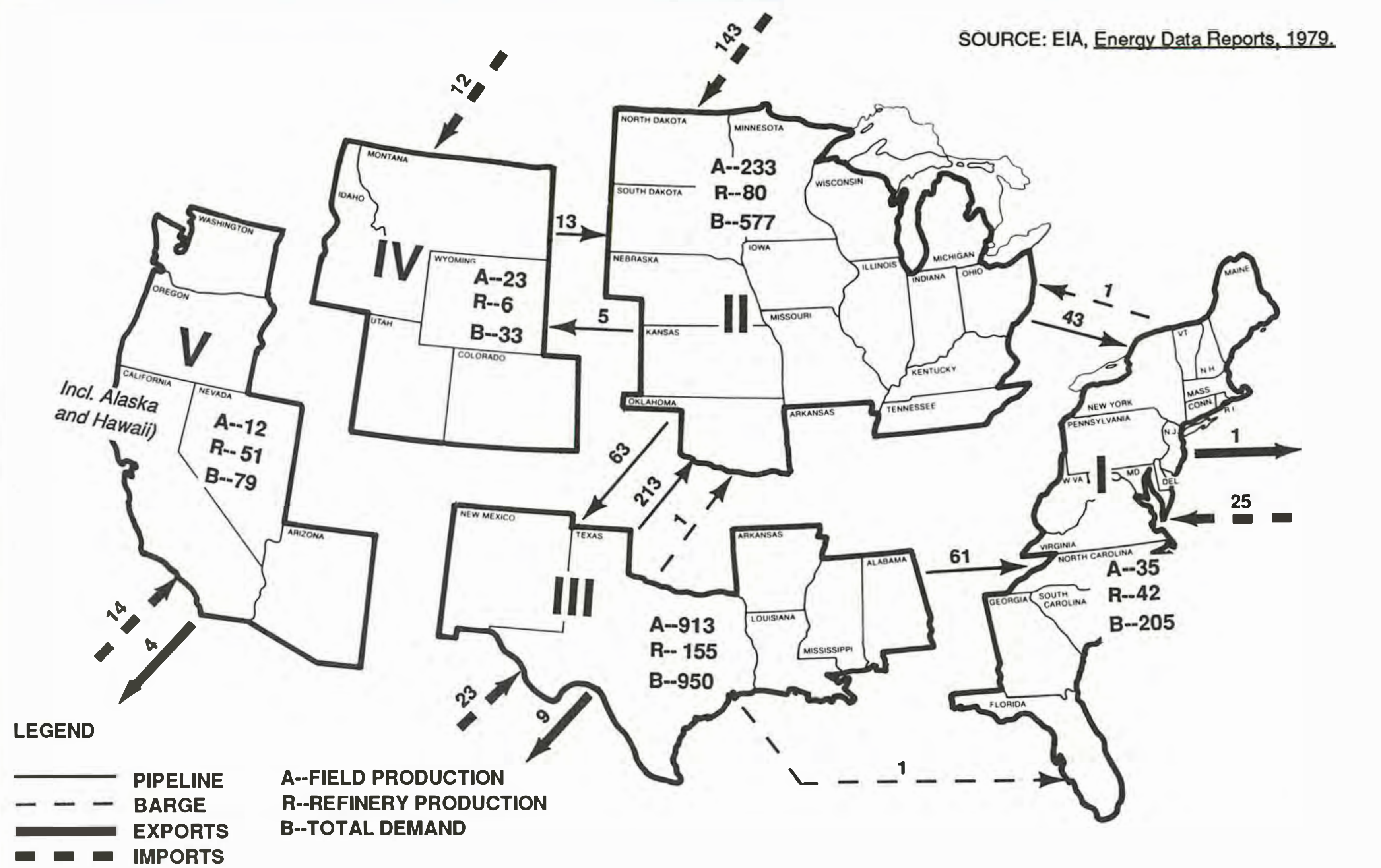



Figure 33. 1979 Inter-PADD LPG Movement (Thousands of Barrels per Day).

## Product Inventory

Table 28 shows the volumes of gasoline, distillate, and residual fuel in primary inventory at year-end 1987. The table also shows the percentage of stocks in refineries, pipelines, and primary bulk storage. Much of the primary inventory is required to maintain ongoing supply operations and is not "available" under normal conditions. Pipeline stocks, for example, are largely line fill, which cannot be drawn if the lines remain in service. Table 28 also shows inventory expressed as gross and net days of supply at average consumption rate. The "net days" figure represents the stock above the "minimum" level required to maintain normal supply operation. Minimum inventory and the concept of "days supply" are presented in detail in Volume IV of this report, Petroleum Inventories and Storage.

Total primary product inventories, excluding LPG, totaled 614 million barrels on December 31, 1987. At current prices this stock would be valued at over $11 billion. Storage and carrying costs for this inventory are a significant ongoing cost.

Figures 34, 35, and 36 illustrate changes in major product inventory since 1979.

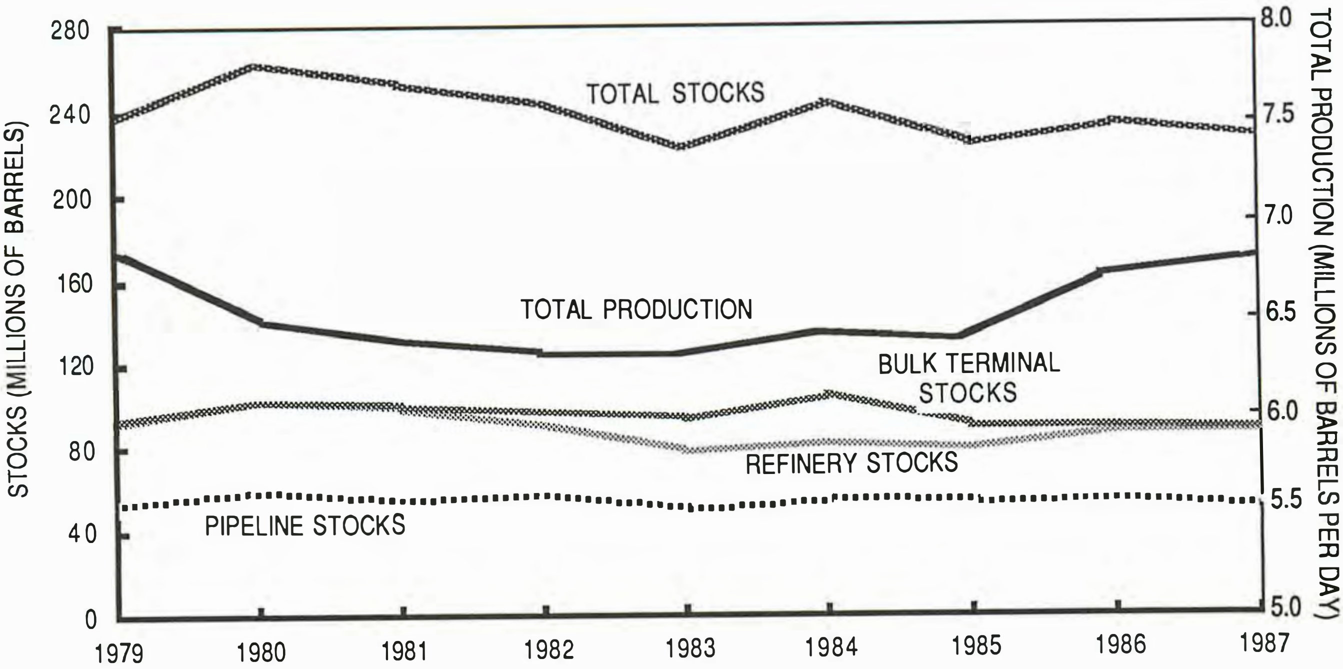
TABLE 28

PRIMARY INVENTORY OF PRODUCTS AT 12/31/87

| | Gasoline* | Distillate Fuel Oil | Residual Fuel Oil |
|---|---|---|---|
| Inventory (Millions of Barrels) | 226 | 134 | 47 |
| Inventory Location (%) | | | |
| Refinery | 39 | 30 | 39 |
| Bulk Terminal | 38 | 49 | 61 |
| Pipelines | 23 | 21 | -- |
| | 100 | 100 | 100 |
| Gross Days Supply | 31 | 45 | 37 |
| Net Days Supply Above Minimum | 3 | 16 | 13 |

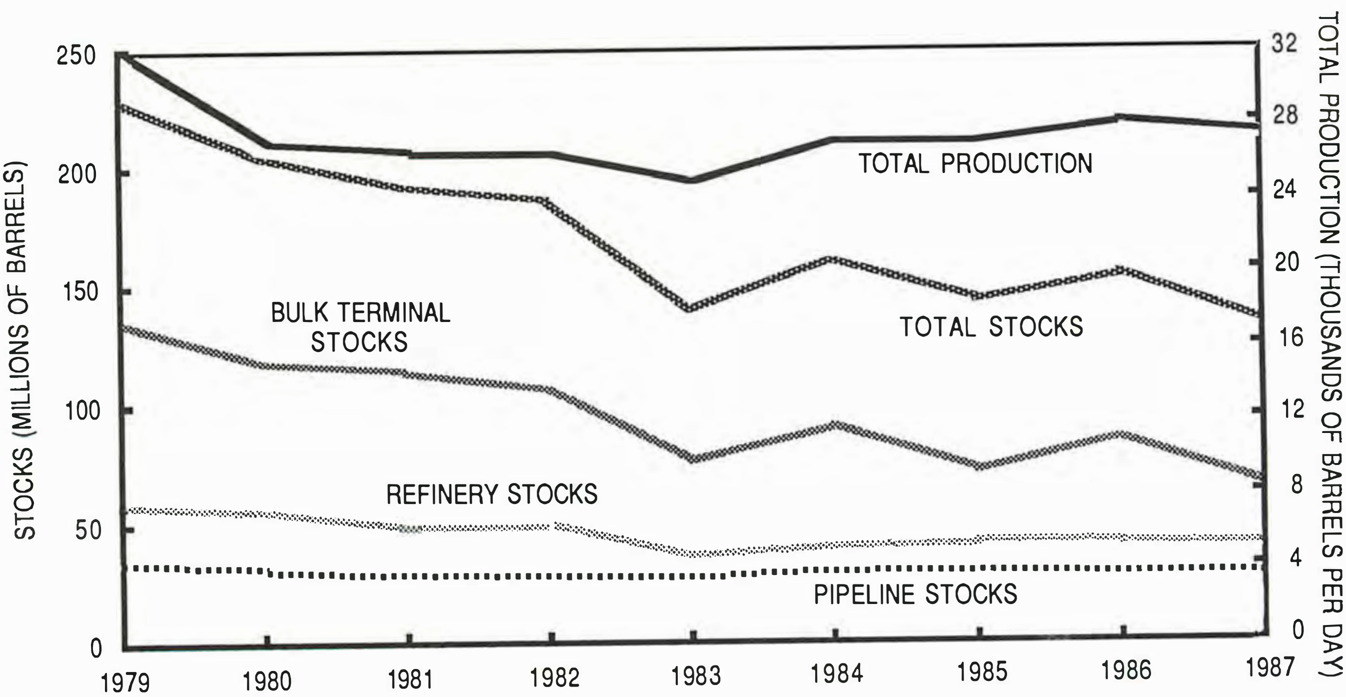
*Includes gasoline blend components.

Source: EIA, Petroleum Supply Annual, 1987.



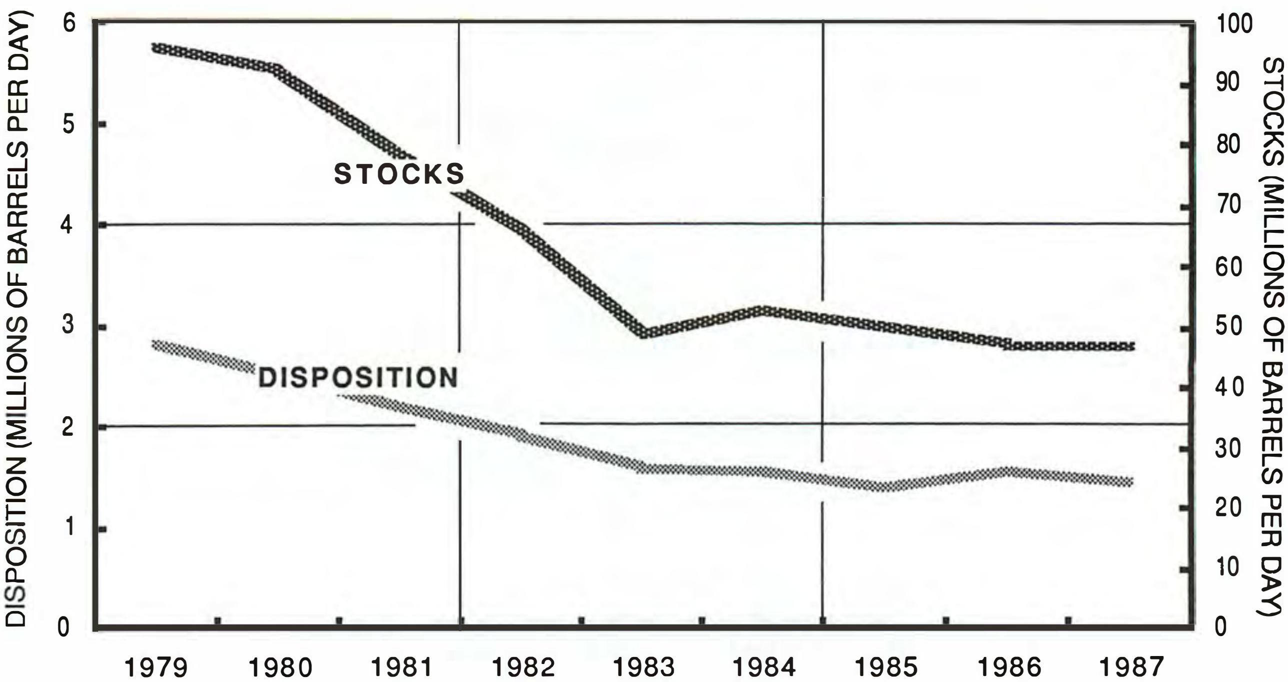

SOURCE: EIA, Petroleum Supply Annual, 1987.

Figure 34. Motor Gasoline (Total Production and Primary Stocks).




SOURCE: EIA, Petroleum Supply Annual, 1987.

Figure 35. Distillate Fuel Oil (Total Production and Primary Stocks).




NOTE: Disposition includes demand and exports. Stocks are as of December 31.

SOURCE: EIA, Petroleum Supply Annual, 1987, Table S6, "Residual Fuel Oil Supply and Disposition."

Figure 36. Residual Fuel Oil Primary Stocks and Demand.

In addition to primary inventory, there is a large volume of product in secondary and tertiary storage owned by jobbers, retailers, and consumers. Because these inventories are at the end of the transportation chain, the volume of "available" (above minimum) stock in secondary and tertiary storage is higher than in primary inventory. Volume IV of this report includes detailed estimates of secondary and tertiary stocks.

## REFINERY SYSTEM FLEXIBILITY

The shutdown of over 2 MMB/D of marginal refining capacity has left the industry with a highly sophisticated refining system capable of upgrading most of the heavy portion of the crude oil input to gasoline and distillate fuels. In simple refineries, this heavy, high-boiling-point portion of the crude oil yields mostly residual fuel oil. Table 29 shows the improvement in secondary (upgrading) facilities relative to base crude oil capacity.

There are, of course, still many relatively simple refineries that produce residual fuels, asphalt, and intermediate stocks as primary products. However, the great bulk of domestic capacity is in complex refineries, and the system normally responds to supply-demand variance with the flexibility and economic motivation similar to that of a complex plant.

TABLE 29

U.S. REFINERIES COKING AND CRACKING CAPACITY AS A PERCENTAGE OF CRUDE OIL CAPACITY

| | 1980 | 1988 |
|---|---|---|
| Cracking | 37 | 44 |
| Coking | 9 | 13 |
| Total | 46 | 57 |

The high capital and fixed costs of secondary or upgrading facilities (the conversion and upgrading process units "downstream" of crude oil distillation) make it very economical for refiners to keep these facilities as fully utilized as possible. Refinery design usually provides for more crude oil distillation capacity than is required to load the secondary units and ample intermediate storage for secondary unit feedstocks. The surplus distillation capacity and the buffer storage (both of which are relatively inexpensive) insulate the normally profitable secondary units from distillation problems; they also provide the refiner with a great deal of flexibility to shift product mix and change the rate and quality of crude oil run.

Utilization of that flexibility is essentially an economic decision based on the refiner's projection of near-term product prices, crude oil costs, and product demand. Computer models of individual refineries (called linear programs) reflect the complex interaction of various refinery units, enabling the refiner to examine the economic and physical parameters of crude oil changes and product shifts. The object is to maintain refinery operation near the maximum profitability. "Optimization" requires almost continuous reassessment in today's volatile market. As a consequence, the industry system responds rapidly to the economic signals of the market. Some of these responses are discussed below.

## Crude Oil Run

In the period from January 1985 through June 1988, monthly U.S. crude oil runs have ranged from 11.4 to 13.5 MMB/D, equivalent to about 75 to 86 percent of rated capacity. Aggregate rated capacity of the U.S. refining system was 15.9 MMB/D at the beginning of 1988 (excluding 0.7 MMB/D in the Virgin Islands, Guam, and Puerto Rico).

In the recent past, refinery utilization has averaged about 83 percent of rated capacity. However, it would be overly optimistic to assume that the unused 17 percent is available under "normal" circumstances. Roughly 6 percent of the nominal spare capacity is in "temporarily idled" units that theoretically could be returned to service within 90 days. Reactivating these generally marginal facilities would require investment, and few are likely to be available in the short term. (They could, however, be reactivated if long-term economic incentives develop.) A portion of the remaining "spare" capacity can be categorized as simple distillation capacity (topping plus reforming, for example) that would be called out only in relatively unusual circumstances. The balance is capacity that would be economic under reasonably "normal" business conditions.

Table 30 illustrates the difference in yield and refinery gross margin from different levels of upgrading capacity for a

TABLE 30

ILLUSTRATIVE
REFINERY YIELDS AND MARGINS*

| | Full Upgrade | Catalytic Cracking | Topping Plus Reforming Max. | Topping Plus Reforming Min. |
|---|---|---|---|---|
| Yields (% of crude) | | | | |
| Gasoline | 58 | 52 | 25 | 20 |
| Distillate | 28 | 19 | 45 | 35 |
| Residual Fuel | 0 | 22 | 25 | 40 |
| Refinery Gross Margin ($/bbl of crude) | 2.90 | 1.70 | 0 | (.80) |

→ increasing capacity utilization

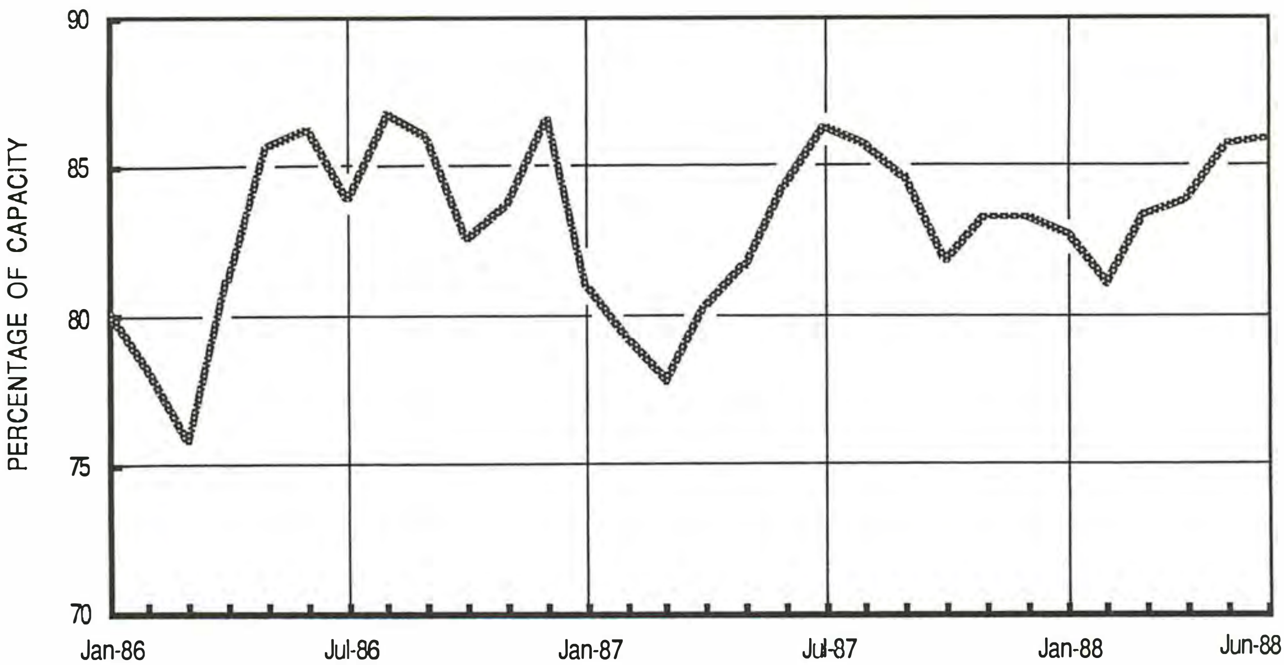
*Incremental yields and margins for West Texas Sour crude oil in various modes. "Full Upgrading" assumes open coking and cracking capacity. The "Catalytic Cracking" mode is based on a similar refinery with loaded cokers. For the simple (topping/reforming) capacity, the "maximum" reflects the type of net yields available from the "first barrel" in the topping/reforming mode in a complex refinery. The "minimum" represents "last barrel" performance. The difference is a reflection of the declining flexibility to optimize refinery performance as the refinery approaches capacity. Margin figures exclude fixed refinery costs.

West Texas Sour type crude oil. In general, lower levels of upgrading capacity produce less gasoline, more residual fuel, and lower valued refinery products overall. The more complex plants also have greater ability to shift product mix. (The margin figures in Table 30 are not indicative of refinery profit because they exclude capital and fixed costs, but they reflect the economic drive to utilize existing facilities.)

Normally, refinery runs in the simple topping/reforming mode are not economic in PADDs I through IV. In PADD V, the low cost of the very heavy crude oils has kept some runs for residual fuel marginally economic.

The substantial flexibility of the U.S. refining system makes the dividing line between spare capacity available under "normal" and under "unusual" conditions very subjective, but a review of recent system performance indicates there is still economic capacity remaining.

Figure 37 shows the actual variation in crude oil run levels (as a percentage of rated capacity) over a 30-month period. The variance reflects seasonal demand levels as well as refinery "turnarounds" (when units are shut down for major maintenance). Turnarounds occur throughout the year, but statistically maintenance schedules have been heavier in the spring and fall, outside heavy gasoline and winter fuel demand periods.




SOURCE: EIA, Petroleum Supply Monthly, June1988.

Figure 37. U.S. Refinery Runs -- Percentage of Capacity Utilized.

The system has maintained an 85-86 percent utilization rate for extended summer periods without inordinate strain. However, an unusual combination of operating problems, unit outages, and unexpectedly strong demand made the summer of 1988 a challenge for refiners. Supply was adequate, but increased product margins and a higher price spread between high- and low-octane gasolines indicated that higher cost supply sources were being utilized.

Refiners seek to optimize the "base" load of the refinery by running the most economic crude oil (usually the lowest gravity and highest sulfur crude oil) that will reasonably load coking and cracking units and produce the required products. Utilization of capacity above the "base" level is progressively more expensive as volume increases because the refiner may have to deviate from the base by:

- Running lighter, higher quality crude oils to stay within internal bottlenecks. Lighter crude oils typically contain a smaller fraction of heavy material, permitting the refiner to run more crude oil without exceeding secondary unit capacities.

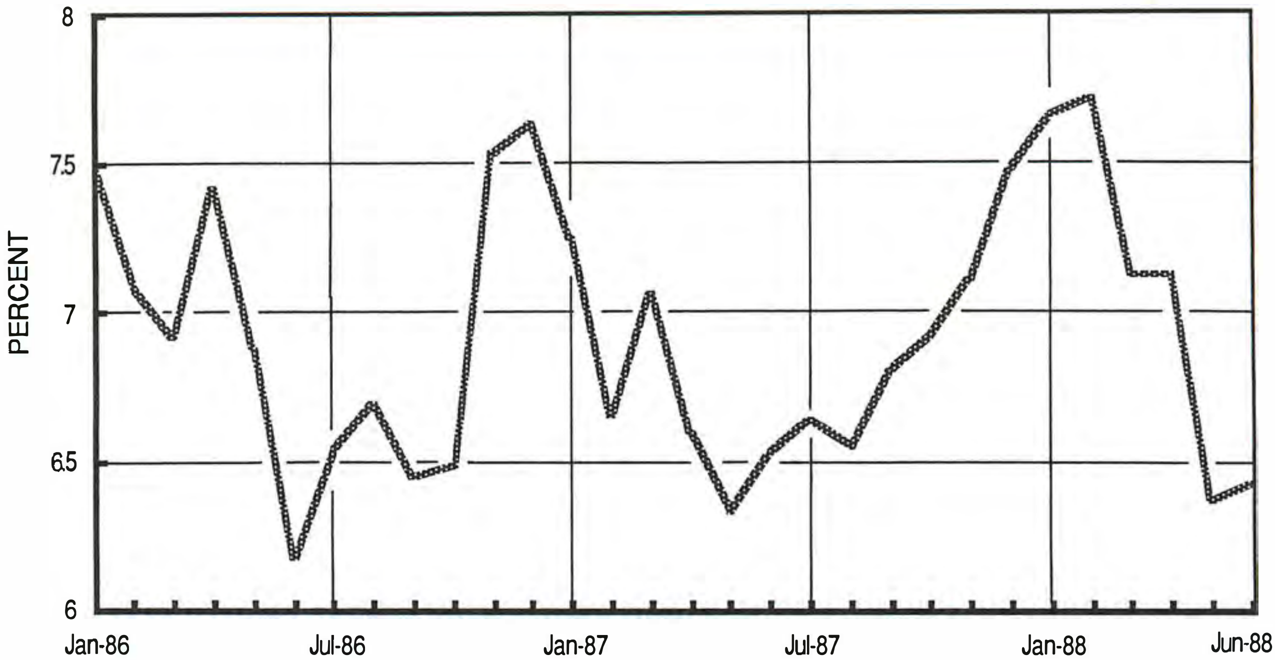
- Operating outside the capacity of secondary units.

However, there is evidence that the overall system retains capacity to run additional heavy, sour crude oil.

Since 1981, the average gravity of crude oil run in U.S. refineries has declined by about 1.7 degrees API to an average of 32 degrees API in the first half of 1988. This reflects improved ability to handle heavy, sour crude oil and the economic incentive to do so. In the same period, the average sulfur level of crude oil input has gone up from 0.88 to 1.07 percent. However, examination of monthly EIA data indicates that the lowest gravity (and highest sulfur) crude oil input generally corresponds to periods of highest crude oil runs. In short, the incremental crude oil has been somewhat lower in quality than the average, indicating that there remains some additional sour crude oil capacity in the system.

Obviously, the system also retains the flexibility to run a much lighter crude oil slate, if it were available, and to produce higher volumes of gasoline and distillates thereby.

For economic reasons, most full upgrading refineries have somewhat lower coking capacity in relation to crude oil capacity than cracking capacity. Therefore, as the refining system approaches its efficient capacity, we would expect an increasing volume of crude oil run would be in the topping/reforming and cracking modes. As illustrated in Table 30, these modes produce significant quantities of residual fuel, so if the system were approaching capacity, we would expect residual fuel production to increase rapidly with refinery run rates. It has not. In fact, the recent history of residual fuel production shown in Figure 38 shows somewhat <u>lower</u> residual fuel yields during the




SOURCE: EIA, Petroleum Supply Monthly, June1988.

**Figure 38. Residual Fuel Oil Production as Percentage of Refinery Runs.**

summer periods of peak crude oil run. (After adjustment for incremental residuum diverted to summer asphalt production, the system residual fuel yields are about the same at both high and low crude oil run levels.)

In summary, the U.S. refining system shows only moderate signs of strain despite the high capacity utilization. There is enough economically viable spare capacity to allow refinery runs to vary significantly with seasonal demands and still cover growing annual average requirements. Performance data shows that the system has met peak demands without degradation of yields or increased crude oil quality requirements. On the basis of this performance, it seems certain that the existing system could be operated at an annual utilization rate of 86 percent (about the same as recent peak rates) without significant economic penalty. This capability, coupled with planned capacity expansions, should be adequate to cover growth into the mid-1990s. However, the actual growth will probably be divided between increased refinery production and added imports depending on relative economics.

## Product Supply Flexibility

Even at today's higher capacity utilization, the U.S. refining system retains considerable flexibility to alter crude oil runs and shift product mix to meet seasonal demands, and to recover from unexpected problems. However, the flexibility of the existing system is expected to shrink as it approaches full capacity.

From a practical standpoint, the industry has the option to provide future seasonal and emergency response capability through a combination of:

- New refining capacity -- As shown in Table 31, both distillation and secondary capacity have increased each year since capacity bottomed out in 1986. Capacity additions are continuing through new unit construction and debottlenecking of existing facilities.

- Inventory variance -- In recent years, seasonal and emergency demand variations have been met primarily by swings in crude oil run rates and shifts in product mix. Inventory variations provide a further alternative to meeting seasonal and other known-in-advance peak needs. In off-peak periods, inventory can be built and stored for use at peak periods when the system production rate is at or near capacity, providing a further source of supply. Although the industry has not operated in this manner in recent years, it may become economic to absorb more of the demand variance from planned inventory builds and drawdowns.

- Imports -- Imported product can provide coverage for demand variances.

TABLE 31

U.S. REFINING SYSTEM
CRUDE OIL AND UPGRADING CAPACITY ADDITIONS
(Thousands of Barrels per Day)

| Year | Crude Distill. | Cracking | Coking |
|---|---|---|---|
| 1986 | 107 | 103 | 48 |
| 1987 | 349 | 103 | 152 |
| | 456 | 206 | 200 |
| Percent Increase* | 3% | 3% | 11% |

*Crude oil run increased 7 percent in the same two-year period.

Source: EIA, Petroleum Supply Annual, 1987.

As discussed below, the degree of supply flexibility varies considerably by product.

Gasoline

Table 32 shows U.S. gasoline supply and demand for 1985 through 1987. Demand has grown about 200 MB/D per year in the period to about 7.2 MMB/D in 1987. Domestic refinery production accounts for about 95 percent of supply; imports have remained at about 5 percent of supply over the period.

TABLE 32

U.S. GASOLINE SUPPLY AND DEMAND

| | 1985 | | 1986 | | 1987 | |
|---|---|---|---|---|---|---|
| | MB/D | % | MB/D | % | MB/D | % |
| U.S. Demand | 6,831 | | 7,034 | | 7,206 | |
| Supply | | | | | | |
| Refinery Prod. | 6,419 | 94 | 6,752 | 96 | 6,841 | 95 |
| Imports | 381 | 6 | 326 | 5 | 384 | 5 |
| Other* | 31 | - | (44) | (1) | (19) | 1 |
| Total Supply§ | 6,831 | 100 | 7,034 | 100 | 7,206 | 100 |

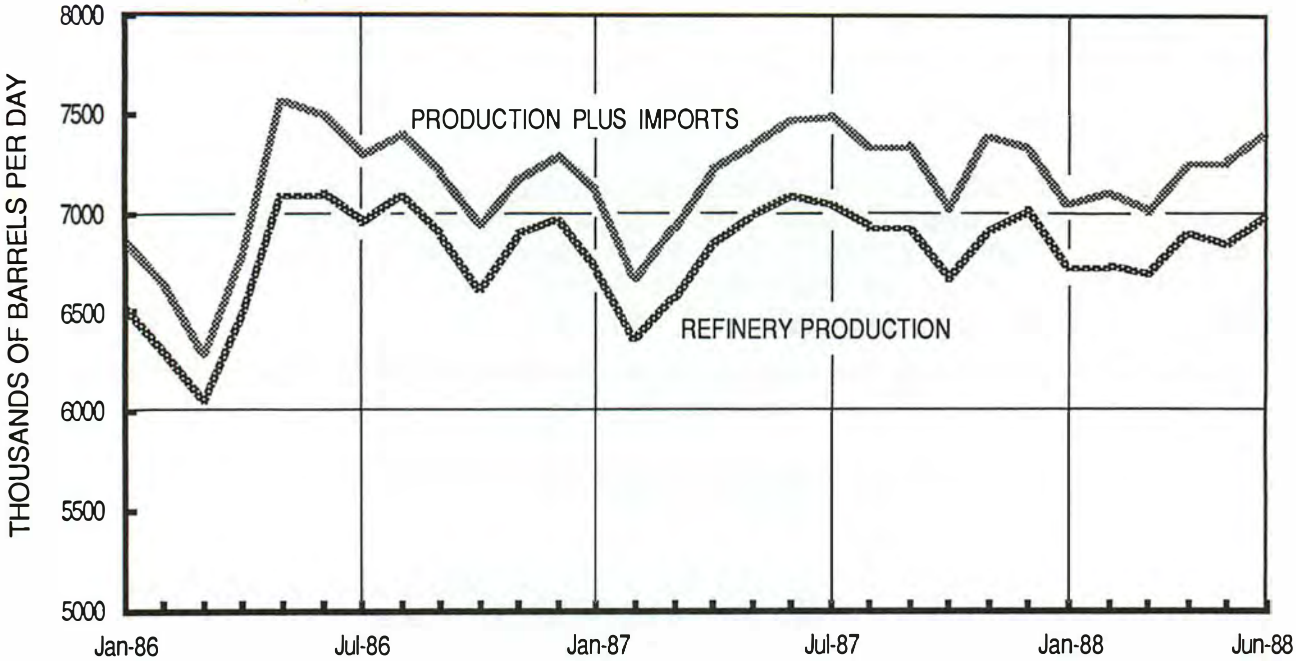
*Inventory draw (or build) less exports.

§Totals may not equal sum of components due to independent rounding.

Source: EIA, Petroleum Supply Annual, 1987.

The 1986 NPC report, U.S. Petroleum Refining, noted that gasoline production in the United States was approaching capacity and could peak as early as 1988. A combination of added facilities, reactivation of idle units, and improved performance from existing capacity has resulted in a system that retains flexibility despite its heavy loading.

Refinery gasoline production averaged 6.9 MMB/D in 1987 and the first seven months of 1988. Monthly performance of the system is shown in Figure 39, a plot of refinery production and total new supply (production plus imports). The graph shows that gasoline production has exceeded 7 MMB/D in several months and production has continued to follow seasonal demand. In 1986 and




SOURCE: EIA, Petroleum Supply Monthly, June1988.

Figure 39. Gasoline Supply.

1987, gasoline production in the May through August peak season averaged about 365 MB/D more than the other eight months. There is clearly some flexibility left in the existing system.

Inventory swings and import variances have not been a significant factor in meeting peak demands to date. Imports have generally increased proportionately less in the summer than production, and in three of the last five years, gasoline inventories actually increased through the peak season. (In 1987, inventory draw added only about 2 percent to summer supply.)

Since 1985, the industry has added significantly to gasoline and octane capacity as shown in Table 33. Besides these physical changes, the existing facilities' capability has been "stretched" by the use of improved catalysts and innovative operating techniques. Much of this capacity has been absorbed by lead phaseout, and more will be absorbed by the pending vapor pressure restrictions, which will reduce butane blending. Gasoline capacity expansions are expected to continue; and in addition, part of the octane demand will be met by increased use of octane-blending supplements, such as MTBE and ethanol.

Neither transportation, tankage, nor terminal capability are seen to limit any of the gasoline supply alternatives.

Distillate Fuel

Table 34 shows U.S. distillate demand (consumption) and supply for 1985 through 1987. Demand has grown about 50 MB/D per

TABLE 33

U.S. REFINING SYSTEM
GASOLINE CAPACITY/OCTANE CAPACITY ADDITIONS
(Thousands of Barrels per Day)

| Year | Reformer Capacity | Isomer-ization | Alkylation Capacity |
|---|---|---|---|
| 1986 | 61 | 68 | 33 |
| 1987 | 86 | 139 | 19 |
| | 147 | 207 | 52 |
| Percent Increase | 4% | 80% | 6% |

Source: Capacity data from EIA, Petroleum Supply Annual, 1987.

TABLE 34

U.S. DISTILLATE SUPPLY AND DEMAND

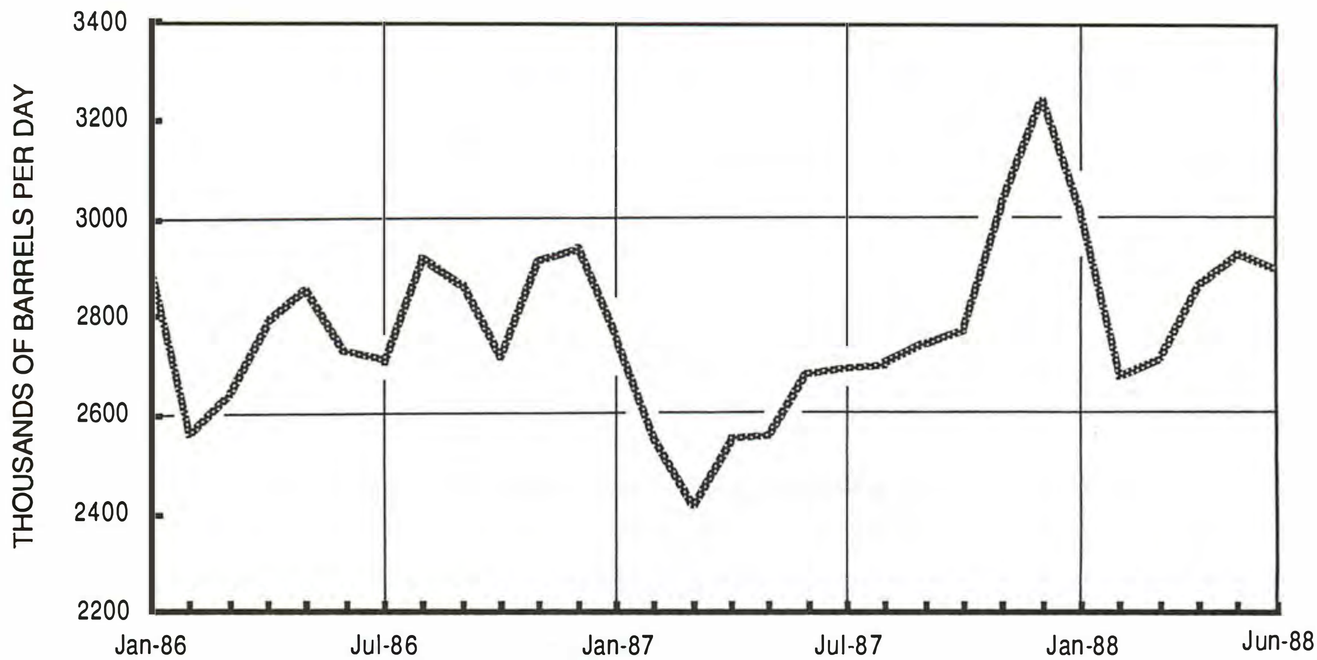
| | 1985 | | 1986 | | 1987 | |
|---|---|---|---|---|---|---|
| | MB/D | % | MB/D | % | MB/D | % |
| Demand | 2,868 | | 2,914 | | 2,976 | |
| Supply | | | | | | |
| Refinery Prod. | 2,687 | 94 | 2,798 | 96 | 2,731 | 92 |
| Imports | 200 | 7 | 247 | 8 | 255 | 8 |
| Other* | (19) | (1) | (131) | (4) | (10) | - |
| Total Supply | 2,868 | 100 | 2,914 | 100 | 2,976 | 100 |

*Inventory draw (or build) less exports.

Source: EIA, Petroleum Supply Annual, 1987.

year to 2,976 MB/D in 1987. Imports provide between 7 and 8 percent of domestic demand, but these are partially offset by exports, which have averaged about 78 MB/D during the period.

As shown in Figure 40, monthly refinery production generally follows a seasonal pattern. Refining incentives for incremental distillate production are often marginal, and distillate production rate is much more sensitive to short-term prices than gasoline. Refinery yields of distillate have ranged from a low of about 20 percent of crude oil run to over 24 percent.




SOURCE: EIA, Petroleum Supply Monthly, June1988.

Figure 40. U.S. Refining System Distillate Production.

The refining system retains a very substantial physical capability to produce additional distillate by:

- Utilizing gasoline-to-distillate-yield flexibility inherent in complex refineries.

- Running incremental crude oil.

Complex refineries can, and routinely do, shift the yield levels of gasoline to distillate over a fairly wide range in response to economic incentive. This flexibility, coupled with incremental crude oil capacity currently available in the U.S. refining system, can provide substantial incremental distillate volumes throughout most of the year. However, economic distillate supply flexibility is expected to shrink somewhat as the system approaches maximum gasoline capacity.

Review of monthly performance indicates a system with ample distillate capacity whose utilization is sensitive to economics. Even in the peak winter demand season, refinery distillate production tends to vary by as much as 400 MB/D in response to perceived margin changes. The pattern of distillate imports also is more consistent with transient price differences between foreign and domestic markets than any supply needs; seasonal increases in imports have been minimal. Peak winter demands have been met; about half from increased refinery production and half from inventory flux.

Distillate supply is not expected to be a problem through the mid-1990s at least. Distillate capacity will increase with crude oil capacity additions, and distillate yields tend to increase unavoidably as run levels approach upgrading capacity. However, existing facilities will accommodate increased imports and/or increased seasonal storage should they become economic.

The proposed regulation of highway diesel fuel sulfur content (limiting sulfur to 0.05 percent), could substantially reduce the distillate supply flexibility, unless the regulatory control schedule allows adequate lead time for the required investments in desulfurization. The existing distillate desulfurizers, even if used to their maximum capacity, could produce no more than about one-third of the current volume of highway diesel to the 0.05 percent sulfur specification. Further, potential import sources would also be greatly limited by any abrupt tightening of the fuel specifications. Refiners, engine manufacturers, and other interested parties should work with the Environmental Protection Agency (EPA) to develop a phase-in schedule that will efficiently introduce 0.05 percent specification fuel concurrently with diesel engines designed to take advantage of the fuel.

### Residual Fuel

Table 35 shows the overall residual fuel supply-demand balances for 1985-1987. Recent internal demand has ranged from 1.2 to 1.4 MMB/D, only about 40 percent of the maximum level reached in 1978. About 45 percent of demand is covered by imports.

The residual fuel category includes a number of products differentiated by sulfur content, viscosity, and pour characteristics required by the end-user. These products are not interchangeable in the market nor are they interchangeable in refinery production. In general, U.S. demand tends toward lower sulfur fuel required by environmental standards, while U.S. refinery production tends to be high sulfur. As a consequence, about 20 percent of U.S. production is exported to areas where it is marketable.

In general, residual fuel production (except for asphalt) is a by-product of gasoline and distillate manufacture, and refiners

TABLE 35

U.S. RESIDUAL FUEL OIL SUPPLY AND DEMAND

| | 1985 MB/D | 1985 % | 1986 MB/D | 1986 % | 1987 MB/D | 1987 % |
|---|---|---|---|---|---|---|
| Demand | 1,202 | | 1,418 | | 1,264 | |
| Supply | | | | | | |
| Refinery Prod. | 882 | 73 | 889 | 63 | 885 | 70 |
| Imports | 510 | 42 | 669 | 47 | 565 | 45 |
| Exports | (197) | (16) | (147) | (10) | (186) | (15) |
| Other* | 7 | 1 | 7 | - | - | - |
| Total Supply | 1,202 | 100 | 1,418 | 100 | 1,264 | 100 |

*Inventory draw (or build) and rounding.

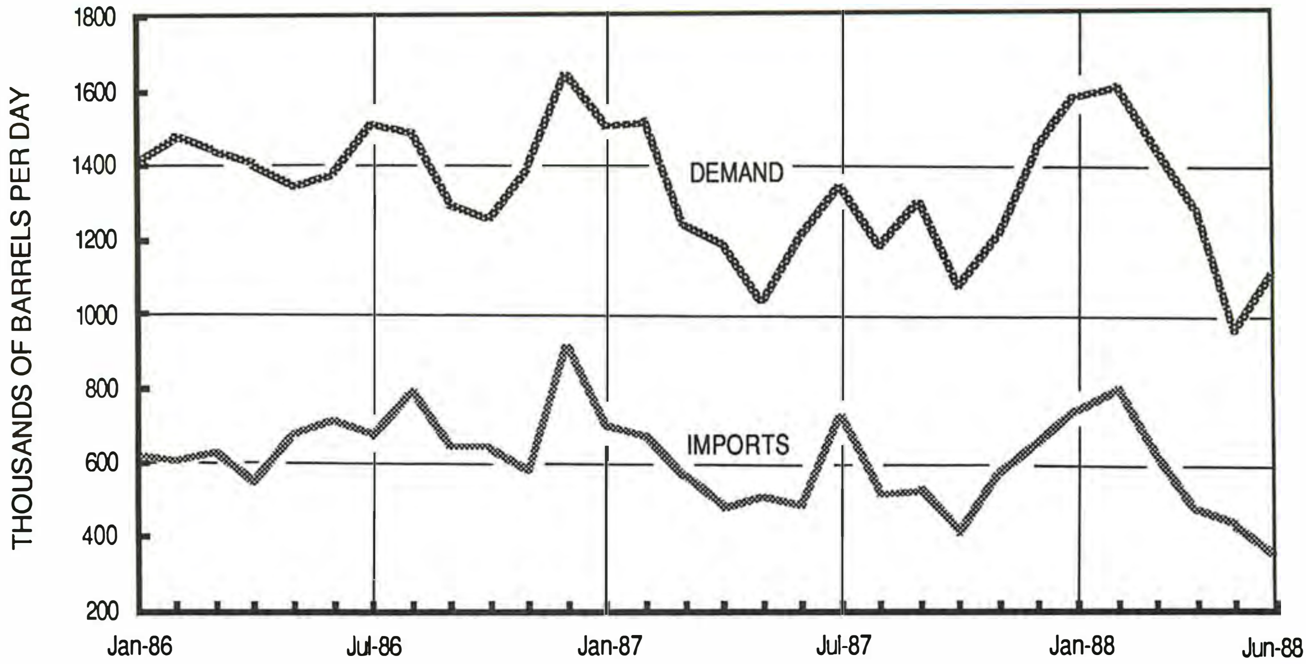
Source: EIA, Petroleum Supply Annual, 1987.

do not normally vary residual fuel production to meet seasonal demand swings. This is illustrated by Figures 41 and 42, which show that demand swings are covered primarily from imports while refinery production is quite uniform throughout the year. Winter is still the highest demand season for residual fuel, but as shown in Figure 41, there is a developing summer peak related to electricity demands for air conditioning.

In 1987, PADD I accounted for 54 percent of residual fuel demand and 93 percent of imports. Exports of residual fuel were about two-thirds from the West Coast (PADD V) and most of the balance from PADD III.

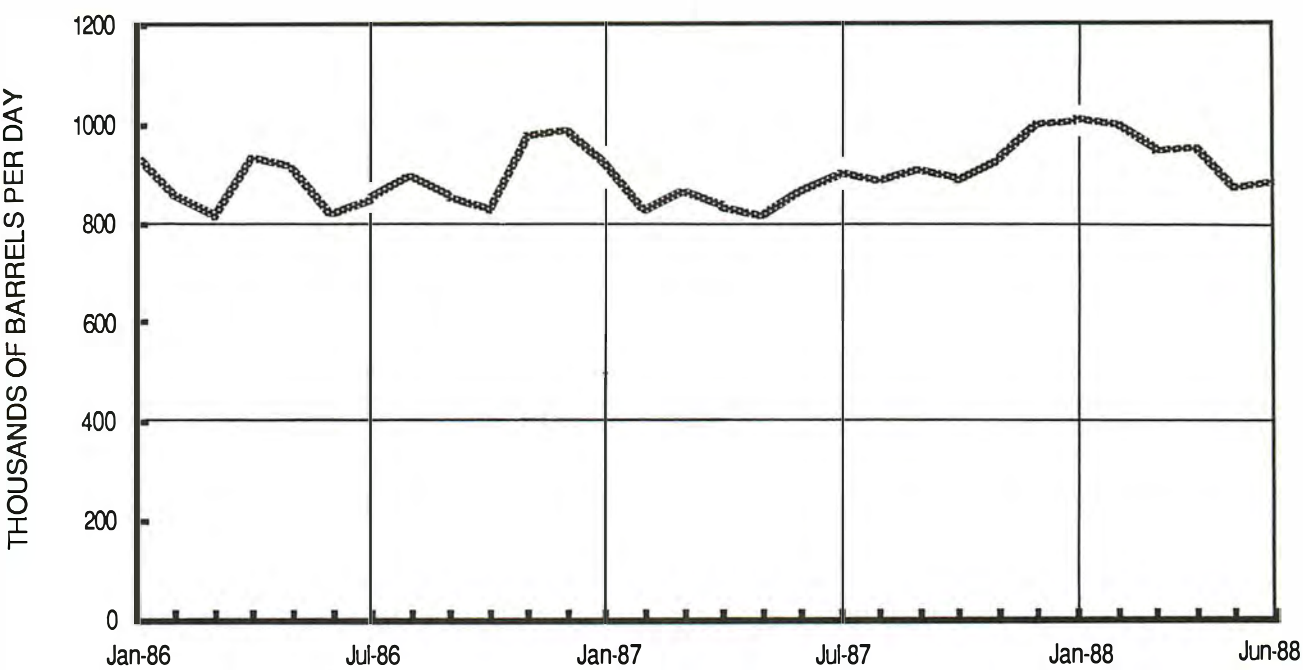
The domestic refinery system has the physical capacity to produce substantially more residual fuel, but it is unlikely to be feasible under reasonably normal economic conditions. It is also unlikely that refineries could meet current sulfur requirements of consumers without waivers of environmental regulations. Barring a major upset, residual fuel production seems certain to remain primarily a by-product of light fuels manufacture.

There is more than ample flexibility in downstream residual fuel facilities to handle short-term demand increases. Terminal and storage capacities still reflect the much higher volumes of earlier years. On the other hand, relatively high levels of




SOURCE: EIA, Petroleum Supply Monthly, June1988.

Figure 41. Residual Fuel Oil Demand and Imports.




SOURCE: EIA, Petroleum Supply Monthly, June1988.

Figure 42. U.S. Residual Fuel Oil Production.

residual fuel inventory in the primary system and in industrial/utility consumer storage provide better insulation from short-term supply upsets for residual fuel consumers than for users of other products.

## CRUDE OIL AND PRODUCT TRADING

In the current business environment, petroleum trading is a major element in the system dynamics. It provides a means to reduce transportation, to optimize the use of existing facility capacity and to respond to supply problems. Further, trading helps ensure that regional crude oil and product prices throughout the country will respond promptly to the world petroleum market.

The volume of crude oil and product traded in the United States is quite large. Virtually every refiner and most large marketers have full-time trading staffs. Typically, a major refiner may handle about 1.5 barrels of crude oil for each barrel of crude oil it refines; its ratio of product handled to marketing sales may be only slightly less. The high ratios reflect crude oil and product traded (via exchange or contemporaneous buy-sell) to reduce cost, improve efficiency, or capitalize on profit opportunities. Trading is an essential part of the supply system, and it is unlikely that any large refiner/marketer could be competitive without the cost savings it offers.

Trading activity can be defined in four broad and overlapping categories according to the objectives:

- Location Trades -- The objective of these trades is to reduce transportation costs. To illustrate, companies often produce or acquire crude oil at locations without convenient pipeline access to their refineries. These companies routinely arrange trades for such crude oil among themselves so that both parties to the deal obtain comparable crude oil with minimum transportation cost. For products, the most common trades are among refiners or marketers who exchange (or buy-sell) their surplus supply in one area for comparable product in another area. During the period of shrinking demand, product trades enabled companies to shut down unprofitable refineries without withdrawing from competitive marketing in the area served.

- Facility Optimization -- These trades are aimed at getting the better utilization or better performance from existing hardware. A simple example: Refiner A with a connection to Explorer pipeline may inject product into that line for Refiner B in return for comparable product injected into Colonial pipeline. Both parties avoid duplicating an expensive connection (usually a pipeline segment and high-volume pumps) and both get higher utilization of existing facilities.

Most facility optimization trades are fairly simple (e.g., exchange of terminaling), but some can be very complex. The trading process in which refiners continuously juggle crude oil input to maximize refinery utilization and profits involves very complex economic analysis and interaction among many refiners with differing needs.

- Balancing Purchase or Sale -- The bulk of system crude oil and product is bought and sold under term arrangements, but a company's term supply and demand are rarely in balance. Traders are usually responsible for buying or selling the crude oil or product necessary to attain a balance. Traders seek the best overall economics, not just the best price. A company needing distillate at the Gulf, for example, may elect to buy it in New York Harbor and translate the volume to the Gulf by reducing pipeline shipment into PADD I or via a location-type trade.

- Opportunity Trading -- The volatility of both world and local markets creates frequent profit opportunities for traders. For example, a high regional spot-market price may motivate traders to pull down inventory to exploit the opportunity while simultaneously arranging for replacement at less cost. Since the added supply is likely to bring prices down, the trader has a tangible incentive to respond quickly. Distressed cargoes, local shortages or surpluses, and differing economic projections create the economic potential for profitable trades.

  Refiners and marketers are active opportunity traders, but there are other companies whose primary business is opportunity trading. These are the companies that purchase crude oil or product for speculative resale, acting as middlemen. These traders monitor markets throughout the country or the world for price disparities and take quick advantage. If U.S. prices rise significantly above parity with world markets, foreign traders quickly shift supplies to the United States; conversely, supplies are promptly shifted away when domestic prices are depressed. Some traders act effectively as "market makers" and expediters for many kinds of domestic as well as foreign trading. The price-and-supply balancing function that these traders help perform is generally beneficial, but some have cautioned that foreign supplies from these middlemen are not secure and may disappear in times of shortage.

Trading expands the flexibility and response capability of the supply system, reduces overall costs, and helps stabilize local markets. These are beneficial by-products of a highly profit-oriented activity, and trading response tends to be proportional to the economic incentive available. Incentives need not be large; recent experience shows that a potential for a fraction of a cent per gallon will elicit vigorous trading activity.

Crude oil and product trading are intensely competitive; parties negotiate hard for a better price, a more favorable differential or more flexible terms. But in the end, each party must perceive an economic benefit or the deal will not be made. The net result is a more efficient and more responsive overall supply system.

Futures trading is essentially a financial activity that has become complementary to "wet barrel" trading described above. The development of trading was a natural response to the uncertainties associated with volatile markets. Futures trading is now an important factor in the dynamics of petroleum supply:

- Futures markets improve price discovery. The determination of prices through open outcry rather than traditional assessments removes uncertainty concerning prices, cuts the bid/asked spread, promotes more trading, and contributes to economic efficiency.

- Futures trading permits the commercial participant (the oil company or trader) to transfer to others the price risk related to the ownership of stocks.

- Vigorous futures trading has contributed to prices (domestic and foreign) that move rapidly in response to world events and perceived changes in supply and demand.

- Although a very small percentage of NYMEX futures contracts are taken to delivery, increasingly, traders are using the "exchange for physicals procedure" to effect wet-barrel transactions. For this activity the futures market has become an effective price clearing house for traders to balance long and short wet-barrel requirements.

- Although the futures exchange does not quote prices for the current month, prices for the first future month are often used as reference for prompt (current month) trades. (e.g., Price at the time of transfer is based on that day's "Merc" price plus or minus a "differential.")

"Volumes" traded in the futures market exceed any physical capacity to deliver by orders of magnitude. Daily trading volumes frequently exceed daily consumption. There is some concern that a severe supply disruption would render the futures market inoperative. Further, there is some concern that a futures market failure would somehow seriously impact the industry's ability to effectively distribute available supplies. It is possible, though speculative, that a severe supply disruption would cause a failure of the futures markets. Rapid large price increases (or decreases) could make the futures markets practically inoperable until the passage of sufficient time (days) to bring exchange trading price limits into line with the real market.

In the unlikely event of a failure of the futures markets, there is not likely to be any significant disruption in physical barrel availabilities or distribution capability.

- Most companies use the futures market as a financial hedge for inventories, margins, timing, etc., not as a source of wet-barrel supply.

- Inventories are not significantly affected by the existence of the futures market as indicated by 87 percent of respondents to the NPC's questionnaire on this subject (Reference Volume IV).

The reaction of futures markets to a supply crisis is untested. Certainly the failure of a futures market would alter market psychology and would be of crisis proportions financially for those traders on the wrong side of a market turn. These events would not, however, change the fact that oil is physically available in the system nor would they change the facilities for its distribution. Commercial transactions to keep this oil moving would be conducted in much the same way as they were prior to the advent of futures markets.

## PRODUCT IMPORTS

Imports are often described as the "balancing supply," filling the gap between domestic production and demand. The process by which the "balance" is obtained is a very important element in U.S. supply system dynamics.

Sources of product imports tend to fall into two general categories:

- Supplies logistically normal to the United States, where preference or transportation advantage makes the United States the usual market for the product (e.g., products from Canada, Venezuela, the Caribbean).

- Supplies logistically normal to other areas, but which can flow to the United States if economics are favorable.

Obviously, U.S. import volumes from Venezuela could be (and are) affected by prices, but the higher transportation costs to other major consuming areas tends to make diversion of product less likely. In fact, product flow from Europe and the Middle

East to the Western Hemisphere is more common. Table 36 shows the proportion of U.S. finished gasoline and distillate imports from the major Western Hemisphere suppliers in 1987.

The Western Hemisphere imports provide a relatively stable base supply volume to the United States. Although foreign refiners use refinery flexibility and inventory strategy to take advantage of market changes, import volumes from the major Western Hemisphere sources tend to be relatively uniform throughout the year. In fact, a significant portion of Western Hemisphere imports is on term contracts.

In sharp contrast, import volumes from Europe and other areas are highly variable and very sensitive to short-term price differences between U.S. and foreign markets. For example, if U.S. product prices rise above European prices by more than about 4¢ to 5¢ per gallon (roughly the shipping cost to the East Coast), imports increase dramatically as traders seek to cash in on opportunity.

Although such price disparities are often short-lived, traders can eliminate much of the risk by "hedging" in the commodity futures market (e.g., by selling a contract for future delivery). Large volumes can be hedged quickly in the futures market. The result is that imports respond very vigorously to even brief price disparities; and the surge in import volume may continue for some time after the price gap has closed.

Figure 43 illustrates the wide variability of these "opportunity" imports. It shows the monthly volume of distillate imports from all areas except the major Western Hemisphere suppliers (defined here as Brazil, Canada, Mexico, Netherlands

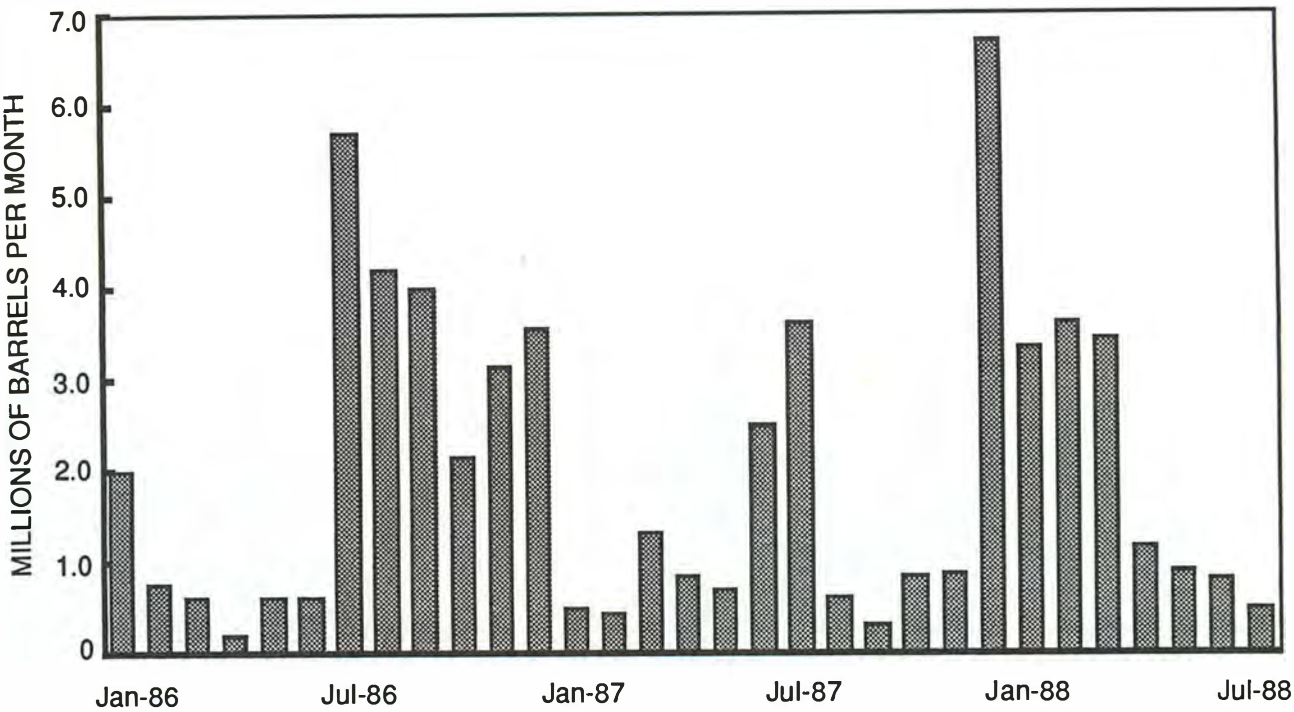
TABLE 36

1987 SOURCE OF PRODUCT IMPORTS

| | Gasoline | Distillate |
|---|---|---|
| Western Hemisphere* | 51 | 79 |
| Europe and Other | 49 | 21 |
| | 100% | 100% |

*Includes only Brazil, Canada, Mexico, Netherlands Antilles, Trinidad, Venezuela, and Virgin Islands.

Source: EIA, Petroleum Supply Annual, 1987.




*Excludes imports from Brazil, Canada, Mexico, Netherlands Antilles, Trinidad, Venezuela, and Virgin Islands.

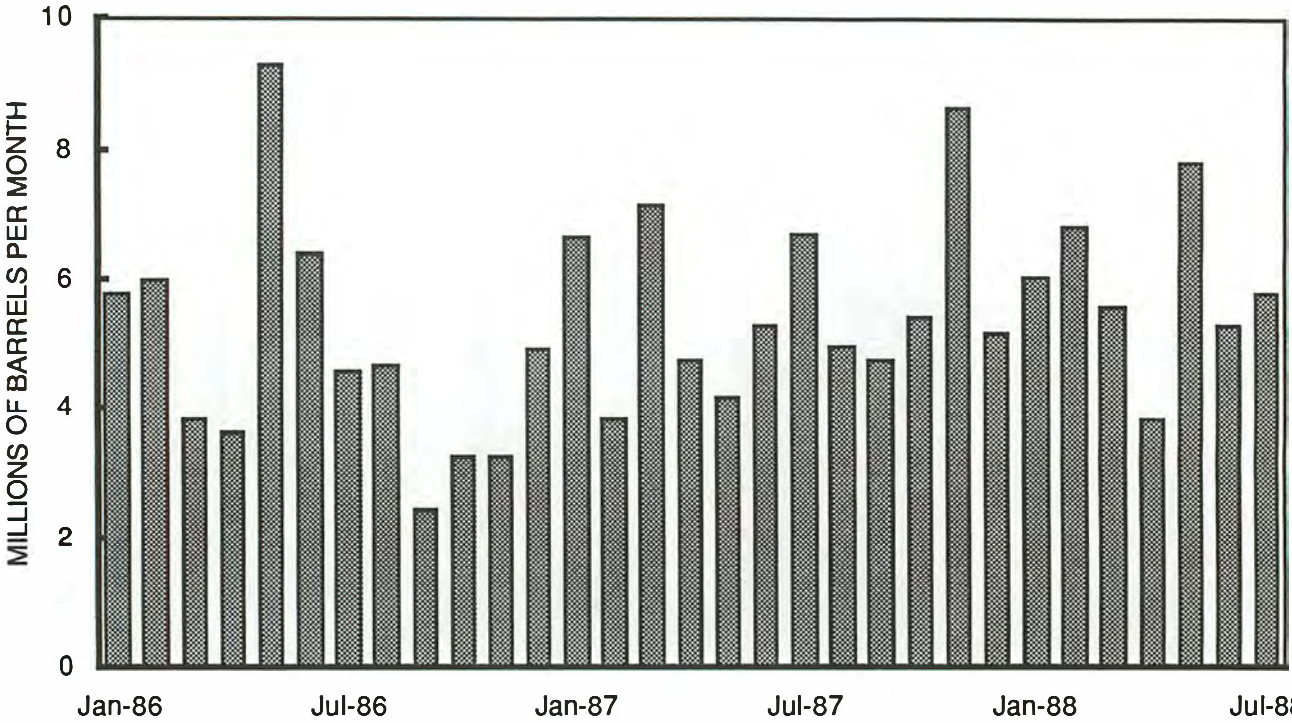
Figure 43. Distillate Import Volumes (Excluding Western Hemisphere).*

Antilles, Trinidad, Venezuela, and the Virgin Islands). Over the 31-month period plotted, the average volume of imports from non-Western Hemisphere sources was 1.9 million barrels per month, but the actual imports ranged from 0.2 million barrels to almost 7 million barrels per month. The import pattern is not seasonal; in 1986 and 1987, peak imports from these sources occurred in the summer. In Europe, summer is often a period of surplus distillate supply and low prices.

As illustrated by Figure 43, the import response to economic incentive can be quite large. Its effect on the domestic market is also large. There is ample evidence that import surges weaken domestic prices -- and low import levels tend to strengthen them. It is worth noting that the major surges in distillate imports resulted from price variances well within "normal" bounds.

Figure 44 is a similar graph showing monthly gasoline imports from areas excluding the same Western Hemisphere countries. Like distillate, gasoline import volumes vary more with price differentials than with the season. The countries of origin for the imports are also variable.

In brief, product imports play a key role in supplementing U.S. production and providing a balancing mechanism for both supply and prices.




*Excludes imports from Brazil, Canada, Mexico, Netherlands Antilles, Trinidad, Venezuela, and Virgin Islands.

Figure 44. Gasoline Import Volumes (Excluding Western Hemisphere).*

NATURAL GAS

In 1987, natural gas provided more than 17 quadrillion BTU of energy for the United States, roughly 23 percent of total energy demand. Although gas supplies about half the energy provided by petroleum and roughly the same amount as coal, the operation and economics of the industry are not widely understood by the general public, in part because of the complex regulations that controlled it in the past.

Natural gas demand and supply for the Lower-48 States are shown in Table 37 in trillions of cubic feet per year. (A trillion cubic feet contain about the same energy as 170 million barrels of oil.) Natural gas demand in 1979 was 20.1 TCF and then declined as conservation and other factors reduced consumption. By 1987, gas demand was down 16 percent at 16.9 TCF. Natural gas supply is predominantly from domestic production; imports account for only 6 percent of demand. Table 37 shows that domestic gas production has declined by 3.1 TCF since 1979. Production was limited by demand, and there remains a substantial, but shrinking, capacity surplus today. The decline in demand and the emergence of surplus production were catalysts for a major change in gas system dynamics.

TABLE 37

LOWER-48 STATES
NATURAL GAS DEMAND AND SUPPLY
(Trillion Cubic Feet)

| | 1979 | 1984 | 1987 |
|---|---|---|---|
| Demand | 20.1 | 17.7 | 16.9 |
| Supply | | | |
| Production | 19.4 | 17.1 | 16.3 |
| Imports | 1.2 | 0.8 | 1.0 |
| Other* | (0.5) | (0.2) | (0.4) |
| | 20.1 | 17.7 | 16.9 |

*Net of inventory flux, exports, losses, and exotic supply.

## The System

The natural gas system differs substantially from the liquid petroleum system in its market orientation, its physical facilities, and its economic-regulatory structure. The physical system for natural gas supply is shown schematically in Figure 45. Most large gas pipelines originate in the Gulf Coast areas of Texas and Louisiana, which account for 60 percent of U.S. gas production. If necessary, field gas is processed to bring it to pipeline standards, and pipelined to the "city gate," where it is delivered to a local distribution company.

Oil and gas serve generally different markets. As shown in Table 38, virtually all demand for natural gas is for some form of heating, while the petroleum market is predominately transportation fuels. On a short-term basis, the oil and gas systems interact only in the industrial-utility market where plants with dual-firing capability can (and do) shift between oil and gas in response to price incentives, supply constraints, or environmental considerations. On the supply side, small volumes of petroleum enter the gas system as refinery gas or synthetic gas, and some liquefied petroleum gas-liquefied natural gas (LPG-LNG) is used to cover peak winter-demand rates.

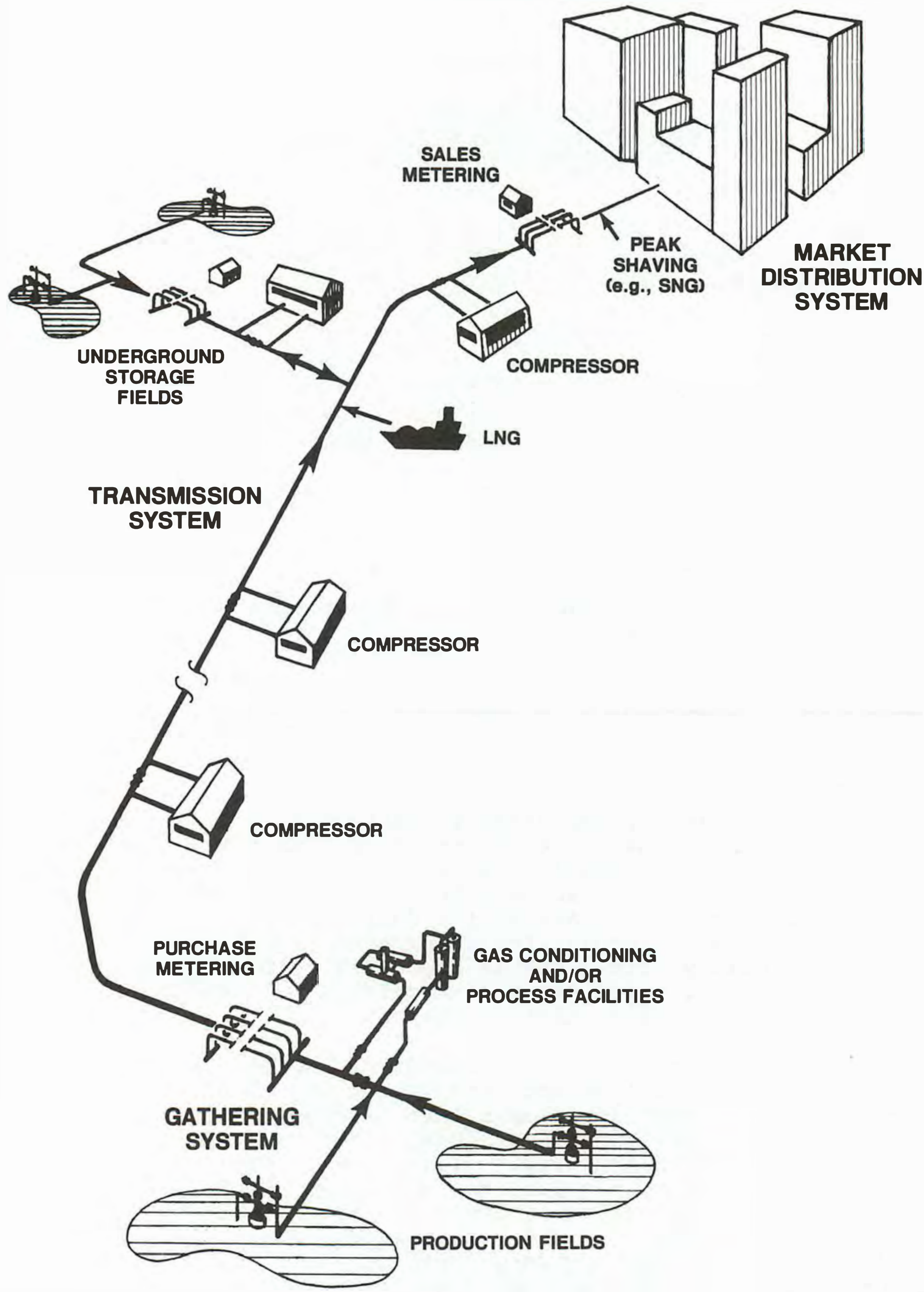



Figure 45. Typical Natural Gas Pipeline System.

TABLE 38

1987 PETROLEUM AND NATURAL GAS MARKETS
(Percentages)

| | Natural Gas Sales | Petroleum Sales |
|---|---|---|
| Transportation* | 3 | 63 |
| Residential/Commercial | 39 | 8 |
| Industrial | 41 | 25 |
| Electric Utility | 17 | 4 |
| | 100 | 100 |

*Includes pipeline fuel.

Source: EIA, Monthly Energy Review, March 1988.

The natural gas industry developed under a regulated public utility structure. The two primary reasons for this structure are still key elements in the present system dynamics:

- First, the high capital cost of the gas delivery grid to supply consumers (particularly residential consumers) made it difficult for effective competition to develop in gas transmission and distribution.

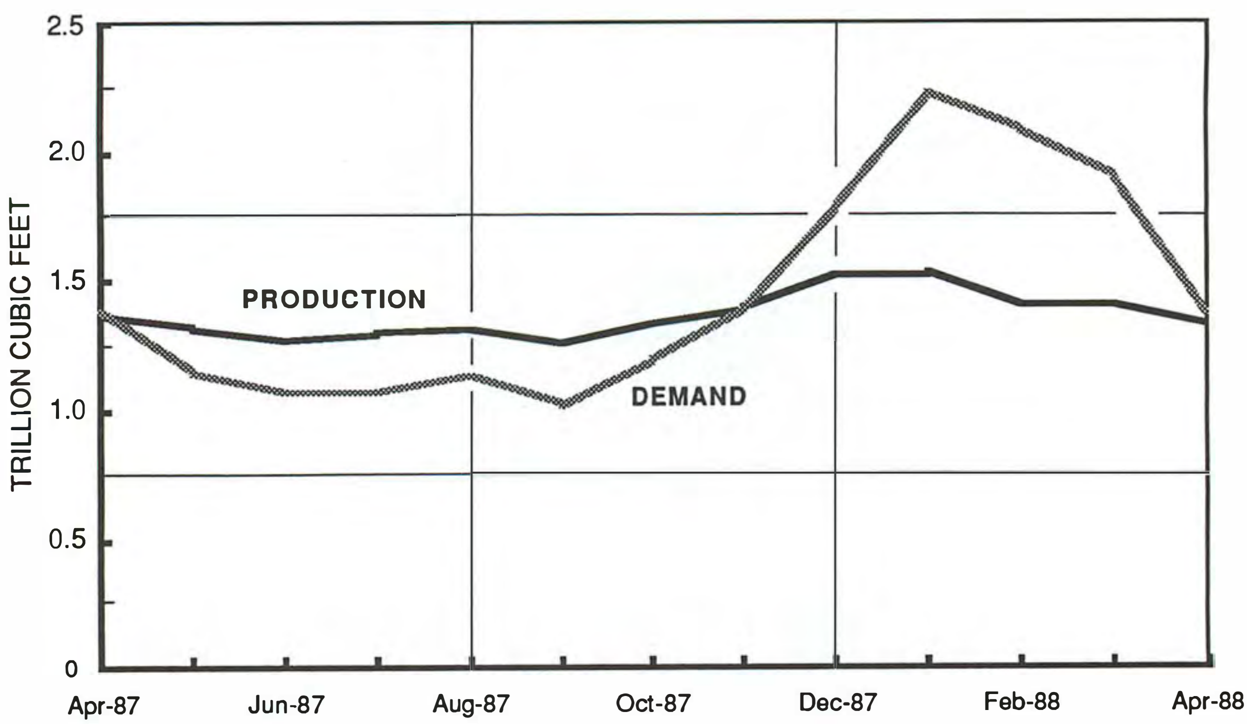
- Second, since gas cannot practically be inventoried by consumers, supply continuity for customers with no alternative energy supply became an overriding objective of the industry. To assure continuity, the system required surplus deliverability at the field level, storage, and peak-shaving facilities downstream to cover winter demands, plus a load-shedding priority program to shift gas from less vulnerable users when necessary.

The system that developed includes local distribution companies, usually under the control of state public utility commissions, that distribute gas to the consumer, set consumer prices, and determine allocation priorities to their customers. Under federal regulation, interstate gas transmission companies purchase gas in the field, transport it to local distribution companies or other pipelines, and provide seasonal gas storage facilities. Unlike oil pipeline companies, which are solely transporters, gas transmission companies buy gas for resale and maintain the right and obligation to allocate their available gas among customers. In recent years, gas transmission companies have been providing transportation for non-owned gas also. In some states (e.g., Texas) intrastate pipeline companies serve the same functions for gas that does not move in interstate commerce.

## Seasonality and Storage

Gas demand is highly seasonal. Historically, consumption in the period from December through March has averaged 55 to 70 percent higher than the balance of the year. Figure 46 shows total U.S. monthly natural gas demand and domestic production for a 12-month period, beginning in April 1987. There is presently surplus production capacity in the United States; but as the graph shows, it falls far short of meeting winter demand.

Increased winter imports provide a small measure of coverage, but the industry must rely on gas storage and peak-shaving facilities to balance the winter demand. Gas transmission companies (and some local distribution companies) have developed underground storage facilities with an aggregate capacity of more than 8,100 billion cubic feet (BCF). Figure 47 shows a recent inventory cycle with summer injection rates of more than 200 BCF per month and winter withdrawal rates approaching 500 BCF per month. Storage drawdown often provides more than 20 percent of peak-month supply.




SOURCE: EIA, Monthly Energy Review, September 1988.

Figure 46. Gas Production and Demand -- April 1987 Through April 1988.

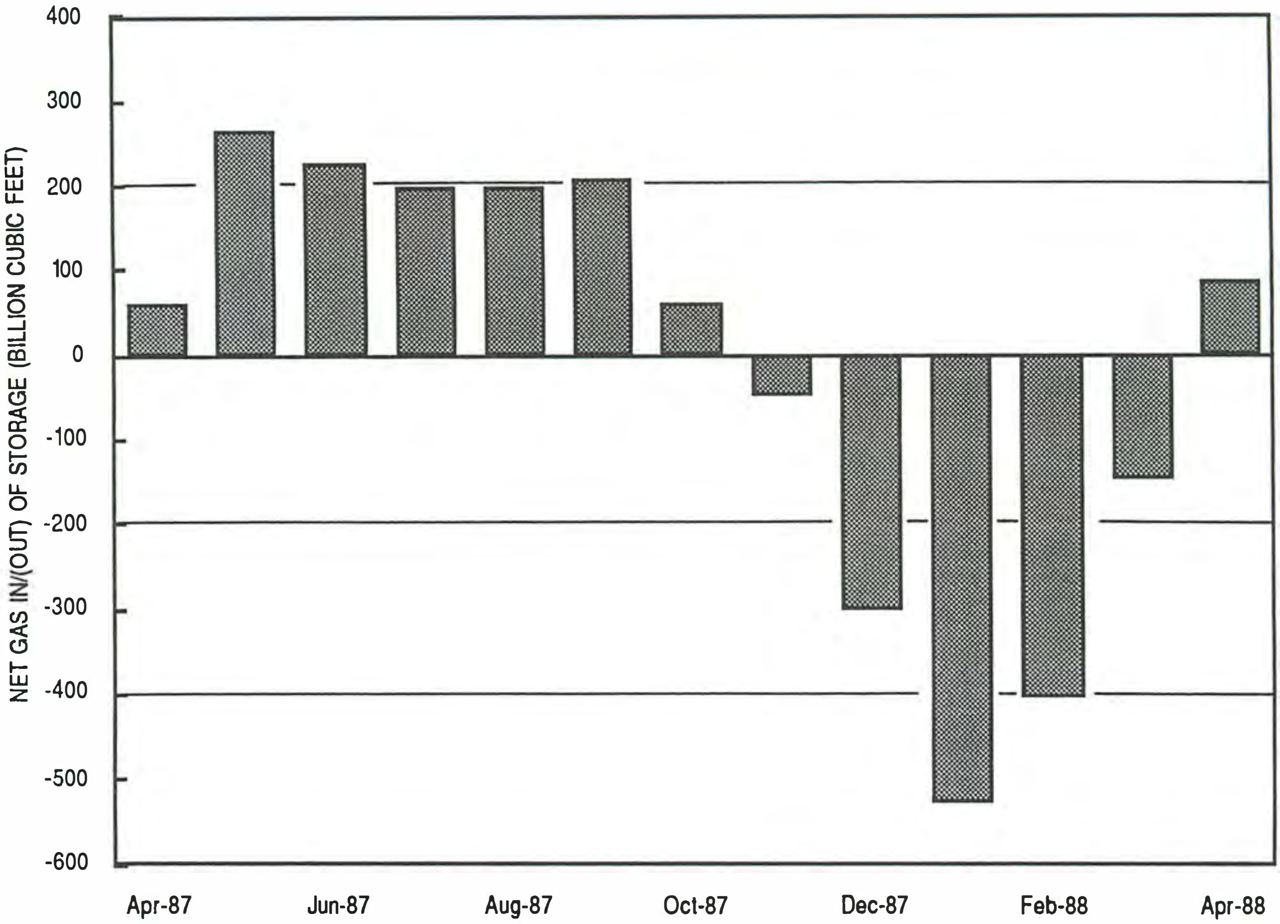



Figure 47. Gas Inventory Cycle -- April 1987 Through April 1988.

Gas flow rates from underground storage decline as volume is withdrawn and pressure declines. To maintain acceptable withdrawal rates, storage facilities retain a "base volume" of gas that is analogous to the "minimum inventory" of liquid products. The base-gas volume could be recovered, but at rates below those required to meet winter demand.

In the 1987-1988 season, the average volume of gas in underground storage was:

| STORED GAS VOLUME | |
|---|---|
| Base Gas Volume | 3.8 TCF |
| Average Working Gas* | 2.5 TCF |
| Total | 6.3 TCF |

*Ranging from a low of 1.7 TCF to a high of 3.1 TCF.

Gas inventory averaged about 130 days of average demand and had a aggregate value of about $14 billion at then-current prices. Recovery of the cost of maintaining this inventory, particularly in a period of volatile prices, is an important element in the economics of gas transmission companies. (At current value, interest cost alone would be $1.4 billion per year.)

Delivery rates from underground storage can be augmented by peak-shaving facilities owned by both transmission companies and local distribution companies. These facilities (e.g., LNG or propane-air injection) are designed to provide high delivery rates for short periods of peak demand. The aggregate capacity of these facilities is estimated at 7.9 BCF per day.

## Consumer Gas Prices

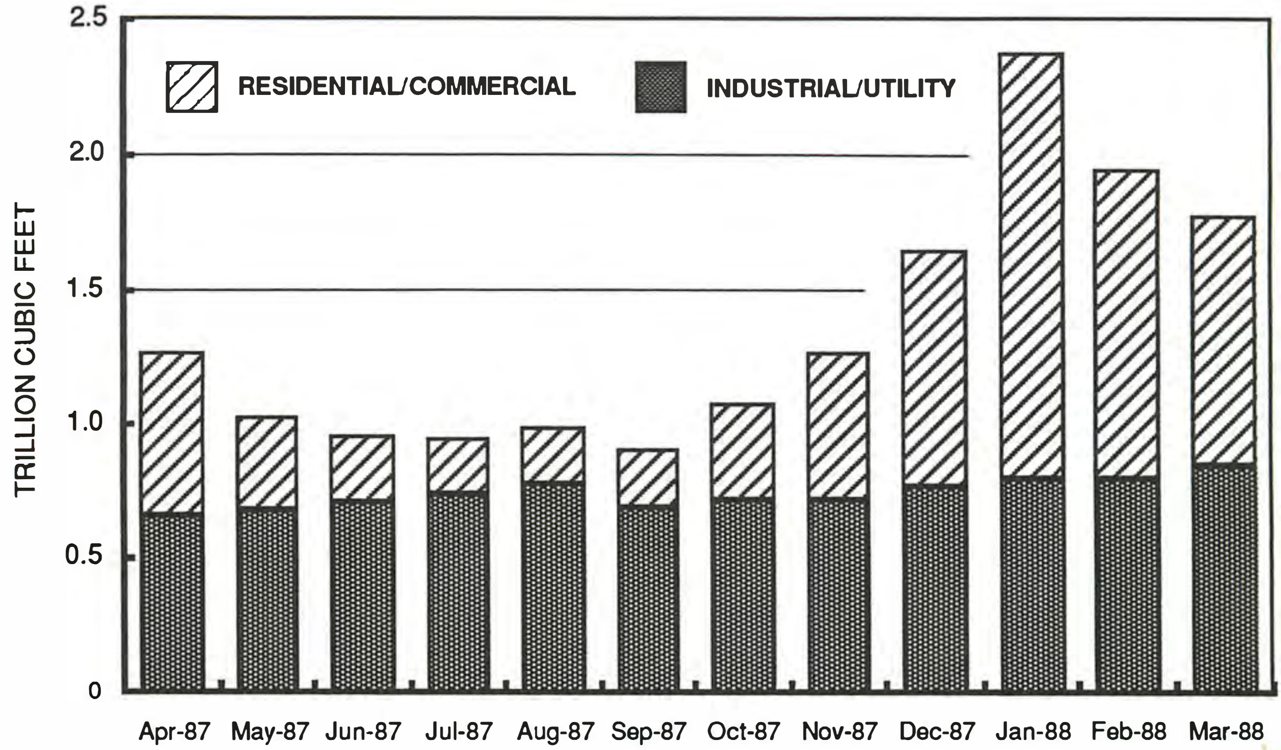
The gas industry is highly capital intensive, and the allocation of the cost (and return) of capital assets is a significant factor in establishing prices to different classes of customer. Gas acquisition costs and mainline transportation costs are generally applicable to all consumers, but the benefits of investment and the costs of local distribution grids and seasonal storage go disproportionately to residential and commercial consumers.

Figure 48 illustrates the very large difference in the seasonal demand variance of industry-utility consumers and residential-commercial customers. Industrial-utility use was relatively even throughout the year, while residential-commercial demand in January was almost six times their August requirements.

The allocation of costs to consumer groups depends in large part on local public utility commission policy; but in general, prices are responsive to the costs and assets committed to the customer class. Figure 49 is a diagram showing U.S. average 1987 prices for gas as it flowed through the system. Gas was acquired at an average wellhead price of $1.62 per million BTU and sold to a local distributor at the city gate for an average of $2.79 per million BTU. This price included the ratable cost of seasonal storage and other assets.

The right half of Figure 49 shows the price to various consumer classes; the width of the bar is proportionate to the demand of each class. On average, local distributors sold gas to electric utilities for less than the city-gate price. That price reflects both the lower capital cost dedicated to these customers and the prices of competing fuels. (In many areas, a utility-industrial customer must have installed dual-firing capacity to qualify for the lowest gas prices.) Along with the low gas price goes low priority in the event load shedding is required.

Residential and commercial consumers receive the highest priority on supply and therefore the highest price. In 1987, residential consumers paid more than three times the wellhead




SOURCE: EIA, Monthly Energy Review, September 1988.

Figure 48. Gas Demand Seasonality -- Industrial/Utility and Residential/Commercial.

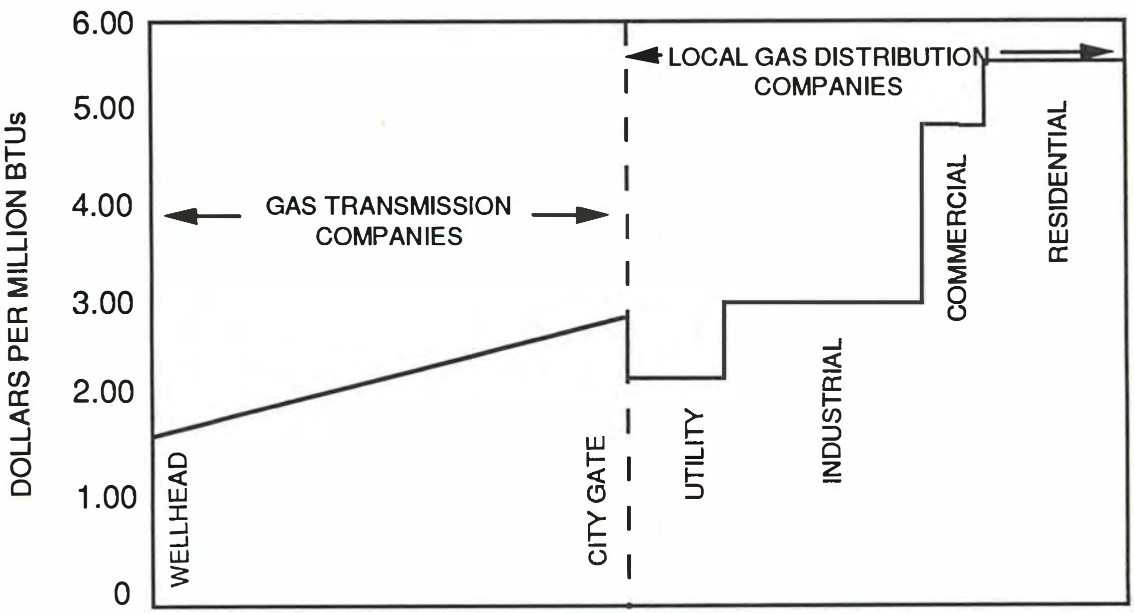



Figure 49. Average 1987 Gas Price Through the System.

price -- an indication of the substantial capital cost and expense required to maintain uninterrupted home delivery.

Burner-tip gas prices are no longer a regulated bargain; gas companies strive to keep prices competitive with petroleum on a current basis for switchable industrial and utility customers and on a longer-term average basis for others. The variance in consumer prices has been reflected as a variance in:

- Wellhead prices to gas producers
- Profit margins of gas transmission companies and, to a lesser extent, of local distribution companies.

Gas System Dynamics -- Before and After

Through the early 1980s, the gas system responded primarily to regulatory economics. Gas transmission companies (and their intrastate equivalents) were virtually the sole buyers of gas production and gas imports. They passed their costs and allowed profit margins to the local distributors that were almost their only customers. The local distributors in turn passed on their costs and allowed margins to local end-users. The system worked well for two reasons:

- FERC controlled producer gas prices at levels that virtually assured that gas would be a bargain to the consumer.
- In the 1970s and early 1980s, potential gas demand exceeded supply, and gas transmission companies were able to commit to take and sell essentially all gas production at regulated ceiling prices.

The decline of gas demand in the Lower-48 States from 20.1 TCF in 1979 to 16.0 TCF in 1986 left gas transmission companies unable to take and sell their contractually committed volumes. Surplus production began to appear in the market. At the same time, the sharp decline in oil prices brought gas sales under real competitive price pressure. It was no longer possible for gas transmission companies and local distributors to pass on their costs to the market. As a result, many gas transmission companies renegotiated the price and volume commitments of their contracts with producers. The result was lower wellhead prices and even more uncommitted gas competing for market. A significant spot market developed. Today, large consumers and local distributors shop for gas at the wellhead level.

For gas transmission companies, a three-tiered structure has evolved based on the level of service and the security of supply the customer desires. Terms vary, but in general the tiers are:

- System Gas Supply -- System gas constitutes the largest percentage of gas movements. The service level associated with this gas is consistent with historical practice. System gas is purchased under transmission company contracts and resold primarily to local distribution companies. It carries a ratable share of the transmission company's fixed costs (including seasonal storage charges), as well as the transmission company's gas acquisition cost. System gas has first priority on the transmission company's transportation capacity.

- Firm Transportation Gas -- Local distributors can and do contract for gas directly from the producer in order to obtain a lower acquisition cost. Transmission companies provide firm transportation for this gas at a price that reflects the full cost of the facilities and assets involved. Transportation gas is the second priority gas in the system, and its carriage is relatively certain. However, the outside gas supply tends to be less reliable than for system gas, because production failures and scheduling problems on gathering lines can result in erratic deliveries to the mainline.

- Spot Transportation Gas -- The decline in demand left most transmission pipelines with surplus capacity. Vigorous competition developed to use this capacity. After projected "system" and "firm transportation" gas demands have been scheduled, transmission companies will negotiate to ship incremental gas at less than the full allocated cost and margin in order to utilize remaining capacity. Spot transportation nominations are ranked in a priority "queue" according to pipeline tariffs, which may include negotiated price. Spot transportation gas is potentially the lowest priced gas, but it also takes the lowest priority. Even with overall capacity surplus, spot nominations are often bumped from a "queue" because of local bottlenecks.

Over 50 percent of the gas transported by transmission companies was non-system gas in 1987. This presents some potential operational and economic problems for transmission companies, such as the determination of unbundled transportation charges sufficient to cover the full system cost -- particularly the cost of the storage facilities and inventory. The storage facilities provide essential flexibility in the daily operation of the physical system in addition to accommodating seasonal volumes.

For example, as the result of upstream scheduling or production difficulties, a local distribution company may fail to deliver nominated volumes of "transportation" or "spot" gas to the transmission company. It is obviously unfeasible to cut off the distributor's delivered gas supply, and the transmission company routinely balances the shortfall from its own stored gas. Conversely, if the customer fails to take delivery of all of its gas, the transmission company must store the balance. The obligation of the transmission company to cover input/output imbalances of shippers is a burden that will grow as the percentage of non-owned gas in the system increases.

Because of these changes, the industry is reassessing the role of the transmission companies and their historical mandate to meet the seasonal requirements of their consumers. At issue is an alternative allocation of seasonal and operational storage costs as the percentage of system gas declines. The industry is addressing these concerns, but the new system dynamics are still evolving.

On balance, the system changes have been painful yet beneficial. Gas prices are set competitively in the market, enabling natural gas to retain and to a certain extent recapture sales from alternative fuel supplies. Sellers and buyers increasingly have direct access to each other, and a number of new participants have entered the marketing/transportation chain. The cost of this shift to a free-market environment can be seen in lower pipeline revenue and dramatically reduced development activity.

### Capacity for the Future

Through 1992, gas demand is projected by the EIA to increase to 18.4 TCF per year, an increase of 1.5 TCF over 1987. The projected 1992 rate is still 1.7 TCF less than actual 1979 demand, leaving most gas transmission lines with adequate reserve capacity on an annual basis.

The demand decline was not uniform. In the New England and Mid-Atlantic regions, gas demand rose significantly. (New England demands are up 41 percent from a relatively small 1979 base and Mid-Atlantic demands are up 10 percent from a large base.) West Coast gas demands remained almost flat between 1979 and 1987, and are now growing.

Increased transmission capacity to serve the Northeast and California has been proposed and is awaiting various regulatory approvals. Additional capacity has also been proposed to serve Florida markets. When these capacity additions are constructed, there will be adequate gas pipeline capacity to fully cover demands through 1992.

## LIQUEFIED PETROLEUM GAS

The liquefied petroleum gas (LPG) market occupies a volatile position between the much larger natural gas and liquid fuels markets. Changes in these major markets have substantially altered LPG supply, demand, and economics in the past and seem certain to impose further change.

Table 39 shows the overall U.S. demand for LPG (ethane, propane, and butanes). In recent years, demand has been in the 1.8 to 1.9 MMB/D range, about 90 percent supplied from domestic production. The components of demand and U.S. production are illustrated in Table 40, based on 1987 data.

TABLE 39

U.S. LIQUEFIED PETROLEUM GAS SUPPLY AND DEMAND

| | 1985 | | 1986 | | 1987 | |
|---|---|---|---|---|---|---|
| | MB/D | % | MB/D | % | MB/D | % |
| Demand | | | | | | |
| Fuel and Chemical | 1,599 | 84 | 1,512 | 83 | 1,612 | 84 |
| Refinery Input | 304 | 16 | 302 | 17 | 304 | 16 |
| Total Demand | 1,903 | 100 | 1,814 | 100 | 1,916 | 100 |
| Supply | | | | | | |
| Refin./Gas Plant | 1,704 | 89 | 1,695 | 93 | 1,748 | 91 |
| Imports | 187 | 10 | 242 | 13 | 190 | 10 |
| Exports | (62) | (3) | (42) | (2) | (38) | (2) |
| Other* | 74 | 4 | (81) | (4) | 16 | (1) |
| Total Supply | 1,903 | 100 | 1,814 | 100 | 1,916 | 100 |

*Primarily inventory draw (or build).

Source: EIA, Petroleum Supply Annual, 1987. Totals may not equal the sum of components due to independent rounding.

TABLE 40

COMPONENTS OF 1987 DEMAND AND PRODUCTION
(Percentages)

| | Demand | Production |
|---|---|---|
| Ethane | 25 | 29 |
| Propane | 49 | 47 |
| N-Butane | 16 | 15 |
| Isobutane | 10 | 9 |
| | 100% | 100% |

About 75 percent of production is from gas plants that extract the heavy hydrocarbons from natural gas streams. The economic rationale for these plants was two-fold:

- To bring the natural gas stream to pipeline standards by extracting butane and/or propane

- To "lift" the value of ethane and other LPG from low, controlled gas prices to the competitive market.

Decontrol of natural gas and the sharp decline in oil prices have substantially closed the gas "price gap," reducing the economics of LPG extraction. So far, the change has not greatly affected overall supply; new supplies from the Rocky Mountain area coupled with a cautious industry response to change have kept production relatively unchanged. However, it seems likely that gas plant production, especially ethane production, will be affected in the longer term.

The market for normal butane will change substantially beginning in 1989 when new regulations will mandate a summer reduction in gasoline vapor pressure for a portion of the country. Butane blending into gasoline will be cut about 65 MB/D on an annual basis, eliminating about 20 percent of total N-butane demand. The EPA is currently reviewing further reductions in allowed gasoline vapor pressure that would virtually eliminate refinery purchases.

There is a great deal of flexibility within the industry to adapt to price or supply change. As prices approach a "floor" level equivalent of natural gas price, LPG tends to "disappear" into the natural gas stream, either through reduced extraction or displacement of gas as refinery fuel. Increased imports tend to limit the upside price range. The petrochemical industry, which accounts for over 40 percent of total U.S. demand, has demonstrated a substantial capability to shift feedstocks between ethane, propane, and heavier hydrocarbons in response to economics. In recent years shifts of over 50 MB/D (up to 100 MB/D) among feed components has been common.

Import capacity is adequate to handle any likely demand for several years. Port and terminal facilities at the Gulf (where import growth is most likely) have operated for a full quarter at almost seven times their average 1987 throughput. This inadvertent "test" occurred when Middle East producing countries elected to sell surplus production in the United States; terminals, pipelines, and underground storage handled the volume surge without stress. Substantial spare capacity is also available in East Coast terminals and Canadian LPG pipelines.

The PADD V LPG market remains relatively insulated from the problems of the rest of the country. With no significant petrochemical demand, PADD V accounts for only 5 percent of U.S. consumption. The market is largely self-contained, with only modest seasonal imports from Canada in the northern portion of

PADD V partly offset by exports to Mexico from the southern portion. No substantial changes in the PADD V situation are projected.

## FUEL SWITCHING

A significant amount of energy consumption in the United States can be switched from one fuel type to another as dictated by economics or supply limitations. Immediately switchable energy consumption in dual-fuel facilities can be an important factor in dealing with short-term oil or gas supply disruptions. In the longer term, fuel switching that involves facility conversion cost is responsive to consumer perceptions of the relative cost, availability, and environmental acceptability of alternative fuels. This section outlines the potential for short-term fuel switching as it may affect oil or gas demand.

Almost all of the immediately switchable energy consumption is in industrial and utility facilities that can use either oil or natural gas. There is relatively little coal/oil dual-fuel capacity and even less coal/gas dual-fuel capacity. Fuel switching to coal cannot significantly reduce both oil and gas consumption in the short term.

As shown in Table 41, it is estimated that about 1.2 MMB/D of oil-equivalent energy demand can be switched immediately between oil and gas. About 0.95 MMB/D of this capacity is presently fueled with gas, and about 0.22 MMB/D is oil fired. These figures reflect utility decisions based on the relative prices of oil and gas in 1987, and they could change quickly if the price relationships change. Recent history indicates that fuel switching in response to price can be constrained or delayed by factors such as contractual obligations, end-use restrictions, environmental requirements, or equipment limitations. However, interruption of gas deliveries to industrial and utility customers under prorationing could result in a rapid shift to oil.

Also shown in Table 41 is an estimate of the total fuel switching that might occur after a year if a significant economic advantage for either oil or gas were to persist. The estimate of the additional switching, much of which would require equipment modification, is based on observed performance during the crisis periods.

### Utility Fuel Switching

The electric utility sector includes over 68,200 megawatts of dual-fuel generating capacity, which can be switched between oil and gas on short notice. Dual-fired facilities account for a little over 10 percent of total U.S. generating capacity. It has been estimated that about 60 MB/D of utility consumption could be shifted from oil to gas on short notice and about 300 MB/D of oil could replace gas immediately. About double these rates could be switched if incentives persist for a year or more.

TABLE 41

1987 FUEL SWITCHING DATA*

| | Total Industry Use | | | From Oil to Gas (MB/D) | | From Gas to Oil (MB/D) | |
|---|---|---|---|---|---|---|---|
| | Oil | Gas | | | | | |
| | MB/D | BCF | Oil Equiv. MB/D | Immed. | One Year | Immed. | One Year |
| Residential | 810 | 4,302 | 2,120 | -- | 30 | -- | -- |
| Commercial | 560 | 2,392 | 1,180 | 40 | 80 | 50 | 100 |
| Industrial | 4,300 | 5,827 | 2,874 | 120 | 160 | 600 | 700 |
| Electric Util. | 550 | 2,814 | 1,388 | 60 | 200 | 300 | 600 |
| Subtotal | 6,140 | 15,335 | 7,562 | 220 | 470 | 950 | 1,400 |
| Transportation | 10,460 | 517 | 255 | -- | -- | -- | -- |
| Total | 16,670 | 15,852§ | 7,817 | 220 | 470 | 950 | 1,400 |

*Switchability estimates reflect the theoretical capability of end-user facilities to use alternative fuels and are calculated on an annual average basis, which assumes no alternative fuel supply constraints.

§Lower-48 States, excluding lease and plant fuel.

NPC analysis based in part on:

1. Energy Information Administration, "Annual Report on Sales of Fuel Oil and Kerosene, 1987," Petroleum Marketing Monthly, June 1988; and Annual Energy Review, 1987.

2. Energy Information Administration, "1985 Manufacturing Energy Consumption Survey: Part II - Fuel Switching Capability."

3. "The Role of Natural Gas in Offsetting Oil," American Gas Association, Energy Analysis 1988-12, October 12, 1988.

4. 1987 Historical Consumption, Energy Information Administration, Natural Gas Annual, 1987.

The amount of dual-fired equipment and the current base fuel in that equipment vary regionally. Table 42 shows the 1987 dual-fuel electric generation capacity by geographic region compared to total installed capacity. Also shown are total oil and gas consumption for the year for all facilities in the region. This table is a summary of extensive data published by the North American Electric Reliability Council (NERC). Figure 50 is a map showing the geographic regions.

The southwest and western regions of the United States have the largest percentage (over 20 percent) of dual-fired electric generation, and it is predominately fueled with natural gas. Oil

TABLE 42

1987 ELECTRIC UTILITY CAPACITY AND OIL/GAS CONSUMPTION

| | Total Capacity (Bil. Watts) | Dual Oil/Gas Capacity (Bil. Watts) | Oil Consump. (MMB) | Gas Consump. (BCF) |
|---|---|---|---|---|
| Eastern U.S.* | | | | |
| Northeast (NPCC) | 53 | 11.0 | 97.3 | 227 |
| Mid-Atlantic (MAAC) | 49 | 0.1 | 26.7 | 95 |
| Southeast (SERC) | 139 | 3.1 | 39.9 | 195 |
| | 241 | 14.3 | 163.9 | 517 |
| Midwest* | | | | |
| East Central (ECAR) | 95 | -- | 3.0 | 12 |
| Illinois/Miss. (MAIN) | 45 | 1.6 | 4.1 | 6 |
| North Central (MAPP) | 29 | 0.7 | 0.4 | 9 |
| | 169 | 2.3 | 7.5 | 26 |
| Southwest* | | | | |
| Texas (ERCOT) | 47 | 6.0 | 0.8 | 916 |
| Other (SPP) | 66 | 16.8 | 0.9 | 637 |
| | 113 | 22.8 | 1.7 | 1,553 |
| Western U.S. (WCSS)* | 126 | 28.8 | 3.6 | 675 |
| Total U.S. | 649 | 68.2 | 176.6 | 2,770 |

*( ) - North American Electric Reliability Council Region.

Source: North American Electric Reliability Council, 1988 Supply/Demand Report.

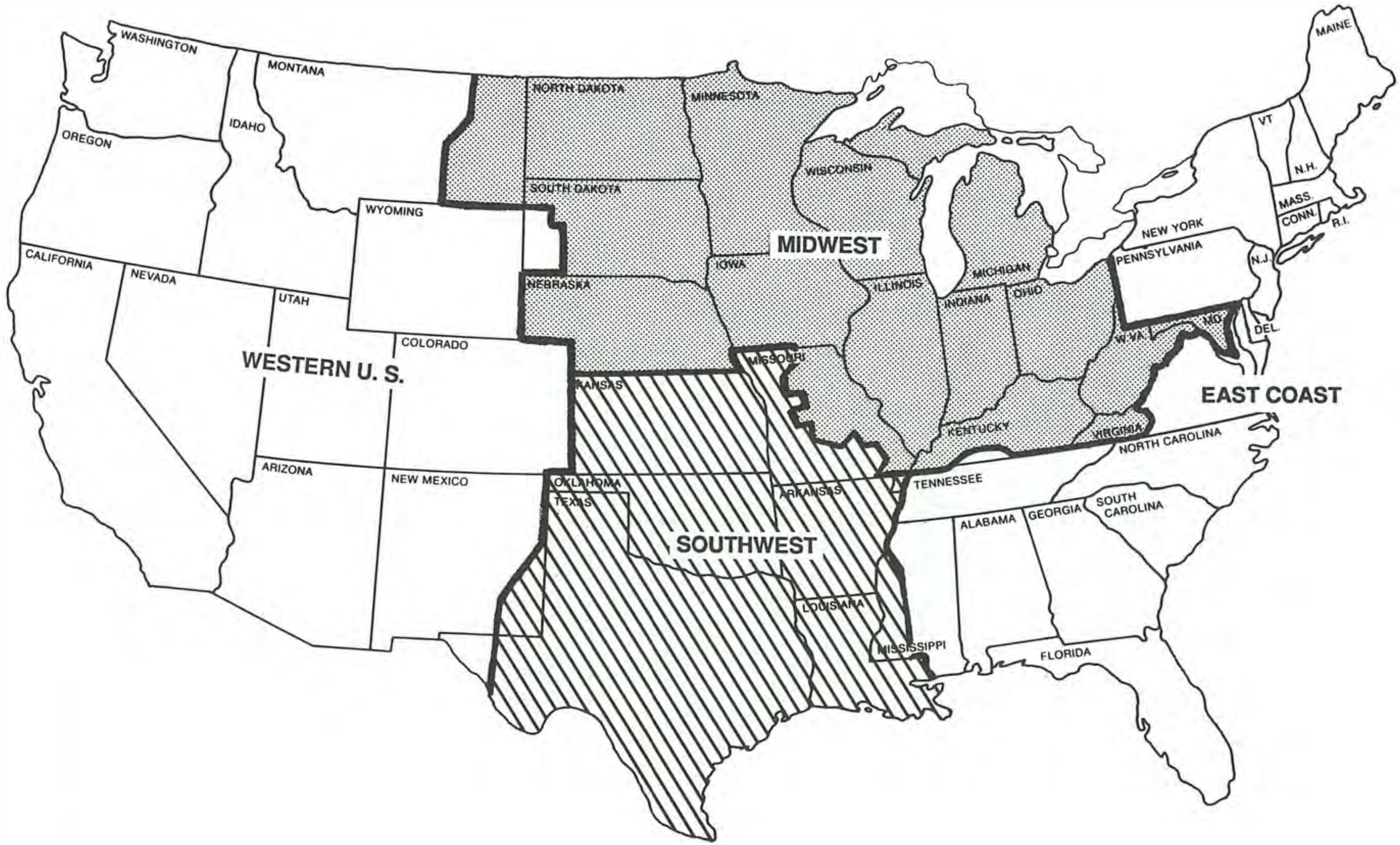



Figure 50. North Amercian Electric Reliability Council (NERC) Regions.

consumption in these two areas totaled only 5.3 million barrels (15 MB/D) in 1987, while gas use was the energy equivalent of over a million barrels of oil per day. The East Coast area includes most of the dual-fuel systems presently using oil. Midwest utilities are largely coal fired; there is little oil or gas consumption in any Midwest generators.

Most of the dual-fuel generating plants use oil or gas to fire large steam boilers. Residual fuel is the primary petroleum fuel used in these plants because of its low cost and high heat content. However, about 19 percent of the dual-fuel systems are engine or turbine driven generators or combined cycle plants, which often require diesel or jet fuel when running oil. As indicated in Table 43, NERC forecasts that this type of dual-fuel capacity will grow in the future at the expense of steam-turbine plants. NERC is forecasting no increase in overall dual-fuel utility capacity in the next five years.

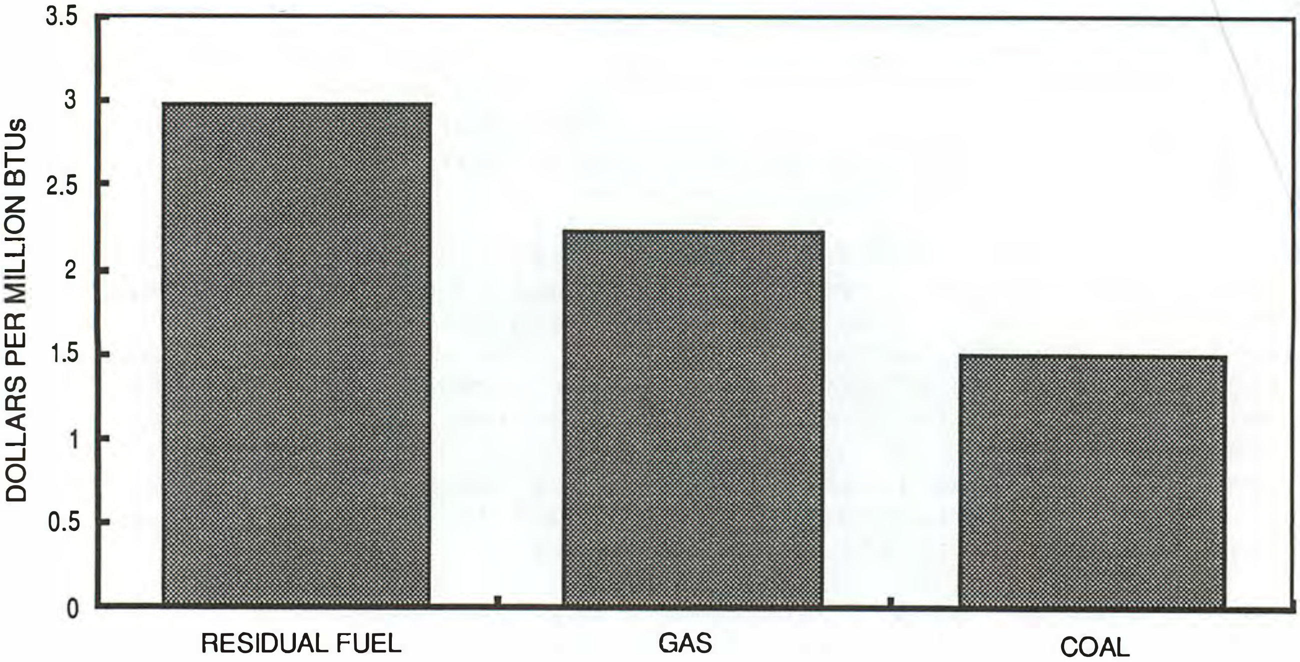
A 1982 DOE study identified a small percentage of generating capacity that could be switched between coal and oil or gas. However, it is highly unlikely that there would be any significant switching to or from coal in response to short- or medium-term incentives. Materials handling equipment and stack scrubbers make the initial cost of a coal-fired plant much higher than a comparable oil- or gas-fueled generator. Once built, however, the lower cost of fuel makes it economic to operate coal-fired units as "base load" and use the higher cost oil- and gas-fired plants to cover variable demand. As shown in Figure 51, the average 1987 cost of coal to utilities was half the average cost of residual fuel and 67 percent of the cost of natural gas. Since coal-fired equipment would economically displace oil- or gas-fired generators under normal conditions, there is little further displacement that can be obtained under abnormal conditions.

TABLE 43

DUAL-FUEL (OIL/GAS)
ELECTRIC GENERATING CAPACITY
(Megawatts)

| | 1987 | 1992 |
|---|---|---|
| Steam Generation | 55.3 | 52.9 |
| Other | 12.9 | 14.6 |
| Total Dual-Fuel | 68.2 | 67.5 |

Source: North American Electric Reliability Council, 1988 Electricity Supply & Demand (for 1988-1997), 1988.




SOURCE: EIA, Monthly Energy Review.

Figure 51. Average Cost of Fuel to Electric Utilities in 1987.

Industrial Fuel Switching

The greatest volume of immediately switchable energy is in the industrial sector. Over 700 MB/D of industrial fuel use can be switched between oil and gas, and currently about 83 percent of this energy demand is provided by natural gas; only about 120 MB/D of oil consumption could be immediately switched to gas. Little, if any, industrial fuel demand could be switched to coal in the short term.

The economics of industrial fuel use are generally similar to those of electric utilities. A recent DOE study indicates that almost two-thirds of the industrial oil consumption that can be switched promptly to gas is located along the coastal areas in PADDs I and V, where overall transportation costs for residual fuel are low compared to inland locations. Industrial use that could be switched to oil is more uniformly distributed.

As with electric utilities, most of the switchable oil and gas demand is for large steam boilers and process heaters. However, there is a significant demand for engine and turbine fuels and for space heating.

Other Fuel Switching

Residential consumers have no significant capability to switch fuels immediately. In many areas, safety and environmental rules discourage dual oil and gas fueling of homes. Portable heaters (kerosine and electric) and wood-burning stoves largely represent the limits of immediate fuel switching by residential consumers. However, history indicates that residential users can and will switch their primary fuel if they perceive a long-term benefit. It is estimated that about 30 MB/D of oil (primarily distillate) consumption could be switched to gas within a year if economic incentives persist.

Some large commercial consumers (e.g., hotels, large stores, and malls) maintain dual-fuel capability. Energy is a major expense to those companies, and they monitor alternative fuel costs routinely. It is estimated that about 40 MB/D of oil consumption by commercial users could be switched to gas on short notice; conversely, gas use equivalent to about 50 MB/D could be shifted to oil. Given ample incentive, roughly twice these volumes could be shifted within a year.

In the transportation sector, there are only 30,000 dual-fuel (gasoline/natural gas) vehicles. Their total consumption is negligible.

## ELECTRIC UTILITY FLEXIBILITY

Electric utilities retain a limited flexibility to respond to regional oil or gas supply problems for two reasons:

- Utilities maintain a reserve generating capacity to cover peak electricity demand and system disturbances.

- In most regions, overall generating capacity includes facilities operating on different fuels.

This flexibility may permit utilities to react to a shortage situation by reducing generation from plants using the short fuel or to transmit electricity from unstressed regions to the problem area. Unfortunately, the magnitude of these potential responses is small and limited to non-peak demand periods.

As shown in Table 44, electric utilities have installed generating capacity (not on line) equal to about twice their average power demand. Reserve capacity is essential to maintain reliable power supply because of the highly variable demand rates and the vulnerability to outside disturbances. During summer peak-demand periods, there is little surplus capacity on a 24-hour basis; winter peak rates leave only slightly more reserve capacity.

### Fuel Mix Adjustment

In non-peak periods, utilities have a limited ability to alter the mix of fuel consumption by shifting the generating load among facilities using different fuels (e.g., increase generation from gas-fired generators and reduce the utilization of oil-fired plants). Because of their high capital costs and low operating costs, hydropower and nuclear power plants are almost always

TABLE 44

1987 ELECTRIC UTILITY CAPACITY AND PEAK/AVERAGE LOADING

| | Total Installed Capacity (Bil. Watts) | Peak Load (Bil. Watts) | Average Load (Bil. Watts) |
|---|---|---|---|
| Eastern U.S. | 240 | 193 | 116 |
| Midwest | 169 | 133 | 80 |
| Southwest | 114 | 87 | 48 |
| Western U.S. | 126 | 83 | 57 |
| Total | 648 | 496 | 302 |
| Percentage of Capacity | | 77% | 49% |

Source: North American Electric Reliability Council, 1988 Electricity Supply & Demand (for 1988-1997), 1988.

operated as base-load capacity. Coal plants likewise tend to be base-load, although excess capacity in some areas has pushed coal plants into variable usage -- generally older plants that are less efficient and fully amortized. Oil and gas plants normally are the last plants pressed into service because of their high fuel costs, although re-powered units operating as combined cycle may operate as base-load capacity.

From a practical standpoint, the trade-off in utility fuel mix would normally be between oil and gas generators. It is highly unlikely that significant idle capacity in coal, nuclear, or hydropower plants would be available to permit reduction of both oil and gas. During peak periods, all generating capacity is likely to be committed, and the potential for fuel mix shift would be very small.

## Wheeling and "Fuel-by-Wire"

Because of the very long lead time required to construct large electric generating facilities, the slowdown in power demand growth left many areas with substantial surplus generating capacity in the early 1980s. To utilize that surplus, the industry developed long-distance energy sales (often called "fuel-by-wire" sales) from areas with surplus capacity to areas with deficient or less economical capacity.

One of the most successful examples of "fuel-by-wire" is the supply of electricity to California from low-cost coal and nuclear generators in Arizona and Utah and high-voltage transmission from the Bonneville Power Administration to Southern California. Stringent California environmental regulations made this trade economic relative to new local capacity despite the inefficiency of long-distance transmission; and it is likely that these power sales will grow.

Electricity wheeling is a special case of long-distance electric sales. A wheeling arrangement involves the sequential transmission of power from one utility to another through a third party (or wheeling utility), allowing the effective transfer of electricity over long distances.

In a regional oil or gas shortage, long-distance power transmission or wheeling could provide power into the affected region, reducing the oil or gas needs of local utilities. From a practical standpoint, this capability is restricted even in non-peak periods by limited very-high-voltage transmission capacity and the power losses associated with long-distance transmission. While some additional long-distance lines are planned (from Quebec to New England and from the Rocky Mountain area to California, for example), regulatory approval for such lines is often difficult and very time consuming.

In summary, the practical ability of electric utilities to respond to oil and gas supply shortages is relatively small. Significant spare generating capacity and fuel flexibility exist only in non-peak periods (Spring and Fall); and even in these periods, economic transmission capacity limits the range of response. Non-peak periods for electrical power demand are also periods of relatively low oil and gas demand for burning. Given their low priority for natural gas allocation, utilities are more likely to be an added demand on oil supply in a supply shortage than part of the solution.

# CHAPTER THREE

# THE SUPPLY SYSTEM UNDER STRESS

## INTRODUCTION

When events disrupt normal supply-demand patterns, the system is said to be under "stress." Refinery downtime, missed pipeline deliveries, or surges in sales can create abnormal situations requiring corrective action. Most of these stresses are localized and involve relatively few companies. Coping with stress situations of this magnitude is part of the normal operation of the system.

This section concerns the actual and projected response of the supply system to major stress situations in which the supply disruption or demand surge is large enough to affect a majority of suppliers in a relatively wide area. Stress situations of this severity are rare, but the methods of response are essentially the same as for routine problems. The principal difference is the wider range of system elements that may be involved in the resolution.

Before discussing specific stress situations, it may be useful to review the mechanics through which the industry responds to a supply problem.

Few stress situations result in acute supply problems, because the system maintains a considerable cushion in the form of inventory, in-transit product, and alternative supply. The system uses this cushion to attenuate the peak severity of the problem and spread the effect over time and over a wider range of potential solutions. The time between recognition of a stress condition and its impact on primary supply capability varies considerably, but the most serious potential supply problems (e.g., pipeline shutdown, crude oil supply cutoff, refinery outages) are "event" related and are usually identified well before consumer supplies are affected.

Most stress situations are of short duration (less than 30 days); and response must come within the limitations of existing facilities. Price increases and scattered supply runouts are both symptoms of a stress situation and important elements of the solution. They inhibit short-term demand and expand the range of supply increments.

Responses to a short-term stress situation tend to fall into three categories -- inventory draw, supply acceleration, and finally, increased direct supply. Timing is the factor that separates the categories. The time to bring new supply into the stress area via normal direct routes can be relatively long, even if both the supply and the transportation capacity are immediately available. Table 45 shows that transit times for indirect supply routes range up to 30 days. To this must be added the time to acquire the product and bring it to the pipeline injection point or the shiploading dock.

Initially, inventory draw is the only available source of incremental supply, and it is usually the most economical response. In general, there is enough inventory in the system to make a very significant contribution. Table 46 shows the estimated total available system inventory (above minimum levels).

The bulk of the available inventory is in secondary and tertiary inventory owned by wholesale distributors (jobbers) and retailers and by consumers. Only a small portion of this inventory can be physically redistributed to alleviate problems, but the same effect can be obtained if wholesalers and consumers elect to draw inventory in lieu of current purchases.

Economics govern the inventory policy of wholesalers and consumers. If they perceive that current prices are high and likely to decline, they will draw inventory and defer purchases. If they believe prices will rise, they will try to buy. On numerous occasions, wholesaler-consumer purchases aimed at beating price increases have exacerbated a stress condition by pulling product out of primary inventory in the early stages. In these cases, product is merely shifted from primary inventory to less flexible secondary or tertiary storage.

Price increases not only encourage inventory liquidation, they also encourage supply acceleration and additions. Supply acceleration is the process of shifting product temporarily from non-stressed areas to the problem region. It permits product to be moved quickly where needed; and non-stressed areas can be replenished by direct supply on a less urgent basis. Pipeline batch trading illustrates the principle; in this method, volume already in the pipeline is traded for equivalent volume in a later cycle and diverted to the problem area. Ship diversion, railway shipments, and trucking from non-stressed areas are among the many forms of accelerated supply.

The scope of accelerated supply activity is proportional to the economic incentive. Primary suppliers routinely adjust their supplies in response to normal problems, but in severe stress situations, the response of a much wider range of supply sources is desirable. Increased price differentials trigger innovative trading and supply realignment, which can bring new supplies and new suppliers from a greatly expanded area.

The final response stage is system recovery via direct resupply. Incremental volume is acquired to rebuild inventory, to replenish product that was "borrowed" for supply acceleration, and to meet longer-term demand increases. The additional supply can come from a variety of sources, but it will almost certainly be at lower cost than the supply increments of earlier stages.

TABLE 45

ILLUSTRATIVE PRIMARY TRANSIT TIMES

| | |
|---|---|
| **Refined Product** | |
| Pipeline - Houston to New York | 15 to 26 days |
| Pipeline - Houston to Chicago | 20 to 30 days |
| Tanker - Rotterdam to New York | 15 days |
| Tanker - Singapore to Los Angeles | 30 days |
| Barge - Houston to St. Louis | 12 days |
| **Crude Oil** | |
| Pipeline - Louisiana to Chicago | 10 days |
| Tanker - Mexico to Philadelphia | 6 days |

TABLE 46

AVAILABLE SYSTEM INVENTORY - ABOVE MINIMUMS*
(Millions of Barrels)

| | Gasoline | Distillate |
|---|---|---|
| Primary Inventory | 26 | 4 |
| Secondary (Jobbers, etc.) | 30 | 8 |
| Tertiary (Consumers) | 41 | 62 |
| | 97 | 74 |
| Memo: No. Days Supply | 14 | 25 |

*Based on 3/31/88 data and methodology outlined in Volume IV of this report, Petroleum Inventories and Storage.

Prices usually decline to normal during this period. It should be noted that the system activity described above is the aggregate result of independent actions of many companies, and the actual transactions which produce that result can be very complex.

The price differentials that trigger the system response to stress situations are for incremental or spot volumes into the relevant area. Sales prices to dealers and consumers within the area are usually much less affected. In the actual stress situations described in this chapter, the levels of industry response activity were very high, but the only effect on individual consumers was small, transient price increases that were largely unnoticed.

In the event of a longer-term stress situation, other potential responses become feasible. First is fuel switching. As discussed earlier, a very substantial amount of fuel could be shifted between oil, gas, or coal, depending on economics. Fuel switching is a normal activity of utilities and some large industrial consumers; and it can be effective fairly quickly if the incentive is likely to persist for more than a month or two. In the longer term, additional capital facilities and permanent supply realignment could become feasible. It's worth noting that there has not been a significant, long-term stress problem since the Iranian crisis.

In brief, the system response to supply stress is a basic application of supply-demand economics. Increased prices attract prompt new supply while encouraging consumers to defer purchases by drawing inventory or switching to cheaper fuel. The universe of potential responders and the intensity of response are proportional to the economic incentive offered. Experience under controls indicates that government interference with the process may prolong the period of stress. (The 1987 NPC report, Factors Affecting U.S. Oil and Gas Outlook, reviews the effect of controls on the supply system in detail.)

In the following section are descriptions of recent actual stress situations of importance and a discussion of their resolutions. These cases reflect the general principles outlined above.

## ANALYSIS OF HISTORICAL SYSTEM STRESSES

### Motor Gasoline Supply Tightness -- Summer 1988

Severe problems at a number of major refineries in the U.S. Gulf Coast reduced gasoline production in the late spring and early summer of 1988, despite modest primary inventories at that time. Then, in late summer, some similar problems emerged in two California refineries. In addition, severe drought lowered Mississippi River levels to nearly unnavigable lows; this constrained barge movement from the Gulf Coast to the Upper Midwest and allowed saltwater encroachment up the Mississippi, threatening operations at several riverside Louisiana refineries. This combination of reduced production and reduced ability to move product raised some concerns about continued gasoline availability. Then, in mid-September, two hurricanes hit the Gulf Coast within one week, closing several refineries for days, and disrupting crude oil production and shipments to many refineries for weeks. Yet, during this time, the only indication of consumer awareness of the gasoline logistical problems was a single report complaining about slightly elevated gasoline-over-crude oil price spreads.

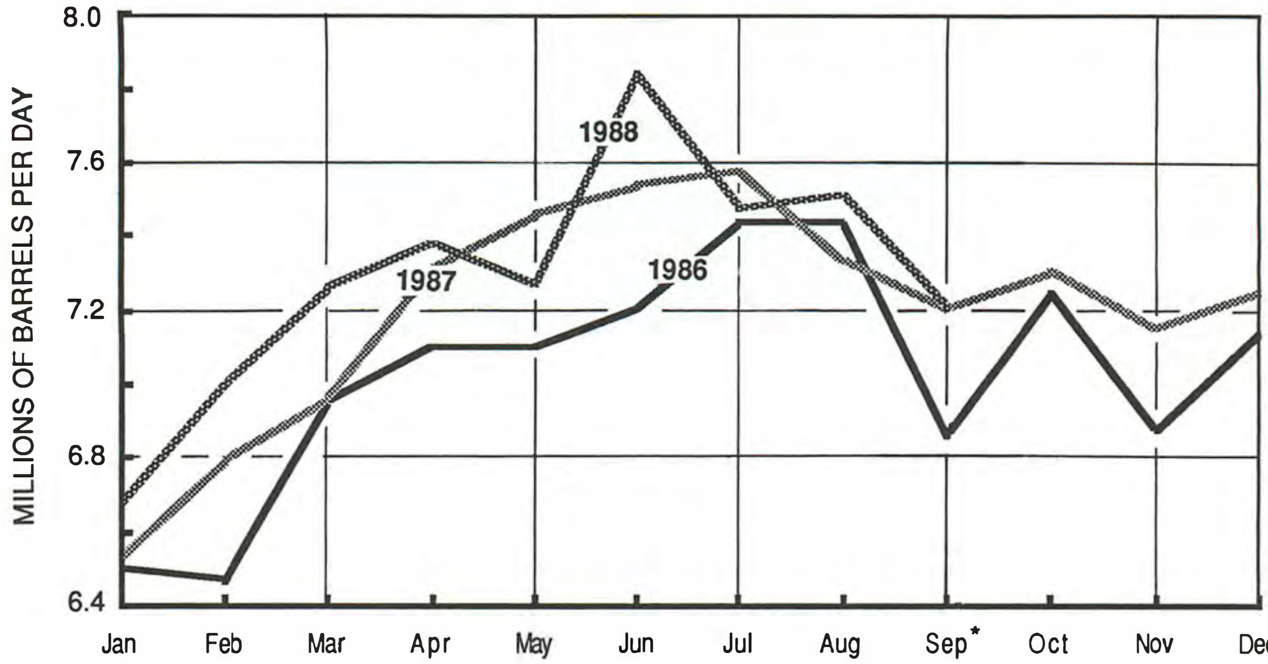
## Summary and Conclusions

Inventories were drawn down close to their theoretical minimum operating levels by the end of June, increasing the flow of gasoline to secondary inventories by more than half a million barrels daily. Gasoline prices held steady or increased modestly, while crude oil prices were dropping, which increased the gasoline differential over crude oil and other products. As a direct result, gasoline output climbed to its highest level in over nine years in July, and rose slightly more in August. Gasoline imports also rose in July and August, to nearly half a million barrels daily. Regional gasoline price differentials kept gasoline flowing into areas that needed it, despite the increased expense of moving it there. No consumer delivery disruptions were experienced, and by the end of September, gasoline primary inventories had risen by more than 12 million barrels, to well in excess of their minimum operating levels.

## Analysis

At the time of the supply tightness, industry press often attributed the problem to surging gasoline demand. According to semi-final figures from the Energy Information Administration, this was true only for the month of June, in comparison with the previous year. In June, primary withdrawals jumped 4 percent above 1987, to 7.8 MMB/D, the highest rate in 10 years. However, as is so often the case in the oil industry, this high primary withdrawal rate in June probably reflected timing of secondary storage filling, as opposed to any surge in consumer demand. Primary storage withdrawals in May were 2.6 percent below 1987, and July withdrawals were 1.4 percent lower, while August and September withdrawals were about 2.4 percent and 2.0 percent above 1987. The average withdrawal rate from May through September was 0.9 percent above 1987. That hardly qualifies as very strong demand growth, though it was the highest peak-driving-season withdrawal rate since 1978. (See Figure 52.)

By contrast, the real gasoline demand surge in 1988 apparently took place in the first quarter of the year, when the primary withdrawal rate was 3.2 percent higher than the previous year. Crude oil runs and gasoline production both were significantly higher in this period than at the same time in 1987, but




* September 1988 estimated

SOURCE: EIA, Petroleum Supply Monthly, August 1988.

Figure 52. Gasoline Demand -- Withdrawals from Primary Inventories.

did not keep pace with demand. As of April 1988, the average monthly year-over-year comparisons of primary withdrawal strength had fallen off considerably.

Gasoline inventories at the beginning of May 1988 were a relatively modest 226 million barrels, nationwide. This was 16 million barrels lower than at the same time in 1987, but 11 million barrels and 19 million barrels higher, respectively, than the same point in 1985 and 1986. This level of inventories is still 21 million barrels above the NPC's best estimate of minimum operating levels, and would have posed no problems normally, as gasoline production typically is quite high in May and June. However, severe and well publicized refinery problems caused May and June output in 1988 to average 125 MB/D less than in 1987. Furthermore, the combination of these problems, plus the threat of disruption of refinery operations along the Mississippi by the saltwater encroachment, plus the threat of Mississippi River closure to gasoline barge traffic, plus the impending Fourth of July holiday, all induced secondary storage operators to rush in to purchase gasoline during June. That, in turn, reduced total U.S. gasoline primary inventories to just above estimated minimum operating levels. (See Figure 53.)

In early July, spot gasoline prices rose 6¢ per gallon on the Gulf Coast and 10¢ per gallon in Chicago, and the primary withdrawal rate slowed. Despite the continued refinery problems, output surged to 7.2 MMB/D, the highest level since January 1979. Along with the rise in imports, this caused primary inventories to begin building once again (see Figure 54). By the end of

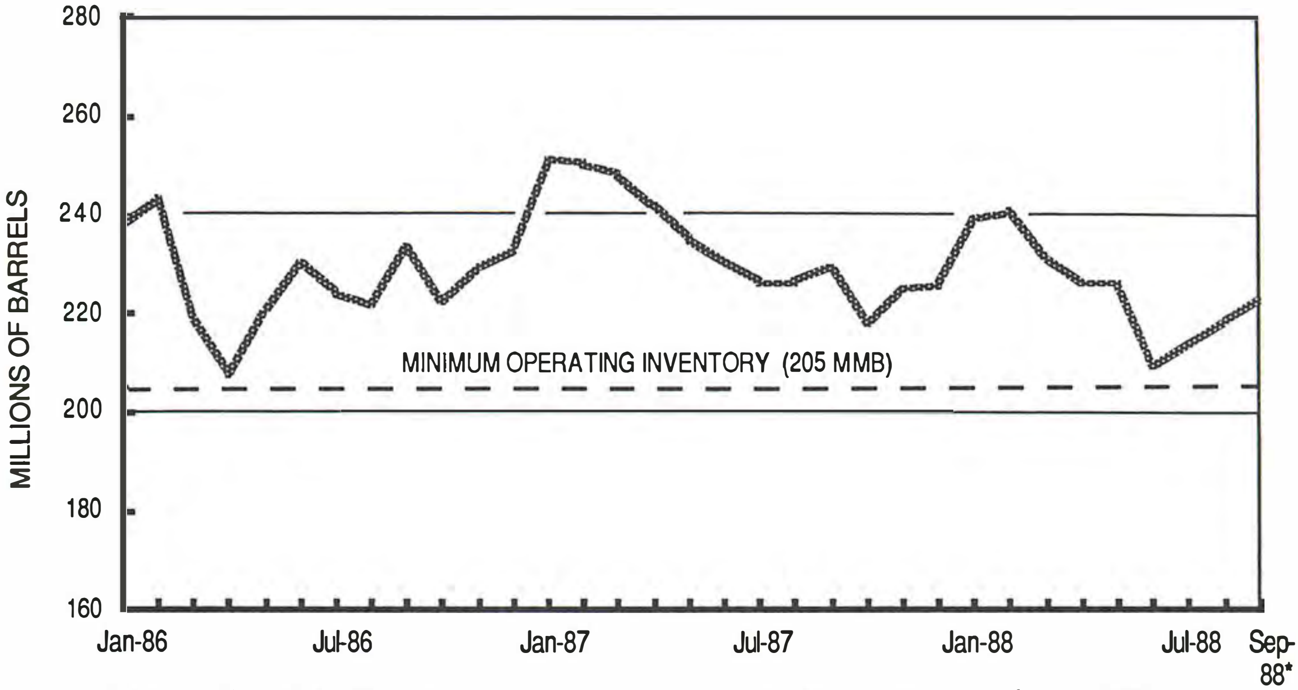



Figure 53. Gasoline Inventory -- January 1986 to September 1988.

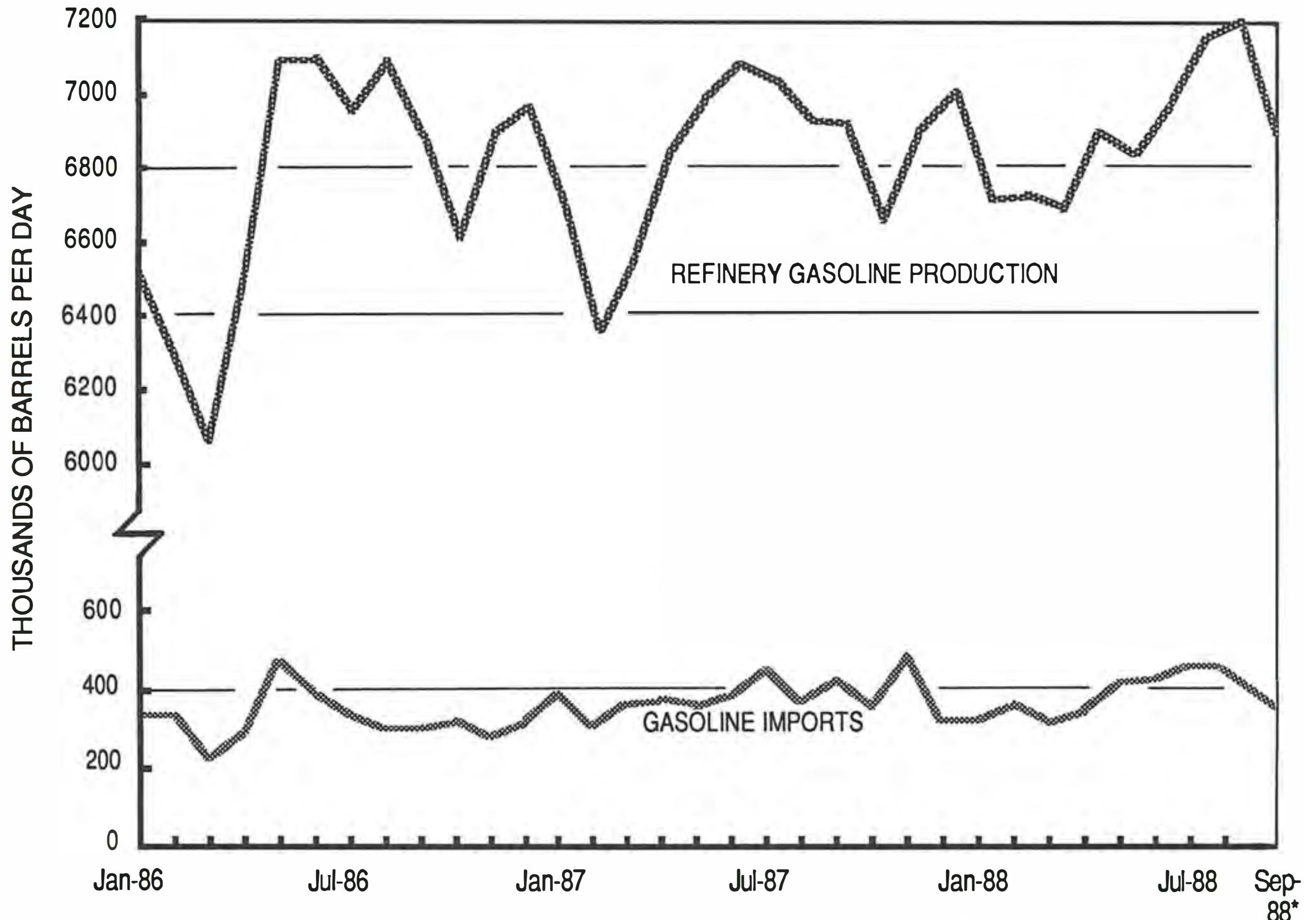



Figure 54. Gasoline Production and Imports -- 1986-1988.

*Estimated

SOURCE: EIA, Petroleum Supply Monthly, August 1988.

July, Gulf Coast spot gasoline prices again dropped 6¢ a gallon. In Chicago, spot prices dropped 10¢ a gallon over the month of August.

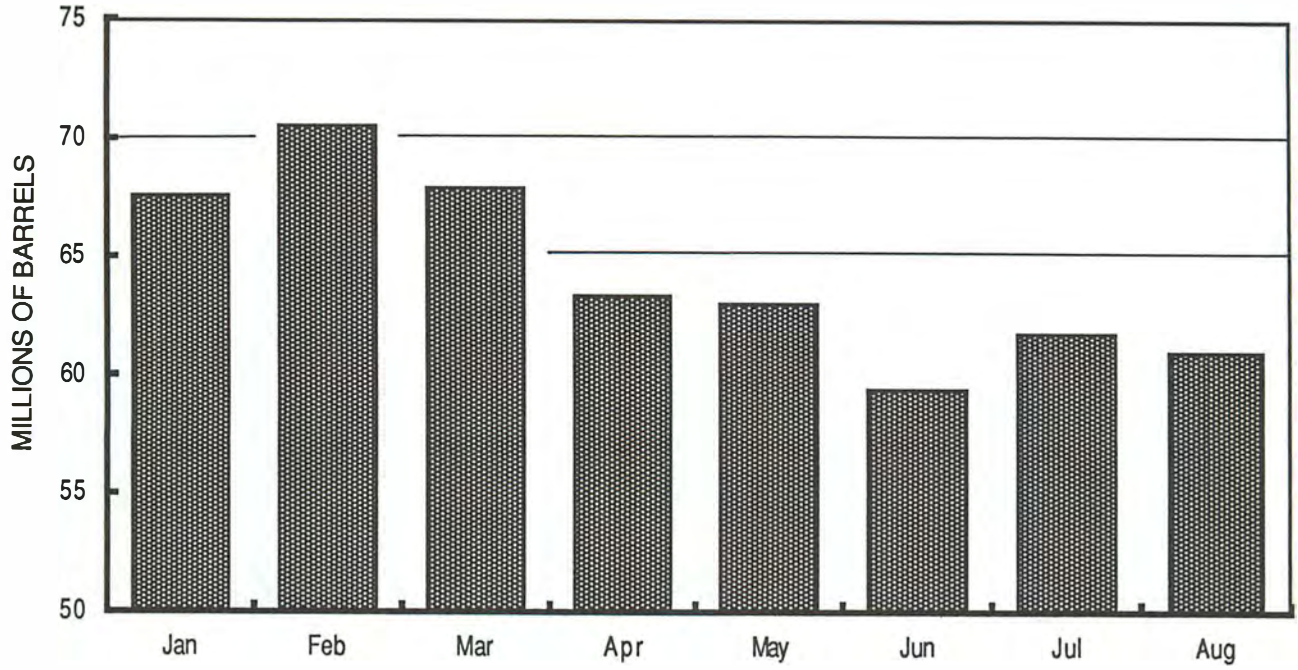
Wholesale prices for high-octane, premium gasoline rose to roughly 10¢ per gallon above regular unleaded crude oil during the summer, an increase of about 6¢ per gallon over the price difference of the spring. This high-octane price spread continued until January 1989, reflecting the strong demand for premium, unleaded gasoline.

Refinery operations along the Mississippi never were disrupted by the saltwater encroachment. Indeed, some refineries were affected by it, but the favorable gasoline price spreads induced them to keep operating by undertaking the expensive practice of barging in fresh water to supply their needs.

Barge traffic along the Mississippi was severely affected by the lower water levels. During the summer, barges from the Gulf Coast refineries typically supply 65 MB/D of gasoline, or about 3 percent, of PADD II demand. A much larger proportion is supplied by pipelines from the Gulf Coast, but during the summer the pipelines frequently operate at full capacity. Hence, barge traffic supplies a small but important marginal volume. That supply became much more expensive to move, since travel times rose and barge-towboat combinations had to travel with much lighter loads. But the price spreads between the Midwest and Gulf Coast regions, and the fortuitous existence of the Tennessee-Tombigbee alternative waterway route, kept that more expensive supply coming. In addition, at least one company even elected to move product volumes into the Midwest via rail.

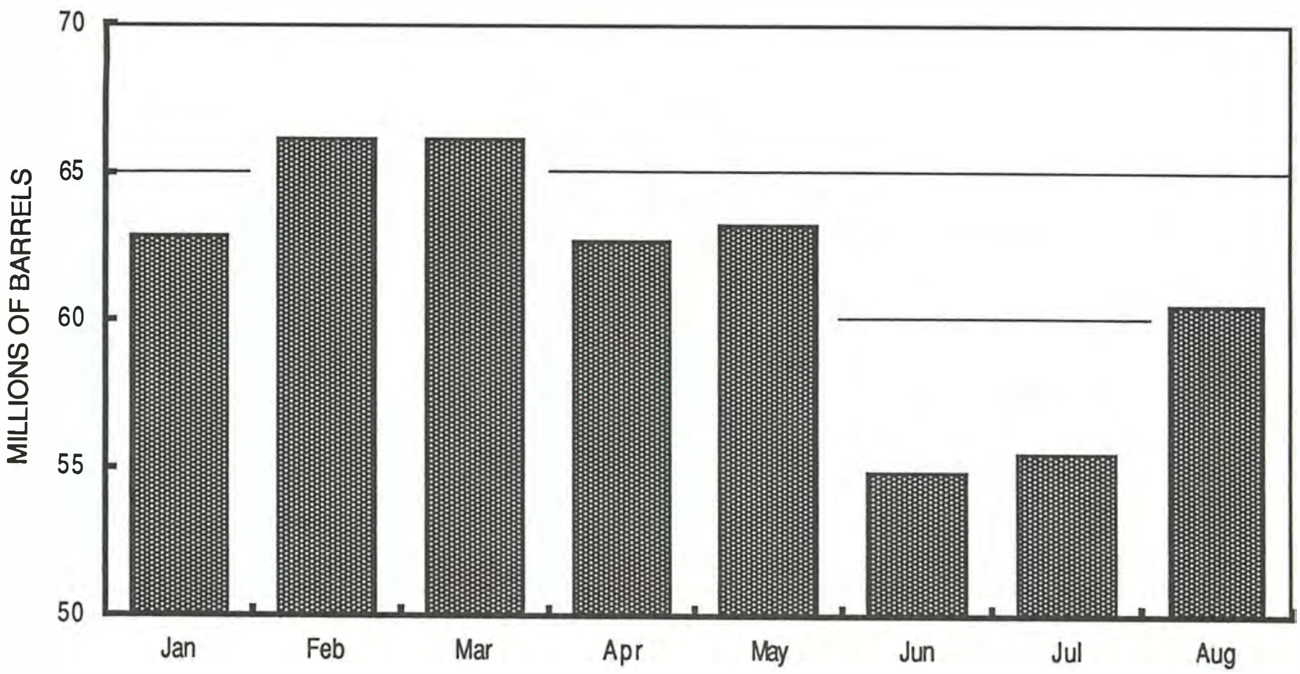
The gasoline supply-demand balances by PADD for June and July show much the same picture as occurred nationwide. In the case of PADD I (the East Coast), about two-thirds of the roughly 2.5 MMB/D demand is supplied by inter-PADD movements by pipeline or tanker from the Gulf Coast. In June and July of 1988, this volume of gasoline from the Gulf Coast dropped nearly 7 percent from 1987, and the June stock draw in PADD I amounted to 3.5 million barrels. However, by July, a slight stockbuild was taking place, as refinery output within PADD I and imports increased and the primary withdrawal rate dropped. In the New York spot market, the accompanying price "spike" amounted to about 5¢ a gallon for gasoline, and lasted about two weeks in July.

In PADD II (the Midwest), a combination of increased refinery output, increased utilization of pipeline capacity, and a drop in primary withdrawals changed a 7.7 million barrel stockdraw in June to a 0.8 million barrel stockbuild in July. PADD III (the Gulf Coast) is the major gasoline exporting district, producing roughly two-and-a-half times its 1.3 MMB/D consumption. In June 1988, it produced about 107 MB/D less gasoline than in June 1987, since the refinery problems were concentrated in this district. PADD III output climbed 206 MB/D in July, despite continued refinery problems, to 2 percent above the previous year. (See Figures 55 through 59.)



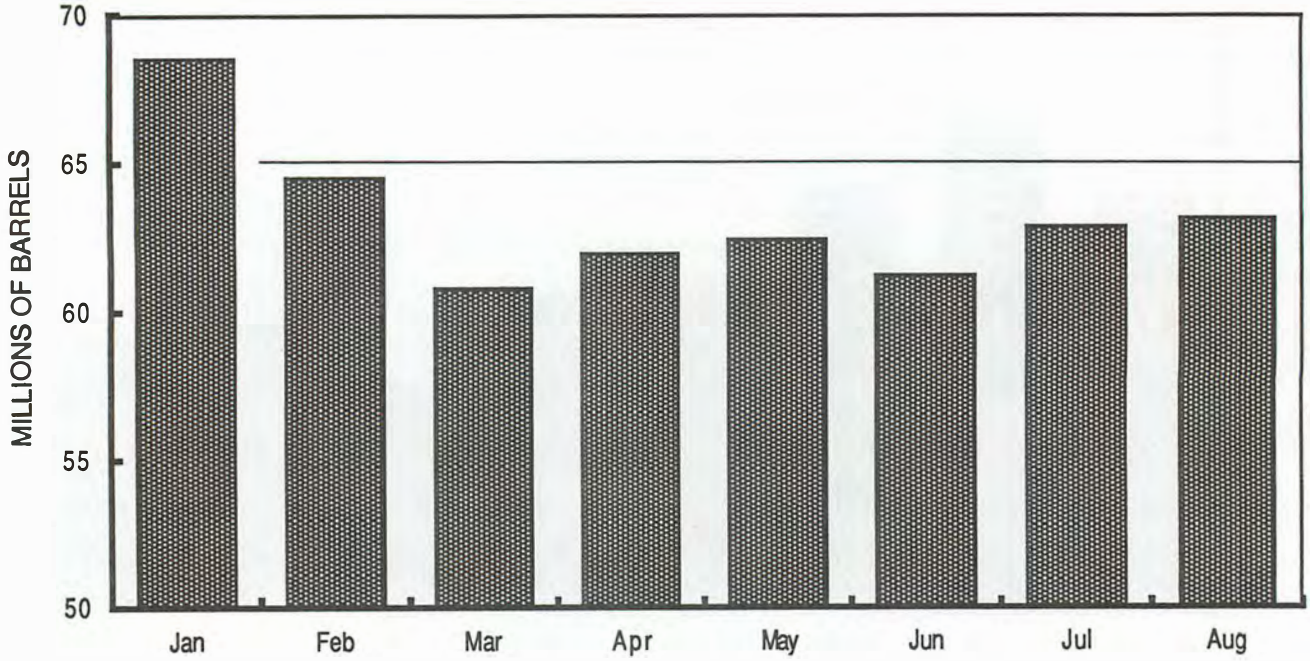

SOURCE: EIA, Petroleum Supply Monthly, August 1988.

Figure 55. 1988 Gasoline Inventories by PADD -- PADD I.



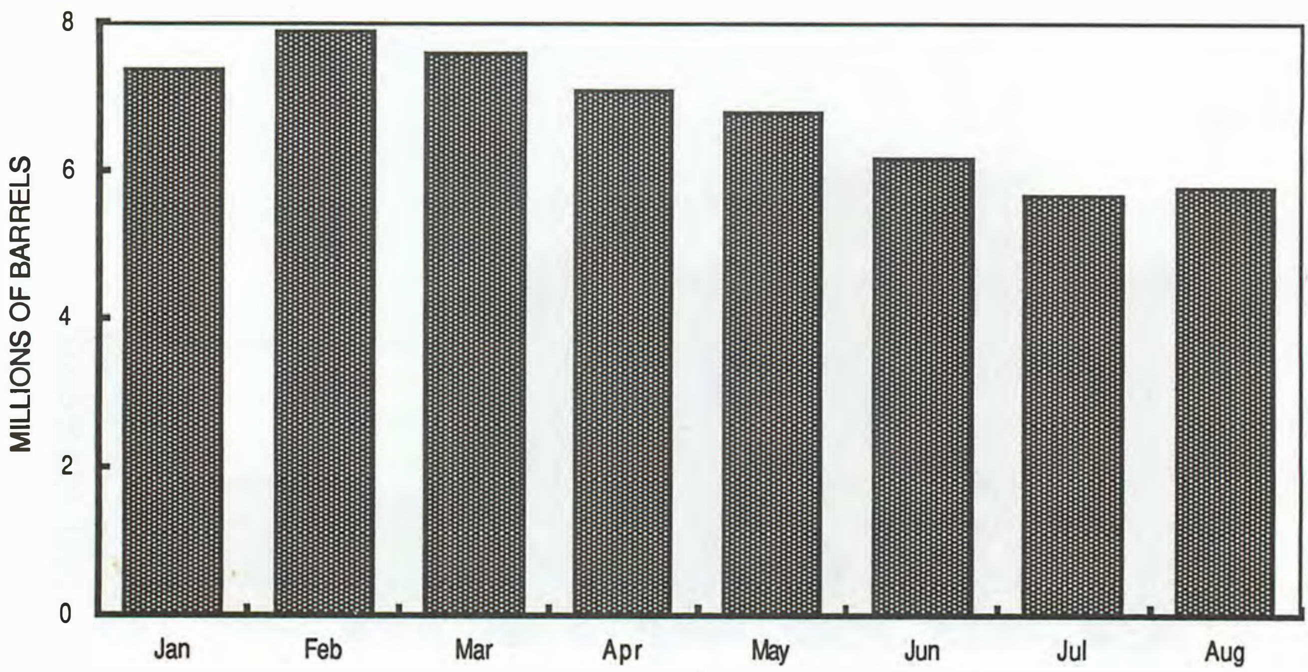

SOURCE: EIA, Petroleum Supply Monthly, August 1988.

Figure 56. 1988 Gasoline Inventories by PADD -- PADD II.



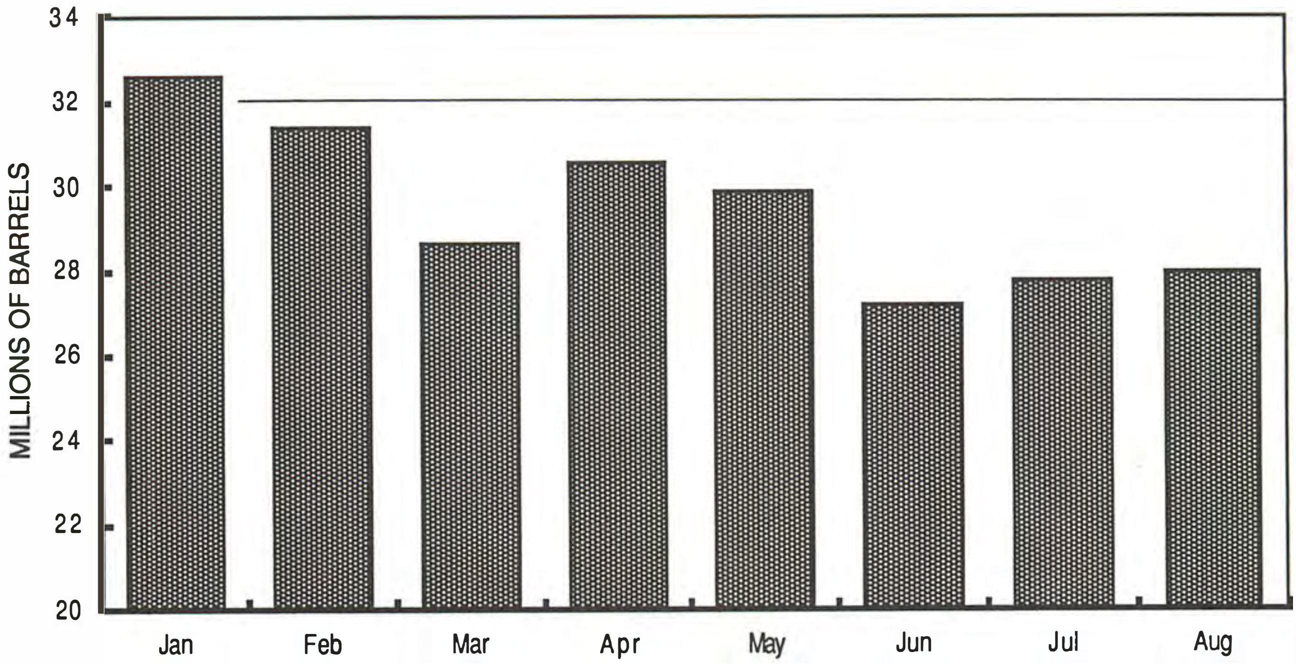

SOURCE: EIA, Petroleum Supply Monthly, August 1988.

Figure 57. 1988 Gasoline Inventories by PADD -- PADD III.




SOURCE: EIA, Petroleum Supply Monthly, August 1988.

Figure 58. 1988 Gasoline Inventories by PADD -- PADD IV.




SOURCE: EIA, Petroleum Supply Monthly, August 1988.

Figure 59. 1988 Gasoline Inventories by PADD -- PADD V.

In PADD IV (the Rocky Mountain states), there was essentially no problem. In PADD V (the Pacific Coast), refinery output jumped in July and changed a 2.7 million barrel June stockdraw into a small stock increase. Stocks rose by an additional million barrels in August, due to continued high refinery output. In September, some refinery problems were reported, which caused a mild price spike. Refinery output fell by 2 million barrels, but that was about the same as the September decline of the previous year. Withdrawals fell by 3.5 million barrels, allowing a 2.5 million barrel inventory build, which left gasoline stocks slightly higher than in the previous year.

The effect of the two hurricanes was to boost spot gasoline prices temporarily in late September, as once again a surge of primary stock withdrawals occurred due to supply concerns. Despite refinery outages and problems with crude oil deliveries to refineries, gasoline primary stocks showed no sign of falling, though increased demands from secondary system operators kept fall gasoline price differentials strong for most weeks through October.

The oil industry had been hit with an abnormal number of natural disasters and equipment problems during the driving season of 1988. These caused the industry to scramble to meet the resulting surges of withdrawals, and caused brief price spikes in the spot market and at the racks. Yet throughout the season, motorists continued to buy all the gasoline they wanted without inconvenience, at inflation-adjusted prices comparable to the 1960s.

<u>Southwest Freeze-Up -- December 1983</u>

Severe cold weather in December of 1983 caused temperatures to fall well below seasonal norms in the Northeast and Upper Midwest for the first time in two years, increasing heating oil demands in these regions. Because Gulf Coast refineries supply both of these regions, fuel oil demands on these refineries increased significantly.

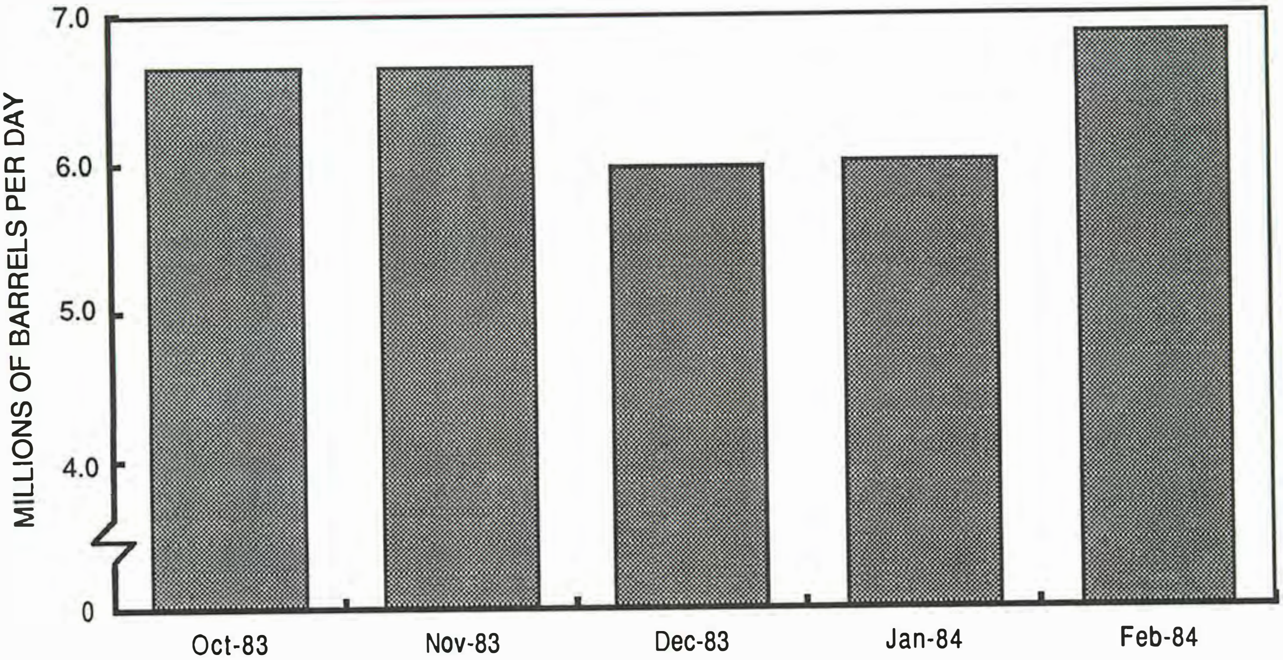
In late December, a wave of cold air swept down through Texas and Louisiana bringing zero-degree temperatures to Gulf Coast areas ill-prepared for the sub-freezing cold. Freezing rain and sleet froze wellhead equipment, cutting off supplies of both oil and gas. Icy roads prevented truck movements of crude oil and interfered with normal crude oil gauging and field maintenance operations. More than 6 million barrels of crude oil production was lost -- almost all in the last seven days of December.

Unlike northern refineries, which are constructed with steam-traced or electrically heated lines, Gulf Coast refineries were not prepared for zero-degree weather. Water lines froze and burst, valves jammed, and ice particles clogged filters and plugged lines. Gas curtailment shut down the boilers that power many refinery units, and normally hot pipelines froze before the boilers could be shifted to alternative fuel. As many as 15 refineries were shut down for periods ranging from a day to two weeks, and refinery production was severely reduced for two weeks extending into January 1984.

Figure 60 illustrates the production loss. It shows the aggregate monthly production from PADD III refineries during the relevant period. Overall, the freeze reduced refinery production by about 35 million barrels in December and January. Gasoline production was down about 15 million barrels and distillate production down roughly 7 million barrels for the same period.

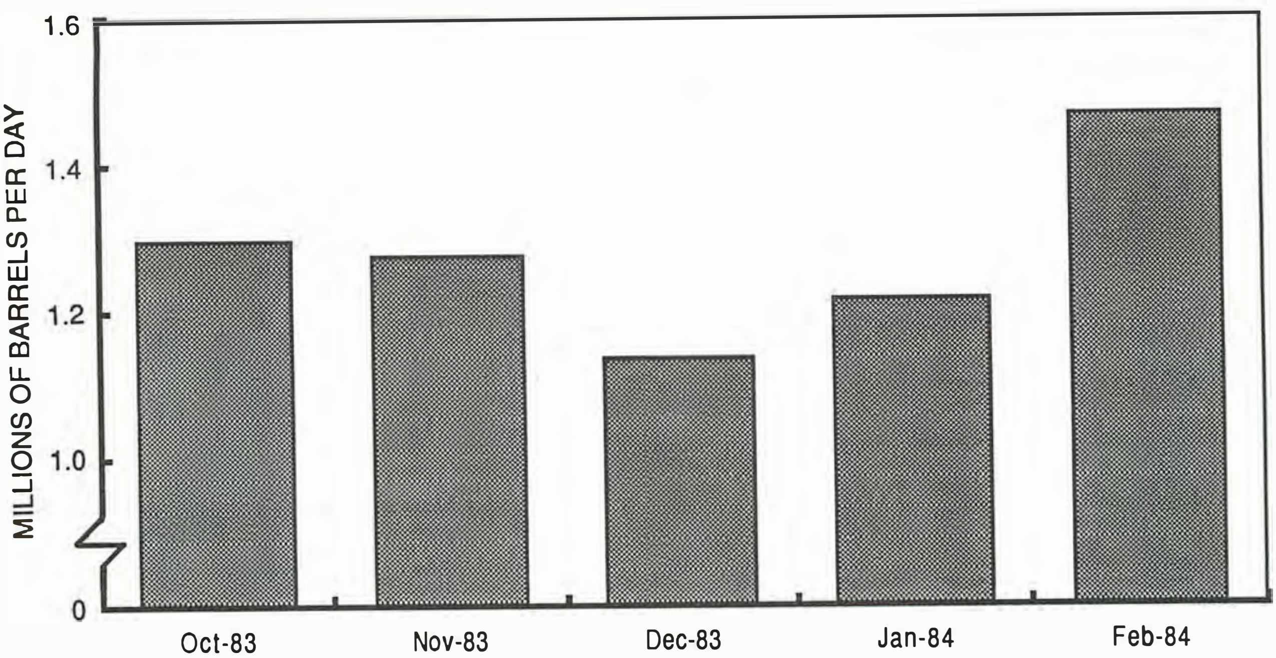
The industry reacted promptly to re-align supply to reduce PADD III product shortfalls. Scheduled deliveries to the Midwest (PADD II) were reduced to retain supply for the Gulf and East Coast areas. PADD II refineries were able to increase refinery production to offset the diverted supply, as Midwest refineries had been operating at only 79 percent capacity.

In PADDs I and III, companies drew inventory to cover immediate needs, and then increased crude oil runs to partially replenish stock. Refineries maximized distillate yields to cover abnormal demands. Figure 61 shows distillate production from PADD III refineries over the winter period; the high level of distillate production following the freeze-up period is apparent.




SOURCE: EIA, Petroleum Supply Annual, 1984.

Figure 60. PADD III Refinery Production -- Winter of 1983-1984.




SOURCE: EIA, Petroleum Supply Annual, 1984.

Figure 61. PADD III Distillate Production -- Winter of 1983-1984.

Overall, it appears that the refinery production lost in the December-January freeze was replaced about as follows:

| | |
|---|---|
| Increased Refinery Runs | |
| PADDs I and II | 10 Million Barrels |
| PADD III | 10 |
| Imports | 15 |
| | 35 Million Barrels |

Figure 62 shows the effect of the refinery freeze-up on Gulf Coast distillate prices. Spot distillate prices (for large-volume transactions) had drifted down from October levels, but began to move upward in mid-December in response to colder-than-normal weather. The refinery freeze-up did not seriously affect prices until early January, when the full magnitude of the lost production became apparent. Spot prices jumped about 15¢ per gallon as companies attempted to negotiate prompt incremental supply.

Within two weeks it became clear that new distillate supply being called out by the price increase would be more than adequate, and spot prices began to fall sharply. By the end of February, spot distillate prices were 6¢ per gallon below October levels despite the massive production loss -- probably a reflection of over-coverage of distillate needs.

Also shown in Figure 62 are distillate prices at the wholesale truck rack level. This is the price paid by large distributors. At this level of distribution, the price reaction

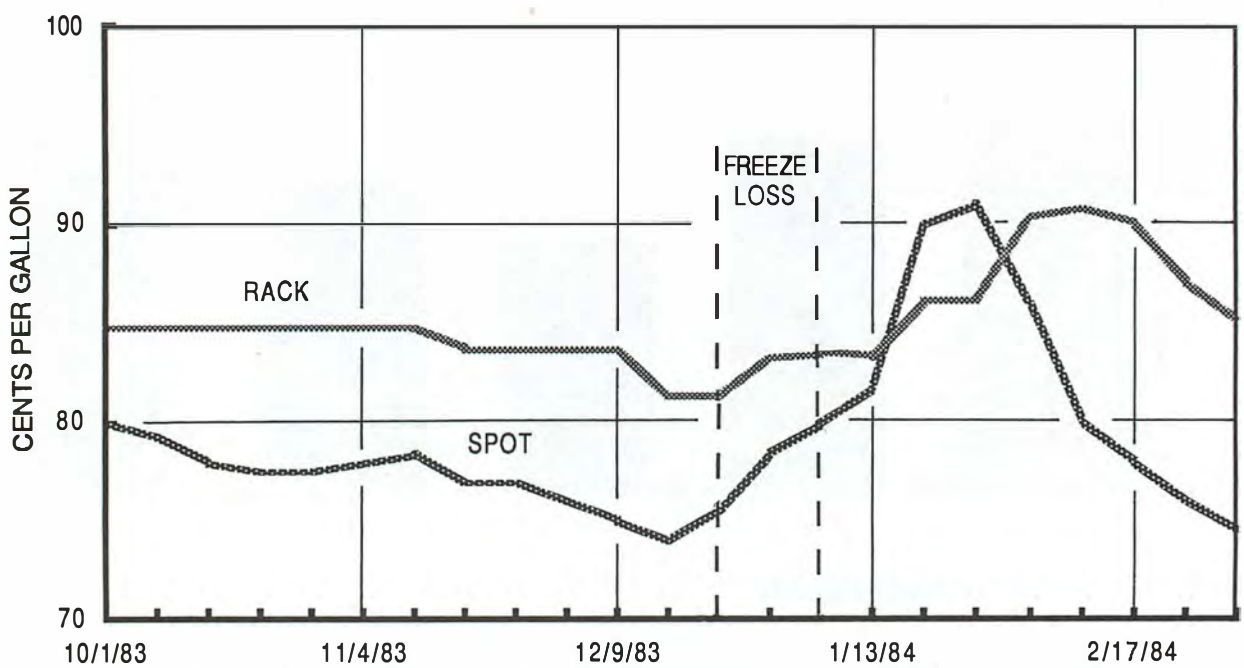



Figure 62. Gulf Distillate Spot and Rack Prices -- Winter of 1983-1984.

to the freeze was noticeable but significantly less than in the spot market. Price increases to home heating oil consumers were small and unnoticed for the most part.

Because winter is a low-demand period for gasoline, the price reaction for this product was much less pronounced. As shown in Figure 63, Gulf Coast spot prices for gasoline had declined in a relatively normal seasonal pattern from about 81¢ per gallon in October to 72-74¢ per gallon in December. Spot gasoline prices increased to about 81¢ in early January. By the end of February, spot prices were back to the normal seasonal level -- roughly the same as in October.

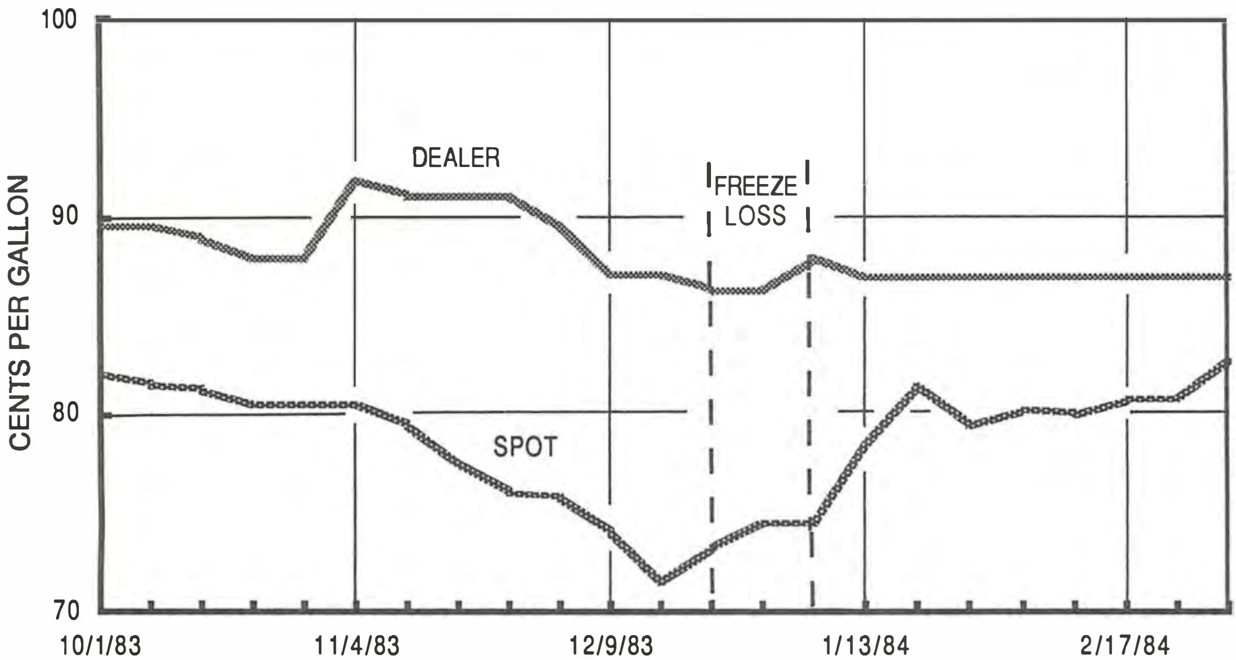



Figure 63. Gulf Gasoline Spot and Dealer Prices -- Winter of 1983-1984.

As is often the case, gasoline prices at the pump did not reflect the spot price run-up. Figure 63 shows typical prices to Houston service station dealers during the period; these prices showed almost no reaction to the freeze-up.

The system response to the refinery freeze-up problem is typical of the normal progression in resolving stress situations. The shortage triggered an increase in the spot prices for immediate incremental supply. Supply from a wide variety of sources flowed into the affected area, bringing spot prices back to a normal range. Downstream wholesale and retail prices did not increase in step with the spot prices of the supplemental supply.

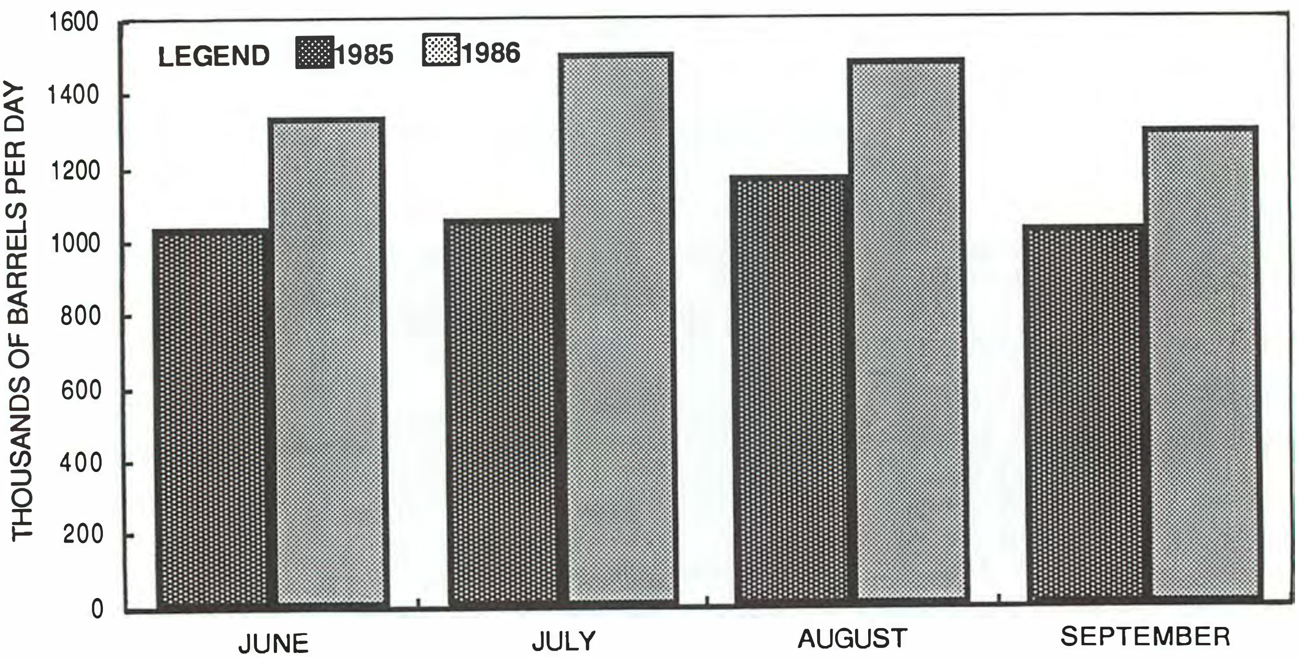
Although the freeze-up was viewed as a major stress situation by the industry, at the consumer level there were no product shortages and no abnormal price increases.

## Fuel Switching Episode -- 1986

The sharp decline in crude oil prices in early 1986 resulted in similar reductions in product prices. By mid-year 1986, residual fuel prices to utilities had dropped about 50 percent from January levels, falling well below the equivalent cost of natural gas in several markets. The lower cost induced many dual-fired plants to switch from gas to residual fuel, resulting in a very large surge in residual fuel demand. A heat wave on the East Coast significantly increased electric generation requirements there, adding further to the petroleum demand. By July 1986, residual fuel consumption by electric utilities nationwide was up 95 percent from the prior year. In some areas, the growth was even greater: in New England and the south Atlantic states, residual fuel oil consumption more than doubled, and in Texas it quadrupled.

Electric utility demand normally constitutes a major portion (35 to 40 percent) of the total residual fuel market, and the overall impact was significant. Figure 64 compares total 1986 residual fuel demand over a four-month summer period with 1985 data. The surge in demand lasted four months, during which total residual fuel demand averaged 32 percent higher than 1985 -- an increase of more than 41 million barrels (340 MB/D) for the period.

A demand surge of this magnitude and duration is a very significant event, requiring substantial expansion of normal supply. Figure 65 illustrates the system response. As indicated above,




SOURCE: EIA, Petroleum Supply Annual, 1987.

Figure 64. 1986 Residual Fuel Oil Demand vs. 1985 -- June to September.

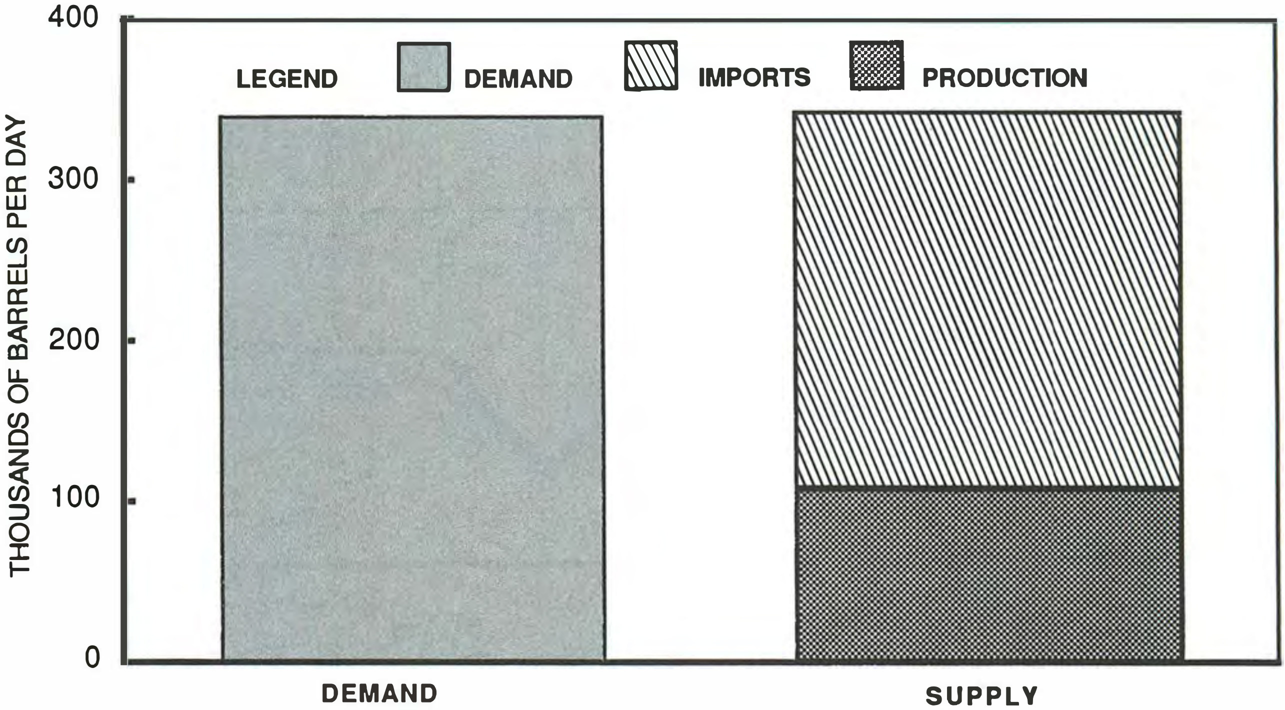



Figure 65. 1986 Residual Fuel Oil Stress Case -- Increased Demand and Supply.

residual fuel demand for the four-month period (June through September) of 1986 averaged 340 MB/D higher than 1985. In the same period, the volume of imported residual fuel increased 235 MB/D over the prior year and domestic refineries produced 109 MB/D more.

The added refinery production was obtained from a number of plants that altered conditions slightly to produce additional residual fuel. The average refinery yield of heavy fuel increased only a few tenths of a percent from seasonal norms. Production could have been increased further had the economics (relative to imports) been favorable. The added import volumes came from 34 different countries, and did not strain the system. Additional imports almost certainly could have been purchased at somewhat higher prices.

Residual fuel inventories were not drawn down during the four-month period, in part because they were not required to maintain supply. Lower price was the driving force underlying the fuel switching; overall energy supply was never an issue as gas supplies continued to be available on call if needed. Utilities apparently decided it would be more economic to buy residual fuel concurrently with their fuel shifts rather than draw inventory and replace it later. Had it been necessary, utility inventories totaling about 55 million barrels could have covered most of the added demand.

Figure 66 plots 1986 spot market prices for high-sulfur residual fuel at the U.S. Gulf Coast and at New York Harbor.

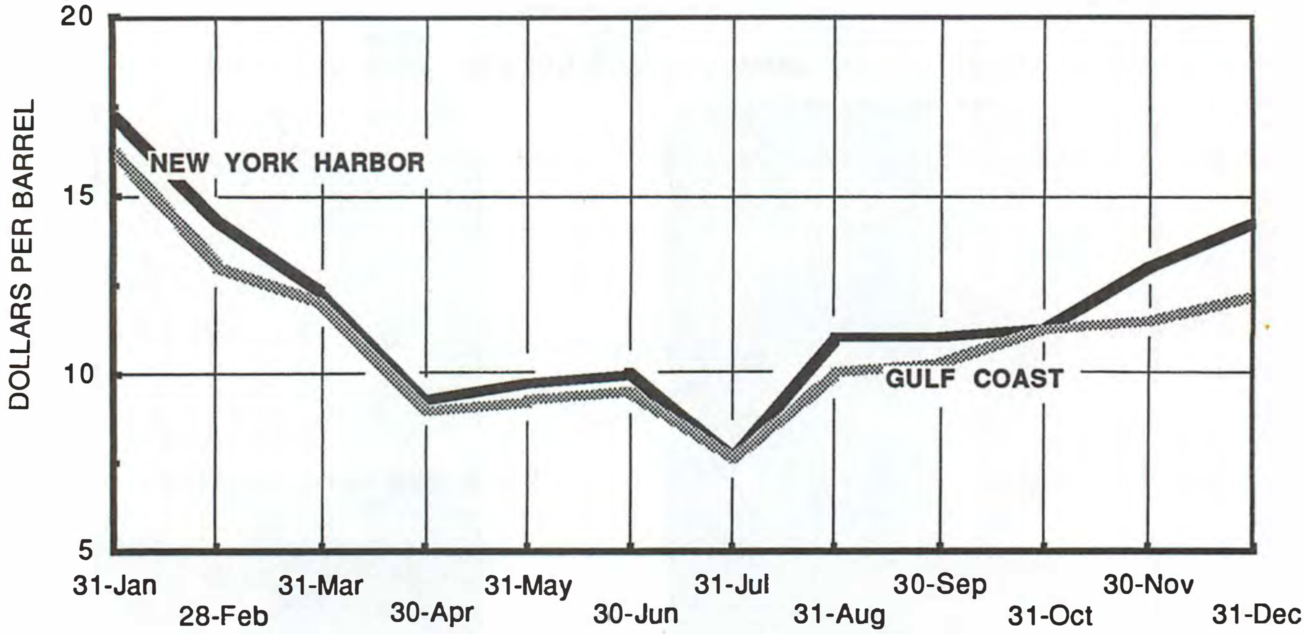



Figure 66. New York Harbor and Gulf Coast Spot Residual Fuel Oil Prices in 1986.

Price movements for other fuel grades were similar. The June-September demand surge almost certainly had some effect on price, but it is difficult to discern the effect because crude oil prices were also changing radically during the period. The impact on competing gas price is easier to observe. Average utility gas costs declined a dollar per million BTU (equivalent to more than $6 per barrel of residual fuel) between January and October. This change coupled with increases in crude oil prices closed the competitive gap and brought residual fuel demand back to near normal.

It can be argued that the 1986 fuel switching episode was not a real "stress" situation but an economic opportunity for residual fuel sellers. However, the system response to economic incentives was essentially the same as in a stress situation. The history of this episode illustrates the magnitude and diversity of response when supply-demand economics are allowed to function.

## OVERVIEW OF HYPOTHETICAL STRESS SCENARIOS

The Secretary of Energy requested the NPC to examine the capabilities of the distribution system to meet energy requirements in periods of supply "stress." Six stress scenarios were selected for this purpose:

1. Oil Import Disruption
2. Colder-Than-Normal Weather
3. Canadian Gas Import Disruption

4. Product Pipeline Disruption (PADD III to PADD II)
5. TAPS Disruption
6. Canadian Crude Oil Import Disruption

These scenarios cover stress situations of various types and differing severity. The situations were analyzed to determine the potential impact of the supply problems on affected consumers and the potential industry capability to resolve the problems.

In all the stress scenarios, it was determined that the system was capable of distributing available supply so as to avoid major problems. For this purpose, major supply problems are defined as those that would result in consumer hardship (e.g., inadequate fuel for heating, business, or transportation needs). However, it would be wrong to conclude that stress situations of the magnitude assumed in these scenarios could be resolved without some impact on consumer cost and convenience.

The effect of the assumed stress situation on consumers would be proportional to the severity of the supply problem. For example, the colder-than-normal weather scenarios are at the edge of "normal" operation. Experience indicates they could be resolved with little awareness of a problem by the general public. On the other hand, the oil import and TAPS disruption scenarios represent very severe problems that would fully tax system capability. Resolution of these supply problems would probably result in higher costs for a period and some inconvenience to consumers. For example, temporary run-outs and limited sales hours and volumes might occur before there were significant withdrawals from secondary and tertiary inventories.

With the exception of the cold-weather scenarios, the stress situations outlined on the following pages represent improbable combinations of severity and duration. They were designed to test the system's capability to deploy and distribute available supply under quite difficult conditions. The scenario reviews indicate that the system has substantial flexibility to do so when free-market conditions permit companies to bid for available supply and transportation in the United States (and in foreign markets where applicable).

The NPC did not consider scenarios that were clearly beyond the practical ability of the system to resolve (e.g., a situation that triggers international obligations under the IEA treaty). These are problems for government resolution; but even in such situations, the supply system flexibility could be a useful asset.

Only one scenario (Oil Import Disruption) involved the use of the Strategic Petroleum Reserve (SPR). In the other cases, it was determined that supplies from normal channels would be adequate. However, the SPR remains a very effective emergency supply source if normal channels should prove incapable of resolving a stress situation.

## SCENARIO 1: OIL IMPORT DISRUPTION

This two-part scenario is designed to examine the potential system response to a major loss of imported crude oil and products within the stated assumptions. In the first case, it was assumed that current imports were reduced by 3 MMB/D (including 0.6 MMB/D of product). In the second case, import volumes in 1992 were assumed to be cut by 4.5 MMB/D (including 0.9 MMB/D of product). The duration of these interruptions was arbitrarily assumed at 90 days, and it was intended that the SPR would be available. Canadian imports were assumed to be unaffected; all lost import volume was from offshore sources.

This scenario examines the industry and SPR capabilities. It is recognized that a disruption of the assumed magnitude may involve international and domestic political considerations that are beyond the scope of this analysis.

### Conclusions

In both cases, the present and projected capacity of the SPR and the distribution capability of the system are adequate to accommodate the loss of crude oil imports. Only a fraction of the reduced product supply could be replaced from domestic refineries, but replacement from foreign refineries is not expected to be a problem. There is enough flexibility in the SPR system to provide crude oil "back-up," if necessary, to replace all lost product imports in both the current case and the future (1992) case. This crude oil could be run in domestic or foreign refineries as necessary to obtain the product supply. (Export of domestic or SPR crude oil would require government approval; it would be feasible and probably economical to divert remaining import volumes to foreign refineries and run SPR crude oil in domestic refineries.)

Although SPR delivery rates are adequate to cover the assumed import loss, it is important that SPR crude oil be made available quickly to avoid a problem in "bridging" the period between the loss of imported oil and full rate delivery from SPR. Current SPR Sales Provisions would permit purchasers submitting financial guarantees to take delivery as early as 16 days after declaration of an emergency. This early delivery option should be adequate to avoid significant shortage in PADDs I and III, the areas most affected by an import reduction.

### Scenario Review

Details of the assumed import losses, as provided by DOE, are shown in Table 47. No assumptions were made as to the specific crude oil or product types that were lost. Overall, the assumed loss would be about 20 percent of current U.S. demand (based on 1987), but it would be a much larger fraction of PADD I requirements.

TABLE 47

SCENARIO 1
ASSUMED IMPORT REDUCTIONS

| PADD | Volume (MB/D) Crude Oil | Volume (MB/D) Product | Volume (MB/D) Total | Percent of Crude Oil Run | Percent of Product Demand |
|---|---|---|---|---|---|
| **Current (1987)** | | | | | |
| I | 510 | 420 | 930 | 41 | 8 |
| II | 270 | - | 270 | 9 | - |
| III | 1,450 | 210 | 1,660 | 25 | 5 |
| V | 140 | - | 140 | 6 | - |
| Total | 2,370 | 630 | 3,000 | 18 | 4 |
| **Future (1992)** | | | | | |
| I | 765 | 630 | 1,395 | 62 | 11 |
| II | 405 | - | 405 | 13 | - |
| III | 2,175 | 315 | 2,490 | 35 | 7 |
| V | 210 | - | 210 | 8 | - |
| Total | 3,555 | 945 | 4,500 | 26 | 5 |

## Current Case

As shown in Table 48, the current case scenario assumes the loss of over half of crude oil imports and about a third of product imports. The ability to redirect the remaining volume via trades can provide considerable flexibility to the system.

The SPR was intended to be used to offset a supply disruption of the assumed magnitude. For the analysis of crude oil supply capability in this scenario, it was assumed that U.S. crude oil supply would provide the feedstock underlying the replacement of lost product imports. This is a "worst case" assumption, which increased the SPR draw to the full 3 MMB/D level.

### SPR Drawdown and Distribution

The SPR is located in three areas with good access to pipelines and marine loading facilities. As shown in Figure 67, these areas are:

- Capline -- This complex includes two major salt-dome storage facilities with pipeline connections to a DOE

TABLE 48

SCENARIO 1
1987 IMPORT VOLUME
(Thousands of Barrels per Day)

| | Crude Oil | | Product | |
|---|---|---|---|---|
| Import Demand | 4,674 | (100%) | 2,004 | (100%) |
| Interrupted Volume | 2,370 | (51%) | 630 | (31%) |
| Remaining Imports | 2,304 | (49%) | 1,374 | (69%) |

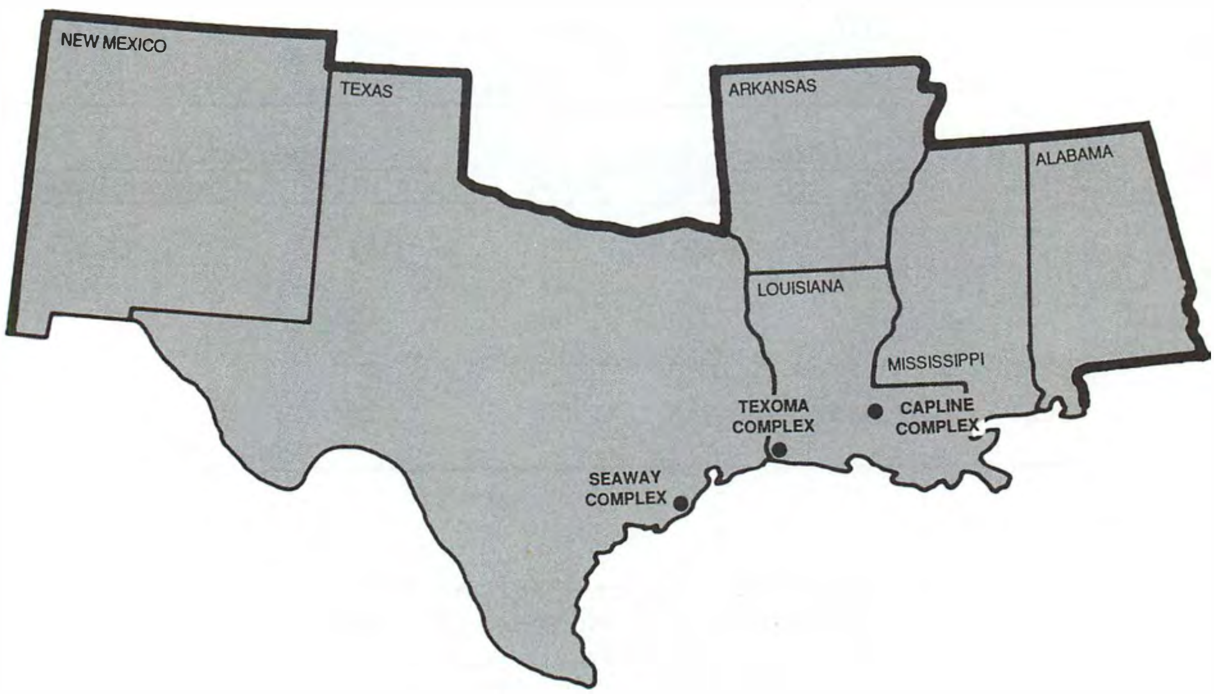



**Figure 67. Strategic Petroleum Reserve Storage Areas -- PADD III.**

terminal at St. James, Louisiana (near Baton Rouge). This terminal provides marine loading capacity and access to a number of major pipelines, including Capline. The facilities can supply SPR crude oil to Louisiana refineries and to PADD II.

- Texoma -- Located near Port Arthur, Texas, this complex includes underground storage in three major salt domes, one of which is still being developed. It is connected to the Sun marine terminal and to a number of primary pipelines. It can supply refineries in the Beaumont, Port Arthur, and Lake Charles areas; and it has the largest marine loading capacity in the SPR system.

- Seaway -- This facility, near Freeport, Texas, has storage in the Bryan Mound salt dome. It is connected to pipelines serving the Houston-Texas City refineries and a refinery at Sweeney, Texas. Marine loading facilities are provided at Freeport and Texas City.

In the aggregate, these SPR facilities are capable of pumping more than 3.5 MMB/D of crude oil from storage. As shown in Table 49, marine loading capacity totals 2.2 MMB/D, and pipeline delivery could be as high as 2.5 MMB/D.

TABLE 49

CURRENT CASE
STRATEGIC PETROLEUM RESERVE DELIVERY CAPACITY
(Thousands of Barrels per Day)

| SPR Complex | Maximum Withdrawal | Max. Delivery Via Pipeline | Max. Delivery Via Marine |
|---|---|---|---|
| Capline | 1,070 | 1,070 | 435 |
| Texoma | 1,400 | 415 | 1,090 |
| Seaway | 1,100 | 1,000 | 650 |
| Total | 3,570 | 2,485 | 2,175 |

Because the SPR's marine loading capacity is less than the maximum withdrawal rate, a portion of the crude oil must be delivered by pipeline. In an actual situation, the economic advantage of pipeline delivery would be expected to maximize pipeline volumes (via trading and supply realignment); however, it was elected to test the system in a "worst case" situation in which:

- SPR crude oil directly replaces the lost imports
- Marine-delivered SPR crude oil provides feedstock to domestic or foreign refineries, which replace interrupted product imports.

As shown in Table 50, after maximum required marine deliveries, there would remain 895 MB/D of SPR marine delivery capacity and over 2 MMB/D of pipeline delivery capacity to provide PADD III requirements of 1,450 MB/D.

SPR crude oil cannot be physically delivered to refineries representing about 30 percent of PADD III refining capacity. These plants cannot receive imported crude oil directly and would be little affected by a reduction in imports. Of the refineries that can receive SPR crude oil, about 34 percent of capacity is

TABLE 50

CURRENT CASE
DELIVERY CAPACITY FROM SPR
(Thousands of Barrels per Day)

| Delivery Method | Pipeline | Marine |
|---|---|---|
| Capacity* | 2,485 | 2,175 |
| Required for | | |
| PADD I | - | 510 |
| PADD II | 270 | - |
| PADD V | - | 140 |
| Offshore Product | - | 630 |
| Subtotal | 270 | 1,280 |
| Balance available for PADD III Delivery | 2,215 | 895 |

*Limited to 3,570 MB/D maximum withdrawal capacity.

not pipeline connected and requires marine delivery. (Table 51 shows the delivery options by area.) Assuming that import losses are spread reasonably evenly, required marine deliveries would be about 500 MB/D, which is well within the remaining SPR capacity. Detailed analysis indicates no capacity problems in any of the three SPR areas.

### Crude Oil Quality Requirements

The SPR contains both high-sulfur (sour) and low-sulfur (sweet) crude oils, which can be delivered from each SPR area on a segregated basis. This dual quality allows for the facilities and metallurgy of some refineries that require low-sulfur feed. (Low-sulfur crude oil has 0.5 percent sulfur content or less; high-sulfur crude oil has more than 0.5 percent sulfur.) As shown in Table 52, about 35 percent of current SPR inventory is dedicated to low-sulfur crude oil; as much as 60 percent of crude oil deliveries in a 90-day period could be low-sulfur crude oil.

Actual 1987 crude oil imports into PADDs I and III averaged about 42 percent low-sulfur crude oil; waterborne imports destined for PADD II averaged 45 percent low-sulfur crude oil. Assuming the lost imports are of similar mix, the implied SPR low-sulfur crude oil demand for PADDs I, II, and III would be 950

TABLE 51

SCENARIO 1
PADD III REFINERY ACCESS TO SPR CRUDE OIL
(Thousands of Barrels per Day)

| | Refinery Capacity | |
|---|---|---|
| **Pipeline Connected** | | |
| Sweeney, Texas | 175 | |
| Houston/Texas City Area | 1,654 | |
| Beaumont/Port Arthur | 990 | |
| Lake Charles Area | 467 | |
| St. James Area | 536 | |
| Pipeline Total | 3,822 | 65.6% |
| **Marine Delivery Only** | | |
| Corpus Christi | 538 | |
| LA Delta/New Orleans | 1,173 | |
| Mississippi | 295 | |
| Marine Only Total | 2,006 | 34.4% |
| Total Accessible to SPR | 5,828 | 100% |

Note: PADD III refineries with 2,374 MB/D capacity have no direct access to either imported crude oil or SPR crude oil. These refineries would be unaffected by a reduction in crude oil imports.

TABLE 52

SPR LOW-SULFUR CRUDE OIL INVENTORY AND DELIVERY RATES

| SPR Area | Low-Sulfur Inventory (Millions of Barrels) | Average Delivery Rate (MB/D) over 90 Days |
|---|---|---|
| Capline | 18 | 200 |
| Texoma | 109 | 1,220 |
| Seaway | 65 | 715 |
| | 192 | 2,135 |
| % of Total | 35% | 60% |

to 1,250 MB/D depending on the quality required to replace product imports. This is well within the overall delivery capacity. However, there are two areas that may require special consideration:

- Low-sulfur crude oil requirements in the area served by the SPR Capline complex are likely to exceed current delivery capacity from that area by sufficient margin to require action. The problem is resolvable by realigning remaining imports and/or onshore supply via trades.

- PADD V-imported crude oil is largely very low-sulfur crude oil and condensate that cannot be replaced in kind from the SPR. Heavier crude oil (e.g., Alaskan North Slope oil) can be substituted in most cases, and the practical effect would be slightly reduced refinery throughput and reduced gasoline yield. Some low-sulfur residual fuel oil production may also be lost.

System Response

As indicated above, the SPR production and distribution facilities are capable of supplying the full import shortfall by direct replacement, but there are some critical points:

- Rapid initiation of SPR withdrawal procedure is essential to minimize disruption. Release of SPR crude oil requires a presidential declaration of an emergency. Such a declaration can be obtained within a day or two of a supply interruption.

- Prompt action to award SPR crude oil volume to bidders and to provide early physical delivery of the crude oil is also critical. Under current policy, bid requests can and will be made immediately after the emergency declaration. Initial shipments of SPR crude oil can take place within 15 days of the presidential declaration, and they can be increased to the full SPR delivery rate within 30 to 35 days.

- Direct supply is inefficient. It would result in expensive cross-hauls of crude oil. In the absence of regulatory barriers, potential transportation savings would provide opportunities for crude oil trading to reduce inefficient crude oil movements.

For the interim, until SPR crude oil can be delivered to refineries, the system can rely on inventory and the arrival of in-transit imports. Transit times for imported crude oil vary considerably, as illustrated by Table 53, but on average 12-to-16-days' supply of waterborne imports is en route at any time. In a major stress situation, some ships might be diverted by foreign suppliers, but it is reasonable to assume that 10-days'

TABLE 53

SOURCES OF MARINE-DELIVERED CRUDE OIL AND TRANSIT TIMES -- 1987

| | Percent Supply | Approximate Transit Time (Days) |
|---|---|---|
| Latin America | 32 | 3-7 |
| Middle East | 24 | 14-35 |
| Africa | 25 | 12-20 |
| Europe | 9 | 14-15 |
| S.E. Asia | 6 | 20-30 |
| Other | 4 | Variable |
| | 100 | Approx. 12-16 |

supply from in-transit volume would arrive over a period of about a month after the event that interrupts imports.

In Volume IV of this study, Petroleum Inventories and Storage, it is estimated that system-wide crude oil inventories totaled 54 million barrels above minimum levels required to maintain usual operation. This inventory level is believed to be in the normal range.

Overall, the crude oil available to bridge the period between import interruption and the arrival of SPR supply is:

CURRENT CASE (1987)
BRIDGING CRUDE OIL SUPPLY

| | Millions of Barrels | Days' Supply of Interrupted Imports |
|---|---|---|
| In-Transit Supply | 24 | 10 |
| Inventory Above Min. | 54 | 22 |
| | 78 | 32 |

If accessible, this volume coupled with product inventory would be adequate to bridge the period until SPR supplies begin to arrive. However, the assumed import loss falls most heavily on PADDs I and III, but not much of the industry inventory could be physically shifted to these districts.

Crude oil trading and exchanges can provide the mechanism through which system-wide inventory can be utilized as "bridging" supply in PADDs I and III. For example, a portion of the uninterrupted import volume could be diverted to PADD I. (Almost all PADD I crude oil must be marine delivered.) Similarly, PADD III refiners could effectively utilize Midwest inventories by temporarily diverting crude oil that would otherwise be shipped north. Trading also provides a mechanism for equalizing in the short term the differing impacts of import losses on individual refiners within a PADD.

In the initial stages of a stress situation of this magnitude, most refiners who give up supply would insist on return of an equal volume by a date certain. Until SPR volumes are awarded and scheduled (13 to 19 days after import interruption), it would be difficult for PADD I or III refiners to make a credible commitment to repay time-traded crude oil. It is anticipated that full SPR delivery rate will be attained within 30 to 35 days because of the time required for buyers to arrange transportation. However, DOE procedures would permit deliveries in as little as 16 days to buyers who provide financial guarantees. Even modest early deliveries would avoid a significant "bridging" gap in supply.

Direct replacement of lost import supply by shipment from SPR is feasible, but economically inefficient. It would result in costly cross-hauling of crude oil and underutilization of low-cost pipeline capacity. Over time, the normal system response to economic incentive would probably alter the crude oil distribution along the following lines:

- SPR shipments to PADD V would be effectively eliminated by trading SPR crude oil for Alaskan North Slope crude oil that normally would be shipped east. It makes no economic sense to tie up inventory and ships to move crude oil to the West Coast while equivalent crude oil is being shipped in the opposite direction.

- A portion of import volume destined for PADD III would be traded for SPR crude oil (or equivalent Gulf Coast supply) and diverted to PADD I. This would reduce U.S.-flag shipments from the Gulf to the East Coast.

- Exchanges among PADD refiners would reduce costly marine outhaul of SPR crude oil and would increase pipeline delivery.

Each of these changes offers economic incentives large enough to stimulate vigorous crude oil trading activity. Normal system response would be expected to improve distribution efficiency substantially within a month or two after SPR volumes were awarded and scheduled.

### Marine Requirements

Delivery of SPR crude oil would impose additional marine tonnage requirements. Initially, the incremental tonnage demands could be quite high, but tonnage requirements should decline quickly as trading and supply realignment increase distribution efficiency. No attempt was made to estimate maximum requirements, but they are expected to exceed surplus U.S.-flag capacity. Foreign-flag tonnage is currently in long supply, and interruption of U.S. imports would make the surplus even larger. Jones Act waivers would be necessary to allow foreign-flag vessels to trade between U.S. ports.

It is believed that the U.S. Maritime Administration will be prepared to move quickly to grant Jones Act waivers on a case-by-case basis and to withdraw waivers as the distribution patterns reoptimize.

### Replacement of Product Imports

The assumed interruption of product supplies offers a less immediate problem than interruption of crude oil, because the volumes are small relative to total demand, and because product inventory is relatively large. (On a national basis, the loss is equivalent to 1.2 days product supply per month.)

Table 54 shows the mix of product imports into PADDs I and III. Options for replacing the product vary according to which products were actually reduced. Among the options are:

- Additional U.S. Crude Oil Runs -- The product mix includes a high percentage of residual fuel oil and unfinished oils typical of simple topping capacity.

TABLE 54

MIX OF PADD I AND PADD III PRODUCT IMPORTS
(Thousands of Barrels per Day)

| | PADD I | PADD III | Total Vol. | Total % |
|---|---|---|---|---|
| Gasoline | 340 | 16 | 356 | 20 |
| Distillate* | 290 | 17 | 307 | 17 |
| Unfinished/Other | 247 | 328 | 575 | 32 |
| Residual Fuel Oil | 527 | 27 | 554 | 31 |
| | 1,404 | 388 | 1,792 | 100 |

*Includes kerosine and jet kerosine.

Source: EIA, Petroleum Supply Annual, 1987.

The industry has spare capacity of this type. Replacement of 150 to 200 MB/D (25 to 30 percent) of the lost product could come from domestic refineries, if economics are favorable.

- Foreign Purchases or Processing -- There is a substantial surplus of foreign refinery capacity. It should be possible to replace essentially all the lost imports via realigned purchases (if crude oil is available in world markets) or by processing U.S. crude oil supply in foreign refineries. Export of U.S. crude oil requires government approval. However, it would be feasible and probably economical to divert a portion of remaining imported crude oil volume to foreign refineries and run SPR crude oil in U.S. refineries.

Future Case (1992)

In this case, the assumed reduction in import volume is:

| | |
|---|---|
| Crude Oil | 3,555 MB/D |
| Product | 945 MB/D |
| Total | 4,500 MB/D |

As shown in Table 55, the SPR delivery capacity is projected by DOE to be 4,500 MB/D, up 930 MB/D from current deliverability. It was assumed that SPR withdrawal would be at maximum rates to make crude oil available for domestic or foreign processing to replace lost product imports. At maximum capacity, SPR would be able to supply enough crude oil to provide feedstock for all the lost product imports.

TABLE 55

1992 SPR DELIVERY CAPACITY
(Thousands of Barrels per Day)

| SPR Complex | Maximum Withdrawal | Max. Delivery Via Pipeline* | Max. Delivery Via Marine |
|---|---|---|---|
| Capline | 1,070 | 1,070 | 635 |
| Texoma | 2,180 | 450 | 1,770 |
| Seaway | 1,250 | 1,000 | 750 |
| | 4,500 | 2,520 | 3,155 |

*Estimated.

Marine delivery rates remain a potential bottleneck. As shown in Table 56, after deducting capacity dedicated to PADD I, PADD V, and offshore product backup, there would be about 1,360 MB/D of SPR marine-delivery capacity remaining. About 34 percent of PADD III refinery capacity that can physically receive SPR crude oil is not pipeline connected and requires marine delivery. If SPR requirements for these plants are reasonably proportional to capacity, marine-delivery requirements would be about 740 MB/D, leaving roughly 620 MB/D of spare terminal capacity.

TABLE 56

FUTURE CASE (1992)
DELIVERY CAPACITY FROM SPR
(Thousands of Barrels per Day)

| | Pipeline | Marine |
|---|---|---|
| Delivery Method | | |
| Capacity* | 2,520 | 3,155 |
| Required For | | |
| PADD I | -- | 765 |
| PADD II | 405 | -- |
| PADD V | -- | 210 |
| Offshore Product | | 820 |
| Subtotal | 405 | 1,795 |
| Available for PADD III§ | 2,115 | 1,360 |

*Limited to a maximum withdrawal rate of 4,500 MB/D.

§Limited to remaining availability of 2,175 MB/D.

## Crude Oil Quality

Current SPR plans call for a mix of low- and high-sulfur crude oils as shown in Table 57. Crude oil backup to replace lost product imports would be predominantly sour crude oil, leaving sweet (low-sulfur) supplies for U.S. refiners. Projected SPR capacity would allow up to 69 percent of SPR deliveries to U.S. refineries to be low-sulfur crude oil. This level is projected to be adequate. Declining U.S. sweet crude oil production is expected to be partially offset by improved sulfur-handling capability of U.S. refineries.

TABLE 57

SPR CRUDE OIL MIX -- 1992
LOW-SULFUR INVENTORY

| | Volume (Millions of Barrels) | Approx. Delivery Rate (MB/D) |
|---|---|---|
| Capline | 34 | 378 |
| Texoma | 181 | 2,011 |
| Seaway | 66 | 733 |
| | 281 | 3,122 |
| % of Total | 37% | 69% |

System Response

Directionally, the system responses would be similar to those of the current case, but the problem of "bridging" prior to arrival of SPR supplies is more difficult. The system-wide supply available to cover the first 30 to 35 days after import interruption is shown below:

FUTURE CASE (1992)
BRIDGING CRUDE OIL SUPPLY

| | Millions of Barrels | Days' Supply of Interrupted Imports |
|---|---|---|
| In-Transit | 36 | 10 |
| Inventory Above Min. | 55 | 15 |
| | 91 | 25 |

Even if all the available system inventory could be utilized, U.S. refinery output would be reduced by 20 to 40 million barrels unless significant "early delivery" volumes are available. Import losses would fall most heavily on PADDs I and III. Drawdown of product inventories would reduce the impact on consumers, but the lost refinery production would mean a longer and more difficult recovery period after SPR supplies become available.

In this case, accelerated delivery of SPR crude oil would become a very important factor in reducing the "bridging" problems of PADDs I and III. Current procedures appear to be adequate, but government agencies should be prepared to act very quickly to award and schedule SPR crude oil in the minimum period and to provide the waivers necessary to arrange transportation.

Product inventories are adequate to avoid consumer shortages during the bridging period, but they would have to be effectively translated to PADDs I and III through trading and supply realignment.

### Replacement of Product Imports

There is enough SPR capacity to cover all of the lost product imports. The crude oil equivalent could be refined in either U.S. or foreign refineries.

## SCENARIO 2: COLDER-THAN-NORMAL WEATHER

A severe winter weather scenario was assessed to determine stresses that may result if temperatures average 10 percent colder than normal for 90 days, or 20 percent colder than normal for 30 days, across the nation. Over the past 57 years, five winters have met the former criterion, and seven have met the latter, with the most recent in December 1983, when heating degree days totaled 22 percent higher than normal.

### Summary and Conclusions

A combination of inventory drawdowns and various resupply alternatives would be able to meet system demand under either possibility for severe winter weather, both at present and by 1992. The natural gas delivery system would be able to meet all residential and commercial demands made of it, but could curtail some utility and industrial users at the height of the severe weather, with more widespread curtailments possible in 1992 than today. Natural gas storage volumes and peak-shaving capabilities are fully utilized, consistent with historical experience, in either case in this scenario. However, a margin of flexibility exists on the oil side, where the extra demand can be met by higher output of fuel oils and LPG, higher rates of stock depletion, or higher imports. The supplies of distillate and residual fuel oils should be adequate to serve all oil-heating demand (which amounts to considerably less than gas-heating demand) and to serve the curtailed industrial and utility gas consumers with fuel-switching capability. The more severe 30-day, 20-percent-colder scenario could pose more of a challenge in 1992 if it occurs in March instead of January. In this hypothetical case, a conceivable though improbable combination of low stocks in the Northeast and low pipeline movements into that region at the beginning of the cold snap could result in unusual, higher cost operating procedures and customer stockdraws for up to two weeks. By 1992, more investment in natural gas delivery capability may be necessary to maintain the system's ability to deal with such a late-season, super-cold-weather scenario.

The point of severest stress in either form of this scenario is natural gas deliverability to and within the East Coast region (PADD I). To provide more flexibility to the winter energy delivery system, it would be necessary to build more gas pipelines to Florida and into the New England states now, and perhaps to reactivate LNG capacity for the Mid-Atlantic states by 1992. Projects to provide the needed capacity have already been proposed to the Federal Energy Regulatory Commission (FERC) by companies wishing to build the lines, and as of now, they could be completed by 1992 if permits are not delayed by litigation. Assuming they are completed by that time, no natural gas curtailments are foreseen in either case in this scenario, and likewise, no heating-oil delivery stresses should be experienced.

In this scenario, prices for heating oil would rise in areas requiring additional supplies, due to the high rate of stockdraw. In the 30-day, 20-percent-colder case, the price rise would tend to slow premature withdrawals of primary system inventories and to encourage drawdown of secondary and tertiary inventories. In the 90-day, 10-percent-colder case, heating oil prices may rise at first to conserve primary inventories, but would then settle to a small differential above other locations, which would be sufficient to bring in the needed additional supplies. It should be noted that many heating oil customers would escape paying higher prices during the severe cold, since many consumers need to replenish supply only two or three times in a winter season and can exercise some control over when to buy.

Some very temporary intra-PADD fuel oil delivery delays could result from unusual events or freakish weather related to the cold. Such delays would be localized and quickly resolvable.

## Assumptions for Analysis

The analysis of this scenario assumes the existence of the present free market for oil products within the United States, where oil product prices act as powerful signals of relative regional needs for product volumes. In the competitive oil market, rates of refined product output, imports, and stock accumulation and depletion always respond to prices, which rise or fall at any one location with rising or falling demand. Relatively small price spreads are sufficient to move fuel oil volumes where they are most urgently needed. Furthermore, persistent or relatively sharp price spreads provide both the signal that more investment in delivery capacity is needed, and the financial incentive to make that investment.

Potential 1988 and 1992 winter natural gas demand by sector and incremental increases in demand, attributable to each form of the severe-winter-weather scenario, are shown in Table 58.

Corresponding potential January 1988 and 1992 demands for distillate, residual fuel oil, and LPG (which includes propane), excluding fuel switching volumes for curtailed gas customers, are shown in Table 59.

The periods used for the 90-day, 10-percent-colder case are December 1987 through February 1988 and December 1991 through

TABLE 58

U.S. NATURAL GAS DEMAND*
(Million Cubic Feet per Day)

| | Average Day | 10% Colder§ | 20% Colder |
|---|---|---|---|
| | January 1988 | | |
| Residential | 27,318 | 29,628 | 31,939 |
| Commercial | 13,314 | 14,331 | 15,349 |
| Industrial | 17,775 | 17,775 | 17,775 |
| Electric Utility | 5,331 | 5,331 | 5,331 |
| | January 1992 | | |
| Residential | 24,939 | 27,052 | 29,166 |
| Commercial | 13,254 | 14,271 | 15,288 |
| Industrial | 22,313 | 22,313 | 22,313 |
| Electric Utility | 7,182 | 7,182 | 7,182 |

*Excludes lease and plant fuel and pipeline fuel.

§Average for December, January, and February.

TABLE 59

U.S. PETROLEUM DEMANDS
(Thousands of Barrels per Day)

| | Normal | 10% Colder* | 20% Colder |
|---|---|---|---|
| | January 1988 | | |
| Distillate | 3,517 | 3,614 | 3,709 |
| Residual Fuel Oil | 1,578 | 1,657 | 1,746 |
| LPG | 2,069 | 2,103 | 2,112 |
| | January 1992 | | |
| Distillate | 4,065 | 4,081 | 4,250 |
| Residual Fuel Oil | 1,840 | 1,884 | 2,040 |
| LPG | 2,112 | 2,154 | 2,154 |

*Average for December, January, and February.

Source: EIA analysis.

February 1992. Since the winter of 1987-1988 was about normal, the assumed demands for natural gas and oil in the colder-than-normal cases are considerably above actual demands for that period. For the 30-day, 20-percent-colder case, January 1988 and January 1992 are used. It is assumed that all sections of the country experience the same proportionally severe weather (a very unlikely occurrence).

It also is assumed that none of the problems addressed by the other scenarios occur in this scenario. Specifically, there are no simultaneous disruptions in oil imports, TAPS crude oil delivery, or gas imports from Canada, etc. Furthermore, no unusually large amount of refinery capacity is assumed to be temporarily shut down. Finally, no serious product pipeline problems are assumed in the continental United States, and all typically ice-free Atlantic ports are assumed to remain open, with normal operations.

In addition, normal peak winter natural gas supply was assumed to be reduced by 10 percent, reflecting the adverse effects of the severe weather. However, gas storage facilities are assumed to be full at the beginning of the heating season, which is normal gas industry practice. Gas storage capacity is the most important resource available for meeting abnormal weather-related demand.

## Analysis

### United States -- Present Cases

Looking at the cases of this scenario from a national perspective first, there does not appear to be any problem in meeting present colder-than-normal winter oil and gas demands in either case. The gas pipeline system has sufficient capacity at present to serve all demands without curtailments in all regions except Florida, where some curtailed utility demand would have to be served by residual fuel oil in either case in the scenario. That amount should be relatively small (in the order of 20 MB/D), and easily filled by drawing on utility inventories and by later increasing residual fuel imports to replenish those inventories.

National demands for fuel oil in severely cold weather also should be met easily, at present. For the 30-day, 20-percent-colder case, the first supply source would be the drawdown of primary inventories. Oil companies build primary inventories of distillate fuel prior to the winter heating season, and the lowest recent stock level at the beginning of January was 123.5 million barrels in 1989. Since the NPC estimates distillate minimum operating inventories to be 85 million barrels, primary inventory draw in January could theoretically rise as high as 1.5 MMB/D, though in practice oil companies would not want distillate inventories to fall to minimum levels in advance of February and March heating demands. Therefore, a brief period of exceptionally heavy primary inventory drawdowns would push distillate prices up, which would slow the draw on primary stocks and induce companies either to increase distillate production and/or to increase imports. Distillate yield from refinery crude oil runs, and the amount of crude oil run at refineries, can both be increased substantially within two weeks. Increased imports of distillate take two weeks to reach the Northeast from Rotterdam. As shown in Table 60, a combination of high (but not maximum) recent amounts from each supply source more than covers the estimated demand for distillate fuel for the 30-day, 20-percent-colder case.

TABLE 60

U.S. SUPPLY POSSIBILITIES OF DISTILLATE FUEL OIL
(Thousands of Barrels per Day)

30-Day Case - 20% Colder

| | Distillate |
|---|---|
| Demand | 3,709 |
| Refinery Output | 3,300 |
| Imports* | 400 |
| Stock Draw§ | 790 |
| Potential Supply | 4,490 |

*Reflects a modest import rate in the first half of month, maximum imports in second half.

§Based on historical performance.

In Table 60, the distillate output figure is based on recent, maximum, monthly crude oil runs, and the recent maximum distillate yield, adjusted downwards slightly to reflect less than maximum production at the beginning of the month. The imports figure is based on modest (200 MB/D) imports at the beginning of January and very high (600 MB/D) imports in the last half of the month. The stockdraw is based on the difference between the recent, lowest, observed, end-of-February inventories and the NPC-estimated minimum operating inventory. This stockdraw rate was chosen since it is applicable both to a late-season, extreme cold snap in March, and to an extremely cold January.

For residual fuel oil, the first source of extra supply for the 30-day, 20-percent-colder case also would be a higher rate of stockdraw. Residual fuel oil primary inventories have not recently demonstrated a systematic build for the winter season, but have held well above the NPC estimated minimum operating inventory level throughout each recent winter. As with distillate, if a higher than desirable stock drawdown rate occurs, prices will rise to induce greater output and imports of residual fuel oil. Residual fuel oil output could rise to high levels within two weeks, while imports could rise to high levels after two weeks, due to transit times from Europe.

Table 61 details the supply calculations for residual fuel oil for the 30-day, 20-percent-colder case. Once again, the refinery output represents a small decrease from a combination of maximum observed, recent, crude oil run rates and maximum observed residual yields. This reflects production rising to a high rate quickly, after being low initially. Imports shown in the table represent a modest initial rate and a very high rate in the second half of the month. The stockdraw rate reflects the difference between the recent lowest end-of-February residual fuel oil inventories and the NPC estimate of minimum operating inventory.

As a general rule, dealing with the 90-day, 10-percent-colder case is less difficult for the oil industry, if it can

TABLE 61

U.S. SUPPLY POSSIBILITIES
OF RESIDUAL FUEL OIL
(Thousands of Barrels per Day)

30-Day Case - 20% Colder

| | Residual |
|---|---|
| Demand | 1,746 |
| Refinery Output | 1,100 |
| Imports* | 850 |
| Stock Draw§ | 170 |
| Potential Supply | 2,120 |

*Reflects a modest import rate in the first half of month, maximum imports in second half.

§March, or late heating season, stockdraws, based on the difference between recent, lowest, observed, end-of-February inventories and NPC estimate of minimum operating inventory.

deal with the 30-day, 20-percent-colder case. The daily demands to be met are lower, and there is more time to bring extra output and imports on line. Once again, the first response to increased demand would be a higher rate of drawdown of distillate and residual inventories. After one week, refinery output could be increased significantly, and after two weeks imports could rise to a high rate. The supply calculations for both fuels are detailed in Table 62.

TABLE 62

U.S. SUPPLY POSSIBILITIES
OF DISTILLATE AND RESIDUAL FUEL OILS
(Thousands of Barrels per Day)

90-Day Case - 10% Colder

| | Distillate | Residual |
|---|---|---|
| Demand | 3,546 | 1,657 |
| Refinery Output* | 3,400 | 1,150 |
| Maximum Imports§ | 600 | 1,150 |
| Stock Draw¶ | 350 | 130 |
| Potential Supply | 4,350 | 2,430 |

*Recent observed high yield and high crude oil run level.

§Based on highest import volume in four-year period (1984-1987) and weekly import data.

¶Maximum average 90-day rate for lowest recent December 1 inventory level to minimum operating inventory.

In Table 62, the stockdraws for each fuel are significantly lower than in the 30-day, 20-percent-colder case, since they are based on a drawdown of inventories from the lowest recent observed beginning-of-December level to minimum operating inventory over 90 days. Actually, the stockdraw at the beginning of the cold weather is likely to be substantially greater, and this would induce higher outputs and imports to slow or reverse the drawdown. The output figures shown are combinations of the highest, recent, observed crude oil runs and the highest, recent, observed yields from crude oil for each fuel, while the imports shown in the table reflect very high, recently observed import rates.

Obviously, in either case, there would be more than enough supply to meet the demand, so some mix of supply options would be used. What that mix would be is impossible to determine, since each of the many oil companies would choose the lowest-cost mix of sources given its own stock levels and available production and transportation investments.

LPG heating demand also would be affected by colder-than-normal temperatures. The particular liquefied gas used for heating and other household purposes is propane, which also is used extensively as a petrochemical feedstock. It is assumed that in very cold weather, adequate propane simply would be bid away from petrochemical use, with other gas liquids, naphtha, and gas oil substituting for the missing propane. Additionally, the stock drawdowns and increased imports could help to cover the added cold-weather propane demand.

<u>Regional Demands -- Current Cases</u>

There also should be no problem meeting the demands of any of the PADDs in severe winter weather. In PADDs II, III, IV, and V, the fuel oils simply are not very intensively used for heating, and these districts often have higher summer demands for distillate and residual fuel. Also, their refinery outputs of the fuel oils equal or exceed their typical winter consumptions.

PADD I presents the most complex supply situation. Its refinery output of distillate and residual fuel oil could cover only about one-fourth of its winter fuel oils demand, which can rise to about twice its summer distillate and residual demand. Heating consumption of distillate and residual fuel oil is very heavy in PADD I, and though primary inventories within the PADD also tend to be quite large, fuel oil imports and inter-PADD movements (mostly from PADD III) play a very large role in meeting winter heating demands.

In the 30-day, 20-percent-colder case, supply options would cover expected distillate demand of about 1.8 MMB/D early in the heating season with no problem, as detailed in Table 63. Even a quite modest level of stocks at that time would cover an average 1 MMB/D stockdraw, and a higher stockdraw rate would be the first supply source used. Output could be raised to recent highs quickly, within two weeks, while extra imports would also take two weeks to reach Atlantic harbors, and both would occur if a heavy stockdraw boosted distillate prices in PADD I relative to other areas. Most inter-PADD distillate fuel arrives via pipeline from PADD III in 15 to 26 days, so extra inter-PADD supply would arrive only in the last third of the month.

A late-season, severe cold snap was considered a source of potential problems, so the March supply-demand balance is also examined in detail in Table 63. March heating demand for distillate would be significantly lower, even if the weather were 20 percent colder than normal. Stocks also would be lower, allowing only a more modest stockdraw. However, with March

TABLE 63

PADD I SUPPLY POSSIBILITIES
OF DISTILLATE FUEL OIL
(Thousands of Barrels per Day)

30-Day Case - 20% Colder

| | Distillate January | Distillate March |
|---|---|---|
| Demand | 1,830 | 1,580 |
| Refinery Output* | 400 | 400 |
| Imports§ | 350 | 350 |
| Stock Draw¶ | 1,000 | 350 |
| Net Inter-PADD Receipts** | 700 | 700 |
| Potential Supply | 2,450 | 1,800 |

*Recent observed high value.

§Half recent low, half recent high, reflecting Rotterdam-New York two-week transit.

¶Based on the difference between recent, low, beginning-of-month level and minimum operating inventory.

**Recent low value for the first two-thirds of the month, recent high for the last one-third of the month based on Houston-to-New York City pipeline time.

demand being so much lower than January demand, the distillate supplies available comfortably exceed demand even in this late season case. If gas curtailments resulted in significant purchases of distillate for replacement fuel, supply would become somewhat tighter but still should pose no problem. Prices would rise a few cents a gallon over other areas of the country and/or over Europe to bring forth the needed supplies.

In a purely hypothetical case of unusually low primary inventories at the beginning of a severe cold snap, distillate prices in PADD I would increase enough to cause buyers with inventories on-hand to delay added purchases and draw down their inventories instead. Utilities and many industrial users maintain sizeable inventories against such a possibility. Secondary fuel oil sellers could also be induced to delay primary purchases, and could conserve their own inventories by deliveries to heating customers on an "as needed" basis, in small increments. Though it raises operating expenses considerably, major companies can even draw primary inventories 5 to 10 percent below their minimum operating inventory levels for short periods. In addition, it is likely that the price spike would induce suppliers to make some use of trucks and rail to move small extra volumes into PADD I quickly. Since it is very unlikely that net inter-PADD receipts and imports would be low when primary inventories are low, this hypothetical worst case is no more than an academic possibility.

In the 30-day, 20-percent-colder case, there would be no problem meeting January residual fuel oil demand, as detailed in Table 64. Residual supplies late in the heating season, when inventories can be substantially lower, would be more modest, but demand also would be a great deal lower. No tightness would develop even if inventories were as low as they were at the end of February 1987, and if imports likewise began the month near recent winter lows. If for any reason residual fuel inventories at the beginning of a cold snap were unusually and severely low, the

TABLE 64

PADD I SUPPLY POSSIBILITIES OF RESIDUAL FUEL OIL
(Thousands of Barrels per Day)

30-Day Case - 20% Colder

| | Residual January | Residual March |
|---|---|---|
| Demand | 1,140 | 880 |
| Refinery Output* | 200 | 200 |
| Imports§ | 800 | 800 |
| Stock Draw¶ | 275 | 75 |
| Net Inter-PADD Receipts** | 25 | 25 |
| Potential Supply | 1,300 | 1,100 |

*Recent observed high value.

§Half recent low, half recent high, reflecting Rotterdam-New York two-week transit.

¶Based on the difference between recent, low, beginning-of-month level and minimum operating inventory.

**Recent low value for the first two-thirds of the month, recent high for the last one-third of the month based on Houston-to-New York City transit time.

price spike which the initial high stockdraw rate would cause should drive sufficient utility purchases from the market to resolve the shortage.

The potential supplies of distillate are more than adeate for the 90-day, 10-percent-colder case, as detailed in Table 65. There is capacity to move at least 1 MMB/D of distillate into PADD I from PADD III, mostly through the Colonial pipeline system, and at least that much exportable winter distillate production capability in PADD III. Combined with production of 400+ MB/D, imports of up to 550 MB/D, and a typical, sustainable, winter-long stockdraw of 300 MB/D, this comfortably exceeds present January demand for this case. Imports and net inter-PADD receipts can reach their maximum values in about 15 to 30 days, so the stockdraw at first probably would be somewhat heavier than shown, and would taper off later as imports and net receipts rose.

Likewise, there would be no problem supplying residual fuel oil to PADD I in the 90-day, 10-percent-colder case. Residual imports of up to 1 MMB/D, district production of 200 MB/D, and other sources of up to another 150 MB/D comfortably exceed the estimated January PADD I residual fuel demand of 970 MB/D in this case.

TABLE 65

PADD I SUPPLY POSSIBILITIES
OF DISTILLATE AND RESIDUAL FUEL OILS
(Thousands of Barrels per Day)

90-Day Case - 10% Colder

| | Distillate | Residual |
|---|---|---|
| Demand | 1,690 | 970 |
| Refinery Output* | 400 | 200 |
| Imports* | 550 | 1,000 |
| Stock Draw§ | 300 | 100 |
| Net Inter-PADD Receipts* | 1,000 | 50 |
| Potential Supply | 2,250 | 1,350 |

*Observed recent high value.

§Based on difference between lowest recent beginning-of-December inventories and minimum operating inventory level.

## 1992 Demand Cases -- U.S. and Regional

By 1992, some additional investment in transportation and storage facilities for natural gas would be made in order to meet national and regional demands during severe winter weather. If they are, natural gas curtailments would not occur under either case. Otherwise, some industrial and utility gas customers in New England, the Middle Atlantic region, and Florida could be curtailed under either case of the severe-winter-weather scenario, with the curtailments amounting to a maximum of 37 million cubic feet per day (MMCF/D) in the 90-day, 10-percent-colder case, and a maximum of 46 MMCF/D in the 30-day, 20-percent-colder case. More pipeline capacity into these areas, and possibly the reactivation of the Cove Point LNG terminal would be necessary to avoid these curtailments. If curtailed customers all were to have fuel-switching capability, these gas cut-offs would result in up to 50 MB/D of extra distillate and residual fuel oil demand for the 90-day, 10-percent-colder case, and 70 MB/D of extra fuel oil demand for the 30-day, 20-percent-colder case.

On a nationwide basis, assuming no change in refinery, oil transportation, or product storage capacities, the oil industry will have no problem meeting the 1992 90-day, 10-percent-colder or the 30-day, 20-percent-colder-weather emergency demands, though both cases would be slightly more stressed than at present. U.S. demand for distillate is projected to be 4,250 MB/D in the 30-day case and 4,081 MB/D in the 90-day case, while total residual fuel oil demand is projected to be 2,040 MB/D in the 30-day case and 1,884 MB/D in the 90-day case. For the United States as a whole, this would leave total possible supplies adequate to cover fuel oil demands in both cases of this cold-weather scenario.

Meeting severe winter fuel oil demands in PADDs II, III, IV, and V is not forecast to become a problem, since heating demand for fuel oil in those regions should remain quite small. In PADD I, demands in the 90-day case should continue to be covered by the supply options. Extra investment probably would be made to meet the demands of the 30-day case, especially in light of the extra 70 MB/D of fuel oil demand that might occur if sufficient gas pipeline capacity is not added. That investment could take the form of holding larger inventories going into the heating season, though that may not be the least-cost option. The optimal solution for meeting likely demand will be determined by each company's decisions in light of its other plans and existing hardware.

## SCENARIO 3: CANADIAN GAS IMPORT DISRUPTION

In this scenario, it was assumed that imported Canadian natural gas volumes were reduced by 50 percent for a 30-day period in January. The overall loss was assumed to be 2,325 MMCF/D allocated as follows:

| | |
|---|---|
| PADD I - New England | 25 MMCF/D |
| PADD I - Mid-Atlantic | 100 |
| PADD II | 410 |
| PADD IV | 555 |
| PADD V | 1,235 |
| | 2,325 MMCF/D |

The allocation of the assumed loss is approximately proportional to 1987 volumes of imported Canadian gas in each area.

The relevant conditions were input to a computer model of the gas distribution system to determine the effect of the Canadian gas reduction. The model is described in Volume III of this report, Natural Gas Transportation. System capability was tested for average January demand and at the peak January day demand rate.

## Current Case

Based on average January 1988 demand, a 50 percent reduction in Canadian imports would have caused no disruption to any customer class in any area of the United States, providing the existing underground storage and LNG storage were filled to normal levels at the start of the heating season. Normal storage management practices of the industry are geared toward a stored gas volume adequate to cover substantially higher than normal demands over the winter. For example, in the relatively normal winter of 1987-1988, only about half the "working" gas inventory was drawn. Obviously, attainment of normal inventory levels presumes availability of adequate off-season supply.

On a peak January day, system gas demands may be 40 percent higher than average. At peak-day rates, a 50 percent reduction in Canadian capacity would require New England industrial and electric utilities to switch from gas to oil approximately as indicated below:

NEW ENGLAND
REQUIRED FUEL SWITCHING

| | From Gas (MMCF) | To Oil (MB/D) |
|---|---|---|
| Industrial | 14 | 2.3 |
| Electric Utility | 5 | 0.9 |
| | 19 | 3.2 |

Florida gas demands are constrained by inadequate pipeline capacity. On peak January days, about 102 MCF of potential gas demand by electric utilities cannot be satisfied. Equivalent oil demand is 17 MB/D. A 50 percent reduction in Canadian natural gas would have no further impact on Florida supply.

Fuel switches of these sizes pose no oil supply problem. They can be covered with existing inventories.

Future Case

Despite projected demand growth, there is adequate transmission capacity to provide full coverage for all gas demands in most areas of the United States even if Canadian supplies are cut 50 percent, assuming that inventories are replenished by the start of the season. With existing gas transmission capacity, New England and Florida gas use would be constrained at peak January demand levels. Disruption of Canadian gas would increase the volume of New England industrial and utility demand that must be switched to oil. Table 66 shows the volume of unsatisfied gas demand that would have to be switched.

In conclusion, the Northeast, being generally capacity constrained, could experience difficulty in the future in the event of a disruption in Canadian gas. The shortfall, however, could be met by the drawing down of fuel oil stocks, by wheeling of electricity or by additional conservation. Sufficient flexibility exists in the non-gas transportation network to meet all

TABLE 66

1992 ANNUAL ENERGY OUTLOOK-FUEL SWITCHING REQUIREMENTS
(PROJECTED UNSATISFIED GAS DEMAND TO BE SWITCHED TO OIL)

| | New England | | | Florida* | | |
|---|---|---|---|---|---|---|
| | MMCF/D | B/D | Sector | MMCF/D | B/D | Sector |
| Average January Day | - | - | - | 26 | 4,333 | Electric |
| Peak January Day | 10 | 1,667 | Industrial | 270 | 45,000 | Electric |
| | 15 | 2,500 | Electric | | | |
| Total | 25 | 4,167 | | | | |
| Average January Day + 50% Canadian Reduction | - | - | - | 26 | 4,333 | Electric |
| Peak January Day + 50% Canadian Reduction | 35 | 5,833 | Industrial | 270 | 45,000 | Electric |
| | 15 | 2,500 | Electric | | | |
| Total | 50 | 8,333 | | | | |

*Insufficient capacity into the state of Florida to satisfy projected 1992 gas demand.

needs as long as the free market is allowed to operate. Short-term price variations could accompany a gas shortfall, of course.

New capacity has been proposed for the Northeast and Florida; if approved, this gas supply situation would be significantly improved.

A Caveat

The conclusion that the assumed Canadian gas disruption would result in no significant problem is qualified by the statement "providing the existing underground storage and LNG storage were filled to normal levels." This is an important caveat. Seasonal storage provides both the volume and delivery rate required to offset the assumed 50 percent loss of Canadian natural gas.

In this scenario, the aggregate supply loss for the 30-day period would be about 70 BCF, only about 3 percent of the 2,200 to 2,300 BCF of "working" gas normally in underground storage at the beginning of January. So long as transmission capacity is available to re-distribute supply, withdrawal from underground storage can offset the assumed supply loss. The computer model showed that ample capacity was available.

For the purpose of this scenario, the import disruption was assumed in January, the peak period for gas demand. For most of the country, January would be the most critical supply period, and the conclusion of "no significant problem" can be extrapolated reasonably to other seasons. However, that extrapolation may not be valid for California.

California gas demand shows less seasonal variation than most of the country because of the climate and the heavy year-round gas consumption by electric utilities and enhanced oil recovery projects. More than half of the Canadian natural gas imports are for PADD V. Interruption of that supply in the spring, when underground storage volumes are normally low, could pose more serious problems than a winter outage. In part, this is because natural gas transmission pipelines from PADDs II, III, and IV do not have substantial spare capacity. The NPC model study did not address a summer disruption, but it is believed that switching electric utilities to residual fuel oil would ease the problem. (Utility gas consumption in California averaged about 1,760 MMCF/D, roughly 140 percent of the assumed Canadian gas loss.)

Companies have proposed three major pipeline projects to provide additional natural gas to PADD V from Louisiana, Texas, Oklahoma, and the Overthrust Belt. If completed, the new capacity would provide increased access to East-of-Rockies production and would reduce the exposure to a summer disruption of Canadian gas.

## SCENARIO 4: PRODUCT PIPELINE DISRUPTION (PADD III TO PADD II)

This scenario is designed to examine the system capability to respond to a major interruption of product flow from PADD III (Gulf Coast) to PADD II (Midwest). For study purposes, it was assumed that Explorer pipeline deliveries to PADD II were shut down for 30 days. Explorer pipeline runs from the Houston, Texas, area to Chicago and delivers about 360 MB/D of product into PADD II. This scenario was analyzed for the current (1987) supply-demand situation and for a 1992 projection.

Pipeline shutdowns are rare and repairs are usually made within one to three days. The likelihood of a 30-day interruption to a major pipeline is very remote.

### Conclusions

Available inventory (above minimum) is more than adequate to cover the assumed product loss. In addition, there are a number of alternatives for effectively increasing supply into PADD II. By the end of the assumed 30-day outage, it is estimated that 160 to 240 MB/D of incremental product could be made available from increased refinery runs, utilization of spare pipeline capacity resourcing peripheral areas now supplied by PADD II to PADD I and III refiners. These options would be generally more costly than normal supply, and many would require contract negotiation or renegotiation to direct supplies to the problem area. It is important that the system not be artificially restrained by unnecessary regulation during the stress period.

### Scenario Review

#### Current Case

Average 1987 PADD II demand for petroleum products that normally move by pipeline (excluding LPG) was 3,230 MB/D (Table 67), 2,532 MB/D of which was supplied by refineries located within PADD II. Products normally moved by pipeline include finished motor and aviation gasoline, jet fuel, kerosine, and distillate fuel oil. Roughly 20 percent of these products, or 700 MB/D, is supplied from PADDs I, III, IV, and Canada. Thus, the 360 MB/D flow disruption would be roughly equal to 10 percent of PADD II demand and 50 percent of the net amount of these products supplied to PADD II from outside of the district.

##### Initial Response -- Inventory Drawdown

Loss of pipeline deliveries would reduce product supply by about 10.8 million barrels -- a little over three days' supply for the PADD. Inventories are adequate to cover a loss of this magnitude.

Table 68 shows the expected available PADD II inventory levels for gasoline, distillate fuel, and jet fuel expressed in days' supply. These show more than adequate availability to

TABLE 67

1987 SUPPLY-DEMAND BALANCE IN PADD II
FOR PRODUCTS NORMALLY TRANSPORTED BY PIPELINE
(Thousands of Barrels per Day)

| Product | Demand: PADD II | Demand: Exports | Supply: Refinery Production | Supply: Imports | Supply: Net Received from Other PADDs |
|---|---|---|---|---|---|
| Finished Motor Gasoline | 2,123.2 | 1.4 | 1,682.4 | 3.9 | 434.8 |
| Finished Aviation Gasoline | 6.4 | - | 3.5 | - | 3.4 |
| Jet Fuel (Kerosine & Naphtha) | 272.0 | 0.4 | 192.0 | 7.2 | 73.7 |
| Kerosine | 11.5 | 0.6 | 15.6 | - | (2.7) |
| Distillate Fuel Oil | 817.4 | 0.6 | 638.4 | 9.3 | 170.1 |
| Total | 3,230.5 | 3.0 | 2,531.9 | 20.4 | 679.3 |

Source: Energy Information Administration, Petroleum Supply Annual, 1987.

TABLE 68

PADD II
AVAILABLE SYSTEM INVENTORY -- ABOVE MINIMUM*
(Days Supply)

| | Gasoline | Distillate | Jet Fuel |
|---|---|---|---|
| Primary Inventory | 4 | 1 | 8 |
| Secondary (Jobbers, etc.) | 4 | 3 | - |
| Tertiary (Consumers) | 6 | 21 | 6 |
| | 14 | 25 | 14 |

*Based on March 31, 1988 data and methodology outlined in the NPC report on Petroleum Inventories and Storage.

cover a loss equivalent to three days' supply. In Volume IV of this study, Petroleum Inventories and Storage, detailed estimates of available inventory are given; the figures in Table 68 assume that PADD II inventories are proportional to the national data presented in this report.

### Additional Supply Options

There are a number of options to accelerate supply into PADD II by effectively utilizing inventory and capacity in adjoining areas. As shown in Table 69, more than 230 MB/D of PADD II product is shipped to adjoining areas.

TABLE 69

LIGHT PRODUCT SHIPMENTS FROM PADD II
(Thousands of Barrels per Day)

| To | Pipeline | Barge |
|---|---|---|
| PADD I | 49 | 51 |
| PADD III | 67 | - |
| PADD IV | 67 | - |
| | 183 | 51 |

Table 70 shows details of this movement by product along with data for inter-PADD shipments into PADD II.

Much of the shipment from PADD II is to boundary areas that have alternative supply routes. These demands can be shifted to other supply sources (re-sourced) allowing more product to be retained in PADD II. Exchanges and trades are the mechanisms for re-sourcing supply to peripheral areas; and such transactions would reflect added cost. The potential for re-sourcing PADD I demand now delivered from PADD II illustrates this option.

Normally, PADD II refineries supply a portion of Buffalo demand by barge and a portion of western Pennsylvania demand by pipeline delivery. As shown in Figure 68, Buffalo and adjacent areas of PADD I are also supplied by pipelines from the Philadelphia and New York areas. Alternative supply for western Pennsylvania is available by pipeline from the Philadelphia area. Diverting these demands from PADD II to PADD I is feasible and is done routinely in response to shifting economic incentives. It can be done quickly.

The additional demand on PADD I products can be covered later with incremental imports or increased pipeline shipments from PADD III. The net effect is to supply PADD II indirectly

TABLE 70

1987 INTER-PADD MOVEMENTS*

(Thousands of Barrels per Day)

| Product | Moved into PADD II from PADD I | III | IV | Subtotal | Moved out of PADD II to PADD I | III | IV | Subtotal | Net Moved into PADD II |
|---|---|---|---|---|---|---|---|---|---|
| Finished Motor Gasoline | 153.3 | 419.7 | 14.7 | 587.7 | 72.8 | 45.2 | 34.9 | 152.9 | 434.8 |
| Pipeline | 153.3 | 358.4 | 14.7 | 526.4 | 40.3 | 45.2 | 34.9 | 120.4 | 406.0 |
| Tanker/Barge | -- | 61.3 | -- | 61.3 | 32.5 | -- | -- | 32.5 | 28.8 |
| Finished Aviation Gasoline | 0.2 | 3.7 | -- | 3.9 | -- | -- | 0.5 | 0.5 | 3.4 |
| Pipeline | 0.2 | 3.4 | -- | 3.6 | -- | -- | 0.5 | 0.5 | 3.1 |
| Tanker/Barge | -- | 0.3 | -- | 0.3 | -- | -- | -- | -- | 0.3 |
| Jet Fuel | 8.7 | 97.4 | 2.7 | 108.8 | 6.2 | 4.5 | 24.4 | 35.1 | 73.7 |
| Pipeline | 8.7 | 86.0 | 2.7 | 97.4 | 3.3 | 4.5 | 24.4 | 32.2 | 65.2 |
| Tanker/Barge | -- | 11.4 | -- | 11.4 | 2.9 | -- | -- | 2.9 | 8.5 |
| Kerosine | 1.1 | 0.5 | -- | 1.6 | 1.0 | 3.2 | -- | 4.2 | (2.7) |
| Pipeline | 1.1 | 0.4 | -- | 1.5 | -- | 3.2 | -- | 3.2 | (1.7) |
| Tanker/Barge | -- | 0.1 | -- | 0.1 | 1.0 | -- | -- | 1.0 | (0.9) |
| Distillate Fuel Oil | 59.1 | 144.1 | 8.4 | 211.6 | 19.9 | 14.1 | 7.3 | 41.3 | 170.1 |
| Pipeline | 58.7 | 110.4 | 8.4 | 177.5 | 5.2 | 14.1 | 7.3 | 26.6 | 150.9 |
| Tanker/Barge | 0.4 | 33.7 | -- | 34.1 | 14.7 | -- | -- | 14.7 | 19.4 |
| Total 1987 | 222.4 | 665.4 | 25.8 | 913.6 | 99.9 | 67.0 | 67.1 | 234.0 | 679.4 |
| Pipeline | 222.0 | 558.6 | 25.8 | 806.4 | 48.8 | 67.0 | 67.1 | 182.9 | 623.5 |
| Tanker/Barge | 0.4 | 106.8 | -- | 107.2 | 51.1 | -- | -- | 51.1 | 56.1 |
| Memo: | | | | | | | | | |
| Total Projected 1992 | 256.5 | 767.3 | 30.0 | 1,053.8 | 115.0 | 77.0 | 77.3 | 269.3 | 784.5 |
| Pipeline | 256.0 | 644.0 | 30.0 | 930.0 | 56.0 | 77.0 | 77.3 | 210.3 | 719.7 |
| Tanker/Barge | 0.5 | 123.3 | -- | 123.8 | 59.0 | -- | -- | 59.0 | 64.8 |

*Numbers may not equal the sum of components due to independent rounding.

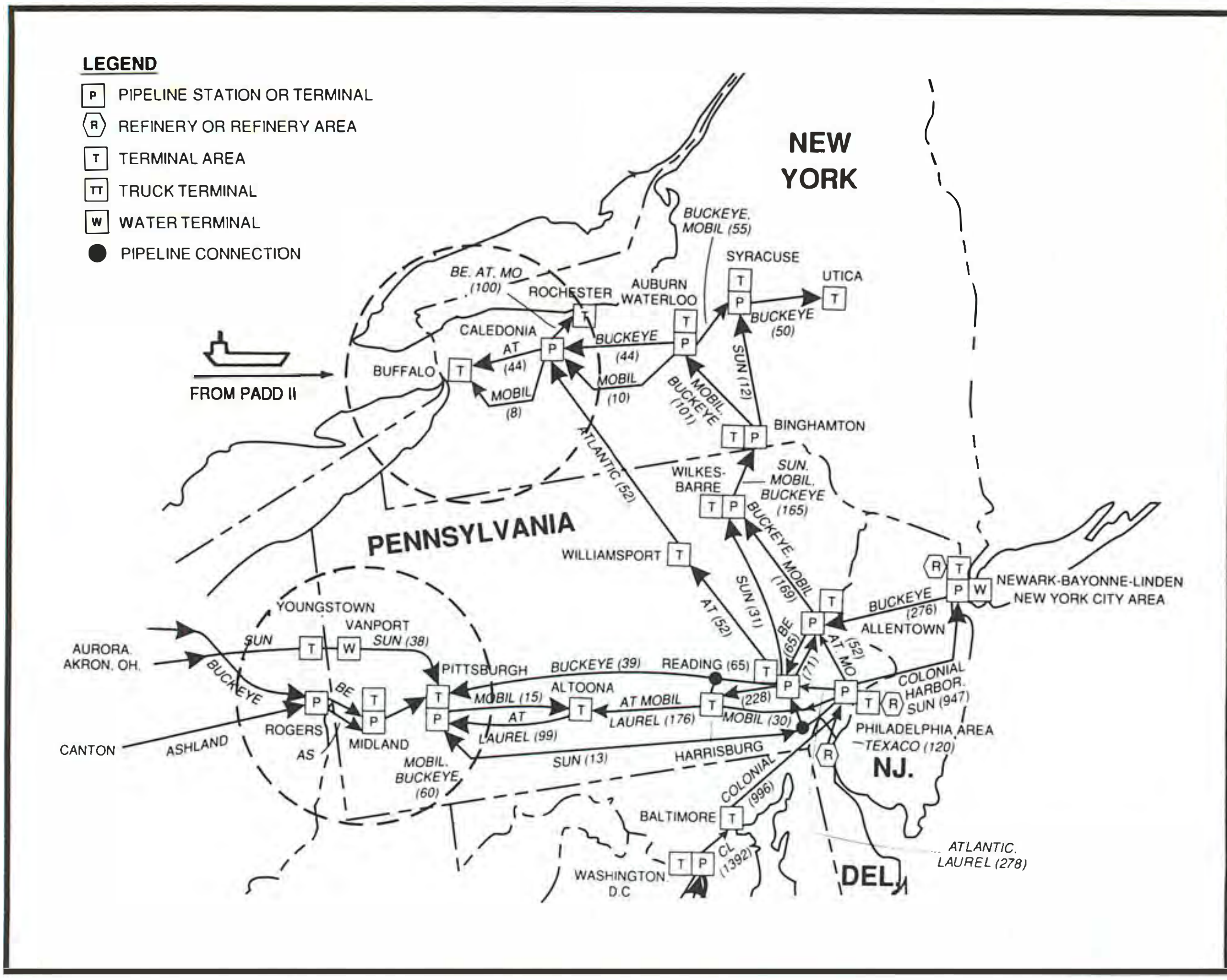



Figure 68. Supply Options for Buffalo and Western Pennsylvania.

from imports or PADD III volume. By utilizing PADD I inventories, the supply can be available in a fraction of the time required for direct delivery.

There are similar options to reverse the flow of inland marine deliveries to "boundary" areas between PADDs II and III. For example, barge supplies to the St. Louis area have often been shifted between PADD II and PADD III refineries in response to economic incentives. The effect of the shift would be to retain product supplies in the "core" areas most affected by these pipeline losses while shifting resupply of peripheral areas that can be resupplied from PADD III easily and promptly.

There is some surplus pipeline capacity into PADD II that could be utilized to partially replace Explorer pipeline deliveries. Table 71 shows the capacity and overall utilization of these lines. In 1987, spare capacity from PADD III to II averaged about 150 MB/D, roughly 20 percent of capacity, but pipeline

TABLE 71

PIPELINE CAPACITIES INTO PADD II*
(Thousands of Barrels per Day)

| Pipeline | Diameter (Inches) | Moves Product into PADD II from PADD I | III | IV | Total |
|---|---|---|---|---|---|
| Colonial | 12 | 88 | | | 88 |
| | 8 | 34 | | | 34 |
| Plantation | 10 | 110 | | | 110 |
| | 8 | 45 | | | 45 |
| Shamrock | 8 | | 27 | | 27 |
| Explorer | 28 | | 360 | | 360 |
| Texas Eastern | 20 | | 225 | | 225 |
| | 16 | | 113 | | 113 |
| ARCO | 8 | | 25 | | 25 |
| River | 6 | | 13 | | 13 |
| Phillips | 16 | | 110 | | 110 |
| Emerald | 6 | | 13 | | 13 |
| Cenex | 8 | | | 16 | 16 |
| WYCO | 6 | | | 14 | 14 |
| Cheyenne | 6 | | | 17 | 17 |
| Total Capacity (into PADD II) | | 277 | 886 | 47 | 1,210 |
| Capacity (Excluding Explorer) | | 277 | 526 | 47 | 850 |
| Est. Actual Movement* | | 222 | 730* | 26 | 978 |

* Including LPG where applicable.

companies indicated that much less spare capacity would be available in 1988. In a stress situation, "batch trading" would permit product already in these lines to be diverted from upstream destinations into PADD II; the diverted supply would be replaced from PADD III in a later pipeline cycle.

Incremental refinery runs could supply additional product, as well. Operating refinery capacity in PADD II was 3.3 MMB/D in 1987, operating at about an 87 percent utilization rate. Additional refinery runs could produce 80 to 150 MB/D of product, depending on the season.

Incremental supply of product by rail tank car and by tank truck also has been utilized in the past to ease acute local problems.

### Incremental Supply

Within 30 days, it is estimated that 160 to 260 MB/D of replacement supply could be obtained as shown below:

| | |
|---|---|
| Re-sourcing to PADDs I & III | 50 to 70 MB/D |
| Incremental Pipeline Shipments | 30 to 40 MB/D |
| Incremental Refinery Runs | 80 to 150 MB/D |
| | 160 to 260 MB/D |

This supply coupled with inventory draw is more than adequate to bridge the assumed loss of 360 MB/D of pipeline products.

In recent years, the most severe test of the supply system flexibility occurred when an unexpected refinery shutdown eliminated 120 to 150 MB/D of product supply in PADD II for an extended period. The product was replaced by the means discussed above with no disruption of consumer supply.

### Future Case (1992)

The impact of a 360 MB/D product loss in 1992, and the potential responses, are very similar to the current case. Currently planned refinery expansions in PADD II will more than offset growth, leaving inter-PADD movements much like the current case.

As with the current case, inventory draw is expected to be adequate to cover the loss of 360 MB/D of product for 30 days. The potential for other short-term supply is expected to be similar to the current case. Re-sourcing volume to PADD I will become more costly, however, as demand growth in PADD I reduces the ability to deliver volumes to adjoining areas.

## SCENARIO 5: TAPS DISRUPTION

In this scenario, it is assumed that the Trans-Alaska Pipeline System (TAPS) is shut down for a period of 30 days, reducing

PADD V crude oil production by 2 MMB/D. This scenario is designed primarily to examine the industry ability to maintain supply to West Coast consumers, but a TAPS shutdown would also disrupt East-of-Rockies deliveries. It was assumed that foreign surplus production capacity could be tapped for direct replacement of lost Alaskan crude oil and for exchange repayment.

## Conclusions

The loss of 2 million barrels of production is a major disruption even in the world market; the loss of 2 million barrels of Alaskan crude oil is particularly difficult because most of the crude oil is consumed on the West Coast, remote from other major crude oil logistics systems. Given current levels of worldwide inventories and surplus foreign production capacity, acquisition of replacement supply for the West Coast should not be a major obstacle; the problem is to maintain continuity of supply until replacement crude oil supply can be delivered.

Examination of the potential crude oil and product supplies available indicate that supply continuity can be maintained to consumers in both the current and future (1992) cases at a noticeable economic cost, but it is likely that some refinery curtailment would result. In the future (1992) case, supplies might be tight enough for a brief period to be recognized by the public because of scattered runouts at terminals and service stations.

Replacement of the Alaskan crude oil supply to East-of-Rockies refineries currently poses no major problem of either supply or timing; by 1992 it is anticipated that Alaskan crude oil movements to the Gulf and Atlantic Coast areas will decline to a negligible volume.

## Scenario Review

### Current Case

As shown in Table 72, TAPS transported 2 MMB/D of domestic crude oil supply in 1987. The crude oil was moved from the North Slope of Alaska to the port of Valdez, from which it was shipped by tanker to markets in PADD V and PADDs I and III. About 600 MB/D of the production was shipped to East-of-Rockies refineries primarily via Panama, and 1.2 MMB/D was consumed in PADD V. More than 100 MB/D was shipped to the Virgin Islands.

The loss of 600 MB/D of East-of-Rockies supply would be a substantial inconvenience but not a serious problem either to consumers or refiners. Alaska North Slope (ANS) crude oil averages less than 6 percent of PADDs I-IV refinery feed. On the West Coast, the problem would be much more severe. Table 73 shows that ANS crude oil constitutes more than 40 percent of California crude oil supply and over 90 percent of Puget Sound area refinery demand.

TABLE 72

1987 ALASKAN CRUDE OIL CONSUMPTION
(Millions of Barrels per Day)

| | Location | MMB/D |
|---|---|---|
| PADD V: | California | 0.7 |
| | Puget Sound | 0.4 |
| | Alaska | 0.1+ |
| | Hawaii | 0.0+ |
| PADDs I, II, III: | Gulf Coast | 0.6 |
| | Caribbean and other | 0.1+ |
| | | 2.0 |

Source: EIA detail delivery reports by city (1987); EIA *1987 Petroleum Supply Annual*; and adaptations from NPC estimates and industry forecasts.

TABLE 73

1987 PADD V CRUDE OIL SUPPLY-DEMAND

| Supply | Location | MMB/D | % Alaskan |
|---|---|---|---|
| | Alaska | 2.0 | 100 |
| | California | 1.0 | - |
| | Far East | 0.2 | - |
| | Canada and other | 0.0+ | - |
| | | 3.3 | |
| Demand | California | 1.9 | 40+ |
| | Puget Sound | 0.4 | 90+ |
| | Alaska | 0.1+ | 100 |
| | Hawaii | 0.1 | 50+ |
| | | 2.5 | |
| Surplus | PADD I, II, III via Panama | 0.6 | 100 |
| | PADD I, II, III via West-East Pipelines | 0.0+ | 50 |
| | Caribbean/Other via Cape Horn | 0.1+ | 100 |
| | | 0.8 | |

Source: EIA detail delivery reports by city (1987); EIA *1987 Petroleum Supply Annual*; and adaptations from NPC estimates and industry forecasts.

Coverage of the West Coast crude oil loss is more difficult than for the Gulf and East Coast areas because:

- PADD V is relatively remote from major foreign production areas and major foreign crude oil shipping routes. Replacement supply cannot be obtained quickly.

- West Coast inventories of crude oil and product are relatively lower than East-of-Rockies inventories. They provide fewer days of supply cushion in a major disruption.

East-of-Rockies/Virgin Islands

In 1987, ANS deliveries to PADDs I-IV totaled 600 MB/D or about 18 million barrels over a 30-day period. A loss of this magnitude would be disruptive, but would not pose a serious supply problem for two reasons:

- The loss represents less than two days of refinery demand and could be covered by drawing normal crude oil inventories. PADDs I-IV crude oil inventory (above the minimum required for normal operation) can normally provide six days of refinery demand.

- Foreign crude oil supply to replace the ANS crude oil could be available quickly.

Volume IV of this report, Petroleum Inventories and Storage, examines the volume of crude oil that can be drawn from inventory without disrupting normal operations. Normally, more than 40 million barrels of crude oil are available in PADDs I-IV to handle supply upsets. This is more than twice the volume required to cover a 30-day disruption of ANS supply to East-of-Rockies refineries.

In addition, a great deal of replacement crude oil supply is potentially available faster than the required ANS delivery time. Table 74 lists typical crude oil transit times for ANS and foreign crude oil to U.S. locations. The table shows that transit time for ANS crude oil to the U.S. Gulf Coast is 20 days. Replacement supplies from Venezuela, Mexico, and Caribbean transshipping storage could be delivered in only two to five days. Supplies from West Africa can also be delivered in less time than ANS crude oil. Diversion of ships bound for Europe offers another potential source of crude oil with a shorter delivery time than ANS crude oil. Diversion of even a small portion of the 3 MMB/D flow to Europe in the Atlantic would be a major contribution to East-of-Rockies supply; the diversion could easily be accommodated from European inventory initially and replaced within 35 to 40 days from the Middle East.

With these potential sources, it should be possible to replace a very significant portion of the ANS crude oil in PADDs I-IV with no net delay or interruption; and the balance could be

TABLE 74

TRANSIT DAYS DURING STRESS SITUATION*

| From | To: Puget Sound | California | Texas/Louisiana | Chicago§ |
|---|---|---|---|---|
| Valdez | 3 | 5-6 | 20¶ | 28¶ |
| Mexico | 13¶ | 10-11¶ | 2 | 10 |
| Venezuela | 13¶ | 10-11¶ | 5 | 13 |
| Caribbean | 15¶ | 12-13¶ | 3 | 11 |
| Far East (Singapore) | 20 | 20-21 | 36¶ | 44¶ |
| Middle East (Persian Gulf) | 31 | 28-29 | 35 | 43 |

*Emergency fast steaming of 15 knots average used versus normal 13 knots average.

§Includes Gulf Coast-Midwest Pipeline Transit.

¶Includes discharge, transit, and reloading to/from Panapipe.

Source: BP America Inc., Supply and Transportation Departments, December 1988.

replaced very rapidly. For this reason, it would be feasible and economic to redirect some ANS crude oil bound for PADDs I-IV back to PADD V.

There is substantial surplus foreign crude oil production capacity in areas closer to the U.S. Gulf Coast than Alaska; much of the ANS replacement crude oil could be purchased directly in these areas. Any required balance could be obtained by "time trades" with European refiners. Replacement supply would undoubtedly command a premium price, but a TAPS shutdown is unlikely to create a shortage either for refiners or consumers east of the Rockies.

The same options apply to replacement of Virgin Islands supply, but there would be less urgency. ANS crude oil for the

Virgin Islands is shipped in large foreign-flag tankers around Cape Horn. The long transit time would allow replacement crude oil to be delivered from the Middle East with no hiatus in refinery supply.

### West Coast

Disruption of the TAPS supply would be a much more serious problem for the West Coast. Surplus production capacity is available in Australia, Indonesia, and mostly in the Middle East; but even at maximum tanker speed, delivery time would be 20 days for Indonesian oil and 30 days for Middle East purchases. Surplus production in the Middle East is adequate to fully replace the ANS supply, so the stress period would be limited to about 30 days even if TAPS were shut down longer. The perception that the problem would be resolved in a definite and fairly brief period is useful because it encourages jobbers, retailers, and consumers to use inventories in lieu of purchases at stress period prices.

In addition to California crude oil production of 1.1 MMB/D and normal import supply (200 MB/D), the principal source of supplemental crude oil for refinery input would be in inventory, including:

- 6.9 million barrels of onshore inventory above the minimum inventory level to maintain normal operation. This crude oil is in refinery, pipeline, and terminal tanks.
- 5.6 million barrels of ANS crude oil in transit to West Coast refineries; it is assumed that this crude oil would be delivered as scheduled.
- 10 million barrels of ANS crude oil in transit to East-of-Rockies refineries or to the Virgin Islands. In-transit crude oil in the Pacific Ocean could be diverted to the West Coast.

These inventory segments coupled with ongoing supply from local production and normal imports could provide crude oil supply equivalent to 23 to 25 days of West Coast refinery demand. Because of the high dependence of Alaskan and Puget Sound refineries on ANS crude oil, these plants are likely to bear a higher share of any shortfall. Table 75 shows refinery demand for California and for Puget Sound/Alaska and illustrates a possible distribution of crude oil supply during a 30-day TAPS outage.

Landed and in-transit inventory would not be adequate to bridge a 30-day cutoff of ANS crude oil supply. As shown in Table 75, an additional 11 to 15 million barrels of crude oil would be required to avoid a reduction in refinery runs. Crude oil acquisition should not be a problem, but it probably would not be possible to deliver the crude oil soon enough to avoid cutbacks in refinery production.

TABLE 75

POTENTIAL USE OF INVENTORY TO OFFSET REDUCED ANS CRUDE OIL SUPPLY IN PADD V

| | California | | Puget Sound/Alaska | |
|---|---|---|---|---|
| | Million Barrels | Days Supply | Million Barrels | Days Supply |
| Refinery Demand | 57 | 30 | 15 | 30 |
| Calif. Production | 33 | 17 | -- | -- |
| Normal Imports | 5 | 3 | 1 | 2 |
| Local Inventory* | 4.4 | 2 | 2.5 | 5 |
| Subtotal | 42.4 | 22 | 3.5 | 7 |
| In-Transit Inventory | | | | |
| To West Coast | 4.3 | 2 | 1.3 | 2 |
| Gulf/V.I. Diversion§ | 1 to 4 | 1 to 2 | 4 to 6 | 8 to 12 |
| Total | 48 to 50 | 25 to 26 | 9 to 11 | 17 to 21 |

*Inventory above minimum to maintain normal operation.

§Assumes 50 to 100 percent of in-transit ANS crude oil in the Pacific Ocean can be diverted from East-of-Rockies/Virgin Islands to PADD V.

Note: Canadian supply to West Coast assumed to be fully committed.

The critical period for crude oil supplies would be the third week of the TAPS shutdown. While some short-haul foreign crude oil would be available in less than 15 days, the volume would probably not be enough to completely supply refineries, particularly since supplies would not be evenly distributed among refiners. Potential sources of foreign crude oil available within 15 to 20 days after the TAPS shutdown include:

- Mexican crude oil for Japan -- Mexico sells approximately 180 MB/D to Japanese buyers, but crude oil availability on the West Coast is expected to increase substantially upon completion of a new pipeline to the Pacific in 1989. It should be possible to trade Middle East crude oil for at least some of the Mexican crude oil; delivery could be made in three to five days. Under current contract terms, approval of Pemex and/or the Mexican government would be required to alter the destination of the crude oil.

- <u>Ecuadorian crude oil</u> -- Ecuador markets about 200 MB/D of crude oil that could be delivered in less than 14 days. Sales are generally committed in advance, but it should be possible to acquire some for the West Coast by resale or exchange.

- <u>Mexican, Venezuelan, and Caribbean crude oils</u> -- These crude oils could be delivered to the West Coast in less than 15 days via the Panama Canal. Because Gulf and East Coast refiners would seek these crude oils to replace their ANS losses, volumes available for the West Coast would probably be small; initially, incremental supplies of these crude oils probably would be traded to retain in-transit ANS crude oil on the West Coast.

It is realistic to expect that 2 to 3 million barrels could be acquired from these sources in the first 20 days of the TAPS outage; a further 2 to 3 million barrels would be available in the last 10 days. These volumes are probably not large enough to avoid reduced crude oil runs in the third week of the stress period.

Substantial additional crude oil supplies would become available after 18 to 20 days from a number of sources:

- <u>Indonesian production</u> -- Incremental Indonesian crude oil may be available from surplus production capacity and inventory. In addition, it should be possible to "trade forward" to acquire Indonesian crude oil promptly in return for a later payback; such trades almost always include a premium or "differential" to the unstressed trading partner. Some Australian crude oil may be available on similar arrangements. The earliest delivery date would be about 20 days after the TAPS shutdown.

- <u>Middle East crude oil in transit</u> -- On average, there is more than 3 MMB/D in transit to Japan, two-thirds from the Middle East. Given a suitable incentive, it should be practical to divert a portion of that crude oil to the West Coast and replace it with incremental purchases of Middle East crude. The earliest delivery date would be 15 to 18 days after the TAPS shutdown.

- <u>Middle East purchases</u> -- Large supplies of Middle East crude oil could be available after 30 days. Surplus production capacity and inventory is adequate to cover the entire TAPS loss. This crude oil would continue to arrive after TAPS resumed operation until inventories were replenished.

Practically, it would be reasonable to expect that 6 to 10 million barrels of crude oil could be made available in the 18th to 30th day of the TAPS shutdown. These volumes are sufficient to cover essentially full refinery demand in the last 10 days after the outage, but overall refinery production would probably be reduced by 3 to 6 million barrels in earlier periods.

A shortfall of this magnitude could be covered from product inventory and product movements from PADD III. Primary inventories of products tend to be lower on the West Coast than in the rest of the country, in part because of the shorter distribution system between refiner and consumer. Table 76 shows primary inventory at March 31, 1988, which is typical. The table shows total inventory and the volume above the minimum inventory required to maintain normal operation. There is little doubt that inventories could be drawn below "normal" minimums in a stress situation of this sort.

Considerably more available product is normally in secondary and tertiary storage held by jobbers, retailers, and consumers. An additional 10 days of gasoline supply and 20 plus days of distillate supply could be drawn from this inventory in lieu of higher priced purchases during the stress period. The perception that the crude oil supply problems have a clear ending date encourages consumption of secondary and tertiary inventory.

Product deliveries from PADD III or foreign sources via the Panama canal could begin as early as 15 days after the TAPS disruption; up to 7 million barrels of product could be delivered in the following 15 days without straining East-of-Rockies supply or inventory. There is little opportunity for more rapid acceleration of product supply from other PADDs because there is little product movement in the interface areas. Gasoline produced to East-of-Rockies specifications may require waivers of special environmental requirements imposed by some California jurisdictions; it is assumed that these waivers would be granted.

TABLE 76

PADD V PRODUCT INVENTORY
(Million Barrels)

| Product | Total Inventory | Available Above Minimum |
|---|---|---|
| Gasoline | 29 | 2 |
| Kerojet | 6 | 1 |
| Distillate | 9 | 1 |
| Residual Fuel | 9 | 4 |
| | 53 | 8 |

Source: Volume IV, Petroleum Inventories and Storage, of Storage & Transportation (National Petroleum Council, 1989).

Marine tonnage to haul the replacement crude oil and product shouldn't be a significant problem; surplus foreign-flag tonnage is available and the U.S.-flag ships that normally carry ANS crude oil would be available. Jones Act waivers for "clean" (light product) ships will be required to permit foreign flag vessels to move product to the West Coast. Offshore lightering may be required for larger crude oil ships with drafts in excess of water depth at West Coast ports; lightering operators were common before ANS production displaced much of the West Coast import volume.

The loss of 2 MMB/D of ANS crude oil would be a serious supply problem; but supply is available and the system should be capable of maintaining consumer supply without serious disruption. However, it seems likely that crude oil supplies could not be delivered in time to avoid the loss of some refinery capacity. Product inventory and potential product movements from PADD III would be more than ample to replace the lost refinery production. The cooperation of local governments would be essential to expedite re-supply from non-normal sources.

Coping with the loss would be expensive. Crude oil costs would be significantly more than normal ANS crude oil costs because of higher transportation costs and trading premiums. Product from PADD III would also be substantially more expensive than normal because of freight charges and premiums.

Hawaii receives 40 to 50 MB/D of ANS crude oil, but replacement should be a less difficult problem than for the mainland. Hawaii is closer to Australia, Indonesia, and the major Asian supply routes. Replacement volumes of crude oil can be acquired and delivered fairly quickly to minimize the gap in crude oil supply.

Future Case (1992)

The loss of TAPS supply for 30 days in 1992 could pose a substantially more serious problem, which would be felt by West Coast consumers for several weeks. Table 77 compares PADD V supply and demand in 1992 with 1987. The table notes some major changes:

- West Coast crude oil consumption is projected to be 300 MB/D higher, but California crude oil production is not expected to increase.

- West Coast demand for ANS crude oil is projected to be 1.4 MMB/D (about half of total crude oil requirement). However, ANS production is forecast to be down to 1.5 MMB/D, leaving only about 100 MB/D moving to East-of-Rockies refineries.

As a result of these changes, a TAPS disruption in 1992 would have a much greater impact on PADD V supply than in 1987,

TABLE 77

1992 PADD V CRUDE OIL SUPPLY-DEMAND
(Millions of Barrels per Day)

| | Location | 1987 | 1992 Est. |
|---|---|---|---|
| Supply | Alaska | 2.0 | 1.5 |
| | California | 1.1 | 1.1 |
| | Far East | 0.2 | 0.3 |
| | Canada and other | 0.0+ | 0.0+ |
| | | 3.3 | 2.9 |
| Demand | California | 1.9 | 2.1+ |
| | Puget Sound | 0.4 | 0.5 |
| | Alaska | 0.1+ | 0.1+ |
| | Hawaii | 0.1 | 0.1 |
| | | 2.5 | 2.8 |
| Surplus | PADD I, II, III via Panama | 0.6 | -- |
| | PADD I, II, III via West-East Pipelines | 0.0+ | 0.1 |
| | Caribbean/Other via Cape Horn | 0.1+ | -- |
| | | 0.8 | 0.1 |

Source: EIA detail delivery reports by city (1987); EIA 1987 Petroleum Supply Annual; and adaptations from NPC estimates and industry forecasts.

because there would be less crude oil in transit to provide continuity in the early days of the cutoff.

### East-of-Rockies/Virgin Islands

The loss of ANS supply to East-of-Rockies refineries would be negligible. It should be practical to divert some foreign crude oil supplies from PADD III to PADD V almost immediately, utilizing inventory to maintain crude oil runs in PADDs II and III.

### West Coast

Crude oil and product supplies would eventually be available to replace the lost ANS crude oil volumes, but long transit times required to bring these supplies to the West Coast would make supplies unusually tight in the 10th to 20th days of the TAPS cutoff. In this period, supplemental supply would be available from:

- Drawdown of crude oil and primary product inventories below nominal "minimums." "Minimum" inventories include a cushion to avoid terminal runouts and refinery shutdowns; these volumes would be drawn to avoid refinery shutdowns or wide-scale runouts.

- Drawdown of secondary/tertiary inventory. Available product inventory in the tanks of distributors, dealers, industrial users, and individual consumers normally amounts to more than 10 days' supply. Tight product supply would undoubtedly result in rapid price increases. These higher prices plus the recognition that supply problems would be of limited duration would encourage middlemen and consumers to use their inventories and defer purchases.

It is probable that some refiners would reduce crude oil runs from the outset rather than shut down their facilities. Likewise, with sharply reduced product supply, some marketers might allocate product very early in the stress period. Prices would be expected to rise rapidly and remain at high levels for the duration of the TAPS disruption, not falling to normal levels until inventories began to be replenished.

As before, significant crude oil supply from Far East production and Middle East in-transit inventory would become available 18 to 20 days after the TAPS shutdown. This volume coupled with higher crude oil and product deliveries via the Panama Canal and product imports from the Far East would essentially replace the lost ANS crude oil in the final 10 days. After 30 to 40 days, very large volumes of Middle East crude oil would be available.

Coping with a TAPS shutdown in 1992 would be a very difficult challenge for the system, but the industry could maintain reasonable supply levels and avoid hardship to individual consumers. However, it seems likely that the public would be quite aware of the problem because of noticeably higher prices and some inconvenience (e.g., scattered runouts at terminals and service stations).

## Summary

The shutdown of TAPS for a period as long as 30 days is a highly improbable event, which would be difficult in 1987 and substantially more so in 1992. Nevertheless, the NPC believes that the system could cover such a loss, maintaining necessary supplies to consumers. The public would be affected by higher prices for a time and the inconvenience of scattered runouts (particularly in 1992) at terminals and service stations for a brief period.

Fast, decisive action by the industry is required in a stress situation of this magnitude. Cooperation of governments at every level is essential to resolution of the problem.

## SCENARIO 6: CANADIAN CRUDE OIL IMPORT DISRUPTION

This scenario examines the system capability to redirect crude oil and product in the event of a 30-day disruption of Canadian crude oil imports on the Interprovincial/Lakehead pipelines. This scenario was analyzed for the current situation and for a 1992 projection.

### Conclusions

Currently, crude oil inventory in PADD II plus potential replacement crude oil from PADD III and imports are adequate to cover the loss of Canadian crude oil in an initial 30-day period, or longer if necessary. In addition, product inventories and potential incremental product supply could provide substantial additional coverage. On average, it is projected that crude oil and equivalent product equal to twice the Canadian crude oil loss could be supplied in the 30-day period at a reasonable cost increment.

By 1992, projected growth in refinery crude oil demand will make replacement of the Canadian volume in kind more difficult. Incremental product supply and product inventory draw would be required to bridge a 30-day loss of Canadian crude oil.

In both cases, the Twin Cities area would pose more difficult (i.e., more expensive) replacement supply problems.

### Scenario Review

#### Current Case

As shown in Table 78, Canadian imports via Interprovincial pipeline totaled 527 MB/D in 1987, most of which was delivered to PADD II. This volume was assumed to be interrupted for a period of 30 days as the result of a pipeline outage. A pipeline shutdown of this length is highly unlikely; downtime on major pipelines rarely exceeds one or two days.

Canadian imports supply about 17 percent of PADD II crude oil requirements; and the loss would be a major upset to that region. However, the overall crude oil loss (16 million barrels over 30 days) is not large compared with crude oil inventories in PADDs I through IV, which aggregated 274 million barrels on March 31, 1988 -- about 44 million barrels above minimum levels required to maintain normal operations. The challenge would be to use those inventories to minimize the immediate effect of the Canadian crude oil loss and provide time to replace the supply from other sources.

TABLE 78

1987 CANADIAN IMPORTS TO THE UNITED STATES

| Pipeline System | Destination (Refining Center) | Volume (MB/D) |
|---|---|---|
| Interprovincial* | St. Paul, MN | 170 |
| | Chicago, IL | 224 |
| | Detroit, MI/Toledo, OH | 37 |
| | Warren, PA | 54 |
| | Other | 42 |
| | | 527 |
| Rangeland | Billings, MT | 65 |
| Other | Various | 18 |
| | Total Imports | 610 |

*Interprovincial also delivered approximately 60-75 MB/D of U.S. crude oil.

Source: Adapted from the National Energy Board report, "Exports of Crude Oil-1987;" Information provided by Interprovincial Pipeline, December 1988; NPC estimates based on industry experience; and EIA 1987 Petroleum Supply Annual.

Assuming all of the crude oil loss would fall on PADD II, the shutdown of Interprovincial pipeline for 30 days would reduce crude oil supply by 16 million barrels, roughly six days of refinery crude oil demand (at 2.8 MMB/D). This loss would be covered initially with inventory draw, but in a very short time additional crude oil supplies from PADDs III and IV could be made available. Finally, waterborne imports delivered via PADD III would be increased to replace the Canadian volume and replenish inventories. Incremental product supply and the draw of product inventory would provide supplemental supplies to maintain product flow to the consumer.

As shown in Table 79, crude oil and product supply potentially available to PADD II in the first 30 days is more than double the assumed Canadian crude oil loss. Even larger volumes could be made available if higher-cost supply alternatives are considered (e.g. rail delivery of crude oil and product). Potential supply sources are briefly explained below.

TABLE 79

POTENTIAL SUPPLY TO REPLACE A
30-DAY INTERRUPTION OF CANADIAN IMPORTS
(PADD II -- Current Case)

| | Supply Potential | | |
|---|---|---|---|
| | Volume in Million Barrels | Days of Refiner Supply | Days of Canadian Supply |
| Reduced Canadian Supply | 16 | 6 | 30 |
| Replacement Crude Oil Supply | | | |
| PADD II Inventory* | 17 | 6 | 32 |
| Pipeline from PADD III | 8 | 3 | 14 to 16 |
| | 25 | 9 | 46 to 48 |
| Incremental Product Supply | | | |
| PADD II Inventory* | 8 to 11 | 3 to 4 | 15 to 21 |
| Pipeline from PADD III | 2 | 1 | 4 |
| | 10 to 13 | 4 to 5 | 19 to 25 |
| Total | 35 to 38 | 13 to 14 | 65 to 73 |

*Inventory above minimums.

PADD II Inventory

Crude oil inventory in PADD II averages about 75 million barrels. Much of this is normally "unavailable" in tank bottoms, pipelines, and "safety" inventory designed to insure continuity of refinery and transport operations. Assuming PADD II is reasonably similar to other East-of-Rockies areas, the "available" crude oil inventory above the minimum levels required for normal operation would be equivalent to about six days of refinery supply or 17 million barrels.

In a stress situation, some additional crude oil inventory could undoubtedly be drawn to avoid refinery shutdowns. Because a portion of the PADD II crude oil inventory is located at pipeline hubs (e.g., Patoka), the system retains unusual flexibility to direct stocks to refineries in particular need.

## Incremental Pipeline Delivery

Initially, drawdown of inventory in the adjacent PADD III could provide a prompt source of accelerated crude oil supply to the Midwest (PADD II). It is expected that refiners in the northern half of PADD II would seek to acquire domestic or landed foreign crude oil with immediate access to pipelines serving PADD II. Typically, this crude oil might be acquired in a "time trade" in which a Gulf Coast refiner gives up crude oil immediately and is repaid at a specified later date, probably with imported crude oil.

These transactions would give PADD II refiners prompt access to additional crude oil and effectively allow the system to utilize PADD III inventory. PADD III crude oil inventory above minimum is normally equivalent to about 12 days' supply for PADD II, so even a small stockdraw can be a significant addition to Midwest supply.

Within a relatively few days, incremental foreign crude oil would be diverted to PADD III for transportation to PADD II and to repay crude oil received earlier on time trades. Some of this crude oil would be shipped directly via pipelines and some would be traded for inland crude oil supply accessible to inter-PADD pipelines.

Pipeline capacity and the time required to arrange transactions and physically transport crude oil are the limiting factors in providing replacement supply in the initial 30-day period. As shown in Table 80, unused pipeline capacity from PADD III to PADD II was estimated to be 500 to 575 MB/D in 1987. This capacity would be roughly adequate to replace the Canadian crude oil when replacement supply has been obtained.

TABLE 80

CURRENT PADD III TO PADD II AVAILABLE PIPELINE CAPACITY

| Pipeline System | Diameter (inches) | Average MMB/D |
|---|---|---|
| Capline | 40 | 250 |
| Mid-Valley | 22 | 50-75 |
| Amoco | 8, 12, 12, 20 | 200-250 |
| ARCO | 24, 22 | |
| Ozark/Shell | 10, 22 | |
| Mobil | 20 | |
| | | 500-575 |

Exchanges can be negotiated and implemented in a day or two, but physical transportation of the crude oil may take longer. Table 81 shows typical delivery times for crude oil to PADD II locations from various sources. The listed times are for a discrete batch to reach the destination; but since pipeline output of crude oil increases immediately when input rates rise, supply may effectively increase five to eight days faster than shown.

Delivery of imported crude oil to PADD III (for transport to the Midwest) can be accelerated by "time trading" with East Coast refiners so that foreign supplies in transit to PADD I can be diverted to PADD III in return for later payback. These trades (which are not uncommon in normal times) allow PADD I inventories to be effectively utilized to ameliorate a Midwest shortage. Trading is not usually an altruistic activity; both parties must be satisfied that they are at an economic advantage.

If only half the spare pipeline capacity could be utilized in the 30-day period because of the time required to obtain supply, the incremental receipt via PADD III would add 7.5 to 8.5 million barrels to PADD II supply, roughly three days' refinery demand (an equivalent to 14 to 16 days of Canadian imports).

TABLE 81

TRANSIT DAYS DURING STRESS SITUATION*

| | To | | |
|---|---|---|---|
| From | Texas/Louisiana | Chicago§ | Ohio/Michigan§ |
| Mexico | 2 | 10 | 16 |
| Venezuela | 5 | 13 | 19 |
| Caribbean | 3 | 11 | 17 |
| Far East | 36¶ | 44¶ | 50¶ |
| Middle East | 35 | 43 | 49 |
| West Texas | -- | 8 | 14 |

*Includes emergency fast steaming of 15 knots averaged versus normal 13 knots.

§Includes Gulf Coast to Midwest pipeline transit.

¶Includes discharge, transit, and reloading to/from Panapipe.

Source: BP America Inc., Transportation Department, December 1988.

Some incremental supply would also be available from PADD IV in this scenario, but it is unlikely to be more than a fraction of a day's refinery consumption.

### Product Supply

To supplement replacement crude oil supply, added product supply would be available from inventory and from inter-PADD movements in the 30-day period. Product inventories vary seasonally, but available primary stocks (above minimums) average three to four days of equivalent refinery crude oil supply.

The capability of supplying incremental product to PADD II is examined in Scenario 4, Product Pipeline Disruption (PADD III to PADD II). This scenario listed 130 MB/D of spare capacity in product pipelines from PADD III to PADD II in 1987. If only half this capacity were utilized, incremental product equivalent to about 2 million barrels of Canadian crude oil could be obtained. Product input would be available initially from PADD III inventory and later (within 10 days) from increased product imports.

Scenario 4 identifies other potential product supply sources for a PADD II stress situation, including drawdown of secondary and tertiary inventories held by jobbers, retailers, and consumers. Product can also be made available from PADD I by assigning peripheral areas to PADD I sources. These options were not included in Table 79 as they were not required.

### Longer-Term Crude Oil Supply

Potential supply from areas outside PADD II was heavily discounted in the initial 30-day period to account for the time required to fully marshal alternative supply sources. If it appeared that the loss of Canadian crude oil would extend beyond 30 days, capacity and supply would be available to replace essentially all the crude oil on a continuing basis.

### Regional Supply Problems

The loss of Canadian imports would not be shared equally by all PADD II refiners. Canadian imports are concentrated in the northern half of PADD II, and some areas would be affected more by the loss or be less able to obtain alternate supply.

- Twin Cities Area -- This area would have the most difficult problem. Refineries in the Twin Cities area are supplied primarily via the Minnesota pipeline. This system connects to the Interprovincial system and brings Canadian crude oil and North Dakota production to St. Paul. Disruption of Canadian imports would reduce supply to Twin Cities refineries by about 170 MB/D. Supply for the 30-day period could be obtained by inventory draw and incremental throughput on the Wood River line. However, with a capacity of about 100 MB/D, the Wood River system cannot fully cover the

Canadian loss. Some crude oil alternative supply via barge or rail would be feasible, but added product deliveries and drawdown of product inventory would probably be required to bridge the 30-day pipeline outage.

- Chicago Area -- Canadian imports into Chicago are split between sweet and sour crude oil. There is ample pipeline capacity to supply the 224 MB/D requirements for the area.

- Toledo/Detroit -- This area would not be significantly stressed. Canadian imports into Toledo/Detroit totaled only 37 MB/D in 1987. Adequate pipeline capacity is available to deliver replacement supplies.

Overall, the system is capable of covering the Canadian crude oil loss without disruption of consumer supplies. The required crude oil and product diversions would add to expense, and there would probably be some reduced refinery utilization. The affected volume is small relative to total PADD II supply, however, and consumer price increases would probably not be excessive.

Future Case

The loss of Canadian imports in 1992 would pose a more difficult supply problem. Refinery expansions are expected to increase PADD II crude oil demand by about 350 MB/D over 1987. Spare capacity in existing crude oil lines would be unable to replace the Canadian crude oil on a steady-state basis and would make a smaller contribution in the 30-day period. Incremental product supply would undoubtedly be required to bridge the 30-day loss. (At least one major crude oil line from PADD III to PADD II could be significantly expanded with pump modifications; it is possible that capacity additions will partially offset the growth of crude oil demand to PADD II, maintaining pipeline capacity reserve.)

Refinery capacity in the Twin Cities area has been expanded, making the crude oil loss an even greater difficulty for this area. Adequate product supply is available to avoid a consumer problem, but some refinery capacity would probably be lost in the 30-day period.

# Appendices

# APPENDIX A

## STUDY REQUEST LETTER AND DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

**The Secretary of Energy**
Washington, DC 20585

February 20, 1987

Mr. Ralph E. Bailey
Chairman
National Petroleum Council
1625 K Street, N. W.
Washington, D. C. 20006

Dear Mr. Bailey:

The National Petroleum Council has prepared numerous studies in the past on the nation's petroleum inventory, storage, and transportation systems. The Council's last comprehensive study on this subject was completed in 1979. The principal objectives of that study were to analyze current inventories, estimate minimum operating inventory levels, determine the total storage capacity of the primary petroleum distribution system, and provide detailed information on the nation's transportation system for oil and natural gas. In 1984, the Council issued a report updating and expanding the inventories and storage capacity portions of the 1979 study.

These studies are the most current, comprehensive treatment of petroleum storage and transportation that are available for reference, with some data being nearly a decade old and the most recent from early 1983. Since the release of these studies, there have been major changes in the production and transportation of crude oil and natural gas, refinery operations, petroleum products distribution networks, and the markets they serve.

Accordingly, I am requesting the Council to undertake a comprehensive new study on petroleum inventory, storage, and transportation capacities updating the Council's earlier studies as necessary. Emphasis should be given to the reexamination of minimum operating inventory levels, the location of storage facilities and availability of inventories in relation to local demand, and the capabilities of distribution networks to move products from refining centers to their point of consumption particularly during periods of stress.

For the purpose of this study, I designate Dr. H. A. Merklein, Administrator, Energy Information Administration, to represent me and to provide the necessary coordination between the Department of Energy and the Council.

Yours truly,

John S. Herrington

John S. Herrington

## DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that this close relationship should be continued and suggested that the Secretary of the Interior establish an industry organization to provide advice on oil and gas matters. Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The sole purpose of the NPC is to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. Matters that the Secretary would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary include:

- <u>Refinery Flexibility</u> (1980)
- <u>Unconventional Gas Sources</u> (1980)
- <u>Emergency Preparedness for Interruption of Petroleum Imports into the United States</u> (1981)
- <u>U.S. Arctic Oil & Gas</u> (1981)
- <u>Environmental Conservation -- The Oil & Gas Industries</u> (1982)
- <u>Third World Petroleum Development: A Statement of Principles</u> (1982)
- <u>Petroleum Inventories and Storage Capacity</u> (1983, 1984)
- <u>Enhanced Oil Recovery</u> (1984)
- <u>The Strategic Petroleum Reserve</u> (1984)
- <u>U.S. Petroleum Refining</u> (1986)
- <u>Factors Affecting U.S. Oil & Gas Outlook</u> (1987)
- <u>Integrating R&D Efforts</u> (1988).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

## NATIONAL PETROLEUM COUNCIL

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# APPENDIX B

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# APPENDIX C

# CRUDE OIL PIPELINE FACILITIES BY PADD

# APPENDIX C

## CRUDE OIL PIPELINE FACILITIES BY PADD

This appendix outlines the crude oil pipeline facilities and capacities in each Petroleum Administration for Defense District (PADD).

### PADD I

Refineries in PADD I (U.S. East Coast) were designed to be supplied by crude oil tanker. Refineries are concentrated in the coastal areas of the Mid-Atlantic states (New Jersey, Delaware, and Pennsylvania). Only one refinery in western Pennsylvania is supplied by pipeline; it receives Canadian or domestic crude oil via the Midwest (PADD II) systems.

As shown in Table C-1, the bulk of PADD I refinery input is imported crude oil. The domestic crude oil supply is largely Alaskan North Slope (ANS) crude oil delivered by tanker. PADD I refineries are limited by water depth to fully loaded ships in the 80 thousand deadweight tons (MDWT) range; but larger ships are routinely accommodated by barge lightering prior to berthing at the refinery wharf.

TABLE C-1

PADD I CRUDE OIL RUNS
(Thousands of Barrels per Day)

| | 1979 | 1987 | Diff. |
|---|---|---|---|
| Domestic Crude Oil | 166 | 117 | (49) |
| Imported Crude Oil | 1,480 | 1,136 | (344) |
| Refinery Runs | 1,646 | 1,253 | (395) |

Source: API Petroleum Industry Statistics (9/88), Table VIII-7.

As shown in Figure C-1, there are few crude oil pipelines in PADD I.* In the north, Portland, Maine is the input point for a line that transports foreign crude oil to eastern Canada, bypassing the ship-size limits of the St. Lawrence Waterway.

Marine receipt capacity of PADD I refineries is more than adequate at current rates. No major expansion of PADD I refinery distillation capacity is projected for the next five years, and

*Figures C-1, C-2, C-3, C-5, and C-6 are fold-out maps and can be found at the end of this Appendix.

marine receiving capacity should not be a bottleneck. In any event, since each refinery provides its own crude oil dock and terminal facilities, necessary capacity would normally be a part of any significant refinery addition.

## PADD II

The pipeline network supplying crude oil to PADD II refineries is shown in Figures C-2 and C-3. Except for inland waterway deliveries aggregating less than a half of one percent, all imported crude oil deliveries and all inter-PADD crude oil movements are by pipeline. Domestic crude oil is delivered from PADDs III, IV, and V. Imported crude oil is delivered from the Gulf Coast through PADD III and from Canada through the Interprovincial/Lakehead pipeline system.

Table C-2 shows the crude oil supply to PADD II refineries in 1979 and 1987. Declining product demand and the closure of

TABLE C-2

PADD II CRUDE OIL SUPPLY
(Thousands of Barrels per Day)

| | 1979 | 1987 | Diff. |
|---|---|---|---|
| PADD II Production | 871 | 865 | (6) |
| Imports From: | | | |
| Canada | 180 | 472 | 292 |
| Offshore via PADD III | 1,346 | 398 | (948) |
| Inter-PADD/Other | 1,332 | 1,109 | (223) |
| Refinery Input | 3,729 | 2,844 | (885) |

Source: EIA, Petroleum Supply Annual, 1987; Energy Data Reports.

uncompetitive refineries reduced overall crude oil requirements in PADD II by 885 thousand barrels per day (MB/D) between 1979 and 1987. In the same time period, Canadian crude oil imports increased by 292 MB/D. The net result was a reduction of about 1.2 million barrels per day (MMB/D) in domestic and imported crude oil movements from PADD III.

The decline resulted in the shutdown (and conversion to gas service) of two major pipelines, Texoma and Seaway, which formerly delivered imported crude oil from the Gulf Coast to pipeline centers in PADD II. Despite the shutdown of these lines, the decline in demand has left other major crude oil lines under-utilized. Table C-3 shows that current pipeline capacity from PADD III to PADD II totals almost 2 MMB/D assuming operation at 90 percent of design capacity. Actual shipments of crude oil from PADD III, including imports, were 1.4 MMB/D in 1987, leaving surplus capacity of almost 30 percent.

TABLE C-3

CRUDE OIL PIPELINE CAPACITY FROM PADD III TO PADD II
(Thousands of Barrels per Day)

| | |
|---|---|
| North TX Area/Cushing | 55 |
| Monroe TX/Cushing | 177 |
| Jacksboro/Cushing | 100 |
| Basin/Cushing | 382 |
| Shell/Cushing | 24 |
| Corsicana/Patoka | 150 |
| St. James/Patoka | 1,076 |
| Longview/Lima | 238 |
| | 2,202 |

Note: Pipeline Operating Allowance x 90 percent = 1,982 MB/D.

Spare capacity at the northern end of the system between Patoka and Chicago, Illinois, was estimated to be 286 MB/D in 1987. Figure C-4 is a schematic diagram of the northeastern section of the PADD II pipeline network.

Planned and completed refinery expansions are expected to increase 1992 PADD II crude oil demand by about 350 MB/D over 1987. PADD II pipeline capacity should be adequate, but capacity to bring imported crude oil from tidewater to inland pipeline origination points may be strained.

## PADD III

Table C-4 shows crude oil supply to PADD III refineries for 1979 and 1987. Most of the PADD III refinery capacity is situated in coastal areas of Texas and Louisiana, with direct access to marine deliveries. Crude oil supply is predominantly from PADD III production and imported crude oil or Alaskan crude oil received by tanker.

Figure C-5 is a map of the primary pipelines in PADD III, which tend to fall into two categories:

- Systems that originate in PADD III onshore or offshore oilfields and terminate at refineries

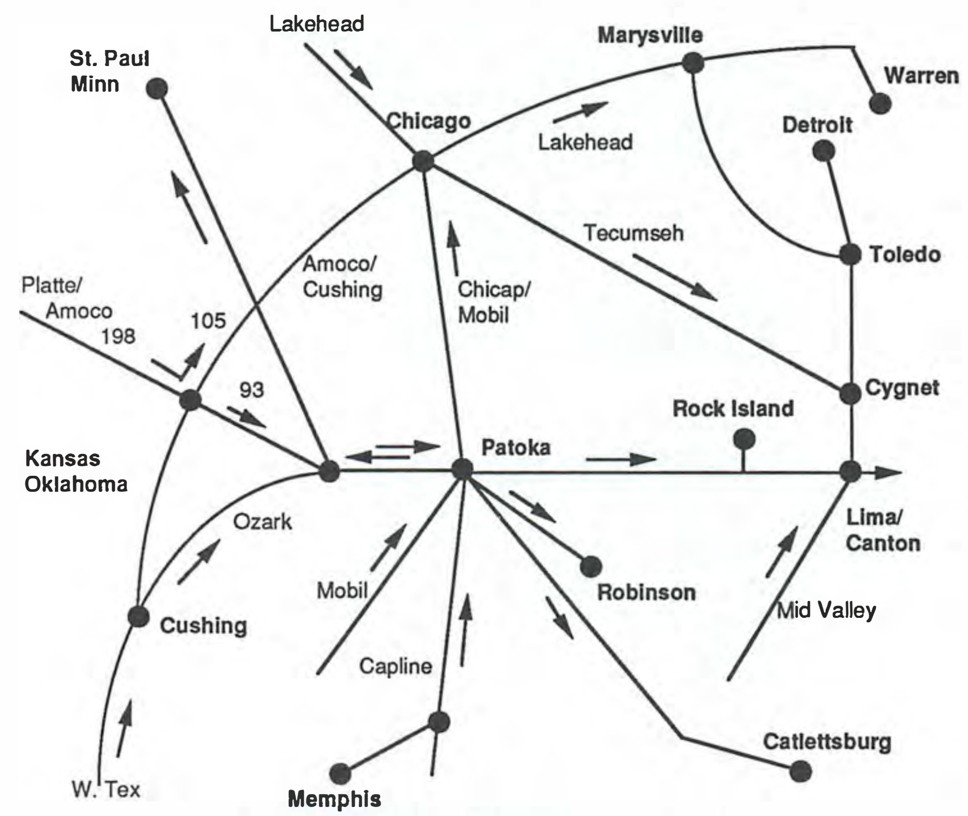



Figure C-4. PADD II Northeastern Section of Pipeline Network.

TABLE C-4

PADD III CRUDE OIL SUPPLY
(Thousands of Barrels per Day)

| | 1979 | 1987 | Diff. |
|---|---|---|---|
| PADD III Production | 4,556 | 3,827 | (729) |
| Imports | 2,969 | 2,431 | (538) |
| Inter-PADD/Other | (1,135) | (419) | 716 |
| Refinery Input | 6,390 | 5,839 | (551) |

Source: EIA, Petroleum Supply Annual, 1987; Energy Data Reports.

- Inter-PADD transportation systems that generally originate at a pipeline hub in PADD III and terminate at a hub in PADD II.

Most of the pipelines shown in Figure C-5 serve specific producing areas and specific refinery centers. These lines are becoming underutilized as PADD III production declines. The West Texas systems in particular have experienced significant declines in throughput.

Inter-PADD movements into and out of PADD III have changed significantly since 1979. In 1979, more than 2.6 MMB/D (net) were pipelined from PADD III to PADD II; in 1987, the volume was down to 1.4 MMB/D. As mentioned above, the decline resulted in the shutdown and conversion to gas service of Seaway and Texoma pipelines. These lines formerly provided connections from marine receiving points to the southern portion of PADD II and to long-haul pipelines serving PADD II.

The volume of total U.S. imported crude oil is projected to increase to 7 MMB/D by 1992 -- up almost 2.3 MMB/D from 1987 and somewhat above the 1979 crude oil import level. A portion of this increase must be delivered to PADD II by a combination of:

- Utilization of current spare capacity.
- Redirection of PADD III production to PADD II. The domestic supply can be replaced in PADD III with increased imports to coastal refineries.
- Construction or conversion of new capacity to deliver imported crude oil to inland hubs serving PADD II.

Reversal of underutilized lines that now run from inland areas to coastal refineries may become attractive as domestic crude oil production declines. One such reversal, an ARCO pipeline between the Houston area and Oklahoma has already been completed.

A new pipeline (All-American) designed to bring very heavy California oil to PADD III began operation in 1987. Ultimately, the system is expected to serve the Houston area and to provide heated pipeline transportation suitable for moving very viscous California crude oils.

## PADD IV

As shown in Table C-5, PADD IV produces more crude oil than its refineries consume. Most of the balance is shipped to PADD II.

Figure C-6 shows the primary crude oil pipelines in PADD IV (and in PADD V). Local systems are designed to move PADD IV production to refineries in the Billings and Casper areas, in the Denver area, and in Salt Lake City. Canadian crude oil is imported into Montana. In 1987, about 237 MB/D was shipped to other PADDs.

PADD IV pipeline systems are not fully loaded at present, and throughput is expected to decline with PADD IV production. Local production is more than adequate to cover PADD IV refinery demands, but inter-PADD movements will almost certainly decline.

TABLE C-5

PADD IV CRUDE OIL SUPPLY
(Thousands of Barrels per Day)

| | 1979 | 1987 | Diff. |
|---|---|---|---|
| PADD IV Production | 608 | 561 | (47) |
| Imports | 65 | 65 | - |
| Inter-PADD/Other | (196) | (189) | 7 |
| Refinery Input | 477 | 437 | (40) |

Source: EIA, Petroleum Supply Annual, 1987; Energy Data Reports.

PADD V

The largest crude oil pipeline in PADD V and in the United States is the Trans-Alaskan Pipeline System (TAPS), which brings crude oil from the North Slope area of Alaska to the year-round port of Valdez. TAPS averaged 1,962 MB/D in 1987. From Valdez, the ANS crude oil was moved by ship to the West Coast, to East-of-Rockies locations, and to Hawaii and the Virgin Islands. Since its completion, TAPS capacity has been less than the ANS production capability. Within the next five years, production rates are expected to fall below present TAPS capacity.

ANS crude oil production makes PADD V a net supplier to the rest of the United States, as shown in Table C-6. In 1987, shipments of PADD V crude oil averaged 605 MB/D.

Figure C-6 shows a number of local California systems designed to transport California production to refining centers in the Los Angeles and San Francisco Basin areas. Pipelines from the San Joaquin Valley are currently operating at capacity following a significant growth in production there. In Washington, a branch of Canada's Transmountain pipeline was formerly the principal supplier of crude oil to Puget Sound refineries. Today, ANS crude oil is the primary feedstock for these refineries; the Transmountain branch delivered less than 12 MB/D in 1987.

A new pipeline system to bring offshore California oil to the Los Angeles area is in the planning stage; political opposition to any route selected seems certain.

Two inter-PADD pipelines run from California to PADD III. The Four Corners system has been in operation for several years; and a new line (All-American) began service in 1987. Total pipeline deliveries from PADD V to PADD III were only about 20 MB/D in 1987.

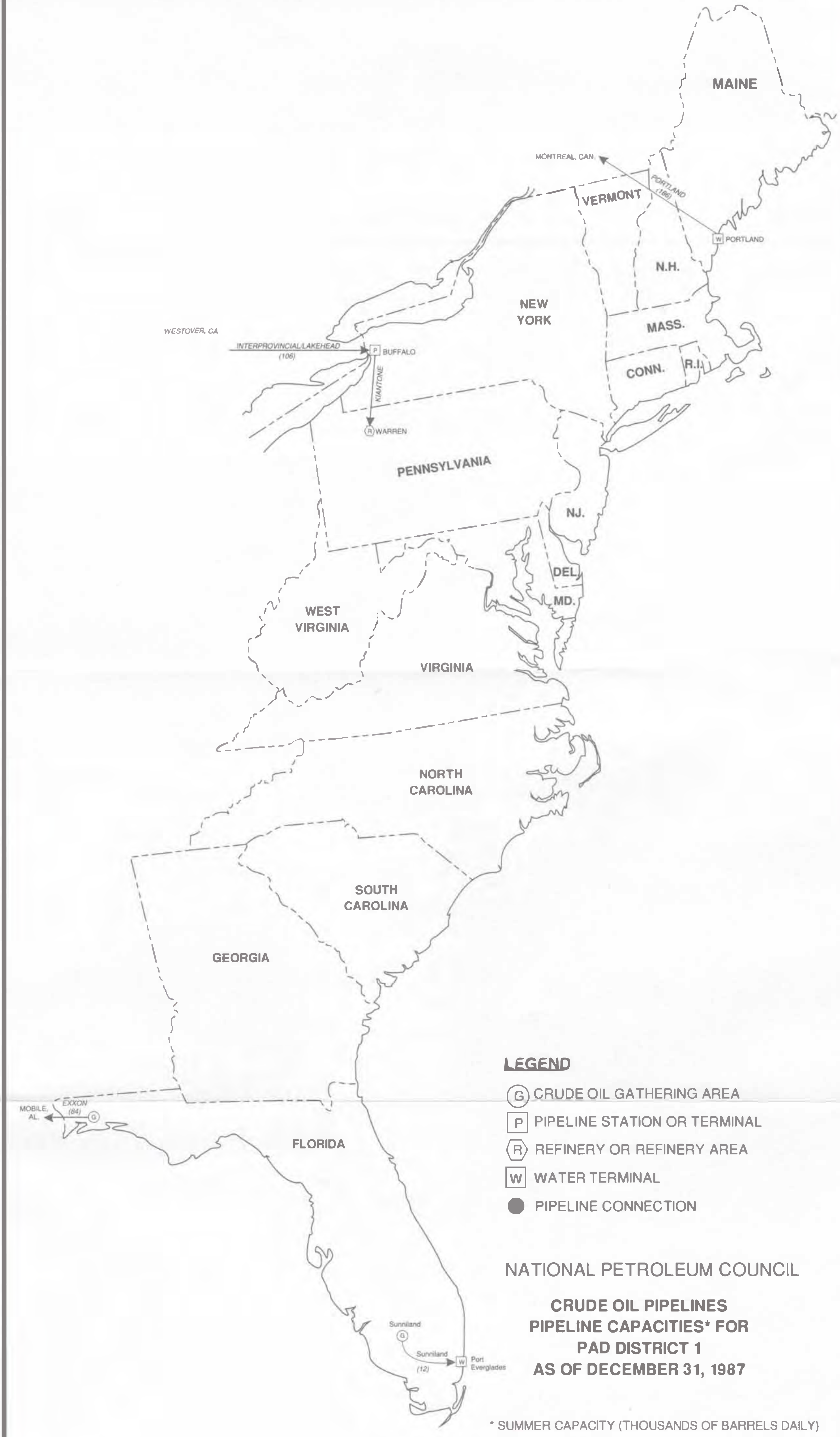
TABLE C-6

PADD V CRUDE OIL SUPPLY
(Thousands of Barrels per Day)

| | 1979 | 1987 | Diff. |
|---|---|---|---|
| PADD V Production | 2,371 | 3,055 | 684 |
| Imports | 528 | 197 | (331) |
| Exports* | (159) | (134) | 25 |
| Inter-PADD | (232) | (605) | (373) |
| Direct Use/Other | (103) | (30) | 73 |
| Refinery Input | 2,405 | 2,483 | 78 |

*Exports are primarily to U.S. possessions (e.g., Virgin Islands).

Source: EIA, Petroleum Supply Annual, 1987; Energy Data Reports, February 1981.

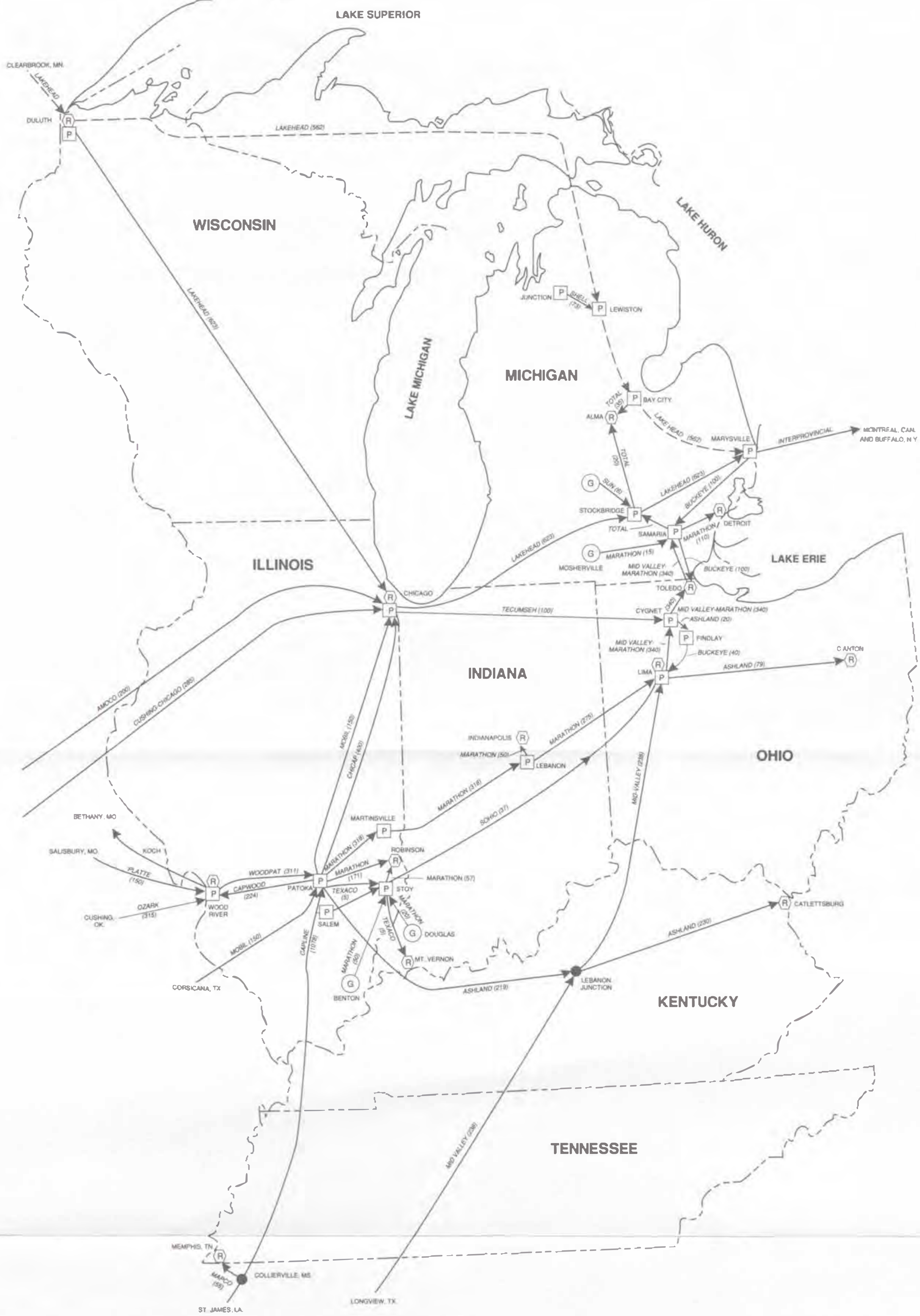



NATIONAL PETROLEUM COUNCIL

**CRUDE OIL PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 1**
**AS OF DECEMBER 31, 1987**

* SUMMER CAPACITY (THOUSANDS OF BARRELS DAILY)

Figure C-1.




NATIONAL PETROLEUM COUNCIL

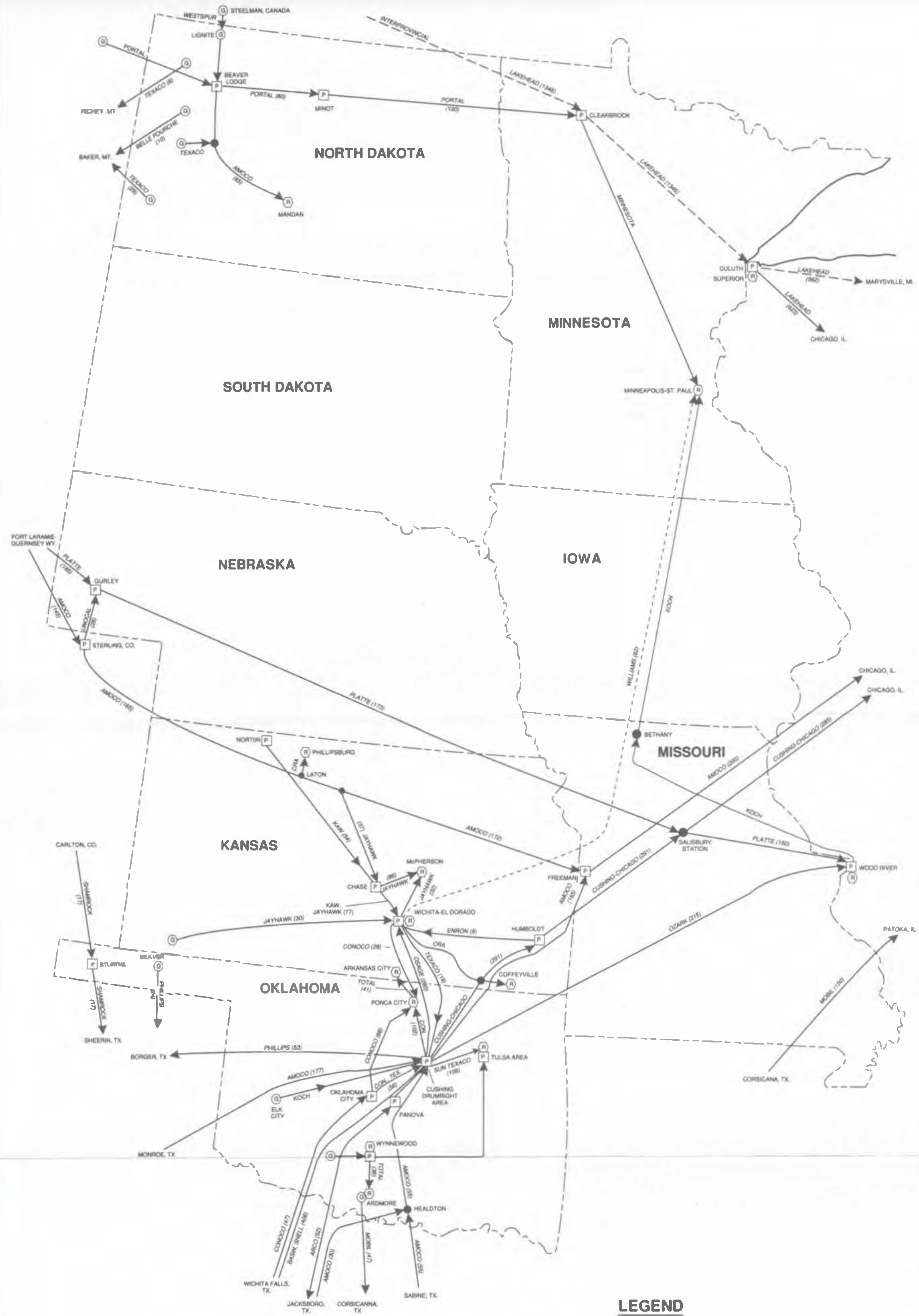
**CRUDE OIL PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 2**
**EAST OF THE MISSISSIPPI RIVER**
**AS OF DECEMBER 31, 1987**

**LEGEND**

G CRUDE OIL GATHERING AREA
P PIPELINE STATION OR TERMINAL
R REFINERY OR REFINERY AREA
● PIPELINE CONNECTION
– – – CRUDE LINE HANDLING LPG

* SUMMER CAPACITY (THOUSANDS OF BARRELS DAILY)

Figure C-2.




**LEGEND**

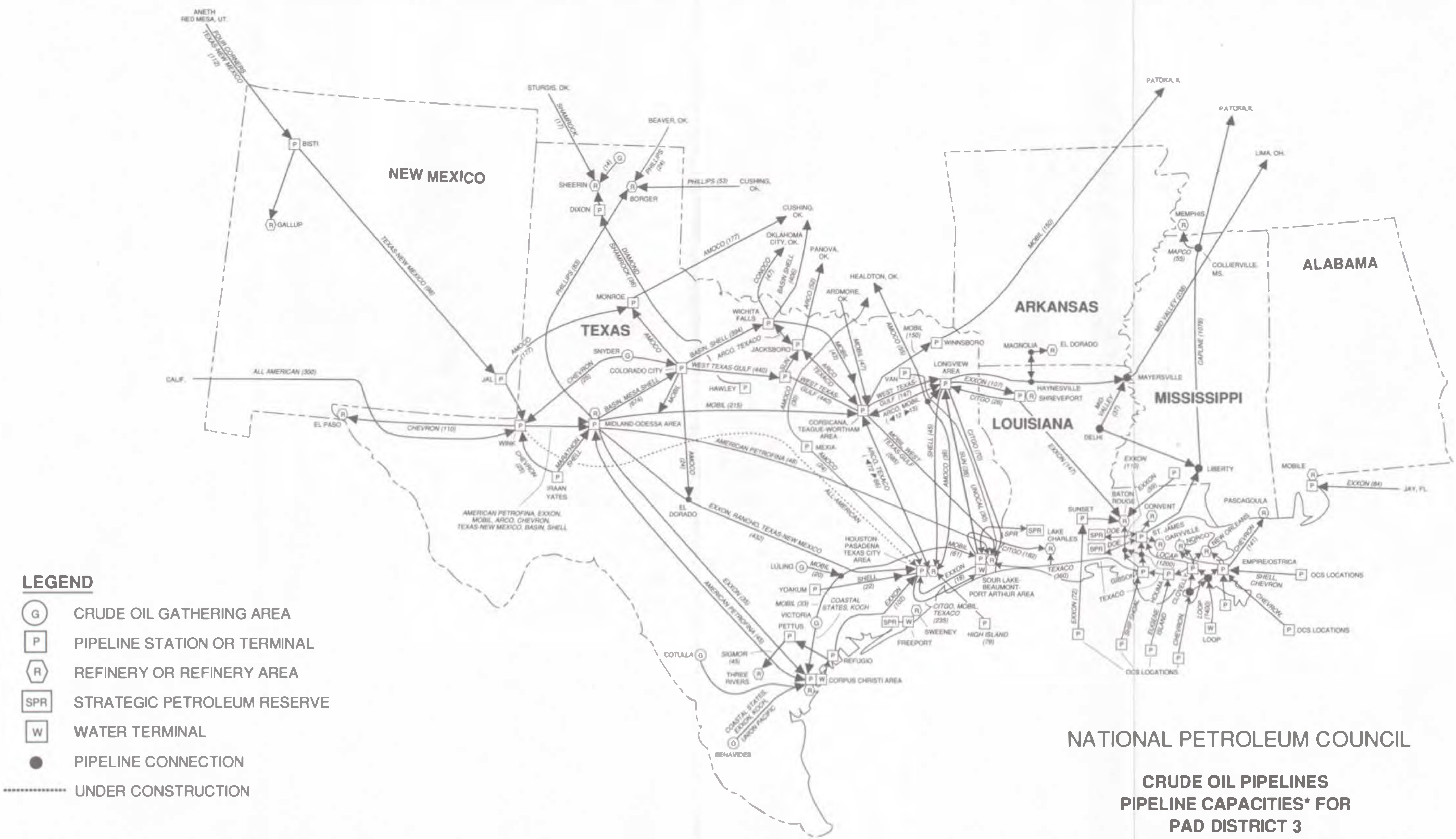
- (G) CRUDE OIL GATHERING AREA
- [P] PIPELINE STATION OR TERMINAL
- (R) REFINERY OR REFINERY AREA
- ● PIPELINE CONNECTION
- ---- PRODUCT LINE HANDLING CRUDE
- — — — CRUDE LINE HANDLING LPG

NATIONAL PETROLEUM COUNCIL

**CRUDE OIL PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 2**
**WEST OF THE MISSISSIPPI RIVER**
**AS OF DECEMBER 31, 1987**

* SUMMER CAPACITY (THOUSANDS OF BARRELS DAILY)

Figure C-3.




NATIONAL PETROLEUM COUNCIL

**CRUDE OIL PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 3**
**AS OF DECEMBER 31, 1987**

* SUMMER CAPACITY (THOUSANDS OF BARRELS DAILY)

Figure C-5.


NATIONAL PETROLEUM COUNCIL
CRUDE OIL PIPELINES
PIPELINE CAPACITIES* FOR
PAD DISTRICTS 4 & 5
AS OF DECEMBER 31, 1987
* SUMMER CAPACITY (THOUSANDS OF BARRELS DAILY)
LEGEND
G CRUDE OIL GATHERING AREA
P PIPELINE STATION OR TERMINAL
R REFINERY OR REFINERY AREA
W WATER TERMINAL
PIPELINE CONNECTION
WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
COLORADO
ARIZONA
ALASKA
FERNDALE
ANACORTES
SAN FRANCISCO
BAKERSFIELD
SANTA MARIA
GAVIOTA
MARICOPA
VENTURA
LOS ANGELES LONG BEACH
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ALL AMERICAN (300)
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STERLING
GURLEY, NE
SALISBURY, MO.
LATON, KS.
CARLTON
STURGIS, OK.
PRUDHOE BAY
TRANSALASKA (1480)
FAIRBANKS
VALDEZ
COOK INLET
GRANITE POINT
DRIFT RIVER

Figure C-6.

# APPENDIX D

# REFINED PRODUCT PIPELINE FACILITIES BY PADD

# APPENDIX D

## REFINED PRODUCT PIPELINE FACILITIES BY PADD

This appendix describes the refined product pipeline system of each PADD. Product pipelines transport gasoline, distillates, and jet fuel primarily, but some lines also move batches of liquefied petroleum gas (LPG) or unfinished product.

### PADD I

Figure D-1* is a map of the product pipelines of PADD I. These lines fall into two general categories:

- Long-haul systems that deliver products from PADD III.
- Local systems that distribute products from PADD I refineries to western Pennsylvania and western New York. In addition there are some small-diameter lines that move product from marine receiving points in New England to inland areas.

As shown in Table D-1, the bulk (70 percent) of PADD I product demand in 1987 was supplied from outside the region by

TABLE D-1

1987 PADD I REFINED PRODUCT SUPPLY

| | MB/D | % |
|---|---|---|
| Refinery Production | 1,473 | 29 |
| Imports | 1,207 | 24 |
| Inter-PADD Net In/(Out) | 2,388 | 46 |
| Inventory/Other | 58 | 1 |
| PADD I Demand* | 5,125 | 100 |

*Totals may not equal sum of components due to independent rounding.

Source: EIA, Petroleum Supply Annual, 1987.

*Figures D-1 through D-5 are fold-out maps and can be found at the end of this Appendix.

imports or shipments from PADDs II or III. Two long-haul pipelines (Colonial and Plantation) delivered more than 2 million barrels per day (MMB/D) of products from PADD III. These large-diameter systems serve the Southeast and the Mid-Atlantic states. Colonial, the longer of the two lines, terminates in the New York Harbor area. Product demands in coastal states north of New York City are supplied primarily by barge and tanker deliveries.

PADD I refineries are concentrated in New Jersey, Delaware, and Pennsylvania. From these refineries a network of smaller pipelines delivers product to western New York (e.g., Buffalo and Syracuse) and western Pennsylvania as far as Pittsburgh. Western Pennsylvania is an interface area with product supply from PADD II. Some of the western Pennsylvania pipeline segments are equipped to pump either east or west so that western Pennsylvania can be supplied either from PADD I or II as dictated by supply economics. In 1987 about 49 thousand barrels per day (MB/D) of finished product (excluding LPG) was delivered by pipeline from PADD II to PADD I, primarily to Pennsylvania.

The long-haul pipelines from Texas and Louisiana are now operating close to capacity during portions of the year. However, it is expected that much of the demand growth in PADD I will be supplied with increased imports. Transportation economics provide an incentive to direct imports preferentially to the northern portion of PADD I. The current capacity of the long-haul systems is expected to be adequate through 1992.

Local distribution pipelines serving western New York have adequate capacity currently. Alternate marine-delivered supply can be obtained from PADD II (via the Great Lakes) or from New York Harbor (via the Hudson River) if required.

## PADD II

Figures D-2 and D-3 show the extensive Midwest pipeline network in this region. Most of the system was originally built to distribute product from a number of separate refinery centers either in the crude-oil producing areas of PADD II (Kansas and Oklahoma) or in the major population centers of Illinois, Indiana, Ohio, and Minnesota.

Table D-2 shows that local refineries provided about 81 percent of PADD II finished product demands in 1987. Most of the balance was provided by product shipped from PADD III. Long-haul product lines from PADD III delivered 559 MB/D of finished product in 1987. An additional volume of 222 MB/D was delivered from PADD I via spur lines from Colonial and Plantation pipelines. (This product also originated in PADD III refineries.)

Spare capacity in the long-haul pipelines between PADD III and PADD II was estimated to average somewhat over 100 MB/D in 1987, but significantly less was available in peak periods. Planned and completed refinery expansions in PADD II are expected

TABLE D-2

1987 PADD II REFINED PRODUCT SUPPLY

| | MB/D | % |
|---|---|---|
| Refinery Production | 3,084 | 81 |
| Imports | 28 | 1 |
| Inter-PADD Net In/(Out) | 689 | 18 |
| Inventory/Other | (9) | - |
| PADD II Demand* | 3,792 | 100 |

*Totals may not equal sum of components due to independent rounding.

Source: EIA, Petroleum Supply Annual, 1987.

to satisfy the bulk of demand growth in the region for the next five years; current inter-PADD pipeline capacity should be adequate through 1992 without major additions.

Overall PADD II product demand in 1992 is not expected to be significantly above 1979 levels. The existing internal product distribution systems should be adequate, on average, for the next five years at least.

PADD III

Product pipelines are shown in Figure D-4. As shown in Table D-3, PADD III refineries produce about twice the volume required for local consumption. Most of the balance is shipped to PADDs I and II by pipeline and marine transport. About 265 MB/D was exported in 1987. Almost two-thirds of this export volume was residual fuel oil and petroleum coke that did not meet local sulfur or other quality specifications.

Long-haul pipelines delivered about 2 MMB/D of gasolines, distillates, and jet fuel to PADD I and 0.56 MMB/D to PADD II. For reasons discussed above, these systems are projected to have ample capacity to meet transportation needs through 1992 despite relatively high current capacity utilization.

Local distribution networks and intrastate trunk pipelines deliver product from Gulf Coast area refineries to major coastal cities and inland population centers (e.g., Dallas). Other systems distribute product from refineries in West and North

TABLE D-3

1987 PADD III REFINED PRODUCT SUPPLY

| | MB/D | % |
|---|---|---|
| Refinery Production | 6,517 | 202 |
| Imports | 147 | 5 |
| Inter-PADD Net In/(Out) | (3,174) | (98) |
| Exports/Other | (267) | (8) |
| PADD III Demand* | 3,223 | 100 |

*Totals may not equal sum of components due to independent rounding.

Source: EIA, Petroleum Supply Annual, 1987.

Texas, East Texas, and Arkansas. These lines pose no major problem in meeting transportation needs through the early 1990s.

In addition to pipeline deliveries, barge and tanker shipments totaling more than 600 MB/D of petroleum product were made from PADD III to PADDs I and II.

## PADD IV

Figure D-5 shows the product pipeline system in PADD IV (and PADD V). The system is fed in the north from refineries in Montana and Wyoming and in the south from refineries in Colorado and Utah.

Overall, PADD IV product requirements are closely matched by refinery production as illustrated in Table D-4. However, the southern area of PADD IV is short and receives balancing supply from PADD II. The northern area is slightly long and delivers surplus product to North and South Dakota (PADD II) and the portions of eastern Washington and Oregon (PADD V) east of the Cascade mountains.

No significant supply problems are anticipated for PADD IV pipelines.

TABLE D-4

1987 PADD IV REFINED PRODUCT SUPPLY

| | MB/D | % |
|---|---|---|
| Refinery Production | 452 | 99 |
| Imports | 4 | 1 |
| Inter-PADD Net In/(Out) | -- | -- |
| Inventory/Other | 1 | - |
| PADD IV Demand* | 457 | 100 |

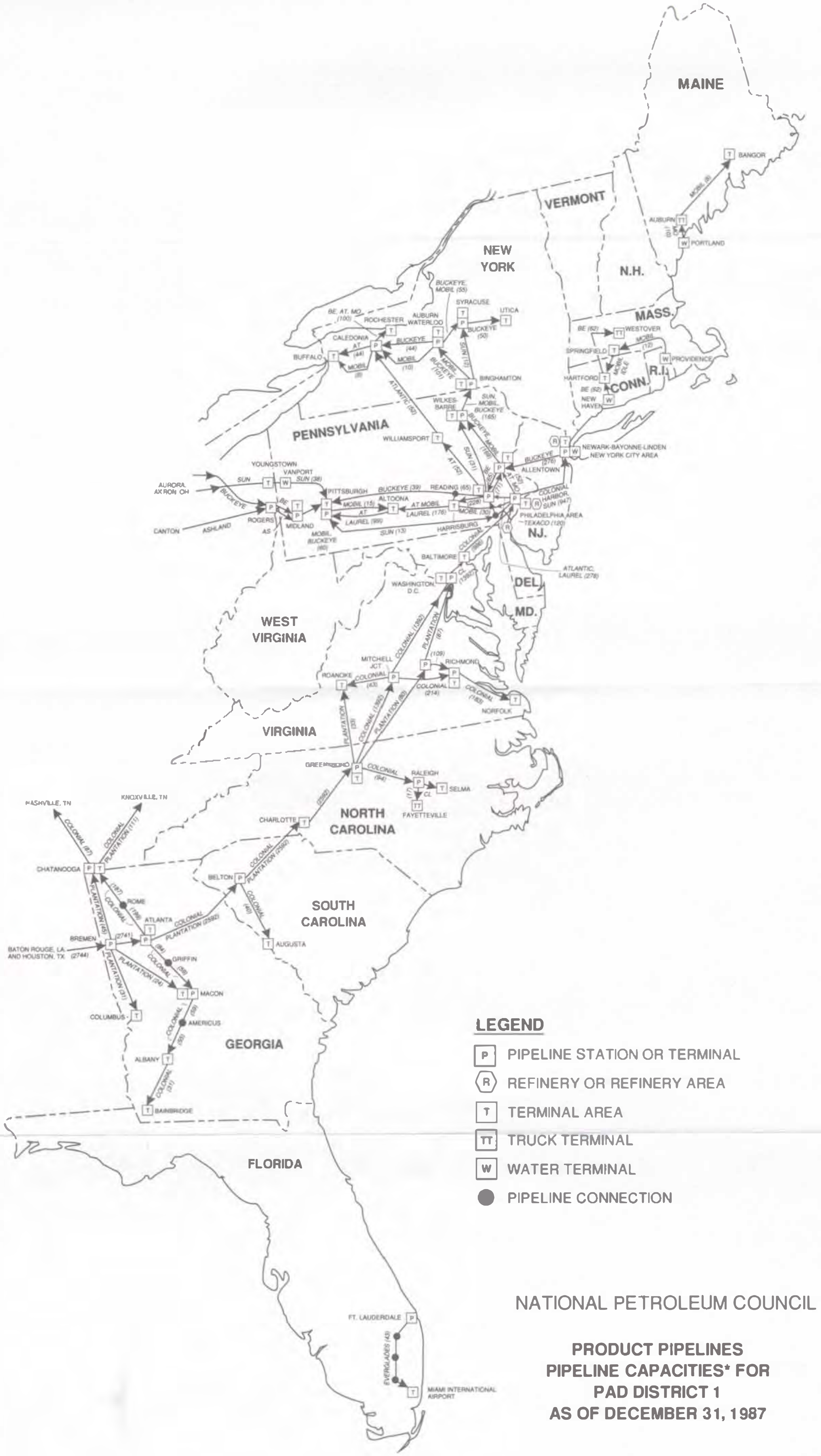
*Totals may not equal sum of components due to independent rounding.

Source: EIA, Petroleum Supply Annual, 1987.

PADD V

With the exception of the lines providing PADD IV product to eastern Washington and Oregon, PADD V product pipelines are all local distribution systems serving refineries in the Los Angeles, San Francisco Bay, or Puget Sound areas. Most of these distribution systems are currently operating near capacity, but this poses no significant problem as alternative transportation modes are available.

The rapid growth of the Phoenix-Tucson area of Arizona has strained pipeline capacity from Los Angeles and Texas into Arizona. Recent expansion of these lines should provide capacity to meet growth requirements for several years.




NATIONAL PETROLEUM COUNCIL

**PRODUCT PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 1**
**AS OF DECEMBER 31, 1987**

* FIGURES INDICATE WINTER CAPACITY IN THOUSANDS OF BARRELS PER CALENDAR DAY FOR PUMPING #2 FUEL OIL. IF NOT AVAILABLE, NORMAL MIX USED.

Figure D-1.


NATIONAL PETROLEUM COUNCIL

**PRODUCT PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 2**
**EAST OF THE MISSISSIPPI RIVER**
**AS OF DECEMBER 31, 1987**

* FIGURES INDICATE CAPACITY IN THOUSANDS OF BARRELS PER CALENDAR DAY FOR PUMPING #2 FUEL OIL. IF NOT AVAILABLE, NORMAL MIX USED.

**LEGEND**

- P PIPELINE STATION OR TERMINAL
- R REFINERY OR REFINERY AREA
- T TERMINAL AREA
- TT TRUCK TERMINAL
- W WATER TERMINAL
- ● PIPELINE CONNECTION

Figure D-2.


**LEGEND**

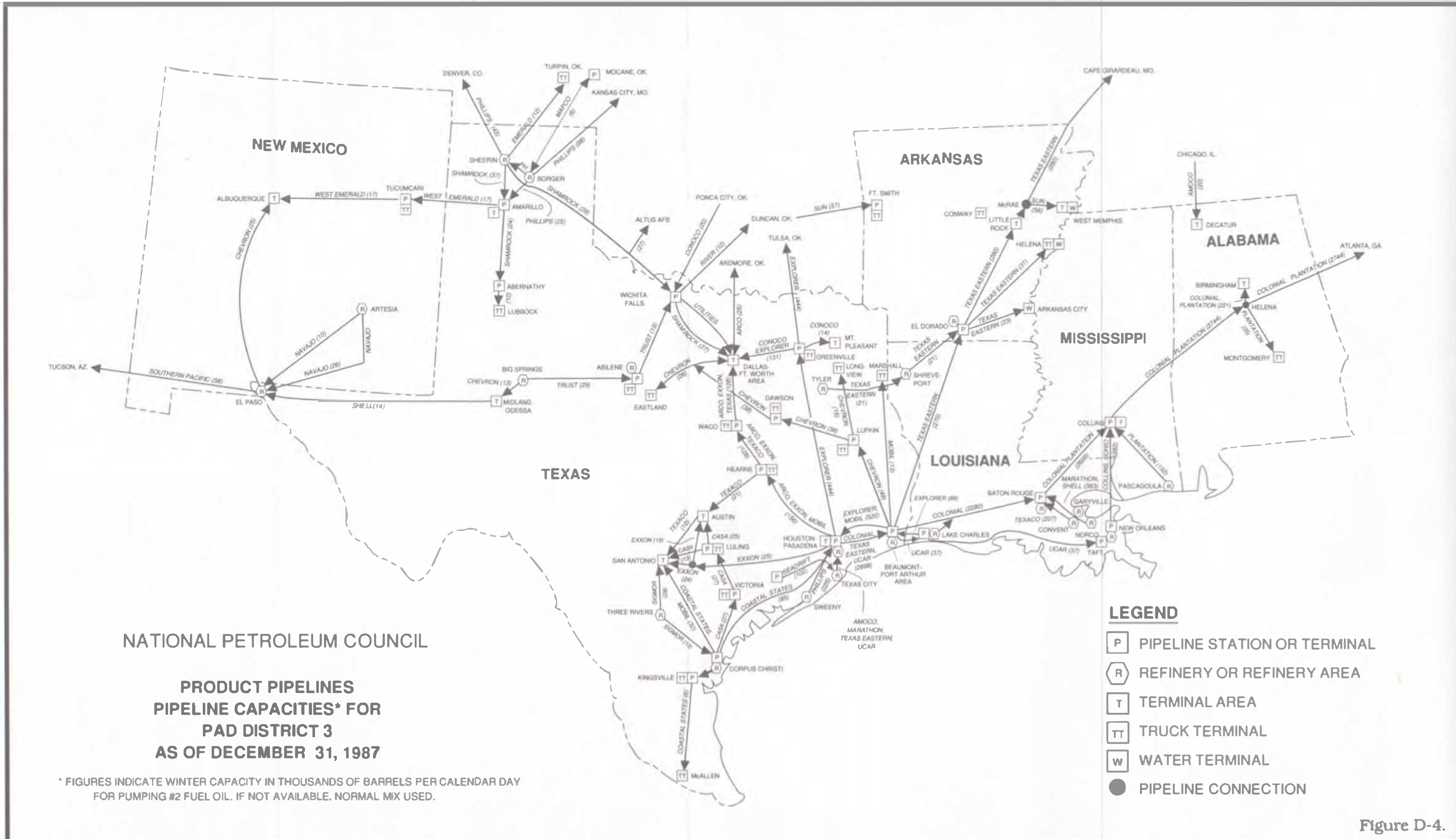
- P — PIPELINE STATION OR TERMINAL
- R — REFINERY OR REFINERY AREA
- T — TERMINAL AREA
- TT — TRUCK TERMINAL
- ● PIPELINE CONNECTION
- ······ PRODUCT LINE HANDLING CRUDE
- — — PRODUCT LINE HANDLING LPG

NATIONAL PETROLEUM COUNCIL

**PRODUCT PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 2**
**WEST OF THE MISSISSIPPI RIVER**
**AS OF DECEMBER 31, 1987**

* FIGURES INDICATE WINTER CAPACITY IN THOUSANDS OF BARRELS PER CALENDAR DAY FOR PUMPING #2 FUEL OIL. IF NOT AVAILABLE, NORMAL MIX USED.

Figure D-3.




NATIONAL PETROLEUM COUNCIL

**PRODUCT PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICT 3**
**AS OF DECEMBER 31, 1987**

* FIGURES INDICATE WINTER CAPACITY IN THOUSANDS OF BARRELS PER CALENDAR DAY FOR PUMPING #2 FUEL OIL. IF NOT AVAILABLE, NORMAL MIX USED.

Figure D-4.


NATIONAL PETROLEUM COUNCIL

**PRODUCT PIPELINES**
**PIPELINE CAPACITIES* FOR**
**PAD DISTRICTS 4 & 5**
**AS OF DECEMBER 31, 1987**

**LEGEND**

- P PIPELINE STATION OR TERMINAL
- R REFINERY OR REFINERY AREA
- TT TRUCK TERMINAL
- T TERMINAL AREA
- W WATER TERMINAL
- ● PIPELINE CONNECTION

* FIGURES INDICATE WINTER CAPACITY IN THOUSANDS OF BARRELS PER CALENDAR DAY FOR PUMPING #2 FUEL OIL. IF NOT AVAILABLE, NORMAL MIX USED.

Figure D-5.

# APPENDIX E

# GLOSSARY

APPENDIX E

# GLOSSARY

## ACRONYMS AND ABBREVIATIONS

ANS -- Alaskan North Slope

API -- American Petroleum Institute

B/D -- barrels per day

BTU -- British thermal unit*

CF -- cubic foot; a measure of gas volume.

DOE -- Department of Energy

DOT -- Department of Transportation

DWT -- deadweight tons*

EIA -- Energy Information Administration

FCC -- Fluid Catalytic Cracking

FERC -- Federal Energy Regulatory Commission

LDC -- Local Distribution Company (for natural gas)*

LNG -- liquefied natural gas*

LOOP -- Louisiana Offshore Oil Port; a marine receiving terminal for crude oil.

LPG -- liquefied petroleum gas*

MARAD -- U.S. Maritime Administration

MB/D -- thousand barrels per day

MCF -- thousand cubic feet; volume measure of natural gas.

MDWT -- thousand deadweight tons

MMB/D -- million barrels per day

MMCF -- million cubic feet

MMCF/D -- million cubic feet per day

MTBE -- methyl tertiary butyl ether; an octane improvement additive.

NGL -- natural gas liquids*

NGPA -- Natural Gas Policy Act

NPC -- National Petroleum Council

OPEC -- Organization of Petroleum Exporting Countries

PADD -- Petroleum Administration for Defense District*

psi -- pounds per square inch

RVP -- Reid vapor pressure; a measure of product volatility.

SPR -- Strategic Petroleum Reserve*

TAPS -- Trans-Alaska Pipeline System

TCF -- trillion cubic feet

VLCC -- Very Large Crude Carriers; a large oceangoing tank ship.

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*See also in Definitions section.

DEFINITIONS

alkylation -- a refining process for chemically combining isobutane with olefin hydrocarbons (e.g., propylene, butylene) through the control of temperature and pressure in the presence of an acid catalyst, usually sulfuric acid or hydrofluoric acid. The product, alkylate, an isoparaffin, has high octane value and is blended with motor and aviation gasoline to improve the antiknock value of the fuel.

available inventory -- volume in storage above minimum operating levels.

barge -- general name given to the flat-bottomed vessel especially adapted for the transportation of bulk cargoes. Barges can be self-propelled, towed, or pushed.

barrel -- the standard unit of measurement of liquids in the petroleum industry, containing 42 U.S. standard gallons at 60 degrees F.

batches -- homogeneous quantities of petroleum shipped through a pipeline usually having a specified minimum acceptable size.

British thermal unit (BTU) -- the standard measurement for heat employed in the U.S. gas industry. One BTU raises the temperature of one pound of water by one degree Fahrenheit from 58.5 to 59.5 degrees under standard pressure of 30 inches of mercury. Natural gas of "pipeline quality" contains about 1,000 BTU per cubic foot.

burner tip -- signifying delivery to the final customer. A burner-tip price, for example, is the price charged the end-user.

butane -- a normally gaseous straight-chain or branch-chain hydrocarbon. It is extracted from natural gas or refinery gas streams. It includes isobutane and normal butane.

ceiling price -- the maximum price permitted by a regulatory authority exercising control of price or profits.

cogeneration -- the simultaneous production of electricity and useful heat. The heat is usually in the form of steam or hot water. Cogeneration usually refers to using heat that is often wasted when an industry or utility generates electricity.

coking -- a process by which heavier crude oil fractions can be thermally decomposed under conditions of elevated temperatures and pressure to produce a mixture of lighter oils and petroleum coke. The light oils can be processed further in other refinery units to meet product specifications. The coke can be used either as a fuel or in other applications such as the manufacturing of steel or aluminum.

combined cycle -- a co-generation technology in which additional electricity is produced sequentially from otherwise lost waste heat from gas-fired turbines. Exiting heat flow is routed to an exhaust-fired conventional boiler or to a heat-recovery steam generator for utilization by a steam turbine to produce electricity.

common carrier -- transportation line or system carrying persons or goods for compensation, impartially for all persons or shippers.

cracking, catalytic -- the refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil.

cracking, hydrocracking -- a refining process that uses hydrogen and catalysts with relatively low temperatures and high pressures for converting middle boiling or residual material to high-octane gasoline, reformer charge stock, jet fuel, and/or high grade fuel oil. The process uses one or more catalysts, depending upon product output, and can handle high-sulfur feedstocks without prior desulfurization.

crude oil distillation -- the refining process of separating crude oil components at atmospheric pressure by heating to temperatures of about 600 degrees F to 750 degrees F (depending on the nature of the crude oil and desired products) and subsequent condensing of the fractions by cooling.

deadweight tons (DWT) -- the number of long tons (2,240 pounds) of cargo, stores, and bunkers that a vessel can carry. It is the difference between the long tons of water a vessel displaces in its "light" and loaded condition. A vessel's cargo capacity is less than its total deadweight tonnage.

distillate fuel oil -- a general classification for one of the petroleum fractions that is used primarily for space heating, on-highway and off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are products known as No. 1, No. 2, and No. 4 heating oil and diesel fuel. Industry parlance often includes jet fuel and kerosine as distillates also.

draft -- the depth of a vessel below the waterline.

enhanced oil recovery -- sophisticated processes to augment recovery of crude oil (e.g., injection of steam into reservoir formations).

ethane -- a normally gaseous straight-chain hydrocarbon. It is a colorless paraffinic gas that boils at a temperature of minus 127.48 degrees F. It is extracted from natural gas and refinery gas streams.

fractionator -- a processing plant that separates natural gas liquids into the marketable components ethane, propane, butane, and natural gasolines.

futures -- for the purpose of this report, refers to futures trading of No. 2 fuel oil/gas oil, motor gasoline, and crude oil on the New York Mercantile Exchange and the London International Petroleum Exchange.

gathering system -- the network of small lines used to collect crude oil and gas liquids from individual production units or facilities.

gravity -- the weight per unit measure of petroleum liquid, usually expressed in either degrees API or related to water as a specific gravity. API gravity is a measure of density in degrees API; specific gravity is the weight per unit of a liquid as related to water.

hedge -- the establishment of an opposite position in the futures market from that held in the physical market as a protection against the possibility of adverse price fluctuations.

idle capacity -- the component of operable capacity that is not in operation and not under active repair, but capable of being placed in operation within 30 days; and capacity not in operation but under active repair that can be completed within 90 days.

isobutane -- the branched chain form of butane that is extracted from natural gas or refinery gas streams. It is normally used as an alkylation process feedstock in a refinery.

isomerization -- a refining process that alters the fundamental arrangement of atoms in the molecule without adding or removing anything from the original material. Used to convert normal butane into isobutane, an alkylation process feedstock, and normal pentane and hexane into isopentane and isohexane, high-octane gasoline components.

Jones Act -- commonly used term for the Merchant Marine Act of 1920 that provides for the protection of the U.S. merchant fleet by excluding foreign-built, owned, or operated ships from the U.S. domestic trades. The Jones Act covers all waterborne transportation between U.S. ports, including inland waterways, Great Lakes, and the oceanborne trade between the U.S. mainland and the noncontiguous areas of Alaska, Hawaii, and Puerto Rico; also designates all vessel personnel, longshoremen, and harbor workers as "seamen" and wards of the federal court.

liquefied natural gas (LNG) -- natural gas becomes a liquid at a temperature of minus 258 degrees F and may be stored and transported in the liquid state.

liquefied petroleum gas (LPG) -- butane, propane, and ethane separated from refinery and natural gas streams. In this report, LPG also includes butane, propane, and ethane in unfractionated mixed streams produced by natural gas plants.

local distribution company (LDC) -- the local service company that primarily sells gas to an end-user through its smaller diameter pipeline network. Residential customers are highly dependent on LDCs.

Maritime Administration (MARAD) -- an agency of the U.S. Department of Commerce that administers programs to aid in the development, promotion, and operation of the U.S. merchant marine industry, including emergency merchant ship operations.

Merc -- New York Mercantile Exchange.

minimum operating inventory -- the lowest inventory at which "normal" supply operations are maintained. At lower levels, the system may incur abnormal costs to maintain consumer supply and there may be other problems (e.g., runouts).

naphtha -- a generic term applied to a petroleum fraction with an approximate boiling range between 122 and 400 degrees F.

natural gas liquids (NGL) -- high vapor pressure, hydrocarbon liquids separated from wet natural gas and moved by pipeline to a fractionation facility where the components are separated into ethanes, propanes, butanes, and natural gasoline.

reforming -- a refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules, thereby converting paraffinic and naphthenic type hydrocarbons (e.g., low-octane gasoline boiling range fractions) into petrochemical feedstocks and higher octane stocks suitable for blending into finished gasoline.

reserves -- the recoverable volume of the resource (oil or gas) that is commercial under current economic conditions with current technology.

residual fuel oil -- the heavier hydrocarbons contained in crude oil that have higher boiling points in the distillation process. Because of its impurities and sulfur content, these "bottoms" (sometimes called No. 6 fuel oil) are burned primarily in larger boilers such as electric-utility and industrial boilers.

re-source -- to assign supply of a customer or area to a different supply source.

spot market -- commodity transactions whereby participants make buy-and-sell commitments of relatively short duration, in contrast to the "contract" market in which transactions are long term.

natural gas processing plant -- a facility designed (1) to achieve the recovery of natural gas liquids from the stream of natural gas which may or may not have been processed through lease separators and field facilities, and (2) to control the quality of the natural gas to be marketed.

oxygenates -- oxygenates include both alcohols and ethers used as octane boosting additives for gasoline (e.g., methyl tertiary butyl ether).

Petroleum Administration for Defense Districts (PADDs) -- a geographic aggregation of the 50 states and the District of Columbia into five districts originally designed by the Petroleum Administration for Defense in 1950 for purposes of administration (see Executive Summary).

peak shaving -- the use of fuels and equipment to generate or manufacture gas to supplement the normal supply of pipeline gas during the seasonal periods of greatest customer demand.

petroleum products -- a generic term used to describe products obtained from distilling and processing crude oil, unfinished oils, natural gas liquids, blend stocks, and other miscellaneous hydrocarbon compounds. Includes all gasoline, jet fuels, kerosine, distillate fuel oil, residual fuel oil, liquefied petroleum gases, petrochemical feedstocks, lubricants, paraffin wax, petroleum coke, asphalt, and many other miscellaneous products.

private carrier -- any person, partnership, or corporation other than common or contract carrier who transports property of which such party is the owner, and the transportation is in furtherance of its commercial enterprise.

sour crude oil -- a crude oil having a sulfur content of more than 0.5 percent (by weight).

Strategic Petroleum Reserve (SPR) -- a federal program created by the Energy Policy and Conservation Act of 1975 to establish a reserve of up to one billion barrels of crude oil and/or petroleum products in order to reduce the impact of disruptions in petroleum supplies and to carry out the obligations of the United States under the International Energy Program.

sulfur content -- the amount of sulfur in crude oil, expressed as a percentage by weight. This sulfur can be in the form of elemental sulfur, mercaptan sulfur, and/or hydrogen sulfide.

sweet crude oil -- a crude oil having a sulfur content of less than 0.5 percent (by weight).

take-or-pay -- a contractual obligation to pay for a certain threshold quantity of gas whether or not the buyer finds it possible (or beneficial) to take full delivery.

tank car -- rail car used for transporting liquids in bulk. It is constructed in accordance with varying specifications, due to physical properties and characteristics of products to be transported.

tariff -- the document published by the common carrier pipeline owner setting rates charged and rules and regulations under which these services will be performed. Interstate common carriers must file tariffs with the Federal Energy Regulatory Commission.

topping plus reforming -- literally atmospheric crude oil distillation capacity plus catalytic reforming capacity (to convert distilled naphtha to gasoline). In this volume and in common industry usage, topping/reforming capacity includes any refinery capacity remaining after coking and cracking capacity is fully loaded.

tow -- one or more barges pushed by a towboat or pulled by a tugboat.

trunk line -- a large-diameter pipeline most usually delivering petroleum into a refinery or production distribution terminal.

unbundled service -- process where gas pipelines offer and charge rates based on costs for each service separately, e.g., the gas commodity, transportation (firm or interruptible), peak shaving, storage, etc.

U.S. flag fleet -- all ships registered in the United States.

waterway -- the more than 25,000 miles of navigable rivers, canals, and channels in the United States, maintained to a depth of at least nine feet.

wellhead -- literally, the surface control valves of an oil or gas well. In practice, "wellhead" refers to price, volume, or quality of production at the first sale or transfer from the producing property.

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