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REPORT TO CONGRESS ON THE FEASIBILITY OF ESTABLISHING A HEATING OIL COMPONENT TO THE STRATEGIC PETROLEUM RESERVE

Volume II: APPENDICES

June 1998

Department of Energy
Assistant Secretary, Fossil Energy
Deputy Assistant Secretary, Strategic Petroleum Reserve

DISCLAIMER

TABLE OF CONTENTS

Appendix A

Northeastern U.S. Distillate Supply Systems

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ICF Kaiser International, Inc

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APPENDIX A
NORTHEASTERN U.S. DISTILLATE SUPPLY SYSTEMS

INTRODUCTION

This appendix addresses distillate fuel oil supply, demand, and distribution in the Northeastern United States. The relatively higher cost of natural gas[1] makes this region much more dependent on distillate fuel oil for heating homes and businesses than other parts of the U.S. In fact, according to the Department of Energy (DOE), the Petroleum Administration for Defense Districts (PADD) Ia and Ib (New England and the Middle Atlantic) account for more than 30 percent of national distillate heating oil demand in the colder winter months.[2] This extraordinary level of consumption is satisfied by various supply sources and intricate distribution systems.

The following analysis provides a review of regional demand levels, supply sources, inter-regional transportation systems, and intra-regional distribution systems. It also looks at how environmental regulations have impacted the market over the years. The appendix is largely based on U.S. Department of Energy/Energy Information Administration data, and interviews, conversations, and meetings held with over 20 firms/associations throughout the Northeast.

It is important to point out that the appendix will refer to home heating oil as "distillate." Until the 1990 Clean Air Act Amendments (CAAA) were imposed, distillate products used as diesel fuel or as heating oil were indistinguishable. The Amendments established that the maximum sulfur level for diesel fuel be reduced from 0.25 percent to 0.05 percent by October 1993. As a result, distillate stocks are now segregated by sulfur content, where they had been interchangeable. In general, stocks of high-sulfur distillate are destined for heating oil use, and stocks of low-sulfur distillate are destined for use as diesel fuel.[3] But the appendix will use the blanket term "distillate." That is, unless otherwise noted, the word "distillate" standing alone will refer to both No. 2 heating oil and diesel. There are two reasons for this. First, this study uses data that was published before the CAAA were implemented and second, in an emergency situation one can substitute diesel for heating oil, but not heating oil for diesel.

OVERVIEW OF THE NORTHEAST DISTILLATE MARKET

The Northeastern section of the U.S. is made up of the New England and Middle Atlantic states. New England is comprised of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. While Delaware, Washington DC, Maryland, New Jersey, New York, and Pennsylvania make up the Middle Atlantic. The two regions are depicted in Exhibit A–1.

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[1]See Appendix C

[2] Energy Information Administration, *Petroleum Marketing Monthly*, "Recent Distillate Fuel Oil Inventory Trends: What EIA Data Show," June 1996, Griffith.

[3] Energy Information Administration, *Weekly Petroleum Status Report*, "Distillate Fuel Oil Assessment for Winter 1996-1997," September 1996, Cranston.

Exhibit A–1
The Northeastern U.S. – The New England and Middle Atlantic States Consumption

The Northeastern markets are atypical in their levels of distillate fuel oil consumption. In recent years, the Northeast has accounted for one-third of national distillate fuel oil demand in the colder winter months.[4] In mid-summer, Northeast use drops to one-sixth of total U.S. sales. The economic reasons for this heavy reliance on distillate heating oil have been addressed in the report text and in Appendix C. To show how important distillate heating oil consumption is in the Northeast, compared to other parts of the U.S., the following comparison with two other regions is provided. The other two regions are the adjacent upper Midwest region that has a similar climate, and in the Gulf Coast states that supply some of the distillate fuel oil to the Northeast. According to standard practice in tabulating geographic data for the oil industry, the regions discussed here are labeled PADD I, II, III. The map in Exhibit A-2 shows where the Northeastern states portion of PADD I are located in relation to the upper Midwest (PADD II) and the Gulf coast (PADD III).

The graph in Exhibit A-3 presents each of these three region's distillate fuel oil sales as percentages of the total U.S. distillate fuel oil sales by month from January 1995 through September of 1996. The importance of distillate heating oil for space heating in the Northeast is clearly evident from the large change in shares of U.S. total sales between winter and summer. The reason that PADD II sales share becomes significantly large in summer months is because the Northeast share has dropped so dramatically.

Actual Northeastern distillate fuel oil sales (not percentages of U.S. total sales) in some winter months are over three times summer sales. In PADDs II and III, the seasonal change in sales in much smaller, with volume increases of only 20 to 35 percent from summer to winter.

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[4]Energy Information Administration, *Petroleum Marketing Monthly,* "Recent Distillate Fuel Oil Inventory Trends: What EIA Data Show, " June 1996, Griffith.

Exhibit A–2
Petroleum Administration for Defense Districts (PADD) I, II, III

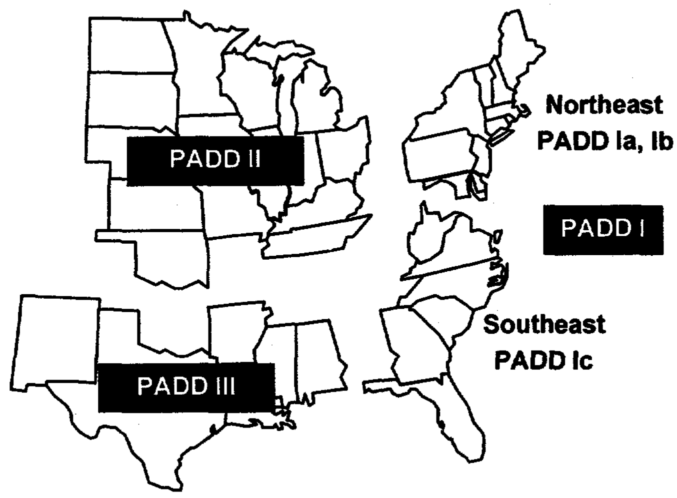
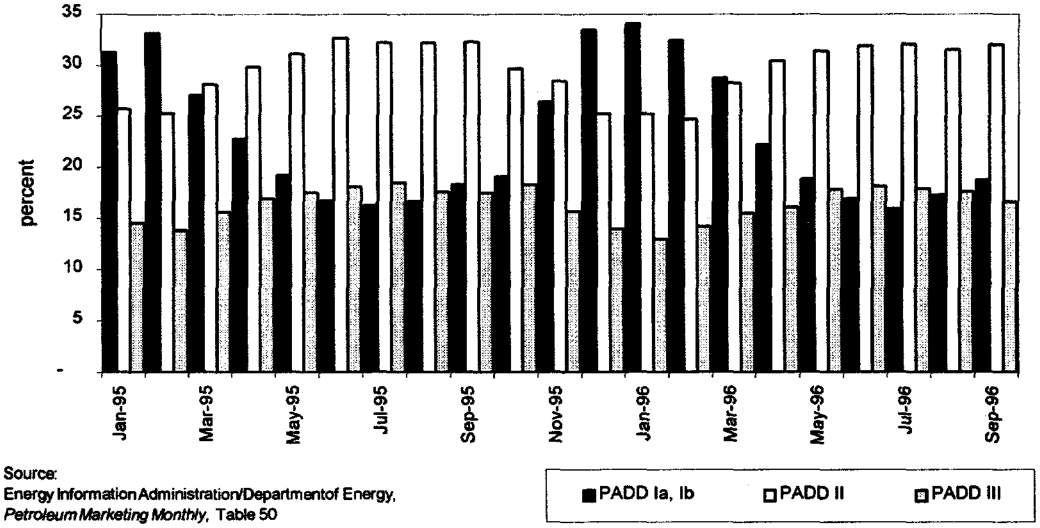


Exhibit A–3
Distillate Fuel Oil Sales in PADDs Ia and Ib, II, and III as Percentages of Total U.S. Sales



Source:
Energy Information Administration/Department of Energy, *Petroleum Marketing Monthly*, Table 50

Supply

In order to meet this exceptional level of demand, the Northeast markets purchase distillate from two sources: domestic refining centers in the Middle Atlantic and the Gulf Coast, and imports from Canadian, Latin American, Asian, and European sources.

Domestic Refineries

The 13 refineries of the Middle Atlantic states supply their own regional market, along with the international community and New England. In 1996, they had a combined crude oil refining capacity of 1,388 thousand barrels per calendar day (Mbbl/cd). Pennsylvania had six refineries with 574 Mbbl/cd of capacity, New Jersey had six with 674 Mbbl/cd, and Delaware had one refinery with a capacity of 140 Mbbl/cd.[5] The Northeast markets are also dependent on PADD III for petroleum products. In 1995, 4,655 Mbbl of distillate was shipped, via tanker and barge, from the refineries of PADD III to New England.[6] The Colonial Pipeline, which will be discussed in detail later in this appendix, moves on average 1,000 Mbbl/d from PADD III to the Northeast.

Imports

Imports satisfy a significant share of demand as well, particularly for New England. Since New England has no refining capacity, nor a direct connection to the Gulf Coast pipeline system, it is more dependent on distillate imports than the Middle Atlantic states. Exhibit A–4 shows that New England imported 46 percent of the amount sold there in 1995, compared with 11.6 percent in the Middle Atlantic states. According to the Energy Policy and Conservation Act, New England is considered "import dependent," that is, it qualifies for a regional product reserve. Exhibit A–5 compares New England and Middle Atlantic distillate imports for 1995 and the first nine months of 1996. In 1995, New England received 37,962 Mbbl from abroad, or 63 percent of all the imports that entered the two regions. For the first nine months of 1996, New England again had a greater share than the Middle Atlantic with 66 percent.[77]

[5] Oil and Gas Journal, "Worldwide Refining", Dec. 23, 1996.

[6] Energy Information Administration, *Petroleum Supply Annual*, Table 34.

[7] Energy Information Administration, *Petroleum Marketing Monthly*, Table 50.

Exhibit A–4
New England and Middle Atlantic Total Distillate Imports as a Percentage Total Distillate Sold – 1995

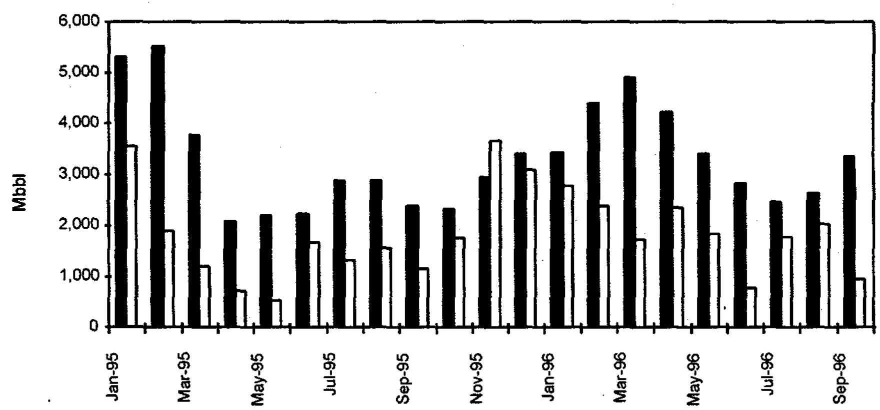
	New England	Mid-Atlantic
Total Distillate Imports (Mbbl)	82,199	188,983
Total Distillate Sold (Mbbl)	37,962	21,994
Imports as a Percentage	46.2%	11.6%

Sources:

Energy Information Administration/Departmentof Energy, *Petroleum Marketing Monthly,* Table 50

Energy Information Administration/Departmentof Energy, Form EIA-814, *Monthly Imports Report*

Exhibit A–5
New England and the Middle Atlantic Monthly Distillate Imports -- 1995-96



Source:
Energy Information Administration/Depàrtmartment of Energy, Form EIA-814 *Monthly Imports Report*

THE NORTHEAST DISTILLATE DELIVERY SYSTEMS

The relatively high level of distillate consumption and the impressive amount of imports has made the Northeastern markets develop an efficient and versatile transportation network. The distillate transportation systems of the Northeast can be classified into two groups: the inter-regional and the intra-regional systems. The inter-regional system supplies distillate to the Northeast via marine and pipeline transport from U.S. and foreign sources. The oil storage facilities located at the receiving harbors and pipeline terminals are considered to be a part of the inter-regional system. Once the imported or domestically refined distillate is put into these primary storage facilities, the intra-regional system takes over to distribute distillate throughout the Northeast region.

This section describes how these two systems work, who their participants are, and how they meet the atypical consumption levels of the Northeast.

Inter-regional Transport System

The inter-regional transport system brings domestic and foreign refined distillate to the Northeast. Its two transport modes are marine and pipelines.

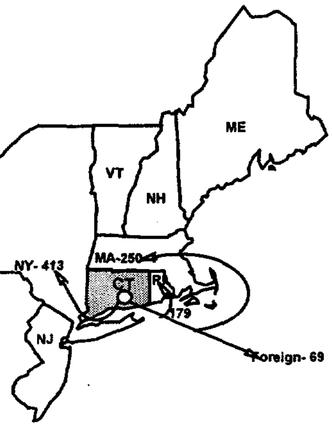
<u>Transport Mode: Marine</u>

Since New England has no refining capacity and no direct connection to the major pipeline system from the Gulf Coast, it depends on marine movements to bring distillate and other petroleum products to its markets. And even though the Middle Atlantic states have some refining capacity and are connected to the pipeline system, they need a well-developed marine system to further satisfy their demand and deliver their products to other states and/or countries.

The ports of New England, New Jersey, and New York not only serve their own markets, but also the rest of the country and other parts of the world. They are petroleum product (i.e., distillate, gasoline, jet fuel, etc.) hubs that exported, re-exported, and imported over 500,000 Mbbl in 1994. Over 220,000 Mbbl of petroleum products went through New England, while 324,000 Mbbl passed through the ports of New Jersey and New York.[8] The maps in Exhibit A–6 depict these petroleum product movements.

[8] U.S. Army Corps of Engineers, Waterborne Commerce Statistics Center, *Navigation Data Center Publications CD-ROM*, 1995.

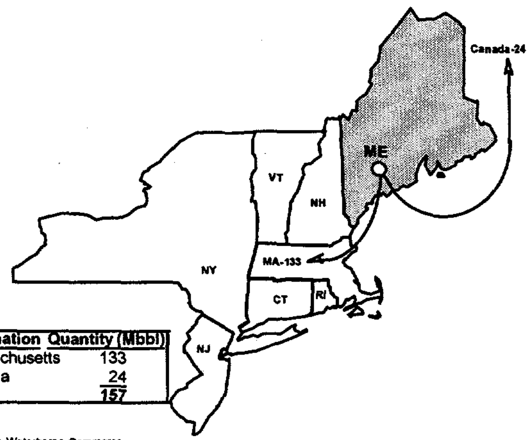
Exhibit A–6
New England, New Jersey, and New York
Marine International and Regional Product Movements – 1994



Origin	Destination	Quantity (Mbbl)
Connecticut	Massachusetts	250
	New York	413
	Rhode Island	179
	Foreign	69
	Total	911

Source:

Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.



Origin	Destination	Quantity (Mbbl)
Maine	Massachusetts	133
	Canada	24
	Total	157

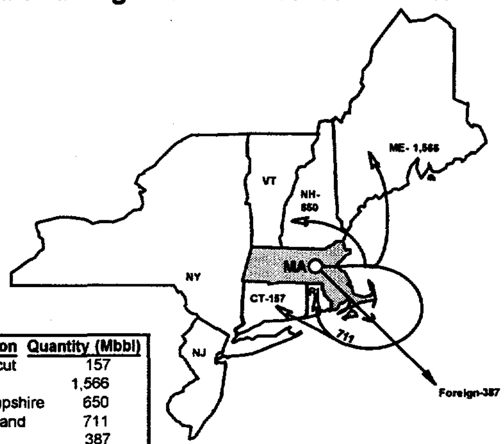
Source:

Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.

Exhibit A-6 con't.

New England, New Jersey, and New York

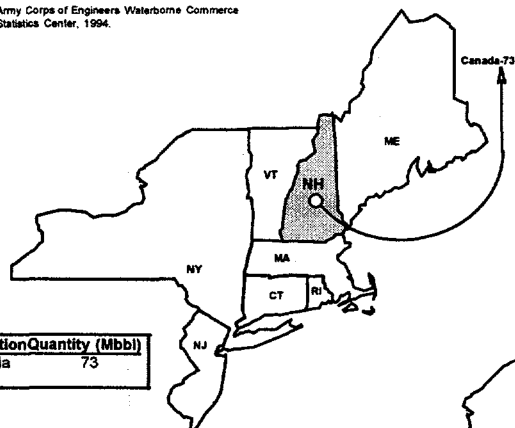
Marine International and Regional Product Movements - 1994



Origin	Destination	Quantity (Mbbl)
Massachusetts	Connecticut	157
	Maine	1,566
	New Hampshire	650
	Rhode Island	711
	Foreign	387
	Total	3,471

Source:

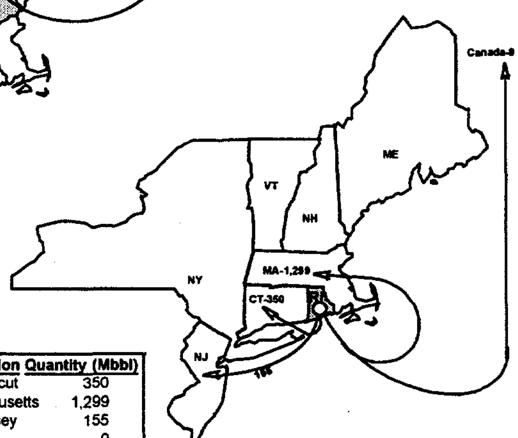
Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.



Origin	Destination	Quantity (Mbbl)
New Hampshire	Canada	73

Source:

Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.



Origin	Destination	Quantity (Mbbl)
Rhode Island	Connecticut	350
	Massachusetts	1,299
	New Jersey	155
	Canada	9
	Total	1,813

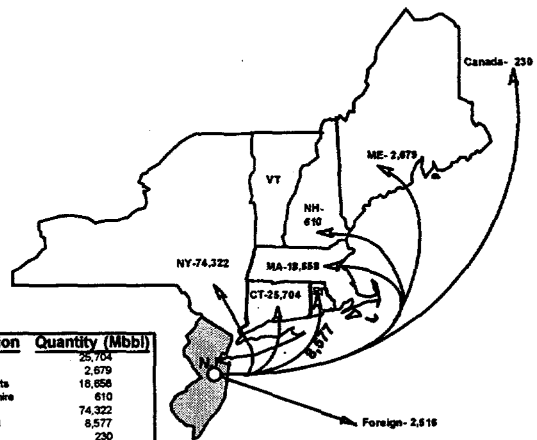
Source:

Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.

Exhibit A-6 con't.

New England, New Jersey, and New York

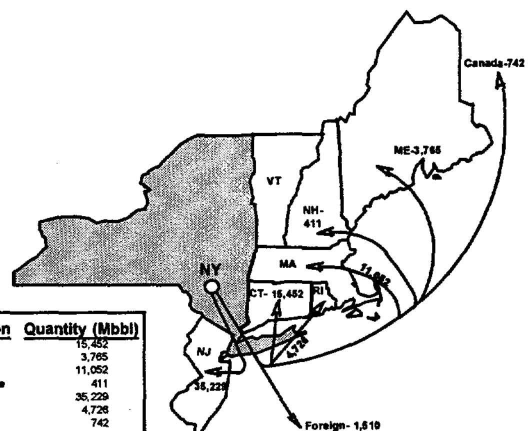
Marine International and Regional Product Movements - 1994



Origin	Destination	Quantity (Mbbl)
New Jersey	Connecticut	25,704
	Maine	2,679
	Massachusetts	18,658
	New Hampshire	610
	New York	74,322
	Rhode Island	8,577
	Canada	230
	Foreign	2,516
	Total	133,296

Source:

Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.



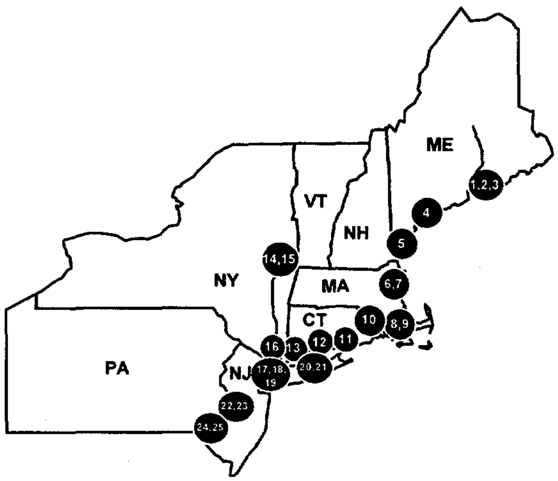
Origin	Destination	Quantity (Mbbl)
New York	Connecticut	15,452
	Maine	3,765
	Massachusetts	11,052
	New Hampshire	411
	New Jersey	35,229
	Rhode Island	4,726
	Canada	742
	Foreign	1,510
	Total	72,887

Source:

Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.

The 25 major ports in the region are depicted in Exhibit A–7 as black circles along the Northeast coastline. The numbers within the circles correspond to Exhibit A–8, which breaks down each of the 25 ports' activity for 1994. These ports are the lifelines for Northeastern distillate distribution.

Exhibit A–7
Major New England and Middle Atlantic Ports



Source:
Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.

The two major forms of water transport are barges and tankers. Barges typically require a tug boat to transport distillate between ports and generally are not self propelled. They can normally carry between 10 and 100 Mbbl. Tankers, on the other hand, are self propelled and can transport more than 200 Mbbl.

Barge movements in the Northeast account for a much greater share of marine distribution than tankers for two reasons. First, many New England ports are not deep enough for tankers, nor are their turning basins large enough for larger tankers to turn around. Second, the current operating norm and competitive market dictate that primary suppliers keep their stocks at a minimum efficient level. This has forced storage facility operators to choose a "steady stream" of smaller distillates volumes from closer supply sources.[9] Since barges deliver smaller loads, are more nimble in tight ports, and can be loaded and unloaded faster than tankers, they have become the most important transport form in the Northeastern market.

[9] Petroleum Industry Research Foundation, Inc., *Distribution of Petroleum in the Northeast*, presentation on June 5, 1996, C. Trench.

Exhibit A-8

Distillate Movements In and Out of the Major New England and Mid-Atlantic Ports - 1994*

	Port	Imports (Mbbl)				Domestic (Mbbl)	
		Foreign	Canadian	Total		In	Out
1	Bucksport Harbor, ME	1,566	125	1,691		105	290
2	Penobscot River, ME	1,566	303	1,869		1,191	53
3	Searsport Harbor, ME	0	1,171	1,171		0	0
4	Portland Harbor, ME	1,382	5,817	7,199		26	0
5	Portsmouth, NH	3,843	1,777	5,619		1,586	46
6	Salem Harbor, MA	0	0	0		0	0
7	Boston Harbor, MA	11,429	5,218	16,647		9,488	6,962
8	New Bedford/Fairhaven Harbor, MA	0	0	0		513	72
9	Fall River, MA	0	0	0		0	0
10	Providence Harbor, RI	704	553	1,257		9,179	421
11	New London Harbor, CT	0	0	0		1,704	1,448
12	New Haven Harbor, CT	4,461	454	4,915		12,627	211
13	Bridgeport Harbor, CT	342	0	342		2,527	66
14	Hudson River, NY	0	0	0		6,633	237
15	Port of Albany, NY	0	0	0		7,567	197
16	Tarrytown Harbor, NY	0	0	0		322	0
17	Port of New York, NY	8,732	1,875	10,607		31,229	43,810
18	New York Harbor, NY	8,738	1,882	10,620		32,150	4,494
19	Newark Bay, NJ	46	7	53		0	0
20	Port Jefferson, NY	0	0	0		4,744	13
21	Hempstead Harbor, NY	0	0	0		980	0
22	Delaware River – Trenton, NJ	770	0	770		1,402	0
23	Trenton Harbor, NJ	0	0	0		99	0
24	Philadelphia Harbor, PA	901	0	901		5,132	5,323
25	Delaware River – Philadelphia, PA	1,099	809	1,908		3,580	19,398

Source:

Army Corps of Engineers Waterborne Commerce Statistics Center, 1994.

<u>Transport Mode: Pipelines</u>

The second component of the inter-regional transport network is the pipeline system that carries distillate and other products to the Northeast from Gulf Coast refiners. The Colonial Pipeline system carries 1,000 thousand barrels per day (Mbbl/d) from PADD III to its terminus in the Linden-Newark-Bayonne, New Jersey area.[10] It does not have a direct connection to the New England market. However, barges do ship some of the piped products to New England's ports after it arrives in New Jersey.

Intra-regional Distribution System

Once distillate is unloaded from a barge, tanker, or the Colonial Pipeline system, it is placed in primary storage terminals. Distillate is held in these facilities until it is either purchased by another primary storage operator or a secondary dealer, who would then sell the product to its customers. The intra-regional distribution system, which handles distillate once it arrives in the Northeast, utilizes

*Boston, MA includes: *Main Waterfront, Chelsea River, Mystic River, and Weymouth Fore River,* an area of approximately 47 sq. miles.
Port of New York includes: *Port Chester, East Chester, Flushing Bay & Creek, Hudson River Channel, East River, Newton Creek, Buttermilk Channel, Bay Ridge & Red Hook Channels, Gowanus Creek Channel, Coney Island, East Rockaway Inlet, Jamaica Bay, Raritan River, Upper Bay New York Harbor, Hackensack River, Passaic River, and New York and New Jersey Channels.*

[10] The 1,000 Mbbl/d capacity is the nominal daily distillate flow.

several transport modes. These transport modes, which include barges, pipelines, trucks, and rail, play a critical role in completing the distillate distribution process.

Transport Mode: Marine

Marine movements account for the largest amount of intra-regional distillate distribution for two reasons. First, the relatively small pipeline system serving New England is not connected to the Colonial Pipeline. Second, the sheer amount of coastline this region has gives it a comparative advantage to using marine as the primary transportation mode compared to other areas of the U.S. Why build expensive pipeline systems, when barges that are relatively inexpensive to own and operate can take advantage of the surrounding waters? Exhibit A–6 (described earlier) shows how petroleum products moved throughout New England, New Jersey, and New York in 1994. According to the Army Corps of Engineers data, 38 percent of the movements depicted in Exhibit A–6 are among the Northeastern states.

Transport Mode: Pipelines

As mentioned above, New England does not have an extensive intra-regional pipeline system. New Jersey and New York, however, are able to satisfy much of their inland demand with pipelines. The massive Colonial system from PADD III ends in northern New Jersey, while central and western New York are served by the Buckeye Pipeline system.

The Colonial Pipeline's terminus is where the Buckeye Pipeline begins. It connects to the Colonial system in the Linden-Newark-Bayonne, New Jersey area. From there it moves product into the metropolitan New York and Long Island areas on a lateral line, and west into Allentown, Pennsylvania, on a major line. From Pennsylvania the Buckeye is joined with two other major product lines. The three lines then move petroleum products throughout western and central New York state.

The Buckeye Pipeline's connection to the Colonial system in New Jersey moves on average 276 Mbbl/d outbound to Pennsylvania, between 50 and 100 Mbbl/d to western and central New York, and supplies much of the metropolitan New York market. It is a key component in linking Northeast markets with the PADD III refining centers.

The New England market is not connected to the Colonial Pipeline, but it is served by three pipeline systems that originate in New Haven, CT, Providence, RI, and Portland, ME. The largest is the Jet Lines Pipeline (owned by Buckeye). It extends from New Haven, CT, through Hartford, and ends in the Springfield, MA area. It moves between 10 and 35 Mbbl/d depending on the season and demand. There are two Mobil Oil Corporation lines that deliver products into Maine and Rhode Island. These lines transport a combined capacity of 30 Mbbl/d. The East Providence, RI to Springfield, MA area line moves approximately 20 Mbbl/d, while the Portland to Bangor, ME line delivers 10 Mbbl/d.

Transport Mode: Truck and Rail

In terms of distributing distillate between primary storage facilities, truck and rail movements are limited compared to those by marine, because it is cheaper to transport via barge or tanker. Once distillate is sold to a secondary dealer, however, it is, according to industry sources, typically loaded into the dealer's truck at a primary storage facility rack. The dealers will either put the distillate in their own storage facilities, keep it in their trucks, or bring it directly to their customers.

As mentioned, marine shipments distribute the majority of distillate to primary storage facilities throughout most of New England. In Vermont, however, this is not the case. Since it is the only New England state that does not have a coastal port, it relies on tanker trucks and rail cars to bring in distillate from Montreal, Albany, NY, Springfield, MA, and Portland, ME. While barges can come up the Hudson River from New York Harbor, or down from Canada, industry contacts maintain that more Vermont distillate is distributed via rail and truck.

Vermont's rail usage has recently expanded and its growth is expected to continue. There are four major rail companies in Vermont. A rail tank car can carry between 550 and 720 barrels of distillate.

Four new rail terminals have been built in Vermont and on its New Hampshire border in the last several years, and there are plans to build three more. These seven "orbits" will add a total of 67 Mbbl of storage, and are expected to have approximately 715 Mbbl in annual sales. The new facilities are part of intra-industry cooperation led by a Middlebury, VT based wholesaler. Other firms involved include a major rail shipping company out of Vermont, and a refining company from Quebec.[11]

The reemergence of rail transports in Vermont has been well received for various reasons. According to industry representatives, environmental regulations make it increasingly expensive to maintain on-site storage and haul petroleum on the state's highways, and, retailers are pleased to pick up their distillate at strategically located rail terminals. Furthermore, the railroad serves as a mobile pipeline system; distillate can be transported relatively quickly and in varying quantities.

Unfortunately, data on the intra-regional transport system, particularly for truck and rail movements, are limited compared to the transportation modes described in the inter-regional system. However, interviews and telephone conversations with various industry sources all concur that, in New England, trucks move more distillate from the primary storage facilities to the secondary sector than pipelines and railways. Distillate movements between primary facilities, however, is mostly carried out by barges.

Distribution Participants

Having reviewed the different modes of distribution, the discussion now turns to the organizations that make these systems work. The roles of distillate market participants have changed dramatically over the years. However, it is fair to say that the changes have affected the New England market more than any other. Given New England's isolation from domestic refining centers and its dependence on distillate versus the other space heating fuel, natural gas, (see Appendix C), it is apparent that changes in the distillate market would have a much greater effect on New England than the Middle Atlantic. Therefore, having compared the consumption and supply patterns, and explained how the two markets interdependently distribute distillate, the remainder of this appendix, unless otherwise noted, will focus on New England.

The players in the Northeastern distillate market are the wholesalers and the retailers, and they operate in two markets – the primary and the secondary. The wholesalers are sometimes referred to as bulk terminal operators, suppliers, or primary market dealers. They purchase distillate either in the spot or futures market, store the product in large primary terminals, and then sell it to retailers either

[11] These firms requested that their names be withheld from this report.

on a contractual basis or on a spot basis at the terminal's rack.[12] In the secondary market, retailers sell distillate to residential, commercial, and institutional customers – the tertiary market participants.

Primary Market: Wholesalers

Three types of companies are involved in the wholesale distillate market of the Northeast. They are independent wholesalers, securities firms/energy traders, and major integrated oil companies. Each of these groups are described below.

Primary Market: Wholesalers – Independents

There are four large independent wholesalers in New England and between 20 and 30 smaller ones. Sprague, Coastal, Global, and Northeast Petroleum account for nearly 80 percent of the total distillate sold in New England.[13] These wholesalers independently establish target inventories for each heating season. These inventories are functions of historical demand, spot/futures prices, weather forecasts, and interest rates. While target levels are set and maintained, wholesalers will purchase/sell distillate throughout the season, depending on the markets, weather, etc. Suppliers are not required to maintain minimum inventory levels, but will always have wet barrels on hand. Industry sources say that most participate in the futures market to hedge inventory or contract positions; however, it is not uncommon for some to act as speculators.

Primary Market: Wholesalers – Traders

Securities firms/energy traders (e.g., Morgan Stanley, Basis, Cargill, etc.) are in the distillate market when they believe they can safely make money. They usually do not own tankage, but will lease it from either another wholesaler or a terminal operator like Wyatt Energy in New Haven, CT, that only provides storage and does not take ownership of any products.

Primary Market: Wholesalers – Integrated Oil Companies

The third group of wholesalers are the integrated oil companies (e.g., Mobil, Tosco, Amerada Hess, etc.). Interviews with industry officials suggest that as environmental regulations increase and profit margins fall victim to higher competition, this wholesale group has taken dramatic steps to change their role in the New England distillate market. It was once common for the majors to fill their storage terminals in New England with products they shipped from their refineries in either the Middle Atlantic or PADD III. Then they would distribute their distillate to the retailers with which they had established annual contracts or lines of credit.

Today, market transparency and aggressive marketing are causing retailers to put pressure on suppliers and brand loyalty has diminished. Retailers are now looking at nine or ten wholesalers, rather than one or two. The slimmer margins resulting from the increased competition, and environmental regulations, have forced many major integrated companies to leave the New England market. For example, Shell, ARCO, Texaco, and British Petroleum have sold, or are selling, their facilities.

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[12] Normally, retailers will purchase distillate both at the rack and on a contractual basis throughout the year.

[13] Interview on Jan. 21, 1996 with Jack Sullivan, EVP and CEO of the New England Fuel Institute.

Primary Market: Wholesale Storage Facilities

Primary storage facilities, or bulk terminals, are the initial receipt points for distillate entering the Northeast. Terminal operators are either large integrated oil companies like Mobil or Exxon, tankage for hire companies like Wyatt or GATX, wholesalers like Sprague Energy or Global Petroleum, or trading firms like Morgan Stanley or Cargill.

In the Northeast there are two types of storage terminals: marine and pipeline. Marine terminals consist of docks, oil unloading facilities, oil storage tanks, and facilities for loading oil into transport for delivery to other locations. The major Northeastern pipeline terminals (Colonial in Linden, NJ and Jet Lines in New Haven, CT) are similar – they too have shipping docks, connecting themselves to the marine distribution system. Terminal operators facilitate the transfer of distillate from the primary to the secondary sector. Their inventories supply the market, and buffer it against expected or unexpected demand changes.[14] This is especially important in the unpredictable markets of the Northeast.

Wholesalers usually begin to build distillate inventories in April or May by purchasing domestically refined distillate or importing it. They begin drawing down stocks at their peak levels in October and continue through February or March. There are two major characteristics that distinguish primary storage facilities from secondary:[15]

- Bulk terminals have at least 50 Mbbl of storage capacity, while secondary storage facilities have less than 50 Mbbl.

- Bulk terminals are integrally connected to import facilities or refineries through large volume transportation systems like pipelines, barges, and/or ships.

Appendix B provides a state by state review of the Northeastern primary storage facilities and their respective capacities.

Primary Market: Changes in Wholesale Storage Facilities

In the 1996 – 1997 heating season primary stock drawdowns supplied much less distillate to the Northeastern markets than in other recent years, because inventories were considerably lower than usual. At the end of September 1996, total U.S. distillate stocks were 2,400 Mbbl below the 3-year average September level, and this shortfall was entirely in PADD I.[16] July is historically the biggest distillate stock building month of the year. The average build over the last three years for PADD I has been about 12,000 Mbbl; July 1996 was less than half of that level at 5,000 Mbbl.[17] As Exhibit A–9

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[14] Energy Information Administration, *Petroleum Marketing Monthly*, "Recent Distillate Fuel Oil Inventory Trends: What EIA Data Show," June 1996, Griffith.

[15] Ibid.

[16] Energy Information Administration, *Petroleum Marketing Monthly*, "Distillate Fuel Oil Assessment for Winter 1996-1997," September 1996, Cranston.

[17] Energy Information Administration, *Petroleum Marketing Monthly*, "Recent Distillate Fuel Oil Inventory Trends: What EIA Data Show," June 1996, Griffith.

demonstrates, the utilization rates for New England bulk terminals have declined from 91.2 percent utilized to 60.6 percent over the 1994 – 1996 period.

Exhibit A–9
Primary Storage Utilization Rates of New England
(1994-1996)

State	Distillate Capacity (Mbbl)	Distillate Stocks (Mbbl) (Oct. 1994)	Percent Utilized	Distillate Stocks (Mbbl) (Oct. 1995)	Percent Utilized	Distillate Stocks (Mbbl) (Oct. 1996)	Percent Utilized
CT	4,685	4,361	93%	4,185	89%	2,367	51%
MA	4,876	4,876	100%	4,582	94%	3,717	76%
ME	1,785	1,369	77%	1,181	66%	1,123	63%
NH	1,451	1,201	83%	1,068	74%	734	51%
RI	1,631	1,454	89%	1,132	69%	862	53%
VT	163	52	32%	37	23%	45	28%
TOTAL	14,591	13,313	91%	12,185	84%	8,848	61%

Source:
Department of Energy

The Energy Information Administration offers the following factors to explain what might have contributed to this low level of distillate stocks in the 1996 – 1997 heating season:[18]

- A late cold spell in April 1996 drove distillate demand to higher levels than normal. Additionally, because of robust economic growth, demand for diesel was higher than normal, causing stock building to be lower in the summer than would otherwise be expected.
- Higher prices in Europe caused U.S. refiners to export more distillate than normal.
- Backwardation in the futures market for both crude and distillate discouraged market participants from holding large inventories. Because future prices for winter were lower than summer spot prices, there was little incentive for those with storage capacity to hold more distillate than the minimum required to satisfy known demand.

Chapter 3 of this report examines the role of backwardation in the distillate futures market in keeping 1996 – 1997 distillate inventories at lower than normal levels.

There is also anecdotal evidence that suggests costly regulatory mandates might have reduced storage capabilities. Sources in industry say that the Underground Storage Tank (UST) Program, the Oil Pollution Act (OPA), and the Clean Air Act Amendments (CAAA) of 1990 have all contributed to the reduction of storage capacity and lower inventory levels.

The UST Program was enacted as part of the Resource Conservation and Recovery Act (RCRA) in 1984. Its objectives are to: (1) identify existing underground facilities and bring them up to a stringent criteria or have them closed; (2) ensure that all new facilities meet strict design and operating

[18]Energy Information Administration, *Weekly Petroleum Status Report*, "Distillate Fuel Oil Assessment for Winter 1996-1997," September 1996, Cranston.

standards; (3) require operators to thoroughly report, investigate, and cleanup releases from UST; and, (4) set the financial responsibility requirements for those who own/operate petroleum UST.[19]

The Oil Pollution Act of 1990 (OPA) is really a product of 20 years of congressional debate on pollution issues. While the UST Program regulates a specific type of storage, OPA is much more comprehensive and stringent. It makes all owners/operators of storage facilities and vessels responsible to direct and manage all oil spill clean up operations. Since the beginning of 1993, all vessel and facility operators have been to file detailed oil spill response plans.[20]

The CAAA of 1990 became effective in 1993. They reduced the fungability of fuels, which industry sources say complicated storage capabilities in the Northeast. The requirements outlined in the CAAA have played a role in increasing the number of discreet storage facilities and lowering inventory levels for each distinct fuel type. Prior to 1993, heating oil and diesel fuel had been stored together because of their similar specifications. Inventory planners could base target levels on combined diesel and heating oil demand. Unexpected demand for either product could be easily pulled from the common inventories and production streams. With segregation, however, this is no longer possible,[21] and a single tank storage facility must be dedicated to one fuel or the other. Since distillates must be now separated, more tank capacity is needed to maintain a minimum operating inventory.

Secondary Market: Retailers

There are approximately 2,500 distillate retailers in New England. They provide distillate and (usually) services for residential, institutional, and commercial customers. Massachusetts has the most with close to 1,100; Connecticut is second with about 770; Maine has a little over 300; Rhode Island has 250; and finally, Vermont and New Hampshire have between 100 and 150 each. According to industry sources, the number of dealers in New England has not really changed in the last several years. The number of owners, however, has decreased and the characteristics of the average secondary marketer have changed. Anecdotal evidence suggests that competition has grown fiercer as large "discount" companies are purchasing small family-run businesses established more than forty years ago.

According to a survey in *Fuel Oil News 1996 Marketer Profile*,[22] the number of service providing distillate marketers has decreased. This further substantiates the industry move away from the "mom-and-pop family business" toward a more specialized, efficient but impersonal operation. Compared to the rest of the country, New England still has the largest share of marketers who sell, install, and/or service all types of heating oil equipment. More than 75 percent of those marketers surveyed said they provide services. This, however, is 15 percentage points below the 1991 survey. Exhibit A–10 provides some characteristics of the New England and Middle Atlantic distillate retailers.

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[19]*Environmental Law Handbook*, p. 77, Sullivan (Editor), Government Institutes, Inc., Rockville, MD, 1995.

[20]Ibid., p. 169.

[21]Energy Information Administration, *Weekly Petroleum Status Report*, "Distillate Fuel Oil Assessment for Winter 1996-1997," September 1996, Cranston.

[22]The *Fuel Oil News*, December 1996. pages 14-30. The *Fuel Oil News* is published monthly by Premiere Publishing Inc., East Lansing, MI.

Exhibit A-10

Average Size of New England and Middle Atlantic Distillate Retailers - 1996

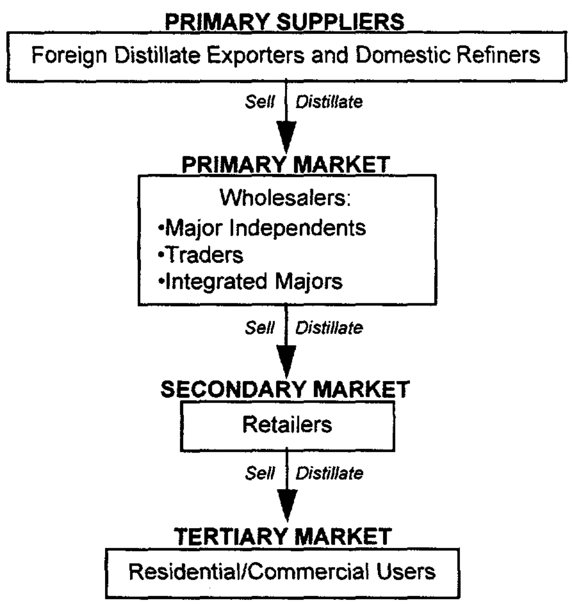
	No. of Residential Accounts	No. of Industrial/ Commercial Accounts	No. of Employees	Gallons of Heating Oil Sold	Gallons of Gasoline Sold	Gallons of Diesel Sold
New England	1,443	380	14	2,084,573	2,726,555	856,383
Middle Atlantic	1,830	164	10.5	2,129,250	1,915,714	555,600

Source:

Fuel Oil News, December 1996

Having reviewed who the market participants are and the facilities they use, Exhibit A–11 graphically depicts where each fall in the distribution process. Wholesalers in the primary market import distillate or purchase it from domestic refiners. Storage facilities hold the distillate until it is sold to another primary wholesaler or is purchased by retailers in the secondary market. Retailers then distribute the product in the tertiary market where it is consumed.

Exhibit A–11
Distillate Distribution Participants in the Northeast –



From the Primary Suppliers to the Tertiary Market

Purchasing and Selling Distillate

Until several years ago, much of the industry was based upon contractual relationships. It was once commonplace for retailers to have annual contracts with no more than two suppliers; wholesalers would establish close relationships with the retailers in order to maintain their business each heating season. Today, however, local dealers have market tracking monitors to check either the rack price in New Haven or the 3 months futures price on the New York Mercantile Exchange (NYMEX). Retailers have grown to be much more sophisticated players in the market. They demand better prices from wholesalers forcing the market to be more transparent. Additionally, participants say No. 2 heating oil has become more commoditized, making it increasingly difficult for the wholesaler to add value through services. Coupled with the environmental mandates, these factors have led to consolidation at every level.

Wholesaler Purchase

At the end of each heating season (March or April), a wholesaler[23] will determine how much distillate will be required to meet market demand for the coming season. Normally, a target inventory level is set and is based on historical demand, spot/futures prices, weather forecasts, and interest rates. While target levels are maintained throughout the heating season, wholesalers are constantly adjusting them in accordance with the same factors that determined the target levels in the beginning (e.g., demand, futures/spot prices, weather, etc.).

Industry sources say that the major independent wholesalers import most of yhe distillate they purchase. For example, about 90 percent of the distillate that passes through Sprague Energy's 3,000 Mbbl of storage capacity in northern New England comes from either Canada or Venezuela. Most imported distillate is purchased through the futures market while domestically produced distillate is typically bought on the spot market.

Integrated oil companies will either import distillate, contract for delivery via the futures market, or use their own refined products to supply retailers. Ten or 15 years ago, these oil companies were vertically organized throughout the New England market. As described earlier, they would ship their refined products up from the Middle Atlantic or PADD III and store them in their New England facilities. Today, few integrated oil companies in New England own their own storage facilities and even fewer maintain inventories like they did in the past. While they still have annual supply contracts with local retailers, there is too much risk for these companies to fill tanks unless risk can be hedged using futures or options.

Retailer Purchase

A typical heating season for a local New England retailer begins in March. Retailers will determine the demand much like wholesalers do – with historical demand, prices, weather, etc. Contracts with wholesalers are set up for the upcoming season. Industry sources maintain that these account for about 30 percent of the total distillate purchased in a season. The rest of the volume will be either be purchased in the spot market, through other contracts later in the season, or at the rack, depending on the same factors that determine seasonal demand. Exhibit A–12 depicts the results of a 1994 survey conducted by the Petroleum Marketers Association of America (PMAA).[24] It shows the breakdown of how retailers throughout the country purchase distillate.

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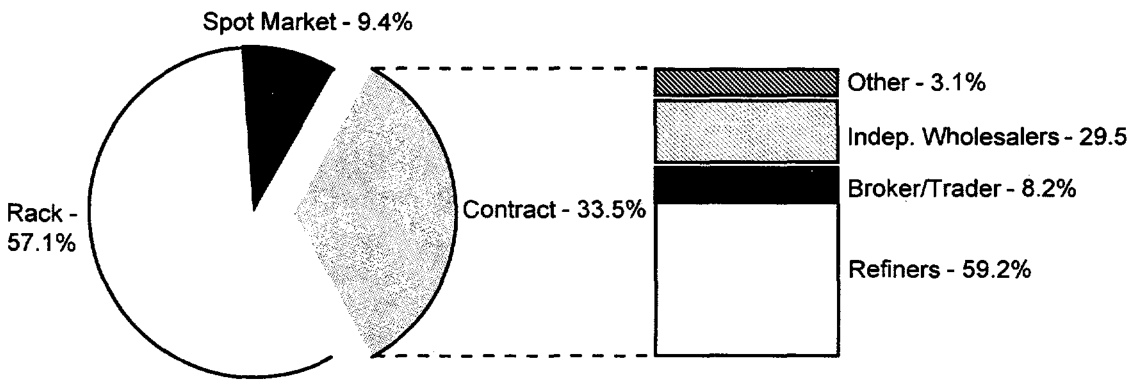
[23] The term "wholesaler" will refer to an independent wholesaler (e.g. Sprague Energy), unless otherwise noted.

[24] Petroleum Marketers Association of America, *1994 Heating Oil Market Review*, November 1994, Hornbeck.

According to the survey over half of total distillate purchases were made at truck loading racks. A little more than 9 percent were spot market transactions and almost 34 percent were made under some type of contract. Most contract purchases were made through refiners. Almost 30 percent were through independent wholesalers and operators. Brokers accounted for just over 8 percent and "other" sources made up the remaining purchases. The results of this survey are for the entire U.S.. After speaking with New England retailers and wholesalers, the share of contracts refiners have in New England is much lower than the PMAA's 59.2 percent, and the share the independents have is much higher than the reported 29.5 percent. The contract breakdown is probably more like 65 percent through the independents, 27 percent through the major refining companies, 5 percent through marketers, and 3 percent through "other" sources.

Exhibit A–12
Retailer Distillate Purchases by Source



Source:

Petroleum Markerters Association of America, *1994 Heating Oil Market Review*, November 1994, Hornbeck.

Exhibit A-13

Percentage Breakdown of 1996 Retail Heating Oil Sales in the Northeast

	Private Homes	Apartments	Institutional Facilities	Commercial	Industrial
New England	88.5%	7.6%	0.0%	3.3%	0.3%
Middle Atlantic	89.4%	5.5%	0.3%	3.6%	0.6%

Source:

Fuel Oil News, December 1996

Customer Purchase

As Exhibit A–10 points out the average distillate retailer in New England sells almost 50 Mbbl each year. On average, private homes purchase more of this distillate than any other customer type. Below, Exhibit A–13 breaks down the average retailer's business by customer, according to the *Fuel Oil News 1996 Marketer Profile*.

Retailers offer their customers a variety of supply contracts for each season. They typically offer price protection plans and posted price plans. The most common price protection plans are those that offer a capped price to the customers. Retailers will not charge above the capped price for the entire heating season. Other protection programs include fixed price plans which enable consumers to purchase all their distillate for the season or each month at a fixed price. How much they contract for is dependent on historical usage. Any balances remaining at the end of the season are settled between the customer and the retailer. Customers who enroll in posted price plans simply purchase their distillate at the retailers' posted price. Changes in the posted prices depend on the wholesale price. That does not mean retailers are changing their prices as often as wholesalers (which can be hourly). Retailers claim to be fair to their customers, absorbing as much of the volatility in wholesale prices as they can.

According to the *Fuel Oil News 1996 Marketer Profile*, 34.5 percent of New England retailers offer price protection plans, 45.5 percent in the Middle Atlantic.

CONCLUSION

The Northeast distillate markets are characterized by their extraordinary level of demand compared to other parts of the U.S. and their intricate distribution systems. Marine movements not only enable them to meet their needs, but also provide an international hub for petroleum product distribution. The market players have been able to adapt to expensive environmental mandates that most industry officials will say are the cause to lower levels of storage capacity. They have also been able to tailor their businesses to meet the demands of an increasingly transparent price structure and a much more competitive market. While the commoditization of distillate has slimmed profit margins and increased industry consolidation, it has also made the Northeast markets more resilient and efficient.

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Appendix B

New England Fuel Oil Storage Capacities and Inventories

Prepared by:

ICF Kaiser International, Inc

APPENDIX B

NEW ENGLAND FUEL OIL STORAGE CAPACITIES AND INVENTORIES

Appendix B provides a detailed look at bulk terminal storage facilities in the Northeast. Exhibits B–1 through B–6 breakdown each state's storage capacities by city and operator. These exhibits show what kind of business the operator runs for each terminal (i.e., leased to other parties, or private use); what types of petroleum products it handles; the number of storage tanks a terminal has; the total terminal shell capacity; and, finally, the terminal's total fuel oil shell capacity.

The data contained in these exhibits are based upon a variety of sources, including: the Energy Information Administration/Department of Energy publications, the U.S. Army Corps of Engineers *Port Series Report 1994*, the Stalsby/Wilson *Petroleum Terminal Encyclopedia*, the Independent Liquid Terminals Association, and the Waterborne Terminal Registry. The data are also based upon conversations and interviews with contacts in the Northeast bulk terminal industry.

Exhibit B–7 depicts each of the New England states inventory levels, except Vermont, as submitted to the Energy Information Administration. The data are monthly for a total period of five years and are in thousands of barrels. The graphs give an indication of how inventory levels for the 1996 – 1997 heating season were quite low compared to other years.

CONNECTICUT						
Facility Location	Facility Operator	Type Storage Business	Products Handled	Storage Tanks	Total Terminal Capacity	Total Fuel Oil Capacity
Stamford	Hoffman Fuel	Private/Closing	No2	6	523,810	523,810
	Sprague Energy	Private	No2	6	57,000	57,000
	Inland Fuel Term	Private	No2	5	38,000	38,000
New Haven	NHT (Waterfront)	Lease	No2/Jet/Chem	31	804,900	500,000
	NHT (E Haven)	Lease	No2/Gas	12	1,750,000	1,038,300
	Wyatt (E Street)	Lease	No2/Asphalt	22	1,448,800	863,800
	Wyatt (Waterfront)	Lease	No2/Gas/Dsl/Kero	16	768,850	294,700
	Wyatt (Hamden)	Lease	No2	11	1,180,614	1,180,614
	Northeast	Private	No2/Dsl/Gas/Kero	21	1,768,700	600,000
	Coastal Oil	Private	No2/No6/Asphalt	7	630,000	270,000
	Gulf Oil	Private	No2/Dsl/Kero	13	580,000	184,000
	Getty Term.	Private	Gas	3	84,000	0
	Q-River Term.	Private	No2/Asphalt	7	178,800	83,800
	Mobil Oil	Sale Pending	No2/Gas/Kero	15	585,550	0
	Amerada Hess	Private/Lease	No2/No6/Gas/Dsl	18	357,000	250,000
	E Coast Environ	Private	Jet	7	92,100	0
	Connecticut Refg	Inactive (3/95)		5	65,000	0
Hartford	Sprague	Private	No2	5	90,000	90,000
Bridgeport	Shell Oil	Private/Others	No2/Gas	13	1,280,000	500,000
	Harborview Term	Private/Others	No2/Dsl/Asphalt	4	207,000	98,000
	Consumer Petro	Others	No2/Dsl/Gas	6	110,000	44,000
	Hoffman Fuel	Private	No2	8	88,500	88,500
	Inland Fuel Term	Private	No2	4	31,000	31,000
Connecticut River	Amerada Hess	Private/Lease	No2/Gas/Dsl/Kero	8	243,000	180,000
	Star Enterprise	Inactive	No2/Gas	8	190,500	190,500
	Vinci Coal	Inactive/For Lease		8	190,000	190,000
	Citgo Petroleum	Leased	Gas Blending	4	181,000	0
	Northeast	Private	No2/Dsl/Kero	8	180,500	110,000
	B&B Petroleum	Private/Others	No2/Dsl/Kero	9	131,000	95,000
	Chevron	Private	Asphalt	7	70,000	0
	Peterson Oil	Dismantling		4	46,500	0
New London	Amerada Hess	Lease	No2/No4/No6	11	835,000	630,000
	Lehigh Oil Co	Retail	No2	5	71,000	38,000
	City Coal Co	Retail	No2/Dsl	7	57,000	57,000
TOTAL					**14,915,124**	**8,226,024**

MAINE						
Facility Location	Facility Operator	Type Storage Business	Products Handled	Storage Tanks	Total Terminal Capacity	Total Fuel Oil Capacity
Portland	Koch Industries	Private/Lease	No2/Jet	29	525,000	225,250
	Sprague Energy	Private	No2/Gas/Dsl/Kero	20	974,000	690,000
	Sprague (Exxon)	Closed		10	829,000	0
	Northeast	Lease	No2/No6/Kero	11	500,000	165,000
	Mobil Oil	Private	No2/Gas/Dsl/Jet	19	722,000	178,300
	Star Enterprise	Private/Lease	No2/Gas/Dsl	12	838,503	230,000
	Gulf Oil	Private	No2/No6/Gas/Dsl	9	758,018	97,000
Searsport	Irving Oil	Private	No2/No6/Jet/Gas	15	1,500,000	150,000
	Sprague Energy	Private	No6	4	383,932	0
	Tenco Services	Inactive		8	1,500,000	
Bucksport	Webber Tanks	Private	No2/Dsl/Jet/Kero	7	778,000	450,000
	Sprague Energy	Private	No6	5	399,200	0
	Eldon Corp	Inactive			166,000	
Bangor	Mobil Oil	Private	No2/Gas/Dsl	12	112,400	23,200
TOTAL					**9,986,053**	**2,208,750**

MASSACHUSETTS						
Facility Location	Facility Operator	Type Storage Business	Products Handled	Storage Tanks	Total Terminal Capacity	Total Fuel Oil Capacity
Salem	Northeast	Lease	No2/No6	3	340,000	130,000
Revere	Coastal Oil	Private	Gas/No2	23	1,400,000	784,000
	Global	Private	Gas/No2	7	520,000	120,000
	Northeast	Private	Gas	6	310,000	0
	Tosco	Private	Gas/No2	11	752,615	270,000
Chelsea	Coastal Oil	Lease	No2/Asphalt	7	277,000	166,000
	Global	Private	No2/No6	14	692,500	317,000
	Gulf Oil	Private	No2/Gas/Jet/Kero	18	1,392,600	210,000
	Northeast	Private	No2	3	285,000	285,000
Everett	Exxon USA	Lease	Gas/No2/No6/Asphalt	49	2,748,200	975,000
E. Boston	Amerada Hess	Closed		10	595,250	
	Mobil Oil	Private	Gas/Dsl/Jet	29	1,238,000	0
S. Boston	Coastal Oil	Private	No2/No6/Jet	26	2,292,000	960,000
E. Braintree	Citgo Petroleum	Private	No2/Gas/Dsl	18	1,259,000	300,000
Weymouth	Sprague	Private	No2	3	400,000	400,000
	Quinoil Ind.	Private	No2/No6/Dsl/Kero	12	672,000	210,000
Fall River	Shell	Closed	Gas/No2	6	500,000	200,000
New Bedford	Global	Private	No2/No6	4	190,000	50,000
Sandwich	Northeast	Private	No2/Dsl		103,000	75,000
Springfield	Mobil Oil	Private	Gas/No2/Dsl	11	283,000	88,700
	Wyatt Energy	Lease	No2/Dsl	2	69,360	50,850
TOTAL					**16,319,525**	**5,591,550**

NEW HAMPSHIRE/VERMONT						
Facility Location	Facility Operator	Type Storage Business	Products Handled	Storage Tanks	Total Terminal Capacity	Total Fuel Oil Capacity
New Hampshire						
Portsmouth	Northeast	Private	No2/Dsl/Jet/Kero	6	552,000	357,000
	Mobil	Dismantled		0	0	0
	Sprague Energy	Private	No2/No6	3	342,000	140,000
Newington	Sprague Energy	Private	No2/Asphalt	12	743,000	497,000
	DFSC	Closed	Jet	4	260,000	260,000
	Sprague Energy	Private	No2/Dsl/Kero	29	1,165,211	830,000
VERMONT						
Burlington	Mobil Oil	Private	No2/Gas/Dsl	15	403,500	176,700
TOTAL					1,828,711	1,266,700

RHODE ISLAND						
Facility Location	Facility Operator	Type Storage Business	Products Handled	Storage Tanks	Total Terminal Capacity	Total Fuel Oil Capacity
Providence	Sprague Energy	Private	No2/No6/Asphalt	10	807,000	310,000
	Northeast	Private	No2/Dsl/Kero	7	162,000	100,000
	Star Enterprise	Private/Others	No2/Dsl/Gas/Avg	25	1,685,313	500,000
	Sun R&M	Inactive		6	132,000	
	Citgo Petroleum	Private/Others	No2/Gas	13	440,000	200,000
E. Providence	Capital Property	Inactive	No2/Dsl	4	342,000	342,000
	Getty Petroleum	Private	No2/Dsl/Gas	12	358,823	63,617
	Gulf Oil	Dismantled				
	Mobil Oil	Private	No2/Dsl/Gas	18	1,353,000	283,600
Tiverton	Inland Fuel	Private/Others	No2/Dsl/Kero/Me	9	614,000	400,000
TOTAL					**5,894,136**	**2,199,217**

NEW YORK/NEW JERSEY						
Facility Location	Facility Operator	Type Storage Business	Products Handled	Storage Tanks	Total Terminal Capacity	Total Fuel Oil Capacity
New York						
Staten Island	GATX	Lease	Gas/Dsl/Jet/No2	67	5,000,000	4,000,000
Staten Island	Mobil	Lease	Gas/Dsl/Jet/No2/No6		2,363,000	217,000
New Jersey						
Bayonne	IMTT	Lease	Gas/Dsl/No2/Chem	638	13,500,000	3,500,000
Carteret	GATX	Lease	Gas/Dsl/No2/Chem	41	5,000,000	1,000,000
Linden	Northville	Lease	Gas/Dsl	22	3,900,000	3,900,000
Linden	Citgo	Lease	Gas/Dsl	38	3,544,000	3,544,000
Perth Amboy	STOLT	Lease	Gas/Dsl/No2	90	2,200,000	1,400,000
Pennsauken	Citgo	Lease	Gas/Dsl/No2	16	1,000,000	1,000,000
Woodbridge	Amerada Hess	Lease	Gas/Dsl/No2/No6	17	5,000,000	2,100,000
					41,507,000	20,661,000
TOTAL					41,507,000	20,661,000

Exhibit B-7
Monthly Distillate Stock Levels in New England States

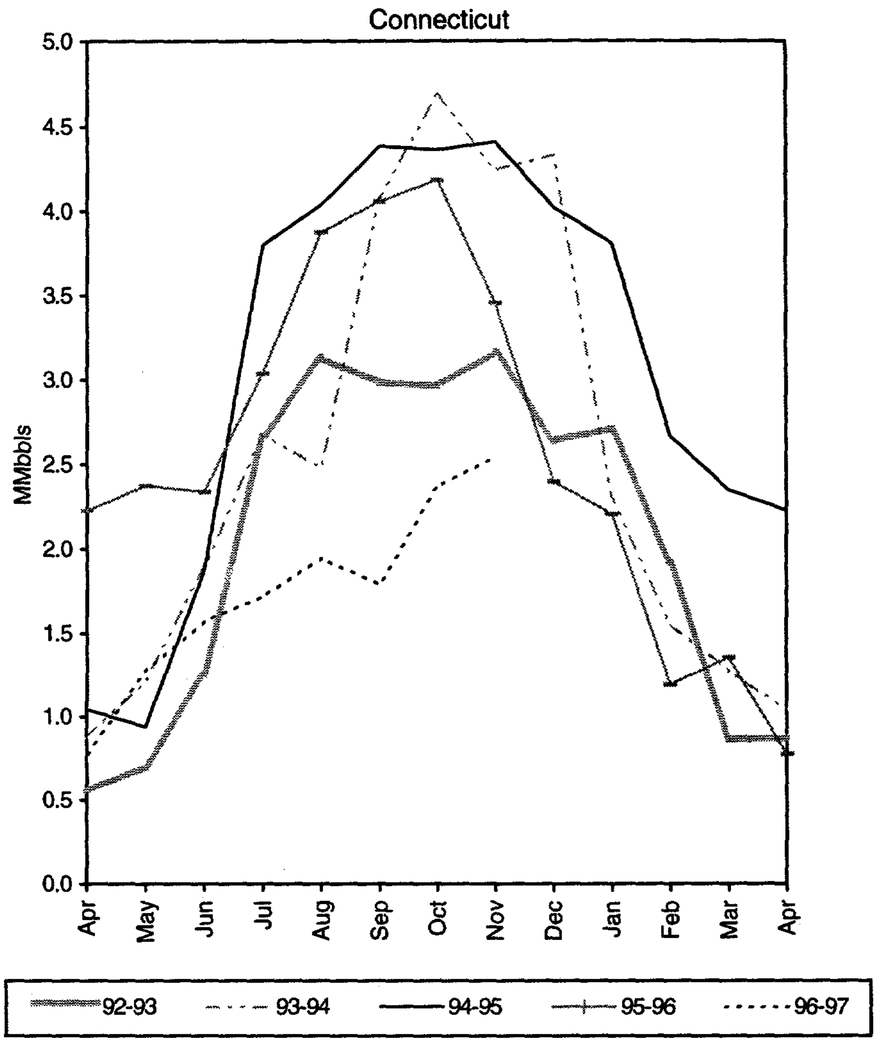


Exhibit B-7 cont.
Monthly Distillate Stock Levels in New England States

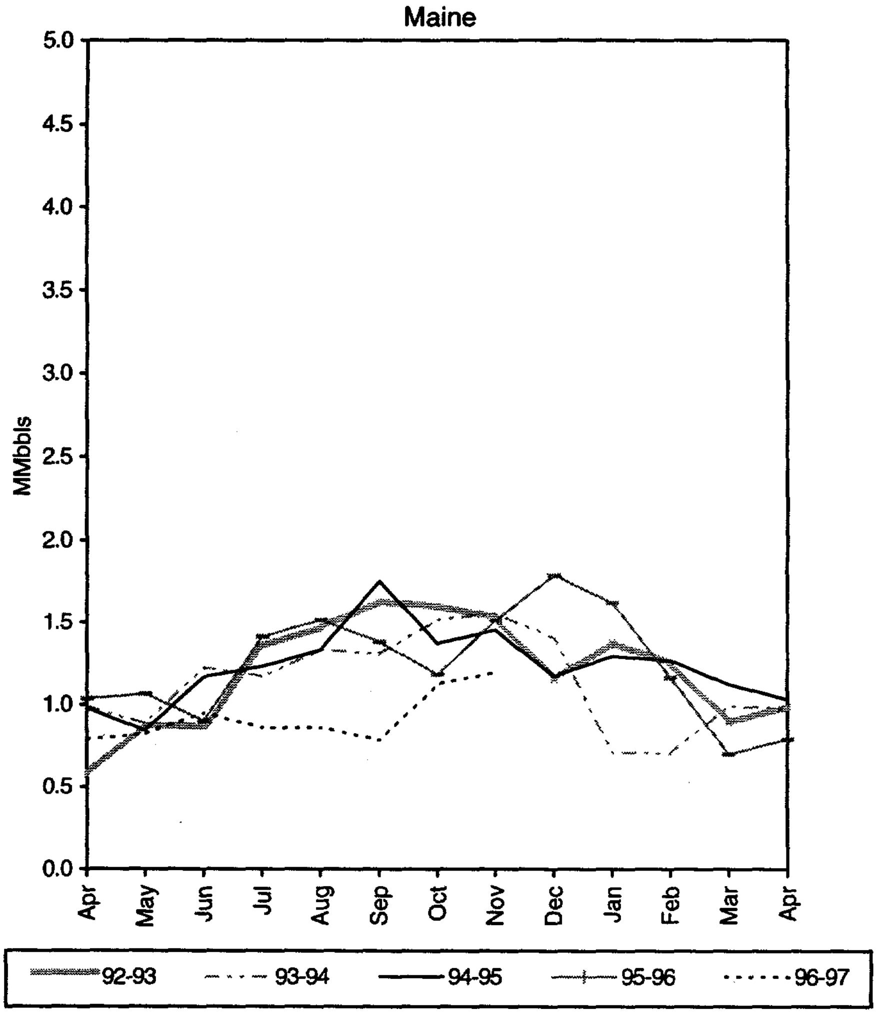
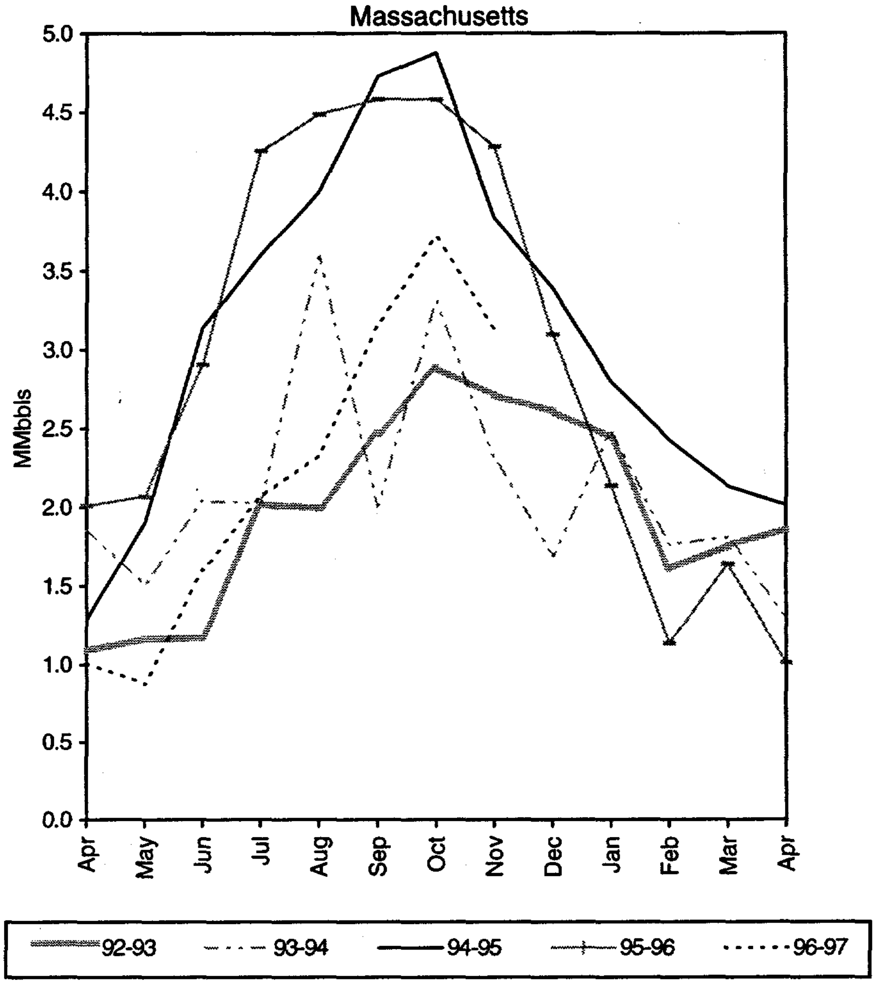


Exhibit B-7 cont.
Monthly Distillate Stock Levels in New England States



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Monthly Distillate Stock Levels in New England States

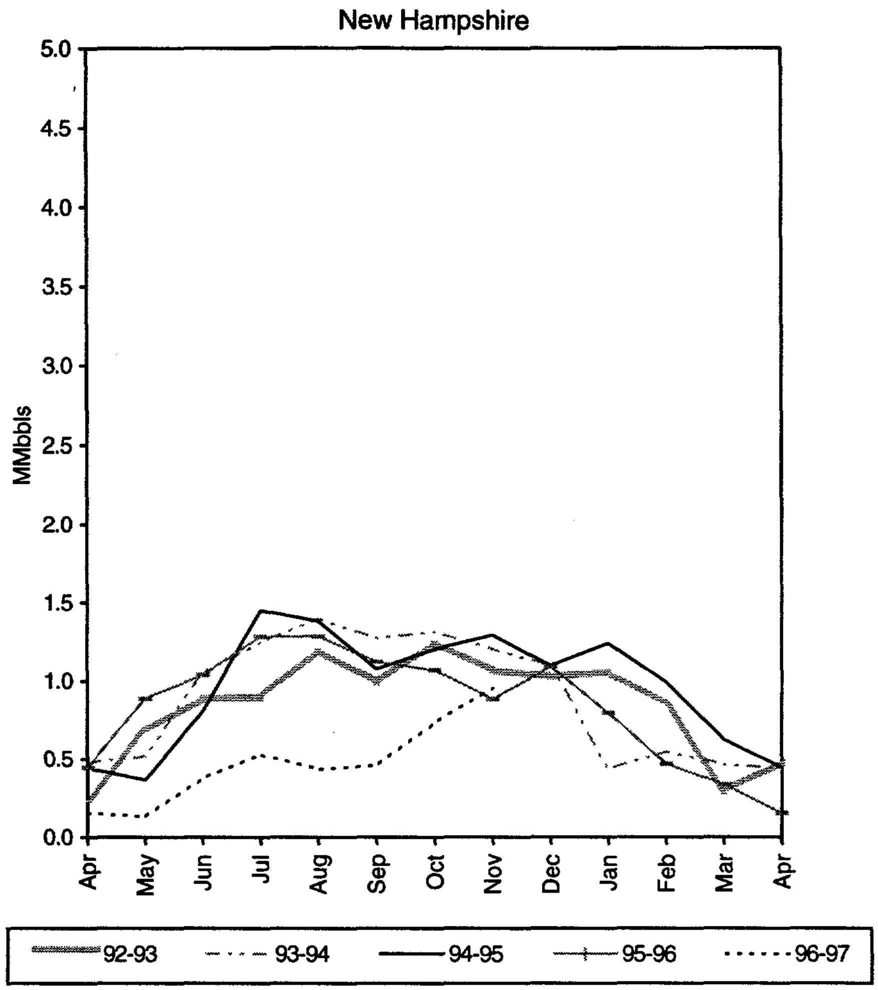
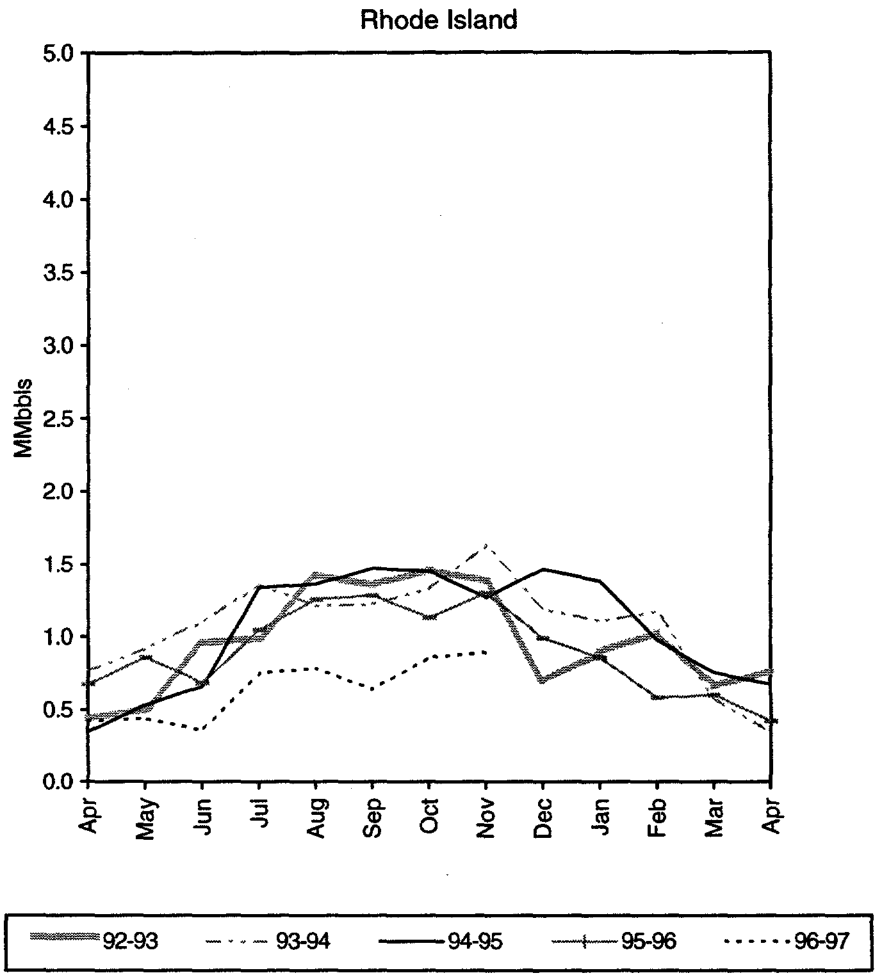


Exhibit B-7 cont.
Monthly Distillate Stock Levels in New England States



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Appendix C

Characteristics of the Northeast Natural Gas Market

Prepared by:

ICF Kaiser International, Inc

APPENDIX C

CHARACTERISTICS OF THE NORTHEAST NATURAL GAS MARKET

This report deals with the Northeastern region of the United States, but there are really two regional natural gas markets in this area. Gas market characteristics are quite different in New England compared to the Middle Atlantic states and compared to the rest of the U.S.[1] These differences affect the competitiveness of gas relative to fuel oils. This appendix describes the major gas market characteristics in the Northeast and the competition between gas and distillate fuel oil in that region.[2]

GAS COSTS IN NORTHEASTERN U.S.

Natural gas is substantially more costly in New England than in any other region of the U.S. In 1995 the average New England city gate price of gas paid by gas distribution companies was $3.71 per million Btu (MMBtu) or $3.82 per thousand cubic feet (Mcf).[3] The city gate price in the Middle Atlantic states averaged $2.80 per MMBtu and the U.S. average was $2.78. Residential gas consumers in New England paid an average of $8.80 per MMBtu while the average residential prices in the Middle Atlantic and total U.S. were $7.45 and $5.88 per MMBtu, respectively. Exhibit C-1 shows the costs of gas by consuming sectors for New England and Middle Atlantic states separately and combined for the years 1986 through 1995. Since the volumes of gas consumed in the Middle Atlantic sectors are four to five times those of New England, the combined Northeastern U.S. prices are much closer to the Middle Atlantic prices. Gas volumes consumed in these two Northeastern regions are described later in the section on competition between natural gas and distillate fuel oil.

Three factors combine to cause higher gas prices in the Northeast, relative to the rest of the U.S. These three factors are the greater gas transportation distance, the large seasonal changes in gas demand, and, for New England, the lack of suitable sites for underground gas storage. These three factors and their effects on gas prices are discussed below.

The Costs of Pipeline Distance

Both the fixed and variable costs of gas transportation by pipeline are functions of the distance the gas is moved. At an average distance of about 1,400 miles, gas deliveries to New England from its major U.S. sources are the longest in the nation.[4] The Middle Atlantic delivery distance, by comparison, is about 1,200 miles. This additional 200 miles to New England markets increases the pipeline investment that must be recovered in the capacity reservation (fixed cost) part of the

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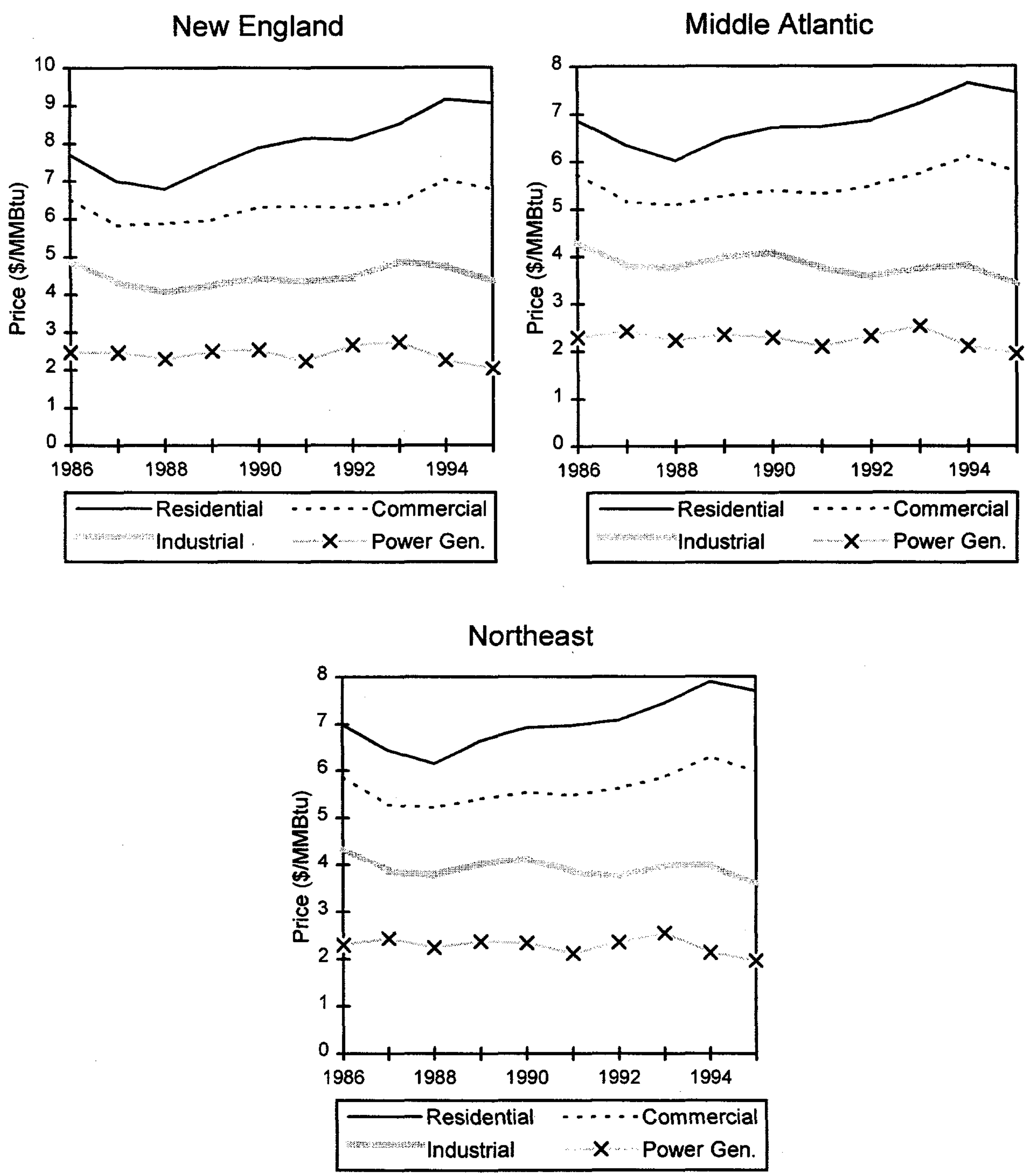
[1]Middle Atlantic states here are those included in PADD District 1a; Delaware, District of Columbia, Maryland, New Jersey, New York, and Pennsylvania.

[2]The terms distillate and distillate fuel oil in this report represent only home heating oil, or Number 2 heating oil.

[3]An Mcf and a MMBtu are near interchangeable for natural gas. A typical Mcf of natural gas contains about 1,030,000 Btu. Essentially all volume and price values for gas and distillate in Appendix C have been converted to MMBtu or $/MMBtu for ease of comparisons. Capacities of gas pipelines are stated as million cubic feet (MMcf) per day.

[4]Distances taken from South Louisiana to approximate geographic centers of gas consumption in New England and Middle Atlantic states.

Exhibit C-1
Natural Gas Prices in the Northeast by Consuming Sectors



Source:
DOE/EIA, *Natural Gas Annual 1991, 1996*

transmission tariff rates and increases the cost of compression required to move gas along the pipeline. Pipeline capacity must be reserved if deliveries are to be guaranteed in periods of maximum demand for pipeline capacity, such as during cold winter days. The tariff rate for firm (guaranteed) capacity from gas storage located in the Middle Atlantic region to New England on Tennessee Gas Pipeline, for example, is $0.40 per MMBtu, if the reserved capacity is fully utilized. Less than 100 percent usage of this transportation service raises the fixed capacity reservation part of this rate ($0.29 per MMBtu) in inverse proportion to the decline in use. The same company has a tariff rate to the New York City area of $0.28 per MMBtu, of which $0.17 is the fixed reservation charge.

An important part of understanding gas transportation economics is that the fixed pipeline costs must be paid whether or not the reserved capacity is used. Fixed costs for most gas pipelines typically represent over 80 percent of the total cost of moving gas. This means that the more fully a gas pipeline customer uses its reserved capacity, the lower the average cost of moving a unit of gas volume.

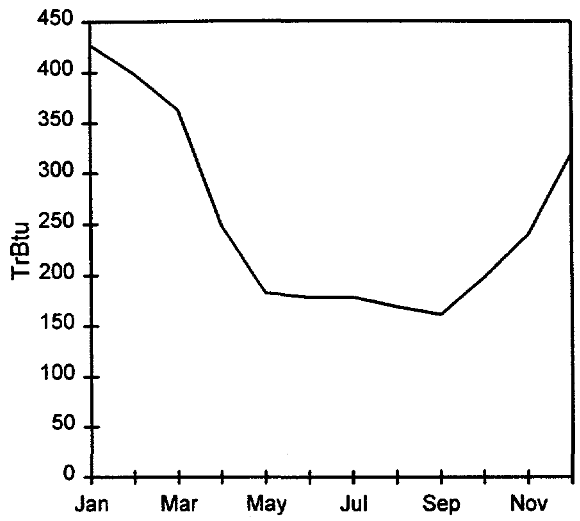
Although there are small gas supply sources closer to the Northeast, the price of gas from these areas tends to reflect the price of gas from the major supply areas that has been transported to the smaller supply areas. This arbitrage behavior is also seen in the pricing of western Canadian gas that travels much longer distances to reach markets in the U.S. Northeast. Gas producers in Canada are willing to accept the net back prices available to them from market prices in the Northeast.[5]

The Cost of Seasonal Gas Demands

Since large shares of gas consumption in all regions are for space heating, the seasonal changes in gas demand are relatively large in colder northern climates, including New England and the Middle Atlantic. In these two regions the peak monthly gas demand (usually January) is about 2.6 times the lowest monthly demand (usually July). Exhibit C-2 illustrates monthly gas consumption rates for the Northeast in 1994, showing the large difference in summer and winter gas use. If pipeline capacity were to be built to provide for the peak month, the annual utilization of the capacity could be as low as 50 percent. This means that the tariff required to cover fixed costs would be much higher than the rate that would be charged if the pipeline were to run full year round. Because of the high cost of providing pipeline capacity for peak periods, pipelines are normally built to supply demands closer to the average daily demand, and other supply sources are used to meet the colder days of winter. The major winter supplemental supply is gas withdrawn from underground storage located near the demand centers.

[5]Net back price is the gas producer price that results from subtracting gas transportation charges from a market area price.

Exhibit C-2
Monthly Gas Consumption in the U.S. Northeast



Source:
Oil & Gas Journal Database

Underground storage located near market areas can provide gas for two to three months in winter at a cost that is lower than that of an equivalent supply by long distance pipeline. This is possible because storage fixed costs are lower than those of pipelines for the same gas delivery rate, but the variable costs are higher. Storage also reduces the price of gas by making more use of the pipelines during summer when storage is refilled. The need to refill storage and the higher variable costs of storage limit the period during which storage is less costly then pipeline capacity.

To assure cold weather gas deliveries from market area storage, shippers must reserve capacity for a much shorter pipeline distance. This reduces the costs caused by cold weather, compared to providing long distance pipeline capacity. Underground storage is particularly useful in the Middle Atlantic region because of the short distances to major gas markets from storage facilities in New York, Pennsylvania, and West Virginia. New England does not have this advantage.

The Cost of Distant Storage

Most underground gas storage facilities are developed from depleted gas and oil reservoirs. The prior existence of commercial quantities of gas or oil in a rock formation indicates that a well sealed trapping mechanism exists and gas leakage should be minimal. Unfortunately, New England has not been blessed with such reservoirs and other possible reservoirs such as aquifers and mined caverns have not been developed. Thus, New England must depend on gas storage located in other regions. This means that pipeline capacity between the storage and market areas must be reserved for longer distances than those required for the Middle Atlantic and many other regions of the U.S. This adds to the cost of assuring winter gas supplies to New England.

Compounding the winter demand problem is the fact that peak day demands in New England and the Middle Atlantic may be three to four times average daily demand during a year. Purchasing guaranteed peak period deliverability from storage facilities and the shorter pipelines that connect them to gas markets is in many cases more costly than another supply source termed peak shaving. Peak shaving supplies are attractive for periods of only five to ten days because of their lower fixed costs and higher operating costs, compared to storage.

The two types of peak shaving gas in common use are liquefied natural gas (LNG) and mixtures of propane and air. Both are used by gas distribution companies in New England and the Middle Atlantic. Because of the longer distance to New England markets from storage areas, peak shaving is a larger share of winter supply than in other regions. Exhibit C-3 shows the relative sizes of gas storage and peak shaving supplies for New England and Middle Atlantic states separately and combined for the years 1986 through 1995. Placed on a scale with underground storage, peak shaving in the Middle Atlantic states appears to be insignificant. Despite the small volume of peak shaving supply in the Middle Atlantic states, this source of gas is important during periods of peak demand.

Peak shaving supplies are less costly than other supplies for New England for severe cold weather, but still raise the cost of gas in that region relative to costs in regions that have more moderate climates and better access to gas storage. LNG costs vary widely in the Northeast, depending on its source, the size of the liquefaction plant, and the age (relative efficiency) of the plant. In New England, most of the LNG used for peak shaving is imported from Algeria by Distrigas of Massachusetts Corp. BostonGas, for example, pays about $0.50 per MMBtu above the average summer cost of pipeline gas for LNG delivered into its storage tanks. If summer gas costs $2.50 per MMBtu, LNG costs $3.00 per MMBtu. This is the lower end of the LNG cost scale. Other gas distributors may not have terms with Distrigas that are this favorable. However, most of the LNG used in New England is trucked from the Distrigas terminal in Everett, Massachusetts to the storage tanks of the distributors.

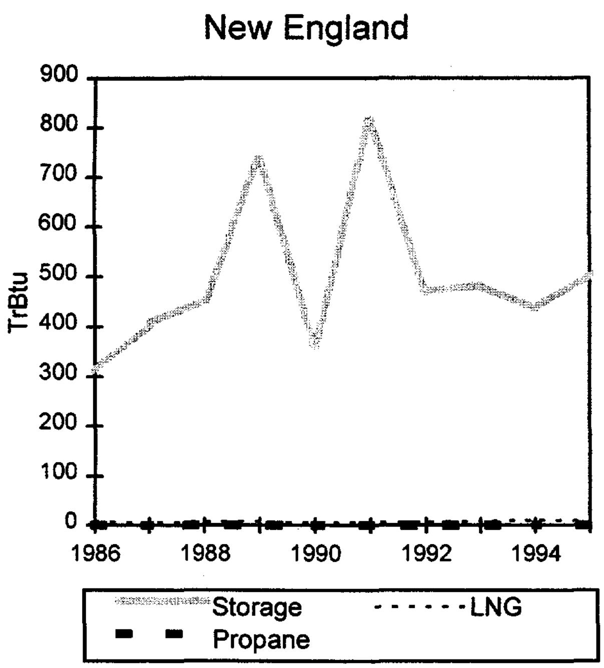
The cost of service tariff for LNG from new facilities that liquefy summer pipeline gas and charge undiscounted rates varies from $10.00 per MMBtu for a facility sized to liquefy and store 1.0 Trillion Btu (TrBtu) per year down to $5.50 per MMBtu for a 4 TrBtu per year facility. These costs exclude the cost of gas used as fuel for the liquefaction process. For a relatively modern plant the fuel use is about 20 percent of the gas input for liquefaction. If summer gas costs $2.50 per MMBtu, the added fuel cost would be $0.50 per MMBtu. Because Distrigas does not supply as much Algerian LNG to the Middle Atlantic as to New England, these cost of service rates for newer facilities are more applicable to the Middle Atlantic. Depending on market conditions and the severity of winters, both old and new LNG facilities may discount their rates for LNG.

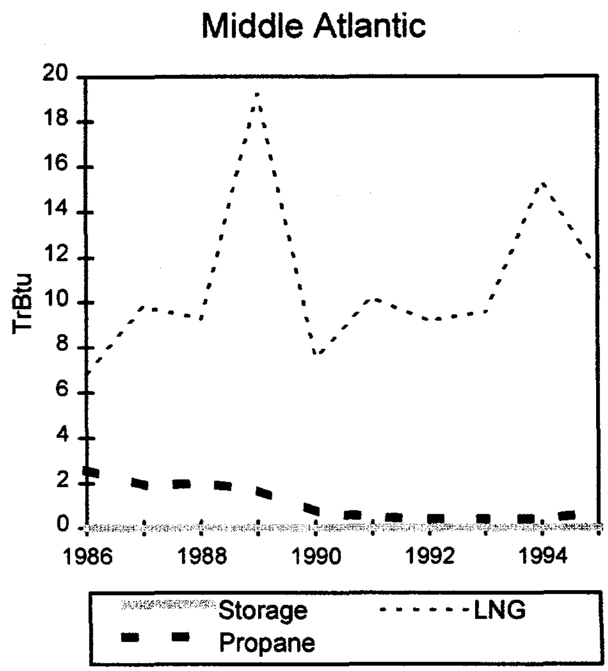
A recent presentation by a representative of New York State Electric & Gas Corp. (NYSEG) quoted average costs for storage and peak shaving at the following rates per million Btu:

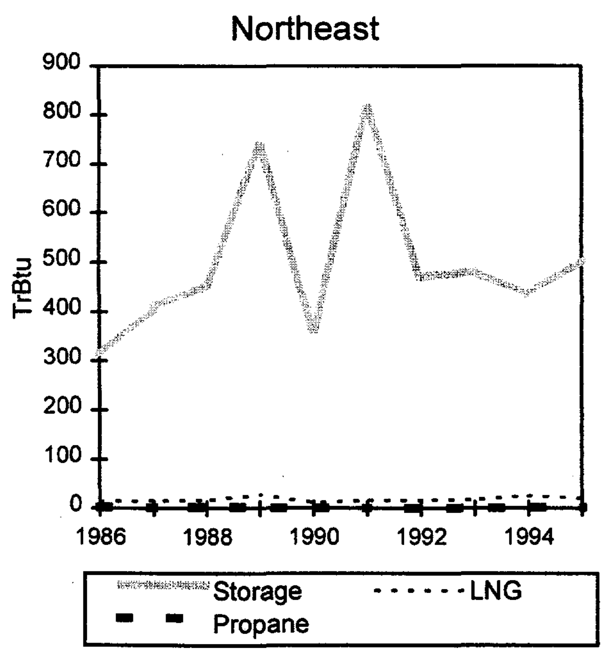
Seasonal storage	$1.34 plus the cost of gas
Propane/air	$7.43

By contrast, if NYSEG reserved pipeline capacity such that it would be used for only ten percent of its annual capacity, the cost of the pipeline transportation would range from $6.85 to $10.86 per MMBtu. This ten percent utilization represents the pipeline capacity that would be required to meet NYSEG's temperature sensitive peak demands.

Exhibit C-3
Gas Storage and Peak Shaving in the Northeast







Source:
DOE/EIA, *Natural Gas Annual 1991, 1996*

Interruptible Service

For those consumers that do not require firm (guaranteed) gas service, such as industrial and power generation plants that can use another fuel, interruptible services for gas transportation and storage are usually available. This type of service, which can be interrupted on short notice when gas demand threatens to exceed gas supply is less costly than firm service because the pipeline or storage capacity is not reserved. This type of tariff greatly reduces the fixed cost part of rates. Gas service interruption is similar to storage and peak shaving in that it provides another gas supply service during peak demand periods by taking gas away from this interruptible customer.

GAS COMPETITION WITH DISTILLATE FUEL OIL

Despite the relatively high cost of gas in the Northeast, gas demand has been growing somewhat at the expense of the demand for distillate fuel oil, except in the residential sector of New England. The relative prices of these two fuels do not adequately explain why this change in fuel preference is occurring. The characteristics of the Northeastern markets for these two fuels, their recent changes and forecast future changes are described in this section.

Recent Sizes of the Gas and Distillate Markets in the Northeast

After trailing distillate demand for total non transportation uses historically, natural gas consumption first exceeded New England distillate consumption in 1990.[6] By 1995 gas consumption exceeded distillate by 50 percent. The residential sector is the only market in New England where distillate continues to dominate gas. Exhibits C-4, C-5, and C-6 provide comparisons of gas and distillate consumption volumes from 1986 through 1995 for each of the four consuming sectors in New England and Middle Atlantic states, separately and combined.

In the Middle Atlantic region gas demand has exceeded distillate demand during each of the past ten years and the margin has been growing. In 1995, gas use in the Middle Atlantic for the four sectors was about 3.5 times that of distillate. This level of gas dominance is essentially the same for the entire Northeast region because the Middle Atlantic demand for both gas and distillate is so much larger than the New England demand.

Even though distillate use in the Middle Atlantic region represents a smaller part of the market for gas plus distillate than in New England, the Middle Atlantic is still more dependent on distillate than other regions with similar climates, such as the East North Central census region.[7] In 1994, for example, gas use for the four East North Central consuming sectors was over 11 times the distillate use. The 1994 average price of gas for these sectors in the East North Central was $4.70 per MMBtu compared to $5.63 for the same sectors in the Middle Atlantic. For the residential sector in particular, the 1994 average East North Central distillate price was $1.23 per MMBtu higher than the gas price. By contrast, in the Middle Atlantic region residential gas in 1994 cost $1.06 per MMBtu more than residential distillate.

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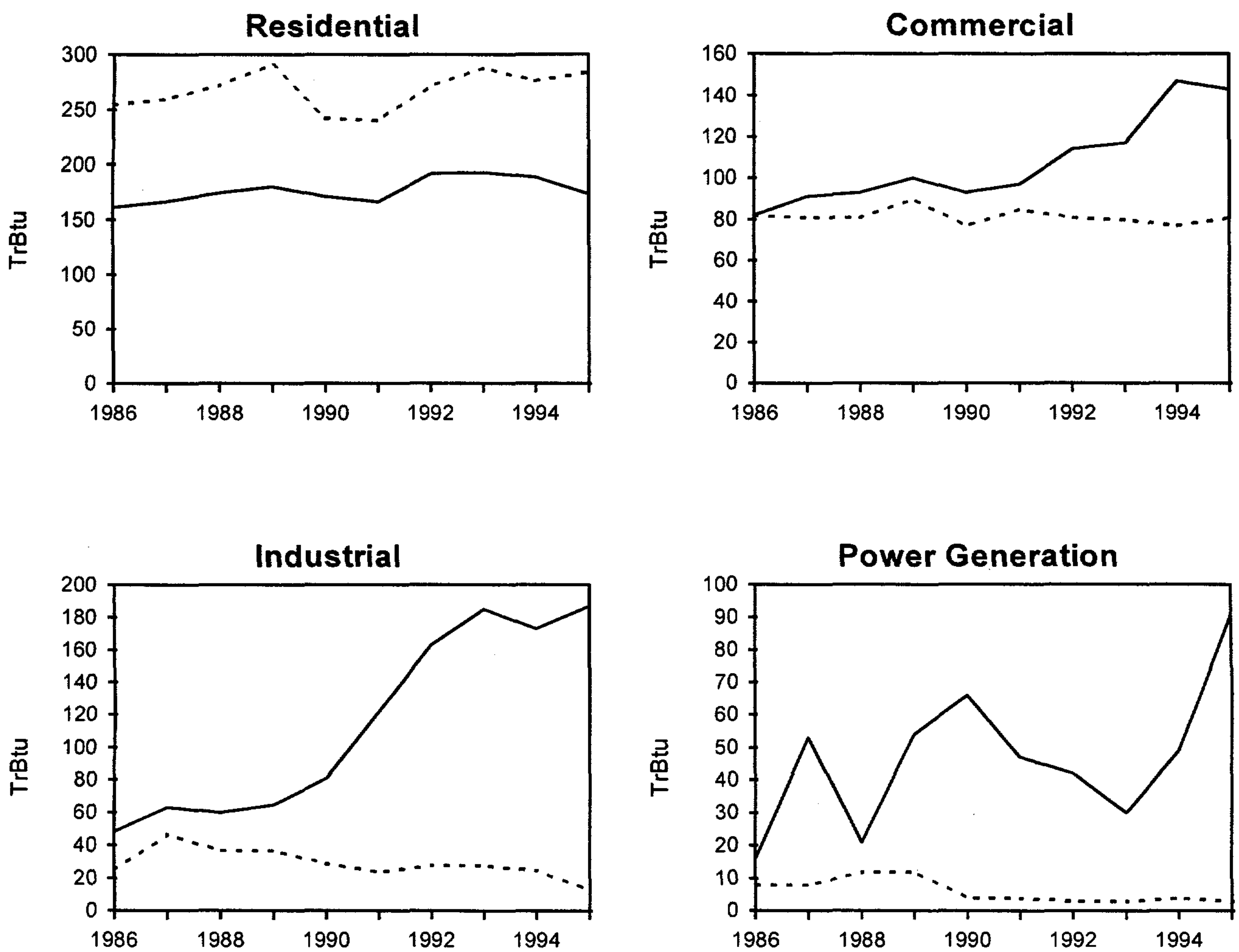
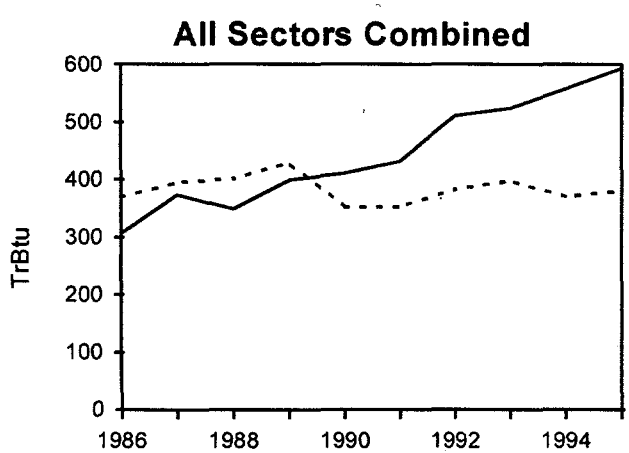
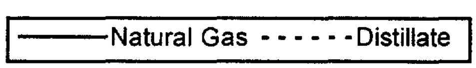
[6] All discussion of gas and distillate fuel oil competition here includes only the fuel consumed in the residential, commercial, industrial, and electric power generation sectors. Diesel fuel for vehicles is excluded.

[7] The East North Central region is comprised of the Upper Midwest states of Ohio, Indiana, Illinois, Michigan, and Wisconsin

Exhibit C-4
Gas and Distillate Consumption in New England by Sector

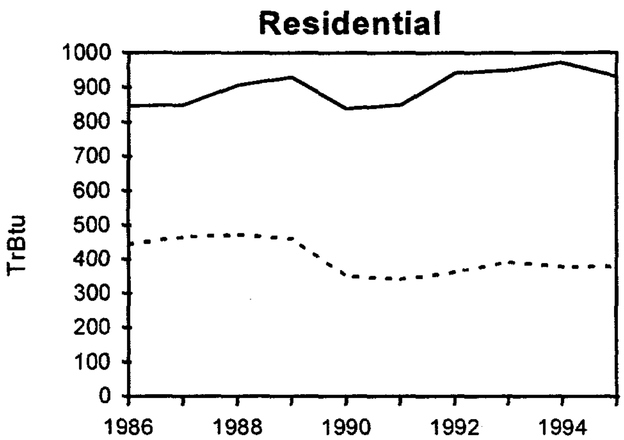


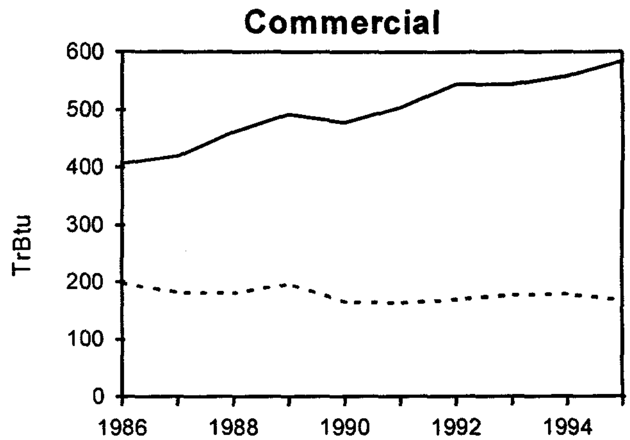


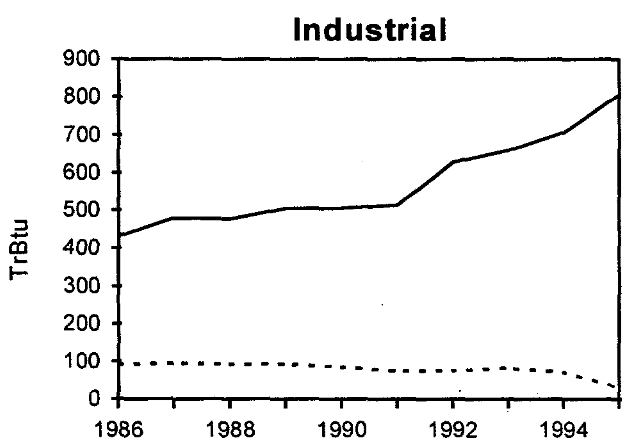


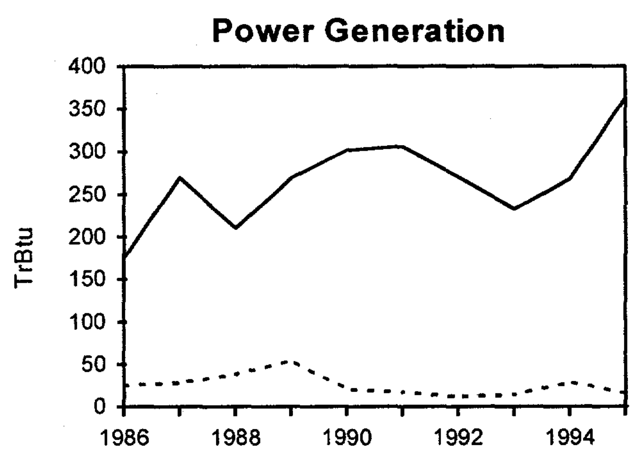
Source:
Distillate - Department of Energy, Energy Information Administration, *State Energy Data Report 1993, 1994*
DOE/EIA, *Fuel Oil and Kerosene Sales 1995*
Natural Gas - DOE/EIA, *Natural Gas Annual 1991, 1996*

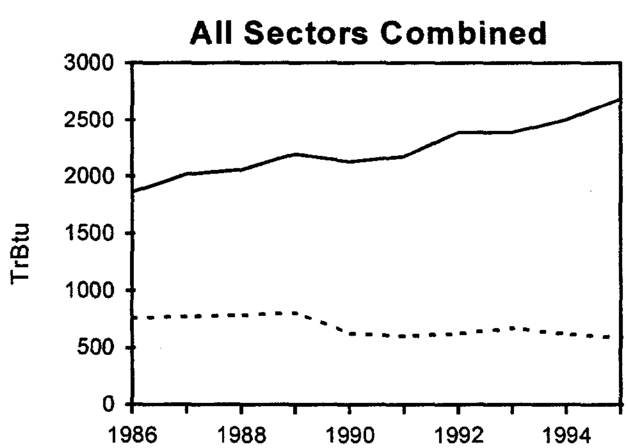
Exhibit C-5
Gas and Distillate Consumption in Middle Atlantic States by Sector







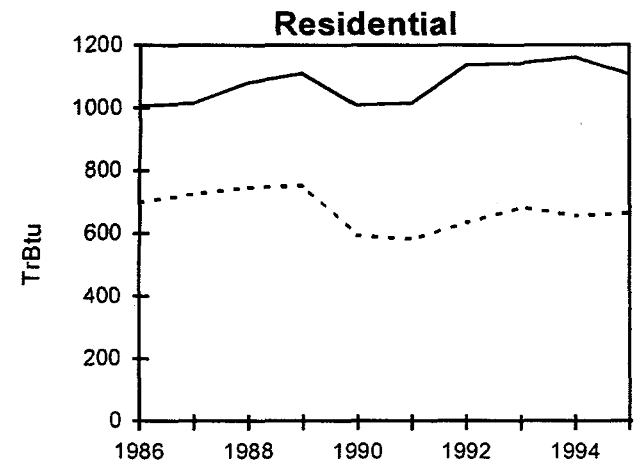


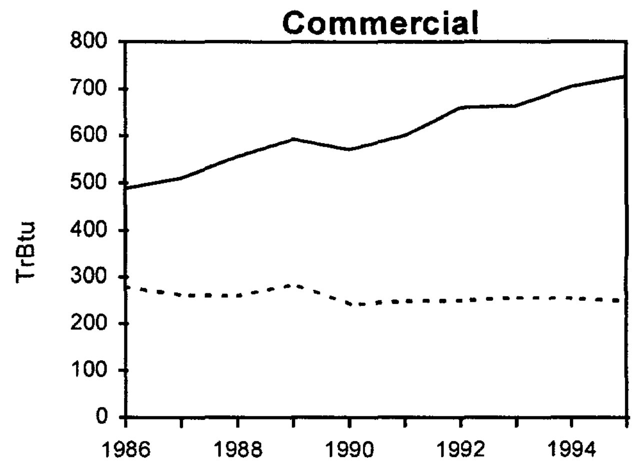


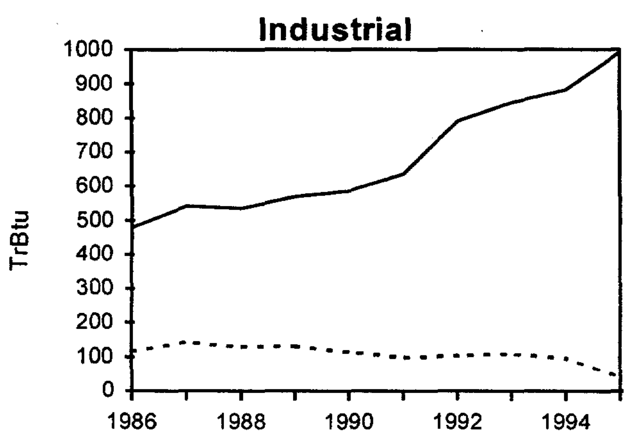
Natural Gas - - - - - - Distillate

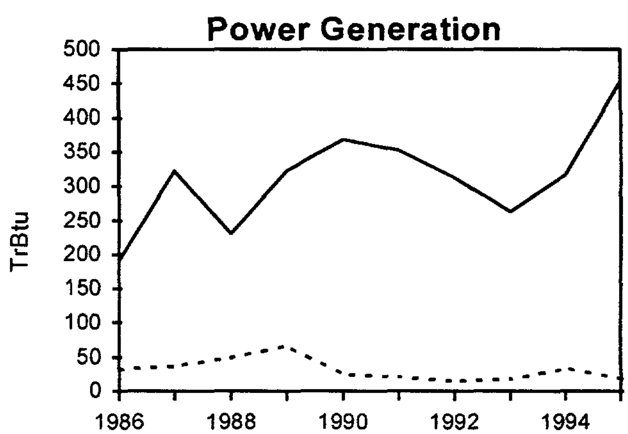
Source:
Distillate - Department of Energy, Energy Information Administration, *State Energy Data Report 1993, 1994*
DOE/EIA, *Fuel Oil and Kerosene Sales 1995*
Natural Gas - DOE/EIA, *Natural Gas Annual 1991, 1996*

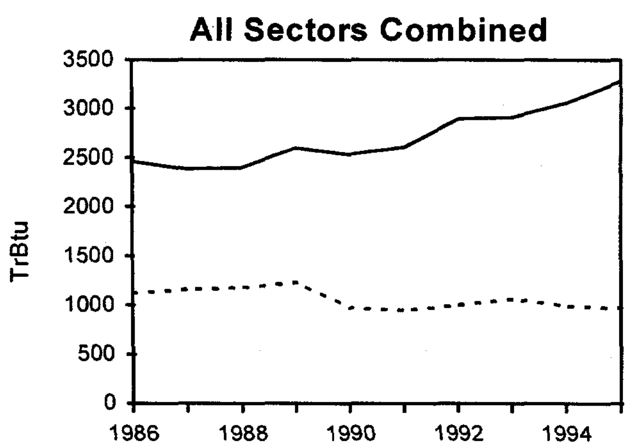
Exhibit C-6
Gas and Distillate Consumption in the U.S. Northeast by Sector











Natural Gas - - - - - Distillate

Source:
Distillate - Department of Energy, Energy Information Administration, *State Energy Data Report 1993, 1994*
DOE/EIA, *Fuel Oil and Kerosene Sales 1995*
Natural Gas - DOE/EIA, *Natural Gas Annual 1991, 1996*

FORECAST GAS AND DISTILLATE CONSUMPTION IN THE NORTHEAST

U.S. Department of Energy forecasts indicate steady increases in natural gas consumption in both the New England and Middle Atlantic regions from 1995 through 2010.[8] At the same time, distillate use is expected to decline slightly in both regions, gradually increasing the dominance of gas over distillate in the four consuming sectors. By 2010, gas consumption in New England is projected to be 848 trillion Btu (TrBtu) versus 335 TrBtu for distillate. In the Middle Atlantic the difference is much greater with gas at 3,098 TrBtu and distillate at 480 TrBtu. Even in the residential sector of New England, which currently is the only sector in the Northeast where distillate consumption exceeds gas, gas use catches up with distillate in the year 2010 at 250 TrBtu that year. In all other consuming sectors of the Northeast, gas maintains substantial leads in use over distillate. Exhibits C-7 and C-8 illustrate these forecast changes in gas and distillate use by consuming sector in the Northeast between 1995 and 2010.

Recent Gas and Distillate Prices in the Northeast

From 1986 through 1995, distillate prices in New England have remained below gas prices for both residential and commercial consumers. These fuel prices were nearly equal in 1990 at about eight dollars per MMBtu for residential and six dollars per MMBtu for commercial, when distillate prices were at their highest in this 10-year period. New England industrial distillate prices, on the other hand, have been higher than gas prices since 1987, but were nearly equal in 1993 and 1994 at close to five dollars per MMBtu. Exhibit C-9 illustrate these price changes for the residential, commercial, and industrial sectors in New England. In 1994 and 1995 residential gas prices in New England averaged about three dollars per MMBtu higher than distillate. In 1994 commercial gas was about two dollars per MMBtu higher priced than distillate. These price differences in the residential and commercial sectors are smaller in the Middle Atlantic states.

In the Middle Atlantic region, residential distillate prices moved above gas prices during the period 1989 through 1992 but have remained below gas prices since then. By 1994 and 1995 Middle Atlantic residentialgas was priced about one dollar per MMBtu above distillate. Middle Atlantic commercial gas prices were about $1.50 per MMBtu higher than distillate in 1994. Although the patterns of distillate and gas price changes have been remarkably similar since 1986, the lower gas prices and higher distillate prices in the Middle Atlantic, compared to New England, have made gas more price competitive in the Middle Atlantic. Exhibit C-10 illustrates these price changes for three sectors in the Middle Atlantic. Compatible distillate price data are not available for the power generation sector in these two regions.[9]

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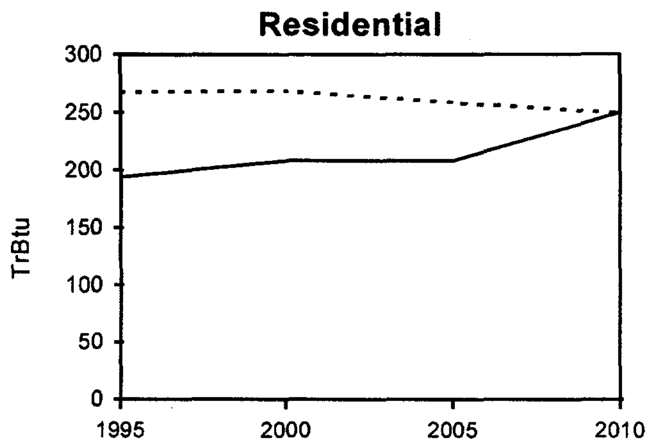
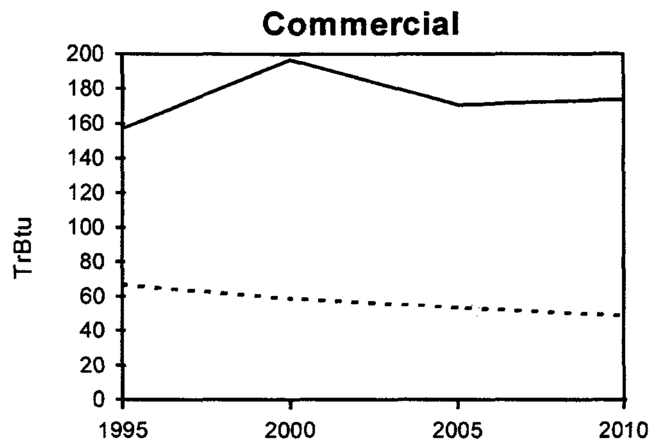
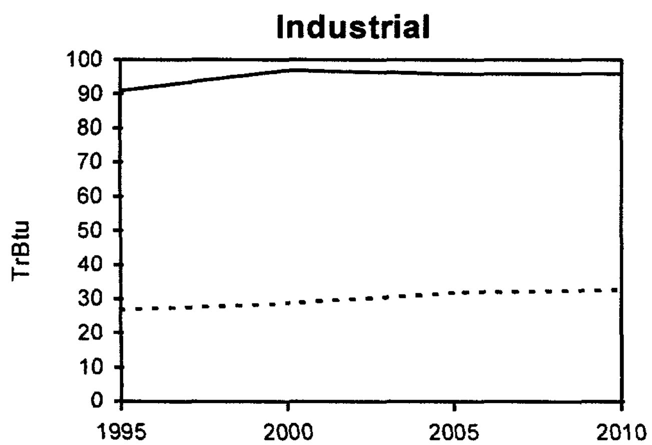
[8]U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1997, Supplementary Tables.*

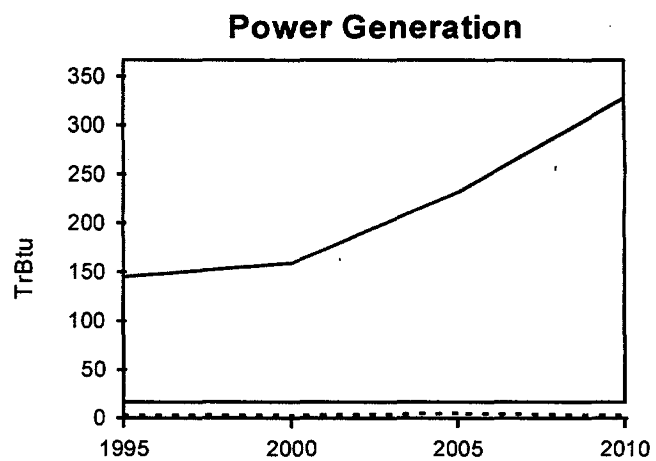
[9]The source for end-user distillate prices, U.S. Department of Energy, Energy Information Administration, *Petroleum Marketing Annual,* does not provide prices for the electric utility sector.

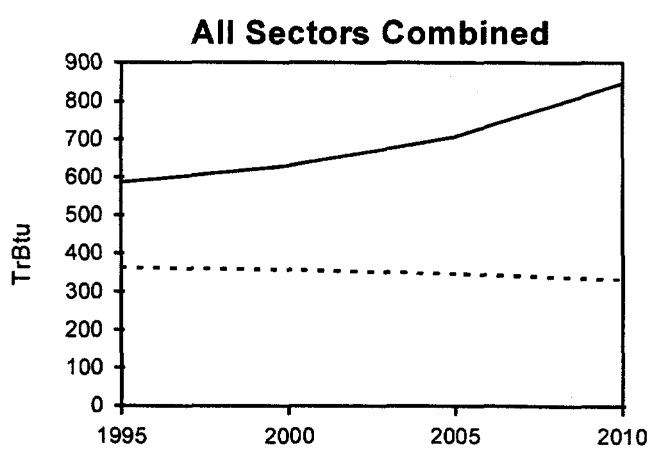
Exhibit C-7
Forecast Gas and Distillate Consumption in New England







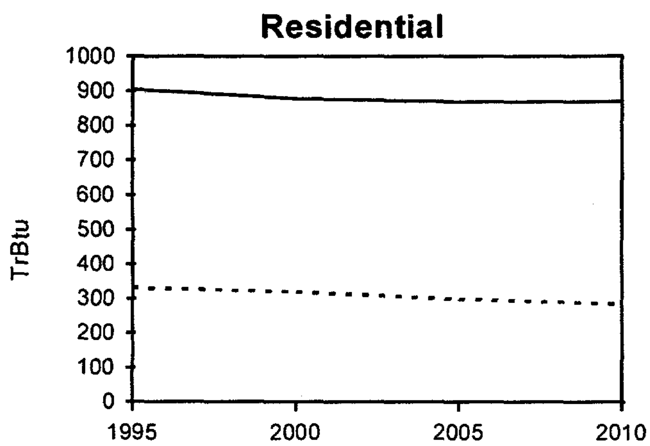


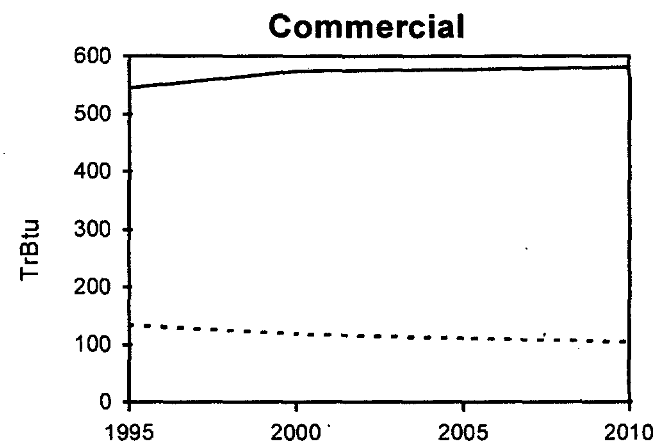


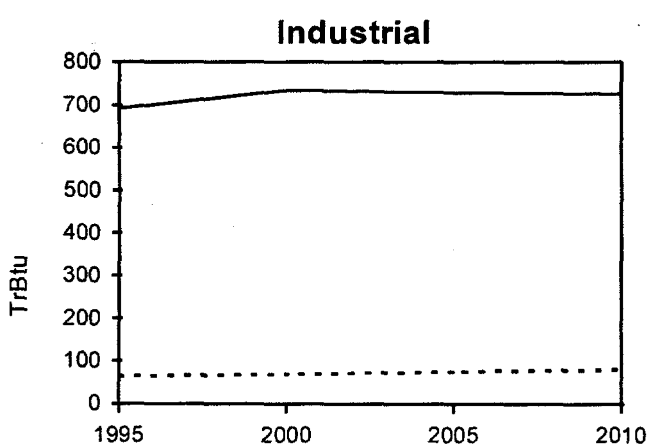
——Natural Gas - - - - - Distillate

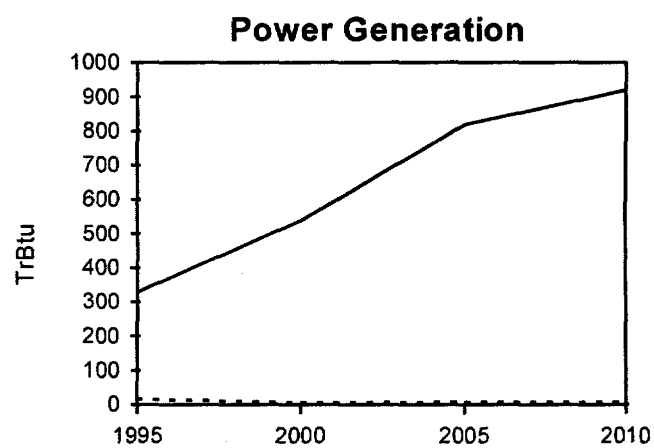
Source:
U.S. DOE, EIA, *Annual Energy Outlook 1997, Supplementary Tables*

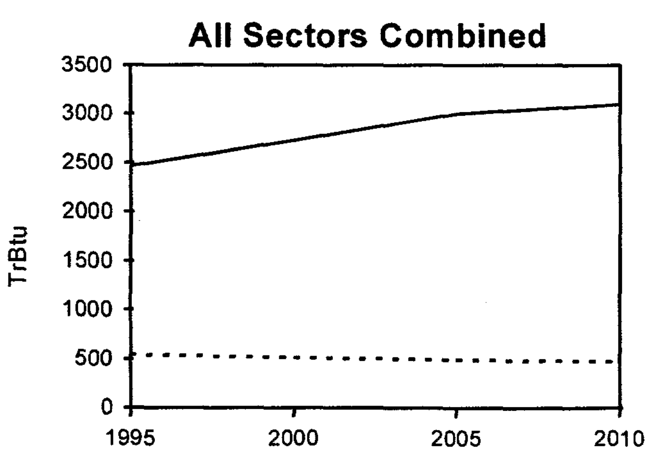
Exhibit C-8
Forecast Gas and Distillate Consumption in Middle Atlantic States







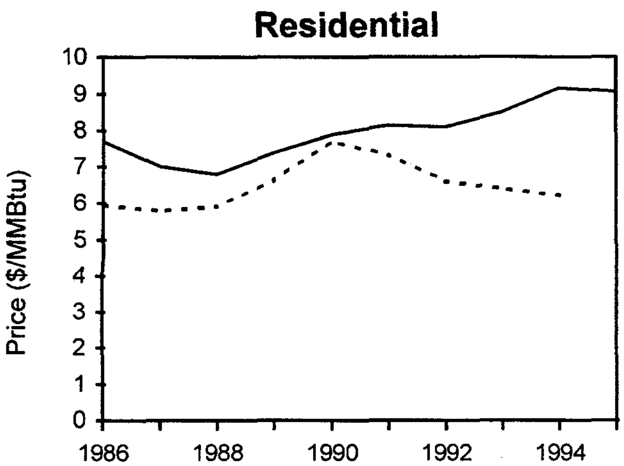


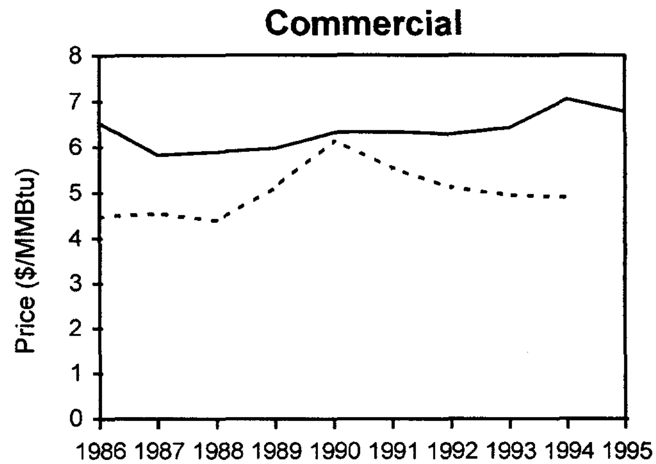


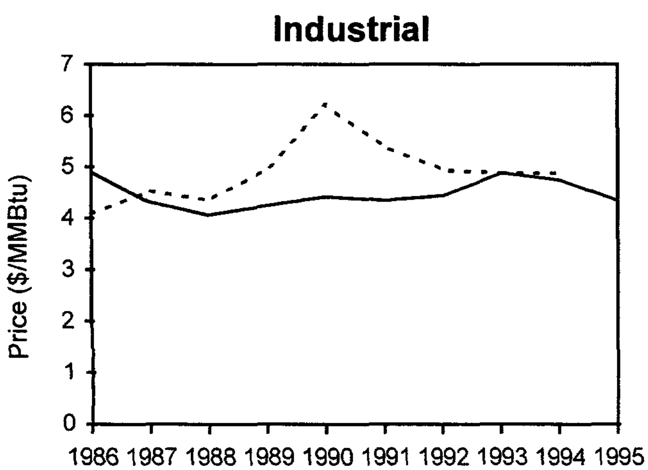
——Natural Gas - - - - - - Distillate

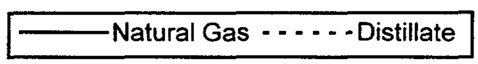
Source:
U.S. DOE, EIA, *Annual Energy Outlook 1997, Supplementary Tables*

Exhibit C-9
Prices of Gas and Distillate in New England



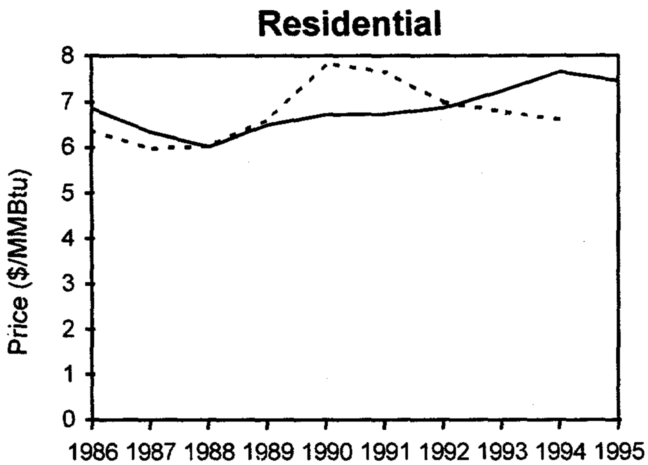


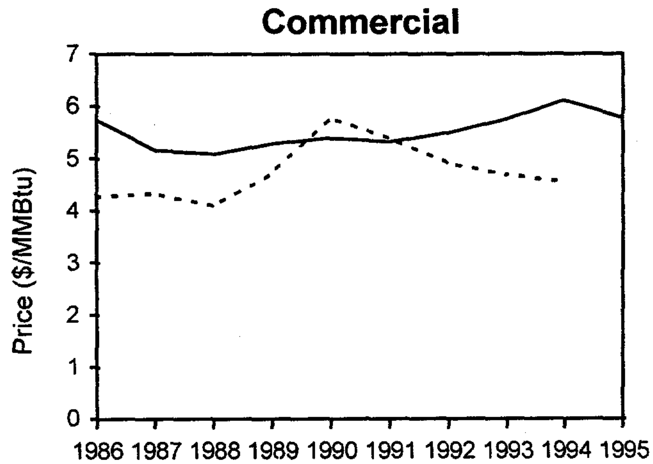


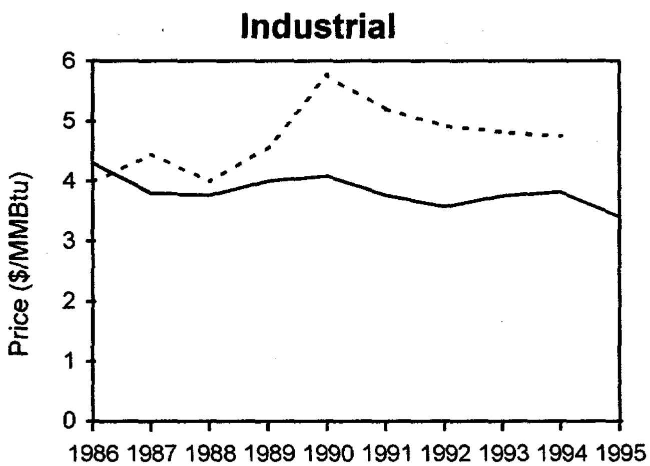


Source:
Distillate - Department of Energy, Energy Information Administration, *State Energy Data Report 1993, 1994*
DOE/EIA, *Fuel Oil and Kerosene Sales 1995*
Natural Gas - DOE/EIA, *Natural Gas Annual 1991, 1996*

Exhibit C-10
Prices of Gas and Distillate in Middle Atlantic States







——Natural Gas - - - - - - Distillate

Source:
Distillate - Department of Energy, Energy Information Administration,
State Energy Data Report 1993, 1994
DOE/EIA, *Fuel Oil and Kerosene Sales 1995*
Natural Gas - DOE/EIA, *Natural Gas Annual 1991, 1996*

Forecast Gas and Distillate Prices in the Northeast

The substantially higher residential prices for gas in New England are thought to largely explain why distillate has maintained a sales edge over gas historically, as shown earlier in Exhibit C-4. On the other hand, in the Middle Atlantic states where residential gas prices have been higher than distillate, but closer to equal, gas consumption has been roughly double distillate consumption. A similar pattern is evident in the Middle Atlantic commercial sector where gas and distillate prices are closer than in New England and gas consumption has grown from double that of distillate in 1986 to reach three times distillate use in 1995. (See Exhibit C-5.) It appears that in areas where distillate does not have a substantial price advantage over gas, gas is the preferred fuel for all consumers. The preference for gas is partially explained by its other uses in a residence or commercial facility, particularly for cooking. Gas is cleaner from the standpoint of spills and emissions, it does not require dependence on truck delivery, and it does not require a storage tank. The financial and environmental liabilities of owning oil storage tanks that may cause soil contamination from leakage are thought to have an increasing influence on the choice of gas instead of distillate in all consuming sectors.

In both New England and Middle Atlantic states, gas prices in the residential and commercial sectors are forecast by the U.S. Department of Energy to decline steadily from 1995 through 2010.[10] Distillate prices in the two regions, on the other hand, are projected to rise in all sectors during these years. Exhibits C-11 and C-12 provide a summary of both gas and distillate prices for these years by consuming sectors in the two regions. These opposing trends in price forecasts cause the distillate prices to exceed gas prices in even the New England residential sector by the year 2010. This change occurs in 2005 in the New England commercial sector. In the Middle Atlantic, distillate prices surpass gas by the year 2000 in both the residential and commercial sectors. In the industrial and power generation sectors, gas greatly improves its historic price advantage over distillate in both regions. These changes in relative prices support the previously described forecasts of increasing gas use at the expense of distillate in the Northeast.

NATURAL GAS ACCESS TO THE NORTHEAST

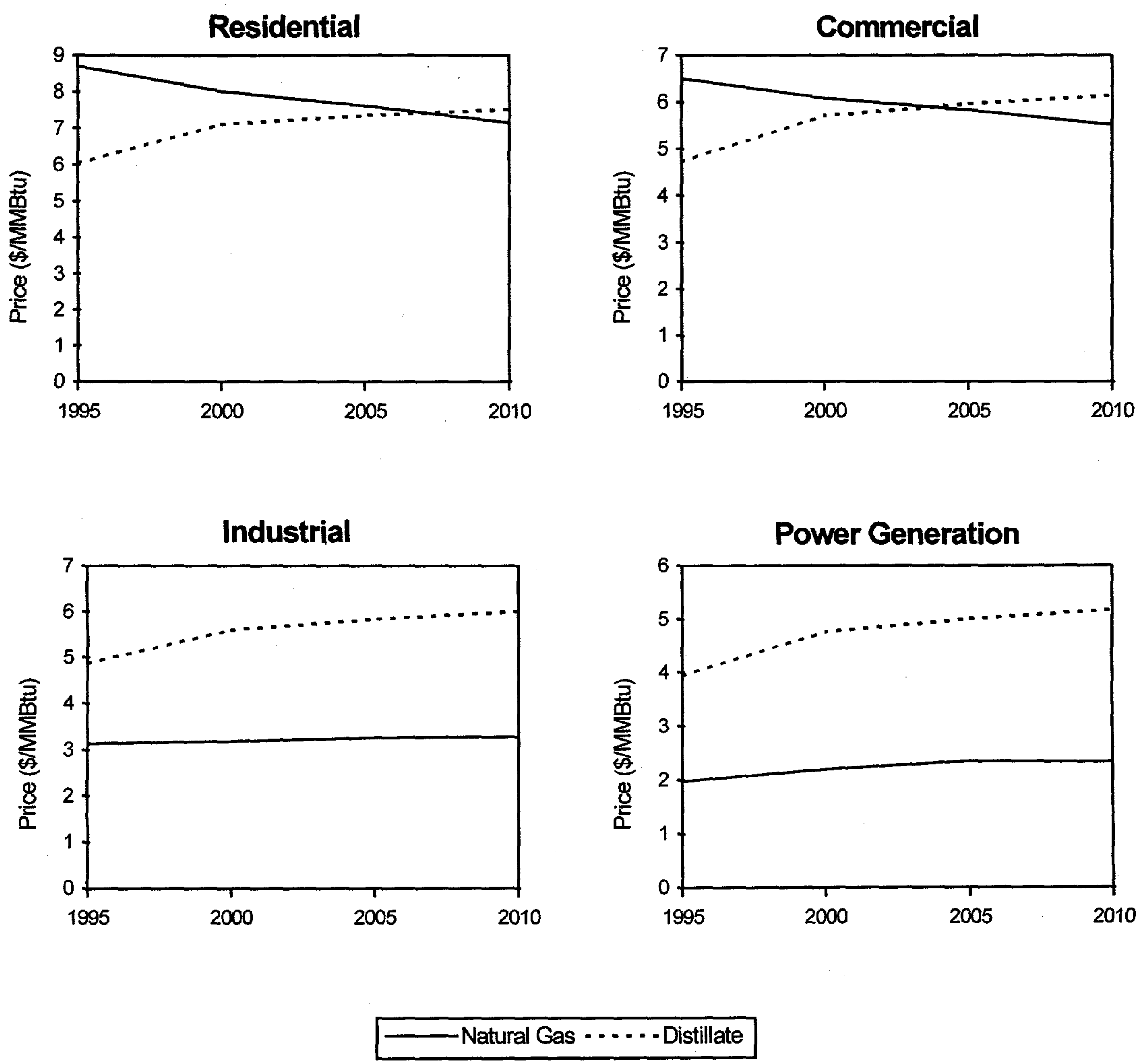
Natural gas enters the Northeast via gas pipelines and LNG tankers. The primary pipeline supplies come from producing areas in the Gulf of Mexico, along the Gulf Coast, in the Southwest, in the Appalachians, and western Canada. The LNG imports originate in Algeria. Exhibit C-13 summarizes capacities of these gas supply routes to the Middle Atlantic and New England states.

Pipeline Capacity

There are 13 pipelines bringing natural gas to the Northeast, ranging in size from 30 to 2,555 million cubic feet (MMcf) per day. The total capacity of these 13 lines is 12,000 MMcf cubic feet per day. (See Exhibit C-14 for the delivery capacities of each pipeline.) Nearly all of the capacity entering the Northeast comes in through the Middle Atlantic states of Pennsylvania, Maryland, and New York. Only two small lines, Granite State Gas Transmission and Vermont Gas Systems, enter New England directly without passing through the Middle Atlantic states. Their combined capacity represents half of one percent of the total entering the Northeast.

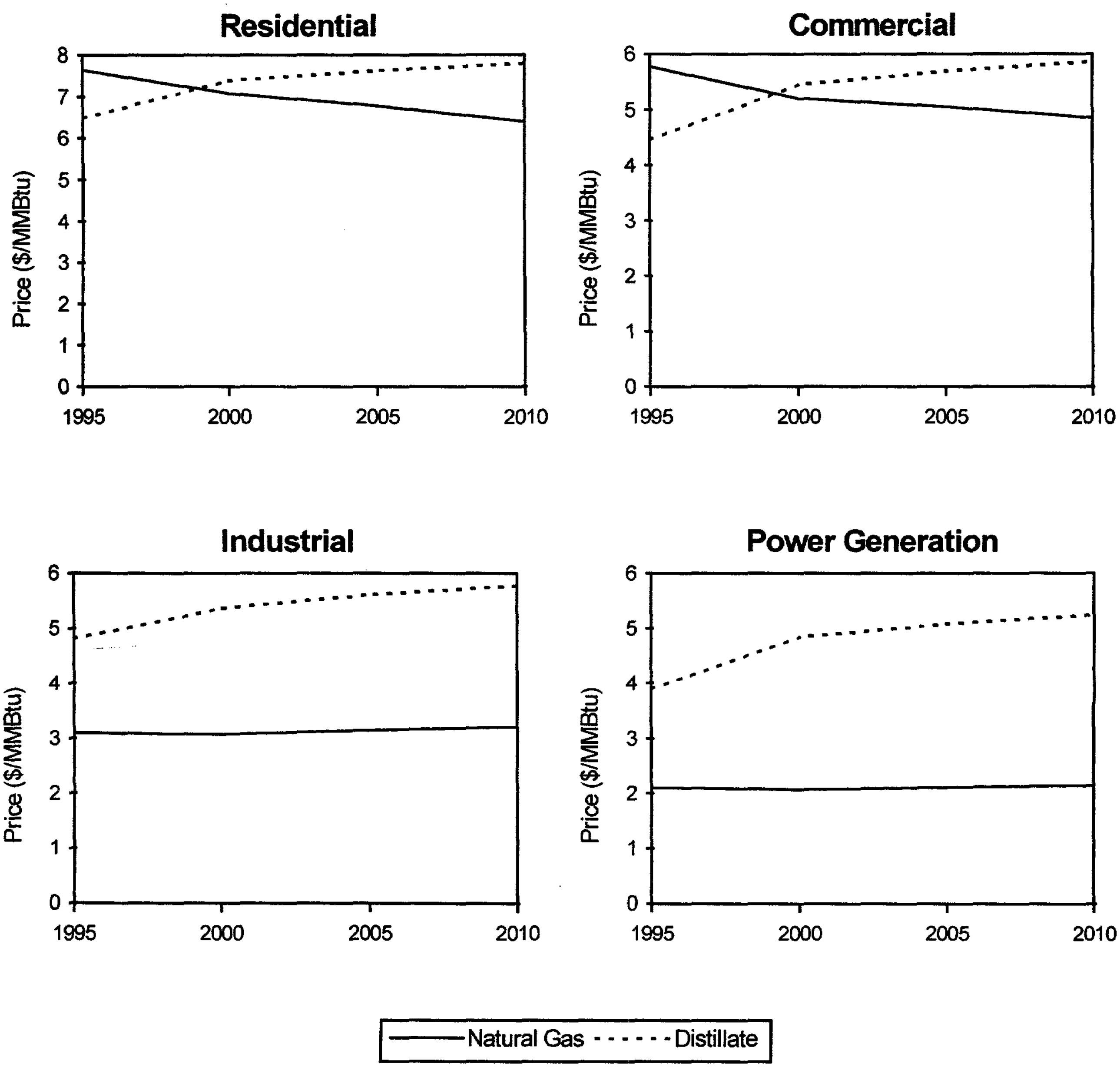
[10] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1997, Supplementary Tables*

Exhibit C-11
Forecast of Gas and Distillate Prices in New England



Source:
U.S. DOE, EIA, *Annual Energy Outlook 1997, Supplementary Tables*

Exhibit C-12
Forecast of Gas and Distillate Prices in Middle Atlantic States



Source:
U.S. DOE, EIA, *Annual Energy Outlook 1997, Supplementary Tables*

Exhibit C-13 Gas Transportation Capacity Into the U.S. Northeast in 1994				
State Entered	**From**	**Capacity MMcfd**	**Average Flow MMcfd**	**Percent Utilized**
Maryland	Virginia	3,217	2,177	68%
New York	Canada	2,072	1,607	78%
Pennsylvania	Ohio	2,135	985	46%
Pennsylvania	West Virginia	4,519	3,224	71%
Vermont	Canada	63	50	79%
Massachusetts	Algeria	385	146	38%
Total	-	12,391	8,188	66%

Exhibit C-14 Capacities of Companies Delivering Gas to the U.S. Northeast in 1994	
Pipeline	**Capacity (MMcfd)**
Carnegie Natural Gas Co.	30
Columbia Gas Transmission Corp.	2,296
CNG Transmission Corp.	1,060
Empire Pipeline Co.	503
Equitrans Inc.	255
Granite State Gas Transmission Inc.	31
Iroquois Pipeline Co.	756
North Country Pipeline Co.	35
St. Lawrence Gas	65
Tennessee Gas Pipeline Co.	2,288
Texas Eastern Transmission Corp.	2,555
Transcontinental Gas Pipeline Co.	2,100
Vermont Gas System Inc.	32
Total	12,006
LNG Terminal	
Distrigas Corp.	385

The primary pipelines serving New England are Algonquin and Tennessee. Algonquin, which originates in New Jersey at a connection with Texas Eastern, enters New England through Connecticut with a capacity of 1,030 MMcf per day. Two branches of Tennessee enter New England through Connecticut and Massachusetts. These two lines have a total daily capacity of 1,180 MMcf. In addition, Iroquois Pipeline, which passes through Connecticut en route to Long Island, has a capacity of 352 MMcf per day entering Connecticut and 250 MMcf per day leaving for Long Island.

An indication of the anticipated growth in gas markets in the Northeast is the large number of projects aimed at increasing pipeline capacity in the region. The U.S. Department of Energy, Energy Information Administration publication, *Natural Gas 1996 Issues and Trends*, lists 26 projects that are announced, pending, or approved for completion in the years 1996 through 2000 in the Northeast. Although the total capacity of these projects is only 2,310 MMcf per day, the number of potential projects is far larger than for any other region.

New capacity planned to bring gas to the Northeast is concentrated in two pipelines entering New England that represent 30 percent of the total. The Portland Pipeline project is scheduled to bring Canadian gas at 250 MMcf per day into Maine by 1998. The second phase of the Maritimes & Northeast project is to deliver 440 MMcf per day of gas from production off Sable Island, Nova Scotia into Maine by 1999. Other new capacity projects into the Northeast are two from West Virginia into Pennsylvania and one from Ohio into New York. The West Virginia lines are by CNG and Tennessee for a combined total capacity of 435 MMcf per day, and the Ohio line by Texas Eastern will add 25 MMcf per day. Lastly, three expansions from TransCanada Pipelines into New York are to add a total of 111 MMcf per day. Thus, of the total 2,310 MMcf per day, 1,261 is for added deliverability into the Northeast, and 1,049 MMcf per day, or 45 percent, is located within the Northeastern states to provide additional delivery flexibility and to meet changing market demands.

LNG Import Capacity

The Distrigas of Massachusetts Corp. (DOMAC) LNG terminal at Everett, Massachusetts is capable of vaporizing 285 MMcf per day of natural gas for delivery into Northeastern U.S. pipeline and distribution systems. In addition, the terminal can load 100 MMcf per day of LNG (gaseous equivalent) into cryogenic tank trucks for delivery to LNG storage tanks in the Northeast.

Distrigas Corp. has been importing LNG from the Sonatrach liquefaction plant in Algeria since 1972 with interruptions from time to time because of contractual problems and maintenance needs at the Sonatrach plant. Now, Distrigas, through its parent Cabot LNG Corporation, is participating in the Atlantic LNG project in Trinidad. The DOMAC terminal in Everett is expected to receive 25 to 30 tanker deliveries per year at 2,800 MMcf each from Atlantic LNG. Facilities at Everett will be expanded to deliver another 150 MMcf per day to the Northeast via gas lines, and additional truck loading capacity is being considered. LNG deliveries from Algeria will be maintained under existing contracts.

The only other LNG import facility in the Northeast is the Cove Point, Maryland terminal on Chesapeake Bay. Unused as a terminal for about 20 years, this facility was converted to LNG peak shaving in 1996. Pipeline supplied gas is liquefied in warm weather and stored in cryogenic tankage for sendout in winter.

CONCLUSIONS

Natural gas consumption first surpassed distillate consumption in New England in 1990 and gas use has been growing faster than distillate use since then. The residential sector is the only market in New England that has seen distillate maintain a consumption lead over gas. However, the Energy Information Administration, in its *Annual Energy Outlook 1997* forecasts that gas consumption will catch up with distillate by the year 2010 as the substantially higher gas prices converge with distillate prices. The *Annual Energy Outlook 1997* supports this future change in consumption leadership with price forecasts that show gas prices falling and distillate prices rising. Between now and the year 2010, gas prices are projected to be lower than distillate prices in all New England consuming sectors.

The Middle Atlantic states have a history of gas consumption exceeding distillate use in all sectors and this leadership is forecast to widen by 2010. In the Middle Atlantic, gas and distillate prices have been much closer to equal than in New England historically and are forecast to be lower than distillate prices in all sectors by the year 2000.

Both New England and the Middle Atlantic states have larger shares of distillate consumption than other regions in uses where distillate competes with gas because gas is more expensive in the Northeast than in other regions. The primary reasons for higher gas prices in New England are: 1) the longer transportation distances from supply sources; 2) the large seasonal changes in gas consumption that cause inefficient use of pipeline capacity; and 3) the lack of underground gas storage facilities in the region. The Middle Atlantic also has longer transportation distances than other northern regions and large seasonal changes in demand but is fortunate to have a major portion of the underground gas storage capacity in the U.S. The shorter distances from storage to markets in the Middle Atlantic reduce the cost of gas transportation in winter.

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Appendix D

Documentation of Statistical Models and Calculation of Benefits

Prepared by:

Applied Statistical Associates, Inc.

APPENDIX D

DOCUMENTATION OF STATISTICAL MODELS AND CALCULATION OF BENEFITS

This Appendix describes the various statistical analyses and models that were developed to analyze distillate market issues. The primary objective of this part of our research was to develop an estimate of the regional cost savings and national benefits that a distillate reserve could be expected to provide.

Not surprisingly, all the models discussed below are time series applications. Some, such as those that involve temperature data alone, are classical ARIMA (autoregressive, integrated, moving average) specifications that predict each new observation as a function of past values and a disturbance term. Others are econometric applications that model the behavior of economic entities as an adaptive process that is best explained by a combination of current and past values of the variables. The time periods of the data used are monthly, weekly, and daily.

Observations on most of the variables of interest are not available on a daily basis. For our purposes, this is unfortunate because the ideal model of how a product reserve would affect the market for distillate would be based on daily data. During a crisis, prices can change substantially from day to day. The models that we have developed make their predictions on a weekly basis but are estimated to be consistent with the available daily data on temperature and spot prices. They also borrow parameter estimates and specifications that were fit to monthly data.

The first several sections below describe the monthly, weekly, and daily models. The next section discusses how these models were used to develop a simulation that could be used to estimate the benefits of a Reserve. The specific steps in the simulation are described in detail and the results of running the simulation are presented and discussed. The final section shows how the models were used to mimic and analyze the market response to the cold wave of December 1989 and to estimate the expected value of a Reserve per household in the Northeast.

The Monthly Models

The market for distillate is very complex, and much of this complexity is related to interactions with seasonality. Many econometric models account for simple seasonal effects and are able to represent the entire annual market cycle. The demand for airline travel, for example, exhibits a seasonality that can be modeled simply as an exogenous, dependable pattern in tastes.

In contrast, the market for heating oil is distinctly different in both endogenous and exogenous factors. Clearly, the effect of temperature seasonality is exogenous and is the most important factor in demand. However, distillate producers do not have sufficient flexibility to meet the increased demand of the heating season with increased production and find it economical to store some heating oil in the summer to sell in the winter. In the summer, equilibrium sales, stock levels, and prices are focused on optimal stock accumulation. In contrast, the heating season is characterized by a complex balance of production and stock drawdown to meet temperature-sensitive demand.

The factors affecting distillate market behavior are so different between the heating and non-heating season that different statistical models are appropriate for simulating them. Further the benefits of a Reserve are determined solely by the behavior of the market during the heating season.

As a result, the balance of this appendix is focused essentially on the heating season models. These models include the following behavioral and statistical relationships:

- **Retail demand.** The quantity of monthly sales is modeled as a linear function of heating degree days (HDD), the residential retail price of distillate, and a constant to represent non-temperature-sensitive demand.

- **Retail supply.** At this step in the supply process, the residential retail price is modeled as a linear function of the wholesale spot price of distillate, the rate of sales, and the retail price lagged one month.

- **Wholesale supply.** The wholesale spot price of distillate is a function of the spot price of crude and deviations of distillate stock levels from normal.

- **Normal stock and HDD levels.** These models were developed to provide a basis for estimating stock and HDD deviations from normal.

The wholesale supply model was investigated by fitting a variety of single-equation models to monthly and weekly data over the same time period. In theory it would be superior to combine this equation with the two in the retail market, but the monthly wholesale supply equation experiences a severe lack of fit during the Big Chill (December 1989 - January 1990), as the effect of stock shortfalls is nonlinear under extreme conditions. This lack of fit imposes more harm than good on the other two equations when all three are estimated simultaneously. This problem is discussed in more detail below.

In any event, the objective of the wholesale supply analysis was to identify the factors that determine the spread between crude and wholesale distillate prices and to see whether those factors vary in magnitude during the heating season.

Each of these models is discussed is more detail in the following sections.

The Retail Market Model

Two of the behavioral relationships introduced above -- retail supply and demand -- were estimated simultaneously using monthly data, and are referred to as the "Retail Market Model". By estimating these two equations together we obtain consistent estimates of the structural parameters and avoid the bias and lack of identification of single-equation models of economic equilibria. The demand equation has this linear form:

$$Q = b_{dc1}p_1 + b_{dc2}p_2 + b_{dp}\ RP + b_{hdd}hdd + nov\ (bdc_{nov} + b_{hddnov}hdd) \qquad (1)$$

where: Q is sales of distillate per day;
RP is the residential, retail price;
hdd is heating degree day;
b_{dc1} is the constant term for FY87-90, December - March;
b_{dc2} is the constant term for FY91-96, December - March;
bdc_{nov} is the constant term for November;
nov is a dummy variable for November,
b_{hdd} is the effect of HDD on sales in December - March;
b_{hddnov} is the effect of HDD on sales in November; and
b_{dp} is the slope of the demand curve.

The retail supply equation takes this form:

$$RP = b_{rtc} + b_{lagp}RP(-1) + b_{spot}dist0 + b_{supq}Q \qquad (2)$$

where the additional variables & parameters are:

b_{rtc} is the constant term;
b_{lagp} is a coefficient for the lagged price effect;
dist0 is the real spot price of distillate;
b_{spot} estimates the current-period effect of the spot price on the retail price; and
b_{supq} estimates the slope of the supply curve.

When these two equations were estimated together, the results were:

Exhibit D-1

Parameter	Estimate	Standard Error	t-statistic	
BDC1	444.727	77.0435	5.77241	Demand constant thru FY90
BDC2	322.477	73.0146	4.41661	Demand constant after FY90
BDP	-1.27489	.626524	-2.0349	Slope of demand curve
BHDD	26.3798	1.26524	20.8496	Demand response to HDD
BDCNOV	571.501	141.069	4.05121	Nov. demand constant
BHDDNOV	11.3093	6.38134	1.77224	Nov. HDD effect
BRTC	12.3534	2.82043	4.37998	Supply eq. constant
BLAGP	.445544	.035637	12.5024	Lagged own price
BSPOT	.622427	.044047	14.1310	Whl price effect in 1st month
BSUPQ	.450064E-02	.160664E-02	2.80128	Inverse slope of supply

Log of Likelihood Function = -346.877
Number of Observations = 48

Demand Equation

Dependent variable: Q per day
Mean of dependent variable =1061.61
Std. error of regression = 42.1045
Std. dev. of dependent var. = 185.129
R-squared = .947174
Sum of squared residuals = 85093.8
Durbin-Watson statistic = 1.62145
Variance of residuals = 1772.79

Retail Supply Equation

Dependent variable: Real retail price
Mean of dependent variable = 92.1246
Std. error of regression = 1.98844
Std. dev. of dependent var. = 12.0095
R-squared = .972003
Sum of squared residuals = 189.786
Durbin-Watson statistic = 1.82350
Variance of residuals = 3.95388

The model indicates that the general level of demand shifted downward, once and for all, beginning with the 1991 heating season. Alternative models that allowed the change in intercept to phase in were inferior. All the demand models that we have tested on time periods that included several years before and after the Big Chill, indicated that there had been a significant change in the demand curve. Allowing for this shift in the intercept is also superior to allowing changes in the sensitivity to HDD and retail prices.

The price effect in the demand equation is significant and has the negative sign expected in a demand relationship. The highly significant HDD effect (BHDD) is actually the average for December through March. However, an analysis of variance of the estimated differences among months indicates that the HDD effect is stable from December to March. This consistency has shown up in many of our previous models and was one criterion for selecting this set of heating season months to include in this model.

November demand is distinctly different, but November was included in the model because lags are clearly important in the analysis of the winter market. It would seem that a model of a December crisis should include the market's behavior in November. November is clearly a transition month. Even though the end-of-month stock data show that annual peak stocks are attained at the end of October, weekly stock data show that the peak can occur at the end of the first or second week of November. The HDD effect is much weaker in November, and the price effect on demand is essentially zero. However, the retail supply process requires no special treatment for November.

The retail supply process is expressed as a partial-adjustment model. The coefficient on the lagged retail price (about 0.45) measures the fraction of retail price adjustments that show up after the current month. Thus 55 percent (one minus 0.45) of each current effect shows up immediately. Therefore, the coefficient on the spot price of distillate of 0.62 indicates that 62 percent of wholesale price increases are passed along in the first month. In the long run, the full markup is just over 100 percent.

The Wholesale Supply Model

The objective of this part of our analysis was to develop a model of the spread between the spot prices of crude and distillate. Estimating a model of this relationship is very difficult. The relationship is complex and exhibits its greatest sensitivity during crisis conditions. Thus the periods of greatest variability are those for which we have the fewest observations, which provides another modeling challenge.

We fit models using both monthly and weekly data, and investigated a variety of alternative approaches. The initial development results and insights can be summarized as follows:

Speed of response. Crude and distillate prices vary day by day in commodity markets. It is clear from inspection of the daily data on spot prices that the spot price of distillate moves in lockstep with the spot price of crude during periods when other factors, such as temperature, are relatively normal and quiet. Both markets react very quickly to current events. The implication of this behavior is that those who sell from primary stocks price their product based on replacement cost.

Effect of stocks. Both casual inspection of the data and complex modeling indicate that stocks are important in explaining the spread between crude and distillate prices. However, it is not stock levels in isolation that explain the spread; it is deviations of stock levels from "normal" or "required" levels. Therefore, when distillate inventories reach their usual annual minimum at the end of each April, there is no panic to drive the spread up. But when stocks get that low in December, the spread rises dramatically. Thus it appears that suppliers have a profile of target or normal stocks in mind and their adaptive behavior seems to be explained in terms of deviations from those targets.

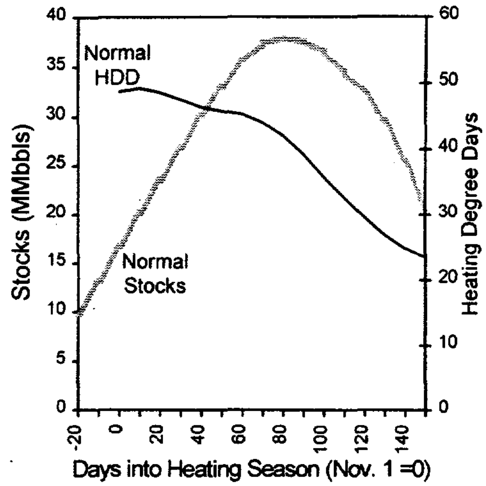
Linearity and monthly models. Even though the market for distillate clears on a daily basis, a model estimated from monthly data might still be useful, if the relationships among the variables were linear. However, all the monthly models of the spot price of distillate that we have developed clearly indicate that this is not the case. All linear monthly models severely underestimate the effect of stock shortfalls on the average spread in December 1989. Also, the December average spread was well below many daily spreads, so the nonlinear relationship would also make a linear regression projection through that average underpredict the even higher weekly or daily spreads. It is clear that a useable model must be based on weekly or daily data. However, the monthly models did provide some useful results when they were fit only to months that did not have extreme stock shortfalls. Then the results indicated that a linear model was adequate for small deviations and that the sensitivity of the spread to a fixed shortfall amount was about the same in all winter months.

Normal stock and HHD profiles. To estimate the deviations of stocks from normal levels, it is first necessary to find the "normal" levels. We estimated a series for normal stock levels through the heating season with averaging and a Bayesian smoothing technique using the weekly series of stock levels from API.[1] Exhibit D-2 provides a graph of the results. Recall, when examining the

[1] As the EIA weekly stocks series is not available before January 1990, the only weekly stock series that covered the period of analysis (1986-97) was API's. However, we adjusted the API series to fit the EIA series as closely as possible by regressing the API series on the EIA series over the period where both were available. The fitted values of the regression were then computed over the entire 1986-97 time period, and these fitted values were used in all the analyses described in this appendix.

exhibit, that the first day of the heating season is November 1. The same technique was used to estimate the typical HDD profile, and Exhibit D-2 shows that profile, too.

Exhibit D-2
Average Stock Levels and Heating Degree Days (HDD)



The final version of the wholesale supply model was estimated from weekly data. It is a composite of the general estimates of the relationship obtained from regressing the spread on the deviations in stocks for all weeks except those in which the stock shortfall exceeded eight million barrels and the specific behavior during the Big Chill. The regression on the "lower" part of the curve had an R^2 of 63 percent and a t-statistic on the effect of stock deviations of 15.75. Also, the residuals were about the same in all heating season months indicating that the relationship, once expressed in deviation terms, is stable across months. Exhibit D-3 illustrates the entire relationship.

While the curve pictured in Exhibit D-3 provides an adequate fit for most of the weekly data, during the weeks on the "down side" of the Big Chill when prices were falling and conditions were returning to normal this model consistently overestimates the spread. In other words, the spreads are lower than that predicted by the current levels of stock deviations. However, traders on this and other markets incorporate foresight into spot prices, and information on near-term imports must certainly be available. We tested this hypothesis by supposing that the market factors next week's imports into its estimate of available stocks. The data support this view, because when the weekly stock deviations are adjusted to count next week's imports as already in primary storage, the model error in predicting the spread falls to only a few cents per gallon.

<u>Other Weekly Models</u>

A weekly model of distillate sales as a function of HDD was developed by inference and indirect estimation. The form of the model is

$$Q = a + bMAHDD \tag{3}$$

where: Q is weekly sales;
MAHDD is a moving average of the last 15 daily HDDs; and
a and b are parameters.

Exhibit D-3
Effect of Stock Deviations on Wholesale Price Spread

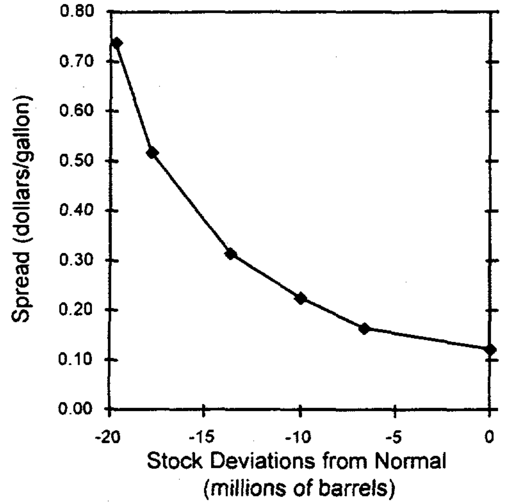
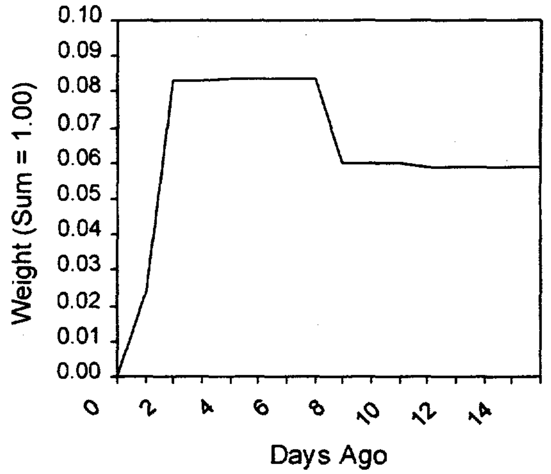


Exhibit D-4
Moving-Average Coefficients Used to Estimate the Effect of HDD on Sales



The parameter a was set at 26.6 thousand barrels per HDD. The value from the structural form of the Retail Market Model was 26.4, and the value from the reduced form (which reflects the simultaneous price effect on demand) was 24.6. However, there is considerable evidence from the various regression models that the value of this parameter is a bit higher during a crisis, perhaps from crossover demand from close substitutes for distillate. The value of 26.6 also seems to replicate the actual monthly demand of peak demand months (such as the Big Chill) when the weekly model predictions are accumulated to the monthly level.

The MAHDD variable was derived by taking a 15-day moving average of daily HDDs in the Northeast. The coefficients for this moving average could not be estimated in a direct fashion, as weekly sales data are not available. As proxy, we took the first difference in stock deviations as a measure of unanticipated changes in weekly stocks. From the standpoint of a supply process that takes about a month to react to temperature shocks, deviations in daily or weekly temperatures should show up as deviations in stock levels. A recursive estimation procedure found that only the last 15 daily HDDs appear to be correlated with these stock changes. The estimation was constrained to produce a set of coefficients that were quasiconcave, that is, no daily coefficient was allowed to be lower than both its neighbors. Exhibit D-4 provides a plot of the estimated moving average coefficients. These coefficients were used to transform the daily HDD into a weekly series for use in the weekly models.

Equation 3 has several variants that are important and useful in the simulation of the expected value of the reserve. If MAHDD is computed by taking the moving average of normal daily temperatures, the equation predicts normal sales quite well. Another variant that is consistent with this result is that a moving average of past HDD deviations predicts changes in stock deviations. This makes good sense. Because temperatures cannot be predicted more than a few days in advance, deviations from normal are unexpected and translate into temporary deviations in stock levels.

These stock deviations are termed "temporary" because they tend to return to normal. Smaller deviations in stock levels are masked by the noise in the system, but our models of the stock data show that the larger negative deviations are correlated with increases in stock levels four to six weeks in the future. This appears to be a reflection of the rational, adaptive behavior of suppliers. When unexpected sales occur and stock levels fall below normal, orders go out to refiners (when extra capacity exists) and to importers to provide replacements. We have adopted the average lag of five weeks in our modeling of this behavior.

Finally, when predicted stock deviations and actual stock additions from imports and extra production are accounted for, the residual standard error in stock levels is about 1.1 million barrels per week during the heating season. This estimate of the residual variance is important for the simulation described below, because this application focuses on extreme events and the probability of exceeding a fixed threshold. The residual variance does not affect the prediction of expected values, but it is a key parameter in the prediction of the level and the probability of extreme events.

A Model of Daily HDD

We estimated a time series model that fits the behavior of daily HDD in the Northeast to form the basis of the weather forecasting component of the model. A model was required to develop distribution of cold spells for use in the benefits analysis. We found that an adequate model consists of a daily random shock and autoregressive weights on the HDDs of the last four days. The model found that the autocorrelation pattern of today's HDD with those of the last four days was 0.707, 0.373, 0.228, and 0.163 with no significant correlations beyond the four-day lag. The residual disturbance term had a standard deviation of 5.88 degrees. The model also found an annual variation in the constant term that had a standard deviation of 0.55 degrees.

Exhibit D-5 provides graphs of the daily HDDs of four heating seasons; three are actuals, and one was produced by the simulation. The simulated series looks no different from the others. Thus, the model seems to fit the general pattern of daily HDDs; it also seems to fit the general and long-run variation, too. NOAA provided monthly average HDDs for the last 102 years. The standard deviation of the average daily HDD in those Decembers was 3.69 degrees. The standard deviation of simulated sets of 31 consecutive daily HDDs matches that almost exactly.

Regional Cost Savings and National Benefits

The objective of this part of our analysis is to estimate the expected annual value of a Reserve. The expected value is basically the product of the probability that the Reserve will be used each year times the value that would be obtained by its use. This value was measured at two levels in this analysis. It was measured, first, from a regional perspective. At this level, the value of the Reserve was taken to be the cost savings that consumers would experience, evaluated at the wholesale level.

These regional savings included the cost savings of sales of both distillate and jet fuel. The volume of distillate sales used in this calculation was a function of temperature, but jet fuel was not. Because jet fuel is chemically so similar to diesel fuel and home heating oil, its price was assumed to move in lockstep with the price of distillate, even though its sales volume could be assumed not to change with temperature.

The regional cost saving was used as an intermediate calculation to arrive at an estimate of national benefits. For reasons explained below and in Chapter IV, a dollar of regional cost saving does not translate into a dollar of national benefit. The methodology of translating regional cost savings into national benefits is explained below in detail.

This analysis uses many of the models based on weekly data that were described in the last section; and it uses several other rules and assumptions that were specific to this derivation. The documentation below presents this complex process with three parallel, complementary descriptions. First, the analysis is summarized in an overview that describes the general derivation and presents the key assumptions that were made. Then, a step-by-step description of the simulation model is provided. Finally, this section concludes with a summary spreadsheet derivation of the expected value of the reserve for a specific winter month.

Overview

The key logical steps and assumptions to arrive at the estimate of benefits can be summarized as follows:

1. Adopt a rule for triggering the use of the Reserve. We assumed that sale of the Reserve would be triggered by a cold wave, if the spot price of distillate were to rise to more than 30 cents per gallon above the spot price of crude oil. Note that it is high spreads and not high distillate prices that trigger the use of the Reserve.

2. Use the model of daily temperatures to simulate a large number of heating seasons through the middle of January. Examination of preliminary results has shown that 1200 interations provides an adequate convergence.

3. Make an initial estimate of the day in December on which the largest stock deviation would occur. Arbitrarily assign that day to be the end of the fifth week of a potential crisis. Average and add all daily variables into series of seven weeks so that the Weekly Model relationships can be applied. (Seven weeks is the period during the Big Chill during which prices and consumption were significantly affected.)

4. Using the relationships described above, estimate sales, stock deviations due to temperature shocks, and wholesale price spreads over the simulated seven-week period. Add a disturbance term to stock levels to represent the residual error found in the weekly model of stock deviations.

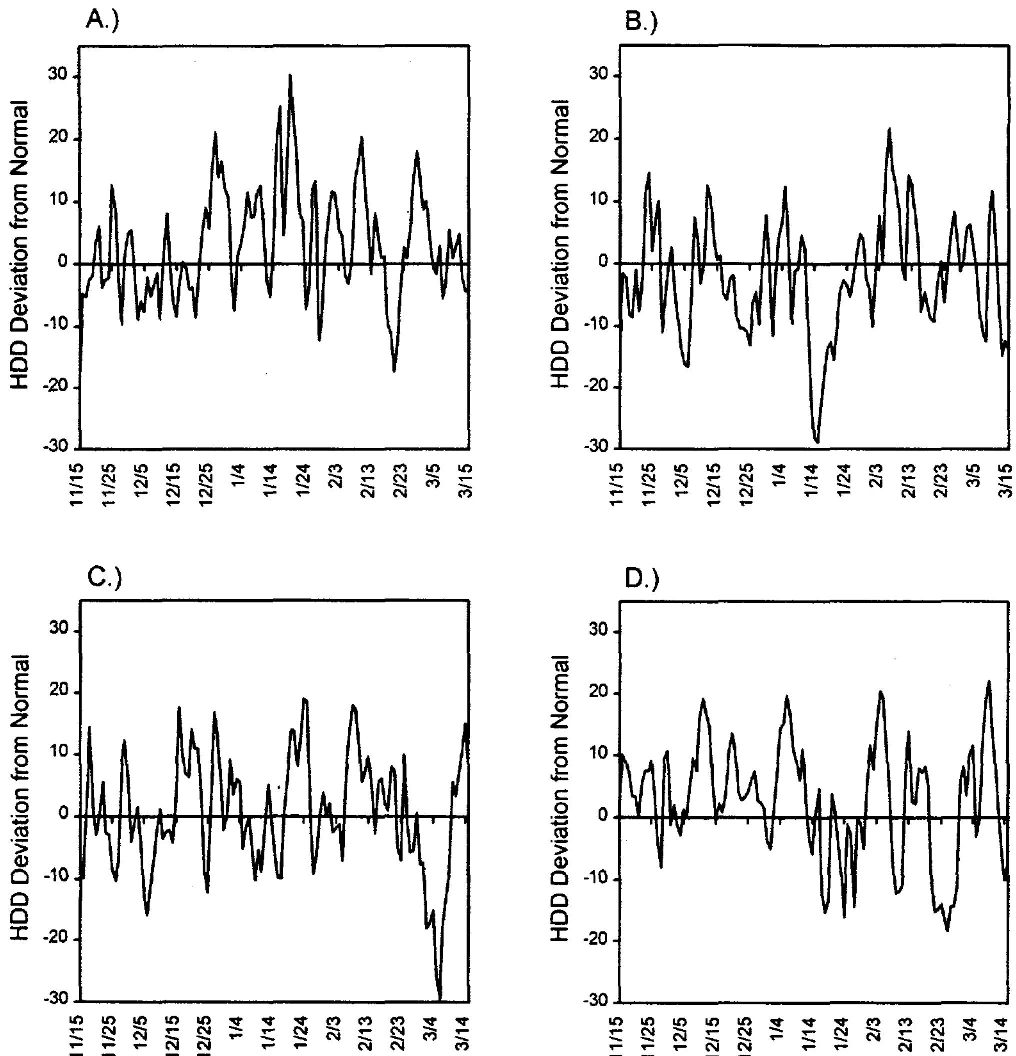
5. Assume that the Reserve is available to sell distillate immediately on any day that the spread exceeds 30 cents per gallon.

6. Estimate probabilities and expected values by accumulating and averaging over all 1200 interations.

7. Make some adjustments to the December analysis to account for different market conditions in January and February, (specifically the availability of some additional supplies from the U.S. Gulf) and repeat the analysis for those two months. Assume March could not have a crisis because its temperatures are milder and refinery flexibility is greater. The specific differences among the months have to do with starting stock levels and the ability of refiners to respond to a crisis with increased production.

8. Estimate the probability of Reserve use given low starting stock levels (presumed to be due to price backwardation) and the annual probability of low stock levels to obtain the overall annual expected cost savings and benefits of having the Reserve.

Exhibit D-5
Simulated and Actual Northeast Heating Degree Days for Four Heating Seasons



Key to Graphics:
A.) 1993-1994 Heating Season B.) 1994-1995 Heating Season
C.) Simulated Heating Season D.) 1995-1996 Heating Season

Source:
National Oceanic and Atmospheric Administration

Simulation Using the Weekly Model

The first step in the simulation of Reserve use in each month is to project daily HDDs deviations from normal. The ARIMA model whose derivation was described above has this specification:

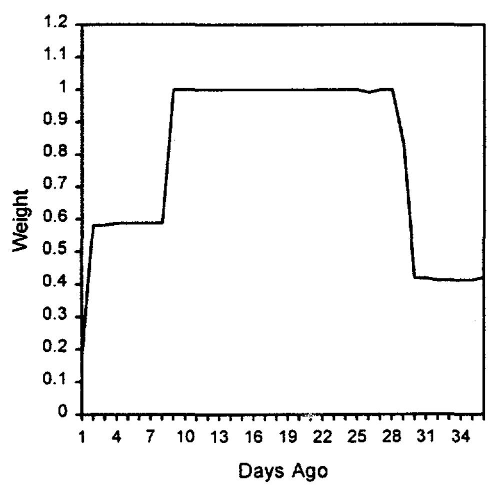
$$HDD_t = A_i + E_t + 0.97\ HDD_{t-1} - 0.47\ HDD_{t-2} + 0.24\ HDD_{t-3} - 0.059\ HDD_{t-4} \qquad (4)$$

The A_i and E_t terms are normally distributed random disturbances. The former varies from year to year (hence the I subscript, which stands for iteration), and the latter is the daily HDD variation not accounted for by lagged HDD effects. Both have zero means. Their standard deviations are 0.55 and 5.88 HDD, respectively, as mentioned above.

To simulate the need for a Reserve in December, for example, the model must project HDD_t over a wider period than just the 31 days of December. The weekly model of a typical crisis requires seven weeks rather than four and a fraction. More lead time is needed because sales in each week are a function of the previous fifteen daily HDDs, as Exhibit D-4 shows. Also, sales in December 1989 were increased somewhat by below-average temperatures during the last week of November, so some additional days should be included before the critical four-week period to capture any such "shouldering" effect. More days are needed after the cold wave has passed to account for the time that it takes stocks and prices to recover to normal levels. During the Big Chill, the shoulder on the recovery side of the crisis was about two weeks long. Finally, more days are needed because a December cold wave could end on any day in December.

Chapter IV explains that the key interval in a cold wave is the four-week period that has the greatest effect on stocks. The lag structure of Exhibit D-4 shows how one week's sales are a function of previous HDDs. Four weeks of sales would be determined by four weeks of this lag structure overlapped and added together. As one week of sales is modeled by a fifteen-day lag and each additional week adds seven more days to the structure, the resulting lag structure for four weeks of sales includes 36 daily HDDs. The complete lag structure is shown in Exhibit D-6.

Exhibit D-6
36-Day Lag Structure
To Find Maximum Four Weeks of Sales



The model uses this 36-day lag structure to find the moving average HDD deviation that ends on every day in December. Exhibit D-7 illustrates this procedure. The day on which the greatest of these deviations falls would occur at the end of the four-week period that would have the highest chance of triggering the Reserve. To make the transition from daily to weekly time periods, this day is assigned to the last day of the fifth week, so that weeks six and seven will be available to model the recovery period.

Exhibit D-7
Finding the Peak 36-Day Heating Degree Day Moving Average

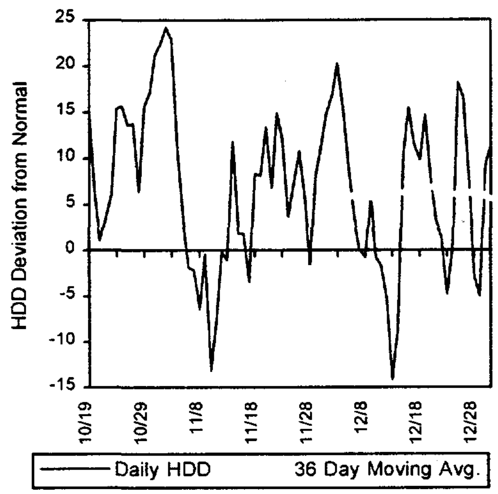
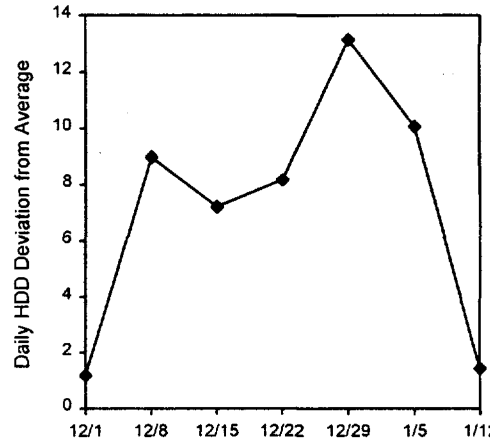


Exhibit D-8
Simulated Weekly HDD Deviations



The model then uses the lag structure of Exhibit D-4 to transform the daily HHD deviations into seven weekly HDD deviations. Exhibit D-8 shows the seven weekly HDD deviations that would be obtained from the daily data shown in Exhibit D-7.

The next step in the simulation is to determine the effect of the weekly HDD deviations on stock levels. As these deviations are unanticipated, they will generate deviations in sales that will be supplied completely out of stocks. This change in weekly stock levels is estimated as:

$$\Delta IT_w = 26.6\ HDDdev_w \tag{5}$$

where: ΔIT_w is the change in inventory due to temperature deviations,
$HDDdev_w$ is the weekly moving average temperature deviation, and
w is the subscript for weeks one through seven.

Exhibit D-9 provides an example of these stock deviations. Note that this series can also be defined as the component of distillate sales due to unanticipated HDD deviations. As the model computes the stock deviations in weeks one and two, it orders replacements, ΔR_w, from increased production and imports that arrive in five weeks:

$$R_w = \Delta IT_{w-5} \tag{6}$$

Temperature deviations are not the only source of weekly stock deviations. After accounting for the effects of temperature deviations, modeling experience has shown a residual disturbance that has a standard error of 1.1 million barrels per week. This r One can draw the inference that they are related to delays in receiving scheduled deliveries of stock replacements, because the deviations do not seem to be independent from week to week. Residual variation could be assumed to represent all other short-term shocks to stocks. Deviations often seem to be associated with other deviations of similar magnitude but opposite sign in "nearby" weeks, implying that they were both caused by an unanticipated delay or advancement in delivery. The model adopted to mimic this behavior generates seven normally distributed, independent disturbances; finds the overall mean of the seven; and subtracts this mean from each leaving seven weekly shocks that have a net disturbance of zero. Exhibit D-10 shows an example of these disturbances. Their variable name in the equations below is D_w.

Together the stock deviations due to temperature variation and residual variation model the total unexpected weekly deviations in inventory levels. Exhibit D-11 provides a comparison of the stock deviations due to temperature and the total weekly deviations that includes the residual variation.

Exhibit D-9
Weekly Sales and Stock Deviations
Due to Temperature Deviations

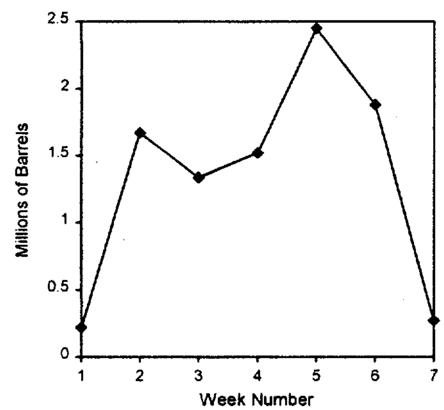


Exhibit D-10
Residual Variation in Stocks

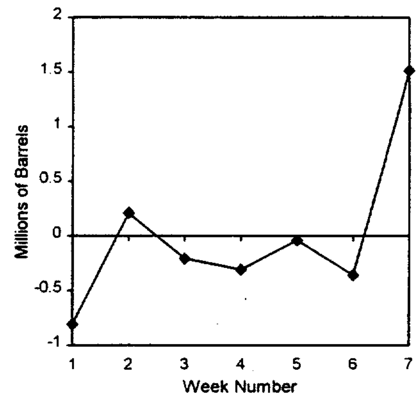
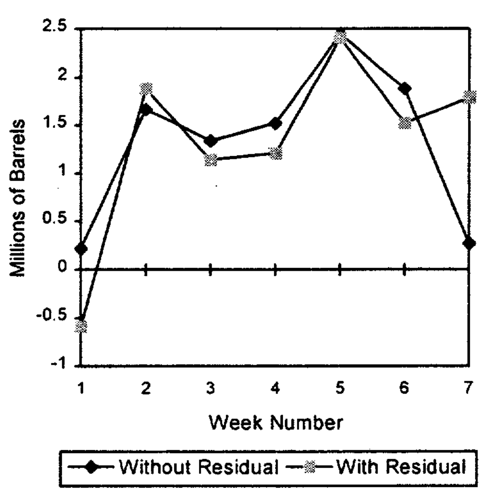


Exhibit D-11
Weekly Stock Deviations
With & Without Residual Deviations



The temperature and residual changes in stock deviation and the arrival of replacement stocks are used in an accounting relationship to find the cumulative stock deviation that would be obtained without the use of a reserve this way:

$$I_w = I_{w-1} + \Delta IT_w + R_w + D_w$$

The only element of this equation that has not been defined above is the value of I_w the week before the simulation begins. The end of week one of the simulation would correspond to Friday, the first of December during the Big Chill. On that day, the level of stocks was 8.03 million barrels below normal. Using this as the starting or reference point for stock levels has the advantage of being consistent with other parts of this analysis that are based on end-of-month stocks. The disadvantage is that this reference point is one week late in the period of analysis. One alternative is to take the actual stock deviation of the week before, 6.54 Mbbl below normal. Another would be to use the model itself to project backward one week by subtracting the effect of the colder-than-normal weather during the last week of November 1989 to yield 6.86 Mbbl below normal. The disadvantage of the latter is that the actual value is more consistent with the spread function. However, the projected value was finally adopted because it is consistent with the practice of choosing the more conservative value of a set of alternatives; a lower starting stock level will yield a higher expected benefit of the Reserve.

For each week in the I_w series the model looks up the wholesale price spread using the function illustrated in Exhibit D-3. Both the cumulative stock deviation and the spread would be affected by the use of a Reserve. The spread function indicates that a spread of 30 cents per gallon corresponds to a stock deviation of -13 Mbbl. The model assumes that the Reserve will be offered for sale immediately when the spread reaches 30 cents, and buyers may take all they like at the absolute price implied by that spread. Therefore, the model generates a cumulative stock deviation profile, given Reserve use, that is capped at -13 Mbbl and a corresponding spread profile that is capped at 30 cents per gallon. Exhibit D-12 provides a comparison of the two stock deviation series; Exhibit D-13 shows both spread series.

Exhibit D-12
Cumulative Stock Deviations

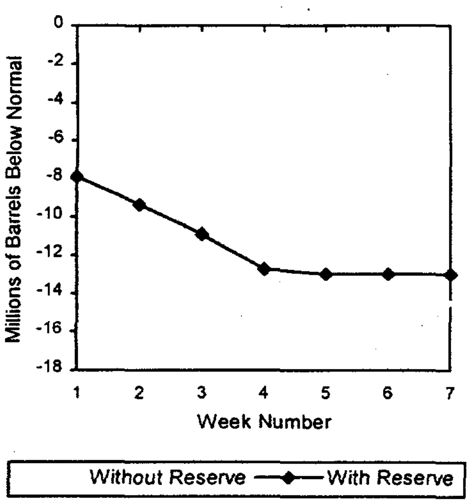
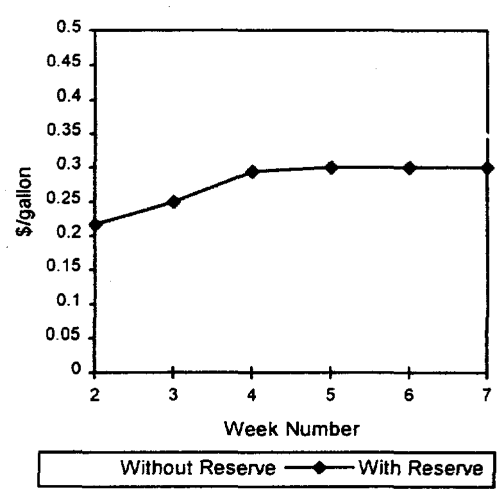


Exhibit D-13
Wholesale Price Spread



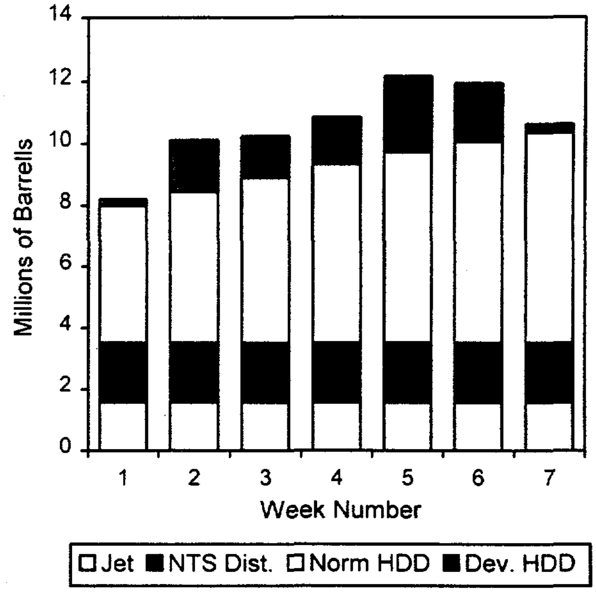
The amount of the Reserve needed to keep the price spread down to the trigger spread is not simply the difference between the two stock deviation series shown in Exhibit D-12, because these are cumulative series. The model assumes than an extra million barrels released from the Reserve will, as long as the crisis continues, continue to reduce the stock deficit. Thus, the Reserve use in the first week of the crisis (week 5 in the example) will be equal to the difference between the two series, about 2.25 Mbbl.; but in week 6 the cumulative stock deviation will also be reduced by that amount. So the requirement in week six would not be the 4.25 Mbbl difference between the two lines but 4.25 - 2.25 = 2.00 million additional barrels, and so forth. The total Reserve use for the fifth and sixth weeks would be 4.25 Mbbl. Week seven would require no additional sales from the Reserve, but the model assumes that the cumulative effect would keep the spread at the trigger level. Beyond week 7 the model assumes that the private sector reacts and adjusts to the release of oil from the Reserve and returns the market to an equilibrium that exhibits no lingering net cost or benefit from the use of the Reserve.

The difference between the spreads without and with the use of the Reserve is taken as an estimate of the average weekly price saving per gallon that the Reserve would provide. To find the cost saving due to the Reserve, the price saving must be multiplied times the corresponding volume of sales. The period of relevant sales would be the weeks during which the Reserve was used to keep the price spread at 30 cents per gallon or weeks 5-7 in the example shown in Exhibit D-13. This interval is called the "duration of the crisis" or the "period of Reserve use" below.

The model accounts for several components of distillate sales in the Northeast. One of the non-temperature sensitive components is kero-jet sales. Jet fuel can be used as a substitute for diesel fuel and heating oil (but not the other way around), and its price path during the Big Chill was highly correlated with heating oil prices. One could expect the use of the Reserve to cap the price of jet fuel, too, and provide a further benefit to its users. The average sales of jet fuel in the Northeast in 1993 was 225,330 barrels per day according to data from SEDS. This sales rate is multiplied by the number of days of Reserve use to estimate the relevant sales of jet fuel.

Sales of heating oil and diesel fuel also have a non-temperature sensitive component that the analysis estimated at 276,703 barrels per day, which is multiplied by the number of days of Reserve use. One component of temperature-sensitive sales of distillate has already been calculated as the series ΔIt_w by equation 2. The last component of sales is the demand due to normal temperatures. The model substitutes normal HDD for each week into equation 2 to derived this component. Total simulated distillate sales and all four of its components are illustrated in Exhibit D-14. The model estimates the regional cost saving due to the Reserve as the sum of the price saving in each week times the total sales in that week. For the example shown in the exhibits, this would amount to $163.7 million, given the occurrence of this event.

Exhibit D-14
Components of Weekly Distillate Sales



Notes:
Jet = Sales of Jet-Kero fuel.
NTS Dist. = Non-temperature-sensitive distillate sales.
Norm HDD = Seasonal sales with normal HDD.
Dev. HDD = Sales caused by deviations of HDD from normal.

Then the model translates regional cost savings into national benefits using two separate computations. One part of the estimated national benefit is obtained by applying an established formula for the effect of crude oil price disruptions on GDP. In theory, such a disruption has a net national cost mainly through its effect on employment. According to that formula, the elasticity of GDP with respect to the relative increase in crude oil prices is -0.021. To use this formula, we assumed that a dollar of product cost saving has the same effect on GDP as a dollar of crude oil cost saving. Given this, the steps in the calculation were:

1. Find the percentage change in the price of crude oil, P^*, that would have generated a change in the annual, national cost of crude oil consumption equal to the regional cost savings. The volume of US crude consumption was assumed to be 6,471 million barrels per year; and the price used was $17.61 per barrel. The value of crude consumed would be $113.9 billion. In the example case the regional cost savings of $163.7 million would represent P^* = 0.114 percent of this value.
2. Multiply P^* by -0.021 to get B^*, the equivalent percentage change in GDP.
3. Multiply annual GDP of $7.393 trillion by B^* to get the estimate of national benefit. In the example case, this would yield a GDP benefit of $223.1 million.

The other part of national benefits is called the "terms of trade" effect. This aspect of the benefits analysis is based on a distribution consideration. If all of the increased cost of buying petroleum products in the Northeast flowed to American citizens and companies around the country, there would be no net national benefit to having a Reserve, as all increased consumption costs in the Northeast would also be increased revenues for someone else in the country. However, some part of the increased costs would flow overseas to pay for imports. Thus the faction of increased costs for a typical disruption that have accrued to imported product would be a true national cost. We estimate that fraction at 25 percent of Northeast distillate consumption during a typical crisis.

In the example case, the terms-of-trade benefit would be \$40.9 million. The sum of the two benefit components in the example case equals \$264 million. This is the final statistic that the simulation computes for each randomly simulated winter month, which is called a "case" or an "iteration". The model collects the results of all cases in each month for which the Reserve would have been used into a spreadsheet. The base case spreadsheet for the month of December is shown in Exhibit D-15 in the next section that describes the computations in the spreadsheet.

In the example traced through above, the simulated month was assumed to be December. January and February have separate simulations that differ from December's in two sets of assumptions, as follows:

- We estimated the starting stock deviations due to backwardation as 8.0, 7.4, and 7.5 million barrels in December, January, and February by direct observation of the historical data.

- Refiners are assumed to have no excess capacity in December. By the end of January, enough excess capacity is usually available to provide one million barrels during the third week of a crisis and two million during the fourth week. Because a January crisis is equally likely to end on any day of the month, not all of this extra capacity would be available for every crisis. The model assumes, therefore, that half of this extra production is available for the average January crisis, and all of it is available during February.

Exhibit D-15
Expected Annual Benefits of a Reserve in December

# of Simulated Events	Average Length of Crisis (weeks)	HDD Deviation from norm	Average Amount of Res. Used (MMbbls)	Price Saving ($/gal)	Relevant Sales (MMbbls)	Regional Consumer Saving ($Mil)	GDP Benefit ($Mil)	Terms of Trade Benefit ($Mil)	Government Profit ($Mil)	Total National Benefit ($Mil)
1	5.00	13.55	6.22	0.212	56.55	502.68	684.96	125.67	43.56	854.19
2	4.50	8.86	4.24	0.121	50.01	253.67	345.66	63.42	29.66	438.73
3	3.33	10.10	3.84	0.130	38.49	210.28	286.54	52.57	26.85	365.96
6	4.17	9.25	3.18	0.083	45.96	161.04	219.43	40.26	22.28	281.98
10	3.40	8.83	3.18	0.077	37.70	121.36	165.37	30.34	22.29	218.00
10	3.10	8.12	2.29	0.058	35.14	85.20	116.09	21.30	16.06	153.45
10	3.00	7.53	2.09	0.050	32.27	67.85	92.46	16.96	14.65	124.07
10	2.30	7.47	1.80	0.046	24.75	47.36	64.54	11.84	12.57	88.95
10	1.80	7.08	1.48	0.039	19.10	31.25	42.59	7.81	10.38	60.78
10	1.40	6.91	1.08	0.030	14.88	19.05	25.95	4.76	7.58	38.29
10	1.90	7.16	0.77	0.015	20.57	13.17	17.94	3.29	5.38	26.62
10	1.60	6.63	0.61	0.012	17.00	8.39	11.43	2.10	4.24	17.77
10	1.40	6.67	0.33	0.007	15.40	4.38	5.97	1.10	2.28	9.35
16	1.06	5.05	0.09	0.002	11.26	1.11	1.52	0.28	0.66	2.45

				Regional Consumer Saving ($Mil)	GDP Benefit ($Mil)	Terms of Trade Benefit ($Mil)	Government Profit ($Mil)	Total National Benefit ($Mil)
Events Requiring Reserve	118		EV* given occurrence ($Mil)	55.97	76.27	13.99	10.86	101.13
Simulations Run	1200		Conditional Prob. of Use	9.83%	9.83%	9.83%	9.83%	9.83%
Conditional Prob. of Use	9.83%		EV* given backwardation	5.50	7.50	1.38	1.07	9.94
Prob. of backwardation	33.33%		Prob. of backwardation	33.3%	33.3%	33.3%	33.3%	33.3%
Marginal Prob. of use	3.28%		Ann. Expected Value ($Mil)	1.83	2.50	0.46	0.36	3.31

* EV= Expected Value

The spreadsheet of summary results from the January and February simulations are shown in Exhibits D-16 and D-17, respectively.

Spreadsheet Summaries of Simulation Results

The results of the simulation for December are summarized in Exhibit D-15. The spreadsheet shown there calculates the expected cost savings of having a reserve in each future December by accumulating and averaging the results of the simulation.

- The first column is a count of the number of iterations that were grouped into each row in the body of the spreadsheet. For example, the first row is reserved for the single iteration that required the greatest use of the reserve and provided the greatest cost saving of $502.68 million.[2] Fewer iterations are averaged into the first few rows to provide more detail to the upper tail of the distribution of value. The lower-valued results are grouped into sets of ten.

- The second column shows the average duration of the crises where duration is taken to be the time during which the reserve would have been used to depress the spread in wholesale prices. The actual duration during the Big Chill was 26 days or about four weeks.

- The third column shows the average daily HDD deviation from normal for each group.

- The fourth column is the average use of the Reserve in millions of barrels.

- The fifth column shows the average reduction in price per gallon that would have been obtained by selling distillate from the Reserve immediately and as needed to keep the spread from exceeding 30 cents per gallon.

- The average relevant sales shown in the sixth column is total sales of distillate and jet fuel during the crisis.

- The numbers in the seventh column, the regional cost saving due to the Reserve, are simply the product of the average price saving and the relevant sales.

The last four columns in Exhibit D-15 show the results of transforming the regional cost savings into national benefits. The next column to the right of the cost savings is the estimated effect of the regional cost savings on the annual gross domestic product (GDP). As the exhibit shows, the GDP benefits are about 60 percent higher than the cost savings. Another part of national benefits is called the "terms-of-trade" effect. This component is shown in the next column. As the discussion in the last section indicated, this equals one-quarter of the regional cost saving.

[2] Note that the first row in this spreadsheet is not a representation of the Big Chill. This case is a simulation, as are all the other cases. The Big Chill was the coldest December in recorded history and the case in the first row is the coldest among the simulated cases. This and any other similarities between the two are purely coincidental. In particular, the Reserve use of 6.38 million barrels in the first simulated case is unrelated to the Reserve use of 6.7 million barrels that might be expected during a repetition of the Big Chill. The purpose of a simulation is to estimate expected values by averaging a large number of cases. The detail on the individual cases is provided here to give an indication of the possible distribution of Reserve use, cost savings, etc., but no particular significance should be attached to the outcome of any single case.

Exhibit D-16
Expected Annual Benefits of a Reserve in January

# of Simulated Events	Average Length of Crisis (weeks)	HDD Deviation from norm	Average Amount of Res. Used (MMbbls)	Price Saving ($/gal)	Relevant Sales (MMbbls)	Regional Consumer Saving ($Mil)	GDP Benefit ($Mil)	Terms of Trade Benefit ($Mil)	Government Profit ($Mil)	Total National Benefit ($Mil)
1	5.00	11.15	4.20	0.110	55.92	257.68	351.12	64.42	29.37	444.91
2	4.50	5.85	4.25	0.117	45.81	224.70	306.18	56.17	29.74	392.10
2	4.50	9.84	3.98	0.097	49.21	201.21	274.17	50.30	27.88	352.35
2	4.50	11.38	3.85	0.074	49.86	154.28	210.23	38.57	26.98	275.78
4	4.25	10.24	2.29	0.053	47.61	106.48	145.10	26.62	16.06	187.78
7	3.29	8.88	2.23	0.052	37.65	82.50	112.42	20.62	15.58	148.62
7	3.14	8.34	1.76	0.038	33.94	54.49	74.25	13.62	12.32	100.20
7	2.57	6.80	1.63	0.034	26.91	38.94	53.06	9.73	11.38	74.17
7	2.43	8.10	1.12	0.026	26.40	28.57	38.94	7.14	7.85	53.93
7	2.00	7.65	1.05	0.023	21.42	20.73	28.25	5.18	7.35	40.78
7	1.43	6.17	0.89	0.021	16.42	14.29	19.47	3.57	6.25	29.29
7	1.86	7.78	0.62	0.012	20.43	10.13	13.80	2.53	4.37	20.71
7	1.14	6.01	0.52	0.012	12.04	5.97	8.13	1.49	3.63	13.25
7	1.00	6.59	0.28	0.007	11.25	3.24	4.42	0.81	1.95	7.18
7	1.00	6.55	0.14	0.004	10.82	1.61	2.20	0.40	0.96	3.57

				Regional Consumer Saving ($Mil)	GDP Benefit ($Mil)	Terms of Trade Benefit ($Mil)	Government Profit ($Mil)	Total National Benefit ($Mil)
Events Requiring Reserve	81		EV* given occurrence ($Mil)	45.28	61.69	11.32	9.44	82.45
Simulations Run	1200		Conditional Prob. of Use	6.75%	6.75%	6.75%	6.75%	6.75%
Conditional Prob. of Use	6.75%		EV* given backwardation	3.06	4.16	0.76	0.64	5.57
Prob. of backwardation	33.33%		Prob. of backwardation	33.3%	33.3%	33.3%	33.3%	33.3%
Marginal Prob. of use	2.25%		Ann. Expected Value ($Mil)	1.02	1.39	0.25	0.21	1.86

* EV= Expected Value

Exhibit D-17
Expected Annual Benefits of a Reserve in February

# of Simulated Events	Average Length of Crisis (weeks)	HDD Deviation from norm	Average Amount of Res. Used (MMbbls)	Price Saving ($/gal)	Relevant Sales (MMbbls)	Regional Consumer Saving ($Mil)	GDP Benefit ($Mil)	Terms of Trade Benefit ($Mil)	Government Profit ($Mil)	Total National Benefit ($Mil)
1	4.00	11.32	3.53	0.096	47.44	190.35	259.38	47.59	24.74	331.70
1	4.00	10.72	2.48	0.078	45.39	148.33	202.11	37.08	17.35	256.55
2	3.00	6.65	2.24	0.066	30.85	85.81	116.93	21.45	15.69	154.07
2	2.50	10.90	1.90	0.051	29.69	63.12	86.00	15.78	13.28	115.06
2	3.50	8.22	1.45	0.033	37.69	52.72	71.83	13.18	10.18	95.19
4	1.75	8.22	1.96	0.055	20.34	47.30	64.45	11.83	13.74	90.02
5	2.00	7.36	1.35	0.032	21.84	29.48	40.17	7.37	9.48	57.01
6	1.50	6.45	0.90	0.022	15.79	14.64	19.95	3.66	6.27	29.88
6	1.33	8.06	0.61	0.013	14.75	8.03	10.94	2.01	4.30	17.25
6	1.33	6.48	0.42	0.009	14.55	5.27	7.18	1.32	2.97	11.47
6	1.33	7.25	0.27	0.006	14.07	3.51	4.78	0.88	1.91	7.57
6	1.17	7.72	0.10	0.003	12.88	1.39	1.89	0.35	0.71	2.95

				Regional Consumer Saving ($Mil)	GDP Benefit ($Mil)	Terms of Trade Benefit ($Mil)	Government Profit ($Mil)	Total National Benefit ($Mil)
Events Requiring Reserve	47		EV* given occurrence ($Mil)	27.14	36.98	6.78	6.80	50.57
Simulations Run	1200		Conditional Prob. of Use	3.92%	3.92%	3.92%	3.92%	3.92%
Conditional Prob. of Use	3.92%		EV* given backwardation	1.06	1.45	0.27	0.27	1.98
Prob. of backwardation	33.33%		Prob. of backwardation	33.3%	33.3%	33.3%	33.3%	33.3%
Marginal Prob. of use	1.31%		Ann. Expected Value ($Mil)	0.35	0.48	0.09	0.09	0.66

* EV= Expected Value

The third component of the national benefit is the profit that the Government could expect to make on the sale of its distillate. This is a component of value that was not discussed above as part of the simulation because it is a linear effect (unlike the GDP formula) that can be added on after the model iterations have been aggregated into the rows of the monthly spreadsheets. The net profit per gallon of selling the Reserve's distillate is assumed to be 16.67 cents per gallon. The gross profit per gallon would be 19 cents because the sale price would be 30 cents above the price of crude oil, and the cost analysis assumes that the Reserve's distillate would be purchased at a spread of 11 cents per gallon. However, the cost analysis also assumes that one-third of the Reserve's stock would be turned over each year. Thus, two-thirds of the Reserve would have to be replaced ahead of schedule during the next refill at a cost of 3.5 cents per gallon. This would yield a net profit rate of 16.67 cents per gallon, and the total profit would simply be this rate times the amount of distillate sold from the Reserve. The last column on the right, "National Total Benefit", is simply the sum of the three components of the national benefit.

Each of the 118 iterations that simulated a crisis is equally likely to occur, so the various expected values of the use of the Reserve are simple averages of the cost savings of those cases. These averages are shown just below the far-right columns as "EV given occurrence" and is equal to $90.27 million in total benefits. Thus, the model predicts that if crude oil prices were in backwardation and if temperatures were low enough in December to trigger Reserve use, then one could expect the benefit to be $90.27 million per occurrence.

Then the probability of having a severe December is 118/1200 or 9.83 percent. This is multiplied by the conditional expected value, "EV given occurrence", to yield the $8.88 million expected benefit of the Reserve given only that backwardation (or low stock levels) has occurred. In the nine years of spot price data available, backwardation during the stockup period seems to have reduced stocks no more than three times, which gives us an estimate of 3/9 = 33.33 percent probability of backwardation. Multiplying this probability by the EV given backwardation gives $2.96 million as the expected benefit of the Reserve each future December. Exhibits D-16 and D-17 show the simulation results for January and February.

Exhibit D-18 provides a summary of annual expected benefits. Recall when interpreting this table that the column showing total national benefits on the far right is the total of the GDP benefit, the terms-of-trade benefit, and the expected Government profit. The regional consumer saving estimates determine the GDP and terms-of-trade benefits but do not add directly into the total estimated benefit.

Exhibit D-18
Summary of Annual Expected Values

	Regional Consumer Saving ($Mil)	GDP Benefit ($Mil)	Terms of Trade Benefit ($Mil)	Government Profit ($Mil)	Total National Benefit ($Mil)
December	1.83	2.50	0.46	0.36	3.31
January	1.02	1.39	0.25	0.21	1.86
February	0.35	0.48	0.09	0.09	0.66
Total Annual Benefit	**3.21**	**4.37**	**0.80**	**0.66**	**5.83**

Using the Weekly Model to Simulate the Big Chill

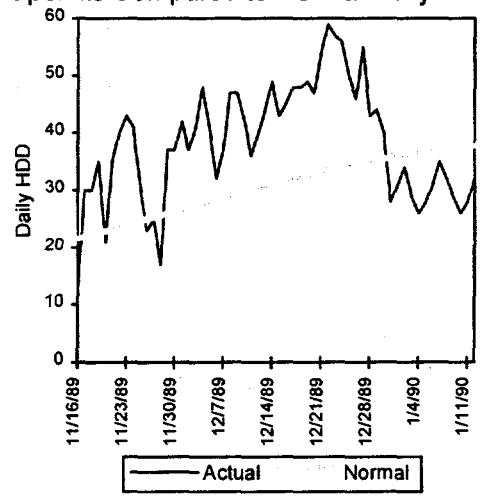
The Weekly Model was also used to replicate and analyze the behavior of the distillate market in the Northeast during the Big Chill. Using the Weekly Model as described above, this analysis provided a detailed, weekly description of the behavior of the market during a cold-wave crisis at the wholesale level. Then, by using the results of the simultaneous equations described at the beginning of this appendix, the weekly pattern of prices and demand at the retail level was also projected by an extension of the model.

These estimates of market behavior on a weekly basis provide a level of detail that is important in policy analysis. These results provide a better estimate of the profiles of sales and prices over time. The model can show how much the cold wave cost the typical consumer and can estimate how much of that cost could have been avoided by the use of a Reserve.

When the Weekly Model is used to mimic the behavior of the market during an actual instead of a simulated cold wave, it does not have to estimate all of the dependent variables. Some of the variables have actual weekly observations during this period; stock level data, for example, are available on a weekly basis. However, other variables, such as sales, are available only on a monthly basis. The Weekly Model can provide inferences about the missing variables that should be quite reliable, because the weekly projections can be aggregated to the monthly level for comparison against the available monthly data.

To produce this analysis the model's equations are applied, when needed, in the same order as that of the simulation. First, the daily HDD deviations for the period from the middle of November 1989 to the end of January 1990 were obtained by subtracting the Weekly Model's estimates of normal HDD from the observed, actual HDDs. The resulting series of daily HDD deviations is shown in Exhibit D-19 as the differences between the normal and actual HDDs.

Exhibit D-19
Heating Degree Days (HDD) During 1989 Cold-
Spell as Compared to Normal Daily HDD



These daily HDD deviations were transformed into weekly deviations using the usual fifteen-day lag structure used in the simulation. The weekly moving-average HDD deviations derived from this transformation are shown in the second column of the table in Exhibit D-20. That same transformation was applied to the normal HDD series to obtain the weekly series of normal HDDs shown in the next column of that table.

Exhibit D-20
Incremental Cost of the Big Chill at Wholesale

Week Ending	Normal HDD	HDD Deviation from Normal	Normal Sales	Sales Deviation from Normal	Assumed Sales Deviation	Assumed Total Sales
12/1/89	24.0	6.10	6.41	1.14	1.14	7.54
12/8/89	26.4	9.67	6.85	1.99	1.99	8.84
12/15/89	28.8	12.31	7.31	2.33	2.33	9.64
12/22/89	31.1	13.88	7.73	2.54	2.54	10.27
12/29/89	33.1	17.59	8.11	3.35	3.35	11.46
1/5/90	35.0	7.68	8.45	1.39	1.39	9.84
1/12/90	36.6	-4.54	8.74	-0.76	0	8.74
Totals		**470.6**	**53.6**		**12.7**	**66.3**

Week Ending	Normal Spread ($1996)	Spread Deviation from Normal	Increased Cost from Increased Sales	Increased Cost from Increased Price	Total Increased Cost	Cost Covered by Reserve
12/1/89	0.1168	0.0788	29.6	56.6	86.2	
12/8/89	0.1168	0.1100	51.7	78.0	129.7	
12/15/89	0.1168	0.1976	60.5	120.5	181.0	5.83
12/22/89	0.1168	0.4012	66.1	216.2	282.3	94.02
12/29/89	0.1168	0.6226	87.2	347.8	435.0	211.48
1/5/90	0.1063	0.3326	36.0	178.8	214.8	57.40
1/12/90	0.1063	0.1920	0.0	107.2	107.2	
Totals			**331.1**	**1105.1**	**1436.2**	**368.74**

Percent of Price Increase Covered by a Reserve	33%

Equation 2 from the Weekly Model was used to estimate distillate sales excluding jet fuel from these HDD series. It is straightforward to estimate normal weekly sales, the deviation in sales, and estimated total weekly sales. All three series are shown in the next several columns of the table. The table has two columns for the sales deviations labeled "Actual" and "Assumed" because sales and consumption were higher than normal for only the first six weeks of the seven-week period modeled here. Then, in the last week of the cold wave, the temperature and sales deviations were actually below normal. Even though one purpose of this exercise is to replicate the experience of the Big Chill, another purpose is to predict what might happen were such an event to occur again. On statistical grounds there is no good reason to expect temperatures the next week after the end of the cold wave to be anything but normal. Therefore, we have set the "assumed" sales deviation to normal; and we have used this series in all further calculations.

The next column in the table is the average spread of the wholesale spot price of distillate. Each weekly entry in this series is simply the observed monthly average spread over the period 1987-96 with the December and January of the Big Chill excluded. The weekly spread deviation from normal in the next column is simply the observed weekly spread minus the normal spread.

The actual data and model estimates discussed so far are the key inputs required to desegregate the extra cost of the cold wave into its components. Unlike a price spike caused by, say, a supply disruption, the cost increases experienced during the Big Chill were due to increases in both consumption and prices. One component of the cost increase can be isolated by considering how costs would have risen just because of the greater consumption caused by the cold wave. Consider this hypothetical example: Suppose the government were to provide a Reserve so large that it could meet all the increase in demand in such a timely and responsive fashion that prices would not rise at all. Even so, consumers would still have to burn extra oil to keep warm and would still have to pay for it at normal prices. The column in the table labeled "Increased Cost from Increased Sales" estimates this component as the product of the deviation in sales times the normal distillate price. The seven-week total extra cost is $331.1 million.

The price of distillate used in this calculation is set at 61.9 cents per gallon, which is the average observed price during periods when the spot and future prices of crude are said to be in cotango. During periods of backwardation, the usual price of distillate averages about ten cents per gallon more than that. We have chosen to account for this effect as part of the increased cost due to higher prices. So this component of increased consumer costs includes both the price increase due to backwardation and due to increased demand. This column in the table is equal to ten cents per gallon plus the increased spread due to stock shortfalls, all times total sales. The seven-week total of this component of the cost increase is $1105.1 million. The sum of the two cost-increase components is $1436.2 million.

If the Reserve had been available for sale the moment that the spread reached 30 cents per gallon, it could have prevented price rises above this point. The model indicates that the maximum stock shortfall attained was -19.7 million barrels. The 30-cent spread point was reached at -13 million barrels; so, in theory, the Reserve's 6.7 million barrels could make up that difference and maintain the price spread at 30 cents per gallon.

The next column calculates the cost saving that use of the Reserve might have provided. This is simply the difference in the spread that would have been obtained without the Reserve minus the trigger spread of 30 cents per gallon times total sales of distillate. During the four weeks that the spread would have been held down to 30 cents, the cost savings generated would have equaled $368.7 million. This represents 33 percent of the total cost increase due to price increases.

The analysis of the Big Chill to this point has used sales of distillate without jet fuel, because this level of aggregation is more relevant to the analysis of the savings per household that follows in the next section. However, it is straightforward to derive the national benefits implied by the regional cost savings shown in Exhibit D-20. To do this, the first step is to add in the regional cost savings from jet fuel sales. Exhibit D-21 shows that this component of regional cost savings would be $56.5 million. This is obtained by using the distillate price saving of $0.213 per gallon derived above and applying that to 6.31 million barrels of jet fuel sales. This rate of sale of jet fuel is the same as that used in the benefits simulation model. This yields the total regional cost saving of $425.2 shown in Exhibit D-21.

Exhibit D-21
Regional Cost Savings with Jet Fuel and National Benefits (Mil$)

Element	Savings/Benefit
Savings without Jet Fuel	$368.7
Average price saving/gallon	$0.213
Jet fuel sales (MMbbls)	6.31
Jet fuel cost saving	$56.5
Total Regional Cost Saving	$425.2
Terms of Trade Benefit	$106.3
GDP Benefit	$685.7
Reserve Use	6.70
Profit per gallon	$0.167
Profit on Reserve Sale	$46.9
Total Benefit	**$838.9**

The next several computational steps shown in Exhibit D-21 use the same formulas and parameter values that were discussed in the section above on the simulation. The total national benefit that would have been obtained is estimated at $838.9 million.

Cost Increases and Potential Savings per Household

The model results for the overall distillate market can be used to estimate the costs per household and the possible savings that the use of a Reserve could provide. The costs and potential savings discussed in the last section included the residential, commercial, industrial, and transportation/utility sectors of the distillate market. For each of the market-wide cost components it is possible to estimate the fraction that should accrue to the residential sector alone.

First, DOE's State Energy Data System (SEDS) shows that the residential sector consumed 53.4 percent (117.2/279.4) of the total fuel oil in the Northeast in 1993. This implies that the residential share of the total $1105 million of cost increases due to price increases would be $590 million.

The residential sector's appropriate share of cost increases due to higher consumption is more than 53.4 percent, because the transportation/utility sector is assumed to have had no increase in consumption during the cold wave. The usual residential share of consumption in the other three sectors is 65 percent. This fraction of $331.1 million is $215 million.

However, this increase in cost at the wholesale level would have experienced the usual retail markup of 61 percent, which would cost the residential sector another $132 million (61 percent of $215 million).

In addition to that, the econometric model of monthly retail prices discussed at the top of this appendix found that increases in sales volume at the retail level caused increases in the retail sales prices. This effect simply reflects the positive slope of the retail supply curve. For the average increase in sales level during the Big Chill, this would amount to 2.8 cents per gallon. This effect cost the residential sector another $51 million or 65 percent of assumed total sales of distillate of 66.3 million barrels (Exhibit D-18) times $0.028 per gallon.

The total of these four components yields an increased cost for the residential sector of $988 million. To convert this to a per-household basis, we referred to DOE's Residential Energy Consumption Survey (RECS). According to that source, the average household in the Northeast region consumed about 740 gallons of fuel oil in 1993. The SEDS 1993 estimate of the annual fuel oil consumption of the residential sector (used above to find the residential share) was 117.2 million barrels. Together, these estimates imply that the number of households in the Northeast that heat with distillate would be 6.65 million (117,200,000 bbl x 42 gpb / 740 gal.).

This implies an average cost increase per household of:

$149 = $988 million / 6.65 million households

It is interesting to compare this to the average bill per household during normal weather. During the seven-week period used in the spreadsheet above, the normal total sales are shown as 53.6 million barrels. Of this amount, the SEDS indicates that 11.8 million barrels will be sold to the transportation/utility sector. Again using the 65 percent conditional share of the residential sector implies that the normal consumption of that sector is 27.3 million barrels during this period. This implies that the normal household consumption during this period would be

172 gallons = 27,300,000 bbl x 42 gpb / 6.65 million households.

As the typical retail price is $1.00/gallon, the typical bill for normal temperatures would have been $172.

Of the $149 cost increase per household, the use of the Reserve would have saved each household only a fraction of the increase due to increased prices. The increased cost due to increased prices per household would have been:

$89 = $590 million / 6.65 million households

In the spreadsheet in Exhibit D-20, the portion of this component of the cost increase that the Reserve could have prevented was estimated at 33%. Therefore the average saving that the Reserve could provide each household would be:

$29 = $89 x 33% (rounded to $30 in the body of the report)

Finally, this represents

20% = $29 / $149

of the total incremental cost per household.

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Appendix E

Regional Product Reserve Study

Prepared by:

PB-KBB, Inc.

APPENDIX E
REGIONAL PRODUCT RESERVE STUDY
DRAFT REPORT - SECOND REVISION

Prepared for

U.S. DEPARTMENT OF ENERGY

STRATEGIC PETROLEUM RESERVE PROGRAM

Task Assignment No. 46

Prepared by

PB-KBB INC.

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HOUSTON, TEXAS 77224

First Revision: April 7, 1997

Second Revision: June 27, 1997

PB-KBB

FENIX & SCISSON

ENGINEERING CONSTRUCTION OPERATIONS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ATTACHMENTS

1.0 INTRODUCTION

1.1 AUTHORITY

Under subcontract to ICF Resources, Inc., PB-KBB was assigned Task No. 46 to contract number DE-AC01-93FE62554 with the Strategic Petroleum Reserve (SPR) Office of the Department of Energy (DOE). This task required PB-KBB to identify the construction and operational requirements, costs and schedules involved with developing a regional refined product reserve to store and supply heating oil for the northeastern United States during severe winter energy emergencies.

1.2 STATEMENT OF WORK

The task called for PB-KBB to identify the technical requirements, estimated costs and schedules, distribution capabilities and manpower requirements for the various alternatives identified by the SPR Office.

1.3 ALTERNATIVES

This report is organized to describe the two alternatives identified by the SPR Office:

- Conversion of an existing crude oil storage cavern at Big Hill.
- Development of three new heating oil storage facilities to be located in the northeastern U.S.

2.0 PRODUCT STORAGE IN EXISTING SPR GULF COAST FACILITIES

2.1 FACILITY CONSTRUCTION REQUIREMENTS

2.1.1 Big Hill SPR Facility Overview

Big Hill SPR storage facility is a complex of 14 underground caverns with a total crude oil storage capacity of 160 MMB. Big Hill is located west of Beaumont/ Port Arthur, Texas and is connected to the Sun and UNOCAL oil terminals in Nederland via a DOE-owned 36" oil pipeline. This pipeline also connects to Texaco's 20" pipeline which extends west to Houston.

2.1.2 Basis of Design

Fundamental design bases for the development of product storage at Big Hill include:

- The product would be heating oil (#2 fuel oil), with a specific gravity of 0.85, viscosity of 4.2 cP @ 60° F (2.9 cP @ 100° F) and RVP = 0.
- The product storage mission would be subordinate to the crude oil storage and distribution mission. Product fill and withdrawal operations will not occur simultaneous with crude oil operations, so existing crude oil handling systems and equipment may be used for product oil transfers.
- Product storage systems would utilize existing site systems and equipment to the maximum practicable extent.
- In order to respond to heating oil shortages, pipelines and piping systems to be used for both product and crude oil will be left in product service during standby storage operations.
- Crude oil systems and equipment which are used for product must at all times be capable of restoration to crude oil service within a period of two weeks.

- Total product storage would be 6.7 million barrels (MMB), located in one existing 11.5 MMB cavern.
- Target product fill and withdrawal flow rates would be 100 and 250 thousand barrels per day (MBD), respectively.
- Withdrawal would be via the DOE 36" oil pipeline to the UNOCAL terminal in Nederland.

2.1.3 Big Hill Product Handing Systems

The proposed product storage facility would consist of converting one existing nominal 11.5 MMB crude oil storage cavern to store heating oil. Cavern conversion would involve relocation of crude oil from the selected cavern and draining and refilling pumps and piping systems prior to product storage operations. Preliminary conceptual designs indicate that virtually all existing systems and equipment are compatible with and suitable for storage of heating oil and no significant site modifications are contemplated, although it will be necessary to install several pig launcher barrels, drop-out spools and additional vents and drains to facilitate line cleaning for service conversion.

2.1.4 UNOCAL Product Handing Systems

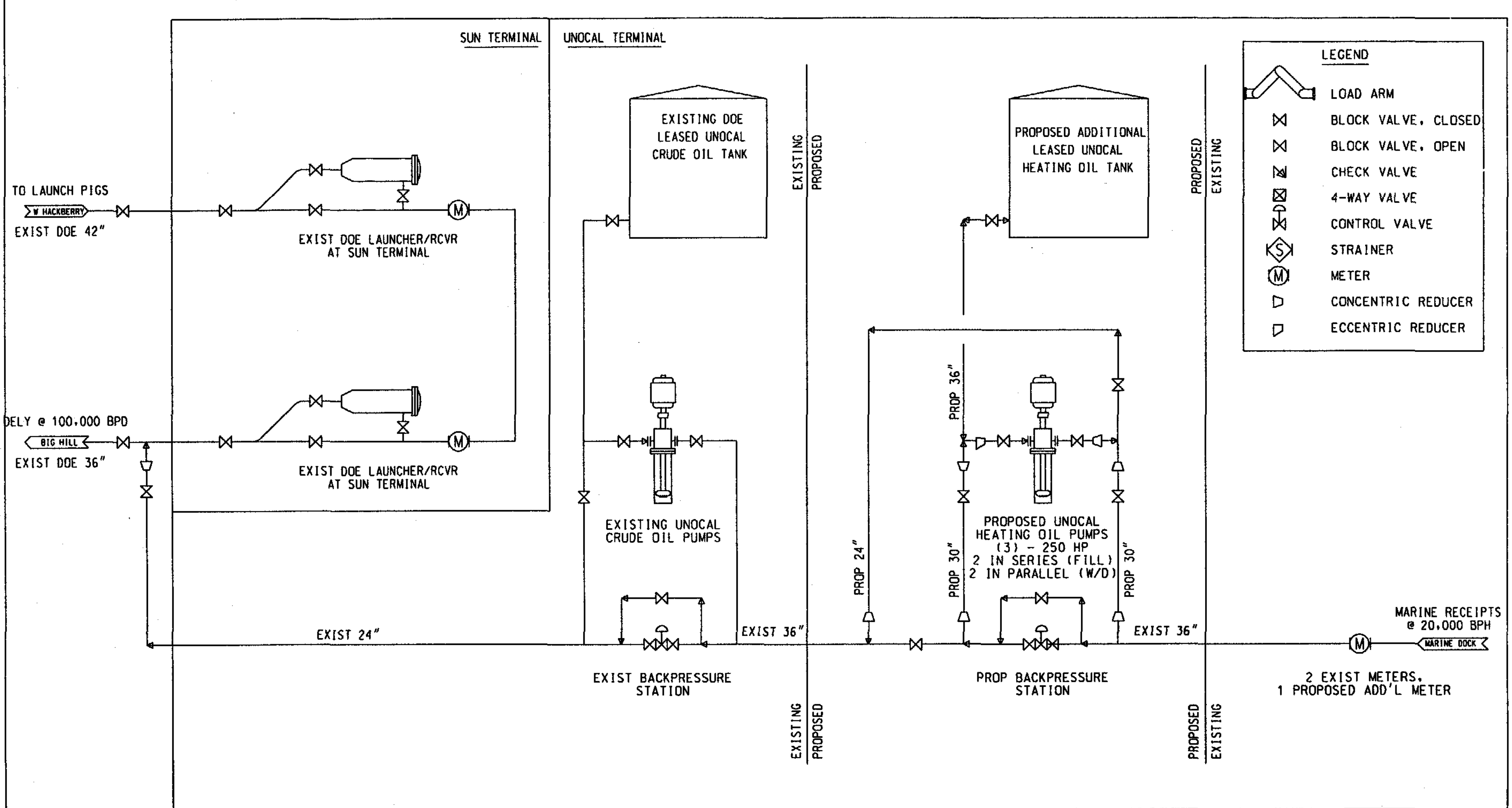
It would be necessary to construct and lease additional facilities to handle SPR heating oil at UNOCAL terminal. Figure 2-1 is a process flow diagram for Big Hill heating oil fill operations and Figure 2-2 presents a process flow diagram for heating oil withdrawal operations. These Figures illustrate both existing and proposed equipment at UNOCAL (and Sun) terminals. Proposed facilities at UNOCAL include:

- One additional leased heating oil storage tank with a minimum capacity of approximately 200 thousand barrels (MB), tied-into the existing 36" UNOCAL crude oil dock pipeline via a new 36" branch line.
- Three new 250 HP heating oil pumps, including two operating and one

installed spare.

- One additional dock meter at the existing crude oil dock meter station, in order to increase the meter station capacity to 250 MBD (25 MBH operating) from its present capacity of 200 MBD. This addition would not be necessary if the withdrawal rate were reduced to 200 MBD.
- Ancillary piping and electrical systems and equipment.

Figure 2-1. UNOCAL Oil Fill Process Flow Diagram



GENERAL NOTES	REFERENCE DRAWINGS	PROJ. No.	REV. No.	LOC.	REVISIONS	REVISED BY DATE	CHECKED BY DATE	APPROVED BY DATE

STRATEGIC PETROLEUM RESERVE OFFICE

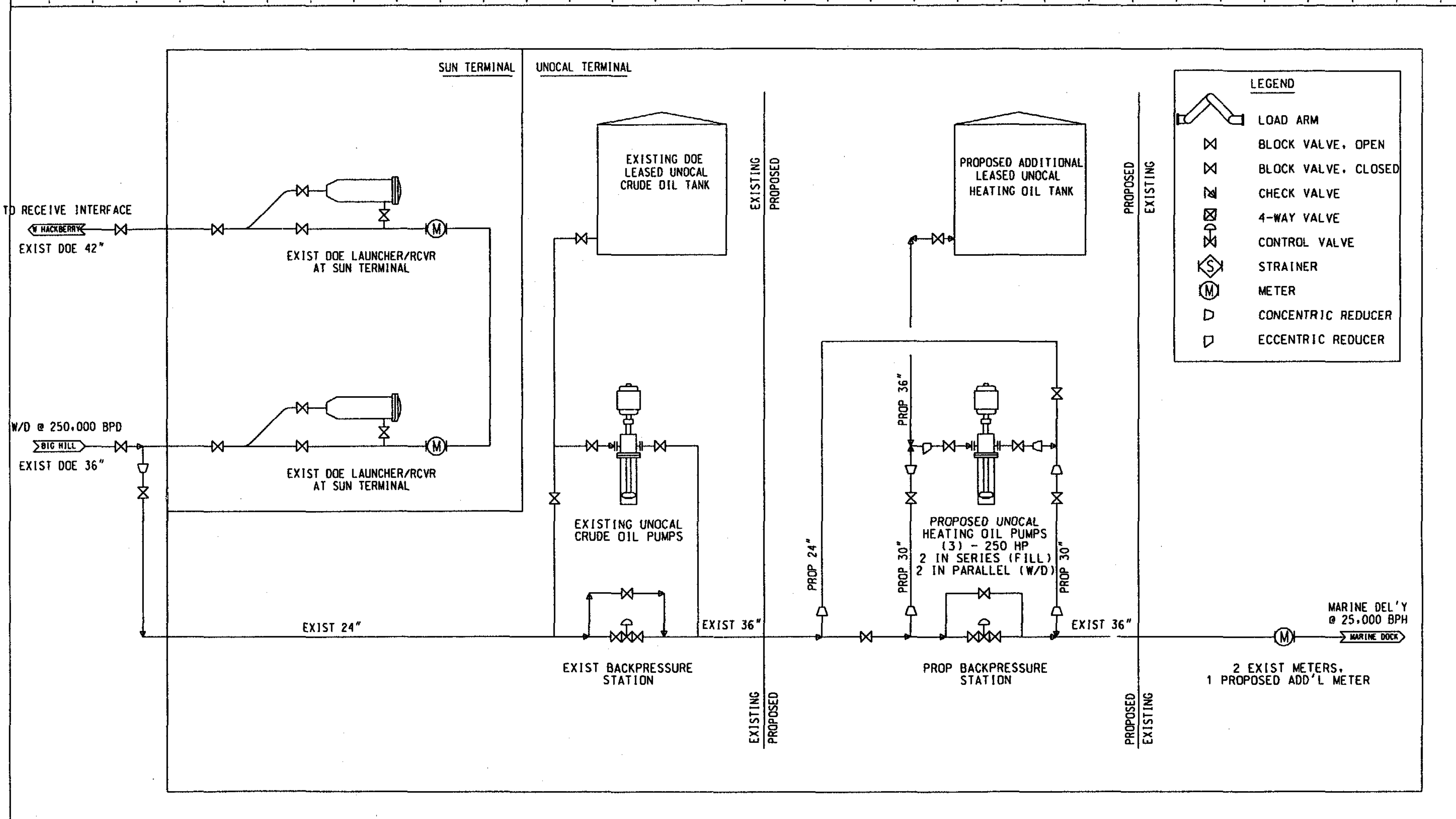
PB-KBB Inc.
Engineering Construction Operations
11757 KATY FREEWAY #800
HOUSTON, TEXAS 77079

TITLE: SPR REGIONAL PRODUCT RESERVE
UNOCAL TERMINAL
OIL FILL PROCESS FLOW DIAGRAM

TR 3-18-97 TR 3-18-97 NONE TASK 46

FIGURE 2-1

Figure 2-2. UNOCAL Oil Withdrawal Process Flow Diagram



GENERAL NOTES

REFERENCE DRAWINGS

PROJ. No.	REV. No.	LOC.	REVISIONS	REVISED BY DATE	CHECKED BY DATE	APPROVED BY DATE

THIS DRAWING PREPARED FOR:

STRATEGIC PETROLEUM RESERVE OFFICE

PB-KBB Inc.
Engineering Construction Operations
11757 KATY FREEWAY #600
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TITLE: SPR REGIONAL PRODUCT RESERVE
UNOCAL TERMINAL
OIL WITHDRAWAL PROCESS FLOW DIAGRAM

TR 3-15-97 TR 3-15-97 NONE TASK 46

FIGURE 2-2

2.2 FACILITY OPERATIONAL REQUIREMENTS

2.2.1 Storage Cavern

For purposes of this study, cavern number 113 has been selected for product storage, since this cavern can both be served by either the "A" or "B" oil headers. Any other cavern would be equally suitable and the final selection should be made with regard to oil inventory volume, specification, ultimate storage configuration objectives, ease of cleaning and draining site piping and choosing a cavern which is expected to allow minimal methane intrusion into the stored product.

The product storage cavern would operate with virtually the same equipment and procedures as existing crude oil storage caverns, although certain operating pressure setpoints should be adjusted to account for the slight gravity difference between crude and heating oils.

2.2.2 Big Hill Piping Systems

Existing piping systems are suitable for handling heating oil. All existing crude oil piping and pipelines, pumps, meters and other equipment to be placed into heating oil service should be thoroughly cleaned, drained and refilled prior to service conversion.

2.2.3 Pumps

Existing pumps are suitable for product storage operations, although it is recommended that the target fill flow rate be reduced. Site oil pumps are inadequate to inject heating oil into a single cavern at a rate of 150 MBD unless the site oil receipt pressure is raised to approximately 200 psig. Under these operating conditions, the casing seat pressure would be raised to a level very close to the maximum allowable casing seat pressure.

Operating a cavern at such great casing seat pressures provides for a very limited margin of safety and could result in violating operating permits and/or jeopardizing the integrity of the casing seat itself, causing catastrophic cavern failure and uncontrollable oil leakage from the cavern.

A receipt pressure of approximately 50 psig is more reasonable, and with this receipt pressure, the site oil pumps can achieve a cavern fill rate of approximately 100 MBD. This pressure and flow rate would also enable the proposed UNOCAL dock pumps to be operated in series to deliver heating oil to Big Hill. This study presumes that the heating oil fill rate would be 100 MBD and that the proposed UNOCAL dock pumps would be used to deliver the oil to the site.

Pumping requirements for oil fill and withdrawal via the 36" oil pipeline are summarized in the Table 2-1 below.

Table 2-1. Big Hill Pumping Requirements

Item	Fill	Withdraw
Flow Rate	100 MBD	250 MBD
Prop UNOCAL Pumps	2 pumps in series	2 pumps in parallel
Site Oil Pumps	2 pumps in series	-
Raw Water Intake Pumps	-	1 pump
Raw Water Injection Pumps	-	4 pumps - 2 stages of 2 pumps in parallel
Brine Intake Pumps	1 pump (intermittent)	-

2.2.4 UNOCAL Operations

Flow diagrams illustrated in Figures 2-1 and 2-2 contemplate that both fill and withdrawal operations would occur at UNOCAL in much the same fashion as presently planned for crude oil withdrawal: the proposed leased heating oil tank at UNOCAL would float on line during both receipt and delivery operations.

Inbound custody transfer would occur on UNOCAL dock meters, since the leased UNOCAL tank must be operated to float on line during oil transfers. From the singular standpoint of product accountability, it would be preferable to achieve custody transfer measurement on the basis of UNOCAL tank gauges, although this would require leasing a second heating oil tank to permit batching operations necessary for tank gauging measurement. This study presumes that DOE would accomplish custody transfer via the UNOCAL dock meters as is presently practiced for DOE crude oil transfers. Measurements at UNOCAL would be verified by the provable Big Hill site oil meters.

2.3 PRODUCT DISTRIBUTION PLAN

2.3.1 Product Receipt

Product fill would occur via UNOCAL docks and the proposed UNOCAL heating oil systems, which would deliver oil to the site via the DOE 36" oil pipeline at a design rate of 100 MBD.

2.3.2 Product Delivery

During product withdrawal, heating oil would be distributed via UNOCAL docks in the same fashion, and with much of the same equipment as presently planned for crude oil distribution. The design distribution rate would be 250 MBD and the design loading rate would be 25 MBH.

2.3.3 Crude Oil Systems Service Conversion

Converting piping systems and the 36" oil pipeline between crude oil and heating oil service will require careful procedures to clean, drain and refill piping and equipment and to minimize and handle the pipeline interface. Handling the interface is complicated by the pipeline configuration in which the 36" pipeline launcher/receivers are located at Big Hill and Sun terminal, and the branch pipeline to UNOCAL is 24" diameter.

Batching pigs can help to minimize the amount of contaminated interface, although their effectiveness diminishes with reduced flow velocities - as would be the case for both product fill and withdrawal operations (1.0 fps and 2.4 fps respectively). Pipeline pigging specialists should be consulted to determine the appropriate type, number and sequence of batching pigs necessary for effective interface control.

2.3.3.1 Converting Crude Oil Systems to Heating Oil Fill Operations

Following are general procedures contemplated for converting the existing crude oil systems from crude oil to heating oil fill operations.

1. Launch a pipeline scraper (cleaning) pig into the 36" Big Hill oil pipeline at Sun Terminal and move the pig several thousand feet downstream of the 24" UNOCAL branch using existing West Hackberry pumps.
2. Launch a batching pig into the 36" oil pipeline at Sun Terminal, using existing West Hackberry pumps to move the pig to a location a few hundred feet beyond the 24" UNOCAL branch.
3. Clean and drain the UNOCAL crude oil piping and equipment, using vacuum trucks and foam pigs propelled with nitrogen as appropriate. This may involve the installation of launching barrels or drop-out spools.
4. Refill the UNOCAL piping and equipment with heating oil.

5. Pump heating oil from UNOCAL to move the first batching pig approximately 800 feet (1,000 Bbl) further downstream.
6. Launch a second batching pig from Sun Terminal by injecting several truckloads of heating oil directly into the launcher at Sun terminal. Move the pig to a location a few hundred feet beyond the 24" UNOCAL branch. Repeat steps 6 and 7 to insert additional batching pigs as determined necessary.
7. Pump heating oil from UNOCAL Terminal and inject the crude oil linefill into a designated cavern at Big Hill.
8. Monitor oil at the Big Hill meter station to detect arrival of the interface.
9. Divert the interface into the surface oil tank at Big Hill. Sample and test the interface to determine it's disposition. It may be either downgraded to crude oil and injected into storage or sold for reprocessing.
10. Continue pumping at UNOCAL and injecting heating oil at Big Hill.

2.3.3.2 Converting Crude Oil Systems to Heating Oil Withdrawal Operations

Following are general procedures to convert product piping and pipeline systems back to crude oil service when necessary to restore Big Hill to crude oil withdrawal operations. These procedures involve diverting the crude/product interface from the DOE Big Hill 36" oile pipeline into the DOE 42" West Hackberry oil pipeline. The interface may either be held in the West Hackberry pipeline, delivered as the leading end of a West Hackberry crude oil delivery, or subsequently delivered into UNOCAL (or Sun) tankage for further disposition.

1. Launch a pipeline scraper (cleaning) pig into the 36" oil pipeline at Big Hill and move the pig several thousand feet downstream, while delivering the pipeline product linefill into UNOCAL tankage.
2. Launch a batching pig into the 36" oil pipeline at Big Hill.

3. Clean and drain the Big Hill crude oil piping and equipment, using vacuum trucks and foam pigs propelled with nitrogen as appropriate. This may involve the installation of launching barrels or drop-out spools.
4. Refill Big Hill piping and equipment with crude oil.
5. Pump crude oil from Big Hill to move the first batching pig approximately 800 feet (1,000 Bbl) downstream.
6. Launch a second batching pig from Big Hill. Repeat steps 5 and 6 to insert additional batching pigs as determined necessary.
7. Pump crude oil from Big Hill and receive the product linefill into UNOCAL tankage.
8. Monitor oil quality at the 24" UNOCAL branch connection to detect the arrival of the interface.
9. Divert the interface into the West Hackberry pipeline at Sun Terminal. Sample and test the interface to determine it's disposition.
10. Continue pumping at Big Hill and receiving crude oil at UNOCAL.

2.4 MANPOWER REQUIREMENTS

Since the proposed heating oil storage operations at Big Hill represent a replacement, rather than an expansion of present operations, no additional operating manpower is contemplated.

2.5 IMPLEMENTATION SCHEDULE AND COST

2.5.1 Schedule

Preparations to store heating oil in one existing cavern would require about 9 months, driven primarily by the scope of construction work necessary at UNOCAL terminal.

It is presumed that the cavern selected for heating oil storage would be full of crude oil, which would be transferred into adjacent caverns at an average rate of 100 MBD for approximately 100 days. A total of 30 days has been allowed for draining and refilling of piping and equipment, and an additional period of 60 days for installation of additional vents, drains and spools to facilitate piping cleaning and draining. The schedule reflects 15 days for initial draining, followed by a period of 60 days for piping modifications, then 15 additional days for refilling.

Figure 2-3. Big Hill Product Storage Implementation Schedule

MONTH	1	2	3	4	5	6	7	8	9
ACTIVITY									
UNOCAL Construction	■■■■	■■■■	■■■■	■■■■	■■■■	■■■■	■■■■	■■■■	■■■■
Inventory Relocation		■■	■■■■	■■■■	■■■■				
Drain/Refill Piping & Eqpt						■■			■■
Big Hill Modifications							■■■■	■■■■	

2.5.2 Estimated Cost

Table 2-2 presents a summary of the estimated costs to convert one Big Hill cavern to product storage. A more detailed cost estimate is included in Attachment "B". Significant bases for the cost estimate include:

- The scope of construction at UNOCAL is as illustrated on Figures 2-1 and 2-2, which were developed during discussions with UNOCAL.
- UNOCAL construction work includes ED&I costs of 25%.
- All items include a contingency of 25%.
- Electrical power costs for inventory relocation are based on a rate of \$0.05/kWh.
- Costs for downgrading product are based on a contaminated pipeline interface volume of 5% of the total pipeline linefill, due to low flowing velocity. Costs presume that this volume of marketable #2 oil would be downgraded to crude oil. No additional oil transportation costs are included.

- Costs exclude tank leasing and any operating costs at Sun and UNOCAL terminals.
- No additional operating manpower costs are included, although an allowance for labor required for service conversion work is included.

Table 2-2. ROM Cost Estimate Summary - Big Hill Product Storage

Item	Total
Big Hill Modifications	
Vent, Drain & Spool Allowance	$ 250,000
ED&I @ 25%	62,500
Subtotal	$ 312,500
Contingency @ 25%	78,125
Total	$ 390,625
Rounded To	**$ 391,000**
UNOCAL Construction	
Piping modifications	$ 505,130
Pumps	161,000
Meter modifications	200,000
Electrical and controls	135,000
Misc items @ 15% of subtotal	150,150
Subtotal	$ 1,151,280
ED&I @ 25%	287,820
Subtotal	$ 1,439,100
Contingency @ 25%	359,775
Total	$1,798,875
Rounded To	**$ 1,800,000**
Inventory Relocation	**$ 395,000**
Grand Total	**$ 2,586,000**
Service Conversion (each), including oil downgrade	**$ 190,000**

3.0 PRODUCT STORAGE IN NEW SPR REGIONAL FACILITIES

3.1 FACILITY CONSTRUCTION REQUIREMENTS

3.1.1 Facility Overview

Design concepts were developed for three identical, generic 2.5 MMB, above-ground storage facilities to be situated nearby to existing marine terminals in the northeastern U.S. Each facility would consist of above-ground storage tanks, a pipeline connecting to the nearby marine terminal, truck loading stations and associated pumps, piping, metering, support and infrastructure systems. The sites are presumed to be relatively flat and accessible, with adequate existing surface drainage and soils capable of supporting 48' tall oil storage tanks with conventional concrete ringwall and granular fill pads. Groundwater is presumed at a depth which would not present construction problems.

3.1.2 Basis of Design

Fundamental design bases for the development of regional product storage include:

- The product would be heating oil (#2 fuel oil), with a specific gravity of 0.85, and viscosity of 4.2 cP @ 60° F (2.9 cP @ 100° F), RVP = 0.
- Product storage would consist of three separate and identical 2.5 MMB oil storage terminals.
- Facilities would be located adjacent to an existing marine oil terminals. For planning purposes, the Wyatt Energy Connecticut terminal complex was identified as the prototypical adjacent facility.
- Target product fill and withdrawal flow rates for each facility would be 50 and 100 MBD, respectively.
- Product fill would be via connection to an existing marine terminal.

- Product distribution from each terminal would include:
  - ◊ 50 MBD to the nearby commercial marine terminal.
  - ◊ 50 MBD via DOE truck loading stations.

3.1.3 Product Storage Facility

3.1.3.1 Civil

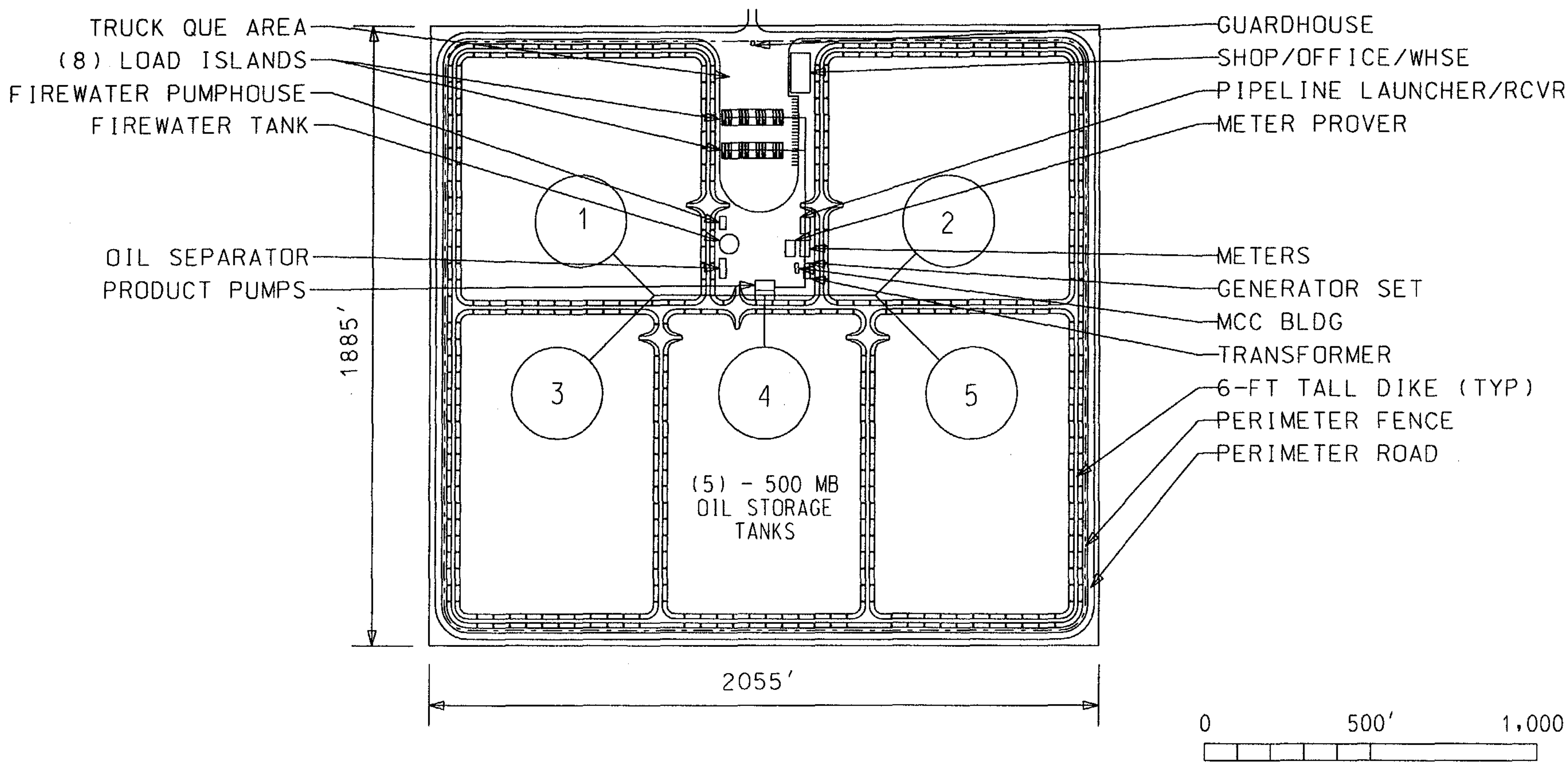
Each 2.5 MMB storage facility would occupy approximately 89 acres. Figure 3-1 illustrates the general arrangement of a typical product storage facility arranged for five, 500,000 bbl, cone-roof, ground storage tanks and associated facilities.

Tank containment would be provided by 6-foot tall earthen tank dikes which would hold the entire contents of each tank, plus one foot of freeboard. Dike crown width would be nominally 12', and each dike would be capped with a crushed stone roadway for maintenance, firefighting and security access.

An all-weather, gravel surfaced road and security fence would extend around the entire perimeter of each site. Truck drive and turning areas would be paved with reinforced concrete.

Design of tank foundations would be based on actual soils investigations, and are presumed to consist of conventional concrete ringwalls with granular fill pads. Approximately 3-4 feet of native earth would be excavated from beneath each tank, then granular backfill would be placed in controlled lifts.

Figure 3-1. 2.5 MMB Terminal Site Plan



GENERAL NOTES

REFERENCE DRAWINGS

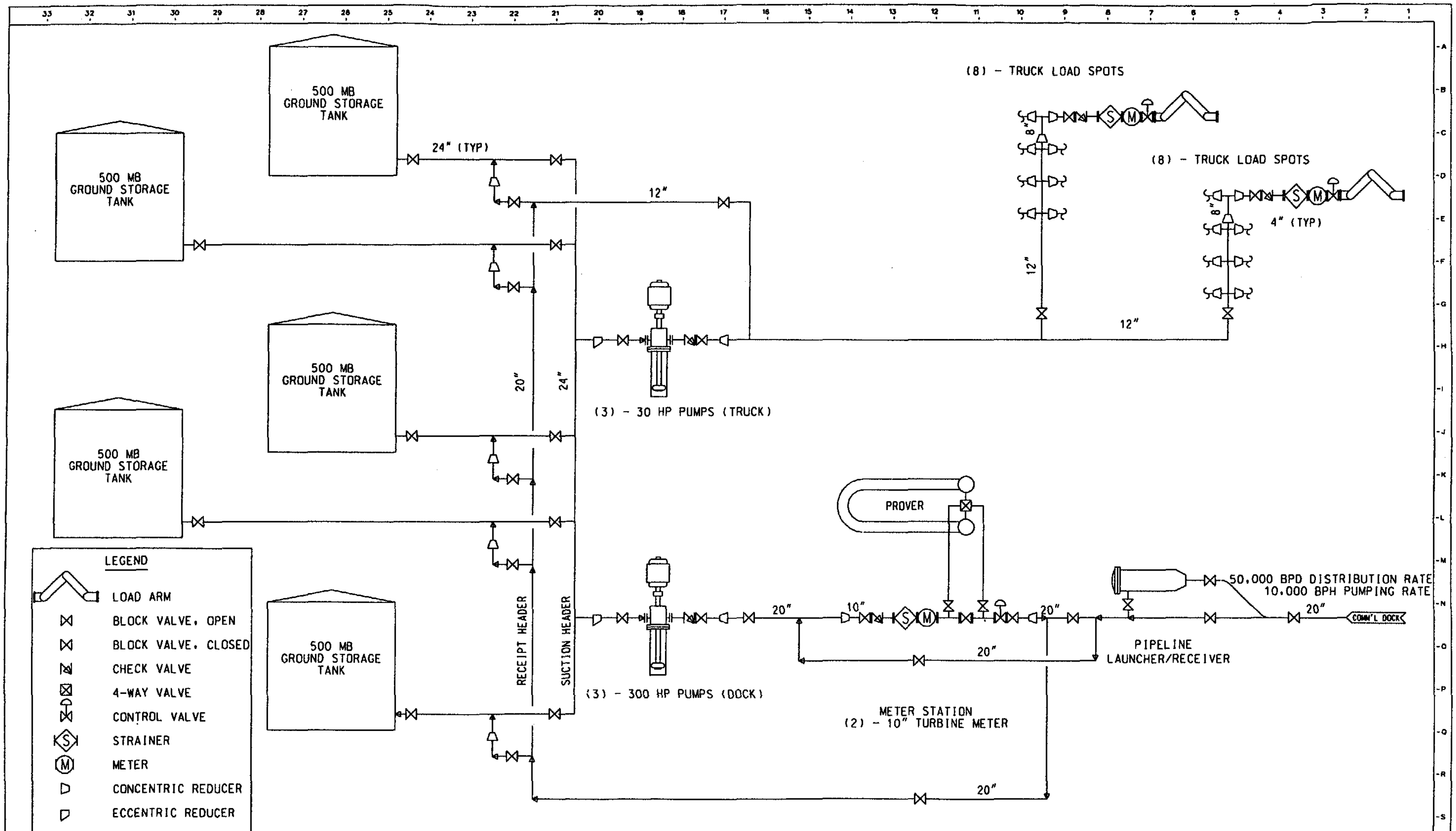
STRATEGIC PETROLEUM RESERVE OFFICE

PB-KBB Inc.
Engineering Construction Operations
11767 KATY FREEWAY #600
HOUSTON, TEXAS 77079

TITLE:
SPR REGIONAL PRODUCT RESERVE
2.5 MMB TERMINAL SITE PLAN

FIGURE 3-1

Figure 3-2. 2.5 MMB Terminal Oil Fill Process Flow Diagram



GENERAL NOTES

REFERENCE DRAWINGS

PROJ. No.	REV. No.	LOC.	REVISIONS	REVISED BY DATE	CHECKED BY DATE	APPROVED BY DATE

THIS DRAWING PREPARED FOR:

STRATEGIC PETROLEUM RESERVE OFFICE

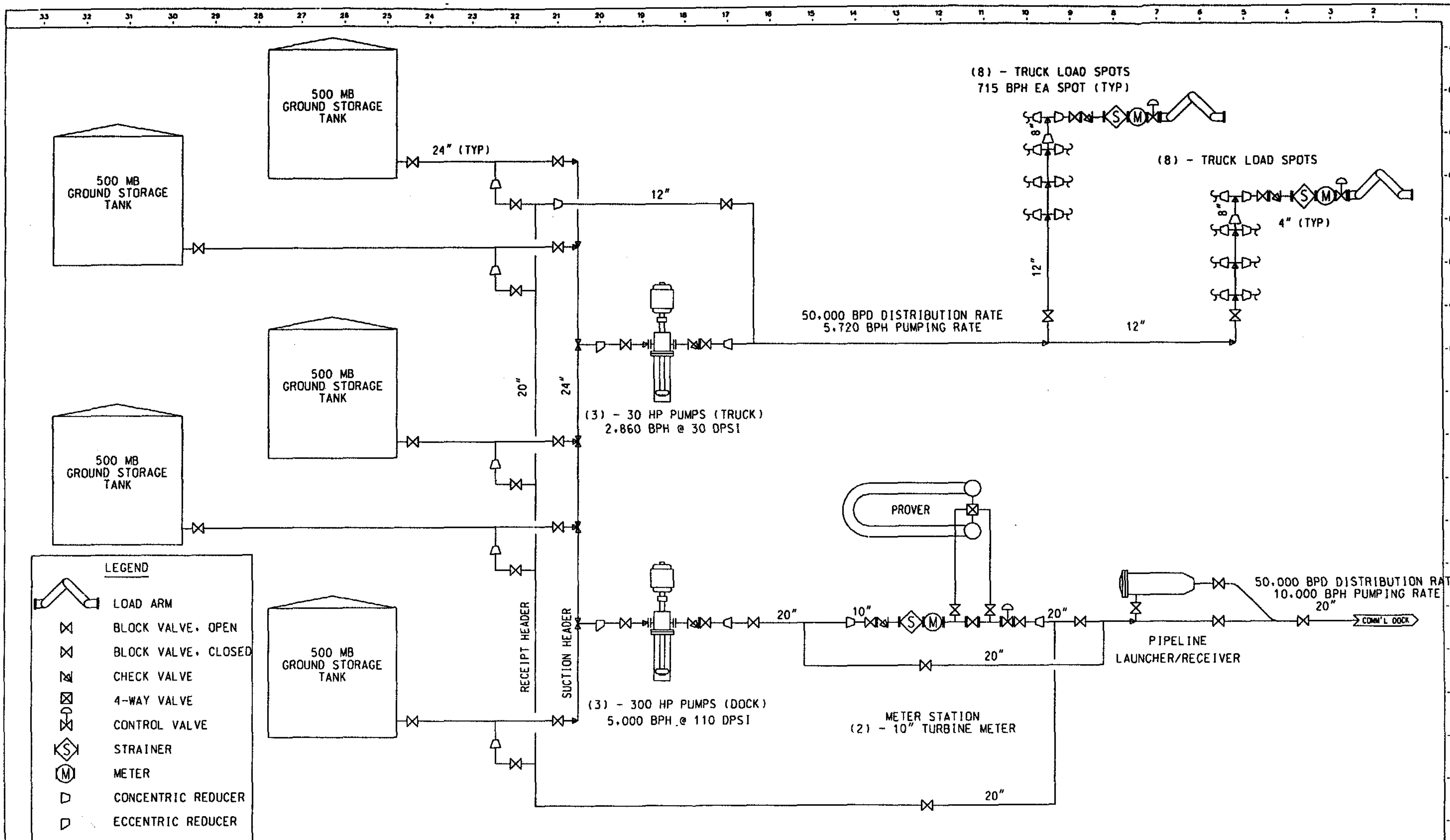
PB-KBB Inc.
Engineering Construction Operations
11757 KATY FREEWAY #600
HOUSTON, TEXAS 77079

TITLE: SPR REGIONAL PRODUCT RESERVE
2.5 MMB HEATING OIL TERMINAL
OIL FILL PROCESS FLOW DIAGRAM

DRAWN BY: TR DATE: 3-15-97 CHECKED BY: TR DATE: 3-15-97 SCALE: NONE
TASK 46

FIGURE 3-2

Figure 3-3. 2.5 MMB Terminal Oil Withdrawal Process Flow Diagram



GENERAL NOTES	REFERENCE DRAWINGS	PROJ. No.	REV. No.	LOC.	REVISIONS	REVISED BY DATE	CHECKED BY DATE	APPROVED BY DATE

STRATEGIC PETROLEUM RESERVE OFFICE

PB-KBB Inc.
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11757 KATY FREEWAY #600
HOUSTON, TEXAS 77079

TITLE: SPR REGIONAL PRODUCT RESERVE
2.5 MMB HEATING OIL TERMINAL
OIL WITHDRAWAL PROCESS FLOW DIAGRAM

TR 3-15-97 TR 3-15-97 NONE TASK 49

FIGURE 3-3

Each tank area would be graded to drain away from the storage tank., and a system of drainage pipes would penetrate each dike to allow rainfall runoff to drain by gravity and discharge into natural drainage channels. Dike drain valves would be normally closed so that the contained water may be sampled for contaminants prior to discharge.

All equipment and operating areas would be covered with canopies, contained and drained into a system of oily water sumps which would discharge into oily water separators. The separators would discharge treated water into naturally drainage patterns and skimmed oil would be collected and periodically hauled off-site.

3.1.3.2 Storage Tanks

Cone roof storage tanks would be designed and constructed in accordance with API Standard 650. Oil tanks are conceptually designed for a nominal capacity of 500 MB each, with a diameter of 280' and height of 48'. Each facility would also include one epoxy-lined, cone roof fire water supply tank, tentatively designed for 20 MB.

3.1.3.3 Offsite Pipelines

This study presumes that connection to the nearby commercial marine terminal would be via a two-mile long 20" pipeline, designed for a peak pumping rate of 10,000 barrels/hour. Pipelines would be designed and constructed in accordance with 49CFR195 "Rules and Regulations for Hazardous Liquid Pipelines"

3.1.3.4 Piping Systems

Figures 3-2 and 3-3 illustrate flow diagrams for the primary product handling systems for fill and withdrawal operations, respectively. All plant piping is envisioned as above-ground, supported on galvanized steel pipe supports. Storage terminal piping systems include:

- 24" tank suction/fill piping.
- 20" tank receipt header.
- 20" marine delivery line.
- 12" truck rack delivery line.

Other major elements of oil piping systems include:

- 20" pipeline launcher/receiver.
- Delivery meters - a custody transfer meter station for marine receipts and deliveries consisting of two 10" turbine meters, including one spare, a meter prover and metering/proving controls.
- Truck loading stations - 16 loading spots complete with fire safe shutoff valves, set-stop meters and controls and bottom loading arms.

3.1.3.5 Pumps

All oil pumps are envisioned as vertical turbine can-type pumps designed to take suction directly from the storage tanks. Each pump station would include one installed spare pump. Oil pumps include:

- (3) 300 HP marine delivery pumps.
- (3) 30 HP truck delivery/tank transfer pumps.

3.1.3.6 Electrical and Control

Electrical systems include:

- Main substation.
- Power transformers.
- Pump, valve and miscellaneous motor power and controls.
- Area lighting system.
- Grounding systems.
- Passive cathodic protection systems,

Site instrumentation and control systems will include:

- Remote tank gauging system, with local and remote level indication, high/low level alarm annuciators and unauthorized level change detection.
- Truck loading controls and recordkeeping systems.
- Custody transfer meter and prover controls.

3.1.3.7 Buildings and Structures

Major buildings at each terminal would include:

- Shop/office/warehouse building.
- Truck load station canopies.
- Pump canopies.
- Main MCC building.
- Field instrument enclosures.

3.1.3.8 Support Systems

Support systems and equipment would include:

- Fire water system - Fire water and jockey pumps, 20 MB firewater tank, 12" firewater loop, branches, hydrants, monitors, carts and extinguishers.
- Oily water system - collection piping, sumps, pumps, separators, skimmers and discharge systems.
- Fresh water system - well, pump, hydropneumatic tank and distribution piping.

3.2 FACILITY OPERATIONAL REQUIREMENTS

3.2.1 Product Receipt

Product would be received from vessels at the adjacent marine terminal via a 20" pipeline at rates of up to 10 MBH. Depending on the nature of receipt operations and arrangements with the connecting terminal, custody transfer may occur on either the connecting terminal's tank gauges (verified by SPR oil meters), or on the SPR oil terminal meters.

3.2.2 Storage

Standby storage operations would involve preventative maintenance, periodic system exercises, recordkeeping and training. Conceptual designs do not include provisions for internal exercising of each oil transfer system component, although oil may be transferred between any two tanks.

3.2.3 Product Withdrawal

Delivery during product withdrawal would be via connections to the offsite commercial marine terminal and into trucks at each terminal. Table 3-1 summarizes the pumping configuration for delivery operations. All operations may occur simultaneously.

Table 3-1. Regional Storage Facility Delivery Pumping Requirements

Item	Receipt (Fill)	Marine Delivery (Drawdown)	Truck Delivery (Drawdown)
Distribution Rate	50 MBD	50 MBD	50 MBD
Design Flow Rate	10,000 BPH	10,000 BPH	5,720 BPH
Truck Pumps -	-		(2) 30 HP
Dock Pumps -	-	(2) 300 HP	

Notes:
1. Distribution Rate is average daily rate, Design Flow Rate is actual pumping rate.
2. Receipt (Fill) rates are presumed and are identified for scheduling and pipeline sizing purposes only. Actual rates may be significantly less or slightly greater, depending upon DOE's objectives and actual vessel capabilities.

Quantities shown are the number of operating pumps. One additional spare pump would be installed for each of the dock and truck pumping systems.

3.3 PRODUCT DISTRIBUTION PLAN

Receipts and deliveries would be as described above:

- Receipt s - 50 MBD at 10,000 BPH from adjacent commercial marine terminal.
- Deliveries - 50 MBD at up to 5,720 BPH into trucks - actual rate will vary with the number of trucks connected at any on time.

  50 MBD at 10,000 BPH to adjacent commercial marine terminal.

3.4 MANPOWER REQUIREMENTS

At design rates, total oil fill for each facility would require approximately 2 months and complete oil withdrawal would require approximately 1 month. Both fill and withdrawal operations would involve 24-hour staffing. For purposes of this study, it is suggested that a minimal permanent party staff be assigned to each terminal, supplemented by personnel from other SPR facilities during times of active operations. Additionally, if oil fill operations for the three facilities were scheduled to be sequential rather than concurrent, then a single supplemental staff could rotate from terminal to terminal until all fill operations are complete.

Table 3-2 summarizes operating manpower requirements, including main gate security guards, contemplated for fill, standby and withdrawal operations, and illustrates both permanent party and supplemental staffing levels. Staffing during 24-hour active fill and withdrawal operations would involve scheduling approximately 6% overtime hours.

Table 3-2. Regional Storage Facility Manpower Requirements

Classification	Number of Personnel, Each Terminal					
	Fill		Standby		Withdraw	
	Perm Party	Supple mental	Perm Party	Supple mental	Perm Party	Supple mental
Operations Supervisor	1	-	1	-	1	-
Shift Supervisor	2	-	2	-	2	2
Control Room Operator	2	2	2	-	2	2
Loader/Operator	4	4	4	-	4	12
Maintenance Foreman	1	-	1	-	1	-
Maintenance Technician	2	-	2	-	2	2
Scheduler	1	-	1	-	1	-
Admin/Clerical	1	1	1	-	1	2
Gate Guard	4	-	4	-	4	-
Subtotals	18	7	18	0	18	20
TOTALS	25		18		38	
Total for (3) Terminals	75		54		114	

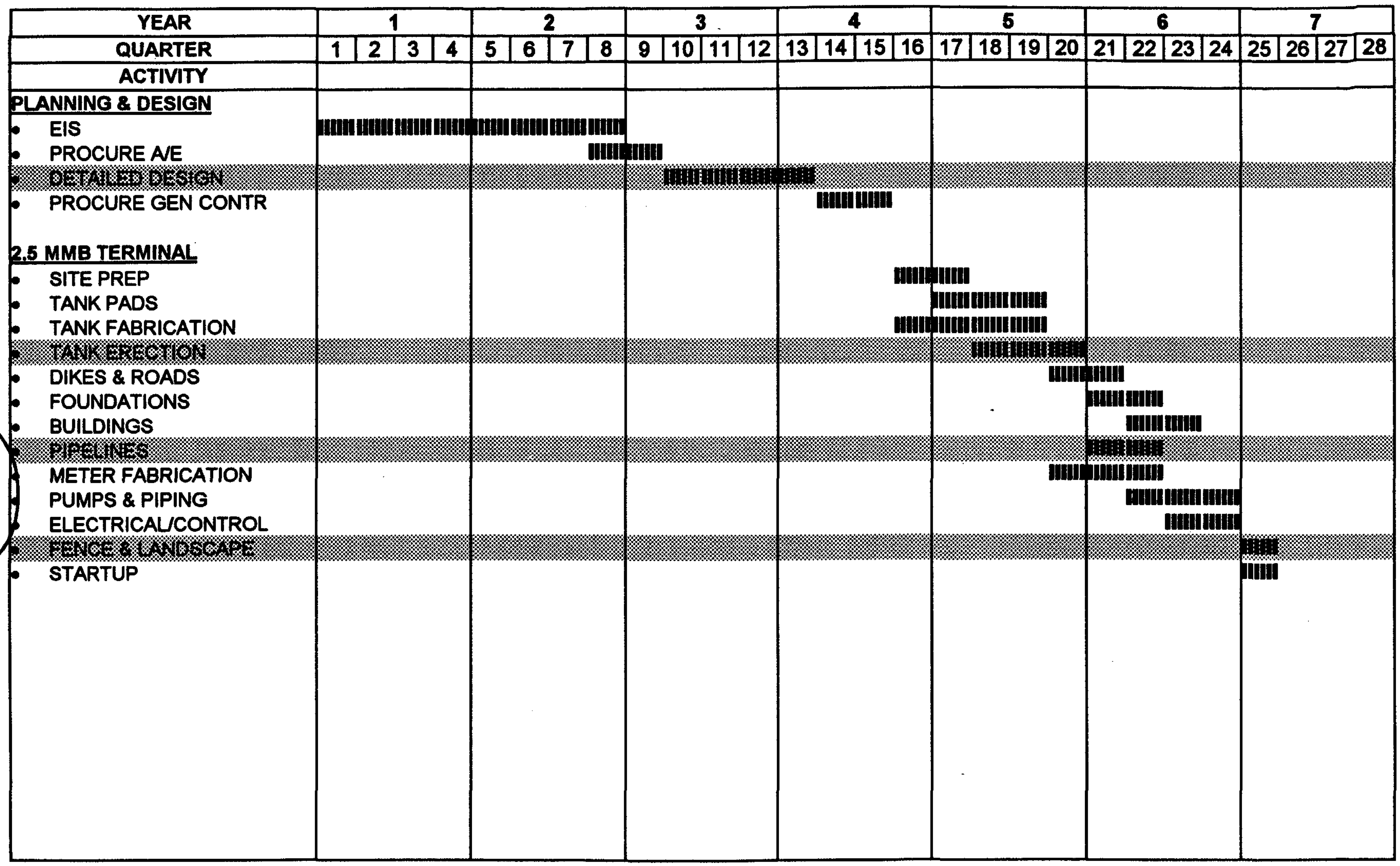
3.5 IMPLEMENTATION SCHEDULE AND COST

3.5.1 Schedule.

Figure 3-3 illustrates the overall schedule for development of a regional product storage facility. This schedule is organized to include durations for major construction disciplines for a 2.5 MMB oil terminal facility, and presumes that all three facilities would be constructed concurrently. The schedule includes an allowance of 24 months for EIS activities and presumes that all permitting can be accomplished within the time frames allotted for EIS and engineering activities.

Complete development of three 2.5 MMB facilities is estimated to require approximately 75 months, including approximately 30 months for field construction activities.

Figure 3-4. Regional Storage Facility Implementation Schedule



3.5.2 Estimated Construction Cost

Table 3-3 presents summary of the estimated construction costs for regional oil storage facilities. Detailed cost estimates are included in Attachment "A". Significant bases for the cost estimate include:

- Costs are estimated in FY 1997 dollars.
- The scope and conditions of construction is as described in this document and generally illustrated by the site plan and flow diagrams attached.
- Cost for real estate, rights of way and acquisition are excluded.
- Costs include ED&I costs of 25% of direct construction costs.
- A contingency of 25% of direct construction is included.
- Costs exclude tank leasing and any operating costs at connecting commercial terminals.
- Costs are for capital construction only, and do not include operating labor or expenses.
- The length of offsite pipelines is presumed to be 2 miles each, across favorable, unpopulated terrain, with no major river or highway crossings.

Table 3-3. ROM Construction Cost Estimate Summary - Regional Product Storage (Million $)

Item	Estimated Cost
Land	*Excluded*
Site Work	$ 5.3
Concrete	3.6
Metals	0.8
Finishes	1.1
Storage Tanks	14.1
Mechanical	5.9
Electrical	3.1
Subtotal	$ 33.8
ED&I @ 25%	8.5
Subtotal	$ 42.3
Contingency @ 25%	10.6
Total	**$ 52.9**
Rounded To	**$ 53.0**
Total for (3) Terminals	**$ 159.0**
$/Bbl	*$ 21.20*

Note - Numbers may not add due to rounding. See details.

3.5.3 Estimated Operation and Maintenance Cost

Table 3-4 presents a summary of estimated operation and maintenance costs for each facility. Detailed estimates are included in Attachment "A".

- Labor costs are intended to include all applicable taxes, insurance, benefits and overhead.
- Expenses include routine supplies, consumables, repair part, tools and equipment as well as travel and living expenses for supplemental staff

during times of active operations.

- Major maintenance expenses include routine painting and allowances for other unspecified major maintenance projects. These costs are presumed not to commence until several years after completion of construction and are not incurred during initial fill operations.

Table 3-4. ROM Operations and Maintenance Cost Summary - Regional Product Storage ($ 000)

Item	Fill (2 Months)	Standby (Annual)	Withdraw (1 Month)
Labor	$ 241.9	$ 1,004.2	$ 121.0
Expenses	73.5	147.0	108.0
Major Maintenance	4.0	324.0	29.0
Subtotal	$ 319.4	$ 1,475.2	$ 258.0
Contractor's Profit	25.6	118.0	20.6
Total	$ 345.0	$ 1,593.2	$ 278.6
Rounded to	**$ 345.0**	**$ 1,593.0**	**$ 279.0**
Total for (3) Terminals	**$ 1,035.0**	**$ 4,779.0**	**$ 837.0**
Monthly Operating Cost for (3) Terminals	**$ 517.5**	**$ 398.3**	**$ 837.0**

Note - Numbers may not add due to rounding. See details.

4.0 RECONVERSION, DEMOLITION AND RESTORATION

4.1 INTRODUCTION

This section describes the general scope of work and ROM estimated costs to reconvert a Big Hill heating oil storage cavern to crude oil service, and to demolish and restore (D&R) the northeastern regional heating oil storage facilities to a pre-development condition.

4.2 BASES

Facility reconversion and D&R is presumed to occur at the end of a 20-year service life. All costs are tabulated in present FY 1997 dollars. Costs exclude any third party terminaling charges.

4.3 RECONVERSION OF EXISTING FACILITIES

Reconversion of a heating oil cavern at Big Hill back to crude oil service would involve relocation of the cavern's inventory, draining and cleaning of piping and downgrading of a portion of the #2 oil linefill, all in much the same fashion as the initial conversion to heating oil service. Refer to the Section 2 for a further discussion of the bases for these costs. Table 4-1 presents a summary of the estimated reconversion costs. Additional cost estimate details are included in Appendix "A".

Table 4-1. ROM Cost Estimate Summary - Big Hill Reconversion

Item	Total
Inventory Relocation	$ 183,000
Drain & Refill Piping	60,000
Downgrade #2 Oil	72,000
Maintenance and Misc Items	47,250
Subtotal	$ 362,250
Contingency @ 25%	90,563
Total	$ 452,813
Rounded To	**$ 453,000**

4.4 D&R OF NEW SPR REGIONAL FACILITIES

The estimated costs to D&R three new regional heating oil storage facilities are based on the following criteria:

- All facilities except the ground storage tanks would be demolished and removed at the government's expense.
- Tanks would be sold for salvage in-place and would be removed by the salvage contractor.
- Mass fill for tank pads and dike berms would be spread on-site.
- Concrete foundations and driveways would be demolished to a depth of 3' below grade.
- Roadway surfacing would be removed.
- All other site improvements, including buildings, fencing, piping and mechanical and electrical equipment would be demolished and removed.
- The site would be free from contaminants requiring environmental remediation.
- Offsite pipelines would be plugged and abandoned in-place.
- Costs do not include salvage values.

Table 4-2 presents a summary of the estimated costs to D&R the regional storage facilities. Additional cost estimate details are included in Appendix "A".

Table 4-2. ROM Cost Estimate Summary - Regional Facility D&R

Item	Total
Site Work	$ 600,560
Concrete	1,078,704
Metals	144,984
Mechanical	252,340
Electrical	89,430
Subtotal	$ 2,166,018
ED&I @ 25%	541,505
Subtotal	2,707,523
Contingency @ 25%	676,881
Total	$ 3,384,403
Rounded To	**$ 3,400,000**
Total for (3) Terminals	**$10,200,000**

ATTACHMENT "A"

COST ESTIMATE DETAILS

SPR REGIONAL PRODUCT STORAGE
CONCEPTUAL COST ESTIMATE
Big Hill Product Storage Facilities

DESCRIPTION	QUANTITY	UNIT	UNIT COST	TOTAL COST
CONSTRUCTION @ BIG HILL				
Vent, drain & spool allowance	1	allow	250,000	250,000
ED&I @	25%		$ 250,000	62,500
SUBTOTAL				$ 312,500
CONTINGENCY @	25%		$ 312,500	78,125
GRAND TOTAL				$ 390,625
ROUNDED TO				**$ 391,000**
CONSTRUCTION @ UNOCAL				
36" Tank line	500	lf	260	130,000
Pump & manifold foundations	44	cy	250	11,000
250 HP vertical pumps	3	ea	50,000	150,000
Pump manifolds	3	pump	75,000	225,000
Add'l dock meter run & piping	1	allow	200,000	200,000
Control valve station	1	allow	150,000	150,000
Electrical Service	1	allow	75,000	75,000
Motor Controls	3	pump	20,000	60,000
Misc items	15%	subtotal	1,001,000	150,150
TOTAL				**$ 1,151,150**
ED&I @	25%		$ 1,151,150	287,788
SUBTOTAL				$ 1,438,938
CONTINGENCY @	25%		$ 1,438,938	359,734
GRAND TOTAL				$ 1,798,672
ROUNDED TO				**$ 1,800,000**
INVENTORY RELOCATON				
Electrical Power	5500	mWh	50	275,000
Maintenance & misc items	15%	subtotal	275,000	41,250
TOTAL				**$ 316,250**
CONTINGENCY @	25%		$ 316,250	79,063
GRAND TOTAL				$ 395,313
ROUNDED TO				**$ 395,000**
SUBTOTAL, BIG HILL, UNOCAL AND INVENTORY RELOCATION				**$ 2,586,000**
SERVICE CONVERSION				
Drain & refill site piping	720	mh	45	32,400
Drain & refill UNOCAL piping	480	mh	45	21,600
Vacuum trucks	20	da	300	6,000
Downgrade #2 oil	8000	Bbl	9	72,000
				-
Misc items	15%	subtotal	132,000	19,800
TOTAL				**$ 151,800**
CONTINGENCY @	25%		$ 151,800	37,950
GRAND TOTAL				$ 189,750
ROUNDED TO				**$ 190,000**

SPR REGIONAL PRODUCT STORAGE

CONCEPTUAL COST ESTIMATE

Generic 2.5 MB Heating Oil Storage Terminal

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL COST
DIVISION 1 - GENERAL REQUIREMENTS				
Land				*Excluded*
DIVISION 2 - SITE WORK				
Clear & grub	88.9	acre	5,000	444,500
Strip & stockpile	71,713	cy	4.00	286,851
Rough grade	215,138	cy	5.00	1,075,690
Catchbasins	14	ea	2,000	28,000
Site drainage systems	1	allow	100,000	100,000
Oil tank pads excav & backfill	34,208	cy	25.00	855,211
FW tank pad excav & backfill	314	cy	25.00	7,854
Tank berm	73,638	cy	20.00	1,472,760
Security fencing	7,880	lf	12.00	94,560
Motorized gates	2	ea	2,000	4,000
Asphalt perimeter road	17,511	sy	15.00	262,667
Stone dike roads	16,364	sy	10.00	163,640
Dike slope stabilization	43,637	sy	3.50	152,731
Oil/water separator w/skim	1	allow	60,000	60,000
Domestic water well & eqpt	1	allow	200,000	200,000
Domestic water piping	1,500	lf	35.00	52,500
Landscaping	1	allow	50,000	50,000
Subtotal				**5,310,963**
DIVISION 3 - CONCRETE				
Pump & misc foundations	583	cy	400	233,333
Pipe support foundations	284	cy	1,000	284,000
Oil tank ringwalls	2,606	cy	700	1,824,451
FW tank ringwalls	42	cy	800	33,510
SOW foundation & slab	1,600	cy	400	640,000
TT load islands	28	cy	250	7,111
TT drive paving	2,773	cy	200	554,622
Concrete curbs	2,000	lf	6.00	12,000
Concrete walks	3,200	sf	3.00	9,600
Subtotal				**3,598,628**
DIVISION 5 - METALS				
Pipe styles & walkways	22	allow	2,000	44,000
Pipe supports	142	allow	1,500	213,000
Pre-engineerd shop/off/whse	7,200	sf	25.00	180,000
Pre-engineerd FW pumphse	800	sf	25.00	20,000
TT loading canopies	18,048	sf	12.00	216,576
Pump canopies	2,000	sf	12.00	24,000
Guardhouse	768	sf	100	76,800
Subtotal				**774,376**

SPR REGIONAL PRODUCT STORAGE
CONCEPTUAL COST ESTIMATE
Generic 2.5 MB Heating Oil Storage Terminal

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL COST
DIVISION 9 - FINISHES				
Coat oil tanks	518,991	sf	1.50	778,487
Coat firewater tanks	23,750	sf	1.50	35,626
Paint piping	45,121	sf	1.75	78,962
Paint equip & misc	16	lot	2,500	40,000
Finish out office space	3,600	sf	45.00	162,000
Subtotal				**1,095,074**
DIVISION 13 - SPECIAL CONSTRUCTION				
500 MB oil storage tanks	5	ea	2,750,000	13,750,000
20 MB firewater tank	1	ea	190,000	190,000
Tank appurtenances	6	ea	25,000	150,000
Subtotal				**14,090,000**
DIVISION 15 - MECHANICAL				
24" commercial dock pipeline	2	mi	750,000	1,500,000
20" tank fill piping	3,000	lf	150	450,000
24" tank suction piping	3,000	lf	190	570,000
10" turbine meter run	2	ls	250,000	500,000
Meter prover	1	ls	250,000	250,000
Pump manifolds	6	pump	50,000	300,000
Delivery/receipt manifolds	10	valve	25,000	250,000
Pump and truck distrib piping	1	ls	181,000	181,000
Truck loading spots	16	ls	17,900	286,400
30HP vertical pump	3	ea	12,000	36,000
300 HP vertical pump	3	ea	60,000	180,000
Fire water distribution	8,000	lf	75.00	600,000
Fire monitor/hydrants	36	ea	3,000	108,000
Fire pump	1	ea	75,000	75,000
Sump pumps	14	ea	3,500	49,000
Pipeline receiver	1	ea	25,000	25,000
Misc small piping	10%			536,040
Subtotal				**5,896,440**
DIVISION 16 - ELECTRICAL				
1.5 mva service	1	ls	200,000	200,000
1.5 mva transformer	1	ea	60,000	60,000
500 kva gen set	1	ea	60,000	60,000
Pump motor controls	6	ea	15,000	90,000
Auxilary motor controls	1	ls	100,000	100,000
Meter station controls	1	ls	300,000	300,000
Oil & FW pump feeders	2,100	lf	20.00	42,000
Area lighting	27	pole	7,500	202,500
Loading controls	16	spot	5,000	80,000
Tank gauging system	1	allow	200,000	200,000
ATS	1	ea	12,500	12,500
Telemetry	1	allow	200,000	200,000

SPR REGIONAL PRODUCT STORAGE
CONCEPTUAL COST ESTIMATE
Generic 2.5 MB Heating Oil Storage Terminal

DESCRIPTION	QTY	UNIT	UNIT COST	TOTAL COST
CCTV systems	1	allow	80,000	80,000
Unspecified security systems	1	allow	1,000,000	1,000,000
Grounding system	24,000	lf	6.00	144,000
Misc electrical	10%			277,100
Subtotal				**3,048,100**
TOTAL				**$ 33,813,581**
ED&I @	25%			8,453,395
SUBTOTAL				$ 42,266,977
CONTINGENCY @	25%			10,566,744
GRAND TOTAL				$ 52,833,721
ROUNDED TO				**$ 53,000,000**
TOTAL FOR (3) TERMINALS				**$ 159,000,000**
$/Bbl, excl land				**$ 21.20**

SPR REGIONAL PRODUCT STORAGE

Regional Oil Storage Terminal - Operating Cost

DESCRIPTION	UNIT	UNIT COST	FILL (2 MONTHS)		STANDBY (ANNUAL)		WITHDRAWAL (1 MONTH)	
			QUANTITY	TOTAL COST	QUANTITY	TOTAL COST	QUANTITY	TOTAL COST
LABOR								
Includes burden and contractor's overhead								
Operations Supervisor	Manhour	55.00	346	19,030	2,086	114,730	173	9,515
Shift Supervisor	Manhour	36.70	692	25,396	4,172	153,112	346	12,698
Control Room Operator	Manhour	29.30	1,384	40,551	4,172	122,240	692	20,276
Loader/Operator	Manhour	25.70	2,768	71,138	8,344	214,441	1,384	35,569
Maintenance Foreman	Manhour	29.30	346	10,138	2,086	61,120	173	5,069
Maintenance Technician	Manhour	27.50	692	19,030	4,172	114,730	346	9,515
Scheduler	Manhour	29.30	346	10,138	2,086	61,120	173	5,069
Admin/Clerical	Manhour	16.80	692	11,626	2,086	35,045	346	5,813
Gate Guard	Manhour	15.30	1,384	21,175	8,344	127,663	692	10,588
Overtime			6%	13,693	0%	-	6%	6,847
SUBTOTAL				**$ 241,915**		**$ 1,004,200**		**$ 120,957**
EXPENSES								
Telephone	ls			1,000		6,000		1,000
Office supplies	ls			2,000		12,000		2,000
Consumables	ls			2,000		12,000		2,000
Small tools & equipment	ls			2,000		12,000		2,000
Repair Parts	ls			4,000		24,000		4,000
Lubricants	ls			500		3,000		500
Groundskeeping	ls			1,000		6,000		500
Safety eqpt	ls			2,000		12,000		2,000
Supplemental Labor - Travel	ls			7,000				20,000
Supplemental Labor - Living	ls			42,000				60,000
Management reserve	ls			4,000		24,000		4,000
Electrical Power	ls			6,000		36,000		10,000
SUBTOTAL				**$ 73,500**		**$ 147,000**		**$ 108,000**
MAJOR MAINTENANCE								
Painting	ls			-	12	100,000		8,333
Subcontract services	ls			4,000	12	24,000		4,000
Other major mtce projects	ls			-	12	200,000		16,667
SUBTOTAL				**$ 4,000**		**$ 324,000**		**$ 29,000**
TOTAL				$ 319,415		$ 1,475,200		$ 257,957
CONTRACTOR'S PROFIT		8%		$ 25,553		$ 118,016		$ 20,637
GRAND TOTAL				$ 344,968		$ 1,593,216		$ 278,594
ROUNDED TO				**$ 345,000**		**$ 1,593,000**		**$ 279,000**
TIMES (3) TERMINALS				**$ 1,035,000**		**$ 4,779,000**		**$ 837,000**
MONTHLY OPERATING COST FOR (3) TERMINALS				**$ 517,500**		**$ 398,250**		**$ 837,000**

SPR REGIONAL PRODUCT STORAGE

CONCEPTUAL COST ESTIMATE

Big Hill Product Storage Facilities

DESCRIPTION	QUANTITY	UNIT	SITE DEVELOPMENT		RECONVERSION TO CRUDE OIL SERVICE			
			UNIT COST	TOTAL COST	2.0 MMB PRODUCT CAP	4.7 MMB PRODUCT CAP	6.7 MMB PRODUCT CAP	NOTES
CONSTRUCTION @ BIG HILL								
Vent, drain & spool allowance	1	allow	250,000	250,000	-	-	-	
ED&I @	25%		$ 250,000	62,500	-	-	-	
SUBTOTAL				$ 312,500	-	-	-	
CONTINGENCY @	25%		$ 312,500	78,125	-	-	-	
GRAND TOTAL				$ 390,625	-	-	-	
ROUNDED TO				**$ 391,000**	-	-	-	
CONSTRUCTION @ UNOCAL								
36" Tank line	500	lf	260	130,000	-	-	-	
Pump & manifold foundations	44	cy	250	11,000	-	-	-	
250 HP vertical pumps	3	ea	50,000	150,000	-	-	-	
Pump manifolds	3	pump	75,000	225,000	-	-	-	
Add'l dock meter run & piping	1	allow	200,000	200,000	-	-	-	
Control valve station	1	allow	150,000	150,000	-	-	-	
Electrical Service	1	allow	75,000	75,000	-	-	-	
Motor Controls	3	pump	20,000	60,000	-	-	-	
Misc items	15%	subtotal	1,001,000	150,150	-	-	-	
TOTAL				**$ 1,151,150**	-	-	-	
ED&I @	25%		$ 1,151,150	287,788	-	-	-	
SUBTOTAL				$ 1,438,938	-	-	-	
CONTINGENCY @	25%		$ 1,438,938	359,734	-	-	-	
GRAND TOTAL				$ 1,798,672	-	-	-	
ROUNDED TO				**$ 1,800,000**	-	-	-	
INVENTORY RELOCATON								
Electrical Power	5500	mWh	50	275,000	55,000	128,000	183,000	1
Maintenance & misc items	15%	subtotal	275,000	41,250	8,250	19,200	27,450	
TOTAL				**$ 316,250**	**$ 63,250**	**$ 147,200**	**$ 210,450**	
CONTINGENCY @	25%		$ 316,250	79,063	15,813	36,800	52,613	
GRAND TOTAL				$ 395,313	$ 79,063	$ 184,000	$ 263,063	
ROUNDED TO				**$ 395,000**	**$ 79,000**	**$ 184,000**	**$ 263,000**	
SUBTOTAL, BIG HILL, UNOCAL AND INVENTORY RELOCATION				**$ 2,586,000**	-	-	-	

SPR REGIONAL PRODUCT STORAGE

CONCEPTUAL COST ESTIMATE

Big Hill Product Storage Facilities

DESCRIPTION	QUANTITY	UNIT	SITE DEVELOPMENT		RECONVERSION TO CRUDE OIL SERVICE			
			UNIT COST	TOTAL COST	2.0 MMB PRODUCT CAP	4.7 MMB PRODUCT CAP	6.7 MMB PRODUCT CAP	NOTES
SERVICE CONVERSION								
Drain & refill site piping	720	mh	45	32,400	32,400	32,400	32,400	
Drain & refill UNOCAL piping	480	mh	45	21,600	21,600	21,600	21,600	
Vacuum trucks	20	da	300	6,000	6,000	6,000	6,000	
Downgrade #2 oil	8000	Bbl	9	72,000	72,000	72,000	72,000	
				-	-	-	-	
Misc items	15%	subtotal	132,000	19,800	19,800	19,800	19,800	
TOTAL				**$ 151,800**	**$ 151,800**	**$ 151,800**	**$ 151,800**	
CONTINGENCY @	25%		$ 151,800	37,950	37,950	37,950	37,950	
GRAND TOTAL				$ 189,750	$ 189,750	$ 189,750	$ 189,750	
ROUNDED TO				**$ 190,000**	**$ 190,000**	**$ 190,000**	**$ 190,000**	
RECONVERSION TO CRUDE TOTAL					**$ 269,000**	**$ 374,000**	**$ 453,000**	

Reconversion ROM Cost Estimate Notes:

1. Product withdrawal. Electrical power cost based on withdrawal @ 250 MBD, $.05/kwh.
2. Costs exclude third party terminaling charges.
3. See Report dated April 7 for other cost bases.

SPR REGIONAL PRODUCT STORAGE
CONCEPTUAL COST ESTIMATE
Generic 2.5 MB Heating Oil Storage Terminal

DESCRIPTION	QTY	UNIT	SITE DEVELOPMENT		DEMO AND RESTORATION		
			UNIT COST	TOTAL COST	UNIT COST	TOTAL COST	NOTES
DIVISION 1 - GENERAL REQUIREMENTS							
Land				*Excluded*			
DIVISION 2 - SITE WORK							
Clear & grub	88.9	acre	5,000	444,500		-	
Strip & stockpile	71,713	cy	4.00	286,851		-	
Rough grade	215,138	cy	5.00	1,075,690		-	
Catchbasins	14	ea	2,000	28,000	85	1,190	
Site drainage systems	1	allow	100,000	100,000	10,000	10,000	
Oil tank pads excav & backfill	34,208	cy	25.00	855,211	5	171,042	1
FW tank pad excav & backfill	314	cy	25.00	7,854	5	1,571	1
Tank berm	73,638	cy	20.00	1,472,760	5	368,190	1
Security fencing	7,880	lf	12.00	94,560	2	15,760	1
Motorized gates	2	ea	2,000	4,000	100	200	
Asphalt perimeter road	17,511	sy	15.00	262,667	0.45	7,880	
Stone dike roads	16,364	sy	10.00	163,640	0.35	5,727	
Dike slope stabilization	43,637	sy	3.50	152,731		-	
Oil/water separator w/skim	1	allow	60,000	60,000		-	
Domestic water well & eqpt	1	allow	200,000	200,000	10,000	10,000	
Domestic water piping	1,500	lf	35.00	52,500	6	9,000	
Landscaping	1	allow	50,000	50,000		-	
Subtotal				5,310,963		600,560	
DIVISION 3 - CONCRETE							
Pump & misc foundations	583	cy	400	233,333	200	116,667	
Pipe support foundations	284	cy	1,000	284,000	100	28,400	
Oil tank ringwalls	2,606	cy	700	1,824,451	200	521,272	
FW tank ringwalls	42	cy	800	33,510	200	8,378	
SOW foundation & slab	1,600	cy	400	640,000	150	240,000	
TT load islands	28	cy	250	7,111	150	4,267	
TT drive paving	2,773	cy	200	554,622	55	152,521	
Concrete curbs	2,000	lf	6.00	12,000	2	4,000	
Concrete walks	3,200	sf	3.00	9,600	1	3,200	
Subtotal				3,598,628		1,078,704	
DIVISION 5 - METALS							
Pipe styles & walkways	22	allow	2,000	44,000	250	5,500	
Pipe supports	142	allow	1,500	213,000	250	35,500	
Pre-engineerd shop/off/whse	7,200	sf	25.00	180,000	5	36,000	

SPR REGIONAL PRODUCT STORAGE
CONCEPTUAL COST ESTIMATE
Generic 2.5 MB Heating Oil Storage Terminal

DESCRIPTION	QTY	UNIT	SITE DEVELOPMENT UNIT COST	SITE DEVELOPMENT TOTAL COST	DEMO AND RESTORATION UNIT COST	DEMO AND RESTORATION TOTAL COST	NOTES
Pre-engineerd FW pumphse	800	sf	25.00	20,000	5	4,000	
TT loading canopies	18,048	sf	12.00	216,576	3	54,144	
Pump canopies	2,000	sf	12.00	24,000	3	6,000	
Guardhouse	768	sf	100	76,800	5	3,840	
Subtotal				**774,376**		**144,984**	
DIVISION 9 - FINISHES							
Coat oil tanks	518,991	sf	1.50	778,487		-	
Coat firewater tanks	23,750	sf	1.50	35,626		-	
Paint piping	45,121	sf	1.75	78,962		-	
Paint equip & misc	16	lot	2,500	40,000		-	
Finish out office space	3,600	sf	45.00	162,000		included above	
Subtotal				**1,095,074**		-	
DIVISION 13 - SPECIAL CONSTRUCTION							
500 MB oil storage tanks	5	ea	2,750,000	13,750,000		-	2
20 MB firewater tank	1	ea	190,000	190,000		-	2
Tank appurtenances	6	ea	25,000	150,000		-	
Subtotal				**14,090,000**		-	
DIVISION 15 - MECHANICAL							
24" commercial dock pipeline	2	mi	750,000	1,500,000	12,500	25,000	3
20" tank fill piping	3,000	lf	150	450,000	15	45,000	
24" tank suction piping	3,000	lf	190	570,000	15	45,000	
10" turbine meter run	2	ls	250,000	500,000	2,500	5,000	
Meter prover	1	ls	250,000	250,000	5,000	5,000	
Pump manifolds	6	pump	50,000	300,000	1,500	9,000	
Delivery/receipt manifolds	10	valve	25,000	250,000	250	2,500	
Pump and truck distrib piping	1	ls	181,000	181,000	10,000	10,000	
Truck loading spots	16	ls	17,900	286,400	1,000	16,000	
30HP vertical pump	3	ea	12,000	36,000	500	1,500	
300 HP vertical pump	3	ea	60,000	180,000	1,000	3,000	
Fire water distribution	8,000	lf	75.00	600,000	6	48,000	
Fire monitor/hydrants	36	ea	3,000	108,000	150	5,400	
Fire pump	1	ea	75,000	75,000	1,000	1,000	
Sump pumps	14	ea	3,500	49,000	500	7,000	
Pipeline receiver	1	ea	25,000	25,000	1,000	1,000	
Misc small piping	10%			536,040		22,940	
Subtotal				**5,896,440**		**252,340**	

SPR REGIONAL PRODUCT STORAGE
CONCEPTUAL COST ESTIMATE
Generic 2.5 MB Heating Oil Storage Terminal

DESCRIPTION	QTY	UNIT	SITE DEVELOPMENT UNIT COST	SITE DEVELOPMENT TOTAL COST	DEMO AND RESTORATION UNIT COST	DEMO AND RESTORATION TOTAL COST	NOTES
DIVISION 16 - ELECTRICAL							
1.5 mva service	1	ls	200,000	200,000	5,000	5,000	
1.5 mva transformer	1	ea	60,000	60,000	2,500	2,500	
500 kva gen set	1	ea	60,000	60,000	2,500	2,500	
Pump motor controls	6	ea	15,000	90,000	500	3,000	
Auxilary motor controls	1	ls	100,000	100,000	5,000	5,000	
Meter station controls	1	ls	300,000	300,000	5,000	5,000	
Oil & FW pump feeders	2,100	lf	20.00	42,000	0.50	1,050	
Area lighting	27	pole	7,500	202,500	250	6,750	
Loading controls	16	spot	5,000	80,000	500	8,000	
Tank gauging system	1	allow	200,000	200,000	5,000	5,000	
ATS	1	ea	12,500	12,500	500	500	
Telemetry	1	allow	200,000	200,000	1,000	1,000	
CCTV systems	1	allow	80,000	80,000	2,000	2,000	
Unspecified security systems	1	allow	1,000,000	1,000,000	10,000	10,000	
Grounding system	24,000	lf	6.00	144,000	1	24,000	
Misc electrical	10%			277,100		8,130	
Subtotal				**3,048,100**		**89,430**	
TOTAL				**$ 33,813,581**		**$ 2,166,018**	
ED&I @	25%			8,453,395		541,505	
SUBTOTAL				$ 42,266,977		$ 2,707,523	
CONTINGENCY @	25%			10,566,744		676,881	
GRAND TOTAL				$ 52,833,721		$ 3,384,403	
ROUNDED TO				**$ 53,000,000**		**$ 3,400,000**	
TOTAL FOR (3) TERMINALS				**$ 159,000,000**		**$ 10,200,000**	
$/Bbl, excl land				**$ 21.20**		**$ 1.36**	

Demolition and Restoration ROM Cost Estimate Notes.

1. Tank pads and berms presumed spread on-site.
2. Tanks presumed sold for salvage in-place. Estimate does not include tank demo costs nor tank salvage revenues. Estimated tank steel weight is approximately 1375 tons each. In-place salvage value for re-erection may range from $100 to $300/ton, for a total of $344,000 - $1,032,000 each site, subject to condition and mar
3. Dock pipeline presumed plugged and abandoned in place.
4. Estimate does not include salvage value.
5. Site presumed free from contaminants requiring remediation.
6. All costs in present calendar year 1997 dollars.

ATTACHMENT "B"

UNOCAL TELEPHONE CONFERENCE

MEMORANDUM

TO:	File	DATE:	2/21/97
FROM:	Tim Reichwein	JOB:	DOE Product Storage
SUBJECT	Telephone Conversation Record - Ron James, UNOCAL		

Following are Ron's suggestions for handling SPR heating oil:

- Install a second backpressure control station on the crude line between DOE's existing tank and the dock.
- Tie-in to an empty #2 oil tank upstream of the new control valve (e.g., tank #216, 209 MB net).
- Install new #2 oil dock pumps near the #2 oil tank.
- For a rate of 250 MBD, install one additional dock meter (present pumps and meters are designed for present rate of 200 MBD).
- Operate the #2 oil system much the same as present plans for operating the crude oil system.

ATTACHMENT "C"

WYATT ENERGY TELEPHONE CONFERENCE

MEMORANDUM

TO:	File	DATE:	2/21/97
FROM:	Tim Reichwein	JOB:	DOE Product Storage
SUBJECT	Telephone Conversation Record - Ed Fuchs, Wyatt Energy		

Wyatt operates four bulk liquid terminals. The '280 Waterfront' complex includes two interconnected terminals which are primarily in gasoline service and the '85 East' complex consists of two interconnected terminals which are primarily in oil service. The oil terminal complex includes one marine dock. Wyatt, like most of the local terminal industry, presently has surplus tankage available for lease.

Normal heating oil movements are in by water and pipeline and out by truck and pipeline (Buckeye).

The oil dock is used primarily for receipts and it's 12" oil line operates at 5,000 to 10,000 BPH, depending upon the vessel's pumping capability. Wyatt has received at up to 16,000 BPH.

The '85' east terminal also includes one 5-bay truck rack which has occasionally delivered up to 20 - 30,000 BPD.

Ed is unaware of any regulation which would either limit the size of or require floating roofs for heating oil tanks.

Appendix F

Other Countries' Experience with Refined Product Storage

Prepared by:

Department of Energy
Office of Strategic Petroleum Reserve

APPENDIX F

OTHER COUNTRIES' EXPERIENCES WITH REFINED PRODUCT STORAGE

Many countries, particularly members of the International Energy Agency (IEA) and the European Union (EU), store petroleum products in addition to or instead of crude oil as part of their oil stockpiling programs. A total of 23 nations are members of the IEA, the principal organization of industrialized countries for responding to oil disruptions. IEA member governments have agreed that in the event of a severe oil supply disruption they will share available supplies and coordinate their energy policies. These provisions were embodied in the International Energy Program (IEP), the agreement by which the Agency was established. The IEA requires that each of its members maintain an emergency requirement amounting to 90 days worth of the previous year's net oil imports. The IEA allows its members some flexibility in determining how these stocks will be maintained. This appendix describes various stockholding mechanisms used by IEA members, addresses the advantages and disadvantages of different approaches, and includes a discussion of the experiences certain IEA countries have had with petroleum product storage.

The three primary stockholding mechanisms in the IEA are company stocks, government stocks and agency stocks:

- **Company Stocks** - These are privately-held oil stocks which count toward a member's IEA reserve commitment. In 1993, company stocks accounted for 69 percent of stocks in IEA countries. The only IEA member countries which do not impose compulsory stockholding requirements on companies are the two net oil exporters, Canada and Norway; a country with small imports, Australia; the United States and New Zealand. Under this approach, strategic stocks may be held by the oil industry on behalf of the government, usually as a legal requirement. Obligations are calculated and monitored by the government. Strategic stocks are part of or considered along side operational stocks.

- **Government Stocks** - These stocks are owned and controlled by member governments and account for 26 percent of stocks in IEA countries. Germany, Italy, Ireland, Japan, and the United States hold government stocks.

- **Agency Stocks** - These stocks are held by agencies created by members for purposes of holding stocks and collaborating between government and industry. Agency stocks are much the same as government stocks, in that they fall under government procedures, are segregated, are of the same quality as government stocks, and are subject to government control. Agency stocks account for 5 percent of stocks in IEA countries. Germany, Denmark, France and the Netherlands hold agency stocks. Some agencies were established by government and some by pressure within the oil industry. Initially, the responsibility for setting aside minimum security stocks fell on refiners and product importers, with individual operators responsible for meeting compulsory storage levels. The creation of compulsory agencies reduced the possibility of operators not respecting their obligation. Also, stocks were more readily available to use in emergency when they were controlled by one organization rather than many. Different rules apply to each agency but all are non-profit and charge fees proportional to members' stock holdings or stocking obligations.

Many members of the IEA are also part of the European Union. The EU requires its members to hold emergency stocks of oil products of three major categories equivalent to 90 days domestic consumption of the previous calendar year. The major categories are: gasoline and related feedstocks; middle distillates; and heavy fuel oil. The level of 90 days must be maintained for each category. Members may substitute crude oil for product stocks, but the crude oil and feedstocks are converted into finished product equivalents in the three categories for purposes of meeting the EU requirements.

The EU has required stockpiling of its members since 1968. When the EU requirement was first imposed, European refineries were not as flexible as U.S. refineries and could not adjust their product slate as readily. Therefore, it made sense to require stockholding of those products expected to be needed most in an emergency. Additionally, it was assumed that refineries would be a prime target for sabotage in a war-time situation and product stocks would need to be readily available to allow for a faster mobilization of forces. (In such a situation, the U.S. might act as a refinery base for NATO.) Many of these countries do not have the large crude oil pipeline system the U.S. has, which facilitates distribution from the central Strategic Petroleum Reserve to refineries in many locations. There may also be some political appeal in various countries in having product stocks spread out in storage locations around the countryside.

Crude Oil vs. Product

Decisions to store crude oil versus petroleum products were made on a country by country basis. The structure of stocks in each country has been tailored to that country's particular circumstances, taking into account costs, refining capacity, market structure and logistics. Storage of crude oil provides more flexibility; petroleum product stocks are often selected for quick response. There are advantages and disadvantages to both.

The U.S. Strategic Petroleum Reserve stores only crude oil. The costs for storing crude oil in salt caverns are much lower than costs incurred by countries storing petroleum products and crude oil is much easier to store compared to products which require turnover. Crude oil is also more flexible because it can be converted to all products. Storage of crude oil makes sense in countries like the U.S. where refinery capacity, logistics and the quality of the crude oil are adequate to process the crude, move it to refineries, and readily distribute it to all consumers. In other circumstances, product stocks can be spread over all regions of a country to permit a quick response in an emergency.

Government vs. Company or Agency Stocks

The U.S. opted for a centralized government reserve, rather than the "industrialized petroleum reserve" or agency concept. Advantages of a government reserve are complete control over storage with release and use of stocks under central control with minimum disruption to the oil industry. Disadvantages are high initial set-up costs and administrative and technical burdens to the government. An amalgamated system provides flexibility but makes it difficult for the government to know how much oil is available in an emergency.

The U.S. differs from many other IEA countries in its means of financing the Reserve. In contrast to the United States, where the costs of the reserves are borne fully by the Government and financed out of general revenues, in countries such as Japan, Germany, and Italy, the costs are shared by the petroleum industry and the end-user.

Advantages of the agency approach to stockpiling are use of oil industry expertise for management, increased consideration of oil industry interests and flexibility in storage and distribution arrangements.

Disadvantages are the high costs to set up such a program unless existing stocks and storage are already available, and the need for arbitration of various industry interests.

The industry stock approach has the benefit of industry storage and distribution facilities and expertise and allows industry greater flexibility to keep stocks for operational or strategic purposes. Disadvantages are dependency on industry locations and difficulty in reconciling different interests of refiners and traders.

Many of the approaches to stockpiling used by IEA member countries evolved as a result of market orientations and management of national petroleum markets. Many countries had established either a wholly or partly state-owned oil company or a "special relationship" with a major oil company. For instance, France has had a tradition of close regulation and participation in the petroleum industry since the 1920s. Italy, also, has been involved in long-term intervention since the early post World War II years. Most of the European programs were initiated prior to the 1973 oil crisis. On the other hand, Japan has legislated oil affairs only recently.

SUMMARY OF PROGRAMS

Company Stocks only:

Fifteen of the IEA's 23 member countries hold only company stocks. These countries are Australia, Austria, Belgium, Finland, Greece, Luxembourg, New Zealand, Portugal, Spain, Sweden, Switzerland and Turkey, plus three net oil exporters with no IEA obligation — Canada, Norway and the United Kingdom.

Company and Government Stocks:

Four IEA member countries hold both company and government stocks-the United States, Japan, Italy and Ireland. The United States Strategic Petroleum Reserve holds crude oil. Private stocks of crude oil and petroleum products held by individual companies are also counted toward the 90 day requirement.

Japan

The Japan National Oil Corporation government reserves are solely crude oil, but company stocks are both crude oil and products. The storage goal for the government reserve is 90 days. As of March 1996, a level of approximately 76 days was in storage.

Private petroleum companies (oil refiners and marketers) must hold a minimum of 70 days stocks, including products. LNG importers must hold 50 days of stocks. Before the end of each fiscal year, beginning in April, the Minister of International Trade and Industry (MITI) informs individual companies of the amount of stocks to be maintained, based on their operations during the previous year. In 1993, company stocks consisted of 46 percent crude oil and 54 percent products. MITI supports stockpiling by private oil companies by providing low interest rate loans for 25 days of the amount held corresponding to 70 days of consumption and low interest rate loans for the construction of oil stockholding facilities.

In a sub-crisis situation, company stockholding obligations will be reduced, taking into consideration the individual companies' oil availability as well as the general oil supply situation. Lowering stockholding obligations may also encourage the release of company stocks in excess of compulsory levels. In an IEP trigger situation, oil companies will be released from stockholding obligations and government stocks can be released by the Japan National Oil Corporation as instructed by the Minister of International Trade and Industry.

During the Gulf Crisis, Japan reduced stockholding obligations of its companies from 82 days to 78 days, thus putting 2 million tons of stocks at the disposal of the market.

Italy

In Italy, the state-owned company ENI is assigned the duty of setting up and managing, on behalf of the Italian Government, a strategic stock of crude oil and finished products. In a 1995 IEA report, Italy reported ENI having 787,000 tons of "strategic stocks." Private companies are required to hold stocks which exceed 90 days of inland consumption (this is the EU requirement). Electric companies and petroleum depot operators are also required to maintain stocks.

Italian stocks are subdivided among strategic stocks owned by the state; stocks maintained by operators who delivered to inland consumption the previous year; stocks maintained by electricity producers; and stocks in commercial depots in proportion to 10 percent of their physical capacity. ENI strategic stocks include 46 percent crude oil, 18 percent gasoline, 17 percent gas/diesel oil and 19 percent heavy fuel oil. These stocks are stored in commercial depots in southern Italy (Milazza - Sicily), central Italy (Gaeta - south of Rome) and northern Italy (Volpiano - near Turin). Stocks held by operators are located in all geographical locations

In January 1991, Italy issued directives for its companies to institute a 1.2 percent stockdraw of total Italian stocks over a period of 30 days. Actual stockdraw in excess of 74,000 barrels per day was performed over a month, more than required. Because most of the Italian reserves are oil products, already distributed in the regional network of depots, wholesalers and retailers, the lead time for initiating stockdraw was very short.

Ireland

In June 1995, Ireland established a National Oil Reserves Agency (NORA) which is responsible for ensuring that sufficient stocks are in place to meet IEA and EU requirements. NORA continually assesses the quantity of stocks held by oil companies (which do not have a stock level mandated). NORA then contracts with companies to hold stocks in quantities sufficient to make up the difference between company stock levels and IEA/EU minimums. Oil importers (those which import at least 5,000 tons of petroleum products per annum for resale) must hold an amount of oil products equal to 80 days of previous year's sales. Part of the Irish company stocks are held in Belgium, the Netherlands and the U.K. under bilateral agreements.

During the Gulf crisis, the Whiddy Terminal was reactivated and 205,000 tons of crude oil were put into tanks. The crude oil is still there and forms part of the strategic stocks. The actual stockdraw during the crisis was a drawdown of 5,000 barrels per day of company stocks through persuasion.

Company and Agency Stocks

Denmark, France and the Netherlands require both companies and "agencies" to hold stocks. These agencies are partnerships established between the government and oil companies for the purpose of holding stocks, with agencies accounting for the difference between company stocks and the IEA/EU stockholding requirements. The close relationship between the agencies and companies facilitate the necessary turnover of product stocks. The most significant IEA stockholding agency is in Germany.

The Netherlands

The Netherlands' oil stockpile consists of 75 million barrels in compulsory company crude oil and product stocks and 16 million barrels of petroleum products held independently by companies. In 1976, the Government established a storage law requiring all Dutch refiners to maintain reserves of motor gasoline, aviation gasoline, jet fuel, light heating oil and residual fuel oil equal to 90 days of inland sales. A corporation known as COVA was established in 1978 to take over responsibility for part of industry's stock requirements. COVA covers its operating costs through incremental excise taxes on covered products paid by consumers and fees paid by member companies.

Oil refiners maintain about 27 percent of the total Dutch SPR, with COVA making up the balance. COVA consists of 40 percent low sulphur North Sea crude oil, 50 percent diesel fuel oil and 10 percent unleaded gasoline. COVA crude oil and products are stored in the Netherlands in conventional above-ground physically segregated storage tanks rented from Dutch independent storage companies, and the integrated oil companies (Refiners and Traders). All crude oil and the majority of products are stored in Rotterdam Harbor. Approximately 23 percent is stored at independent company terminals in Amsterdam and the remainder in Flushing Harbor and 5 inland terminals.

Crisis stockdraw procedures have been tested as part of ASTs and in the Gulf Crisis; however, no physical drawdown has occurred. Stockdraw as an instrument in a subcrisis situation will primarily take place through COVA. Mandatory stockdraws by companies will only be implemented in a crisis situation. During the Gulf crisis, product stocks held by COVA were made available.

Denmark

Denmark has a petroleum stockpile of 35 million barrels including compulsory company stocks which contain 11 million barrels of crude oil and products and independent commercial crude oil stocks equal to 24 million barrels, held by refiners and importers.

There is a 2 tiered system of compulsory stockpiling — "civil preparedness stocks" designated as emergency supply in the event of a war (contains motor gasoline and gas/diesel oil and are counted toward the country's EEC obligations), and a second category, "minimum stocks", which bridge the gap between civil stocks and EEC stockpiling requirements. Companies may store gasoline, middle distillates and residual fuel oil. A certain portion is reserved for national crisis and is the last to be drawn down in case of an IEA drawdown initiated during an International supply crisis. This consists mostly of motor fuel.

When civil preparedness stocks were introduced in 1964, companies facing stockpiling obligations formed a holding association known as FDO. The FDO originally assumed responsibility for holding civil stocks but also took on responsibility for EEC storage requirements. Currently the FDO hold two-thirds the gasoline obligation and all middle distillate and fuel oil. The FDO covers operating costs through company fees based on individual gaseline sales ($0.20/bbl).

The FDO is the oldest stockpiling organization in Europe. As Denmark has grown as an oil producer, it has been able to sell off some of its excess stocks to pay for operating costs. Membership in the FDO is not obligatory and a few oil companies are not members. Some manufacturing companies and all power stations cover their full stock obligations with their own stocks.

The original task of the FDO was to build storage capacity and to acquire oil products for strategic stocks of gasoline and diesel fuels. There were two kinds of membership — emergency stocks for the security infrastructure and minimum stocks to meet EC directives and IEA commitments.

By the end of the 1980's, FDO stocks and facilities were almost fully amortized and therefore operating costs were low due to the policy of storing products long term. For instance, some gasoline had been in FDO tanks more than 20 years and was still technically sound. This was straight-run, non-cracked material. In 1988, a total rotation occurred. Quality monitoring gave evidence of a deterioration in stability of new products. The new replacement products did not have the product stability required for long term storage and needed to be rotated every 1-3 years. New environmental standards led to faster obsolescence of products. Aging problems increased.

The options were to either replace product with crude oil, or rent stock coverage and switch to faster rotation of products. A decision was made to integrate FDO stocks into the oil company delivery chain, while keeping them physically separate. In 1992 stock levels were reduced from 125 days to 90 days.

Under drawdown, the Minister of Energy lowers stockpiling obligations. During stockdraw, advance notice of 8-10 days for middle distillates and 30 days for fuel oil. The preferred method is a loan of products. During the Gulf Crisis, stocks of FDO were made available to member companies in January 1991 including 11,000 b/d stockdraw. About 50 percent were accepted for the months of February and March 1991. Released product stocks were sold to companies at market prices for distribution at Shell refinery, Statoil refinery and Statoil main depot. Under the Contingency Plan for the Gulf crisis, deliveries of heating gas oil could only take place when there was space for at least 75 percent of the tank volume — or the user would be subject to a penalty.

FDO has an agreement with two refineries that have pipeline connections to the FDO's major installations. Under this agreement, the refining companies have undertaken to turn over the bulk of FDO's products at regular intervals, since FDO's stocks are included in the refiners' delivery chain. This way, physical capability is tested on a regular basis. Fuel oil is stored in tanks which are heated only when the product is to be delivered. Approximately 5 weeks of continuous heating are needed for fuel oil to be liquid and pumpable.

France

Since 1928, France has required all importers to establish emergency stocks. France holds approximately 125 million barrels in stocks. Compulsory stocks of crude oil and products equal 100 million barrels and independent commercial and product reserves equal 15 million barrels. Target levels for compulsory stocks are 90 days of inland sales.

In 1988, the emergency stock agency SAGESS was formed. SAGESS was responsible for half of each importer's obligations and met this obligation with stocks of its stockholders and its own stocks. SAGESS owned some stocks and leased others. Companies retained ownership of leased stocks as well as the balance of compulsory stocks. SAGESS also leased tankage from companies. Stocks were not necessarily segregated, but may have been amalgamated.

In 1993 SAGESS was replaced by the CPSSP, the professional committee on strategic oil stocks, or "Comite Professionel". Registered operators had to meet the obligation by holding 50 percent of the stocks themselves in 1993. This proportion was reduced progressively to 20 percent by January 1, 1996. The balance of the obligation is met by fees to the Comite Professionel. The Comite uses the fees to build and hold stocks equivalent to 90 days of imports. SAGESS retains 16 days of consumption with which it can propose to cover the CPSSP obligation and can continue to provide a service with regard to strategic stocks on behalf of its stockholders.

Companies must make monthly declarations of their stocks for each category of products: gasoline, gas oil, heating oil, diesel, jet fuel, heavy fuel oils, crude and middle distillates. Random checks are make of a number of companies each year. The Comite can only own or accept, at its disposal, refined products, although the law admits the eventuality of buying crude oil. Approximately 40 percent are SAGESS-owned stocks; 60 percent are put at CPSSP's disposal by operators who have a surplus. SAGESS does not own storage tanks but contracts with owners.

Government, Company, and Agency Stocks:

Germany

The stockpiling policy of Germany reflects a philosophy that both crude oil and product stocks should be held for emergencies-crude oil for flexibility; petroleum products for quick response. Germany is the only IEA member which uses all three stockholding methods - company, agency and government stocks. Companies hold stocks and the Federal Government maintains the Federal Crude Oil Reserve (7.3 million tons as of an IEA 1995 report). Germany holds substantial reserves of finished products, particularly distillate fuel oil. Because of the large product reserve, Germany is most likely to be the supplier of first resort in Europe. Product stocks are very evenly distributed in Germany and can be very quickly made available to the consumer's market.

A significant portion of German stocks are held by the Erdolbevorratungsverband (EBV) the German stockholding agency. EBV was created to distribute the financial burden of stockholding equitably between refiners and product importers and to ensure the full availability of stocks in a crisis. The EBV ensures industrial stockpiling requirements are equitably imposed on oil companies. All refining and oil importing companies are required to join. The EBV holds all stocks and is financed by the capital market. Operating costs are paid by member companies. The operating costs of the EBV are met through fees paid by member companies based on product sales--(most recent fee noted - $0.55 bbl.). Costs are expected to be passed onto consumers. The corporation is prohibited from selling stocks at a loss.

Germany is required to hold 80 days of stocks, with a ratio of 60 percent petroleum products and 40 percent crude oil, but is moving toward of ratio of 40 percent petroleum products to 60 percent crude oil. About 60 percent of EBV's storage capacity is rented, with the remainder, mainly salt caverns, owned by EBV. It has been Germany's experience that large product caverns suffer mainly from the need to exchange product (today this is due mainly to changes in environmental requirements) and the need to provide alternate capacity when exchanging products outside an emergency drawdown period. The close relationship with industry allows regular turnover of products to ensure the necessary quality. Changes in sulphur level requirements will force the EBV into joint storage with manufacturers/operators in order to guarantee a continuous exchange of products.

During the Gulf crisis, on January 18, 1991, the Minister of Economics announced that a total of 650 thousand tons of petroleum products would be made available including 230 thousand tons of gasoline, 360 thousand tons of middle distillate and 60 thousand tons of fuels oil. Of this, 145 thousand tons of middle distillate were picked up.

Consumers in Germany tend to have large household heating oil storage, which allows them to fill their tanks in the summer, and tend to buy heavily when prices are low. This means that they are able to buy sufficient oil in the summer months to get them through the winter months without having to "top off."

Appendix G

Global Refining Supply Demand Appraisal

Prepared by:

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APPENDIX G
GLOBAL REFINING SUPPLY DEMAND APPRAISAL

INTRODUCTION AND SUMMARY

This appendix examines the outlook for global refining relative to demand. The concern is with middle distillates in particular but also petroleum products in general.

This report presents the contractor's evaluation based on a combination of expert opinion research, literature review, and limited data/trend analysis to develop an appraisal of the worldwide situation out to the year 2000. A critical factor about the period to 2000 is that the degree of achievable refinery expansion - at least through 1998 - is largely already set, since it takes 2 to 3 years to design, install and start up a major new refinery process unit. Therefore general growth in demand and any short term surges will have to be met from an essentially given capacity base.

The primary questions addressed here are:

- Is the world now or in the next three years likely to be in a constrained position vis-a-vis petroleum product demand and supply;
- Is the constraint year round or seasonal;
- Does the constraint apply to all products or to some; and if only to some, which ones; and
- Is this a new position for the world market?

The picture that has emerged is that we are already in a period of tightening distillate supply and of sustained economic and global petroleum demand growth which will heavily emphasize distillates. Over the next few years this situation will coexist with refinery capacity expansions and revamps that, based on current projects, are inadequately geared to distillate production. Barring rapid adjustments by the global refining industry, this will lead to a growing tightness in distillates supply/demand.

Consolidation trends and shifts in operating practices towards lower inventories in the refining sector are occurring in the U.S., Europe and elsewhere and are likely to exacerbate the trend toward distillate tightness.

Historically high refinery utilizations and a relatively rapid move in North America, Europe, and Asia-Pacific towards tighter product specifications on gasolines and diesel fuels is likely to restrict refiners' flexibility to adapt in the medium term. In addition, the tanker market is becoming tighter. Freight rates are increasing, especially for long haul clean product movements that will increasingly be needed to and within the Asia-Pacific region and elsewhere to meet growing demands.

From now until 2000, approximately half the world's increase in petroleum product demand will be for distillates (jet fuel, kerosene, diesel fuels and heating oil). As widely acknowledged, distillates are the leading growth product group in Asia-Pacific, but they are also the leading growth group in the USA and Europe. Gasoline and "other products" will each comprise around a quarter of the demand growth with residual global fuel demand essentially flat.

The bulk of distillate and total product demand growth will take place in the Asia-Pacific region — yet at annual percentage growth rates that are actually lower than have been obtained in many regional countries in recent years. The enormous economies and petroleum demands of China and India represent particular wild cards. Both countries have refining strategies that may lead to inadequate refinery expansion and resulting higher than expected product import demands that will put added strain on other world refineries. In both countries, distillates comprise an important part of total petroleum demand.

Against this outlook, the world's refining capacity base is more oriented to gasoline than to distillates production, especially in terms of key secondary processes in the U.S. and Europe. Combined large and small refinery capacity additions in the period to 2000 are geared to producing incremental gasoline and distillates but with insufficient emphasis on distillates to offset an emerging deficit in global distillates refining capacity. Conversely, gasoline production is projected to trend into surplus.

Opportunities may exist to redress the projected imbalance between distillates and gasoline producibility between now and 2000. These are, however, most likely to take effect towards the end of this period or beyond 2000. Areas of optimism include:

- Utilization of inherent refining flexibility to produce more distillates at the expense of gasoline. This would likely entail catalyst changes and revamps, especially on catalytic cracking units together with debottlenecking of distillate desulfurization and hydrogen plant capacities. The degree to which flexibility exists today is uncertain and potentially limited, particularly in terms of meeting the increasingly stringent qualities that apply to diesel fuel in the U.S., Europe and Asia-Pacific.

- Refining technology developments mainly to increase capability for refiners to produce distillates at the expense of gasoline. The refining catalyst and process technology sector is resourceful in adapting to new yield and quality challenges. In the period before 2000, this sector may be able to develop new catalyst or other process adaptations that would further increase distillate yields. However, refinery revamps could be required such that these technology improvements would be unlikely to have much practical impact before 1999.

- Utilization of the spare refining capacity that exists, particularly in the Former Soviet Union and to a much lesser degree in South America. Major questions however hang over the feasibility, logistical and economic, of utilizing supposedly spare available Russian refining capacity effectively discounting this from the picture. In addition, much of the nominally spare capacity is simple capacity such that each barrel of incremental distillate would bring with it unwanted barrels of gasoline and residual fuel oil.

- Particularly by 2000 and beyond, improved technologies to convert natural gas directly to distillates may offer a way to generate substantial new volumes of distillate fuels, thereby alleviating distillate tightness and reducing dependency on crude oil.

The body of this report examines in detail the themes underlying this projected outlook as outlined above:

- Section 2 of the report reviews trends in U.S. distillate supply and demand.

- Section 3 assesses global trends and factors affecting supply and demand, both from a negative and positive perspective, with regard to distillate supply/demand balance in particular.

Throughout this report the term distillates or total distillates is used to refer to the product group comprising jet fuel, kerosene, diesel fuel and heating oil. The term middle distillates is used to refer to the subgroup of heating oil and diesel fuel. The term light distillates applies to the subgroup of jet fuel and kerosene. The term gasoil is used to refer to middle distillates and vacuum gasoil to the intermediate light residual stream produced from a vacuum distillation unit. (Note that some analysts and reports use the term middle distillates to refer to gasoline, naphtha, jet fuel, kerosene, diesel fuel and heating oil. Also, outside the U.S., "gasoil" invariably refers to diesel/heating oil.)

U.S. DISTILLATES SUPPLY/DEMAND

Distillates Net Imports Have Been Rising

The U.S. is both an importer and an exporter of distillates. As shown in Exhibit G-1, imports of distillates remained relatively constant at around 300 thousand barrels per day (Mbbl/d), exports have declined such that net imports in 1996 were close to 100 (Mbbl/d).

Exhibit G-1
U.S. Distillate Imports and Exports

Mbbl/d						
	1991	**1992**	**1993**	**1994**	**1995**	**1996**
Jet Fuel						
Imports	67	82	100	117	106	109
Exports	43	43	59	20	26	48
Net Imports	24	39	41	97	800	61
Kerosene						
Imports	12	9	1	3	1	1
Exports	3	8	4	1	2	2
Net Imports	9	1	-3	2	-1	-1
Middle Distillate						
Imports	205	216	184	203	193	224
Exports	215	219	274	234	183	190
Net Imports	-10	-3	-90	-31	10	34
Total Imports	284	307	285	323	300	334
Total Exports	261	270	337	255	211	240
Total Net Imports	23	37	-52	68	89	94

Source: EIA data

U.S. Refineries are Running at High Utilization Rates with Rationalizations Offsetting Debottlenecking

The shift towards the U.S. becoming a net importer of distillates has occurred because both light and middle distillate demands have continued to grow in a period which has been matched by continued rationalization of U.S. refinery capacity. For the past year, all U.S. refining regions East of the Rockies have been running flat out at record utilization levels of around 92-95 percent. At these levels, capability to produce significant incremental quantities of distillate is extremely limited. Exhibit G-2 shows the utilization rate for U.S. refineries.

Exhibit G-2
U.S. Refinery Utilizations - December 13, 1996

Region	Utilization %
East Coast (PADD I)	91.4
Mid-West (PADD II)	95.3
Gulf Coast (PADD III)	94.6
Mountain (PADD IV)	89.9
West Coast (PADD V)	90.4
Nationwide	93.5
Nationwide one year before	91.6

Source: *Oil & Gas Journal*, December 30, 1996

Secondary utilization rates for the fluidized catalytic cracker (FCC) and Coker units are approximately equal to those of the crude distillation unit, i.e. at around 94 percent of stream day capacity. Hydrocracking units are running at an 84 percent utilization rate, or 10 points lower, due to the lower service factor for this unit.[1]

Total U.S. refinery capacity has remained flat in recent years as closures and cutbacks have largely offset debottlenecking projects and the occasional major expansion project.

U.S. Distillate Demand is Forecast to Grow Faster then Other Product Groups and Faster than the Increase in U.S. Producibility

The gap that has developed between U.S. distillate demand growth and producibility is projected to widen. The Energy Information Administration's (EIA's) 1997 *Annual Energy Outlook* Reference Forecast indicates both jet fuel and middle distillates demands growing by around 245 Mbbl/d each between 1995 through 1999. Conversely, in the period through 1999 we project that U.S. refinery capability to produce incremental distillate will improve by only 80 Mbbl/d based on known projects

[1]These high utilization rates on key secondary units reinforce the lack of spare processing capacity available today in U.S. refineries. *Oil & Gas Journal*, 2/5/96, T. Lidderdale et al, "Secondary Processes Key to Gauging U. S. Refining Capability".

and at the time of writing. The implication is that net imports of distillates into the U.S. will rise by some 400 Mbbl/d between 1995 and 1999 unless U.S. refineries undertake significant additional debottlenecking and expansion projects.

While exports of U.S. distillates occur mainly from the Gulf Coast and West Coast, imports are dominated by the East Coast. Therefore, despite the trend to displace heating oil use with gas in the U.S. Northeast, that region will still be the most heavily affected over the next several years by the trend towards imports.

Expansions at the Principal Foreign Refineries that Supply Distillates to the U.S. are Minimal

Imports into the U.S. of distillates are dominated by movements into the U.S. East Coast (predominantly the Northeast). The imports come overwhelmingly from three overseas refining regions, notably:

- Eastern Canadian refineries — 19.7 percent
- US Virgin Islands (the Amerada Hess St. Croix refinery) — 32.7 percent
- Venezuela and the Netherlands Antilles — 42 percent

Other sources comprise 5.6 percent. Exhibit G-3 shows the amount of distillate imported from each region, while Exhibits G-4 and G-5 summarize U.S. distillate exports.

These three sources comprise the primary stable suppliers of distillates into the U.S., but analysis of announced construction plans at the relevant refineries in Eastern Canada, St. Croix, Venezuela and Netherlands Antilles indicates only minimal expansions through 1999. Therefore, barring major changes in their construction plans, little opportunity exists for meeting the anticipated growth in U.S. distillate imports from these primary sources. The implication is that the bulk of the projected U.S. distillate imports will have to come from supply sources further afield.

Exhibit G-3
U.S. East Coast Distillate Imports 1995

	Mbbl/d		
Origin	**Jet Fuel**	**Middle Distillates**	**Total**
Canada	0.8	51.4	52.2
U.S. Virgin Islands	28.7	58.2	86.9
Venezuela	43.2	57.7	100.9
Netherlands Antilles	10.3	0.2	10.5
Other	2.5	12.5	15.0
Total East Coast	85.5	180.0	265.5
Total U.S.	96.0	193.0	289.0

Source: EIA, *Petroleum Supply Annual 1995*, Table 20

Exhibit G-4
U.S. Distillate Exports by Source Region 1995

	Mbbl/d			
	East Coast (PADD I)	Gulf Coast (PADD III)	West Coast (PADD V)	Total
Kerojet	2.5	14.0	5.9	22.7
Kerosene	0.9	0.5	0.1	1.9
Middle Distillate	9.5	97.4	74.8	183.3
Total	15.4	111.9	80.8	207.9

Source: EIA, *Petroleum Supply Annual*, Table 27

Exhibit G-5
U.S. Distillate Exports by Destination Region - 1995

Major Destinations	Mbbl/d (greater than 1 million barrels in the year)			
	Jet Fuel		Middle Distillates	
	Country	Region	Country	Region
Canada	9.5		8.6	
Caribbean & Latin America			46.7	
Bahamas			4.1	
Brazil			8.2	
Guatemala			4.1	
Netherlands Antilles			3.9	
Panama			12.2	
Puerto Rico			5.9	
Venezuela			3.3	
Asia Pacific				87.3
Japan	6.4		12.0	
Korea			37.5	
Singapore			27.1	
Taiwan			12.0	
Thailand			5.4	
Europe				14.8
Italy			7.1	
Netherlands			4.4	
UK			3.3	
Israel	4.9		2.8	
Other	4.9		26.0	
Total	25.7		183.4	

Source: EIA, *Petroleum Supply Annual 1995*

Scene is Set for Higher Distillates Import Dependency

The summary outlook for the U.S. is that: between now and 2000 the industry is set for increased dependency on product imports, especially distillates; that it will become more dependent on distillates importers outside of its traditional sources, i.e., from further afield; and that this increased import dependency will be augmented by an increased sensitivity to market fluctuations elsewhere in the globe and — possibly — by reduced inventory levels.

GLOBAL TRENDS AFFECTING REFINED PRODUCT SUPPLY/DEMAND

Introduction

Petroleum product supply comprises a complex global co-product industry where many resource, capacity, technology, economic and demand factors interplay to affect national, regional and global petroleum product supply balances and economics. Central to this picture, it must be understood that:

a. All petroleum products interact with each other, as the following instances illustrate:

- Several refinery process units have capability to adjust yields between gasolines, distillates and residual fuel oils;
- LPG range products are converted to gasoline range products and vice versa;
- Naphtha is a product in its own right, mainly as a petrochemical feedstock, but is also a major component of gasoline and a marginal component of jet fuels;
- Distillates are used as components of residual fuels to meet specifications.

b. Events in one part of the world are highly interdependent with events in another. Many analyses have shown that price trends in the major world petroleum market centers, notably New York, U.S. Gulf Coast, Rotterdam/Northwest Europe, and Singapore, are highly interrelated.

Therefore any analysis of a specific question such as supplies of heating oil into the U.S. Northeast needs to be set in a global context for the factors that will effect the regional scenario to be fully understood. The balance of this section reviews major factors currently and potentially impacting global supply/demand balance of refined products.

A wide range of factors is covered, including current trends. However, at the core of the analysis is an assessment of the prospects for refinery capacity expansions through 1999 to meet demand growth, with particular emphasis on refiners' capability to meet growth in demand for the major light products, i.e. gasoline/naphtha and distillates.

Factors Pointing to Increased Tightness in Global Distillates Supply/Demand

Our analysis has led to the overall conclusion that global gasoline supply/demand is set to slacken by 2000 while distillates supply/demand tightens. This conclusion has been arrived at through the quantitative analysis, but is consistent with the views of industry experts who have been contacted both inside and outside the U.S.

Factors that impact demand are considered first followed by factors affecting supply including refining and transportation.

DEMAND FACTORS

The World's Economies are Set to Expand on all Major Fronts

Many of the Asia-Pacific economies are experiencing sustained strong growth. We have seen petroleum product demand growth rates as high as 10-15 percent in several Asia-Pacific countries in recent years and continuing growth rates are projected to be in the range of 3-8 percent. The established "tigers" are likely to be joined soon by new regional tigers (e.g. Philippines, Vietnam) that currently have very low energy intensities.

By contrast, economic growth in North America and OECD Europe has been moderate and petroleum demand growth there is projected to be modest.

The main factor that is changing the global situation is that the countries of the Former Soviet Union and Eastern Europe are pulling out of their plunge in economic activity and associated slide in petroleum product demand. According to the International Monetary Fund, total economic output for these countries dropped by the order of 10-15 percent per annum in the period 1991-1994. Signs of improvement began to appear in 1993 however, and in 1994 the economies of Eastern Europe grew about 2.8 percent, while the contraction in the Former Soviet Union slowed to 4.6 percent.

At the same time the consensus outlook is that oil prices will be moderate over the period through 2000, probably in the range of $20 per barrel, which will support worldwide economic growth. This situation is setting a stage for consistent petroleum product demand growth in all regions of the world, totaling 1.5 million barrels per day (MMbbl/d) or more for each of the next 3 to 4 years. Exhibit G-6 shows the projected growth rates for the major global economies.

Exhibit G-6
Economy Growth Rates

	1996	1997	1998	1999
OECD	2.6%	2.8%	2.8%	2.7%
Developing Countries	6.3%	6.0%	5.9%	5.7%
CIS/East Europe	3.4%	3.7%	4.0%	4.0%

Source: *Oil & Gas Journal*, April 22, 1996

Distillates are the Leading Product Group Outside the U.S.

The U.S. petroleum product demand pattern is dominated by gasoline which constituted 43.7 percent of total petroleum demand in 1995. This situation is, however, the exception. In essentially all regions outside North America, including OECD Europe, Japan, Asian and non-Asian emerging economies, gasoline accounts for only 20-25 percent of total product demand. The most significant product group is total distillates (jet fuel, kerosene, diesel fuel and heating oil). In Europe and Asia these account for 40 percent of the product demand barrel and in other emerging economies over

36 percent; the proportion in the U.S. is 30.8 percent. The significance is that on a global basis distillates constitute the largest petroleum product group accounting for over 36 percent of the total against around 28.5 percent for gasoline. Exhibits G-7 and G-8 show the 1995 demand for product and distillates by world regions.

Exhibit G-7
Regional Product Demand Mix 1995

	U.S.	Canada	OECD Europe	Japan	Asian Emerging	Non-Asian Emerging
Gaso-lines	42.7%	32.3%	24.7%	24.2%	20.0%	21.6%
Distil-lates	30.8%	33.6%	41.4%	35.7%	42.1%	36.4%
Residual Fuel	5.7%	8.4%	16.4%	22.8%	27.2%	26.4%
Other Product	20.8%	25.7%	17.5%	17.3%	12.7%	15.6%

Source: *BP Statistical Review of World Energy 1996*

Exhibit G-8

Regional Distillates Product Demand - 1995

1995	Million tonnes	MMbbl/d	Growth Rate	One Year Addi-tion
U.S.	248.4	4.92	+0.8%	0.039
Canada	26.9	0.53	+3.3%	0.018
Mexico	13.5	0.27	-8.3%	-0.022
OECD Europe	271.4	5.38	+2.3%	0.124
Japan	95.4	1.89	+3.6%	.068
Australasia	15.8	0.31	+6.1%	0.019
Asian EME's	215.4	4.27	+8.2%	0.350
Total Asia	326.6	6.47		
Non-Asian EME's*	177.3	3.51	+3.0%	0.105
		27.55		0.701
* Excludes Central Europe				

Source: *BP Statistical Review of World Energy 1996*

Distillates as a Group are Growing Fastest

It is therefore understandable that the world outside North America pays primary attention to developments in distillate demand which totaled over 27.5 MMbbl/d outside the Former Soviet Union and Central Europe in 1995. Distillates assume even greater importance in the global picture in the period from now to 2000 because there is broad anticipation by industry experts and analysts that they will constitute the highest proportion — 50 percent — of total product demand growth in the period.

In the high growth economies of Asia-Pacific, light distillates, middle distillates and gasoline are at the forefront in terms of high growth rates, projected at 4.5-5 percent per annum for the Asia-Pacific region as a whole.

Distillates also comprise the highest growth rate product pools in other parts of the world. According to the EIA's *1997 Annual Energy Outlook*, U.S. demand growth for jet fuel through 2000 will exceed 2 percent per annum, and for middle distillates will be 1.2 percent per annum; both these rates exceeding those for gasoline of 0.8 percent per annum.[2] In the U.S., growth in jet fuel and diesel demand is closely linked to growth in the economy with steady diesel transport demand growth partially offset by substitution of heating oil by natural gas. Exhibit G-9 shows the increase in global demand by product group during the period 1996-1999.

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[2] According to the January 1997 EIA Short Term Energy Outlook, Table A-5, U.S. demand for jet fuel and middle distillates each grew by 5 percent in 1996. Projected average rates for 1997 and 1998 are 1.6 percent and 1.9 percent respectively.

Exhibit G-9

Global Demand Increases by Product Group 1996-1999

Global Demand Increases (Mbbl/d)					
	Gasoline	**Total Distillate**	**Residual Fuels**	**Other Products**	**Total**
1995	-1,468	692	1,295	772	1,291
1996	365	690	25	310	1,390
1997	380	720	20	330	1,450
1998	340	725	45	330	1,440
1999	330	725	25	320	1,400
Global Demand Increases Percent Per Annum					
	Gasoline	**Total Distillate**	**Residual Fuels**	**Other Products**	**Total**
1995	-7.7%	3.2%	13.7%	7.5%	2.1%
1996	2.1%	3.1%	0.23%	2.8%	2.3%
1997	2.1%	3.1%	0.19%	2.9%	2.3%
1998	1.9%	3.1%	0.42%	2.8%	2.2%
1999	1.8%	3.0%	0.23%	2.7%	2.1%
average (1996-1999)	2.0%	3.1%	0.27%	2.8%	2.2%
Global Demand as Percent of Total					
	Gasoline	**Total Distillate**	**Residual Fuels**	**Other Products**	**Total**
1995	28.5%	36.1%	17.5%	17.9%	100%
1996	28.5%	36.4%	17.2%	18.0%	100%
1997	28.4%	36.7%	16.8%	18.1%	100%
1998	28.3%	37.0%	16.5%	18.2%	100%
1999	28.2%	37.3%	16.2%	18.3%	100%
Global Demand Growth as Percent of Total					
	Gasoline	**Total Distillate**	**Residual Fuels**	**Other Products**	**Total**
1996	26.3%	49.6%	1.8%	22.3%	100%
1997	26.2%	49.7%	1.4%	22.8%	100%
1998	23.6%	50.4%	3.1%	22.9%	100%
1999	23.6%	51.8%	1.8%	22.9%	100%

Source: *Oil & Gas Journal*, Three Year Outlook, April 1996

In Western Europe a somewhat similar picture obtains. In the period through 1999, jet fuel/kerosene demand is projected to grow by 4 percent per annum, and middle distillates by 2 percent per annum. This compares to only 1.1 percent for gasoline and -0.5 percent for residual fuel. The growth in jet fuel and kerosene demand is again linked to economic activity. The growth in middle distillate demand is focused primarily on continuing "dieselisation" of the Western European vehicle fleet underpinned by EU policies. This trend is expected to continue for at least the next 2 to 3 years, although concerns over diesel vehicle particulate emissions may eventually curb the trend.

In Latin America and other non-Asian developing regions, distillate demand is also projected to grow significantly, of the order of 2-4 percent. In global terms this translates into distillate demand growth rates to 2000 of 2.5 - 3.1 percent, as shown in Exhibit G-10.

Exhibit G-10

Relative Product Demand Growth Rates 1995-2000

	Percent per Annum						
	Jet Fuel	**Kerosene**	**Middle Distillates**	**Total Distillates**	**Gasoline**	**Residual Fuel**	**Other Products**
U.S. 1995-2015[1]	2.3%	-0.3%	1.2%		0.8%	1.2%	0.8%
Western Europe 1997-1999[2]	4.0%		2.0%		1.1%	-0.5%	
Asia-Pacific 1995-2000[3]	4.0%	4.0%	5.0%	4.7%			
Asia-Pacific 1995-2000[4]	4.5%	4.5%	4.8%		4.8%	1.7%	
Latin America 1994-2000[5]	1.7%	1.7%	2.2%	2.1%	2.1%	1.5%	1.7%
Global 1996-1999[6]				2.5%	2.7%	1.34%	0.97%
Global (excluding FSU, Eastern Europe) 1996-1999[7]				3.07%	1.96%	0.27%	2.8%

Source:

1. U.S. EIA *1997 Annual Energy Outlook* Table A-2
2. Western Europe: High & Watt Associates
3. Asia-Pacific: Institute of Energy Economics, Japan, December 1996
4. Asia-Pacific: East-West Center, Energy Advisory #166, January 1996
5. Latin America East-West Center, Energy Advisory #180, June 1996
6. Global: EIA *1996 International Energy Outlook*
7. Global (excluding FSU, Eastern Europe): *Oil & Gas Journal*, April 1996

The base demand projection used in the analysis equates to an annual increase in global distillate demand of some 725 Mbbl/d for each of the three years, 1997 through 1999. This is very comparable to the approximately 700 Mbbl/d demand additions excluding FSU and Eastern Europe experienced in 1995 and 1996. Distillates will therefore comprise 50 percent of total global demand growth in the period to 2000.

China's and India's Refining Strategies Could Increase Asia-Pacific Dependance on Product Imports and the Strain on the Global Refining System

India and China represent the two largest petroleum product consumers in the Asia-Pacific region after Japan and South Korea. In 1995, India's oil consumption was 1.5 MMbbl/d and China's 3.3 MMbbl/d. Corresponding growth rates over 1994 were 7.6 percent for India and 5.3 percent for China. Both of these countries have been experiencing increases in product imports. These could further increase in the future unless domestic refining capacity is able to catch up with sustained increases in product demand growth.

Uncertainties in the refining sectors of both of these countries may create a potential burden on the rest of the world's refining industry to supply refined product imports over the period to 2000.

The potential burden on foreign refineries to supply distillates is particularly significant since diesel fuel accounts for 42 percent of India's total product consumption and is a primary fuel in China. In fiscal 1994-1995 India imported nearly 300 Mbbl/d of products. China's refined product imports are projected to reach 400 Mbbl/d this year, up from 358 Mbbl/d in 1996 and 165 Mbbl/d in 1992.[3]

Per capita consumption of energy in India is only 15 percent of the world average and less than three percent than that of the U.S. Therefore very substantial potential exists for sustained rapid growth in the country's energy demand. Against this backdrop, the country has been moving only slowly to privatize and deregulate its energy sector. India has become almost notorious for not implementing a series of refinery projects, totaling a potential increase of more than one MMbbl/d of grass roots capacity. Medium term product import levels into India will therefore depend on how the current impasse on refining construction is resolved.

China also has a government controlled refining sector. Until recently, this was moving down a strategic path of major joint ventures with western oil companies. Seven coastal joint venture refineries were in the offing with potential partners including Amoco, ARCO, ARAMCO, Caltex and Exxon. As of mid 1996, however China had reportedly been able to grow its refining capacity to in excess of 4 MMbbl/d, i.e. sufficient in principle to meet total domestic demand.

Apparently driven in part by this development in its domestic refining capacity, China has recently changed its refining strategy to exclude foreign oil companies and to focus on debottlenecking and upgrading existing refineries over the next five years rather than on expanding capacity through grass roots joint venture projects.

This decision was taken: because product demand growth had moderated to the 5-6 percent range; because the government believed the massive refinery build-up in Asia and surplus capacity in Europe and Middle-East would mean access to ample product supplies; and because the Chinese could access or develop adequate refinery process technology.

But, question marks hang over all these assumptions. Much of China's existing capacity is of "home-made" technologythat is not up to industry standards. Also, significant portions of capacity are located away from the main demand centers. Consequently, China's refinery throughput has not exceeded 3 MMbbl/d, leaving a surplus only on paper.

According to the East-West Center,[4] no joint venture project other than the Total-SinoChem refinery is likely to be in operation by 2000. The risk is that, if China's new refining strategy fails, the demand for product imports will grow rapidly. Again, this is particularly significant for distillates since kerosene and diesel comprise substantial proportions of China's petroleum demand.

SUPPLY FACTORS

World Markets are Already in a Period of Tightening Distillates Supply but Relative Gasoline and Residual Surplus

Analysis of crude oil and product prices at four major world petroleum centers (New York Harbor, U.S. Gulf Coast, Rotterdam/North West Europe, Singapore) was undertaken to determine if recent price trends indicate any shifts in petroleum product supply/demand tightness. To assess this, price differential against crude oil were analyzed for kerojet, #2 heating oil/gas oil, gasoline and residual

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[3]Hart's *Refining Economics Report*, March 1997

[4]East-West Center, *Energy Advisory #182,* July 1996, "China's Petroleum Industry: Closing the Downstream Door" Fereidum Fesharaki & Kang Wu

fuel from January 1994 to November 1996. Exhibits G-11 through G-14 provide graphs of these price differentials. These brought to light an increasing tightness in distillate supply and conversely a trend to increased gasoline and residual fuel supply surplus. More specifically:

- Average kerojet - crude price differentials have increased over the three year period from 8 to 10 cents per gallon (see Exhibit G-11).
- Heating oil/gas oil - crude price differentials have risen similarly from 6 to 8 cents per gallon (see Exhibit G-12).
- Regular gasoline to crude price differentials have declined from 8 to 5.5 cents per gallon (see Exhibit G-13).
- Residual fuel to crude price differentials have widened from 6 to 10 cents per gallon, indicating a trend to growing residual fuel surplus (see Exhibit G-14).

These trends indicate a distinct difference between the position of distillates and that of gasoline and residual fuels, with the latter trending into surplus while distillates trend to tightening availability.

Exhibit G-11
KeroJet/Crude Price Differentials

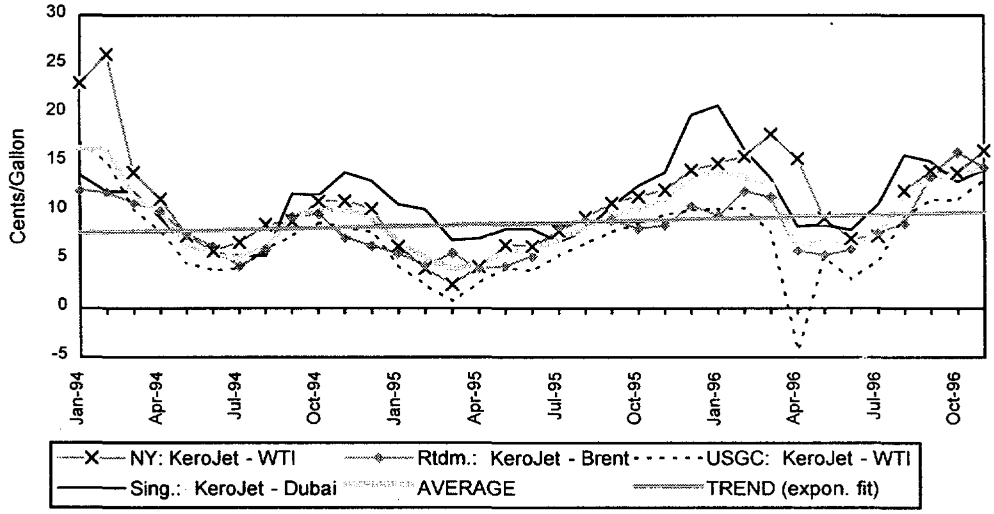


Exhibit G-12
#2 Fuel Oil/Crude Price Differentials

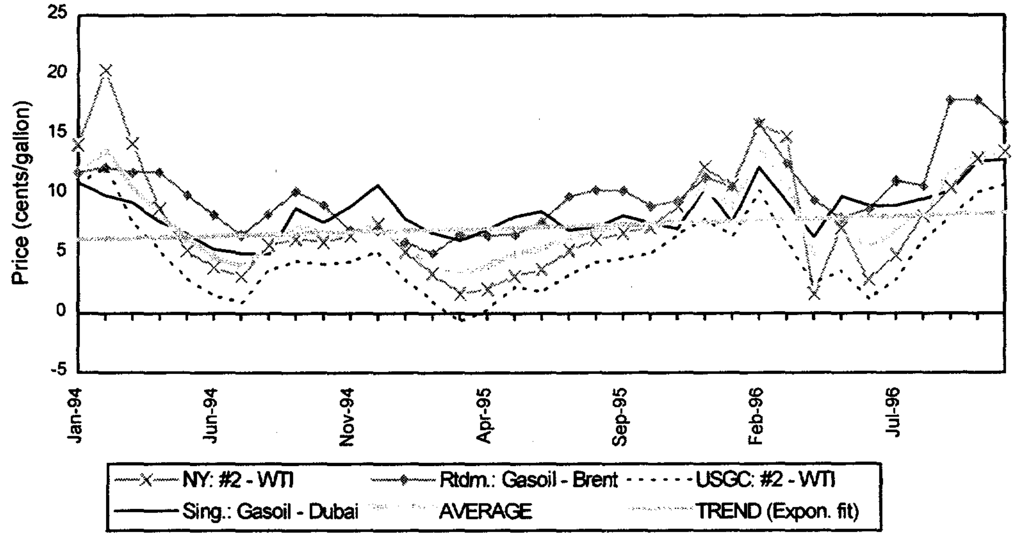


Exhibit G-13
Conventional Regular Gasoline/Crude Price Differentials

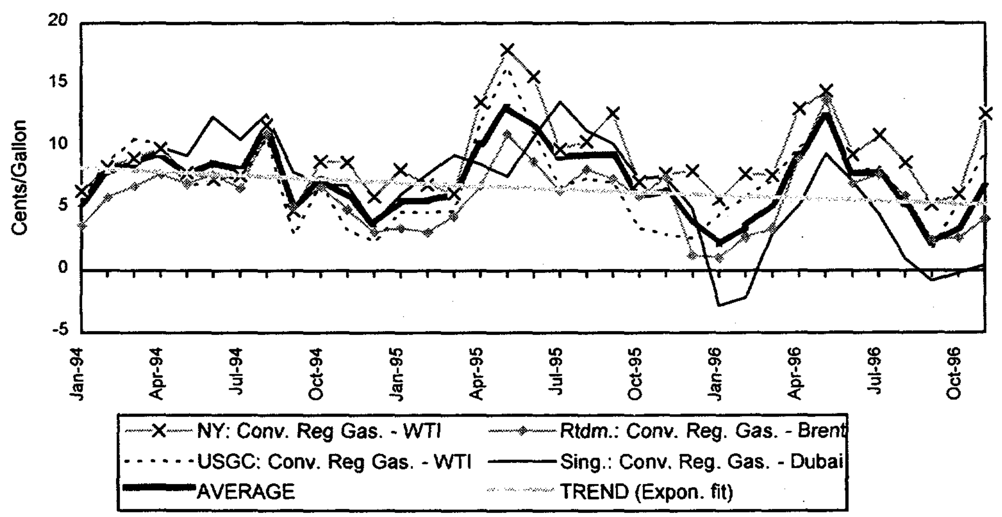
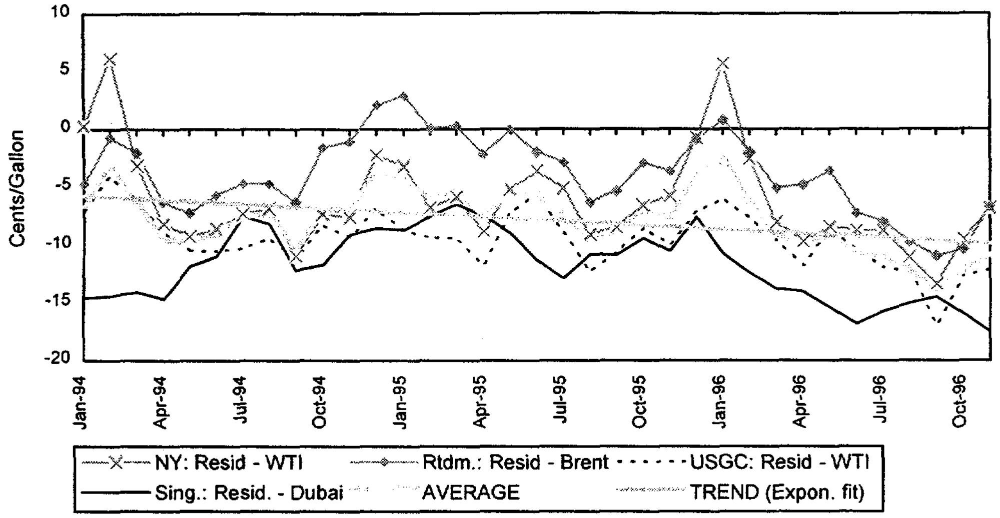


Exhibit G-14
Residential Fuel Oil/Crude Price Differentials



Refinery Capacity Additions Are Not Keeping up with Demand Growth and the Capacity Base is Geared Too Much to Gasolines, Not Enough to Distillates

Estimated firm capacity additions from Jan. 1996 to Jan. 1999 indicate that the global refining industry — led by Asia Pacific — is focusing on distillate-producing hydro-cracking investments. Worldwide, these will add 854 Mbbl/d of new capacity as against 714 Mbbl/d for catalytic cracking and 366 Mbbl/d of coking. Will this situation redress the imbalance in supply of distillate relative to gasoline?

To assess the future supply/demand balance, the incremental producibility of major products from world regional refineries was estimated using a simple refinery simulation model. This model assumed an average crude quality of 34° API, which appears realistic relative to the outlook for the quality of incremental crude supplies as discussed elsewhere. The model also assumed that incremental process capacities for distillation and major secondary units including vacuum distillation, catalytic cracking, hydrocracking and coking would be fully utilized.

Exhibit G-15

Firm Upgrading Capacity Additions Jan. 1996 - Jan. 1999

Actual/Projected Capacities (Mbbl/d)						
Region	**Hydro Cracking**		**Catalytic Cracking (FCC)**		**Coking/Visbreaking**	
	1/96	**1/99**	**1/96**	**1/99**	**1/96**	**1/99**
Asia-Pacific	269	749	1,091	1,675	469	507
West Hemisphere	120	170	1,479	1,478	779	881
Middle East	466	622	315	350	442	509
Europe	730	871	2,900	3,091	2,900	2,897
U.S. &Canada	1,551	1,578	5,662	5,567	2,058	2,220
Totals	3,136	3,990	11,447	12,161	6,648	7,014
3 year increase		854		714		366

Source: *Hydrocarbon Processing* the *Oil & Gas Journal*, 1996 surveys

With projected additions to global distillation capacity of 1.0 MMbbl/d in 1997, 1.34 MMbbl/d in 1998 and a firm 0.6 MMbbl/d in 1999 the survey indicates that total refining capacity expansions are not going to keep pace with projected global product demand of 1.4 to 1.5 MMbbl/d each year to 2000. Consequently global refinery utilizations are set to further increase over the period as discussed elsewhere.

A second key result is that the comparison of refinery capacity and construction with the product demand outlook indicates that capacity is geared too much to gasoline output and not enough to distillate output. As shown in Exhibit G-16, global catalytic hydrocracking capacity (generally installed primarily to meet distillates demand) equates to only 28 percent of global catalytic cracking capacity (geared primarily to gasoline production).

Analysis in the period 1996 through 1998, annual gasoline producibility increase is projected to run some 100 to 400 Mbbl/d ahead of annual demand growth. Conversely, distillates annual producibility increase is estimated to run 225 to 325 Mbbl/d behind annual demand growth. For residual demand growth the picture fluctuates, but the cumulative imbalance to 2000 between producibility and demand is relatively moderate.

In 1997 through 1998, the contractor's estimates are that a forthcoming surplus in gasoline producibility of 550 Mbbl/d over the period will be almost exactly offset by a corresponding deficit in incremental distillates producibility relative to demand. As discussed earlier, the implication of these findings is that market developments over the next two to three years will extend the trends already visible in recent price history and that the gasoline-distillate supply imbalance will worsen.

Exhibit G-16

Worldwide Refining Capacity

Region	# of ref.	Crude (barrels/calender day -b/cd)	Vacuum distillation b/cd	Catalytic cracking b/cd	Catalytic Reforming b/cd	Catalytic Hydro-cracking	Catalytic Hydro-heating	Coke t/d
Asia/Pacific	138	16,286,761	3,347,078	2,305,105	1,806,161	545,540	2,609,340	9,161
Western Europe	112	14,121,455	5,080,968	2,125,500	2,157,887	716,730	2,220,051	11,051
Eastern Europe & C.I.S.	96	12,650,148	3,830,250	836,593	1,482,509	90,860	54,230	11,727
Middle East	42	5,422,790	1,781,970	264,100	566,873	497,560	393,392	2,680
Africa	45	2,849,025	461,818	174,740	344,121	38,500	132,300	541
North America	191	18,804,405	8,280,805	5,910,031	4,225,283	1,586,540	1,741,430	81,144
South America/ Caribbean	77	5,931,718	2,056,704	1,145,837	388,519	101,180	158,000	4,194
Total regions	701	76,066,302	24,839,593	12,761,906	10,971,353	3,576,910	7,308,743	120,498

Source: *Oil & Gas Journal*, December 23, 1996

Moreover, a comparison of the demand growth estimate with those of EIA and the International Energy Agency (IEA) indicated that growth may have been underestimated. Adjusting annual global growth from 1.5 MMbbl/d to 1.7 MMbbl/d to 2000 to bring it more into line with recent history and the very latest EIA projections would add 0.1 MMbbl/d additional distillate demand and resulting deficit each year. Exhibit G-17 shows the global trend in refinery construction, while Exhibit G-18 shows the projected increases in refinery producibility.

Exhibit G-17
Refinery Construction Global Totals

	U.S. & Canada	Europe	Mid East	Asia	Australasia	Other West Hemisphere	Africa	Global Total
Number of Revamp Projects Excluded								
1996	28	23	1	7	10	4	1	74
1997	7	13	1	6	2	4		33
1998	2	2	1	4	1	0		10
1999	0	2	0	5	0	0		7
Total	37	38	3	17	13	8	1	117
Distillation Capacity Additions (Mbbl/d)								
1996	238	86	0	924	40	50	108	1,445
1997	9	543	232	108	35	55	27	1,009
1998	0	22	45	1,277	0	0	0	1,344
1999	50	0	0	514	0	30	3	597
Total	297	651	277	2,823	75	135	138	4,395
								4,395
				Capacity Increase		1999 - 1996		2,951
				C F O G J forecast		1999 - 1996		2,350

Note: The excluded revamp projects are primarily for environmental improvements and other expenditures that do not appear to improve productive capacity.

Source: Based on data in Table G-16

Exhibit G-18
Refinery Producibility and Supply/Demand Analysis
1996-1999

PROJECTED INCREASES IN REFINERY PRODUCIBILITY
BASED ON FIRM EXPANSION PROJECTS TO 2000
Mbbl/d

U.S. + CANADA	1996	1997	1998	1999	cumulative 4 years	% global total
LPG	-4	8	2	2	8	4.7%
Gasoline/Naphtha	-19	38	8	16	43	2.1%
Distillate	35	35	4	12	86	5.3%
Residual Fuels	11	48	9	3	71	23.9%
Total Increase	23	129	23	32	207	5.1%
Percent Increase	0.14%	0.80%	0.14%	0.20% (estimated)		

EUROPE (incl. East Europe & Russia)	1996	1997	1998	1999	cumulative 4 years	% global total
LPG	-8	33	4	2	31	18.5%
Gasoline/Naphtha	-23	246	25	19	267	13.4%
Distillate	-45	183	11	17	166	10.3%
Residual Fuels	-204	-269	-22	12	-483	-163.0%
Total Increase	-280	193	18	49	-20	-0.48%
Percent Increase	-1.1%	0.79%	0.07%	0.20% (estimated)		

MIDDLE EAST	1996	1997	1998	1999	cumulative 4 years	% global total
LPG	-1	5	18	5	27	16.3%
Gasoline/Naphtha	76	100	80	104	360	18.0%
Distillate	36	66	41	54	197	12.2%
Residual Fuels	-7	56	-121	-4	-76	-25.6%
Total Increase	104	227	18	159	508	12.5%
Percent Increase	1.8%	3.8%	0.29%	2.8%		

Exhibit G-18 (cont.)

ASIA - PACIFIC	1996	1997	1998	1999	cumulative 4 years	% global total
LPG	23	9	50	4	86	51.9%
Gasoline/Naphtha	404	76	578	131	1,189	59.7%
Distillate	451	53	428	154	1,086	67.2%
Residual Fuels	532	-55	208	212	897	302.6%
Total Increase	1,410	83	1,264	501	3,258	80.0%
Percent Increase	15.1%	0.77%	11.7%	4.1%		

OTHER WESTERN HEMISPHERE	1996	1997	1998	1999	cumulative 4 years	% global total
LPG	6	2	5	1	14	8.6%
Gasoline/Naphtha	1	88	33	16	138	6.9%
Distillate	-2	55	17	12	82	5.1%
Residual Fuels	-6	-61	-51	6	-112	-37.9%
Total Increase	-1	84	4	34	121	2.3%
Percent Increase	-0.01%	1.24%	0.06%	0.50% (estimated)		

GLOBAL TOTAL	year to year					
	1996	1997	1998	1999	cumulative 4 years	% global total
LPG	16	57	79	14	166	100%
Gasoline/Naphtha	439	548	724	285	1,996	100%
Distillate	475	392	501	249	1,617	100%
Residual Fuels	326	-281	23	228	296	100%
Total Increase	1,256	716	1,327	776	4,075	100%

GLOBAL TOTAL	cumulative			
	1996	1997	1998	1999
LPG	16	73	152	166
Gasoline/Naphtha	439	987	1,711	1,996
Distillate	475	867	1,368	1,617
Residual Fuels	326	45	68	296
Total Increase	1,256	1,972	3,299	4,075

EXHIBIT G-18 (CONT.)

PROJECTED PRODUCT DEMAND

	Mbbl/d (cumulative)			
	1996	1997	1998	1999
Gasoline	17,565	17,930	18,310	18,650
Distillates	22,250	22,940	23,660	24,385
Residual Fuels	10,785	10,810	10,830	10,875
Other Products	11,030	11,340	11,670	12,000
Total Demand	61,630	63,020	64,470	65,910

PROJECTED INCREASE IN PRODUCT DEMAND

	Mbbl/d			
	1996	1997	1998	1999
Gasoline	365	380	340	330
Distillates	690	720	725	725
Residual Fuels	25	20	45	25
Other Products	310	330	330	320
Total Increase	1,390	1,450	1,440	1,400

	Percent			
	1996	1997	1998	1999
Gasoline	2.1%	2.1%	1.9%	1.8%
Distillates	3.1%	3.1%	3.1%	3.0%
Residual Fuels	0.2%	0.2%	0.4%	0.2%
Other Products	2.8%	2.9%	2.8%	2.7%
Total Increase	2.3%	2.3%	2.2%	2.1%

Exhibit G-18 (cont.)

INCREASE IN REFINERY PRODUCIBILITY VERSUS
INCREASE IN PRODUCT DEMAND 1995 - 1999
Mbbl/d

	Producibility	Demand	Projected Surplus/(Deficit)
Gasoline	1,996	1,415	581
Distillate	1,617	2,860	(1,243)
Residual Fuels	296	115	181
Other (incl. naphtha)	---	1,290	
LPG	166	---	
Total	4,075	5,680	(1,605)

INCREASE IN REFINERY PRODUCIBILITY VERSUS
INCREASE IN PRODUCT DEMAND 1996 -1999
Mbbl/d

	Producibility	Demand	Projected Surplus/(Deficit)
Gasoline	1,557	1,050	507
Distillate	1,142	2,170	(1,028)
Residual Fuels	(30)	90	(120)
Other (incl. naphtha)	---	980	
LPG	150	---	
Total	2,819	4,290	
	2,950	*(equals projected total Mbbl/cd capacity addition 1996-1999)*	

Exhibit G-18 (cont.)

DEMAND INCREASE VERSUS PRODUCIBILITY INCREASE YEAR BY YEAR 1996 through 1999 (4 years)					
	Mbbl/d				
	1996	**1997**	**1998**	**1999**	**cumulative**
Gasolines					
- *producibility*	439	548	724	285	1,996
- *demand*	365	380	340	330	1,415
- *surplus/(deficit)*	74	168	384	(45)	581
Distillates					
- *producibility*	475	392	501	249	1,617
- *demand*	690	720	725	725	2,860
- *surplus/(deficit)*	(215)	(328)	(224)	(476)	(1,243)
Residual Fuels - unadjusted					
- *producibility*	326	(281)	23	228	296
- *demand*	25	20	45	25	115
- *surplus/(deficit)*	301	(301)	(22)	203	181

Refinery Margins Are Projected to Improve Only Moderately and Could Affect U.S. Refineries Adversely, Constraining Investment

Assuming residual fuel supply/demand remains in balance over the next three years, the projected decline in gasoline price relative to crude oil will tend to offset projected increases in distillate prices relative to crude oil with the net effect that refinery margins will not substantially improve. More than one industry expert opinion is that over the next few years refinery margins as a whole may improve modestly, by approximately 50 cents per barrel. This however is not considered sufficient incentive to encourage refiners to make wide scale major refinery investments, although it must be said that historically the refining industry has tended to over-invest.

One implication of the shift of gasoline into relative surplus and distillate into relative deficit is that different refineries and different regions will be affected in different ways. With their very heavy reliance on gasoline output, U.S. refineries will arguably be adversely affected by continuing softness in gasoline differentials relative to crude oil. This in turn will tend to dampen the profitability of the U.S. refining sector and its willingness or ability to undertake major investments.

Conversely, refineries in regions where output of distillates represents a higher proportion of the barrel and particularly those refineries with hydro cracking capacity rather than catalytic cracking are likely to benefit from the distillate shift in prices relative to crude oil. In Europe, selected refineries will benefit but much of the region's capacity emphasizes fluid catalytic units for gasoline. In Asia-Pacific, the development is likely to reinforce regional refiner economics and capacity expansion incentives.

For multinational oil companies, the development may therefore reinforce the trend to minimize refining investments in the U.S. and to shift funds into potentially more attractive investments in Asia-Pacific and possibly other parts of the world.

Refinery Utilizations Are High and Projected to Continue to Increase

From historically poor levels, refinery utilizations have risen steadily in recent years through a combination of capacity rationalization and product demand growth. As a result, a global utilization rate that stood at 75.1 percent in 1994 had risen to 82.8 percent by 1994. Since distillation capacity additions are projected to not keep pace with product demand growth through 2000, utilizations are projected to continue to rise reaching 86.2 percent worldwide in 1999.

U.S. refiners are already running at historically high levels, 94.2 percent nationwide average in December 1996, up from 93.4 percent a year earlier. Moreover, all refining regions East of the Rockies (PADDs I-II-III-IV) are running at utilization rates of close to or above 94 percent. In particular, U.S. Gulf Coast (PADD III) refinery utilizations have risen to a record high level of 97 percent. This indicates a change in the role of these refineries from swing supply to running consistently flat out with the implication that demand fluctuations will have to be met by adjusting imports. The only U.S. region with indicated spare capacity is the U.S. West Coast (PADD V). This was indicated to be running at 86.8 percent utilization in December 1996, indicating spare capacity of 380 Mbbl/d.

Utilization rates have also risen in Western Europe, especially in the North where more rationalization has taken place than in the South. The region's much reported over-capacity problem has not been fully resolved, but modest demand growth and further rationalizations are likely to remove much of the spare capacity that exists on paper. The contractor's forecasts are for reductions in availability of export gasoline from Europe of 93 Mbbl/d in the period through 1999 and for increases in imports of distillate of 85 Mbbl/d.

Utilization rates are also historically high in many other parts of the world, especially in the high-growth-rate Asia-Pacific region including Singapore. For the total region, including Australasia, Japan and China, combined utilization was 87.7 percent of calendar day capacity in 1995, even allowing for the low utilization rate of 67.5 percent of calendar day capacity in China.

In 1995, only five regions/countries had appreciable spare capacity, namely Europe (2.2 million barrels per calender day - MMbbl/cd), Central & South America (1.4 MMbbl/cd), Japan (0.7 MMbbl/cd), China (1.3 MMbbl/cd) and the Former Soviet Union (5.4 MMbbl/cd). In Western Europe and potentially Japan, much of the nominally spare capacity is subject to rationalization, as discussed above. In all the world's regions, the spare capacity is almost always spare simple refining capacity only, comprising little more than atmospheric distillation capability. This is of limited use in satisfying a market demand for primarily one product group since running additional crude to make distillates will produce approximately one barrel of gasoline/naphtha and two barrels of fuel oil with each barrel of distillates, with only limited scope to vary yields by altering the type of crude run.

Furthermore, much of the nominally spare capacity is also in poor or dubious operating condition. This situation applies particularly to the huge "spare" capacity in the Former Soviet Union. Much of this relates to simple refining configurations and outdated refinery equipment that is in poor condition. Exhibits G-19 and G-20 show the refinery utilizations in major world regions in 1995 and 1996, respectively.

Exhibit G-19
Refinery Utilizations in Major World Regions - 1995

Region	Mbbl per calender day Capacity	Throughput	Utilization (%)	Spare Capacity
U.S.	15,235	13,970	91.7%	1,265
Canada	1,835	1,560	85.0%	275
Mexico	1,520	1,315	86.5%	205
S&Central America	6,235	4,835	77.6%	1,400
Europe (West & East)	16,595	14,395	86.7%	2,200
FSU	10,325	4,900	47.5%	5,425
Middle East	5,315	5,145	96.8%	170
Africa	2,860	2,315	80.9%	545
Australasia	780	805	103.2%	-25
China	4,015	2,710	67.5%	1,305
Japan	4,865	4,170	85.7%	695
Other Asia	6,845	6,795	99.3%	50
Total World	76,425	62,915	82.3%	13,510

Source: *BP Statistical Review of World Energy 1996*

Exhibit G-20

Refinery Utilizations in Major World Regions - 1996

	Percent Utilization
U.S.:	94%(1)
Canada:	90%(2)
Latin America:	80%
Western Europe:	95%(3)
Eastern and Central Europe:	65%*
FSU:	60%(4)
Africa:	75%*
Asia/Pacific:	92%(5)
(China)	84%(6)
(India)	95%(7)
Australasia:	88%(8)
Middle East:	80%*
World	84.2%(9)

Notes: Refinery Capacity Figures are from OGJ 12/23/96 Worldwide Refining Survey and are given in BPCD. The percentage utilization sources are noted below. Percentage utilization is defined as throughput (BPCD) divided by stream day capacity (BPSD) multiplied by 100.

* No sources have been located for these regions to date. They were selected because they provide an approximate check for the world total.

(1) OGJ 12/30/96, *API Refining Survey*, p 51.

(2) OGJ "Big Investments lie ahead for Canada's Refining Industry", Patrick Crow, OGJ, May 29, 1995.

(3) OGJ, 3/25/96,"Shakeout gathers momentum in Europe's Refining Sector", p 21.

(4) OGJ, 11/6/95, IEA: Russia's refining program headed for Woes, p 26.

(5) Edwards N. Krapels, ESAI, Asia-Pacific Refining: Uncertain Capacity, Surging Product Demand, Crude Oil Deficits, August 1994. Forecast for 1997 ,p 77.

(6) OGJ , 5/8/95, "Government will Shape China's Refining Boom" Haijiang Wang, ESAI, p 43. This is a 1994 estimate.

(7) OGJ , 5/8/95, "Demand, Deregulation May Attract More Refiners to Asia". Demand figures corrected for imports and compared to OGJ 12/30/96, API Refining Survey, p 93 national refinery capacities.

(8) OGJ , 5/8/95, "Demand, Deregulation May Attract More Refiners to Asia". Demand figures corrected for estimated imports and compared to OGJ 12/30/96, API Refining Survey, p 93 national refinery capacities.

(9) OGJ, 4/22/96, OGJ's 3-Year Forecast, "Strong Demand Growth Seen for Oil and Gas in 1997-99".

Contrary to Industry History, High Refinery Utilizations Have Not Produced High Refining Margins and Profitability

In previous periods of high refinery utilization, refinery margins and profitability have also tended to be high, justifying new investments and capacity additions. What is unusual about the high utilizations that have been obtaining, especially in U.S. refineries, is that these have not brought robust margins. As the analysis of 1994 through 1996 product prices versus crude shows, gasoline and residual fuel prices have been declining relative to crude oil.

A better than anticipated global crude slate quality has been one primary contributor to this situation. Continued growth in North Sea output to levels above 6 MMbbl/d - and contrary to many earlier forecasts of impending decline - has been a major factor. In addition, production developments in other areas such as Yemen and Colombia have also brought on-stream higher quality crude oils. Also, the Saudis have deliberately shifted their production output towards a lighter slate in order to maximize revenues. These trends have maintained global crude quality when a decline had been expected.

This development has been augmented by the introduction into several world markets of 100 Mbbl/d of oxygenates as gasoline blendstocks. Since the principal oxygenate, MTBE, is derived from methanol and butane, it brings into the petroleum pool new light feedstocks.

The availability of plentiful light crudes and oxygenates has prevented refiners from earning high economic rents on key upgrading units, particularly the primary conversion unit, catalytic cracking (FCC), which converts residual material principally to gasoline. The FCC capacity surplus has been more marked in Europe than in the U.S. and has led to the closure of one or two older FCC units in the region during recent refinery shutdowns.

Redressing Refinery Yield Imbalance to Obtain More Distillates is an Expensive Proposition

Because of flash point, freeze point, smoke point and distillation specifications on jet fuel and kerosene, and cloud point and gravity specifications on diesel fuel and heating oil, refiners' flexibility to increase distillate yields from crude oil is limited. Unlike gasoline, for which options are available to produce components via various process routes, hydrocracking represents the sole refinery process geared to producing high quality distillate as its primary product. Hydrocrackers crack heavy vacuum gas oil or residuum stream into jet and diesel fractions, at the same time desulfurizing and hydrogenating to produce high quality blendstocks that require no further processing. Catalytic crackers and cokers also yield appreciable volumes of mainly middle distillate, but this must invariably be further processed, via hydrotreating to be of acceptable quality.

Global hydrocracking capacity lags far behind catalytic cracking capacity, although investment in hydrocracking has increased in recent years.

Nonetheless a primary deterrent to broad investment in hydrocracking remains its high initial and operating costs, together with a high level of process and operating complexity. A typical vacuum gasoil hydrocracker has an initial capital cost, including expensive ancillary hydrogen production capacity, of potentially $100-150 million higher then that of a catalytic crackers unit of the same capacity. Hydrocracker operating costs are three to four times those for catalytic cracking.

A good example of a major hydrocracking investment is the 80 Mbbl/d "PER2" hydrocracking complex being built at the Shell Pernis refinery in Holland. Its total capital cost will exceed $1 billion.

The current U.S. and European capacity base emphasizes catalytic cracking and gasoline production. In the period Jan. 1996 to Jan. 1999, global hydrocracking capacity additions will actually exceed FCC additions, with 854 Mbbl/d capacity added in Asia-Pacific, Middle East and Europe against 714 Mbbl/d new FCC capacity. The FCC additions are almost entirely in Asia-Pacific to meet the region's growing gasoline as well as the distillates demand. (In the U.S., both hydrocracking and FCC capacities are essentially flat over the period.)

What is indicated as to redress the gasoline-distillate producibility imbalance, however, is additional hydrocracking and less catalytic cracking investment. The high costs of hydrocracking, allied with the continued likelihood of modest refining margins, may act to deter refiners from undertaking the necessary major hydrocracking investments that are needed. In addition, by virtue of its complex nature and high cost, design, construction and start-up of a new hydrocracker represents a relatively long term project.

Therefore, even if additional hydrocracker projects were announced in the near future, they would not add to potential distillate production until 1999 at the earliest. More modest approaches to improving distillate producibility, such as FCC catalyst variants geared to higher distillate yields, may therefore represent important means to correct the projected supply imbalance.

Looked at globally, the projected production surplus for gasoline and deficit for distillates equate respectively to only 1.5-1 percent of corresponding global demand for the product. This indicates that over time it should be possible for the global refining industry to adapt its product output.

Middle East Refinery Expansions Will Not Meet Other Regions' Growing Import Requirements

Traditionally, the main Middle East exporters of refined products have been Saudi Arabia and Kuwait. Both have also sought a strategy of buying into refining and marketing assets in other world regions (notably Saudi Arabia in the U.S. and Kuwait in Europe) as well as investing in local export refining. Kuwait's refineries have only just recovered from their devastation in the 1990/91 Middle East Crisis.

Firm projects add up to appreciable further additions to Middle East capacity by 2000 (417 Mbbl/d). However, regional product demand growth is appreciable at 2-3 percent per annum and some of the projects, notably in Iran, have uncertain financing.

It is unlikely, therefore, that in the period to 2000 the Middle East region can function as the "supplier of last resort" to meet potential import demand for distillates in Asia-Pacific, as well as Europe and the U.S. A 1995 consultant estimate projected that the Middle East's net product exports for kerojet and middle distillates would grow by 36 Mbbl/d and 49 Mbbl/d respectively between 1995 and 2000.[5] This is well below the likely growth in import demand.

High Refinery Utilizations, Lower Inventories and Tighter Product Specifications Reduce Production Flexibility

A fact of high refinery utilizations is that when nearly all units are running at full capacity, the refinery has reduced flexibility to modify its mix of product output compared to a situation where it is running at lower throughput. Thus the continuing trend toward higher utilizations cuts refiners' short term ability to adapt to fluctuations in market demand, e.g. because of severe cold weather. This is particularly the case for the U.S. East-of-the-Rockies refineries which appear likely to remain at utilizations of 93 - 95 percent. Operating with lower inventories further reduces supply flexibility by limiting the ability of stocks to function as a buffer against sudden fluctuations in demand.

The ongoing trend towards more stringent product specifications, especially for gasoline and distillates, in North America, Europe and the Far East, tends to make production of each product more specialized and to further reduce refiners' flexibility to move blend stocks from one clean product

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[5] Purvin & Gertz July 1995, *Oil & Gas Journal* June 10, 1996

to another. (Reformulated distillates, and especially gasolines, have to be produced to meet a large number - up to 10 or more - quality specifications. This constrains production and blending to more of a defined "recipe" even "molecular" approach.)

These factors combined tend to mitigate against the global refining industry adjusting easily to a situation where it needs to convert gasoline output to distillate.

OECD Refining Is in a Period of Rationalization and Corporate Consolidation

Inside OECD refining is in a period of rationalization. Seven, mainly small refineries shut down of which six are within the U.S.. The most significant among these was the closure, at least for the time being, of the 181 Mbbl/d Marcus Hook Pennsylvania refinery, by its new owner, TOSCO Refining Company. However, this refinery will restart in the summer of 1997. The other significant U.S. closure was that of the 56 Mbbl/cd Total, Arkansas City, Kansas refinery.

Europe has long been considered as having excess refining capacity. In Europe the 105 Mbbl/d Mobil Woerth refinery recently closed, and the Gulf Milford Haven refinery in England (112 Mbbl/d capacity) closed as of January 1997.

These closures and rationalizations are, however, part of continuing trend. Sun Oil announced in December 1996 that its 85 Mbbl/d Yabucoa, Puerto Rico refinery will switch from processing crude oils to processing solely heavy feedstocks for its lubricants operations. The effect will be a loss of some 50 Mbbl/d of fuels products output including at least 30 Mbbl/d of gasoline and distillates.

In addition, six more European refineries may close in 1997 or 1998 representing additional closures of 612 Mbbl/d of which 322 Mbbl/d capacity is considered likely for 1997, with the rest likely to close by 1999. Two or three additional European refineries may also close by 2000.

Current refinery closures in part reflect a major new trend in the refining industry toward corporate consolidation through joint ventures and mergers. Several important mergers are either under way or have been announced:

Europe

- BP and Mobil are consolidating their refining and marketing operations across Europe with attendant refinery capacity rationalization as indicated in the table.
- Elf, Gulf Oil and Murco are combining their downstream assets into a new company. One immediate effect of this (as mentioned above) is the closure of the 112 Mbbl/d Gulf Milford Haven refinery. This closure is significant for the U.S. since the refinery exported much of its gasoline product to the U.S. East Coast. Potential Western Europe refinery closures are summarized in Exhibit G-21.

Exhibit G-21
Potential Western Europe Refinery Closures

	Capacity Mbbl/d	Status
Woerth	105	already closed
Gulf Milford Haven	112	announced for closure Jan 97
KPC Denmark	57	closure anticipated in 1997
Wilhelmshaven	180	likely in 1997
BP Pernis	100	
BP Lavera	190	
OMW/Exxon	85	likely in 1997
Total	829	

Source: *High & Watt Associates*

U.S.

- Ultramar and Diamond Shamrock have agreed to merge their operations;
- Shell Oil, Texaco and Star Enterprise are forming a U.S. refining and marketing alliance.[6]

These mergers are driven by a determination to cut costs and to eliminate unprofitable refining operations. Refinery capacity and producibility will be reduced as a consequence but so will inventories. Refinery cutbacks and closures will reduce associated refinery storage, but distribution and marketing co-ordination (as part of the mergers) may lead to a secondary consolidation of terminal operations and inventories.

The consolidation and merger trend is unlikely to stop with the four announced to date. Other refiners in the U.S., Europe, and possibly Japan — which is opening up to deregulation — are suffering from the same difficulties and are likely to seek similar remedies. Storage joint ventures aimed at cutting inventory holdings are already beginning to appear in the Asia-Pacific region. In addition, recent price and import deregulation in Japan has slashed refiners' margins there by 50 percent. This may precipitate a round of mergers and rationalizations in that country.

Product Specifications Are Tightening Rapidly

The U.S. has already seen the introduction of Federal Phase I and California Phase I and II reformulated gasolines and the switch to 0.05 percent low sulfur diesel. These trends are now being followed by Europe, Japan and the high growth economies of Asia-Pacific. Also to a lesser degree, other countries outside OECD are moving towards improved product quality specifications, notably increases in gasoline octane and reductions in middle distillate sulfur.

The EU recently announced its proposals for future product quality for gasoline and diesel fuel. These move those products towards U.S. specifications but to a less severe degree on gasoline. Diesel, however, was moved to 0.05 percent sulfur maximum, starting last October, 1996. Exhibit G-22 shows the proposed new EU Mogas specifications.

[6]The new venture could number interests in 14 U.S. refineries plus pipeline networks and storage complexes, opening up potential for closures.

Exhibit G-22
Proposed New EU Mogas Specifications

Parameter	Unit	Minimum	Maximum
RVP (Summer)	kPa	-	60
% Evap. @ 100°C	vol%	46.0	-
% Evap. @ 150°C	vol%	75.0	-
Olefins	vol%	-	18.0*
Aromatics	vol%	-	45.0
Benzene	vol%	-	2.0
Oxygen	wt%	-	2.3
Sulfur	ppm	-	200
Lead	gr/l	-	0.005
***21% for ULG 91**			

Source: Concawe

In addition, EU regulations on sulfur emissions for major industrial burners have all but eliminated the European industrial and electric sector market for high sulfur residual fuel oil. Power generators and industrial consumers in Northern Europe are tending to switch to natural gas, taking advantage of North Sea supplies. This trend will increase in Southern Europe as more gas supplies become available from North Africa via trans-Mediterranean pipelines. The exception in Southern Europe is Italy's national electric utility ENEL, which is almost entirely based on residual fuel for power generation and has switched to one percent maximum sulfur specification.

In South Korea, Thailand, Taiwan, Malaysia and other high growth Asia-Pacific nations, governments are moving rapidly towards U.S. and even California style specifications. In general, these new, more stringent quality requirements regulations are expected to be in place by 2000. Exhibit G-23 shows the trends in Asia Pacific quality specifications.

Exhibit G-23

Asia Pacific Product Quality Specification Trends as of 1994/95

GASOLINE

Australia	Leaded gasoline being phased out
China	Most gasoline unleaded because of TEL cost
India	Discussing reducing lead content
Indonesia	Currently 0.4 percent Pb; to be phased out
Japan	Zero lead. Up to 7 percent vol MTBE allowed Octanes 89 RON regular, 96 RON premium
Korea, S	Lead to be phased out by 1995
Malaysia	Eliminated lead in 1995
New Zealand	Leaded gasoline being phased out
Philippines	Lowered from 0.84 to 0.4 percent Pb regular, 0.6 percent premium
Singapore	Lowered from 0.4 to 0.15 percent Pb
Taiwan	Currently 0.026 percent Pb max; to be phased out
Thailand	Eliminated lead in 1995

KERO/DIESEL

India	Domestic kero may contain 0.25 percent S
Japan	Plans 0.05 percent S standard for diesel by 1996
Korea, S.	Industrial diesel 0.5 percent S; transport 0.2 percent S, sulfur reductions proposed
Malaysia	Plans to reduce transport diesel from 0.5 percent to 0.2 percent S by 1996; industrial from 1 percent to 0.5 percent S
Philippines	Controls on diesel likely in next decade
Taiwan	Industrial diesel 0.5 percent S; automotive currently 0.4 percent, possibly 0.05 percent by 1996
Thailand	Plans 0.25 percent by 1996

RESIDUAL FUEL OILS

Australia	Relatively strict S controls
China	Local crude is low in S; most pollution is from coal, hence fuel oil specs lax
Indonesia	Local crude is low in S, hence fuel oil specs lax
Japan	Specs match or exceed any OECD country
Korea, S	Until recently 4 percent S legal; 1-1.5 percent S grades being phased in; target 0.5 percent by 1996
New Zealand	Relatively strict S controls
Taiwan	Until recently 4 percent S legal; 1-1.5 percent S grades being phased in; target 0.5 percent by 1996

S = sulfur Pb = lead

Source: "Assessment of the Energy Market Impacts of Potential Asia-Pacific Crises", Briefing Report, Mathtech Inc. and EnSys Energy & Systems, Inc., November 1994

Distillate Desulfurization Capacity Additions Look Adequate but Timing of Additions May Cause Periods of Quality Tightness

Recent and projected firm construction data indicate that huge additions to distillate desulfurization capacity are going ahead in both Europe and many Asia-Pacific countries. The consensus is that these capacity additions are sufficient in volume terms to meet the demand for sulfur reductions in middle distillates. However, according to ESAI,[7] a careful analysis of the timing of Asia-Pacific distillate desulfurization capacity additions relative to proposed implementation dates for new diesel sulfur regulations indicates that there may be periods between now and 2000 when insufficient new desulfurization capacity has actually been brought on stream.

In the event that the relevant government authorities do not delay implementation of the new sulfur regulations, the prospect is that these timing difficulties could lead to periods of increased tightness for low sulfur distillate demand. This will tend to soak up any surplus supplies from other world regions but will also rebound back on the kerojet fraction because this is generally of very low sulfur.

In other words, there could be temporary increases in both low sulfur diesel and kerojet supply tightness with attendant price spikes and movements from the U.S. West Coast or Europe into Asia-Pacific to cover the temporary deficit.

Future Russian Gasoil Exports are Uncertain

Russia has traditionally exported gasoil, primarily into Europe. The EU's change to 0.05 percent sulfur maximum on diesel fuel has rendered the Russian gasoil off-spec for Western Europe such that other markets will need to be found.

Moreover, as the Russian economy and attendant petroleum product demand are both uncertain, future availability of export gasoil is open to question. The outlook ties closely to developments in Russia's refining sector, also subject to uncertainties. Perhaps not surprisingly, forecasts conflict, but future volume availability is clearly uncertain.

Seasonal Factors Will Exacerbate Any Increased Distillate Supply Tightness

Past experience borne out by analysis of historical price variations signifies clearly that there is a strong seasonal pattern to distillate supply/demand tightness. Prices for both middle distillates and jetfuel/kerosene increase substantially relative to crude oil in the winter months and decline in the summer. In the three years 1994 through 1996 middle distillate to crude price differential ranged from a low of 2-4 cents per gallon in summer up to 15-20 cents per gallon in the winter. Kerojet prices relative to crude oil show even more marked fluctuations, from 3-6 cents per gallon above crude price in the summer to 20-25 cents per gallon above crude price in the winter.

These price fluctuations are due in large part to increases in heating oil demand, particularly in the U.S. and Europe during the winter.[8] Further, the increases in the kerojet price in particular also relate to several factors:

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[7]Forthcoming ESAI report on product quality and desulfurization capacity in Asia-Pacific.

[8]*Petroleum Argus* reports that German consumers have over 200 million barrels of heating oil capacity storage, the largest single concentration of tertiary distillate stocks worldwide. Despite a switch to gas central heating in the last three years, German heating oil consumers still account for about 37 percent of annual European heating oil demand of 2.4 million barrels per day. Sudden changes in weather conditions in Germany or inventory build or draw there will have a marked impact on worldwide demand for middle distillates.

- The trend seasonal fluctuation in demand for kerosene for winter heating in the Asia-Pacific region;
- The need to blend more kerojet components into heating and diesel oils sold in northern climates in the winter in order to meet tight winter cloud point specifications; and
- The need to blend additional distillates into residual fuels in the winter to meet more stringent seasonal pour-point specifications.

These strong seasonal trends mean the global petroleum supply system is much more sensitive to weather or other problems in the winter than in the summer. Recent price history indicates the high volatility of distillate price relative to crude oil during the winter months.

In January, February 1994 the extreme U.S. Northeast winter caused the New York Harbor heating oil and kerojet prices to spike at over 20 cents per gallon above crude price but prices relative to crude were also somewhat elevated in Rotterdam and Singapore. Conversely, in the relatively mild 1994-1995 winter kerojet and fuel prices peaked at only 11-14 cents per gallon over crude price.

Tightening Product Specifications are Changing World Oil Trade Patterns

Tightening global product specifications for gasolines and middle distillates are making products less fungible and supplies more specialized. This in turn is altering product trade patterns where export refiners have invested in quality upgrading or where less quality-constrained markets will allow lower-quality products to be offloaded.

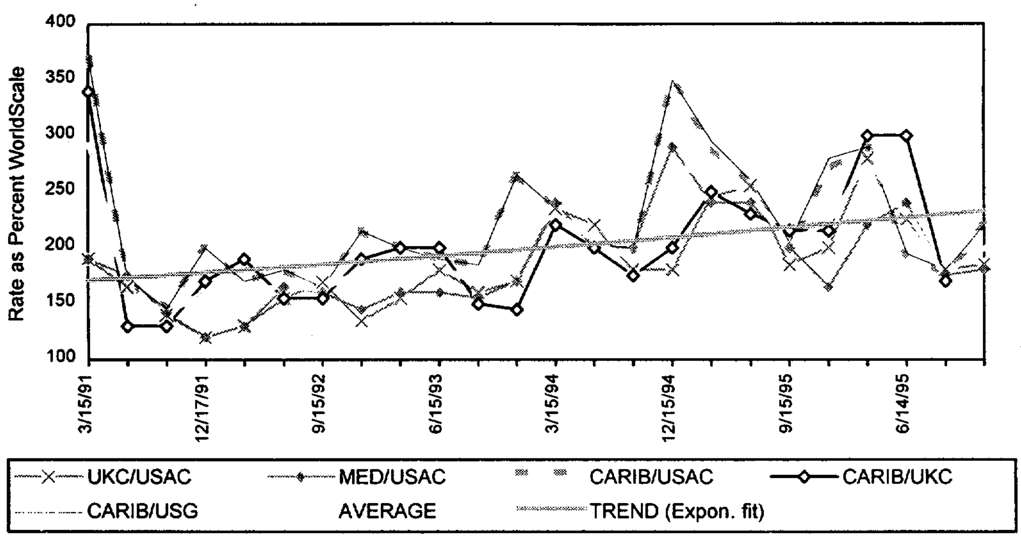
In the U.S. Federal Phase I, RFG had limited impact on trade patterns but the more stringent Phase II regulations will further restrict producibility of RFG.

The Tanker Market Has Been Tightening — Especially on Long Haul Clean Product Movements — and is Projected to Continue to Tighten

In 1972-73, the substantial crude oil price increases imposed by OPEC were triggered to some degree by a short term tightness in the crude tanker market. At that time, WorldScale rates for spot movements of crude oil from the Middle East reached over 150 WorldScale points as against the norm of one third that level. Since that time, the petroleum supply industry has been accustomed to surplus tanker capacity and relatively low and flat tanker freight rates, especially for "dirty" movements of crude oils and residual fuels.

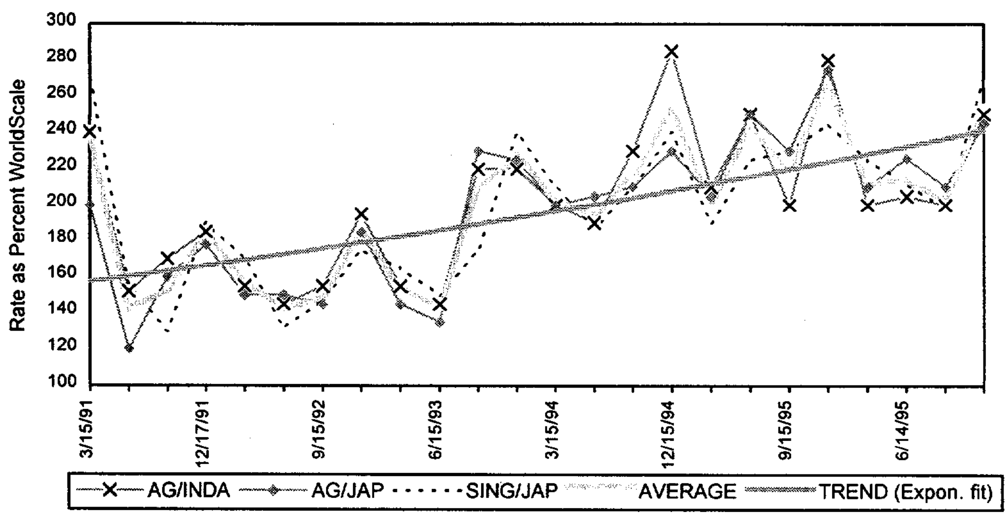
Exhibit G-24 shows that in the five years from late 1991 through late 1996, WorldScale rates for long haul Atlantic Basin clean product movements rose from a low of around WorldScale 150 to a peak of close to WorldScale 300 before dropping back to closer to 200. Nonetheless this represents a sustained trend and a roughly 50 percent increase in freight rates on these long haul movements. This level of increase in turn equates to an increase of around 1.2 cents per gallon of gasoline or distillate moved.

Exhibit G-24
Long Haul Atlantic Basin Clean Movements



As can be seen in Exhibit G-25, similar percentage increase has occurred in long haul Pacific basin clean movements. From a low of about WorldScale 150 in late 1991/1992 to an average around WorldScale 240 in late 1996. On a movement of gasoline or distillate from the Middle East to Japan,

Exhibit G-25
Long Haul Pacific Basin Clean Movements



this corresponds to a price increase of 3 cents per gallon.

Exhibit G-26 shows that freight rate increases on short haul clean tanker movements have been much more moderate. From around WorldScale 130 in late 1991 to around WorldScale 170 in late

Exhibit G-26
Short Haul Clean Movements

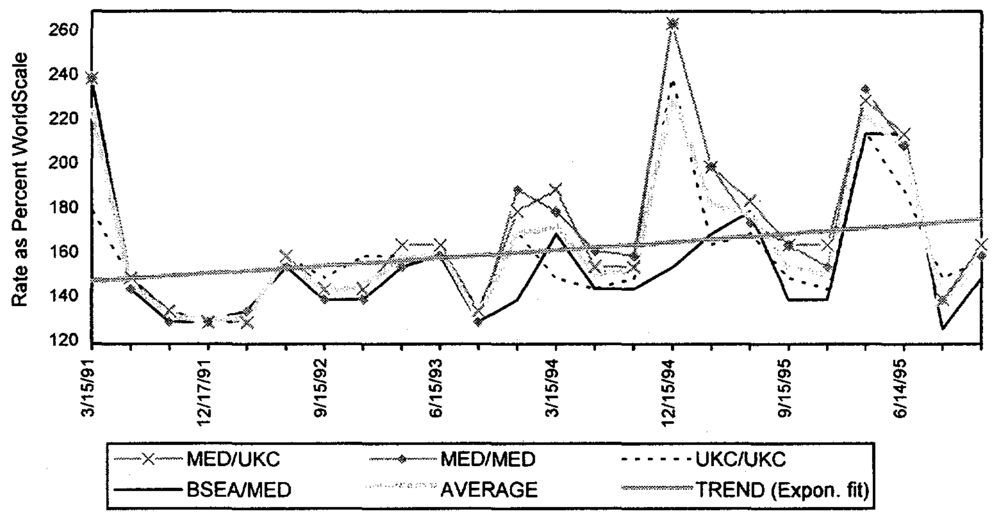
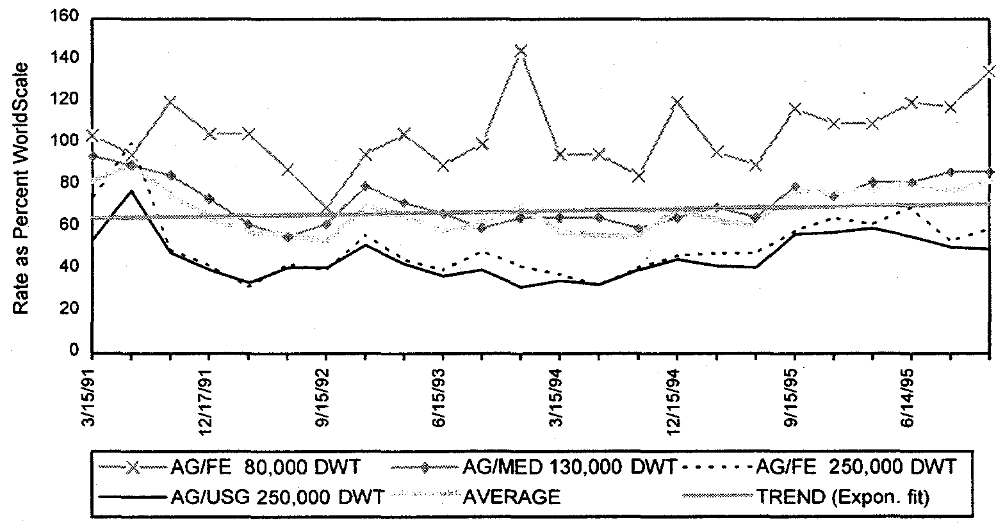
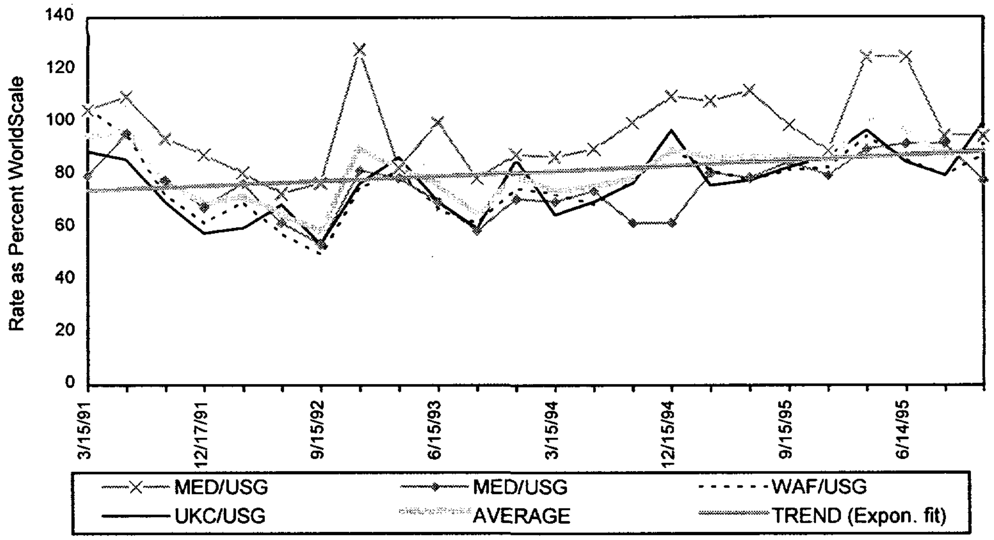


Exhibit G-27
Dirty Movements ex Arabian Gulf



1996. WorldScale rates on dirty tanker movements have also trended upward but far more modestly (see Exhibits G-27 and G-28). The forecasts by industry experts are, however, that crude and product tanker costs will both tend to continue to increase over the medium to long term. This is in part because the age of the existing large crude carrier fleet necessitates extensive scrapping and replacement with new vessels built to higher standards (such as double hulls) at high cost.

Exhibit G-28
Dirty Movements to U.S. Gulf Coast



Growth in Requirements for Clean Product Imports Will Be for Long Haul Movements, Potentially Impacting Tanker Rates

The future of tanker freight rates will depend on the interplay between available tanker fleet capacities and required tanker utilizations to meet crude and product import and export trade movements. A general thrust of the contractor's analysis which is borne out by analyses by other industry experts is that the current refinery capacity versus product demand outlook to 2000 equates to requirements for increased product movements, especially distillates and especially into the U.S., Western Europe, and the Asia-Pacific region.

These required incremental movements will be a long haul. Moving one ton of product from the Middle East to Asia Pacific will consume 3-4 times more tanker capacity than moving one ton from the Caribbean to the U.S. Northeast, and 2 times more capacity than moving the product trans-Atlantically from northwestern Europe to the U.S. Northeast.

Consequently, projected increases in import requirements into and also within the huge Asia Pacific region are likely to have a marked upward impact on product tanker capacity utilizations and freight rates.

In addition, since the Asia Pacific region is anticipated to be the main engine of petroleum product demand growth to 2000 and since indigenous crude production in the region is relatively flat, the incremental crude oil required shipments into the Asia Pacific will all come via long haul movements, principally from the Middle East, but also to a lesser degree from West Africa and the North Sea, as is already occurring.

According to a recent projection by Ocean Shipping Consultants Ltd., (Chertsey, UK) "vessel demand is set to grow even faster than trade volumes because of an increase in relative significance of long haul trades". Ocean Shipping projects product volumes carried by tanker will rise by 21.8 percent to 643 million metric tonnes in 2000.

Depending on the level of net additions to the dirty tanker fleet over the medium term, crude tanker freight rates may also move up significantly.

Exhibit G-29
Marine Distances

Nautical miles - One way		
Origin	**Destination**	**Nautical Miles**
Montreal, Canada	Boston	1,309
Hess, Virgin Islands	Boston	1,580
Amway Bay, Venezuela	Boston	1,915
Rotterdam	Boston	3,215
Ras Tanura, Saudi Arabia	Yokohama, Japan	6,593
Singapore	Yokohama, Japan	2,892
Trieste, Italy	Yokohama, Japan	9,200 (via Suez Canal)
Los Angeles	Yokohama, Japan	4,842
Houston	Yokohama, Japan	9,259 (via Panama Canal)

The overall effect may be for increasing tightness in distillates supply worldwide to be augmented by increasing tightness in crude and product tanker utilizations, in turn leading to increases in delivered prices of crudes and products.

Over the longer term, sustained high freight rates on product movements will justify and encourage additional refining investments with the aim of curtailing product imports. However, any such refining investments would be unlikely to have an impact on the period to 2000. High freight rates will also encourage new tanker construction - but at new-build costs that will be higher than historical costs.

Factors Which Could Alleviate Projected Tightness in Global Distillate Supply/Demand

Several factors exist which may help to offset the projected increase in tightness in distillate supply/demand worldwide. These are discussed below.

Incremental Crude Slate Is Projected to Be of Good Quality

Worldwide petroleum exploration and development activity continues to expand as new regions become available for exploration and as existing producing regions turn to more commercial relationships with oil company partners.

In addition, substantial advances in exploration and production technologies over the last few years have significantly cut the costs of the exploration and production of oil, notably offshore. These trends, combined with cost cutting measures in E&P companies, have made it economically attractive for small, marginal as well as medium and large oil fields to be developed at crude oil prices under $20/barrel.

In addition, several of the primary OPEC producers including Saudi Arabia, Venezuela and Abu Dhabi all have plans to significantly expand production capacity. Therefore the consensus outlook is that there should be ample crude oil supplies available through 2000 with moderate associated crude oil prices.

Much of the new crude oil that is coming on stream is of relatively light gravity or moderate to low sulfur. Major developments that fall into this category include those in

- Colombia, the Cuisiana and Cupiagua fields;
- North Sea, where production is projected to continue to grow for at least the next 3-4 years;
- Yemen;
- Brazil; and
- India.

In addition, Saudi Arabia has a declared strategy of shifting to a lighter crude production mix. In this regard production of the heavier Arab Medium and Arab Heavy grades has been curtailed in recent years and Saudi Arabia is promoting development of new light oil fields. These include the Arab Super Light field, 44 - 50° API crude, which is already at production of 150 Mbbl/d. More significantly, the huge Shaybah field (7 billion barrels estimated reserves) south of Riyadh will augment Arab Light/Extra Light production. Output from this 40 - 42° API, 0.7 percent sulfur field should reach 500 Mbbl/d by 2000.

The return of Iraq crude oil to the market will also tend to improve world crude API gravity, if not sulfur. In addition, significant incremental volumes of natural gas liquids/condensates are coming on stream in association with increasing gas production.

Offsetting these trends towards high quality incremental crude oils, projected increases heavy oil production, especially from Venezuela and secondarily Canada. Both these countries, however, have plans to upgrade their heaviest oils to syn-crudes of typically 22-28° API gravity, adding at least 450 Mbbl/d over the next several years. Note that syn-crudes, while not light, contain virtually no vacuum residuum or sulfur, improving their marketability.

The overall projection for crude quality that emerges is that, contrary to past conventional wisdom, quality should not decline but should be maintained or even slightly improved, especially with regard to gravity, relative to the recent global average of around 31.7° API and 1.1 percent sulfur.

Small Project Capacity Creep May Help Diminish the Distillate Deficit

To estimate future refinery producibility in the period through 2000, the contractor took careful account of minor and revamp projects as well as major capacity additions. Furthermore, certain likely refinery closures in Europe, beyond those identified, were not taken into account, nor were any further closures of U.S. refineries or, for that matter, any cancellations of major new projects currently under engineering.

All of these factors lead to the view that the estimated refinery process unit capacity additions were not underestimated. Nonetheless, small projects may have been missed and the industry does have the capability to adapt when economic incentives arise. Also, some 117 revamp projects were identified in the literature as having no associated capacity expansion. Many were not related to process units. However, some of these may lead to improvements in process unit service factors or yields, effectively improving producibility. It is therefore possible that these projects and, as-yet-unannounced small projects may add something to the projected refinery capacity expansions.

These will not make a sufficient difference to global refinery capacities and producibilities in the period 1997 through 1998 to eliminate the projected gasoline-distillates imbalance. As mentioned elsewhere, 1999 is less certain because there is still scope for refiners to announce and implement major capacity expansions for startup in that year.

Refiners Have Processing Flexibility to Switch Between Gasoline and Distillates

Refinery conversion processes including catalytic cracking, gasoil and residuum hydrocracking and coking provide refiners with the capability to produce clean products by upgrading residual fractions; also to adapt to changes in crude mix and to vary the product slate yields of gasoline and distillate. In addition, hydrofining processes such as residuum desulfurization and deep hydrotreating of middle distillate fractions have the potential for releasing additional blending stocks to the diesel and heating oil product pools by offsetting higher sulfur content streams and allowing them to augment the distillate blend.

These secondary processes are concentrated most heavily in the larger and more complex refineries which characterize the U. S. refining industry - although processing complexity in other world regions is advancing. Their ability to vary the product yields between gasoline and distillate is summarized below:

Gasoline to Distillate Yield Variation:

♦ Catalytic Cracker	37 percent/47 percent to 60 percent/20 percent (gasoline/distillate)
♦ Vacuum Gas Oil Hydrocracker	15 percent/100percentto 110 percent/15 percent
♦ Residuum Hydrocracker	Limited ability to vary the gasoline to middle distillate yield ratio.
♦ Residuum Desulfurizer	Same as above.
♦ Coker	Same as above; also limited yield of gasoline and distillate fraction streams all of which require extensive additional processing to make them acceptable as final product blendstocks.

The information indicates that significant gasoline/distillates yield flexibility exists only on catalytic cracking and vacuum gasoil hydrocracking units; further that only the hydrocrackers are designed to produce distillates as their primary product. Although vacuum gasoil hydrocrackers have the advantage of wide yield flexibility between gasoline and distillates, refiners generally do not build hydrocrackers primarily for gasoline production, because of their high cost. As distillate demands grow, hydrocrackers can be expected to be operated consistently in maximum distillate mode, thereby throwing the primary burden of gasoline to distillate yield flexibility back onto the world's catalytic crackers.

On paper, the need to meet an estimated supply deficit of 767 Mbbl/d of distillate by 1998 and possibly 1,243 Mbbl/d by 1999 can be accommodated by the yield flexibility of the 13 MMbbl/d of FCC capacity in place. However, whether their flexibility exists in practice without extensive catalyst changes and unit revamps is open to question and further investigation:

- Industry information does not indicate that the existing FCC capacity base can be readily used to raise distillate output by up to 10 percent of total yield.
- Increases in distillate yields on FCCs are achieved by lowering conversion levels. This has the effect of lowering gasoline yield but raising fuel oil yield, generating surplus residual material that could not readily be disposed.

- The distillate material produced from FCCs is not suitable for direct blending into finished products. It must first be hydrofined to reduce sulfur and aromatics levels. Raising FCC distillate yields would therefore strain available distillate desulfurization capacity.

Process Technology/Catalyst Suppliers May Be Able to Gear Existing Processes to Better Distillate Yields

Tailored catalytic cracker (FCC) catalysts have been developed to:

- maximize conversion to gasoline,
- reduce the olefin and sulfur contents of gasoline in connection with gasoline formulation,
- reduce the coke content of the FCC catalyst prior to regeneration, and
- allow deeper residuum cuts to be processed by passivating metals concentrated on FCC catalysts.

The FCC unit is a common target for catalyst development efforts because the potential for improved profits is so great and because the catalyst can be changed while the unit is on stream. Catalyst manufacturers are continually improving existing catalysts and European refiners and catalyst suppliers have already identified the need to maximize distillate yield in future from FCCs.

In the near to medium term it may therefore be feasible to improve catalyst selectivity to produce additional light cycle oil distillate. As discussed above, the light cycle oil is normally hydrofined prior to inclusion in the middle distillate diesel and home heating oil product pools. Mild hydrocracking of the FCC feed will also increase effective distillate yield by 5-10 percent but requires substantial investment.

Substantial Spare Capacity in Former Soviet Union May Be Usable to Meet Distillate Deficit

On paper, the FSU processes over 5 MMbbl/d of "spare" refining capacity that, in principle, might help to reduce the projected distillate deficit. However, much of the capacity is simple or old or located in regions that do not lend themselves to exporting. Furthermore, as in many developing countries, the full potential of key secondary units tends not to be realized because of disrepair and/or inadequate operator expertise to manage the added process complexity. Nonetheless some potential may exist in the FSU.

Longer Term, Natural Gas to Distillates Technology Could Lead to Substantial Increases in Distillate Availability

Processes based on Fischer Tropsch technology to produce liquid petroleum fuels from natural gas and coal feedstocks have been in existence since the 1930's. The technology was employed by Germany during World War II, by Sasol in South Africa, and by Mobil in New Zealand to produce gasoline from natural gas. A Shell synthetic distillates plant has been in operation in Malaysia for several years. Until recently, gas-to-liquids plants have been built only where constraints existed on conventional fuels products supply or, as in the case of the Shell plant, to gain long term operating experience on a near commercial scale.

Continuing refinements to the technology have brought it to the brink of a new era of much broader application. Exxon has completed feasibility studies and is currently negotiating with the Qatar government to develop the huge North Field (250 trillion cubic feet reserves) using its "*Advanced Gas Conversion 21st Century*" *AGC-21* gas-to-liquids technology. The plant will convert 500 million square feet per day (MMSCF/D) of natural gas into 50 Mbbl/d of essentially sulfur free petroleum liquids. Project initiation is subject to successful closure of commercial negotiations and no start-up date has yet been set.

The AGC-21 technology is primarily geared to production of distillates but incorporates flexibility to increase the naphtha yield for gasoline or petrochemical feedstock, or the yield of vacuum gasoil boiling range product for lubes production or for use as catalytic cracker (FCC) feedstock to produce gasoline. This is illustrated in Exhibit G-30.

Exhibit G-30
Possible Product Slate Configurations
Exxon AGC-21 Technology

	Maximum Diesel/Jet	**Maximum Vacuum Gasoil for Cracker Feed or Lubes**
Naphtha	30%	15%
Diesel/Jet Fuel	70%	50%
Cat Cracker Feedstock/Lubes	0%	35%
Total	100%	100%

Source: *Exxon data and Salomon Brothers, Inc.*

The Exxon technology is geared to the largest gas fields and opens up the possibility for an alternative and more economic means to exploit the resources of large remote gas fields as compared to LNG. Other variants on the Fischer-Tropsch technology have been developed, such as by Tulsa based Syntroleum, that are designed for exploitation of smaller gas fields, e.g. with liquids production of the order of 5 Mbbl/d. Both forms of the technology are claimed to be economic at crude oil prices of $20/bbl or less.

The implications of these developments are potentially very far reaching. Global gas reserves are almost as large as known global oil reserves. Yet much of the gas exists in remote locations: Middle East, Former Soviet Union, Indonesia, and Alaska. Commercial gas-to-liquids technologies open up the potential to exploit these remote reserves in both large and smaller gas fields. In regions where bans on gas flaring prevent development of oil fields because of the associated gas, gas-to-liquids technology thus presents an opportunity to raise oil production levels.

While this new technology will not affect the 1997-1999 time frame, it could bring on stream substantial new supplies of premium quality distillates in the period immediately beyond. Significant volumes of gas-to-liquids distillates would potentially eliminate distillate deficits, but would also have far-reaching impacts on world regional trading patterns and refining/supply economics, and would act to reduce oil and imports dependency in the U.S.

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Appendix H

Summary of Federal Authorities Relevant to the Establishment of Petroleum Product

Prepared by:

Department of Energy
Office of Strategic Petroleum Reserve

APPENDIX H

SUMMARY OF FEDERAL AUTHORITIES RELEVANT TO THE ESTABLISHMENT OF PETROLEUM PRODUCT RESERVES

I. ENERGY POLICY AND CONSERVATION ACT AUTHORITIES (EPCA) (42 U.S.C. §6231 et seq.)

A. STRATEGIC PETROLEUM RESERVE PLAN

EPCA requires the Secretary of Energy to prepare a Strategic Petroleum Reserve (SPR) Plan detailing proposals for designing, constructing, filling, and using the SPR; EPCA generally provides DOE with statutory authority to implement the Plan. The requirement for a Plan and the elements to be included are found in section 154 of EPCA. The original Plan was transmitted to the Congress in January 1977. The Plan can be amended, subject to a sixty-day waiting period, by transmitting an amendment to the Congress. There have been amendments to the Plan, the most recent of which, a Distribution Plan, was transmitted to the Congress in December 1982. In addition, a number of amendments to EPCA have been enacted authorizing various new initiatives, which permitted the Secretary to take action without a Plan amendment.

B. ACQUISITION AND OPERATION OF STORAGE FACILITIES

EPCA provides broad authority to acquire, develop, and operate SPR storage facilities, including any facilities that might be needed for a regional petroleum reserve. Acquisition can be by purchase, condemnation, construction, development, lease, and other means. Petroleum may be stored in facilities not owned by the Federal Government if the facilities are subject to "audit," for which purpose EPCA provides special powers to require record keeping and to permit inspection.

C. ACQUISITION AND STORAGE OF FUEL OIL

DOE has broad authority to acquire petroleum products for the SPR. Section 159 authorizes the acquisition of petroleum products by "purchase, exchange, or otherwise", subject to the directive of section 160(b) that:

The Secretary shall, to the greatest extent practicable, acquire petroleum products for the Reserve, including . . . the Regional Petroleum Reserve in a manner consonant with the following objectives:

(1) minimization of the cost of the Reserve;
(2) orderly development of the Naval Petroleum Reserves to the extent authorized by law;
(3) minimization of the Nation's vulnerability to a severe energy supply interruption;
(4) minimization of the impact of such acquisition upon supply levels and market forces; and
(5) encouragement of competition in the petroleum industry.

A 1990 amendment authorizes the Secretary to contract for petroleum product not owned by the United States. Any contract negotiated under this authority must be transmitted to Congress, and cannot become effective until 30 days after the date of the transmittal, unless the President determines that the contract is required as a result of a severe energy supply interruption or an obligation of the U.S. under the International Energy Program (IEP).

D. REGIONAL PETROLEUM RESERVE

Section 157 of EPCA authorizes the establishment of one or more RPRs as part of the SPR. Section 157 requires that the SPR Plan provide for the establishment of an RPR for each Federal Energy Administration region which is determined to rely on refined product imports for more than twenty percent of its demand. The amount to be stored in the RPR must not exceed the region's highest three months of imports during the previous 24 month period. However, section 157 also provides that the Secretary may store crude oil, residual fuel oil, or refined petroleum product in another location in substitution for the RPR as long as the substitution may be made without adversely affecting the purpose of the Regional Reserve.

E. INDUSTRIAL PETROLEUM RESERVE AUTHORITY

Section 156 authorizes the Secretary to establish an Industrial Petroleum Reserve, which is defined as that part of the SPR consisting of petroleum products owned by importers or refiners (rather than owned by the Federal Government), but maintained under the requirements of section 156. Section 156 grants the Secretary of Energy discretionary authority to require refiners and importers of petroleum products to acquire, store, and maintain in readily available inventories, up to three percent of the previous years throughput or imports, as long as the IPR is accomplished in a manner that is appropriate to the maintenance of an economically sound and competitive petroleum industry. The Secretary is also authorized to exempt firms that are inequitably affected or otherwise incur special hardships, and to permit any refiner or importer to store their petroleum products required to be stored under this section in surplus storage capacity owned by the Federal Government.

F. DRAWDOWN AND DISTRIBUTION AUTHORITY

The SPR's drawdown and distribution authority is found in EPCA Section 161. There are two key prerequisites to drawdown and distribution. First, with limited exceptions, no drawdown and distribution of the SPR may be made except in accordance with the provisions of the Distribution Plan contained in the Strategic Petroleum Reserve Plan. Second, no drawdown and distribution of the SPR may be made unless the President has found that implementation of the Distribution Plan is required by a "severe energy supply interruption or by obligations of the U. S. under the international energy program."

A severe energy supply interruption shall be deemed to exist if the President determines that:

(A) an emergency situation exists and there is a significant reduction in supply which is of significant scope and duration;
(B) a severe increase in the price of petroleum products has resulted from such emergency situation; and
(C) such price increase is likely to cause a major adverse impact on the national economy.

With two exceptions, no drawdown or distribution of the Reserve can occur without a Presidential declaration of either a severe energy supply interruption under the preceding tests, or obligation under the International Energy Program. The first exception, permits test sales from the SPR without a Presidential declaration. Section 161(g) currently permits test sales in amounts not to exceed 5,000,000 barrels. Tests sales must be conducted in accordance with the Distribution Plan and implementing regulations, modified as appropriate, taking into consideration the artificialities of a test and the absence of a severe energy supply interruption. Any such modification of the Plan, must be submitted to both houses of Congress 15 days before the test. Prices accepted for any crude oil during a test sale under this subsection must be at least ninety percent of the current sales price of comparable crude, otherwise the Secretary may cancel the sale.

The second exemption, permits a limited drawdown of amounts in the SPR in excess of 500 million barrels, not to exceed 30 million barrels in total or for more than 60 days, if the President finds that:

A) A circumstance, other than those described in subsection (d), exists that constitutes, or is likely to become, a domestic or international energy supply interruption of significant scope or duration; and

(B) Action taken under this subsection would assist directly and significantly in preventing or reducing the adverse impact of such shortage.

During any period in which there is a drawdown and distribution under this subsection, the Secretary must transmit a monthly report to the Congress containing an account of the drawdown and distribution of petroleum products and an assessment of its effect.

II. SUMMARY OF OTHER FEDERAL EMERGENCY AUTHORITIES RELEVANT TO SIGNIFICANT PETROLEUM PRODUCT SUPPLY PROBLEMS

Jones Act Waiver: Public Law No. 81-891 directs the Secretary of the Treasury to waive the provisions of section 27 of the Merchant Marine Act of 1920 ("Jones Act"), which require the use of vessels built in, documented under the laws of, and owned by citizens of the United States in coastwise trade, "upon the request of the Secretary of Defense to the extent deemed necessary in the interest of the national defense by the Secretary of Defense." In addition, Public Law No. 81-891 authorizes the Secretary of the Treasury to waive compliance with the Jones Act either upon his or her own initiative or upon the written recommendation of the head of another agency whenever the Secretary "deems that such action is necessary in the interest of the national defense."

For energy emergencies, DOE, Treasury, and the Maritime Administration have an interagency agreement for expediting the waiver process, and the agreement specifies the responsibilities of each agency in establishing the need for and granting waiver requests. DOE is responsible for monitoring energy supply needs to ascertain whether an energy supply shortage exists or is imminent, coordinating with States in identifying sources of supplemental energy supplies, and recommending to the Treasury Department whether waiver in particular cases is necessary in the interest of national defense. MARAD advises on whether adequate Jones Act vessels are available on a timely basis. Treasury determines whether or not to grant a waiver request.

LIHEAP Discretionary Funds: In addition to the $1 billion of FY 1997 block grant funds provided to states for distribution to low-income families, $420 million of discretionary funds are available for distribution by the Department of Health and Human Services (HHS). These funds can be distributed according to criteria that relate to the type of emergency that precipitates their need. For example, very high heating oil and propane prices could justify distributing funds to states based on the state use of these fuels or other variables that reflect state needs. DOE and HHS have been in close contact and HHS is prepared to expeditiously release these funds should they be required. In 1992, HHS released discretionary funds for an almost identical situation as December heating oil prices had risen 20%

higher than the average prior year retail price. Discretionary funds were also provided to help low-income households pay for unusually high energy expenses during the summer heat-wave of 1995.

III. ENVIRONMENTAL REQUIREMENTS

A. NATIONAL ENVIRONMENTAL POLICY ACT

Dedicating a displacement-type cavern at Big Hill for distillate storage could probably be accommodated within existing National Environmental Policy Act (NEPA) documentation and permits. At the opposite extreme, construction of new government-owned capacity would require a new Environmental Impact Statement (EIS) which would take at least 24 months, including initial coordination with the Host State and public scoping.

Both long-term and short-term leasing alternatives would require an Environmental Assessment (EA) which would take at least 12 months. No circumstances have been identified that would preclude a Finding of No Significant Impact. Either a long- or short-term lease could conceivably meet a provision of EPCA that would enable exemption from NEPA, namely, if the lease could be designated as "interim storage" and if the facilities existed on July 1, 1982 and have not been modified to increase capacity. Although an IPR was addressed in the Programmatic EIS, implementation which required any new legislation or regulation must be preceded by a NEPA review, presumably an EA.

B. STATE COASTAL ZONE MANAGEMENT PROGRAMS FOR FUEL OIL ASTs

Delaware - In Delaware, the Coastal Zone Act (7 Del. Laws, c. 70, §7001 through §7013) controls the location, extent, and type of industrial development in Delaware's coastal areas. Specifically, the Chapter seeks to prohibit entirely new construction of heavy industry in coastal areas. Section 7003 states, "Heavy industry uses of any kind not in operation in June 28, 1971, are prohibited in the coastal zone and no permits may be issued therefor." Section 7002 defines heavy industry use to mean "a use characteristically involving more than 20 acres and characteristically employing...equipment (such) as...tanks." Examples of heavy industry include oil refineries. Section 7004 states that, except for heavy industry uses, manufacturing uses are allowed in the coastal zone by permit only, as provided for under the section. In deciding permit requests, environmental impact as well as other factors are considered. According to §7002(a), "æThe coastal zone' is defined as all that area of the State, whether land, water or subaqueous land between the territorial limits of Delaware in the Delaware River, Delaware Bay and Atlantic Ocean, and a line formed by certain Delaware highways and roads..."

New Jersey - In New Jersey, the Coastal Area Facility Review Act (§13:19-1 through §13:19-21) regulates construction in the coastal area. Section 13:19-5 of the Act provides that "no person shall construct or cause to be constructed a facility in the coastal area until he has applied for and received a permit issued by the commissioner." Under §13:19-3(c)(10), the definition of facility includes bulk storage, handling, and transfer facilities for crude oil, gas and finished petroleum products not on the premises where petroleum refining occurs. Section 13:19-6 provides that the permit shall include an environmental impact statement, as well as other information that the commissioner may proscribe. Section 13:19-10 states that the commissioner shall issue a permit only if he finds that the proposed facility meets certain standards. Section 13:19-4 defines the coastal area in detail. Section 13:19-20 provides that the Act shall be liberally construed to effectuate its purpose and intent.

New York - In New York, the Waterfront Revitalization of Coastal Areas and Inland Waterways Act (Executive Law, §910 through §923) discusses development in coastal areas; however, it is geared primarily toward revitalization of existing structures and does not discuss new industrial uses. Although §921 discusses the amendment of the coastal zone management program, it does not provide details concerning the state's coastal zone management program. Section 921(1) only states that "the secretary shall amend the state's coastal zone management program to incorporate the requirements of this section."

Connecticut - In Connecticut, the Coastal Management Act (C.G.S.A. §22a-90 through §22a-113) governs development in the coastal area. Section 22a-92 outlines the legislative goals and policies of the Act. Section 22a-92 (b)(1)(E) states that in carrying out their responsibilities, Federal, State, and municipal agencies must follow certain policies concerning development, facilities, and uses within the coastal boundary. Included is the policy "to disallow the siting within the coastal boundary of new tank farms and other new fuel and chemical storage facilities which can reasonably be located inland and to require any new storage tanks which must be located within the coastal boundary to abut existing storage tanks or to be located in urban industrial areas and to be adequately protected against floods and spills." Section 22a-94(b) defines the coastal boundary as "a continuous line delineated on the landward side by the interior contour elevation of the one hundred year frequency coastal flood zone...or a one thousand foot linear setback as measured from the mean high water mark in coastal waters." Subsections (a) through (f) provide additional information about mapping the coastal boundary.

Rhode Island - In Rhode Island, the Coastal Resources Management Council Act (§46-23-1 through §46-23-24) states that "it is the policy of the state to preserve, protect, develop, and, where possible, restore the coastal resources of the state..." Section 46-23-2 creates a Coastal Resources Management Council and §46-23-6 vests this Council with certain authority over coastal areas. Section 46-23-6(2)(iii) states, "The authority of the council over land areas (those areas above the mean high water mark) shall be limited to two hundred feet (200') from the coastal physiographic feature or to that necessary to carry out effective resources management programs. This shall be limited to the authority to approve, modify, set conditions for, or reject the design, location, construction, alteration, and operation of specified activities or land uses when these are related to a water area under the agency's jurisdiction, regardless of their actual location. The council's authority over these land uses and activities shall be limited to situations in which there is a reasonable probability of conflict with a plan or program for resources management or damage to the coastal environment. These uses and activities are:...(B) Chemical or petroleum processing, transfer, or storage."

Massachusetts - In Massachusetts, §4A of the act establishing the Environmental Affairs Office (21A §4A) provides for a coastal zone management office. The section states that the secretary (of environment) "shall direct the coastal zone management office, consistent with state law, to adopt, and from time to time amend rules, regulations, procedures, standards, guidelines, and policies which shall constitute the Massachusetts coastal zone management program." The same section states that the purpose of the program "shall be secure for the inhabitants of the commonwealth the objectives and benefits of the federal Coastal Zone Management Act."

New Hampshire - New Hampshire has only approximately 16 miles of coastline. In New Hampshire, there is no State law covering coastal zone management. The New Hampshire Coastal Zone Management Program is based on the general environmental laws of the State (e.g., the wetland laws, clean water laws). Therefore, although there are no petroleum tank requirements specific to coastal areas, the general state-wide aboveground storage tank (AST) requirements for petroleum apply in coastal areas, as well as elsewhere. The State environmental division in charge of regulating

ASTs is currently in the process of developing rules for petroleum ASTs. These rules, set to be adopted next month, specify standards for the construction of new facilities. In addition, they cover operations (e.g., inspections), tank construction, and require SPCC plans for all facilities (not just for those facilities with a reasonable expectation of effecting navigable waters as required by federal law.)

Maine - In Maine, the Coastal Management Policies (Chapter 19 §1801 through §1803) states that development of the coastal area is increasing rapidly and that this development poses a significant threat to the resources of the coast. In §1801, the legislature directs that state and local agencies and federal agencies...with the responsibility for regulating, planning, developing or managing coastal resources, shall conduct their activities affecting the coastal area consistent with policies to maintain water and air quality. Section 1802 defines the coastal area as "all coastal municipalities and unorganized townships on tidal waters and all coastal islands. The inland boundary of the coastal area is the inland line of coastal town lines and the seaward boundary is the outer limit of the United States territorial sea."

Appendix I

Product Stability and Turnover Requirements

Prepared by:

Department of Energy
Office of Strategic Petroleum Reserves
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APPENDIX I
PRODUCT STABILITY AND TURNOVER REQUIREMENTS

In developing a refined petroleum product reserve, a critical consideration is the long-term storage stability of the petroleum product to be stockpiled. The product of concern for this study and potentially selected for the reserve is Grade No. 2 distillate fuel oil. Two storage scenarios have been considered for the purposes of this study: (1) storage in aboveground tanks in either New England or the New York Harbor area, and (2) storage in solution-mined caverns in the Gulf Coast of the United States collocated with existing SPR stockpiles.

A number of European countries have petroleum reserves similar in concept to the United States' SPR, although smaller in size. The German and French reserves are stored predominantly in salt dome caverns, while the Scandinavian reserves are stored in cavities excavated in granite and other hard rocks. In addition to crude oil, a variety of refined products are stored in the European reserves. These products include gasoline, aviation turbine fuel, automotive and marine diesel fuels, and home heating oil. The Europeans, unlike the United States, have many years of experience with product storage, and this experience can be drawn on for decisions about a regional reserve.

INTRODUCTION

In planning development of a refined petroleum product reserve, an important consideration is that of long-term storage stability of the petroleum product to be stocked. It is imperative to know the quality, stability, and compatibility of each batch of the product, whether they are to be stored separately or commingled. The stability of the product, the form of the product, and the frequency with which it must be turned over have implications for the costs of the various options.

There can be great variations in stability that occur between various batches of a product, even though all meet a common specification. Recent experience by industry has raised concern about even greater variations between batches due to changes in refining processes. These observations indicate that some type of screening to eliminate products of high instability should be applied to any shipments destined for a refined petroleum product reserve.

This study is focused on storage of fuel for domestic use and in small industrial burners in New England during a supply shortfall. Consequently, only the stability of Grade No. 2 distillate fuel oil is discussed in this section. This appendix first of all looks at experience elsewhere in world, notably in Europe, and summarizes what can be concluded from this experience. This is followed by a brief summary of U.S. experience, largely military. A technical discussion of the middle distillate range and some of its problems follows, and the appendix ends with some conclusions and a bibliography.

SUMMARY OF WORLDWIDE PETROLEUM PRODUCT RESERVES

Two modes of underground petroleum storage have been used in various parts of the world since about 1915. These are porous media, used largely for methane storage, and open cavities. The open cavities have been abandoned mines and purpose-excavated tunnels in granite, rock salt or other suitable rock formations, as well as solution-mined cavities in salt. These latter have been used for storage of a wide range of petroleum including crude oil, ethane, butane, propane, liquefied petroleum gases, gasoline, middle distillate fuel oils, and residual fuel oil. Giles (2) has provided a comprehensive review of worldwide petroleum stockpiles.

A variation on underground storage is the use of concrete or steel-lined concrete tanks constructed inside excavations in rock. These provide an excellent means of ensuring product quality, but are generally smaller than mines, tunnels, or solution-mined cavities, and are considerably more expensive to construct.

For aboveground storage, conventional steel tanks and floating vessels are used, with steel tanks being predominant. Floating vessels include surplus tankers and large, specially-constructed barges permanently moored in lagoons and bays.

Several countries in Europe including Germany, France, Britain, the Netherlands, Switzerland and Denmark have had experience with strategic stock piling of crude oil and products stretching back to the 1950s. In addition, the Japanese have held strategic crude oil stocks for many years and have recently begun to consider the question of holding product stocks. The German reserves are stored predominantly in salt dome caverns, while the Scandinavian reserves are stored in cavities excavated in granite and other hard rocks, or in cut-and-cover tanks. France also has a sizeable petroleum stockpile in solution-mined cavities in salt but, for the most part, this stockpile is operational and stocks are periodically rotated. In addition to crude oil, a variety of refined products are stored in the European reserves. These products are monitored at regular intervals for indications of imminent degradation. If analyses indicate that the stored product is tending to go off specification, drawdown and use of product is initiated before degradation reactions advance to a point where the product is unsuitable for use. When the contents of the reservoir have been consumed, new product is then recharged.

Several governments, including Germany, France, and Japan, have also imposed regulations requiring that reserves of products also be kept by various oil companies to ensure against petroleum shortages. Salt dome cavities, mined rock caverns, aboveground steel tanks, floating barges, and underground concrete tanks are typically utilized for this industrial product storage.

Below is a brief summary of the storage experience of several European countries and Japan.

Denmark

The Danish emergency stock holding agency (FDO) was founded in 1972 with compulsory stocks set at a minimum of 125 days forward consumption. (This was subsequently dropped to 90 days.) Up until 1988 the FDO had successfully held products in storage for apparently as long as twenty years. However, changes in national product specifications necessitated a complete rotation of the inventory. The original products were all straight run non-cracked material. Purchased replacement products all contained cracked stocks because of the shift to lighter complexity in European refining. The FDO found that these did not have the product stability required for long term storage, but instead needed rotation every 1 to 3 years. Danish experience with distillates includes both above and belowground storage.

France

The French underground storage complex at Manosque, near Lavera on the coast of Southwest France, consists of 28 salt caverns with a total capacity of 41 million barrels (Mmbbl). This facility is used for the storage crude oil, diesel oil, gasoline and naphtha. The system is interlinked with three refineries, two chemical plants, the Port of Lavera and two pipelines. The complex was created after the Suez crisis of 1956, initially, purely as a strategic storage facility. Its strategic function has been retained but it is now also operated as a component in the logistics chain of the refineries of the south of France. Thus the facility is operated so that it has a commercial as well as strategic function and value, e.g. to meet seasonal requirements for petroleum products.

Germany

The main German strategic storage complex is located in northern Germany and is operated by the organization EBV. The complex includes stocks at eight cavern sites and comprises crude oil, blend stocks, and finished products. The German philosophy is that by storing a mixture of crude oils, light product blend stocks, and finished products, supply flexibility to deal with different kinds of emergencies is maximized.

Exhibit I-1
EBV Cavern Storage Inventory
(millions of tons)

Crude oil	7.9
Product blend stocks	2.3
Finished gasoline	0.9
Finished distillates/gasoils	0.9
Total	12.0

This complex is near the Rhine river pipeline terminals and refineries and the coast of Northern Germany; thus, (like the French facility) it is well integrated with the regional logistics system. Cost of the facility is claimed to be one-third of that of equivalent aboveground storage.

<u>Diesel Fuel Storage</u>

Critically for the proposed U.S. reserve, the finished gasoil in these caverns has been successfully stored for as long as eight and a half years and EBV technical management believe 10 years is achievable. Product rotation has been caused, not by degradation, but by the need to refill with stock conforming to new diesel fuel and heating oil quality specifications. In order to maximize the life of the gasoil in the cavern, EBV has a very strict specification for the fuel which all tenders must satisfy. This "cavern gasoil" specification is far tighter than the standard new specification (EN-590) for European diesel fuel, particularly in respect to olefins and cracked components.

The cavern diesel specification is believed to emphasize:

- Use of straight run blend components (avoidance or limitation of cracked stocks);
- Hydrogenation of all components;
- Sulfur in the low ppm range;
- Low olefins content; and
- End point potentially cut back to approximately 620°F.

In addition, additives to control degradation are employed, including metal deactivators, corrosion, and antioxidants. Fuel performance additives for cetane and lubricity are added only when the fuel is removed from the cavern.

Geothermal Heating

The EBV caverns are at approximately the same depth as or deeper than the SPR caverns, with a top of 1,000 meters (3,300 feet) below the surface and a bottom 1,600 meters (5,200 feet) below the surface. Due to geothermal heating, the oil in the cavern warms over time to an equilibrium temperature of around 60°C (140°F). This temperature is very comparable to that anticipated by the Department
of Energy as being the final equilibrium temperature in the SPR caverns. The crude oil blend stocks and finished products, including diesel fuels, have therefore maintained their quality under these temperature conditions.

Gas Intrusion

According to EBV technical management they are concerned about gas encroachment into the oil in the caverns and have had to deal with one problem already. EBV's emphasis now is on taking care to ensure that gasoil is not stored in caverns where gas might intrude. Since gas encroachment is a feature of the SPR caverns, care will have to be takenin the selection of the cavern in the underground storage option.

Switzerland

The Swiss have reported storing diesel fuel in underground caverns for up to 10 years without serious degradation. Information obtained indicates, however, that the fuel is specially produced to demanding specifications, notably:

- Highly paraffinic (no cracked stocks);
- Very low ppm sulfur (believed to be 100 ppm or less);
- Very low nitrogen level;
- Potentially end point cut back to approximately to 620°F; and
- Heavily hydrogenated to achieve the very low sulfur and nitrogen levels, very low aromatics content, and the virtual elimination of poly-nuclear aromatics.

Japan

Long-term product storage outside of refinery stocks has been nonexistent. Two years ago, the Japanese government planned to introduce petroleum product stockpiling and asked the Japan National Oil Company (JNOC) to study this issue, including quality changes and degradation of petroleum products held in storage for long periods of time. This study has not been completed.

Oil product storage in Japan is handled in small tanks. In the case of heating oil (kerosene), product is turned four to five times per month, particularly during the winter season. At the refineries, kerosene is kept in storage tanks at the longest for six to eight months beginning in spring time for the winter season. Anti-oxidation additives are used for kerosene because its product quality tends to deteriorate with exposure to oxygen. Partly because of the repercussions from the recent move to deregulate the Japanese market, Japanese refiners face a series of consolidation and fuel production issues that will impact their long term product storage.

Fuel Quality Prediction System (EQPS)

The experience in Europe has been that the long-term storage potential (i.e. degradation potential) of crude oil and products has been very difficult to predict. "Deterioration is generally detected after the fact without any chance to reverse the process of degradation." EBV has therefore developed a system to predict the aging process with reasonable accuracy. This quality prediction system (EQPS) is PC based but is highly complex. It incorporates a knowledge base of statistical data combined with artificial intelligence reasoning logic and integrates up to 90 different parameters ranging from standard laboratory aging tests to manufacturing data, tank and climate data, microbiological experience, and storage and handling specifics. Today the system is used in five European countries.[1]

The system is designed to predict quality degradation for up to 10 years from the date of inspection and currently handles gasoline, jet fuels and middle distillates. As of early 1994, a test version of crude sludge also existed. The EQPS system could be valuable in helping to examine and compare storage lives for middle distillates in the U.S. based on varying fuel quality, storage facility and other parameters.

Military Experience

The U.S. military and NATO have extensive experience with long term storage of diesel fuels, jet fuel, and gasoline. With storage in aboveground tanks, jet fuel has reportedly been stored successfully for as long as five years without significant degradation with relevant additives included in the fuel. Diesel fuel has apparently been stored successfully for up to three years in similar conditions, again with additives included.

The UK military has successfully stored aviation kerosene in partially buried tanks for 5 years. The period was set by military, not storage, requirements. Problems were experienced with condensation, leading to fuel emulsification, but these were handled.

For long-term diesel fuel storage (e.g. in mothballed M-60 tanks or other equipment likely to be static for a year or more) the U.S. Army mandates the use of an Octel fuel oil additive package (FOA15) in conjunction with a specific biocide (BIOBOR JF). Together, these provide five functions to control degradation:

- Antioxidant;
- Metal deactivator;
- Dispersant;
- Corrosion inhibitor; and
- Biocide.

Several tests undertaken by the army showed that diesel fuel and JP5 aviation turbine fuel could be kept in the vehicle tanks, in a variety of ambient conditions, for up to two and a half years without appreciable degradation.

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[1]Denmark (FDO), France (SAGESS), Germany (EBV), Netherlands (COVA), and Switzerland (CARBURA).

This military experience reaffirms the potential to store additive-treated distillates successfully in aboveground facilities for two years or more. The experience also points to the need to specify fuel "accelerated stability" standards and additive packages as part of the specification for delivery of any distillate into a product reserve.

IMPLICATIONS FOR U.S. DISTILLATE STORAGE

The primary finding from the European experience is that middle distillates and other petroleum products can successfully be stored for 2 years or more in above-ground tanks and in salt cavern conditions for as long as 10 years. However, it is clear that this can only be successfully achieved by very careful attention to **all** the key parameters, including:

- specification and manufacturing of a fuel with tight specifications that probably need to go beyond those of current U.S. on road diesel fuel (for cavern storage) particularly in regard to eliminating impurities and cracked (olefinic) hydrocarbons which tend to be chemically reactive;
- the use of additives to maintain product stability;
- proper design and operation of the storage facilities, e.g. minimizing air and water contact and the intrusion of natural gas; and
- an appropriate quality monitoring system to detect the beginnings of fuel degradation, preferably used in conjunction with an advanced quality prediction system.

It is also clear from the European experience that distillate aging is a more complex process than that for gasoline or crude oil.

Based upon the experience cited above, it is feasible to store No. 2 fuel oil in aboveground steel tanks that have been coated inside with epoxy to reduce corrosion and iron oxide catalysis. Underground storage has the advantage of limiting temperature fluctuations- and minimizing air contact. However, it could have the disadvantage of water contact that would require the use of a biocide or brine to eliminate biodegradation processes. Concrete tanks would need to be waterproofed externally, and coated with epoxy inside to eliminate water infiltration and fuel leakage. These tanks offer one of the best options from a quality standpoint, but the cost of such tanks is likely to be prohibitively expensive.

Standard accelerated storage tests can be used to select the proper distillate fuels for storage and to evaluate inhibitors for their effectiveness. Candidate fuel oils must be tested for stability and compatibility before acceptance and commingling with existing stocks. Further, a periodic sampling and testing program must be initiated to permit the detection of stability problems at least six months in advance, thus permitting a coordinated turnover and replenishment program. The EQPS system used by most European stockpiling entities for monitoring quality of their stocks would be imperative.

DISTILLATE FUELS - Technical Considerations

Generally, the literature addresses No. 2 fuel oil, No. 4 fuel oil, and diesel fuel as distillate fuels. Although the literature seldom differentiates between the various grades of distillate fuels in stability discussions, an attempt has been made in subsequent sections to list citations that deal primarily with the storage stability of Grade No. 2 distillate fuel oil.

Grade No. 2 fuel oil is a distillate product that is intended for use in atomizing type burners that spray the oil into a combustion chamber where the tiny droplets burn while in suspension. This grade of oil is used in most domestic burners and in many medium capacity commercial-industrial burners.

Background

Much of the original European distillate stockpiles were comprised of then readily available straight-run gasoil. Concerns today in Europe and Japan - and with regard to a potential U.S. reserve - center on the presence of chemically reactive cracked stocks in much of the middle distillate fuel pool.

Before the advent of cracking processes, and up to around 1946, distillate fuels consisted predominantly of straight run products. Although they were subject to oxidative attack, their stability on the whole was adequate for the demands placed upon them. With the increase in catalytic cracking and the greater demand for diesel fuel, both thermal- and catalytically-cracked stocks are found in distillate fuels, greatly increasing their susceptibility to oxidation. Oxidative attack results in the formation of soluble and insoluble materials of higher molecular weight and boiling point than the original fuel. This insoluble gum or sediment can cause plugging of filters, screens, and nozzles in both diesel and burner installations.

Processing and Treatment

Special refinery treatments, such as hydrogenation of thermal and catalytically-cracked stocks, have been found to improve distillate fuel stability; the use of additives, including antioxidants, metal deactivators, and dispersants, also improves stability. One company especially interested in long-term fuel storage intended for use in emergency standby generating equipment recommends the use of a dispersant containing a metal deactivator (but not antioxidants) as the most effective stabilizing package for distillate fuels. Fuel shelf life up to 20 years is claimed for diesel fuels (3).

Mabley and Wallace (4) have shown how a UK refinery used a proprietary stabilizer (additive) package to permit by-passing of straight run and/or conversion material around their hydrotreater, thus increasing the distillation blending options. Corrosion performance tests showed that the additive package blended with a conventional distillate plus 10 percent virgin light cycle oil and 5 percent virgin visbroken gasoil yielded test results superior even to conventional distillate. They concluded that by using the additive multi-functional stabilizer technology, a company cannot only save money, but also produce heating oil with superior long-term storage characteristics.

However, the general consensus is that any fuel produced for long term storage should not include cracked stocks since olefins react to form sediments. In addition, today's U.S. heating oil contains appreciable sulfur (around 0.25 percent) and nitrogen. These factors, with present industry operating experience, essentially eliminate "standard" No. 2 heating oil from contention as a candidate for a long term "heating oil" reserve.

Industry experts agreed that undercutting the endpoint of the fuel increases its stability, but there were differences of opinion on the need to do so. One company did not believe that undercutting fuel oil was necessary to reduce the polyaromatic hydrocarbons, while another recommended undercutting the fuel oil end point to 620°F (as opposed to a typical 650°F and a higher 700°F) to reduce unstable compounds which concentrate in the tail-end of the fuel oil. However, it was noted that this would be at the expense of a Btu loss, more noticeable in diesel than in home heating fuel oil.

However, the consensus is that aromatics and polyaromatic hydrocarbons in themselves are not a stability factor if styrenic olefins are hydrotreated. This opens up the potential to consider a highly refined distillate fuel that contains deeply hydrotreated cycle oil stocks. The severe deep hydrotreating removes essentially all impurities and hydrogenates the aromatic light cycle oil components to stable naphthenes. These in turn offer advantages in terms of high Btu content and low pour point, helping to offset the Btu loss from potential end point under-cutting and the high pour point associated with paraffinic blendstocks.

For aboveground storage, there is evidence that conventional and low sulfur diesel fuel oil can be stored for extended periods of time. Raw cracked stocks which have not been subject to hydrotreating are generally precluded from diesel fuel blends because of the cetane number specification.

Reaction Mechanisms

Taylor and Frankenfeld (5) have studied and reported information relative to the chemistry and mechanisms of distillate fuel stability. Heating oils were included in their study. They reported that sediment formation during storage involves complex, coupled chemical and physical state processes. This process can be characterized by reacting heating oil with oxygen to form a hydroperoxide that in turn becomes an insoluble product that may be high in oxygen, sulfur and nitrogen. Through nucleation or agglomeration, sediment can then form during storage

Bernasconi, and others (6) reported that the storage stability of middle distillates is of great importance in France, because of increasing demand and the evolution of refining processes that produce more unstable cracked products which promote gum and sediment formation. Several mixtures of straight run gasoils and catalytically-cracked light cycle oils (LCO) were subjected to accelerated aging tests. They found that 12 weeks at 43°C was the equivalent of one year at ambient temperature storage. Gas chromatographic and mass spectrometric analyses showed that alkylindoles appear to be involved in LCO degradation. Although hydrogenation was very effective in stabilizing the fuels, it was considered too costly. They found that stabilizers such as aliphatic tertiary amines with a metal deactivator minimized the gum and sediment formation. However color darkening was harder to control. Fuel oil color darkening does not necessarily indicate that the fuel is not usable, although color stability indicates that the fuel in storage has not degraded

Pedley and Hiley (7) partially confirmed the findings of Bernasconi by characterizing sediment precursors in middle distillates as consisting of indoles linked to polycyclic aromatic hydrocarbons. They concluded that the precursor compounds could have been formed by the condensation of oxidation products with indoles

U.S. Experience with Long Term Storage of Distillate Fuel

Aside from the examples of diesel fuels that have been stored for up to 5 years under chance circumstances, a database cataloguing commercial experience with storing middle distillates over an extended period of time does not appear to exist.

Most oil companies normally aim to stabilize their fuel oils for one month to six months storage periods. Hydrotreated low sulfur diesel fuel has not been in the market place long enough to draw any conclusions concerning long term storage stability characteristics and one company contacted stated that, even with a good additive package, they would not predict storage stability exceeding one year for currently produced home heating oil.

Fuel oil storage stability tests, such as ASTM D 5304, have not exceeded 12 months (12 weeks of testing) and the stability tests themselves were not designed to predict fuel oil stability for the longer periods of storage. Therefore a testing program devised to predict the stability characteristics of different fuel formulations must also consider the applicability of the stability tests which are employed. Two companies contacted voiced preference for a filter pad test to measure sediment in the fuel. Three of the companies contacted prefer the ASTM D 5304 storage stability test as the only one that correlates with long term storage stability (one week of testing is required for each month of storage life). The problem with more accelerated tests is that the more severe test conditions induce chemical reactions that will not necessarily occur in the storage tank. However, some companies preferred a shorter duration test such as the ASTM D 2274 fuel oil stability test.

Additives Recommendations

Industry consensus is that a comprehensive additive package should be added to the stored product and should contain:

- Corrosion inhibitor, a stability additive to counteract peroxide formation in conjunction with Careful monitoring of the peroxide concentration, a metal deactivator chelate;
- A phenolic antioxidant for the lower sulfur and nitrogen content fuel oils and a tertiary amine antioxidant for the higher sulfur and nitrogen content levels;
- A dispersant;
- Pipeline corrosion inhibitor for aboveground; and
- Biocides, with less required aboveground if good water draining housekeeping practices are followed.

The extra additive cost is estimated at 3/4 to 1 cent/gallon of fuel oil to ensure long term storage stability. Oxidation and water create sediments. The use of dispersants keep sediment particles away from each other by detergent action and keep them from growing, but they do not resolve the water and oxidation effects.

Storage

Giles and Niederhoff (11) have reported on studies of bulk distillate fuel oil stored in a solution-mined cavern in salt at Lesum, West Germany for about 18 months. Little difference in quality among the samples was observed, and the variations were attributed to differences in quality originally present in the various batches of products stored. All of the samples conformed to the West German standard specifications for the products. Although not covered by these specifications, an apparent increase in salt content had occurred in several of the samples. This increase did not seem to have had a deleterious effect on the product's quality with respect to its corrosiveness as evidenced by the results of the copper strip corrosion test. It was postulated that this increase in salt content was due to thermal convection cells in the oil induced by a geothermal gradient of up to 10°C in the salt mass from bottom to top of the cavern. Thermal convection cells should also have caused an increase in water content, but amounts of less than 0.1 mass percent were not detectable by the analytical method used

Gartenmann (12) has reported that in Switzerland middle distillates are stored for ten or more years. Periodic quality control testing is performed for the middle distillates including the existent stability as measured by Conradson Carbon Residue, ASTM color, and residue on evaporation. The long-term stability is measured by an accelerated test. The existing stability is measured at the beginning of storage, and then at intervals of two years starting from the third year The potential stability is also measured at the beginning of storage, and later after 5 and 9 years.

One sample of No. 2 fuel oil was in storage for nine years before an accelerated aging test indicated incipient instability in the future. In still another case, a gasoil was stored for 20 years in a fixed-roof, aboveground tank. All test measurements showed the fuel oil was good, and accelerated aging tests after 20 years of storage indicated a further long-term storage potential of several years.

Aboveground Tanks

If a fuel-water interface exists during storage, bacterial and fungal activity will probably occur. This activity has been the subject of many investigations involving surface storage, and it is generally agreed that it can best be arrested by good housekeeping practices, such as ensuring a minimum water bottom in the storage container. Certain biocidal additives have been found to be effective in controlling microbiological activity. Storage of distillate fuels over brine may tend to reduce microbial growth.

Water metabolizes the growth of bacteria at the water-oil interface. Fuel oil going to tankage contains 50-150-200 ppm dissolved water and this will be released from the fuel over time. Dry diesel fuel is hygroscopic and will rise to the 100-200 ppm water content level through condensation and tank breathing.

Tank water will usually settle at the aboveground tank bottom interface, but water-oil interfaces have been known to form along the tank walls as well, a factor in favor of using a biocide in aboveground tanks. Good housekeeping and periodic draining of the tank bottoms water is a necessity in any event.

Without adequate precautions, the presence of tank water will propagate bacteria at a geometric rate and spread from the oil water interface to degrade the entire fuel oil tank, unless checked by a biocide additive,

Epoxy tank liners are recommended for aboveground storage tanks. (The epoxy lining prevents the oil from being contacted by iron which catalyzes oxidation reactions.) However it was noted by several companies that if the epoxy lining is not installed properly it will not be effective. With a poorly installed liner, water can infiltrate under the epoxy liner and the contact with the steel wall will introduce iron into the fuel oil and catalyze and accelerate fuel oil degradation.

CONCLUSIONS

Based upon documented experience, it is anticipated that Grade No. 2 distillate fuel oil (ASTM D 396) can be stored for reasonably long periods by specifying stringent standards for the fuel oil to be stored, and judicious use of inhibitors. It is feasible to store No. 2 fuel oil in aboveground steel tanks that have been coated inside with epoxy to reduce corrosion and iron oxide catalysis. Regardless, even with well-maintained tanks, turnover time will probably be shorter than in underground storage.

Underground storage in hard rock caverns, solution-mined salt caverns, or concrete tanks is a second choice option for storage. Storage in underground reservoirs would have the advantage of limiting temperature variation, and minimizing air contact. It would have the disadvantage of water contact that would require the use of a biocide or brine to eliminate biodegradation processes.

Concrete tanks should be waterproofed externally, and coated with epoxy inside to eliminate water infiltration and fuel leakage

Standard accelerated storage tests can be used to select the proper distillate fuels for storage and to evaluate inhibitors for their effectiveness. Candidate fuel oils must be tested for stability and compatibility before acceptance for mixing in the reservoir. Further, a periodic sampling and testing program must be initiated to permit the detection of stability problems at least six months in advance, thus permitting a coordinated turnover program. Turnover time for No. 2 fuel oil is estimated to be a maximum of two years aboveground and as long as 10 years in underground storage.

A successful storage program for No. 2 fuel oil will require minimization of contact with water as well as minimization of contact with air. The latter will slow the oxidation reactions that precede sedimentation. Careful selection of the storage facility (either underground or aboveground), judicious selection of fuels to be stored based upon analytical tests for stability and compatibility, use of additives to retard sedimentation and sludge formation, and a regular test program to assess the turn-over time requirements of the reserve must be performed

In comparing the advantages and disadvantages of storing distillate fuel oil in either aboveground or underground tanks, the following factors must be evaluated. Temperature fluctuations in aboveground tanks are greater than in underground storage. These temperature fluctuations promote the "breathing" of the stored product that makes more oxygen available for initial oxidation of the fuel. Aboveground steel tanks have the advantage of permitting epoxy lining that can reduce corrosion and iron oxide catalysis, and also that can have a fixed roof that in turn minimizes contact with air and water.

Recommendations

An extensive study of published data confirm that stringently formulated distillate fuel can be stored for prolonged periods without undergoing deleterious changes in quality. The most practical and economic mode of storage, especially for large volumes of petroleum, is in caverns in salt deposits. Other modes of storage, such as aboveground steel tanks with interior epoxy coating to reduce corrosion and iron oxide catalysis are feasible. Underground concrete tanks are another viable candidate, but their cost is considered prohibitively high.

If aboveground tanks are used, oxygen and moisture must be excluded to the maximum extent practicable. Water is likely the most significant contributor to petroleum degradation because it will harbor microorganisms and fungi that metabolize hydrocarbons. Brines existing in solution-mined caverns effectively inhibit microbial activity. Otherwise, biocides have been recommended to control biodegradation reactions *in situ*. The physical and chemical properties of any stockpiled oil must be thoroughly evaluated periodically to assess its quality and determine whether stocks need to be turned over. An "expert" system is well suited to this purpose.

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Mobil
CITGO
Conoco
Ethyl Corporation
Octel America
Petrolite
NALCO
Caleb Brett Inchcape
Defense Fuels Supply Center
Oil Pipeline Agency (UK)
International Energy Agency
Central Organization for Stock Piling of Oil Products (Rotterdam, Netherlands)
EBV (the management organization for the German Strategic Stock Pile)
Japan National Oil Company
Idemitsu Kosan
Petroleum Association of Japan
Pennsylvania Power and Light

Various recent papers on oil storage and quality degradation were also reviewed including an important February 1994 IEA conference:

Stock Draw and Emergency Response: Policies & Management, Japan 22-24 February 1994 Conference Proceedings.

"Storage in Salt Caverns and Quality Prediction", Dr. J.W Joachim Koenig, Technical Manager, EBV Germany.

"Salt Cavern Storage at Manosque and Related Facilities", Mr. Gilles Le Ricousse, Operation Manager, Geostock Company, France.

"Solution of' Product Obsolescence Problem in Denmark", Mr. Kjeld Rvbner, Head of Section, Ministry of Energy, Denmark.

"Issues Resulting from Deterioration Oil Products in Long Term Storage", Mr. Francusco Tamburrano, Principal Administrator, Emergency Planning and Preparation Division, IEA.

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Oil & Gas Journal;

Fuel Technology & Management; and

Institute of Petroleum.

Technical Addendum
Background to Petroleum Product Quality Degradation and Control in Long Term Storage

Most oil products are susceptible to aging and/or deterioration if kept in storage for a long time, due to the presence of small amounts of non-hydrocarbon compounds, organic or not, including sulfur, organic acid, and oxygen.

In some cases the deterioration is biological, due to the development of micro-organisms in the liquid mediums. In other cases problems arise from the volatility of some petroleum products, causing losses. Problems can also ensue when market specifications change causing stored products to become obsolete.

Storage disability may affect the marketability of the products, or may result in deterioration of the characteristics that determine performance, and often result in color darkening and/or gum formation.

The presence of organic/inorganic acids or alcohols (if originally present in the fuel) causes corrosion of the equipment in contact with the liquid oil product, because alcohols draw water which sheds when temperature falls. Water then coalesces in the bottom where anaerobic bacteria grow and form acids. This is unlikely to occur in gasoline, but is a problem in diesel. In turn, corrosion may cause flaking of the containment materials, and formation of deposits in the lower portion of tanks, piping, and other equipment. These sludges cause mechanical problems in pumps, plugging of suction filter screens, and malfunction of measuring or control instruments.

Some of these inconveniences may be overcome by treatment of the products before undergoing long-term storage: among the most common are caustic extraction, addition of corrosion inhibitors or biocides, and various forms of hydrogenation which is the most effective method to kill initiators of aging.

While some of these operations are carried out as general practice, even if no long-term storage is foreseen, others are done specifically in anticipation of long storage periods and add to the cost of the final product. In some cases problems associated with long term storage arise anyway, even if preventive measures have been taken. One of these measures is the removal of water and particulate matter. Free water causes corrosion throughout a fuel distribution system. Particulate matter in a fuel can have disastrous effects on gas turbine blades and may block filters or the fine orifices of fuel injection and burner systems. Even if a bright and clear product has been pumped into a clean tank, the oil absorbs water from the atmosphere above it, due to condensation and temperature changes. Most products are not hygroscopic unless they contain alcohols. Tanks undergo external temperature cycles: night or seasonal cooling causes the atmospheric humidity inside the tank to condense on the internal walls. This water, separated out on the sides of the tank, forms droplets sliding down along the walls, and collects as water bottoms. If oxygen is present, corrosion then occurs along the walls, even if the water is not acidic (e.g, pH>=7). In the long term, iron oxide or hydroxide particles resulting from corrosion tend to detach and are carried by the sliding water droplets (or as corrosion flakes) into the oil bulk and into the water collecting in the tank bottom.

Also, during long storage periods, bacterial slime accumulates at the interface between water and oil, and ferric hydroxide forms in the water bottoms. The agitation in the tank during subsequent pump-out operations disperses the water and particulate matter throughout the oil, causing a haze which is extremely difficult to remove.

Diesel Engine Fuels, Light Heating Oils and Gasoil

Over time unsaturated components like olefins or even more, diolefins if present, have a tendency to polymerize or condensate to higher boiling heavy molecules (gums, organic sediments).

Fuels with high gravity and/or high 90 percent and final boiling point (EP) have a tendency to form particulates. This tendency is enhanced by high aromatics and carbon content.

Aging processes are enhanced by the presence of basic nitrogen and sulfur containing components (e.g. mercaptans, elemental sulfur, sulfotic acids), forming gum and/or aggressive molecules leading to corrosion of metal surface. Aging is promoted by metals (e.g. naked steel of tank walls after sandblasting, copper piping, brass fittings). The average temperature of a tank storing kerosene or middle distillates has an effect on the speed of chemical or biological reactions: the higher the temperature, the faster the reactions. Although the fuel itself is not a favorable environment for microbial growth, the presence of water-hydrocarbon interfaces enhances the possibility of the development of aerobic bacteria, with consequences on fuel properties such as cleanliness, total acidity, and increased corrosiveness. The degradation process and build-up of microbial mass is slow; under normally occurring conditions it may take more than three years for a significant aerobic growth, but the time needed could be much shorter in tropical climates if poorly maintained small storage tank batteries, which cannot be water drained, are used. Fuels most susceptible to biological degradation are the straight run products coming directly from atmospheric distillation with high normal-paraffin content.

As with other fuels, precautions must be observed in the storage of the middle distillates: limiting the content of cracked components, excluding light gas from coking operations, using antioxidant and biocide additive, etc.

Fuel Stability Additive Functions

Degradation of fuel quality is restricted mainly by using the following types of additive:

<u>antioxidant</u>

- This retards the tendency for autoxidation to occur. Diesel fuels will normally undergo autoxidation and deterioration which causes formation of particulates, gums and acid complexes.

<u>metal deactivator</u>

- This removes free copper and other trace metal from reacting in the autoxidation process and allows the antioxidant to function effectively. Without the metal deactivator, the effectiveness of the antioxidant would be reduced significantly.

<u>dispersant</u>

- This causes any sediment or agglomerates present to be maintained in a finely dispersed state. It prevents the formation of large particulates and reduces the tendencies for deposits to occur on critical fuel system components.

<u>corrosion inhibitor</u>

- This reduces the tendency for corrosion of ferrous or metallic surfaces by forming a protective barrier over the surface. It is designed to protect fuel-wetted surfaces from corrosion, but will not function in environments of heavy water contamination (i.e. water bottoms or sump regions).

<u>biocide</u>

- This functions to kill any micro-organisms that originate at the fuel-water interface in fuel storage/tank environments