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RESIDUUM AND RESIDUAL FUEL OIL SUPPLY AND DEMAND IN THE UNITED STATES - 1973-1985

Industrial Environmental Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
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RESIDUUM AND RESIDUAL FUEL OIL SUPPLY AND DEMAND IN THE UNITED STATES--1973-1985

by

James A. Monk, Jr., Mary M. Menino, Ellen S. Quackenbush,
Nigel Godley, Linsey R. Clark, Malcom E. Cloyd,
Indrakumar L. Jashnani, and Raymond P. Stickles

Arthur D. Little, Inc.
Acorn Park
Cambridge, Massachusetts 02140

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EPA Task Officer: Samuel L. Rakes

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, NC 27711

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Office of Research and Development
Washington, DC 20460

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C.1 INTRODUCTION

In response to Task Order Number 19 of the Environmental Protection Agency (EPA) contract number 68-02-1332, Arthur D. Little, Inc. has prepared this report on the Supply and Demand for Residuum in the United States. The purpose of the report is to define the available supply of residuum and residual fuel oil now and in 1985, to determine the demand for residuum and residual fuel oil now and in 1985, and to assess the factors which control and impact on the supply and demand.

Under terms of the Task Order, this report has been prepared using literature from the public domain as the reference source. It was found that available literature was inadequate for the level of detailed analysis which had been originally anticipated. This problem is discussed more fully in C.2.

The report has three main groups of chapters. Chapters C.3 and C.4 develop a historical data base on the supply and demand for residuum and its products. The emphasis in the report has been on residual fuel oil rather than the other residuum products, but perspective on the total amount of residuum has been maintained. Having developed a base of information about the current supply and demand situation, Chapters C.5 to C.10 discuss the factors which impinge on the petroleum industry, the world oil market, the use of residual fuel oil and its distribution to users. Finally, C.11 and C.12 discuss the future demand for and supply of residual fuel oil. C.12 further contains some summary conclusions about the future supply/demand for residuum.

C.2 DATA AVAILABILITY

C.2.1 INTRODUCTION

This report has been prepared using publicly available information. On some specific topics no data was available and the report either uses estimates or was reduced in scope on that particular topic. This chapter describes the main data sources for the historical supply and demand analyses. Other sources which were used infrequently or were referenced only indirectly will be mentioned in the text where such data was used.

C.2.2 DATA AVAILABILITY FOR RESIDUUM SUPPLY

The primary source of all information on the supply of residual fuel oil in the U.S. is the Department of the Interior, Bureau of Mines (BOM) Division and, in particular, two publications in the Mineral Industry Surveys series:

- Crude Petroleum, Petroleum Products and Natural Gas Liquids, released in monthly and annual summary forms and referred to as the "Petroleum Statement."
- Availability of Heavy Fuel Oils by Sulfur Levels, released in a monthly form which contains annual summaries in the December issue and is referred to as the "Availability of Fuel Oils by Sulfur Content."

While some information is available on PAD district sub-divisions (production and stocks of fuel oil) and other on the state level (imports and selected interdistrict product movements) complete information on the regional supply of residual fuel oil is available only on the PAD district level. Also, complete information on some subjects (refinery internal energy needs) is only included in the annual summary editions of BOM publications. Because the 1974 annual Petroleum Statement was not available at the time of writing this report, the year 1973 was chosen for the discussion of the U.S. refining industry. For other supply analyses complete information was available for 1974, and this latter year was selected for non-refining discussions.

Sulfur content data is limited to information available at the Office of Oil and Gas or from statistics collected by a BOM survey of individual oil companies and shippers. The former excludes military and bonded imports (7% of 1974 imports) and crude oil burned as fuel and exports (both less than 1% of domestic fuel oil supply). The BOM survey covers transfers from PAD District III only, thus omitting 5% of the 1974 interdistrict trade in residual fuel oil. The volume of fuel oil transfers from PAD Districts II, IV and V is gathered by the Department of Commerce, Corps of Engineers Division and published in the annual Petroleum Statement, but sulfur content of these shipments is not monitored.

Imports of residual fuel oil are reported by country of last origin which may not be indicative of either the refinery location or the actual crude oil source. Although almost 75% of 1974 Latin American crude production was of Venezuelan origin, and Venezuela does have a large residual fuel oil production capacity, not all Venezuelan crude is refined in Venezuela, nor do all Venezuelan refineries charge solely Venezuelan crude. Venezuelan crude, which varies in quality by field location, is shipped throughout the Caribbean for refining, and once it enters a foreign country it loses its Venezuelan identity. This identification problem is compounded by Caribbean islands such as the Netherlands Antilles which import all their crude needs, and whose product exports cannot be associated with any specific crude without extensive analysis. Furthermore, some inter-country product shipments may take place after a product leaves its country of refining and before it enters the U.S.

C.2.3 DATA AVAILABILITY FOR RESIDUAL FUEL OIL DEMAND

Publicly available analyses of residual fuel oil demand usually deal with actual sales; that is, there is no continuing effort conducted to determine that portion of demand that is not met by marketed supplies. Certain trade journals periodically provide some analytical information concerning the residual fuel oil market, but the majority of information used in this study of residual fuel oil demand was prepared and published by the Bureau of Mines Division of the U.S. Department of the Interior. The information is collected by the BOM by a direct mail survey technique, covering refineries and other distributors who have annual sales of at least 10,000 barrels of fuel oil and/or kerosene, and therefore provides the most comprehensive demand statistics prepared on the subject. In addition, use of the BOM demand data insures consistency with the supply data. The most detailed information; i.e., breakdown of U.S. residual fuel oil sales by end-use, PAD District and States, is published for calendar years only.

Annual detailed demand information published by the Bureau of Mines appears in the following two publications:

- Sales of Fuel Oil and Kerosene (annual), which is part of BOM's Mineral Industry Surveys effort. This document, also referred to as Fuel Oil Sales (annual), is prepared by the Division of Fuels Data and is released in September or October with data covering the preceding calendar year; i.e., data for 1975 will not be released until Fall, 1976. Fuel Oil Sales (annual) presents the statistical breakdown of total U.S. demand for residual fuel oil by major end-use category (heating, electric utilities, etc.), by PAD District and by State. In addition, U.S. demand for each end-use category is also broken down by PAD District and by State. There is no monthly detail.

The only caution that must be exercised when using this data concerns the end-use categories for heating and industrial purposes (for both oil companies and other industries). While industrial sales are requested to be stated excluding residual fuel oil used for heating, this has typically not been the case. Consequently, the industrial sales category is commonly considered to include industrial fuel oil sales for heating. Likewise, the category presented as fuel oil sales for heating use is perceived as being more closely representative of fuel oil sales to the Residential/Commercial sector only.

- Crude Petroleum, Petroleum Products, and Natural Gas Liquids (annual), is published at least a full year after the end of the calendar year in question: it is also called the Petroleum Statement. It includes a table called "Supply and Demand of All Oils in the U.S.," which presents the monthly as well as the annual demand levels for residual fuel oil.

  Another table, entitled, "Fuels Consumed for All Purposes at Refineries in the U.S., by States", presents annual residual fuel oil consumption in refineries. This table gives an indication of the portion of residual fuel oil sales to oil companies used by refineries. There is a companion table which details the consumption information by refining district rather than state. These refinery fuel consumption tables are first published in the Monthly Petroleum Statement issued for the month of April following the calendar year in question.

Monthly residual fuel oil data published by the Bureau of Mines appears in the Crude Petroleum, Petroleum Products, and Natural Gas Liquids (i.e., the Petroleum Statement), issued for each month. There is a three or four month time lag in its publication. That is, information covering

December, 1975 should be out by the end of April. This document gives total U.S. demand and supply levels for residual fuel oil.

Other sources for residual fuel oil demand data include the Federal Energy Administration and the Oil and Gas Journal. The FEA in its Federal Energy News issues a weekly FEA Demand Watch, which gives U.S. demand levels for four week periods for major petroleum products, including residual fuel oil. This information is based on weekly data from the American Petroleum Institute. The Oil and Gas Journal usually publishes at least one article during the last quarter of the calendar year which discusses anticipated residual fuel oil demand for the upcoming heating season. In addition, the magazine publishes other articles on available forecasts of petroleum products, which often include details for residual fuel oil.

C.3 RESIDUUM AND RESIDUAL FUEL OIL SUPPLY IN THE UNITED STATES

C.3.1 INTRODUCTION

This chapter is divided into four parts. The first presents an overview of domestic residual fuel oil supply, including historic factors that led to a U.S. dependence on Caribbean fuel oil imports as well as current legislation that encourages domestic production. The impact of sulfur restrictions on this market is also discussed. The second section outlines the problems faced by domestic refiners as the source and quality of their crude oil changes. Amenability of several important crude oils to desulfurization is discussed. The third section discusses 1973 operations of U.S. refineries, focusing on the regional supply of residuum. Uses for residuum that compete with residual fuel oil production are highlighted. Finally, in the fourth section actual 1974 supply of residual fuel oil by region is outlined in detail. Regional self-sufficiencies in supply versus reliance on imported fuel oil are discussed. For reasons of data availability we have used 1973 for the discussion of refining but have been able to use 1974 data for the detailed analysis of supply and demand and have used 1975 data where available for an up-to-date assessment of the residual oil market.

C.3.2 DISCUSSION OF THE HISTORIC DOMESTIC RESIDUAL FUEL OIL MARKET

The U.S., with the exception of the East Coast, has historically relied on low-cost domestic supplies of natural gas and coal to meet its need for industrial and public utility energy sources. The East Coast, being physically separated from western reserves of coal and southern reserves of natural gas, developed a dependence on Caribbean-refined residual fuel oil for use in public utility and industrial boilers.

In the sixties and early seventies, shortages of natural gas shifted domestic energy demand toward residual fuel oil and coal, causing more areas in the U.S. to join the East Coast's dependence on fuel oil imports. Over the period 1969-1972 annual domestic demand for fuel oil increased 203 MMBBLS from the 1969 demand of 722 MMBBLS to 925 MMBBLS in 1972. In response, fuel oil imports jumped 176 MMBBLS (38%) to 637 MMBBLS, while domestic production of fuel oil rose only 28 MMBBLS (10%) to 293 MMBBLS per year. As a result of the U.S. government's initiation of the Old Oil Entitlements and Oil Import Fee Program, the relative growth rates of fuel oil imports and domestic production were reversed in 1974. Under these programs domestic crude prices were pegged at a level well below the world crude market price, and a fee was levied on all crude oil and product imports. Caribbean refiners faced world prices for crude and potentially lower U.S. market prices for residual fuel oil. Due to the availability of low-cost domestic crude, U.S. refiners had the advantage of a composite crude oil cost that fell below world levels and a residual fuel oil product price that was set by relatively high-priced Caribbean substitutes. Thus, there was an obvious economic incentive for domestic refiners to increase their fuel oil yield. From 1972 to 1974 U.S. demand for residual fuel oil rose 32 MMBBLS (3%) to 958 MMBBLS. In turn, domestic output of fuel oil jumped 98 MMBBLS (48%) to 390 MMBBLS, while imports actually dropped 64 MMBBLS (10%) to 574 MMBBLS per year.

Recent federal and state air quality regulations have focused attention on the sulfur content of domestic energy sources. Standards for the burning of residual fuel oil are most strict for new or large facilities, for urban areas and for the East and West Coasts. Residual fuel oil provides only a small portion of total energy needs on the Gulf Coast and in the Midwest, and, therefore, high sulfur* residual can be burned

*Unless noted otherwise, sulfur contents in residual fuel oil will be defined as follows:

Very Low	- less than 0.5% sulfur by weight
Low	- Less than 1.0% sulfur by weight
High	- greater than 1.0% sulfur by weight
Very High	- greater than 2.0% sulfur by weight

in these areas without greatly altering ambient air quality. However, on the East and West Coasts where residual fuel oil is a major energy source a large percentage of the fuel oil burned must be low sulfur to maintain ambient air quality. To meet this demand profile which is heavily skewed toward low sulfur fuel oil, U.S. refineries selectively charge low sulfur domestic, African and Indonesian crudes which produce a naturally low sulfur product. In contrast, Caribbean refiners rely both on selective charging of low sulfur African crudes and on extensive residual hydrodesulfurization of the heavy, high sulfur Venezuelan and Saudi Arabian crudes that make up the bulk of the world crude supply. In recent years, as U.S. domestic crude production declined, U.S. refiners have attempted to maximize imports of low sulfur foreign crudes to avoid installing the desulfurization capacity that would be required to handle high sulfur foreign crudes. In 1974 a nominal 10.5 MBCD of residual fuel oil hydrodesulfurization capacity was maintained at U.S. refineries. Importation of high sulfur Saudi and Venezuelan crudes will undoubtedly increase in the future and desulfurization of domestically produced residual fuel oil, either in the refinery or at the end-user's site, will be required before the fuel may be burned.

C.3.3 DIFFERENCE BETWEEN RESIDUUM AND RESIDUAL FUEL OIL

The term residual fuel oil has a loose application in the U.S. oil industry, referring both to the heavy hydrocarbons that comprise a large portion of the natural crude oil barrel and to numbers 5, 6 and bunker "C" residual fuel oil products. When discussing refining, this report will focus on "residuum," defined as that portion of the crude oil barrel left unvaporized at 650°F (343°C) and normal atmospheric pressures, and which can be used as a feedstock to further processing or be blended, with little alteration, into any one or all of the following end products: asphalt, road oil, lubricating oil, waxes and residual fuel oil. When discussing the supply and demand of residual fuel oil this report will concentrate on residual fuel oil products as a class. The terms residual fuel oil, fuel oil, residual and resid will be used synonymously to refer to the latter class of petroleum products.

C.3.4 CRUDE OIL SUPPLY FOR U.S. REFINERS

C.3.4.1 Volumetric Supplies

In 1973, 26% of the crude oil refined in the U.S. was imported, 31% of this foreign oil originating in Canada, 23% in the Middle East, 22% in Africa and 11% in Venezuela (see Table C.3-1). (By 1975 this dependence on foreign crude oil has grown to 32%.) The most common crudes imported into the East Coast in 1973 were Nigerian and Venezuelan, into the Gulf Coast, Nigerian and Saudi Arabian, into the middle U.S., Canadian and into the West Coast, Canadian, Indonesian and Saudi Arabian. Dependence on crude imports varied by Petroleum Administration for Defense (PAD) districts (see Figure C.3-1 for a definition of these regions) as shown in Table C.3-2. The East Coast (PAD District I) imported 84% of its 1973 needs, the Gulf Coast (PAD District III) imported only 8% and other districts imported intervening percentages as shown on Table C.3-2. As Table C.3-3 shows, most of the domestic crude refined in the U.S. is produced in Louisiana and Texas. This production has made District III more than self-sufficient in crude supplies, such that in 1973 District III had crude production equal to 125% of crude runs in the district's refineries. PAD District IV likewise produces more than it needs, while the other districts have less oil production than runs to refineries. It should be noted that District III actually imported 8% of its total crude runs so it is not possible to say that crude produced in a given district will necessarily be refined in that district.

C.3.4.2 Crude Oil Quality Characteristics

Crude oils are physical mixtures of hydrocarbons ranging from light, short chain hydrocarbons such as liquefied petroleum gas (bottle gas) to moderate weight hydrocarbons such as gas oils (distillates), to heavy, long chain hydrocarbons such as residual fuel oil and waxes. The proportionate yield of each of these hydrocarbons as well as overall qualities such as sulfur and metals content vary widely among crudes. These qualities and yields determine how a crude responds to different processing. For example, vanadium and other metals de-activate the

Table C.3-1

Percent of U.S. Crude Oil Imports by Country of Origin for 1973

Country of Origin	Total U.S.A.	I	II	III	IV	V
Algeria	3.7	8	6	3	--	--
Canada	30.9	9	83	--	100	30
Indonesia	6.2	1	--	1	--	23
Iran	6.7	10	3	8	--	5
Libya	4.1	6	2	12	--	--
Nigeria	13.8	26	--	27	--	--
Saudi Arabia	14.2	8	--	20	--	29
United Arab Emirates	2.2	3	--	--	--	4
Venezuela	10.6	21	--	13	--	3
Other	7.3	7	6	16	--	7
Total	100.0	100	100	100	100	100
Total Imports (MBBLS)	1,183,966	466,074	260,368	145,654	16,132	295,768
Percent Total Imports	100.0	39.3	22.0	12.3	1.4	25.0

Source: Department of The Interior, Bureau of Mines, 1973 Annual Petroleum Statement.

Figure C.3-1

Petroleum Administration For Defense (PAD) Districts of the United States

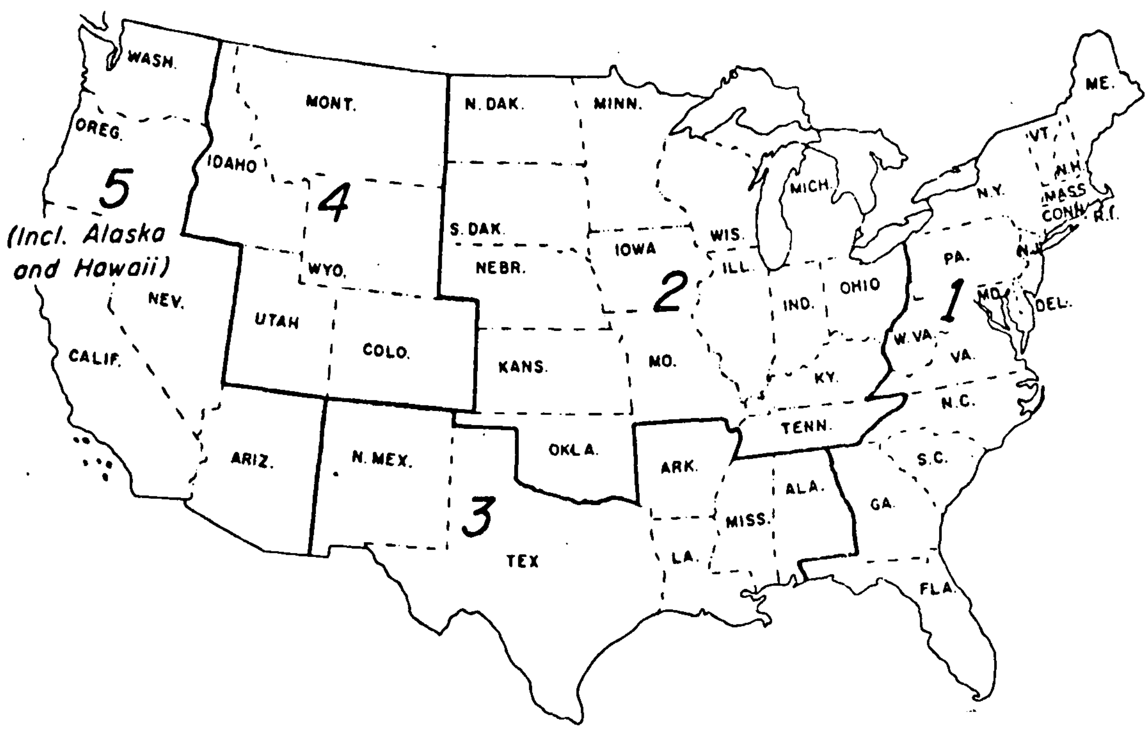


Table C.3-2

Percent Domestic and Foreign Crude Run in U.S. Refineries in 1973

	PAD I	PAD II	PAD III	PAD IV	PAD V	Total U.S.A.
Crude Source						
Domestic	15.8	79.6	92.1	89.4	59.1	74.1
Foreign	84.2	20.4	7.9	10.6	40.9	25.9
Total	100.0	100.0	100.0	100.0	100.0	100.0
Total Crude Run (MBBLS)	548,027	1,271,998	1,844,698	151,521	721,010	4,537,254

Source: Department of the Interior, Bureau of Mines, Mineral Industry Surveys, Crude Petroleum, Petroleum Products, and Natural Gas Liquids, 1973; Annual Petroleum Statement.

Table C.3-3

Percent Domestic Crude Oil Production by PAD District and Key States in 1973

PAD/State	Crude Oil Production: As a Percent of Total U.S. Crude Production	Crude Oil Production: As a Percent of District Refinery Runs
PAD I		
Florida	1.0	6.1
Other	0.2	1.3
Total PAD I	1.2	7.4
PAD II		
Oklahoma	5.7	15.1
Kansas	2.0	5.2
Illinois	1.0	2.6
Other	1.8	4.8
Total PAD II	10.5	27.7
PAD III		
Louisiana	24.7	45.0
Texas	38.5	70.1
New Mexico	3.0	5.5
Other	2.6	4.7
Total PAD III	68.8	125.3
PAD IV		
Wyoming	4.2	93.2
Other	3.1	68.7
Total PAD IV	7.3	161.9
PAD V		
Alaska	2.2	10.3
California	10.0	46.6
Total PAD V	12.2	56.9
Total U.S.A.	100.0	74.1
Total U.S.A. (MBBLS)	3,360,903	3,360,903

Source: Department of the Interior, Bureau of Mines, 1973 Annual Petroleum Statement.

catalysts used in current residuum hydrodesulfurization processes. Likewise, asphaltenes, which are highly complex hydrocarbon ring structures, "lock" sulfur into the hydrocarbon molecule and make desulfurization difficult.

Qualities of several domestic and foreign crudes are given in Table C.3-4. In general, domestic crudes are light (high °API gravity), yield relatively low percentages of residuum and have low sulfur contents. Californian and Alaskan crudes are exceptions in that they have a relatively high residuum yield and sulfur contents, but these are not major U.S. crude sources at the present time. Major foreign crudes from the Persian Gulf area are fairly heavy (low °API gravity), have a high residuum yield and are often high in sulfur. African, Canadian and Indonesian crudes are generally sweeter (lower in sulfur) and lighter but only African crudes are currently an important source of U.S. crude supply. The average sulfur content of the crude refined in the U.S. will tend to increase as U.S. crude imports increase and sulfur removal for sulfur-sensitive products will become more important. Reclassification of foreign crudes by ease of residual hydrodesulfurization, a function of nickel, vanadium and asphaltene contents, yields the ranking given in Table C.3-5. As will be discussed in more detail in Chapter C.9, Type I crudes can be desulfurized "directly," i.e., as the residuum comes straight from the atmospheric distillation tower. Type IV crudes are not suitable for direct desulfurization but must be preprocessed to allow the desulfurization operation to be less affected by the metals content. Indirect desulfurization cannot remove as much sulfur from residuum as can direct desulfurization.

In conclusion, if low sulfur fuel oil must be burned domestically and crudes of Type I are not available to domestic and Caribbean refiners, then an alternative to direct hydrodesulfurization, such as the CAFB, may be attractive to fuel oil consumers.

Table C.3-4

Quality Characteristics and
Residuum Fractions (650° +F) of Typical Crude Oils

	Crude Oil Specific Gravity °API	Residuum Yield (650° +F), % Liquid Volume	Crude Oil Sulfur Content, % Weight
Domestic Crude Oils			
Texas Sweet Mix	35.4	20.0	0.20
West Texas Sour	33.4	31.9	1.63
Louisiana	36.2	38.1	0.22
Oklahoma	40.2	38.3	0.21
Alaskan North Slope	27.5	53.0	0.96
California Ventura	29.7	47.6	1.56
California Wilmington	19.6	64.5	1.28
Foreign Crude Oils			
Arabian Light	34.5	43.2	1.70
Arabian Heavy	28.2	63.0	2.80
Kuwait	31.5	58.9	2.50
Nigerian Forcados	29.4	38.9	0.21
Algerian Hassi Messaoud	44.7	27.7	0.13
Iranian Light	33.9	41.0	1.40
Iranian Heavy	31.0	50.0	1.60
Lybian Amna	35.9	48.0	0.20
Lybian Brega	40.4	32.0	0.20
Indonesian Minas	35.3	59.0	0.07
Venezuelan Bachaquero	17.0	58.8	2.44
Venezuelan Tia Juana	26.3	57.8	1.51
Canadian Mixed	39.0	36.2	0.55

Source: Arthur D. Little, Inc.
Exxon Corp.

Table C.3-5

<u>Characteristics of Crude Oil Residuums</u>
<u>Related to Ease of Catalytic Hydrodesulfurization</u>

Ease of Desulfurization	Crude Quality	Example Crude
I. Can be desulfurized directly	Low metals, low asphaltenes	Arabian Light Kuwait Qatar
II. Can be desulfurized directly at a higher catalyst cost than I.	Moderate metals, low asphaltenes	Iranian Light Iraqi Kirkuk
III. Can be desulfurized directly, at a process severity and/or final sulfur level that is considerably higher than I.	Moderate metals, high asphaltenes	Arabian Heavy Arabian Khafji
IV. Direct processing lowers catalyst life substantially; judged uneconomical to desulfurize.	High metals, high asphaltenes	Iranian Heavy Venezuelan Tia Juana Venezuelan Bachaquero

Source: "Management of Sulfur Emissions" R.E. Conser, DOP Process Division; presented at NPRA 72nd annual meeting, Miami, April 1974.

C.3.5 U.S. REFINERY PRODUCTION AND USE OF RESIDUUM

Crude characteristics are a major factor in the internal layout of a refinery. In fact, most refineries are designed around a specific group of crudes and would require major internal processing changes to handle any significant change in crude intake. The second major consideration in refinery design is the anticipated product demand. Given a crude slate and thus a set of natural yields for each hydrocarbon group, a refiner constructs the combination of processing units that will transform the crude barrel's "natural" yield to the desired product mix. Most U.S. refineries are the conversion type and are designed to maximize gasoline production from light to moderately light, low sulfur domestic crudes. These refineries would have excess capacity if either gasoline demand dropped or the natural yield of gasoline-range hydrocarbons in the input crude rose. As can be seen in Figure C.3-2 most hydrodesulfurization units (HDU) in a U.S. refinery are associated with feed to the catalytic reformer, which is very sensitive to sulfur content, or with streams which are blended into low sulfur distillate products such as kerosene and home heating oil. There is very little desulfurization capacity used for the residuum stream going to residual fuel oil. In contrast, the typical Caribbean refinery, as depicted in Figure C.3-3, is of the hydroskimming type designed to utilize the natural yield of heavy crudes to maximize residual fuel oil production. Many Caribbean plants dedicated to the U.S. market install residuum hydrodesulfurization facilities for the atmospheric bottoms (650°F+ [343°C+]) stream.

The initial processing unit in both conversion and hydroskimming refineries is the atmospheric distillation tower which thermally separates hydrocarbon streams by the differing temperatures at which each group vaporizes. Sulfur and metals tend to "fit" most securely into the largest (heaviest) hydrocarbon molecules so that as the lighter streams are boiled off in the distillation process most, up to 80%, of the sulfur and all of the metals remain in the residuum

Figure C.3-2 Conversion Refinery Flow Diagram - Sweet or Sour Crude Intake

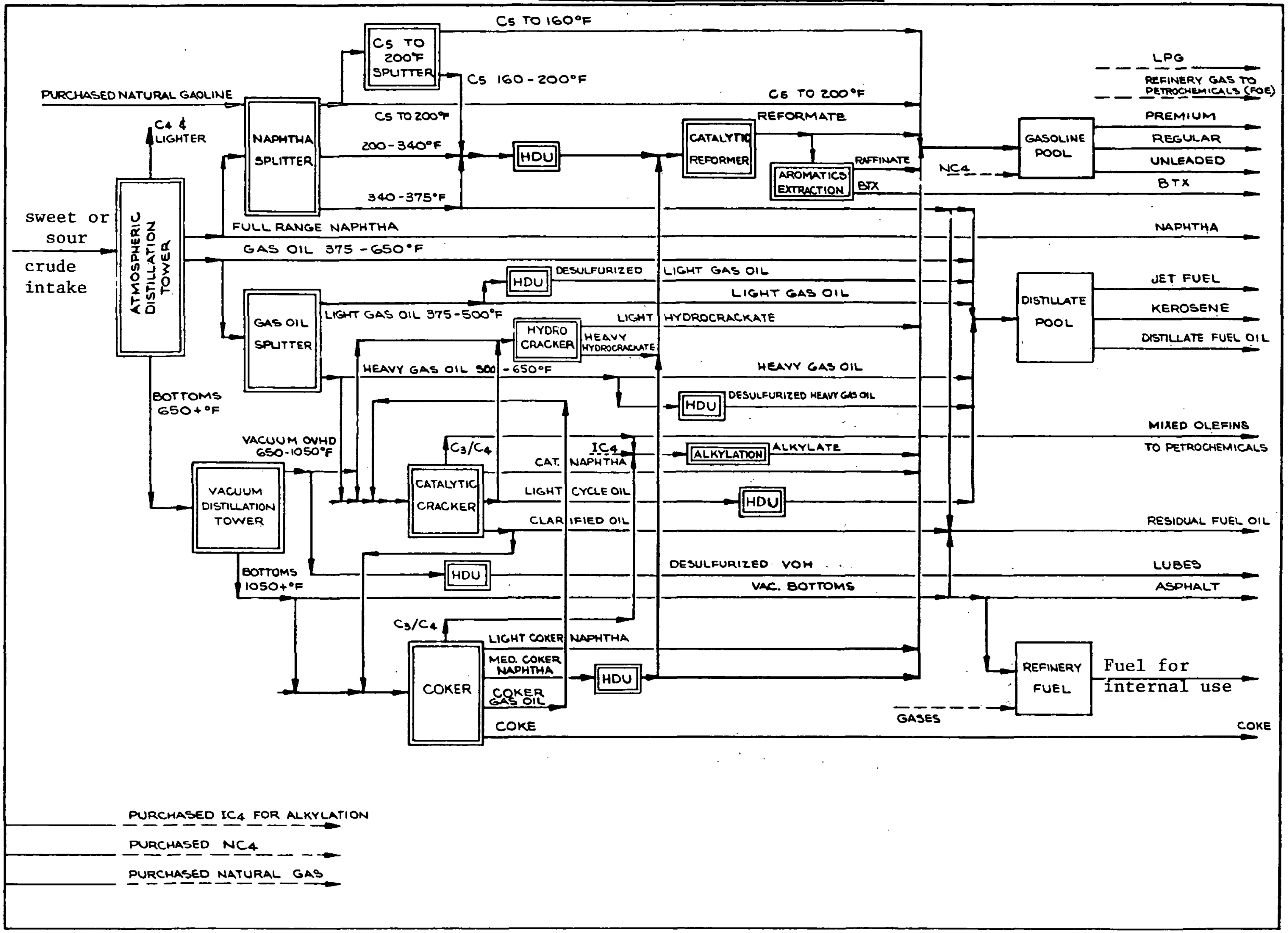
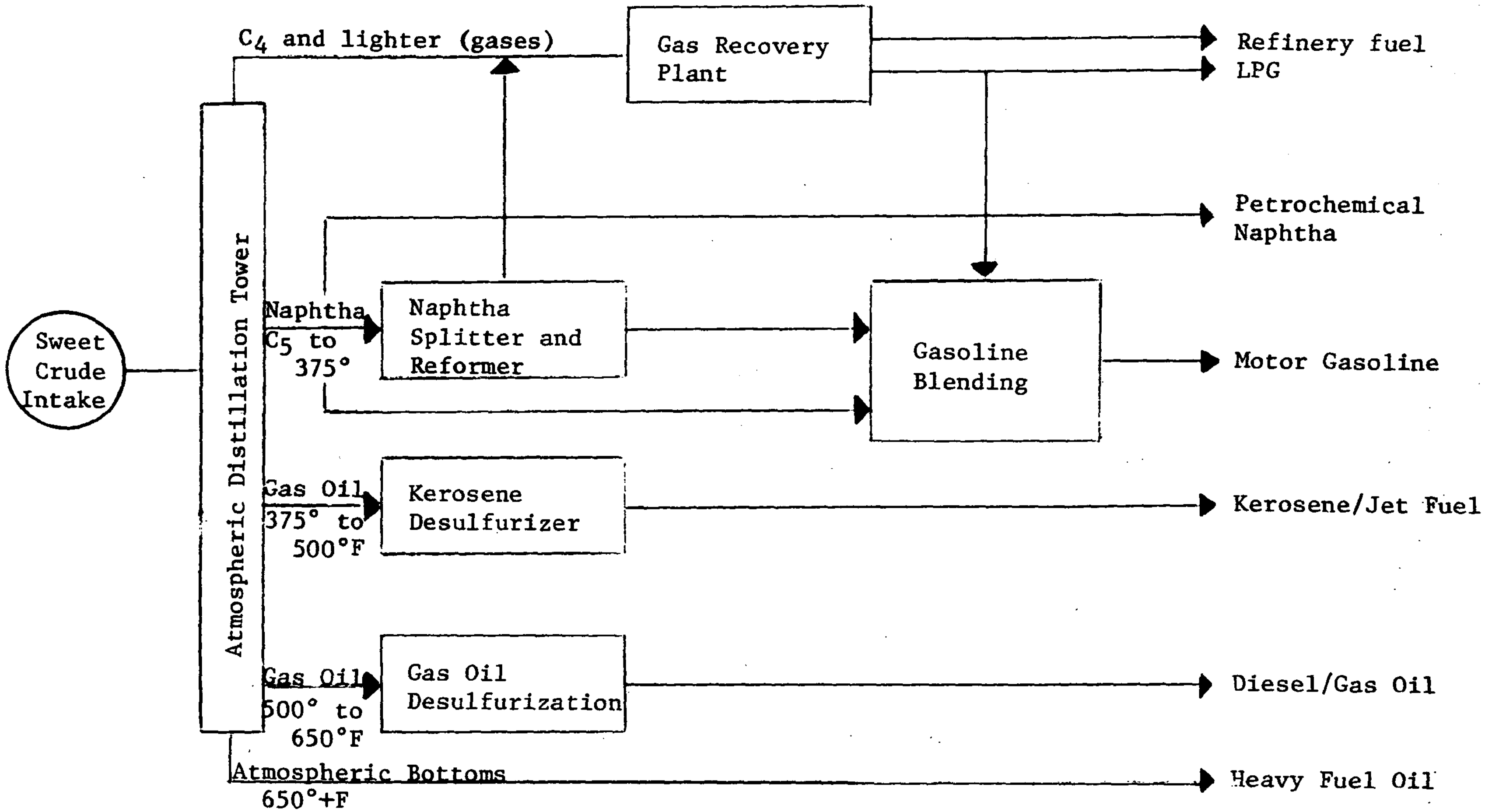


Figure C.3-3

Hydroskimming Refinery Flow Diagram - Sweet Crude Intake



not vaporized at the typical maximum temperature of the distillation tower, 650°F (343°C). Streams as they exit the tower may be divided roughly into three groups:

- Gases and naphthas - these undergo further splitting and are either blended directly into products (LPG, petrochemical feedstocks) or undergo an octane-upgrading process (catalytic reforming) before being blended into gasoline.
- Atmospheric gas oils - these may be split and/or desulfurized and blended into distillate products (aviation jet fuel, kerosene, home heating oil) or be processed by chemically altering hydrocarbon chain length (catalytic conversion) and reformed for gasoline blending.
- Residuum or atmospheric bottoms - most of this stream undergoes further thermal separation in a vacuum distillation tower and is either blended directly into products (lubrication oils, waxes, road oil, asphalt, coke, residual fuel oil), burned in the refinery's internal fuel system or upgraded through conversion processing (catalytic cracking, etc.) into lighter products. One conversion process, coking, yields a heavy non-converted output, coke, which is sold directly as a product.

Although general refinery design reflects crude input and product output, each actual refinery's throughput and operating severity for each processing unit as well as exact blending "recipes" for each product are extremely proprietary. Furthermore, detailed crude slates which are reported to the Bureau of Mines by every U.S. refiner are not published on either the national or PAD district level. The only publicly available data relevant to a study of refiners' usage of residuum at the PAD district level and their respective sources are:

- Crude slates by percent foreign and domestic crude and total crude input (Bureau of Mines).
- Percent yield of each hydrocarbon groups for individual crudes (crude assays published by oil companies).
- Installed capacity by processing unit (Oil and Gas Journal).
- Internal refinery usage of residuum for process heating (Bureau of Mines).
- Product outputs (Bureau of Mines).

Missing from the available information is data on detailed crude slates and yields of output streams from certain processing units by PAD districts. To alleviate this problem, this information has been derived from a recent EPA study of the U.S. refining industry* and was used in the manner described below to give an estimate of domestic refiners' 1973 usage of residuum which is presented in Tables C.3-6 and C.3-7. Note that both tables are identical, except that Table C.3-6 shows absolute volumes of residuum by source and use while Table C.3-7 presents this data as a percentage of crude charge.

The total amount of residuum available to domestic refiners by PAD district (column 3) is the result of multiplying the volume of crude charge (column 1) times the residuum yield on crude (column 2) both listed by PAD district. Crude charge by district is a published Bureau of Mines figure. Yield on crude is a composite yield which was obtained by combining district crude slates (from the EPA study) with their respective crude assays to generate the total residuum yield per thousand barrels of crude charge. Disposition of this residuum supply is given in columns 4-8 of each table and is based on Bureau of Mines figures for liquid refinery fuel needs (column 4) and product outputs

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*The Impact of SO_x Emissions Control on Petroleum Refining Industry by Arthur D. Little, Inc. Prepared for the Environmental Protection Agency December 1975. Contract No. 68-02-1332, Task Order No. 1.

Table C.3-6

Estimated Domestic Refiners' Usage of Residuum Hydrocarbons (650° +F) in 1973

(MBBLS)

		Residuum Yield on Crude		Residuum Disposition					Conversion Use	
	(1) Crude Charge	(2) % Liquid Volume	(3) Volume (MBBLS)	(4) Refinery Fuel (Internal Use)	(5) Residual Fuel Oil	(6) Asphalt and Road Oil	(7) Lubes and Waxes	(8) To Conversion Units	(9) Coker Feed	(10) Catalytic Cracker and Hydrocracker Feeds
PAD I	548,027	42.9	235,104	14,814	52,258	37,122	13,514	117,396	23,183	94,213
PAD II	1,271,998	40.3	512,615	20,112	71,120	61,741	11,919	347,723	64,840	282,883
PAD III	1,844,698	39.8	734,190	2,140	88,455	41,497	43,181	558,917	83,625	475,292
PAD IV	151,521	53.0	80,306	2,004	9,864	11,155	485	56,798	8,362	48,436
PAD V	721,010	53.0	382,135	4,939	132,900	23,695	6,411	214,190	70,082	144,108
Total U.S.A.	4,537,254	42.9	1,944,350	44,009	354,597	175,210	75,510	1,295,024	250,092	1,044,932
% Crude Charge	100.0	-	42.9	1.0	7.8	3.9	1.7	28.5	5.5	23.0

Source: Department of the Interior, Bureau of Mines, 1973 Annual Petroleum Statement
Arthur D. Little, Inc.

Table C.3-7

<u>Estimated Domestic Refiners' Percent Use of Residuum Hydrocarbons (650° +F) in 1973</u>

(% Crude Charge)

		Residuum Yield on Crude		Residuum Disposition					Conversion Use	
	(1) Crude Charge	(2) % Liquid Volume	(3) Volume (MBBLS)	(4) Refinery Fuel (Internal Use)	(5) Residual Fuel Oil	(6) Asphalt and Road Oil	(7) Lubes and Waxes	(8) To Conversion Units	(9) Coker Feed	(10) Catalytic Cracker and Hydrocracker Feeds
PAD I	100.0	42.9	235,104	2.7	9.5	6.8	2.5	21.4	4.2	17.2
PAD II	100.0	40.3	512,615	1.6	5.6	4.9	0.9	27.3	5.1	22.2
PAD III	100.0	39.8	734,190	0.1	4.8	2.3	2.3	30.3	4.5	25.8
PAD IV	100.0	53.0	80,306	1.3	6.5	7.4	0.3	37.5	5.5	32.0
PAD V	100.0	53.0	382,135	0.7	18.4	3.3	0.9	29.7	9.7	20.0
Total U.S.A.(%)	100.0	42.9	1,944,350	1.0	7.8	3.9	1.7	28.5	5.5	23.0
Total U.S.A. (MBBLS)	4,537,254	-	1,944,350	44,009	354,597	175,210	75,510	1,295,024	250,092	1,044,932

Source: Department of the Interior, Bureau of Mines, <u>1973 Annual Petroleum Statement</u>
Arthur D. Little, Inc.

(columns 5-7). Residuum channeled to conversion units is the remainder of column 3 after usages represented by columns 4-7 have been subtracted out. Conversion uses have been further broken down into coker feed and catalytic cracker/hydrocracker feed. Bureau of Mines 1973 coke production divided by the estimated coke yields by PAD districts generate the regional coker feeds in column 9.

This estimated 1973 refiners' usage of residuum has assumed that heavy product blends and liquid refinery fuel are entirely from "straight-run" residuum; that is, that no lighter hydrocarbon streams such as gas oils are downgraded. We also assume that residuum entering a conversion unit is lost to the internal refinery fuel and product blending system. This simplification is not entirely accurate as the heaviest output from the catalytic cracker, a conversion unit oriented toward gasoline production, remains in the residuum system and is typically burned as liquid refinery fuel, blended into residual fuel oil product or fed into the coking unit. In addition, heavy gas oils and naphthas may be blended into residual fuel oil if their supply is in excess of demand, their sulfur content is too high for distillate product specifications or if the density requirements of residual fuel oil require the addition of lighter hydrocarbons. Thus, feed to conversion units (column 8) may be underestimated and should be considered residuum volume upgraded to lighter products net of "recycling" and hydrocarbon downgrading.

Two important comments on the availability and usage of residuum should be made:

- Usages given in columns 4-8 are equivalent and substitutive. That is, the output for any given product, such as residual fuel oil, is essentially a blending choice and not limited by process capacity.
- Refineries, especially on the Gulf and West Coasts, burn gaseous as well as liquid fuels and as the supplies of natural gas decline, liquid hydrocarbons

(most likely 650° + F) will be diverted into the refinery fuel system and reduce the residuum blending flexibility noted above.

The fact that residual fuel oil production is a blending choice is in direct contrast to gasoline production which is process-intensive and limited by a refiner's conversion and reforming capacities. With little additional investment a refiner can trade increased fuel oil production (at a sulfur level that is proportional to the crude sulfur level) for decreased output of competing products or usages. Thus from 1970 to 1974 the Gulf Coast increased its fuel oil production by 72 MMBBLS (119%) to 132 MMBBLS per year. Production of low sulfur resid can be accomplished by preferential blending, provided that other residuum usages or products are insensitive to sulfur content and can absorb high sulfur streams. Usually asphalt serves as the refinery's sulfur sump as high sulfur content and qualities beneficial to asphalt production often co-exist in the residuum streams. In addition coke products can tolerate fairly high sulfur contents, although the steel industry has been tightening coke sulfur specifications in the last few years. The West Coast produced almost one-half of its 1974 fuel oil output of 124 MMBBLS as very low sulfur resid. This sulfur content was accomplished partially by preferential blending of residuum streams derived from sweet Indonesian crude and partially by direct desulfurization of these streams.

Other than residuum products, drains on the residuum blending pool include the use for upgrading to lighter products and for internal refinery fuel. In 1973, U.S. refineries derived 71.3% of their internal energy requirements from gaseous fuels, 36.2% from natural gas and 35.1% from internally produced refinery gas (see Table C.3-8). We anticipate that natural gas supplies will eventually be unavailable for use as refinery fuel causing refiners to divert more liquid hydrocarbons (most likely residuum) into the refinery fuel system. In 1973, Gulf and West Coast refineries derived 54% and 31%, respectively, of their total internal energy requirements from natural gas. If 1973 gaseous

Table C.3-8

Fuels Consumed by Refineries

by PAD District 1973

Area	Total B.T.U. Requirement (billion BTU)	Energy Source, percent total B.T.U. Natural Gas(1)	Refinery Gas(1)	Coke(1)	Residual Fuel Oil(1)	Other(2)	Total Fuel Source
PAD District I	353,395	9.4	38.5	14.4	26.4	11.3	100.0
PAD District II	714,596	19.0	41.4	16.9	17.7	5.0	100.0
PAD District III	1,426,446	53.5	29.6	10.7	0.9	5.3	100.0
PAD District IV	96,592	29.1	34.7	18.5	13.0	4.7	100.0
PAD District V	466,747	31.3	40.0	12.6	6.7	9.4	100.0
Total U.S.	3,057,776	36.2	35.1	13.1	9.0	6.6	100.0

(1) Heating values: natural gas - 1,031 B.T.U./cubic foot.
refinery gas - 990 B.T.U./cubic foot.
coke - 30,120,000 B.T.U./short ton (5 bbl per short ton).
residual fuel oil - 6,287,000 B.T.U./bbl.

(2) Includes crude oil, liquified petroleum gas, coal, purchased electricity and purchased steam.

Source: Department of The Interior, Bureau of Mines, <u>1973 Annual Petroleum Statement</u>.

volumes on the Gulf and West Coasts were totally replaced by residuum an additional 121 and 23 MMBBLS, respectively, would be diverted from those districts' residuum pools. For the entire U.S. refinery industry in 1973 this figure would be 176 MMBBLS which would have been 9% of the total available residuum for that year. Diversion of residuum to conversion units is a function of complex forces, including product quality requirements. For example, if gasoline sulfur contents must be reduced without lowering octane levels additional catalytic reforming of desulfurized streams will be required. Because reforming units yield less than 100% of their liquid input as gasoline product, intake volumes will have to be increased to replace these processing losses. The tendency of these forces to increase residuum upgrading and decrease the residuum blending pool is uncertain but is certainly influenced by economics.

As long as a refiner can make more money by sending residuum to conversion units this is the preferred course of action, and this has been the normal situation for years for U.S. refineries. Since the advent of the Crude Oil Entitlements Program the economics have shifted and refineries have seen an opportunity to sell lower cost residuum in a market where prices are primarily set by higher-priced foreign imports. This has led to the marked increase in residual fuel oil production by domestic refiners. In the same way, higher values assigned to lubes or asphalts or use of residuum for petrochemical feedstock, say, would tend to pull production from residual fuel oil to those products. Thus relative economics, rather than physical processing capacities, is one of the main driving factors in determining residuum use.

C.3.6 1974 SUPPLY OF RESIDUAL FUEL OIL BY PAD DISTRICT

Having outlined the general forces affecting U.S. production of residual fuel oil, we will now focus on regional supplies. Tables C.3-9 through C.3-13 summarize 1974 supply by PAD district and have been developed from detailed analyses of residual fuel oil supplies which are shown in Table C.3-14. Table C.3-14 has data for each year from 1970 to the

Table C.3-9

Source of Residual Fuel Oil Demand by PAD District in 1974

(Expressed as Percentage of Consumption)

Area	Refinery Output (% Self-sufficiency)	Imports[a]	Inter-PAD Transfers (net)	Other[b]	Total Local Consumption %	Total Local Consumption MBBLS
PAD District I	9.0	85.2	6.2	0.4	100.0	624,664
PAD District II	77.2	9.3	12.6	0.9	100.0	85,239
PAD District III	142.9	12.8	(53.6)	(2.1)	100.0	92,371
PAD District IV	101.3	0.0	(3.0)	1.7	100.0	12,231
PAD District V	86.6	15.1	0.5	(2.2)	100.0	143,306
Total U.S.	40.8	59.9	0.0	(0.7)	100.0	957,811

[a]Includes foreign crude oil burned directly as fuel (1.3% of total U.S. imports in 1974).

[b]Stock changes and domestic crude oil burned directly as fuel minus exports.

Source: Department of the Interior, Bureau of Mines, 1974 Monthly Petroleum Statement.

Table C.3-10

Distribution of Domestic Production of Residual Fuel Oil by Sulfur Content - 1974

	% Sulfur by Weight				Total Production	
	Low Sulfur[a]		High Sulfur[a]			
Area	<0.50	0.51-1.00	1.01-2.00	>2.00	%	MBBLS
PAD District I	19	38	24	19	100	56,164
PAD District II	4	41	34	21	100	65,775
PAD District III	19	34	10	37	100	132,002
PAD District IV	18	30	18	34	100	12,396
PAD District V	46	4	44	6	100	124,154
Total U.S.A.	25	26	27	22	100	390,491

[a]Very low sulfur is defined as less than .50% weight; very high sulfur greater than 2.00% weight.

Source: Department of The Interior, Bureau of Mines, 1974 Monthly Petroleum Statement.

Table C.3-11

Imports of Residual Fuel Oil by Sulfur Level and Exporting Country 1974
(MBBLS)

Country of Origin[a]	% 1974 Total Imports	% Sulfur by Weight: Low Sulfur[b] <0.50	0.51-1.00	High Sulfur[b] 1.01-2.00	>2.00	Total Imports[c]
Bahamas	7.3	14,183	9,033	4,206	11,763	39,185
Canada	5.1	9,169	3,773	3,663	10,860	27,465
Italy	2.3	8,678	1,598	585	1,191	12,052
Netherland West Indies	23.4	40,371	39,584	6,234	39,058	125,248
Trinidad	7.2	15,307	9,997	10,428	3,058	38,790
Venezuela	29.5	33,887	25,956	27,552	69,937	157,332
Virgin Islands	19.3	55,051	11,188	19,964	16,685	102,885
Other	5.9	19,588	5,552	3,113	3,123	31,376
Total Imports[c]	100.0	196,234	106,681	75,745	155,675	534,335
% 1974 Total Imports	-	36.7	20.0	14.2	29.1	100.0

[a] Country exporting directly into the United States; not necessarily refinery location or crude source.

[b] Very low sulfur is defined as <0.50% weight.
Very high sulfur is defined as >2.0% weight.

[c] Excludes bonded and military imports (39,417) whose volumes are not available by sulfur content.

Source: Department of the Interior, Bureau of Mines, Mineral Industry Surveys, Availability of Heavy Fuel Oils by Sulfur Levels Monthly 1974.

Table C.3-12

Interdistrict Movements of Residual Fuel Oil Between PAD Districts in 1974
(MBBLS)

Destination	Movement From PAD I	PAD II	PAD III	PAD IV	PAD V	Total Receipts	% Total Receipts
PAD District I	--	2,450	36,023			38,473	73.5
PAD District II		--	13,209			13,209	25.2
PAD District III			--			0	0.0
PAD District IV				--		0	0.0
PAD District V			316	365	--	681	1.3
Total Shipments	0	2,450	49,548	365	0	52,363	100.0

Source: Department of Interior, Bureau of Mines, 1974 Monthly Petroleum Statements.

Table C.3-13

Estimated Percent Availability
of Residual Fuel Oil by Sulfur Content 1974

Area	% Sulfur by Weight[a]				Total Availability[b]	
	Low Sulfur		High Sulfur			
	< 0.50	0.51-1.00	1.01-2.00	>2.00	%	MBBLS
PAD District I	33	24	15	28	100	591,338
PAD District II	9	41	29	21	100	87,176
PAD District III	15	26	12	47	100	87,648
PAD District IV	18	31	18	33	100	12,342
PAD District V	51	4	39	6	100	140,111
Total U.S.A.	32	23	19	26	100	918,615

[a]The split between low and high sulfur is 1.00% weight. Very low sulfur is defined as less than 0.5% weight; very high sulfur as greater than 2.00% weight.

[b]Based on refinery output, non-military and non-bonded imports, shipments from PAD III to other districts and stock changes (94.7% of 1974 supply). Excludes military and bonded imports, shipments from all districts except PAD III, domestic crude burned directly as fuel and exports.

Source: Department of Interior, Bureau of Mines, 1974 Monthly Fuel Oil Availability.

Table C.3-14

Detailed Residual Fuel Oil Domestic Supply and Consumption by PAD Districts - 1970-1974
(MBBLS)

PAD District I	1970	1971	1972	1973	1974	1974 (6 mos)	1975 (6 mos)
Refinery output	35,059	37,125	37,582	52,258	56,164	28,336	36,126
Imports - residual fuel oil	N.A.	N.A.	607,051	626,457	527,563	272,481	207,540
- crude burned directly	N.A.	N.A.	9,939	13,154	4,787	241	200
Total Imports	536,968	558,771	616,990	639,611	532,350	272,722	207,740
Domestic crude burned[a]	0	0	0	0	0	0	0
Domestic receipts from							
- PAD II	1,210	1,009	1,798	796	2,450	1,470	1,470
- PAD III	28,704	32,588	30,389	16,960	36,023	14,791	24,064
- PAD V	0	40	160	0	0	0	0
Total domestic receipts	29,914	33,637	32,347	17,756	38,473	16,261	25,534
Stock changes	3,024	3,097	(2,935)	1,120	2,221	1,437	11,024
Total PAD supply	598,917	626,436	689,854	708,505	624,766	315,882	258,376
Exports	872	606	1,502	87	102	55	5
Local PAD consumption	598,045	625,830	688,352	708,418	624,664	315,827	258,371
Stock year-end	24,136	27,233	24,298	25,418	27,639	26,518	37,542
PAD District II							
Refinery output	62,839	58,890	65,848	71,120	65,775	32,661	35,906
Imports - residual fuel oil	N.A.	N.A.	4,978	4,152	5,209	1,866	6,842
- crude burned directly	N.A.	N.A.	480	1,916	2,721	352	427
Total Imports	4,207	3,953	5,458	6,068	7,930	2,218	7,269
Domestic crude burned[a]	579	576	578	578	578	289	289
Domestic receipts from							
- PAD III	7,785	4,732	7,407	10,523	13,209	5,835	6,190

Table C.3-14 Detailed Residual Fuel Oil Domestic Supply and Consumption by PAD Districts - 1970-1974 (Cont'd)

(MBBLS)

PAD District II (Cont'd)	1970	1971	1972	1973	1974	1974 (6 mos)	1975 (6 mos)
Stock changes	2,508	565	(1,304)	226	(261)	(211)	1,211
Total PAD supply	72,902	67,586	80,595	88,063	87,753	41,214	48,443
Domestic shipments	1,210	1,009	1,798	796	2,450	1,470	1,470
Exports	316	316	511	179	64	24	23
Local PAD consumption	71,376	66,261	78,286	87,088	85,239	39,720	46,950
Stock year-end	8,806	9,371	8,067	8,293	8,032	6,522	7,733
PAD District III							
Refinery output	60,342	60,894	65,047	88,455	132,002	54,070	80,803
Imports - residual fuel oil	N.A.	N.A.	6,212	10,471	11,805	6,598	2,557
- crude burned directly	N.A.	N.A.	0	0	0	0	0
Total Imports	11,029	6,553	6,212	10,471	11,805	6,598	2,557
Domestic crude burned[a]	1,785	1,783	1,781	1,784	1,784	892	892
Domestic receipts	0	0	0	0	0	0	822
Stock changes	763	1,125	(1,180)	1,002	3,006	2,935	(383)
Total PAD supply	72,393	68,105	74,220	99,708	142,585	58,625	85,457
Domestic shipments	36,494	37,320	37,796	29,381	49,548	20,942	31,271
Exports	4,211	3,167	4,667	2,127	666	60	219
Local PAD consumption	31,688	27,618	31,757	68,200	92,371	37,623	53,967
Stock year-end	6,119	7,244	6,064	7,066	10,072	9,995	9,612
PAD District IV							
Refinery output	9,100	9,886	9,152	9,864	12,396	5,571	6,545
Imports - residual fuel oil	N.A.	N.A.	0	0	2	2	0
- crude burned directly	N.A.	N.A.	0	0	0	0	0
Total Imports	52	41	0	0	2	2	0

Table C.3-14 Detailed Residual Fuel Oil Domestic Supply and Consumption by PAD District - 1970-1974 (Cont'd)

(MBBLS)

PAD District IV (Cont'd)	1970	1971	1972	1973	1974	1974 (6 mos)	1975 (6 mos)
Domestic crude burned[a]	252	252	252	252	252	126	126
Domestic receipts	0	0	0	0	0	0	0
Stock changes	72	404	(533)	495	54	384	(56)
Total PAD supply	9,332	9,775	9,937	9,621	12,596	5,315	6,727
Domestic shipments[b]	365	730	365	365	365	219	219
Exports	0	3	0	0	0	0	0
Local PAD consumption	8,967	9,042	9,572	9,256	12,231	5,096	6,508
Stock year-end	515	919	386	881	935	961	905
PAD District V							
Refinery output	90,170	107,889	114,890	132,900	124,154	60,798	70,231
Imports - residual fuel oil	N.A.	N.A.	8,741	16,040	21,665	13,945	6,126
- crude burned directly	N.A.	N.A.	0	4,035	0	0	0
Total Imports	5,589	8,382	8,741	20,075	21,665	13,945	6,126
Domestic crude burned	1,701	1,954	711	3,512	2,137	1,068	1,068
Domestic receipts from							
- PAD III	5	0	0	1,898	316	316	1,017
- PAD IV[b]	365	730	365	365	365	219	219
Total domestic receipts	370	730	365	2,263	681	535	1,236
Stock changes	(10,768)	496	1,487	(4,579)	1,194	1,535	(27)
Total PAD supply	108,598	118,459	123,220	163,329	147,443	74,811	78,688
Domestic shipments	0	40	160	0	0	0	822
Exports	14,386	9,125	5,380	6,114	4,137	2,017	2,082
Local PAD consumption	94,212	109,294	117,680	157,215	143,306	72,794	75,784
Stock year-end	14,418	14,914	16,401	11,822	13,016	13,895	13,868

Table C.3-14 Detailed Residual Fuel Oil Domestic Supply and Consumption by PAD Districts - 1970-1974 (Cont'd)

(MBBLS)

Total U.S.A.	1970	1971	1972	1973	1974	1974 (6 mos)	1975 (6 mos)
Refinery output	257,510	274,684	292,519	354,597	390,491	181,436	229,611
Imports - residual fuel oil	N.A.	N.A.	626,982	661,155	566,244	294,892	223,065
- crude oil burned	N.A.	N.A.	10,419	15,070	7,508	593	627
Total Imports	557,845	577,700	637,401	676,225	573,752	295,485	223,692
Domestic crude burned	4,317	4,565	3,322	6,126	4,751	2,375	2,375
Stock changes	(4,401)	5,687	(4,465)	(1,736)	6,214	6,080	11,769
Total U.S. supply	824,073	851,262	937,707	1,038,684	962,780	473,209	443,910
Exports	19,785	13,217	12,060	8,507	4,969	2,156	2,329
Domestic consumption	804,288	838,045	925,647	1,030,177	957,811	471,060	441,580
Stock year-end	53,994	59,681	55,216	53,480	59,694	57,891	69,660

[a] PAD consumption of crude for direct burning estimated for PAD I-IV (BOM estimates)

[b] Estimated from BOM daily statistics for year

Source: Department of the Interior, Bureau of Mines, Mineral Industry Surveys, Crude Petroleum, Petroleum Products, and Natural Gas Liquids, 1973; Annual Petroleum Statements, 1970, 1971, 1972, 1973; Monthly Petroleum Statements, 1974, 1975.

first six months of 1975 by PAD district. Figures C.3-4 through C.3-8 present graphically the 1974 supply data for each PAD district which is presented in tabular form in Table C.3-14. Note that 1974 is being used here since it is the latest available full year of residual fuel oil supply information. For further discussion about data availability see C.2.

C.3.6.1 Overview at PAD Districts

The United States, in particular the East Coast, imports most of its residual fuel oil needs (Table C.3-9). In 1974, 60% of total U.S. domestic fuel oil supplies were derived from product imports. District IV imported no resid while District I imported 85% of its requirements. The balance of domestic supply was produced at U.S. refineries with approximately 1% being supplied by stock changes and direct burning of domestic crude oil. Domestic resid production in 1974 was evenly split between the West Coast, the Gulf Coast and the rest of the U.S. and was distributed fairly evenly along a spectrum ranging from very low to very high sulfur content as shown in Table C.3-10. However, the demand profile by sulfur content did not match the production profile and imports of low sulfur fuel oil were needed to balance demand. Table C.3.11 shows that 37% of 1974 imports were low sulfur with 77% originating in the Caribbean or Venezuela. Sulfur level demand by PAD districts also did not match the production profile and resulted in fuel oil imports to the East Coast and interdistrict transfers from the Gulf to the East Coast. Virtually all (99%) of the imports listed in Table C.3-11 and most (74%) of the interdistrict transfers detailed in Table C.3-12 were destined for the East Coast. Also to be noted is the fact that the Gulf Coast was a net supplier of residual fuel oil in 1974, shipping 50 MMBBLS (35%) of the district's supplies (production plus imports) of 143 MMBBLS to other districts. The final estimated percent availability of residual fuel oil by sulfur content and by PAD district for 1974 is given in Table C.3-13.

While reading the following district-by-district discussion, frequent reference should be made to Tables C.3-9 through C.3-13. Table C.3-9 shows how self-sufficient each district was in residual fuel oil supplies. Tables C.3-10 and C.3-11 break down local production and imports by sulfur level while Table C.3-12 shows movements between districts. The result is Table C.3-13 which shows the 1974 supply of residual fuel oil by sulfur content levels by PAD district. It should be noted that some estimating was required to derive Table C.3-13 since data about the sulfur content of 5.3% of total U.S. supply was not available.

C.3.6.2 PAD District I - The East Coast (Figure C.3-4)

The East Coast is the least self-sufficient of all districts, having produced only 9% (56 MMBBLS) of its 1974 needs, imported 85% (532 MMBBLS) and received 6% (38 MMBBLS) from interdistrict transfers (Table C.3-9). Virtually all (99%) of the fuel oil imported into the U.S. was destined for the East Coast and most (74%) originated in the Caribbean and Venezuela. A historical relationship has developed between Caribbean hydroskimming refiners and East Coast fuel oil consumers, principally public utilities. Extensive desulfurization capacity in the Caribbean is dedicated to the processing of high sulfur Venezuelan crudes into low sulfur residual fuel oil. Imports of North African and other low sulfur crudes into Caribbean refineries is earmarked for the production of very low sulfur residual which is needed by East Coast utilities to satisfy air quality regulations. In 1974, local PAD District I production of low sulfur fuel oil (32 MMBBLS) was supplemented by large imports of low sulfur oil (277 MMBBLS) and some transfers from other districts (28 MMBBLS) or almost 75% of such movements. The distribution of fuel oil availability by sulfur content given in Table C.3-13 reflects regional differences in sulfur regulations which will be discussed in detail in C.5. Briefly described, these regulations require the burning of very low sulfur fuel oil in most urban areas (Boston, metropolitan New York City, Philadelphia) and all of Connecticut. Low

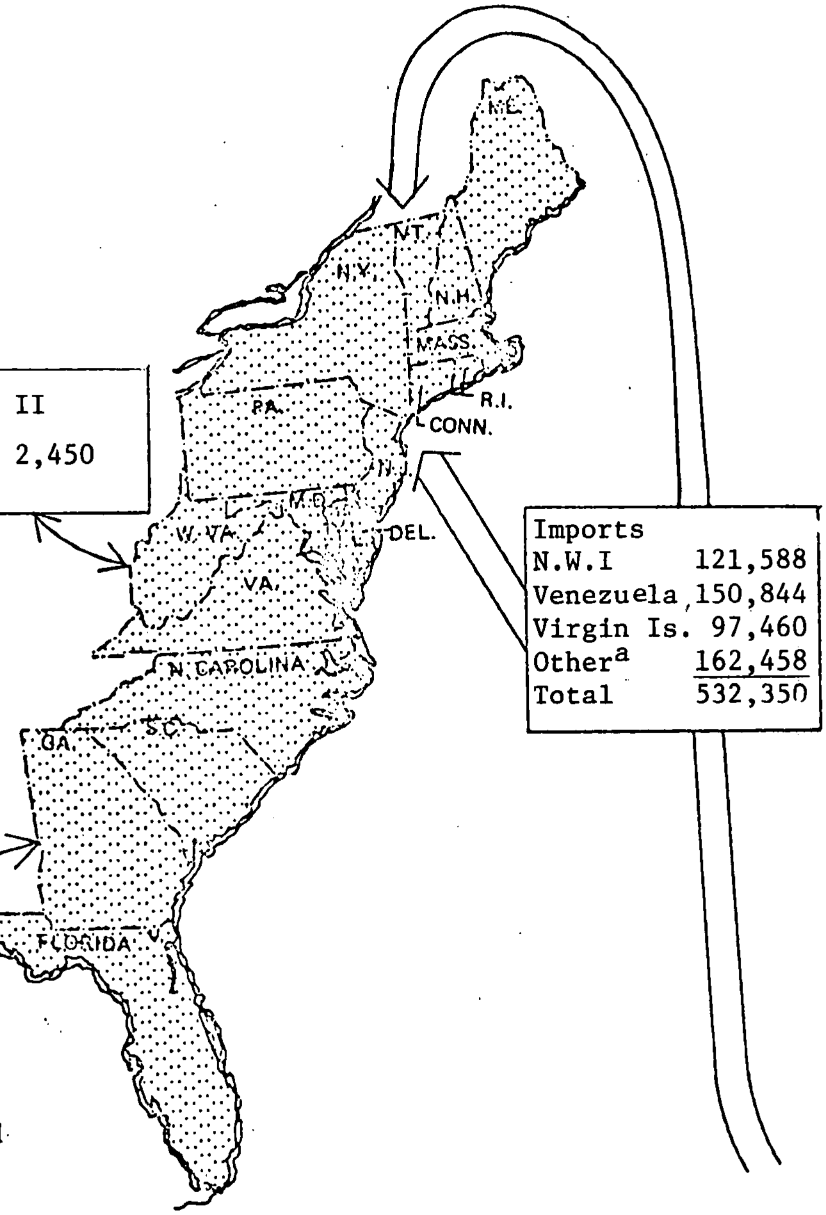
Figure C.3-4

PAD District 1

1974 Residual Fuel Oil Product Position
(MBBLS)

Supply	
Refinery Output	56,164
Imports	532,350
Domestic Receipts	38,473
Stock Changes	2,221
Dom. Crude Burned	--
Total	624,766
Disposition	
Local Consumption	624,664
Domestic Shipments	--
Exports	102
Total	624,776

District II
Receipts 2,450



District III
Receipts 36,023

[a]Includes all military and bonded imports of residual fuel oil.

Source: Department of the Interior, Bureau of Mines, 1974 Monthly Petroleum Statements.

sulfur resid is required in most of New England, all of New Jersey, Maryland and the District of Columbia. High sulfur fuel oil may be burned in Maine, New Hampshire, the Virginias, the Carolinas, Georgia and Florida.

C.3.6.3 PAD District II - The Midwest (Figure C.3-5)

In 1974 this area was 78% self-sufficient in fuel oil supply, imported 9% of local demand from Canada and received 13% from PAD District III. PAD Districts II and III are the only major interdistrict shippers of residual fuel oil, the Midwest having sent 2 MMBBLS to the East Coast in 1974. Sulfur regulations are typically more lenient in PAD District II than in PAD District I allowing the burning of high sulfur fuel oil in most states and in all non-urban areas. Only low sulfur fuel oil may be burned in Oklahoma and Illinois, yet no legislation currently in force in PAD District II restricts combustion of fuel oil to very low sulfur levels.

C.3.6.4 PAD District III - The Gulf Coast (Figure C.3-6)

The Gulf Coast is a net shipper of fuel oil, having produced 143% of its own district demand in 1974 and imported another 13%. The excess supply was shipped to other districts, 36 MMBBLS to PAD District I and 13 MMBBLS to PAD District II. Comparison of PAD District III production by sulfur content (Table C.3-10) and final availability (Table C.3-13) reveals that most of the shipments out of the Gulf Coast in 1974 were of low sulfur fuel oil even though sulfur regulations in Texas and Louisiana require the burning of low sulfur oil. However, New Mexico, Arkansas, Mississippi and Alabama allow the burning of high sulfur fuel oils.

C.3.6.5 PAD District IV - The Rocky Mountains (Figure C.3-7)

This district was fully self-sufficient in residual fuel oil in 1974. Its refinery output of 12 MMBBLS was split evenly between low and high sulfur as was its final availability of fuel oil by sulfur content. Both imports and interdistrict transfers were minor in 1974. In all states except Colorado the burning of high sulfur fuel oil is permitted.

Figure C.3-5

PAD District II

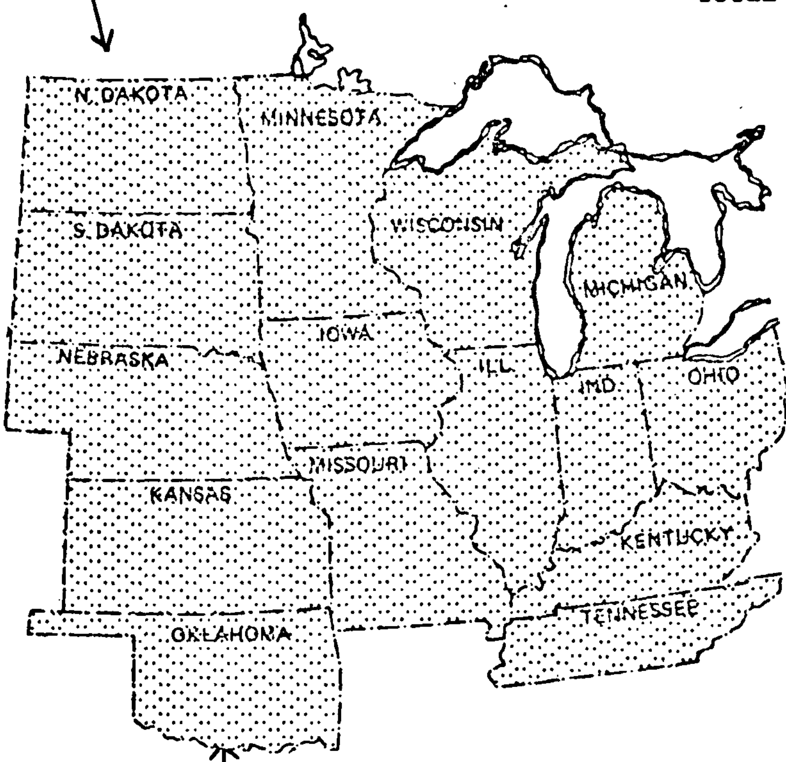
1974 Residual Fuel Oil Product Position

(MBBLS)

Supply	
Refinery Output	65,775
Imports	7,930
Domestic Receipts	13,209
Stock Changes	(261)
Dom. Crude Burned	578
Total	87,753

Disposition	
Local Consumption	85,239
Domestic Shipments	2,450
Exports	64
Total	87,753

Imports	
Canada	7,483
Venezuela	447
Total	7,930



District I

Shipments 2,450

District III

Receipts 13,209

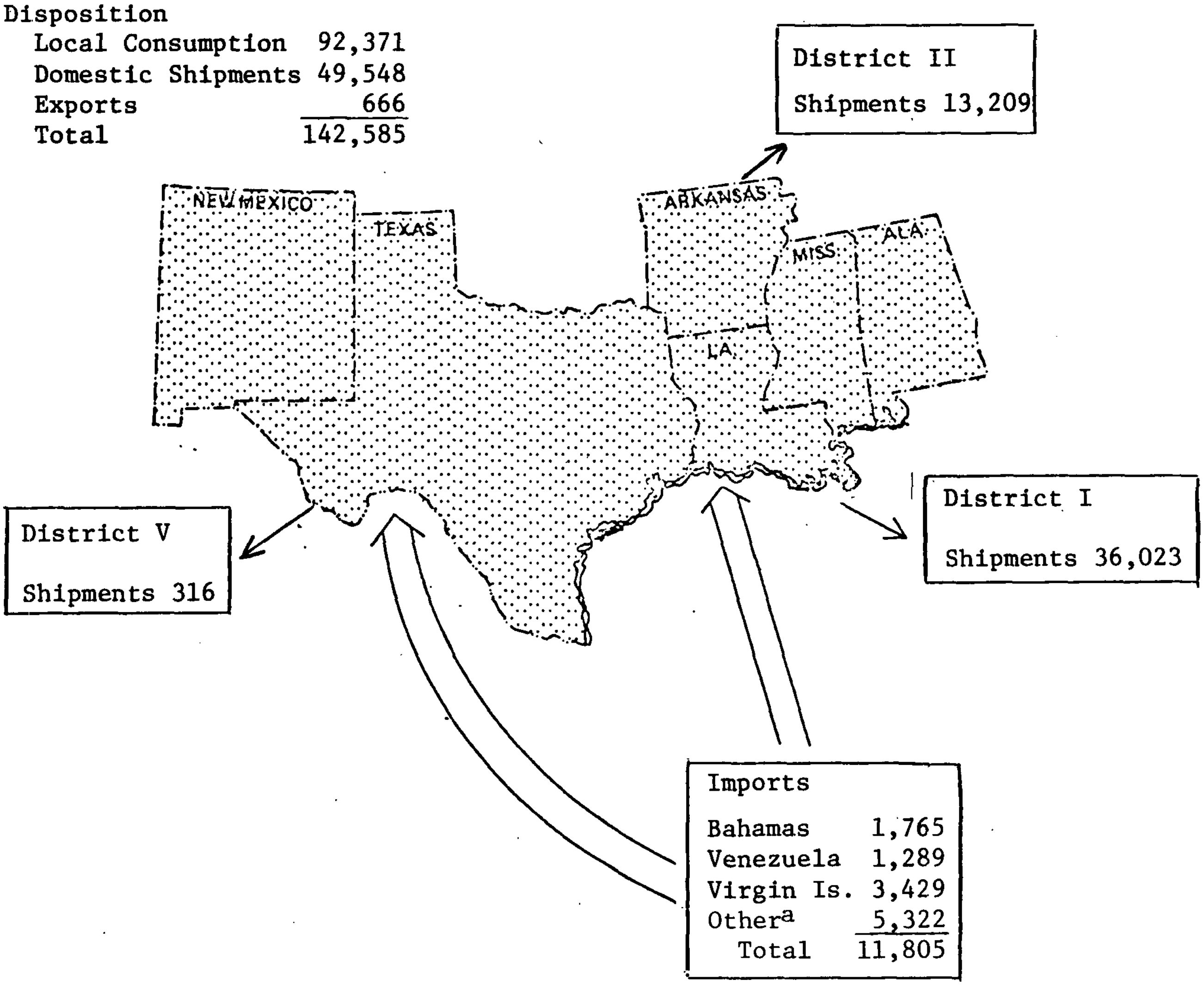
Source: Department of the Interior, Bureau of Mines, 1974 Monthly Petroleum Statements.

Figure C.3-6

PAD District III

1974 Residual Fuel Oil Product Position
(MBBLS)

Supply	
Refinery Output	132,002
Imports	11,805
Domestic Receipts	--
Stock Changes	3,006
Dom. Crude Burned	1,784
Total	142,585
Disposition	
Local Consumption	92,371
Domestic Shipments	49,548
Exports	666
Total	142,585



[a]Includes all military and bonded imports of residual fuel oil.

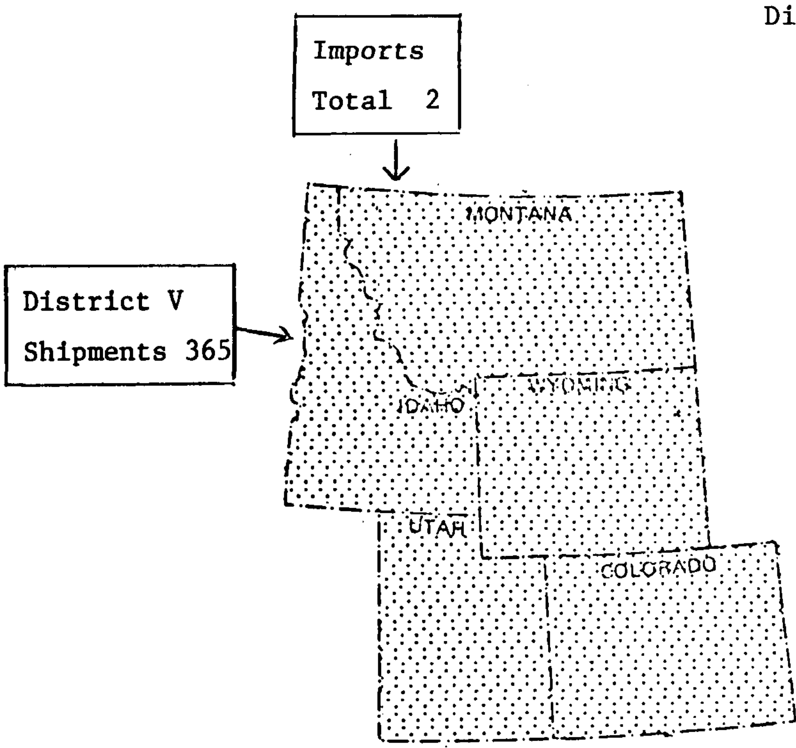
Source: Department of the Interior, Bureau of Mines, 1974 Monthly Petroleum Statements.

Figure C.3-7

PAD District IV

1974 Residual Fuel Oil Product Position
(MBBLS)

Supply	
Refinery Output	12,396
Imports	2
Domestic Receipts	--
Stock Changes	54
Dom. Crude Burned	252
Total	12,596
Disposition	
Local Consumption	12,231
Domestic Shipments	365
Exports	--
Total	12,596



Source: Department of the Interior, Bureau of Mines, 1974 Monthly Petroleum Statements.

C.3.6.6 PAD District V - The West Coast (Figure C.3-8)

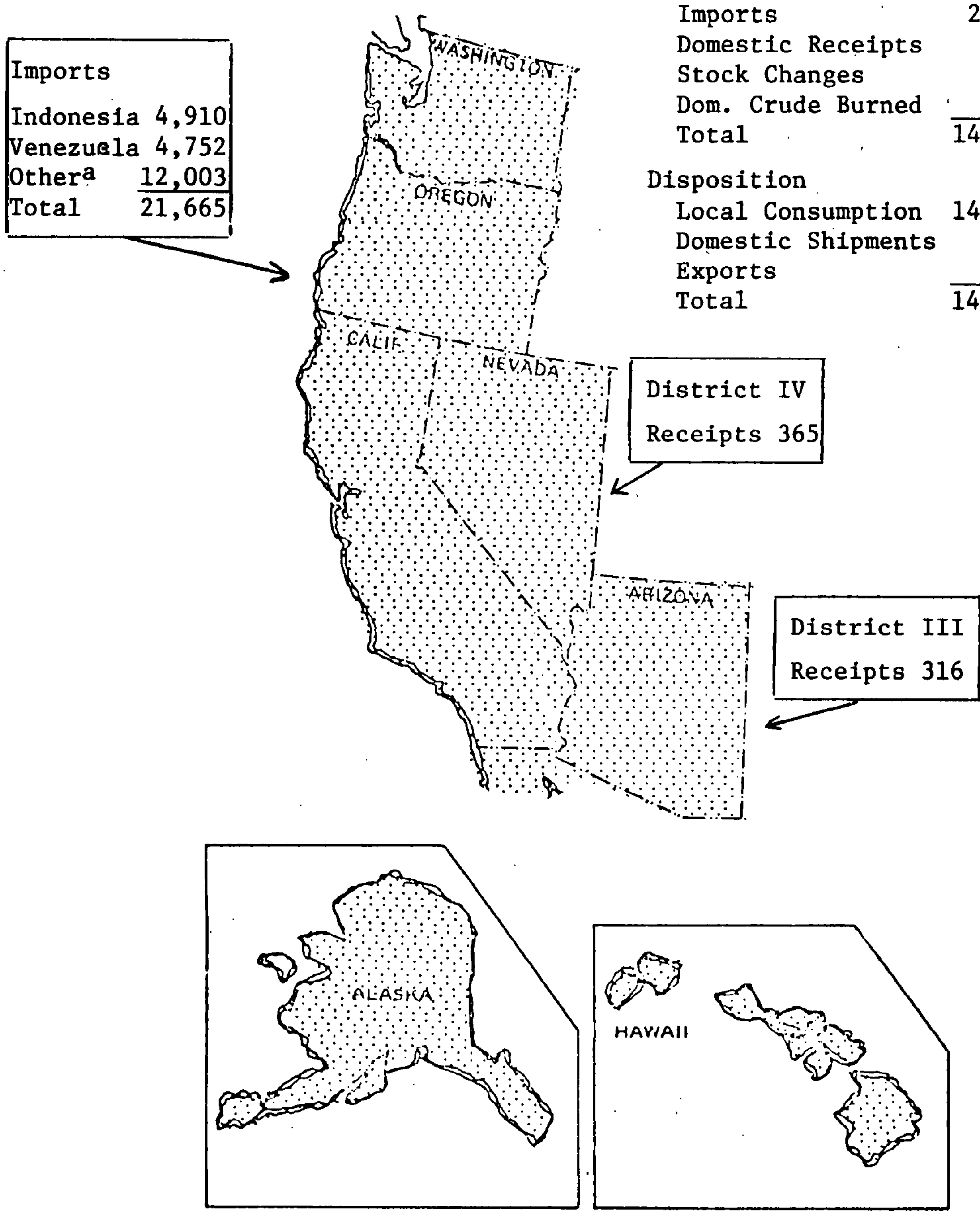
The West Coast produced 87% of its 1974 fuel oil consumption, imported 15% and received a small amount from interdistrict transfers. (These figures sum to 100% when exports of 2% are netted out.) Approximately one-third of both total 1974 U.S. fuel oil production and U.S. production of low sulfur fuel oil originated in this district. PAD District V 1974 fuel oil production and final availability by sulfur content shows a bulge in the very low sulfur and high sulfur categories. This distribution corresponds to current sulfur regulations of .5% in urban California areas and 1.9% in non-urban areas.

Figure C.3-8

PAD District V

1974 Residual Fuel Oil Product Position
(MBBLS)

Supply	
Refinery Output	124,154
Imports	21,665
Domestic Receipts	681
Stock Changes	1,194
Dom. Crude Burned	2,137
Total	147,443
Disposition	
Local Consumption	143,306
Domestic Shipments	681
Exports	4,137
Total	147,443



[a]Includes all military and bonded imports of residual fuel oil.

Source: Department of the Interior, Bureau of Mines, 1974 Monthly Petroleum Statements.

C.4 DOMESTIC DEMAND FOR RESIDUUM PRODUCTS

C.4.1 INTRODUCTION

Marketed residuum products, comprising residual fuel oil, lubricants, waxes, coke, asphalt, and road oil, represent approximately one fifth of demand for all refined petroleum products in the United States (see Table C.4-1). Residual fuel oil, accounting for approximately three-quarters of this product grouping, is obviously the major determinant of the overall demand for the entire category. Consequently, this discussion of historical demand will concentrate on residual fuel oil and will briefly summarize the remaining products.

Information on fuel oil sales, which is used as a proxy for demand, is available in very complete detail at the state level. All of the relevant state data has been assembled and included in Tables C.4-9 to 14. To be consistent with other sections of the report, the state-by-state data has been aggregated to the PAD District level for analysis. Tables C.4-9 to 14 provide an up-to-date data base for any in-depth state-by-state analysis that may be conducted in the future, as well as displaying the information availabilities at the state level. While our actual discussion of demand highlights some of the significant characteristics of the states, the main focus is at the regional and national levels.*

C.4.2 OVERVIEW ON MARKET DEMAND

In the last few years, developments related to the petroleum industry

*See Chapter C.2 on data availability for a full explanation of sources, etc.

Table C.4-1

The Importance of Residual Oil Products in Domestic Consumption of Petroleum Products 1970-1974

Petroleum Products	Demand Levels (MMBBLS) 1970	1973	1974	Demand Levels (Percentage Distribution) 1970	1973	1974
Gasoline	2131.3	2452.7	2402.4	39.7%	38.8%	39.6%
Jet Fuel	353.0	386.6	362.6	6.6	6.1	6.0
Ethane	83.8	119.4	124.6	1.6	1.9	2.0
Liquefied Gases	363.1	409.3	388.2	6.8	6.5	6.4
Kerosene	96.0	78.9	64.4	1.8	1.3	1.1
Petrochemical Feedstocks	101.2	129.9	132.5	1.9	2.1	2.2
Special Naphthas	31.4	32.2	32.0	0.6	0.5	0.5
Distillate Fuel Oil	927.2	1128.7	1072.8	17.3	17.9	17.7
Residual Fuel Oil	804.3	1030.2	957.8	15.0	16.3	15.8
Lubricants	49.7	59.2	56.7	0.9	0.9	0.9
Waxes	4.6	6.9	6.8	0.1	0.1	0.1
Coke	77.2	95.2	87.1	1.4	1.5	1.4
Asphalt	153.4	182.6	168.7	2.9	2.9	2.8
Road Oil	9.6	7.8	6.9	0.2	0.1	0.1
Subtotal Residuum Oil Products	1098.9	1381.9	1284.0	20.5	21.8	21.2
Still Gas	163.9	176.8	175.7	3.1	2.8	2.9
Miscellaneous	14.8	18.9	24.3	0.3	0.3	0.4
Plant Condensate	NA	1.9	6.1	NA	--	0.1
Total Petroleum Products	5364.5	6317.3	6069.5	100.0	100.0	100.0

Notes: Columns may not sum to totals due to rounding.
NA indicates data not available.
--indicates value less than 0.05.

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys: Petroleum Statement, Annual (1970, 1973), Monthly (December, 1974).

have resulted in dramatic changes in the market for petroleum products, both in market size and structure. Obviously, the primary development was the spiraling prices for foreign crude petroleum. The impact rippled through every facet of the petroleum industry and caused alterations in all aspects of petroleum product usage. Conservation measures, reinforced by the widespread economic recession in the U.S. and most other parts of the world, fostered an unprecedented turnaround in demand for petroleum products.

Growth in petroleum product demand, which had been advancing at an annual rate of 5.6 percent from 1970-1973, actually declined nearly 4 percent in 1974, down from 6.3 billion barrels to 6.1 billion barrels. Marketed residuum products exhibited an even more remarkable falling off, absorbing nearly half of the drop in demand. Demand for all residual oil products dropped nearly 100 million barrels in 1974, down to 1284 million barrels from a level of 1382 million barrels a year earlier. Growth in that year was a negative 7 percent, after having advanced at an annual rate of nearly 8 percent for the preceding three years. Residual fuel oil, itself, which had been growing at closer to 9 percent per annum, also dropped 7 percent in 1974, compared to 1973 consumption. The only petroleum products to show any increase in 1974 were related to the manufacture of petrochemicals. Table C.4-1 shows the domestic demand levels for all refined petroleum products for 1970, 1973, and 1974 and also provides the breakdown of demand by product group. By scanning the percentage distribution columns, it becomes apparent that percent demand by product categories has been remarkably stable with only residual oil products showing any noticeable increase in demand share, rising from 20.5 percent in 1970 to 21.2 percent by 1974. The only other product categories to register any gain in demand share were distillate fuel oil, petrochemical-related products, and miscellaneous.

On a geographic basis, as defined by the five PAD Districts, the East Coast was the largest regional consumer of residual oil products, commanding nearly 60 percent of total domestic demand. PAD District II and V each accounted for about 15 percent of the total, while the Gulf Coast region represented approximately 10 percent; the Rocky Mountain region (PAD District IV) held the remaining 2 percent of national demand. This is shown in Table C.4-2, which shows average calendar day demand.

C.4.3 RECENT HISTORY OF NON-ENERGY DEMAND FOR RESIDUUM-BASED PRODUCTS

Residuum-based products other than residual fuel oil fall into three product groupings:

Lubricants and Waxes
Coke
Asphalt and Road Oils

Together they account for approximately 5.5 percent of total petroleum product demand. Individually, asphalt and road oils are the largest with 3.0 percent; coke accounts for approximately 1.5 percent; and lubricants and waxes, the remaining 1.0 percent.

These residuum products are predominantly used for non-energy purposes. Including petrochemical feedstocks (most of which are not residuum), nearly two-thirds of the non-energy petroleum products have historically been consumed in the industrial sector for the manufacture of petrochemicals, for aluminum fabrication, as lubricants and waxes, and for other miscellaneous purposes. An additional 30 percent has been accounted for by the commercial sector, mostly as asphalt and road oil, and the remaining 5 percent as lubricants in the transportation sector.

Asphalt and road oil constitute the second largest use of petroleum as a raw material after petrochemical usage; these products are used extensively for paving roads, manufacturing shingles and other building materials, waterproofing, and miscellaneous uses. The growth in demand for these products is governed to a great extent by both the highway construction program and general building activity.

Table C.4-2

Domestic Demand for Residuum; by Product Type, by PAD District
1973
(MBCD)

PAD District	Residual Fuel Oil	Lubricants	Wax	Coke	Asphalt	Road Oil	Total Residual Oil
I	1,940	66	7	30	141	2	2,186
II	239	39	3	99	176	12	568
III	187	40	6	87	91	-	411
IV	26	-	-	11	34	2	73
V	430	17	3	34	58	6	548
U.S. Total	2,822	162	19	261	500	22	3,786

Percentage Breakdown of Product Usage by PAD District

PAD District	Residual Fuel Oil	Lubricants	Wax	Coke	Asphalt	Road Oil	Total Residual Oil
I	88.8	3.0	0.3	1.4	6.5	0.1	100.0
II	42.1	6.9	0.5	17.4	31.0	2.1	100.0
III	45.5	9.7	1.5	21.2	22.1	-	100.0
IV	35.6	-	-	15.1	46.6	2.7	100.0
V	78.5	3.1	0.6	6.2	10.6	1.1	100.0
U.S. Total	74.5	4.3	0.5	6.9	13.2	0.6	100.0

Percentage Breakdown of Product Usage Across PAD Districts

PAD District	Residual Fuel Oil	Lubricants	Wax	Coke	Asphalt	Road Oil	Total Residual Oil
I	68.8	40.7	36.8	11.5	28.2	9.1	57.7
II	8.5	24.1	15.8	37.9	35.2	54.5	15.0
III	6.6	24.7	31.6	33.3	18.2	-	10.9
IV	0.9	-	-	4.2	6.8	9.1	1.9
V	15.2	10.5	15.8	13.0	11.6	27.3	14.5
U.S. Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys: Crude Petroleum Statement, 1973.

The principal uses for petroleum coke have been for refinery fuel and the making of electrodes of which a significant amount has been for metallurgical electrodes used in aluminum reduction plants and for electrodes incorporated in electric motor brushes. Approximately one quarter of U.S petroleum coke production has been exported, mainly to Japan, Canada, and Europe.

The demand for lubricants and waxes reflects some technical trends: improved quality of all types of lubricating oils and greases lengthens their useful life and enables them to withstand harder use; changes in engine and other equipment design reduce lubricant requirements. In addition, a decline in exports caused by increased foreign manufacture has led to a decline in lubricants and wax demand on domestic refineries as a percent of refinery output. These reasons account for the decline in lubes and waxes from 2 percent of total petroleum demand to the current 1 percent share.

C.4.4 DOMESTIC DEMAND FOR RESIDUAL FUEL OIL

C.4.4.1 On The National Level

The domestic market for residual fuel oil is broken into the following market segments:

- Residential/Commercial and Industrial users
- Electric Utilities
- Railroads and Vessels and
- Military and Miscellaneous.

In addition to this sales market, real residual fuel oil demand also includes resid retained for use within the oil companies, especially for refinery fuel. Although there are other internal refinery uses, mainly the diversion of potential residual fuel oil to alternative residuum-based products, this is perceived as a supply factor rather than a demand usage and has been discussed accordingly in the supply section of this report.

As previously stated, total U.S. demand for residual fuel oil, as measured by the Bureau of Mines sales information, increased at an average annual rate of 8.6 percent from 1970-1973. (See Table C.4-3) While decreases in its use by Railroads and the Military have occurred during that period, all other consuming sectors registered gains from slightly more than 1 percent for Residential/Commercial to the nearly 18 percent shown for Electric Utilities. However, the year to year rates of growth during this period were not stable. In 1971, all major user categories, except Electric Utilities, actually experienced a reduction in demand relative to 1970. While the other sectors of demand were still showing the effect of the 1970 economic slowdown, the Electric Utilities demand for residual fuel oil was being supported by the EPA's efforts to convert electric power plants to oil from coal for environmental reasons. This trend continued until the oil embargo in 1973, when the reverse process was instituted due to the shortage of oil. The net result was that Electric Utilities were the only major user-category to experience any expansion in demand share from 1970-1973; its share of total residual fuel oil sales rose from just under 40 percent in 1970 to nearly 50 percent in 1973. (See Table C.4-4 which contains the same information as Table C.4-3 but expressed in percentage terms.) In terms of market share, the second most significant user-category is Industrial, which represents an additional 20 percent of residual fuel oil demand and includes oil company use of residual as well as any external sales to industry for heating and/or processing purposes.* The industrial share of the market went from 22 percent in 1970 to approximately 20 percent since that year. The other significant user-category is Residential/Commercial, whose share of fuel oil sales also declined from 1970 to 1973, with 23 percent in 1970 and 19 percent in 1973.

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*The Bureau of Mines solicits fuel oil sales information using a direct mail survey involving companies which sell in excess of 10,000 barrels of fuel oil and kerosene during the year in question. While industrial sales are requested to be stated <u>excluding</u> fuel oil for heating, this has typically not been the case. Consequently, industrial sales are commonly considered to include industrial fuel oil sales for heating. Likewise, the category presented as fuel oil sales for heating use is perceived as being more closely representative of fuel oil sales to the Residential/Commercial sector only.

Table C.4-3

Residual Fuel Oil[1] Use In the United States: 1970-1974
(MBBLS)

Use	1970	1971	1972	1973	1974	Average Annual Rates of Change 1970-1973	1973-1974
Residential/Commercial	185,831	182,062	191,111	192,252	167,415	1.1	-12.2
Total Industrial	177,965	168,847	186,611	202,919	193,962	4.5	- 4.4
Industry	139,647	136,221	142,320	152,267	143,726	2.9	- 5.6
Oil Company Use	38,318	32,626	44,291	50,652	50,236	9.7	- 0.8
Electric Utility	312,420	371,820	435,348	509,457[2]	475,204[2]	17.7	- 6.7
Transportation Total	92,072	79,989	79,069	93,629	92,304	0.6	- 1.4
Railroads	2,222	1,262	1,137	1,214	1,176	-18.2	- 3.1
Vessels	89,850	78,727	77,932	92,415	91,128	0.9	- 1.4
Other Total Use	35,999	35,326	33,508	31,920	28,926	- 3.9	- 9.4
Military	28,704	29,217	24,622	22,892	20,423	- 7.3	-10.8
Other Misc.	7,295	6,109	8,886	9,028	8,503	7.4	- 5.8
Total United States	804,287	838,044	925,647	1,030,177	957,811	8.6	- 7.0

[1]Includes Navy grade and crude oil burned as fuel.

[2]Data for 1974 excludes 26,683,000 barrels of distillate fuel oil used at steam-electric plants. The 1973 data excludes approximately 25,323,000 barrels of distillate fuel oil used at steam-electric plants.

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys: Sales of Fuel Oil and Kerosene, 1970, Table 3.

Table C.4-4

Percentage Residual Fuel Oil Use In the United States: 1970-1974

Use	1970	1971	1972	1973	1974
Residential/Commercial	23.1	21.7	20.6	18.7	17.5
Total Industrial	22.2	20.2	20.2	19.7	20.2
Industry	17.4	16.3	15.4	14.8	15.0
Oil Company Use	4.8	3.9	4.8	4.9	5.2
Electric Utility	38.8	44.4	47.0	49.5	49.6
Transportation Total	11.5	9.6	8.5	9.1	9.6
Railroads	0.3	0.2	0.1	0.1	0.1
Vessels	11.2	9.4	8.4	9.0	9.5
Other Total Use	4.5	4.2	3.7	3.1	3.0
Military	3.6	3.5	2.7	2.2	2.1
Other Misc.	0.9	0.7	1.0	0.9	0.9
Total United States	100.0	100.0	100.0	100.0	100.0

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys: Sales of Fuel Oil and Kerosene, 1970, Table 3.

The quadrupling of OPEC prices initiated dramatic changes in the traditional patterns of residual fuel oil consumption in the United States; most notably the decline in every category of end-use. The residual fuel oil industry has been further affected by turnarounds in the supply situation of its traditional competitor, natural gas. Curtailments of natural gas supplies have forced users, especially electric utilities, to secure alternative fuel sources. With an inadequate transportation network and production capacity limiting the ability of coal producers to absorb this new demand, the residual fuel oil suppliers have been confronted with a potentially growing market, while trying to accommodate their existing market in the face of reduced crude petroleum supplies.

A result of this new operating environment has been altered demand throughout the residual fuel oil market, with every user category responding with reduced consumption at the national level. For 1974, these reductions ranged from less than 1 percent for Oil Company usage to over 12 percent for Residential/Commercial. Other significant cutbacks appeared in Military (down 11 percent) and Electric Utilities, whose usage dropped nearly 7 percent. In terms of absolute volume, the utilities registered the largest 1974 decline, 34.6 million barrels; this is equal to almost half of the total decline in residual fuel oil sales. One reason for the drop in Electric Utility usage of residual fuel oil is the decline in demand for electricity itself in 1974 and zero growth in 1975. However, from 1973 to 1974, the Electric Utility share of total demand for residual fuel oil remained fairly stable at 49.5 percent of the total; the demand share attributed to the Industrial sector actually increased to 20.2 percent in 1974, from 19.7 percent in 1973. Vessel usage, which is predominantly composed of Bunker C sales, also rose in 1974 to a demand share of 9.6 percent, up from 9.0 percent in 1973. This increase in bunker demand was probably the result of domestic crude prices being at a controlled level which was under parity with international oil market prices. However, Bunker C demand is typically the most volatile segment of the residual fuel oil market, so that short-term fluctuations may not indicate a continuing trend.

While the Bureau of Mines detail data for annual fuel oil sales were not available for 1975 for inclusion in this report, other sources estimate the 1975 level of residual fuel oil demand at a total of approximately 923.4 million barrels, i.e. a 3.6 percent decline from the 1974 level.* Total petroleum product demand was shown to be off only 1.3 percent. This second consecutive year of decline in petroleum product consumption is generally attributed to the impact of the economic recession. Industry expectations in the fall of 1975 were for petroleum product demand to make a significant turnaround in 1976 and, in fact, to again approach the 1973 level of demand. Residual fuel oil was expected to experience the highest rate of growth among the major product categories and again top the billion barrel mark for the year. However, the economic recovery has been somewhat slower than originally anticipated and the traditional heating season, including IV Quarter, 1975 and I Quarter, 1976, has thus far experienced warmer than normal temperatures. Consequently, slack demand for residual fuel oil has appeared among the Residential/Commercial, Industrial, and Electric Utility users. The Oil and Gas Journal, which periodically reviews the fuel demand situation, currently envisions fuel oil demand to be off over 4 percent for the I Quarter 1976 relative to the comparable period a year ago.+ The I Quarter demand for residual fuel oil typically accounts for approximately 27-30 percent of the year's total; but this can be reduced when warmer than normal weather exists.

The long range outlook for residual fuel oil will be discussed separately in a later section of the report.

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*Petroleum Industry Research Foundation, Inc. (PIRINC), "PIRINC sees rising energy, oil demand," Oil and Gas Journal, November 24, 1975.

+The Oil and Gas Journal, January 12, 1976, "No serious fuel shortages seen in U.S. this winter".

C.4.4.2 Regional Demand for Residual Fuel Oil

Residual fuel oil consumption has historically been concentrated in the coastal regions of the United States, primarily due to considerations of supply availability and transportation economics, vis-à-vis alternative fuels. Another reason for the concentration of residual fuel oil consumption along the coasts is that residual fuel oil is very difficult to transport. As shown in Table C.4-5 PAD Districts I and V represented 80 percent of total residual fuel oil consumption in 1974. While the East Coast has remained the single, largest regional consumer through recent history, its share has fallen off in the last few years, dropping from nearly three-quarters of the total in 1970 to less than two-thirds in 1974. Although detailed sales data by PAD district were not available from the Bureau of Mines for the entire year of 1975, data available for the five month period running April through August indicate that this share may have been even further reduced, to less than 60 percent.* From 1970-1974, the Pacific Coast share has risen slightly, from 12 percent to 15 percent. The region in the United States that has shown the most significant increases in residual fuel oil consumption is the Gulf Coast area, whose demand share has risen from 4 to 10 percent over the same period. The April-August 1975 data indicate a further expansion in this share to almost 13 percent.

As was true at the national level, abrupt regional changes have appeared after 1973 in the consumption pattern for residual fuel oil. This was especially true in the East Coast region where demand dropped 12 percent in 1974, after having grown at an average rate of nearly 6 percent per year from 1970-1973. This reflects warmer heating seasons and a major decline in electricity demand, due to the economic slowdown. The Pacific Coast also registered a significant decline in 1974, down 9 percent, having grown at nearly 19 percent annually during the preceding three year period.

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*Department of Interior, Bureau of Mines, Mineral Industry Survey, U.S. PAD Districts Supply/Demand, monthly, April, August, 1975; this survey was published in April, 1975 for the first time.

Table C.4-5

The United States Residual Fuel Oil Demand
by PAD District, 1970-74
(MBBLS)

PAD District	1970	1971	1972	1973	1974	Average Annual Rates of Change 1970-73	1973-74
I	596,834	625,857	686,554	708,412	622,214	5.9%	-12.2%
II	72,586	66,261	80,084	87,088	87,689	6.3	0.7
III	31,688	27,617	31,757	68,206	92,371	29.2	35.4
IV	9,195	9,347	9,622	9,456	12,452	0.9	31.7
V	93,984	108,962	117,630	157,015	143,085	18.7	-8.9
United States Total	804,287	838,044	925,647	1,030.177	957,811	8.6	-7.0

Table 4.a

Percentage of Residual Fuel Oil in the United States
by PAD District, 1970-74
(MBBLS)

PAD District	1970	1971	1972	1973	1974
I	74.2%	74.7%	74.2%	68.8%	65.0%
II	9.0	7.9	8.7	8.5	9.2
III	3.9	3.3	3.4	6.6	9.6
IV	1.1	1.1	1.0	0.9	1.3
V	11.7	13.0	12.7	15.2	14.9
United States Total	100.0	100.0	100.0	100.0	100.0

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys, Sales of Fuel and Kerosene, Annual 1970-1974.

By contrast, the Gulf Coast has shown dramatic increases in its residual fuel oil consumption. This district's usage grew at an overall rate of 29 percent per year from 1970 to 1973, and grew 35 percent in 1974, which predominantly reflects the decreased availability of natural gas supplies. The Rocky Mountain region, although a relatively small consumer, had a rate of demand growth above 30 percent for 1974.

It is possible to identify some of the driving forces in the changing demand picture by reviewing the distinct usage patterns for the individual regions. Table C.4-6 presents the actual levels of demand for the five PAD Districts; illustrative distribution and growth calculations appear on Tables C.4-7 and C.4-8.

Comparative analysis of regional end-usage for the years 1970 and 1974 reveals some of the apparent demand trends. (See Table C.4-7.) The most striking variation in the usage pattern over this period is evidenced by the continuing erosion of the East Coast's (District I) dominant position in its demand share in all the end-use categories. Thus by 1974, the Gulf Coast had increased its share for every category, and, in fact, assumed the position of largest regional consumer of residual fuel oil for transportation purposes with 43% of Transportation demand occurring in District III. This reflects the cheaper cost of Bunker C relative to the Caribbean, where international crude prices (as opposed to domestically-controlled crude prices) set the market price.

While Transportation remains the major use of residual fuel oil within District III, its share of the district total has declined relative to other sectors, especially Electric Utilities. The shift in Electric Utility usage towards residual fuel oil is the result of the declining availabilities of natural gas. At the end of 1972, 95 percent of all generating equipment in service in the region serviced by the Southwest Power Pool and the Electric Reliability Council of Texas was designed

Table C.4-6

Profiles of Regional Residual Fuel Oil Demand, by End Use Category, 1970-1974
(MMBBLS)

	1970	1971	1972	1973	1974
Residential/Commercial	151.0	152.0	155.5	156.9	122.7
Industrial	109.6	107.8	111.8	116.9	107.1
Electric Utilities	271.0	301.8	354.5	369.0	343.6
Transportation	41.8	39.3	39.2	42.5	31.7
Other	23.3	25.0	25.5	23.2	17.2
District I Total	596.8	625.9	686.6	708.4	622.2
Residential/Commercial	22.7	17.6	19.8	19.1	23.2
Industrial	33.1	27.9	40.3	42.6	40.0
Electric Utilities	12.8	18.7	17.1	22.3	21.1
Transportation	2.2	1.1	1.3	1.4	2.0
Other	1.9	1.0	1.6	1.6	1.5
District II Total	72.6	66.3	80.1	87.1	87.7
Residential/Commercial	0.7	0.6	1.4	2.7	6.4
Industrial	4.6	3.7	6.6	14.1	16.9
Electric Utilities	2.7	5.5	5.2	19.9	23.1
Transportation	21.5	16.6	16.9	27.2	39.4
Other	2.1	1.2	1.7	4.3	6.6
District III Total	31.7	27.6	31.8	68.2	92.4
Residential/Commercial	1.6	1.7	1.7	1.9	3.2
Industrial	4.5	4.8	5.5	6.0	7.3
Electric Utilities	2.1	2.3	1.9	1.1	0.9
Transporation	0.6	0.3	0.3	0.3	0.3
Other	0.4	0.2	0.2	0.2	0.6
District IV Total	9.2	9.3	9.6	9.5	12.5
Residential/Commercial	9.8	10.2	12.7	11.7	11.8
Industrial	26.2	24.7	22.5	23.3	22.8
Electric Utilities	23.8	43.5	56.7	97.2	86.6
Transportation	25.9	22.7	21.4	22.2	18.9
Other	8.4	7.9	4.5	2.6	3.0
District V Total	94.0	109.0	117.6	157.0	143.1

Note: Columns may not sum to totals due to rounding.

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys: Sales of Fuel Oil and Kerosene, Annual, 1970-1974.

Table C.4-7

Residual Fuel Oil Demand by
End-Use Category by District, 1970 and 1974

	1970 PAD Districts					
End-Use Category	I	II	III	IV	V	U.S. Total
Residential/Commercial	81.2%	12.2	0.4	0.9	5.3	100.0
Industrial	61.6	18.6	2.6	2.5	14.7	100.0
Electric Utilities	86.7	4.1	0.9	0.7	7.6	100.0
Transportation	45.4	2.4	23.3	0.7	28.1	100.0
Other	64.7	5.3	5.8	1.1	23.3	100.0
Total Residual Fuel Oil	74.2	9.0	3.9	1.1	11.7	100.0

	1974 PAD Districts					
End-Use Category	I	II	III	IV	V	U.S. Total
Residential/Commercial	73.3	13.9	3.8	1.9	7.0	100.0
Industrial	55.2	20.6	8.7	3.8	11.7	100.0
Electric Utilities	72.3	4.4	4.9	0.2	18.2	100.0
Transportation	34.3	2.2	42.7	0.3	20.5	100.0
Other	59.5	5.2	22.8	2.1	10.4	100.0
Total Residual Fuel Oil	65.0	9.2	9.6	1.3	14.9	100.0

Note: Columns may not sum to 100.0 due to rounding.

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys: Sales of Fuel Oil and Kerosene, Annual, 1970, 1974, reflects data shown in Tables I.B-4. and I.B-5.

Table C.4-8

Growth Profile of Regional Fuel Oil Demand by End-Use Category, 1970-1974

	Percentage distribution by end use					Average Annual Rates of Growth in Demand	
	1970	1971	1972	1973	1974	1970-73	1973-74
Residential/Commercial	25.3	24.3	22.6	22.1	19.7	1.3	-21.8
Industrial	18.4	17.2	16.3	16.5	17.2	2.2	- 8.4
Electric Utilities	45.4	48.2	51.6	52.1	55.2	10.8	- 6.7
Transportation	7.0	6.3	5.7	6.0	5.1	0.6	-25.4
Other	3.9	4.0	3.7	3.3	2.8	- 0.1	-25.9
District I Total	100.0	100.0	100.0	100.0	100.0	5.9	-12.2
Residential/Commercial	31.3	26.6	24.7	21.9	26.5	- 5.6	21.5
Industrial	45.6	42.1	50.3	48.9	45.6	8.8	- 6.1
Electric Utilities	17.6	28.2	21.3	25.6	24.1	20.3	- 5.4
Transportation	3.0	1.7	1.6	1.6	2.3	-14.0	42.9
Other	2.6	1.5	2.0	1.8	1.7	- 5.6	- 6.2
District II Total	100.0	100.0	100.0	100.0	100.0	6.3	0.7
Residential/Commercial	2.2	2.2	4.4	4.0	6.9	57.0	137.0
Industrial	14.5	13.4	20.8	20.7	18.3	45.0	19.9
Electric Utilities	8.5	19.9	16.3	29.2	25.0	95.0	16.1
Transportation	67.8	60.1	53.1	39.9	42.6	8.2	44.9
Other	6.6	4.3	5.3	6.3	7.1	27.0	53.5
District III Total	100.0	100.0	100.0	100.0	100.0	29.2	35.4
Residential/Commercial	17.4	18.3	17.7	20.0	26.0	5.9	68.4
Industrial	48.9	51.6	57.3	63.2	59.3	10.1	21.7
Electric Utilities	22.8	24.7	19.8	11.6	7.3	-19.4	-19.2
Transportation	6.5	3.2	3.1	3.2	2.4	-21.0	0.0
Other	4.3	2.2	2.1	2.1	4.9	-21.0	200.0
District IV Total	100.0	100.0	100.0	100.0	100.0	0.9	31.7
Residential/Commercial	10.4	9.4	10.8	7.5	8.2	6.1	0.9
Industrial	27.9	22.7	19.1	14.8	15.9	- 3.8	- 2.1
Electric Utilities	25.3	39.9	48.2	61.9	60.5	60.0	-10.9
Transportation	27.6	20.8	18.2	14.1	13.2	- 5.0	-14.9
Other	8.9	7.2	3.8	1.7	2.1	-32.0	15.4
District V Total	100.0	100.0	100.0	100.0	100.0	18.7	- 8.9

Note: Percentage columns may not sum to 100.0 due to rounding.

Source: U.S. Department of Interior, Bureau of Mines, Mineral Industry Surveys: Sales of Fuel Oil and Kerosene, Annual, 1970-1974.

strictly for continuous operation on natural gas. In response to increasingly heavy curtailments of gas supply for power plant use, these electric utility groups lessened their natural gas dependency primarily by shifting to oil. Hence, use of residual fuel oil by utilities in District III expanded at an average annual rate of approximately 95 percent over the three year period 1970-1973. (See Table C.4-8.) Since the oil embargo, the area has tried to limit further dependence on oil; this is reflected in the 1973-1974 rate of change, which moderated substantially to 16 percent, vis-à-vis more than tripling in 1972-1973.

Another distinguishing feature of the Gulf Coast's usage of residual fuel oil is that it was the only district not to register a decline in at least one of its major consumption categories, again because natural gas supplies were being curtailed. In direct contrast, the East Coast showed significant declines in residual fuel oil usage in every category in 1974, as compared with 1973, again reflecting the warmer heating season, the economic slowdown, and conservation measures.

In all Districts except District IV (Rocky Mountain), Electric Utilities usage showed the highest rate of growth from 1970-1973 of any of the end-use categories. In the Rocky Mountain region, Industrial use captured that rank. Interestingly, Industrial Users in the Rocky Mountain region expanded their demand for residual fuel oil faster than comparable users in other districts, due to the acute natural gas supply situation in that area of the country.

C.4.4.3 State Detail on Demand for Residual Fuel Oil by End-Use Category

Detailed data on the level of residual fuel oil demand at the state and district level for the years 1970-1974 are presented in Tables C.4-9 through C.4-14. State information is provided for each of the end-use categories in the following order:

C.4-9 Total Demand, all end-use categories

C.4-10 Residential/Commercial Demand

C.4-11 Industrial Demand

C.4-12 Electric Utilities Demand

C.4-13 Transportation Demand

C.4-14 Other Demand

As shown in Table C.4-9, there were only two states which consumed in excess of 100 million barrels of residual fuel oil in 1974; they were New York (in District I), with 153 million barrels, and California (District V), with 106 million barrels. Together, these two states represented 27 percent of the total U.S. demand in that year, although they have only 19 percent of the U.S. population.

If New England is regarded as one "state", it, too, would have a 1974 level of demand which surpassed the 100 million barrels mark (134 million barrels). This would push the combined demand of large consumer-states to approximately 40 percent of the national total. By comparison, total district demand for Districts II, III, and IV were all less than 100 million barrels and these districts represent 26 of the 50 states.

There were three states consuming between 50-100 million barrels of residual fuel oil in 1974. They were Florida (75 million barrels), New Jersey (64 million barrels), and Pennsylvania (56 million barrels); all three states are in District I. All together, the six "states" mentioned account for approximately 60 percent of the U.S. total demand. A summary of the demand breakdown for these states is presented in Table C-4-9.

By individual, end-use categories, other states qualify as the leading users. This is especially evident in Transportation, in which Texas and Louisiana represent over one-third of the national total; virtually all of these states' transportation demand for residual fuel oil is for tanker traffic using Bunker C.

Table C.4-9

Total Sales of Residual Type Fuel Oils in the United States
(MBBLS)

	1970	1971	1972	1973	1974	1975
District I						
New England						
Connecticut	36,057	34,564	40,706	43,180	38,223	
Maine	11,693	18,331	21,365	19,860	15,272	
Massachusetts	86,063	82,917	87,930	86,282	69,385	
New Hampshire	5,514	6,016	5,961	5,382	4,786	
Rhode Island	9,739	10,036	9,811	8,376	6,216	
Vermont	903	898	954	876	535	
Subtotal New England	149,969	152,762	166,727	163,956	134,417	14.0%
Delaware	6,581	6,194	9,640	13,117	12,632	
Washington, D.C.	11,148	10,748	10,656	11,200	7,037	
Florida	55,169	62,414	76,325	82,873	75,440	
Georgia	10,255	10,488	12,960	13,888	12,954	
Maryland	22,446	30,059	38,273	42,534	38,910	
New Jersey	80,840	75,213	80,761	79,204	63,917	
New York	152,487	159,069	164,123	169,669	152,627	
North Carolina	6,922	10,433	15,926	15,393	13,819	
Pennsylvania	60,389	59,973	58,490	59,371	56,101	
South Carolina	5,328	5,493	6,395	9,636	9,577	
Virginia	33,236	40,565	44,530	46,123	43,074	
W. Virginia	2,064	1,906	1,748	1,448	1,709	
District I Total	596,834	625,857	686,554	708,412	622,214	
Total U.S.	804,287	838,044	925,647	1,030,177	957,811	

Table C.4-9 - Total Sales of Residual Type Fuel Oils in the United States (MBBLS) (Cont'd)

	1970	1971	1972	1973	1974	1975
District II						
Illinois	28,618	23,708	29,581	28,795	28,532	
Indiana	9,757	12,194	14,326	15,536	16,078	
Iowa	408	411	325	679	628	
Kansas	1,247	827	1,974	2,847	2,660	
Kentucky	1,061	674	1,159	1,094	2,084	
Michigan	10,059	11,605	11,388	14,560	14,876	
Minnesota	5,150	4,075	6,943	7,069	5,883	
Missouri	3,615	2,904	2,552	2,959	2,375	
Nebraska	798	597	706	639	1,045	
North Dakota	726	645	781	898	1,190	
Ohio	6,532	5,259	5,840	6,866	8,330	
Oklahoma	744	637	1,355	1,629	1,201	
South Dakota	348	227	335	234	137	
Tennessee	596	365	523	650	883	
Wisconsin	2,927	2,133	2,296	2,633	1,787	
District II Total	72,586	66,261	80,084	87,088	87,689	
Total U.S.		838,044	925,647	1,030,177	957,811	
District III						
Alabama	3,283	2,601	3,170	6,151	10,496	
Arkansas	1,584	2,887	3,183	10,720	10,369	
Louisiana	11,270	8,384	8,667	16,952	24,478	
Mississippi	896	1,074	2,365	3,955	7,436	
New Mexico	215	466	621	1,220	1,714	
Texas	14,440	12,205	13,751	29,208	37,878	
District III Total	31,688	27,617	31,757	68,206	92,371	

Table C.4-9 -Total Sales of Residual Type Fuel Oils in the United States (MBBLS) (Cont'd)

	1970	1971	1972	1973	1974	1975
District IV						
Colorado	1,531	1,572	1,984	2,317	3,179	
Idaho	276	276	246	243	597	
Montana	1,249	1,236	1,485	1,705	2,290	
Utah	4,657	5,030	4,538	3,649	4,295	
Wyoming	1,482	1,233	1,369	1,542	2,091	
District IV Total	9,195	9,347	9,622	9,456	12,452	
District V						
Alaska	1,034	1,043	1,166	1,051	1,098	
Arizona	94	723	1,139	4,288	6,943	
California	65,503	80,467	83,978	121,059	105,814	
Hawaii	10,162	10,631	11,316	11,580	11,495	
Nevada	144	272	242	612	690	
Oregon	6,679	6,538	7,977	7,439	6,650	
Washington	10,368	9,288	11,812	10,986	10,395	
District V Total	93,984	108,962	117,630	157,015	143,085	
Total U.S.	804,287	838,044	925,647	1,030,177	957,811	

Source: U.S. Department of Interior, Bureau of Mines, Annual Fuel Oil Sales.

Table C.4-10

Use of Residual Type Fuel Oils in the United States for Residential/Commercial Purposes for PAD District I by State, 1970-1975
(MBBLS)

State	No. 5 1970	No. 5 1971	No. 5 1972	No. 5 1973	No. 5 1974	No. 5 1975	No. 6 1970	No. 6 1971	No. 6 1972	No. 6 1973	No. 6 1974	No. 6 1975	Total 1970	Total 1971	Total 1972	Total 1973	Total 1974
New England																	
Connecticut	47	56	61	68	50		4,710	4,606	4,916	5,431	4,379		4,757	4,662	4,977	5,499	4,429
Maine	675	894	867	794	423		2,221	3,055	3,151	3,026	2,220		2,896	3,949	4,018	3,820	2,643
Massachusetts	8,104	7,684	8,086	7,921	5,293		22,562	21,655	22,694	22,491	18,577		30,666	29,339	30,780	30,412	23,870
New Hampshire	422	456	510	488	249		659	1,027	1,613	1,413	943		1,081	1,483	2,123	1,901	1,192
Rhode Island	830	1,067	1,203	1,200	520		1,473	2,085	2,221	2,224	1,715		2,303	3,152	3,424	3,424	2,235
Vermont	67	36	30	30	20		329	395	504	432	274		396	431	534	462	294
Subtotal New England	10,145	10,193	10,757	10,501	6,555		31,954	32,823	35,099	35,017	28,108		42,099	43,016	45,856	45,518	34,663
Delaware	258	212	244	285	85		260	252	252	781	414		518	464	496	1,066	499
District of Columbia	751	661	518	559	317		7,536	6,858	5,190	4,618	2,350		8,287	7,519	5,708	5,177	2,667
Florida	127	53	31	20	70		1,539	1,631	2,696	2,725	2,124		1,666	1,684	2,727	2,745	2,194
Georgia	1,079	1,144	890	875	417		807	1,614	1,687	1,617	1,522		1,886	2,758	2,577	2,492	1,939
Maryland	1,474	1,710	1,742	1,936	1,120		3,812	3,774	3,777	3,942	3,082		5,286	5,484	5,519	5,878	4,202
New Jersey	1,984	2,262	2,592	2,480	1,325		12,233	11,377	11,301	11,477	9,528		14,217	13,639	13,893	13,957	10,853
New York	1,483	1,824	1,384	1,300	625		58,274	57,291	57,768	58,110	49,055		59,757	59,115	59,152	59,410	49,680
North Carolina	696	931	1,020	1,302	928		618	880	809	895	819		1,314	1,811	1,829	2,197	1,747
Pennsylvania	6,552	6,554	7,216	7,471	5,145		6,998	7,626	8,068	8,336	7,420		13,550	14,180	15,284	15,807	12,565
South Carolina	132	119	152	245	227		122	20	55	55	53		254	139	207	300	280
Virginia	349	461	457	480	286		1,301	1,039	1,282	1,421	965		1,650	1,500	1,739	1,901	1,251
West Virginia	507	577	488	285	118		54	65	71	122	58		561	642	559	407	176
District Total	25,537	26,701	27,491	27,739	17,218		125,508	125,250	128,055	129,116	105,498		151,045	151,951	155,546	156,855	122,716
Total U.S.	42,837	39,181	41,108	41,120	32,922		142,994	142,881	150,003	151,132	134,493		185,831	182,062	191,111	192,252	167,415

Table C.4-10 (Cont'd)

Use of Residual Type Fuel Oils in the United States for Residential/Commercial Purposes for PAD District II by State, 1970-1975
(MBBLS)

	No. 5						No. 6						Total					
State	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
Illinois	7,431	3,359	4,163	3,906	4,120		6,915	5,598	6,045	5,642	6,472		14,346	8,957	10,208	9,548	10,592	
Indiana	532	384	592	468	553		1,785	3,923	3,379	3,186	4,343		2,317	4,307	3,971	3,654	4,896	
Iowa	94	101	82	77	51		66	81	42	226	394		160	182	124	303	445	
Kansas	104	86	23	94	47		127	65	36	38	34		231	151	59	132	81	
Kentucky	7	--	--	--	--		109	128	152	211	315		116	128	152	211	315	
Michigan	284	264	356	473	576		718	352	691	717	904		1,002	616	1,047	1,190	1,480	
Minnesota	668	394	410	390	369		325	221	411	399	434		993	615	821	789	803	
Missouri	1,032	763	740	588	562		727	531	422	508	577		1,759	1,294	1,162	1,096	1,139	
Nebraska	77	63	99	72	95		53	51	106	170	138		130	114	205	242	233	
North Dakota	33	40	93	116	381		36	18	130	187	356		69	58	223	303	737	
Ohio	107	111	117	114	316		383	207	713	580	915		490	318	830	694	1,231	
Oklahoma	33	66	32	50	9		32	72	54	55	59		65	138	86	105	68	
South Dakota	10	2	4	3	2		5	--	--	--	--		15	2	4	3	2	
Tennessee	5	--	16	20	95		10	2	270	182	395		15	2	286	202	490	
Wisconsin	635	417	313	243	303		330	273	288	380	385		965	690	601	623	688	
District Total	11,052	6,056	7,040	6,614	7,479		11,621	11,522	12,739	12,481	15,721		22,673	17,572	19,779	19,095	23,200	
U.S. Total	42,837	39,181	41,108	41,120	32,922		142,994	142,881	150,003	151,132	134,493		185,831	182,062	191,111	192,252	167,415	

Table C.4-10 (Cont'd)

Use of Residual Type Fuel Oils in the United States for Residential/Commercial Purposes for PAD Districts III, IV, and V, by State, 1970-1975
(MBBLS)

District/	No. 5						No. 6						Total					
State	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
District III																		
Alabama	78	78	201	524	1,093		-	-	123	449	956		78	78	324	973	2,049	
Arkansas	-	-	18	67	285		-	-	254	400	878		-	-	272	467	1,163	
Louisiana	5	1	2	4	22		11	-	8	11	75		16	1	10	15	97	
Mississippi	5	-	-	-	-		44	44	100	66	223		49	44	100	66	223	
New Mexico	2	1	-	7	45		1	1	21	60	184		3	2	21	67	229	
Texas	17	22	25	63	386		537	485	647	1,091	2,264		554	507	672	1,154	2,650	
District Total	107	102	246	665	1,831		593	530	1,153	2,077	4,580		700	632	1,399	2,742	6,411	
District IV																		
Colorado	129	101	54	56	193		212	207	480	555	798		341	308	534	611	991	
Idaho	57	52	58	53	216		61	100	110	112	266		118	152	168	165	482	
Montana	163	158	163	161	244		20	19	46	47	132		183	177	209	208	376	
Utah	306	393	339	315	389		362	386	186	242	498		668	779	525	557	867	
Wyoming	177	147	87	88	147		163	181	214	230	380		340	328	301	318	527	
District Total	832	851	701	673	1,189		818	893	1,036	1,186	2,054		1,650	1,744	1,737	1,859	3,243	
District V																		
Alaska	5	-	-	-	-		30	22	20	13	11		35	22	20	13	11	
Arizona	7	2	-	-	-		7	3	-	-	-		14	5	-	-	-	
California	939	704	417	596	683		1,444	1,478	3,064	3,573	4,312		2,383	2,182	3,481	4,169	4,995	
Hawaii	114	81	113	65	33		141	100	10	19	158		255	181	123	84	191	
Nevada	23	52	72	66	50		17	21	17	15	28		40	73	89	81	78	
Oregon	1,971	2,365	2,605	2,586	2,385		1,336	1,564	1,908	1,220	1,153		3,307	3,929	4,513	3,806	3,538	
Washington	2,250	2,273	2,423	2,116	2,054		1,479	1,498	2,001	1,432	978		3,729	3,771	4,424	3,548	3,032	
Dist. Total	5,309	5,477	5,630	5,429	5,205		4,454	4,686	7,020	6,272	6,640		9,763	10,163	12,650	11,701	11,845	
Total U.S.	42,837	39,181	41,108	41,120	32,922		142,994	142,881	150,003	151,132	134,493		185,831	182,062	191,111	192,252	167,415	

Note: Residential/Commercial includes No. 5 and 6 heating oils; data reflect sales.

Source: U.S. Department of Interior, Bureau of Mines, Annual Fuel Oil Sales.

Table C.4-11

Use of Residual Type Fuel Oils in the United States for Industrial Purposes, for PAD District I, by State, 1970-1975
(MBBLS)

State	General Industry						Oil Companies, exc. Actual Refining						Total Industrial					
	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
New England:																		
Connecticut	9,800	7,109	7,036	7,103	6,100		81	83	87	176	147		9,881	7,192	7,123	7,279	6,247	
Maine	2,494	7,970	8,237	7,519	6,964		17	12	64	36	21		2,511	7,982	8,301	7,555	6,985	
Massachusetts	9,689	7,659	7,249	7,901	6,887		109	90	62	115	111		9,798	7,749	7,311	8,016	6,998	
New Hampshire	1,823	1,896	1,580	1,449	1,301		1	--	2	2	3		1,824	1,896	1,582	1,451	1,304	
Rhode Island	1,727	1,337	1,398	1,220	1,212		68	48	49	29	39		1,795	1,385	1,447	1,249	1,251	
Vermont	480	446	397	403	233		1	--	1	2	2		481	446	398	405	235	
Sub Total New England	26,013	26,417	25,897	25,595	22,697		277	233	265	360	323		26,290	26,650	26,162	25,955	23,020	
Delaware	3,358	3,312	3,371	3,442	2,289		72	59	31	229	129		3,430	3,371	3,402	3,671	2,418	
District of Columbia	60	75	119	63	47		7	48	7	7	9		67	123	126	70	56	
Florida	6,620	6,157	7,248	8,218	7,479		305	523	223	338	191		6,925	6,680	7,471	8,556	7,670	
Georgia	6,619	5,445	6,449	7,114	6,590		1	--	89	152	54		6,620	5,445	6,538	7,266	6,644	
Maryland	2,111	6,832	6,981	7,063	4,896		491	427	191	497	204		2,602	7,259	7,172	7,560	5,100	
New Jersey	12,951	9,252	9,015	9,441	8,746		6,654	5,987	4,795	5,759	5,564		19,605	15,239	13,810	15,200	14,310	
New York	16,516	9,619	9,212	9,481	8,551		112	178	526	697	972		16,628	9,797	9,738	10,178	9,523	
North Carolina	4,221	6,766	9,534	7,288	6,997		58	46	41	66	42		4,279	6,812	9,575	7,354	7,039	
Pennsylvania	13,239	12,048	10,818	11,920	11,614		5,340	5,287	6,023	6,698	7,896		18,579	17,335	16,841	18,618	19,510	
South Carolina	1,152	2,778	3,486	3,746	3,093		118	112	101	186	135		1,270	2,890	3,587	3,932	3,228	
Virginia	2,015	4,948	6,659	7,933	8,012		258	420	139	201	161		2,273	5,368	6,798	8,134	8,173	
W. Virginia	1,055	800	495	323	304		10	2	50	62	60		1,065	802	545	385	364	
District Total	95,930	94,449	99,284	101,627	91,315		13,703	13,322	12,481	15,252	15,740		109,633	107,771	111,765	116,879	107,055	
U.S. Total	139,647	136,221	142,320	152,267	143,726		38,318	32,626	44,291	50,652	50,236		177,965	168,847	186,611	202,919	193,962	

Table C.4-11 (Cont'd)

Use of Residual Type Fuel Oils in the United States for Industrial Purposes, for PAD District II, by State, 1970-1975
(MBBLS)

State	General Industry						Oil Companies, exc. Actual Refining						Total Industrial					
	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
Illinois	5,907	4,083	4,007	4,455	4,178		3,400	2,948	7,547	7,604	7,396		9,307	7,031	11,554	12,059	11,574	
Indiana	2,213	3,714	4,184	5,310	4,781		4,625	3,440	5,549	5,812	5,894		6,838	7,154	9,733	11,122	10,675	
Iowa	60	57	123	125	137		--	--	--	--	--		60	57	123	125	137	
Kansas	460	300	533	499	380		28	25	940	992	906		488	325	1,473	1,491	1,286	
Kentucky	595	200	50	59	539		50	25	620	700	1,040		645	225	670	759	1,579	
Michigan	3,097	2,657	3,232	2,604	2,166		911	620	628	657	703		4,008	3,277	3,860	3,261	2,869	
Minnesota	2,327	2,041	4,365	3,894	3,242		909	709	869	988	720		3,236	2,750	5,234	4,882	3,962	
Missouri	1,156	990	505	511	471		298	267	410	715	516		1,454	1,257	915	1,226	987	
Nebraska	199	171	79	42	96		12	20	63	55	50		211	191	142	97	146	
North Dakota	74	38	10	10	14		487	303	518	579	421		561	341	528	589	435	
Ohio	3,111	2,767	1,758	2,256	2,324		1,240	1,041	2,083	2,148	1,825		4,351	3,808	3,841	4,404	4,149	
Oklahoma	335	289	703	953	758		186	82	219	321	206		521	371	922	1,274	964	
South Dakota	31	23	67	53	47		--	7	18	15	13		31	30	85	68	60	
Tennessee	571	354	233	264	300		1	--	--	45	19		572	354	233	309	319	
Wisconsin	667	587	765	655	562		116	154	246	319	269		783	741	1,011	974	831	
District II Total	20,803	18,271	20,614	21,690	19,995		12,263	9,641	19,710	20,950	19,978		33,066	27,912	40,324	42,640	39,973	
U.S. Total	139,647	136,221	142,320	152,267	143,726		38,318	32,626	44,291	50,652	50,236		177,965	168,847	186,611	202,919	193,962	

Table C.4-11 (Cont'd)

Use of Residual Type Fuel Oils in the United States for Industrial Purposes for PAD Districts III, IV, and V, by State, 1970-1975
(MBBLS)

District/State	General Industry						Oil Companies, exc. Actual Refining						Total Industrial					
	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
District III																		
Alabama	1,410	970	1,033	2,014	2,109		21	21	151	200	203		1,431	991	1,184	2,214	2,312	
Arkansas	165	163	576	1,445	2,262		17	17	184	442	223		182	180	760	1,887	2,485	
Louisiana	960	930	1,005	2,045	2,775		105	210	159	326	639		1,065	1,140	1,164	2,371	3,414	
Mississippi	22	11	270	719	950		195	53	597	685	322		217	64	867	1,404	1,272	
New Mexico	2	2	163	472	575		10	15	13	50	113		12	17	176	522	688	
Texas	507	401	1,785	3,280	4,750		1,184	947	620	2,452	1,955		1,691	1,348	2,405	5,732	6,705	
District III Total	3,066	2,477	4,832	9,975	13,421		1,532	1,263	1,724	4,155	3,455		4,598	3,740	6,556	14,130	16,876	
District IV																		
Colorado	656	774	730	742	878		54	81	120	180	252		710	855	850	922	1,130	
Idaho	116	116	70	66	91		--	--	--	--	--		116	116	70	66	91	
Montana	109	225	227	243	465		792	732	967	1,112	1,307		901	957	1,194	1,355	1,772	
Utah	1,870	2,007	1,953	1,974	2,336		265	276	738	737	799		2,135	2,283	2,691	2,711	3,135	
Wyoming	252	257	130	301	288		371	304	573	639	871		623	561	703	940	1,159	
District IV Total	3,003	3,379	3,110	3,326	4,058		1,482	1,393	2,398	2,668	3,229		4,485	4,772	5,508	5,994	7,287	
District V																		
Alaska	770	762	842	640	679		17	15	3	2	21		787	777	845	642	700	
Arizona	36	72	69	240	287		--	--	2	1	4		36	72	71	241	291	
California	10,613	11,724	6,028	6,466	6,296		6,925	4,640	5,364	5,495	5,810		17,538	16,364	11,392	11,961	12,106	
Hawaii	530	466	551	595	305		776	737	744	563	639		1,306	1,203	1,295	1,158	944	
Nevada	17	17	74	40	34		--	--	--	--	--		17	17	74	40	34	
Oregon	1,826	1,662	2,793	3,060	2,581		292	274	283	189	185		2,118	1,936	3,076	3,249	2,766	
Washington	3,053	2,942	4,123	4,608	4,755		1,328	1,341	1,582	1,377	1,175		4,381	4,283	5,705	5,985	5,930	
District V Total	16,845	17,645	14,480	15,649	14,937		9,338	7,007	7,978	7,627	7,834		26,183	24,652	22,458	23,276	22,771	
U.S. Total	139,647	136,221	142,320	152,267	143,726		38,318	32,626	44,291	50,652	50,236		177,959	168,847	186,611	202,919	193,962	

Note: Data reflect sales.

Source: U.S. Department of Interior, Bureau of Mines, Annual Fuel Oil Sales.

Table C.4-12

Sales of Residual Type Fuel Oils in the United States for Electric Utility Company Use, in PAD Districts I and II, by State, 1970-1975
(MBBLS)

District/State	1970	1971	1972	1973	1974	1975
District I						
New England:						
Connecticut	21,025	22,221	27,963	29,380	26,782	
Maine	4,872	4,764	5,542	4,900	3,982	
Massachusetts	42,327	42,387	46,284	44,751	36,929	
New Hampshire	2,538	2,601	2,215	2,009	2,262	
Rhode Island	3,017	2,598	2,655	2,375	1,886	
Vermont	23	18	17	4	1	
Subtotal New England	73,802	74,589	84,676	83,419	71,842	
Delaware	1,541	1,612	4,162	5,915	7,611	
District of Columbia	2,776	3,097	4,673	5,438	3,509	
Florida	43,335	51,606	64,050	68,755	63,070	
Georgia	1,536	2,120	3,572	3,489	3,715	
Maryland	10,371	13,768	22,038	25,260	25,888	
New Jersey	37,826	36,593	41,193	40,090	32,488	
New York	57,224	72,075	79,855	82,605	81,094	
North Carolina	603	1,311	4,048	5,497	4,785	
Pennsylvania	22,535	22,046	20,055	17,504	17,137	
South Carolina	2,041	921	1,385	4,126	5,342	
Virginia	16,982	21,632	24,171	26,284	25,960	
W. Virginia	432	461	643	584	1,136	
District I Total	271,004	301,831	354,521	368,971	343,577	
Total U.S.	312,420	371,820	435,348	509,457	475,204	

	1970	1971	1972	1973	1974	1975
District II						
Illinois	3,942	7,014	7,139	6,513	5,692	
Indiana	212	453	397	566	82	
Iowa	57	119	78	251	46	
Kansas	506	331	304	1,098	1,222	
Kentucky	121	271	333	121	188	
Michigan	4,528	7,594	5,862	9,347	9,796	
Minnesota	843	678	751	975	622	
Missouri	185	302	341	492	79	
Nebraska	194	105	155	118	483	
North Dakota	25	213	26	2	16	
Ohio	796	733	825	1,529	2,446	
Oklahoma	3	55	25	193	142	
South Dakota	291	191	246	163	75	
Tennessee	--	--	--	--	--	
Wisconsin	1,127	655	610	960	181	
District II Total	12,830	18,714	17,092	22,328	21,070	
Total U.S.		371,820	435,348	509,457	475,204	

Table C.4-12 (Cont'd)

Sales of Residual Type Fuel Oils in the United States for Electrical Utility Company Use, in PAD Districts III, IV and V, by State, 1970-1975
(MBBLS)

District/State	1970	1971	1972	1973	1974	1975
District III						
Alabama	--	--	--	--	--	--
Arkansas	1,347	2,652	2,081	8,229	6,521	
Louisiana	273	905	959	3,694	5,449	
Mississippi	609	934	1,244	2,054	5,200	
New Mexico	81	386	396	389	373	
Texas	428	611	506	5,508	5,527	
District III Total	2,738	5,488	5,186	19,874	23,070	
District IV						
Colorado	269	284	484	646	629	
Idaho	--	--	--	--	--	
Montana	9	--	16	71	3	
Utah	1,775	1,890	1,272	327	126	
Wyoming	9	82	111	72	169	
District IV Total	2,062	2,256	1,883	1,116	927	
District V						
Alaska	21	4	2	6	3	
Arizona	8	599	936	3,903	6,515	
California	16,871	35,218	47,340	84,183	70,613	
Hawaii	6,717	7,434	8,236	8,523	8,790	
Nevada	81	181	75	485	571	
Oregon	79	94	17	14	--	
Washington	9	1	60	54	68	
District V Total	23,786	43,531	56,666	97,168	86,560	
Total U.S.	312,420	371,820	435,348	509,457	475,204	

Note: Data are based on Federal Power Commission Statistics.
Data for 1972 exclude approximately 13,000,000 barrels of distillate fuel oil used at steam-electric plants; data for this fuel use, formerly included as a residual fuel oil sale have been reclassified as a distillate fuel oil sale since 1972.

Source: U.S. Dept. of Interior, Bureau of Mines, Annual Fuel Oil Sales.

Table C.4-13

Use of Residual Type Fuel Oils in the United States for Transportation Purposes for PAD District I by State 1970-1975
(MBBLS)

State	Railroad 1970	Railroad 1971	Railroad 1972	Railroad 1973	Railroad 1974	Railroad 1975	Vessel Bunkering 1970	Vessel Bunkering 1971	Vessel Bunkering 1972	Vessel Bunkering 1973	Vessel Bunkering 1974	Vessel Bunkering 1975	Total Transportation 1970	Total Transportation 1971	Total Transportation 1972	Total Transportation 1973	Total Transportation 1974	Total Transportation 1975
New England:																		
Connecticut	10	7	-	-	-		102	102	191	714	592		112	109	191	714	592	
Maine	26	26	-	26	29		1,357	1,536	3,399	3,459	1,557		1,383	1,562	3,399	3,485	1,586	
Massachusetts	10	5	-	2	2		1,733	1,404	1,262	1,483	795		1,743	1,409	1,262	1,485	797	
New Hampshire	-	-	-	-	-		2	-	-	-	11		2	-	-	-	11	
Rhode Island	23	25	13	3	2		194	142	113	102	47		217	167	126	105	49	
Vermont	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
Subtotal New England	69	63	13	31	33		3,388	3,184	4,965	5,758	3,002		3,457	3,247	4,978	5,789	3,035	
Delaware	26	26	34	28	27		536	327	793	801	1,087		562	353	827	829	1,114	
District of Columbia	1	-	2	4	2		2	-	-	32	113		3	-	2	36	115	
Florida	9	4	-	-	-		2,067	1,291	1,521	2,458	2,223		2,076	1,295	1,521	2,458	2,223	
Georgia	8	-	-	-	-		148	121	83	396	559		156	121	83	396	559	
Maryland	1	1	2	5	2		3,517	2,638	2,642	2,988	3,013		3,518	2,639	2,644	2,993	3,015	
New Jersey	2	3	1	1	1		6,051	6,627	8,603	6,789	4,044		6,053	6,630	8,604	6,790	4,045	
New York	67	76	98	45	16		16,632	16,796	13,687	14,999	10,676		16,699	16,872	13,785	15,044	10,692	
North Carolina	7	7	5	2	1		201	76	78	143	114		208	83	83	145	115	
Pennsylvania	113	82	57	40	42		4,015	3,694	3,119	3,602	3,521		4,128	3,776	3,176	3,642	3,563	
South Carolina	10	2	2	1	2		1,386	1,275	1,009	1,028	540		1,396	1,277	1,011	1,029	542	
Virginia	7	6	7	11	8		3,581	3,044	2,496	3,344	2,643		3,588	3,050	2,503	3,355	2,651	
W. Virginia	5	-	-	-	-		-	-	-	-	-		5	-	-	-	-	
District I Total	325	270	221	168	134		41,524	39,073	38,996	42,338	31,535		41,849	39,343	39,217	42,506	31,669	
Total U.S.	2,222	1,262	1,137	1,214	1,176		89,850	78,727	77,932	92,415	91,128		92,072	79,989	79,069	93,629	92,304	

Table C.4-13 (Cont'd)

Use of Residual Type Fuel Oils in the United States for Transportation Purposes for PAD District II by State 1970-1975
(MBBLS)

State	Railroad 1970	Railroad 1971	Railroad 1972	Railroad 1973	Railroad 1974	Railroad 1975	Vessel Bunkering 1970	Vessel Bunkering 1971	Vessel Bunkering 1972	Vessel Bunkering 1973	Vessel Bunkering 1974	Vessel Bunkering 1975	Total Transportation 1970	Total Transportation 1971	Total Transportation 1972	Total Transportation 1973	Total Transportation 1974	Total Transportation 1975
Illinois	177	59	117	122	129		84	123	92	83	96		261	182	209	205	225	
Indiana	104	52	--	--	--		192	165	166	103	261		296	217	166	103	261	
Iowa	26	6	--	--	--		--	--	--	--	--		26	6	--	--	--	
Kansas	2	13	26	41	29		--	--	--	--	12		2	13	26	41	41	
Kentucky	144	48	--	--	--		1	1	4	3	2		145	49	4	3	2	
Michigan	70	43	88	30	133		352	33	189	211	242		422	76	277	341	375	
Minnesota	18	2	7	8	9		1	--	110	401	487		19	2	117	409	496	
Missouri	10	10	4	5	6		--	--	20	19	13		10	10	24	24	19	
Nebraska	223	171	180	166	173		--	--	--	--	--		223	171	180	166	173	
North Dakota	41	18	--	--	--		--	--	--	--	--		41	18	--	--	--	
Ohio	292	105	--	--	--		414	187	196	89	318		706	292	196	89	318	
Oklahoma	59	30	--	--	--		--	--	--	--	--		59	30	--	--	--	
South Dakota	6	4	--	--	--		--	--	--	--	--		6	4	--	--	--	
Tennessee	3	1	--	1	3		--	--	--	--	--		3	1	--	1	3	
Wisconsin	2	6	51	50	24		3	3	3	11	56		5	9	54	61	80	
District II Total	1,117	568	473	523	506		1,047	512	780	920	1,487		2,164	1,080	1,253	1,443	1,993	
U.S. Total	2,222	1,262	1,137	1,214	1,176		89,850	78,727	77,932	92,415	91,128		92,072	79,989	79,069	93,629	92,304	

Table C.4-13 (Cont'd)

Use of Residual Type Fuel Oils in the United States for Transportation Purposes for PAD Districts III, IV, and V, by State, 1970-1975
(MBBLS)

District/State	Railroad						Vessel Bunkering						Total Transportation					
District III	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
Alabama	--	--	--	--	--		1,538	1,369	1,454	2,438	5,166		1,538	1,369	1,454	2,438	5,166	
Arkansas	2	--	--	5	7		2	--	--	2	6		4	--	--	7	13	
Louisiana	5	--	--	--	--		8,678	5,687	5,746	9,109	12,886		8,683	5,687	5,746	9,109	12,886	
Mississippi	--	--	--	--	--		3	--	154	431	741		3	--	154	431	741	
New Mexico	11	7	--	--	--		--	--	--	--	--		11	7	--	--	--	
Texas	21	10	14	150	103		11,267	9,478	9,559	15,043	20,485		11,288	9,488	9,573	15,193	20,588	
District III Total	39	17	14	155	110		21,488	16,534	16,913	28,023	39,284		21,527	16,551	16,927	27,178	39,394	
District IV																		
Colorado	99	50	22	20	42		--	--	--	--	--		99	50	22	20	42	
Idaho	2	--	--	--	--		--	--	--	--	--		2	--	--	--	--	
Montana	74	40	32	28	44		--	--	--	--	--		74	40	32	28	44	
Utah	4	10	20	24	37		--	--	--	--	--		4	10	20	24	37	
Wyoming	468	234	244	200	223		--	--	--	--	--		468	234	244	200	223	
District IV Total	647	334	318	272	346		--	--	--	--	--		647	334	318	272	346	
District V																		
Alaska	8	5	6	7	6		124	220	226	313	326		132	225	232	320	332	
Arkansas	--	--	--	--	--		--	--	--	--	--		--	--	--	--	--	
California	30	25	57	54	48		21,611	19,708	18,897	19,356	16,212		21,641	19,733	18,954	19,410	16,260	
Hawaii	--	--	8	6	2		1,738	1,755	1,289	1,380	1,062		1,738	1,755	1,297	1,386	1,064	
Nevada	--	--	--	--	--		--	--	--	--	--		--	--	--	--	--	
Oregon	33	22	29	23	21		868	229	137	166	194		901	251	166	189	215	
Washington	23	21	11	6	3		1,450	696	694	919	1,028		1,473	717	705	925	1,031	
District V Total	94	73	111	96	80		25,791	22,608	21,243	22,134	18,822		25,885	22,681	21,354	22,230	18,902	
U.S. Total	2,222	1,262	1,137	1,214	1,176		89,850	78,727	77,932	92,415	91,128		--	--	--	--	--	

Source: U.S. Department of Interior, Bureau of Mines, Annual Fuel Oil Sales, Selected Years.

Table C.4-14

Sales of Residual Type Fuel Oils in the United States for Unspecified Use, (including Military) for PAD District I, by State, 1970-1975
(MBBLS)

State	Military						Miscellaneous						Total Unspecified					
	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
District I																		
New England																		
Connecticut	246	337	346	245	140		36	43	106	63	33		282	380	452	308	173	
Maine	29	30	50	50	55		2	44	55	50	21		31	74	105	100	76	
Massachusetts	1,465	1,996	1,793	1,301	673		64	37	500	317	118		1,529	2,033	2,293	1,618	791	
New Hampshire	67	35	40	20	15		2	1	1	1	2		69	36	41	21	17	
Rhode Island	2,297	2,654	2.108	1,200	787		110	80	51	23	8		2,407	2,734	2,159	1,223	795	
Vermont	2	2	2	2	3		1	1	3	3	2		3	3	5	5	5	
Subtotal New England	4,106	5,054	4,339	2,818	1,673		215	206	716	457	184		4,321	5,260	5,055	3,275	1,857	
Delaware	108	130	104	409	114		422	264	649	1,227	876		530	394	753	1,636	990	
Washington,D.C.	10	5	145	477	687		5	4	2	2	3		15	9	147	479	690	
Florida	163	346	267	225	161		1,004	803	289	134	122		1,167	1,149	556	359	283	
Georgia	16	12	155	200	77		41	32	35	45	20		57	44	190	245	97	
Maryland	405	389	669	719	692		264	520	231	124	13		669	909	900	843	705	
New Jersey	3,009	2,956	3,109	3,052	2,151		130	156	152	115	70		3,139	3,112	3,261	3,167	2,221	
New York	1,712	1,360	1,324	2,164	1,518		467	390	269	268	120		2,179	1,750	1,593	2,432	1,638	
North Carolina	136	68	50	37	79		382	348	341	163	54		518	416	391	200	133	
Pennsylvania	1,408	2,126	1,985	2,719	2,585		189	510	1,149	1,081	741		1,597	2,636	3,134	3,800	3,326	
South Carolina	206	103	90	207	141		161	163	115	42	44		367	266	205	249	185	
Virginia	8,387	8,542	8,653	6,110	4,770		356	473	666	334	269		8,743	9,015	9,319	6,444	5,039	
W. Virginia	--	--	--	--	--		1	1	1	72	33		1	1	1	72	33	
District I Total	19,666	21,091	20,890	19,137	14,648		3,637	3,870	4,615	4,064	2,549		23,303	24,961	25,505	23,201	17,197	
U.S. Total	28,704	29,217	24,622	22,892	20,423		7,295	6,109	8,886	9,028	8,503		35,999	35,326	33,508	31,920	28,926	

Table C.4-14 (Cont'd)

Sales of Residual Type Fuel Oils in the United States for Unspecified Use, (including Military) for PAD District II, by State, 1970-1975
(MBBLS)

State	Military 1970	Military 1971	Military 1972	Military 1973	Military 1974	Military 1975	Miscellaneous 1970	Miscellaneous 1971	Miscellaneous 1972	Miscellaneous 1973	Miscellaneous 1974	Miscellaneous 1975	Total Unspecified 1970	Total Unspecified 1971	Total Unspecified 1972	Total Unspecified 1973	Total Unspecified 1974	Total Unspecified 1975
District II																		
Illinois	206	167	20	68	103		616	357	451	402	346		822	524	471	470	449	
Indiana	33	18	13	26	34		61	45	46	65	130		94	63	59	91	164	
Iowa	--	--	--	--	--		105	47	--	--	--		105	47	--	--	--	
Kansas	6	--	37	25	10		14	7	75	60	20		20	7	112	85	30	
Kentucky	--	--	--	--	--		34	1	--	--	--		34	1	--	--	--	
Michigan	4	--	5	83	87		95	42	337	338	269		99	42	342	421	356	
Minnesota	10	2	--	--	--		49	28	20	14	--		59	30	20	14	--	
Missouri	153	15	30	29	65		54	26	80	92	86		207	41	110	121	151	
Nebraska	2	--	--	--	--		38	16	24	16	10		40	16	24	16	10	
North Dakota	--	--	--	--	--		30	15	4	4	2		30	15	4	4	2	
Ohio	50	23	8	8	10		139	85	140	142	176		189	108	148	150	186	
Oklahoma	16	3	297	37	15		80	40	25	20	12		96	43	322	57	27	
South Dakota	--	--	--	--	--		5	--	--	--	--		5	--	--	--	--	
Tennessee	--	--	--	131	63		6	8	4	7	8		6	8	4	138	71	
Wisconsin	1	7	--	--	--		46	31	20	15	7		47	38	20	15	7	
District II Total	481	235	410	407	387		1,372	748	1,226	1,175	1,066		1,853	983	1,636	1,582	1,453	
U.S. Total	28,704	29,217	24,622	22,892	20,423		7,295	6,109	8,886	9,028	8,503		35,999	35,326	33,508	31,920	28,926	

Table C.4-14 (Cont'd)

Sales of Residual Type Fuel Oils in the United States for Unspecified Use, (including Military) for PAD Districts III, IV, V, by State, 1970-1975
(MBBLS)

	Military						Miscellaneous						Total Unspecified					
District/State	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975	1970	1971	1972	1973	1974	1975
District III																		
Alabama	137	62	26	100	375		99	101	182	426	594		236	163	208	526	969	
Arkansas	1	--	--	--	--		50	55	70	130	187		51	55	70	130	187	
Louisiana	996	578	569	1,176	1,717		237	73	219	587	915		1,233	651	788	1,763	2,632	
Mississippi	--	--	--	--	--		18	32	--	--	--		18	32	--	--	--	
New Mexico	--	--	--	--	--		108	54	28	242	424		108	54	28	242	424	
Texas	354	145	154	524	1,044		125	106	441	1,097	1,364		479	251	595	1,621	2,408	
District III Total	1,488	785	749	1,800	3,136		637	421	940	2,482	3,484		2,125	1,206	1,689	4,282	6,620	
District IV																		
Colorado	--	--	8	37	66		112	75	86	81	321		112	75	94	118	387	
Idaho	--	--	--	--	--		40	8	8	12	24		40	8	8	12	24	
Montana	45	45	32	16	80		37	17	2	27	15		82	62	34	43	95	
Utah	21	24	10	5	19		54	44	20	25	111		75	68	30	30	130	
Wyoming	--	--	--	--	--		42	28	10	12	13		42	28	10	12	13	
District IV Total	66	69	50	58	165		285	172	126	157	484		351	241	176	215	649	
District V																		
Alaska	3	6	12	10	6		56	9	55	60	46		59	15	67	70	52	
Arizona	--	--	--	--	--		36	47	132	144	137		36	47	132	144	137	
California	6,282	6,371	2,126	1,134	1,711		788	599	685	202	129		7,070	6,970	2,811	1,336	1,840	
Hawaii	2	--	--	--	--		144	58	365	429	506		146	58	365	429	506	
Nevada	1	--	4	5	4		5	1	--	1	3		6	1	4	6	7	
Oregon	167	204	108	103	116		107	124	97	78	15		274	328	205	181	131	
Washington	548	456	273	238	250		228	60	645	236	84		776	516	918	474	334	
District V Total	7,003	7,037	2,523	1,490	2,087		1,364	898	1,979	1,150	920		8,367	7,935	4,502	2,640	3,007	
U.S. Total	28,704	29,217	24,622	22,892	20,423		7,295	6,109	8,886	9,028	8,503		35,999	35,326	33,508	31,920	28,926	

Source: U.S. Department of Interior, Bureau of Mines, Annual Fuel Oil Sales, Selected years.

C.5 GOVERNMENT FACTORS

C.5.1 INTRODUCTION TO DISCUSSION OF FACTORS AND TRENDS

This, and the next five chapters, discuss various factors and trends which will influence the future need for residual fuel oil. Of particular focus are those factors that would change the supply patterns, alter the supply potential, affect demand or change the technical environment of residual fuel oil usage. Specific chapters discuss:

- Government factors
- Foreign factors
- Energy production trends
- Technological trends
- Handling problems
- Demand trends

C.5.2 OVERVIEW ON GOVERNMENT FACTORS

In the present domestic petroleum market, the direction of government policy and the numerous federal energy programs have an important impact on the availability and consumption of oil products. The significance of government policies is heightened in the case of residual fuel oil, because historic policies have resulted in supply and demand patterns for this product which are unique by comparison with other petroleum products. In this chapter we will describe the major ways in which federal policy has influenced the supply and demand for residual fuel oil in the past and give a general forecast as to the future impact of governmental regulations.

As a result of a series of events and government policies which are described in detail in the "Domestic Refining" section below (See C.5.3), the United States has come to be dependent upon foreign sources (primarily Caribbean and Canadian) for 60% of its residual fuel oil requirements in 1974. At the same time, consumption of residual fuel oil has come to be concentrated on the East Coast due to a combination of the scarcity of indigenous domestic energy substitutes, a relaxed import policy, relative supply economics, and government air pollution control regulations. The details behind these factors, as well as a discussion of the probable impact of current and projected government policies are presented in this chapter. The specific topics to be covered are:

- Domestic refining -- how the government's policies have and will influence the amount of domestic refining capacity and the yield of residual fuel oil from this capacity.
- EPA regulations -- trends in restrictions on the quality of residual fuel oil which can be burned and how these regulatory trends will impact on the supplies of residual fuel oil
- FEA's mandatory conversion program -- the impact of the mandatory conversion program on residual fuel consumption.
- Promotion of research -- the direction of government-funded research efforts as an indication of what substitutes may be able to replace residual fuel oil fired operations.

Another important governmental factor, that of regulation and control of the natural gas industry, is discussed in C.7, Energy Production Trends.

C.5.3 DOMESTIC REFINING

C.5.3.1 Introduction

In line with its objective of increasing domestic energy self-sufficiency, the FEA has announced a goal of encouraging increased domestic oil refining capacity. However, the precise incentives and program with which the FEA hoped to induce construction of additional capacity have never been clearly or consistently defined. Since the inception of the Project Independence ethic by President Nixon in May of 1973, refiners or would-be refiners have been faced with a constantly changing short-term situation and an equally uncertain longer-term outlook. Domestic product demand has remained below 1973 levels for two consecutive years. At the same time, the direction of future government policy has been extremely ambiguous with regard to such critical matters as import controls on crude and products, continued close federal government regulation of the petroleum industry, EPA restrictions on refinery siting and emissions, and taxation of refining profits. Given such uncertainty, refiners found it difficult to obtain financing or sign long-term crude supply contracts for new refining capacity. As a result, many refiners responded by postponing or cancelling plans to expand existing capacity or build new capacity.

With the passage of the Energy Policy and Conservation Act in December, 1975 (the so-called "Omnibus Energy Bill"), only the outlook over the short-term has been clarified. The longer-term questions such as the degree and terms of government regulation of the domestic petroleum industry and the tariffs and levels for crude and product imports remain unanswered. In addition, uncertainties regarding environmental issues still have to be resolved--environmentalists' objections to proposed sitings, refinery emission standards, and quality standards for refined products (particularly, the lead and sulfur specifications for gasoline).

This section will review current and projected refining capacity serving the U.S. market and discuss the impact of current government policies on future refining capacity.

C.5.3.2 Current and Projected Domestic Refining Capacity

Table C.5-1 summarizes operable domestic refining capacity in the U.S. by P.A.D. district as of January 1, 1975, and gives an estimate of additional capacity which was scheduled to be completed during 1975. As shown, almost 70% of the capacity is located in the Gulf Coast (P.A.D. District III) and in the Midwest (P.A.D. District II), historically the greatest production areas of domestic crude oil. By contrast, only 47% of the total U.S. demand for petroleum products is in Districts II and III.

Even without the uncertainties that exist in today's petroleum industry, it would be difficult to construct long-range forecasts of future increases in refinery capacity with great accuracy. Lead times required to plan and execute refinery construction projects are normally two to three years, but environmental opposition to proposed siting plans have begun to cause considerable delays (if not total blockage) in original deadlines. Thus, forecasts of capacity can be made with reasonable accuracy for only two to three years into the future. Table C.5-2 presents the FEA's latest forecast of refining capacity by district through 1979. In addition to the capacities quoted in Table C.5-2, the FEA lists another 4185 thousand barrels per day of capacity which either has been judged uncertain or as in the early planning stages, and a further 1900 thousand barrels per day of capacity being held up by environmental opposition.

Beyond 1979, further expansion of capacity will be a function of such factors as product demand growth, trends in government policy, the general state of the economy, the availability of sufficient crude supplies and worldwide refinery capacity.

Table C.5-1

Present Operable U.S. Refining Capacity
By PAD District
(MBBLS/Day)

	P.A.D. DISTRICT					
	I	II	III	IV	V	Total U.S.
Operable Capacity as of January 1, 1975	1611.1	4012.8	6239.2	530.1	2357.5	14750.7
Estimated New Capacity added in 1975	84.0	105.2	163.2	3.0	30.0	385.4
TOTAL ESTIMATED CAPACITY AS OF JANUARY 1, 1976	1695.1	4118.0	6402.4	533.1	2387.5	15136.1

Note: Figures indicate operable capacity. In reality, refineries do not operate constantly at 100% of operable capacity. Instead, annual utilization of capacity rarely exceeds 90% of rated operable capacity.

Source: Capacity as of January 1, 1975, from Office of Oil and Gas, FEA.
1975 capacity additions from "Trends in Refinery Capacity and Utilization," June, 1975, FEA.

Table C.5-2

Forecast of U.S. Refining Capacity
By PAD District, 1975-1979
(MBBLS/Day)

	P.A.D. DISTRICT					
	I	II	III	IV	V	Total
Estimated Capacity as of January 1976	1695	4118	6402	533	2388	15136
Net additions in 1976	42	70	511	7	404	1034
Subtotal	1737	4188	6913	540	2792	16170
Net additions in 1977	22	54	335	7	47	465
Subtotal	1759	4242	7248	547	2839	16635
Net additions in 1978	22	54	485	7	32	200
Subtotal	1781	4296	7333	554	2871	17235
Net additions in 1979	272	54	85	7	32	450
Total Forecast Capacity as of January 1980	2053	4350	7818	561	2903	17685

Note: In addition to firm projects, the FEA added 200,000 barrels per day of capacity from 1976 onward to account for small unannounced expansions. This allowance for small unannounced projects was distributed among the districts in proportion to each district's share of current total capacity.

Source: "Trends in Refinery Capacity and Utilization," FEA, June 1975; Arthur D. Little, Inc. estimates.

C.5.3.3 Caribbean Refining Capacity

In addition to the onshore domestic capacity just described, the U.S. has traditionally relied heavily on Caribbean refining capacity (including Venezuela) to supply product, especially residual fuel oil, to the U.S. East Coast. For example, in 1974, the Caribbean refineries provided an average of 1.25 million barrels per day of residual fuel oil, or 73% of PAD I residual fuel demand. Table C.5-3 details the refining capacity currently available in the Caribbean.

The dependence of the East Coast on refineries in the Caribbean for residual fuel has a long history. Under the terms of the Mandatory Oil Import Program proclaimed by President Eisenhower in 1959, the quantity of crude and product imports permitted into Districts I-IV was restricted to 12.2% of estimated annual domestic production in those districts (minus special exemptions for Canadian overland imports and product imports from the Virgin Islands and Puerto Rico). Licenses or tickets to import products were allocated to historic importers on the basis of their proportion of 1957 imports. These controls on imports were necessitated by the fact that the price of U.S. oil production was controlled at the wellhead and was generally priced higher than foreign crudes transported to the U.S. To provide economic justification for higher crude costs, U.S. refiners maximize gasoline yield since gasoline sales provide the greatest profit.

In 1966, the regulations of the Mandatory Oil Import Program were amended to effectively permit free importation of residual fuel oil into District I. This change merely recognized what was at that point the prevailing supply mode for residual fuel oil on the East Coast. Because of their access to cheaper foreign crudes, their lower operational and labor costs, and the availability of deepwater terminal sites,

Table C.5-3

Caribbean Area
Refinery Processing Capacities
As at 1/1/75
(MB/CD)

Country	Company	Atmospheric Distillation	Catalytic Cracking	Thermal Cracking (Visbreaking & Coking)	Catalytic Reforming	Hydrogen Processing		Vacuum Distillation
						HDS	HDT	
Antigua	W.I.O.C.	16.0	-	-	2.0	7.5	-	1.5
Bahamas	BORCO (NEPCO/SOCAL)	500.0	-	-	-	-	-	70.0
Barbados	Mobil	3.0	-	-	-	-	-	-
Colombia	(All Companies)	172.1	48.5	17.5	2.0	-	-	85.0
Costa Rica	R.C.P.	11.0	-	3.0	1.5	-	3.5	0.5
Dominican Republic	Falconbridge & Refidomsa	45.5	-	-	7.0	7.0	12.0	-
El Salvador	Acajutla	14.0	-	-	2.6	-	9.5	-
Guatemala	Texas & Guatcal	24.8	-	-	5.5	-	9.5	-
Honduras	Texaco	14.0	-	-	1.8	-	5.0	-
Jamaica	Exxon	32.6	-	-	3.0	18.9	-	1.5
Martinique	S.A.R.A.	10.4	-	-	2.5	3.3	3.5	-
Neth. Antil.	Shell & Lago (Exxon)	900.0	35.0	379.0	15.0	140.0	223.0	230.0
Nicaragua	Exxon	13.2	-	-	2.6	10.6	-	1.9
Panama	Refpan	100.0	-	22.0	7.5	-	30.0	14.0
Puerto Rico	Gulf, Sun & COR	283.8	47.8	22.0	75.5	112.4	12.0	114.2
Trinidad	T.T.O.C. & Texaco	461.0	26.5	-	27.0	80.0	67.0	194.0
Venezuela	Chevron, CVP, Creole (Exxon), Gulf, Mobil, Phillips, Sinclair, Texas	1,531.7	48.6	109.8	20.6	262.0	67.0	360.0
Virgin Is.	Hess	665.0	-	-	55.0	193.6	-	185.0
Total		4,784.1	206.4	553.3	230.7	853.3	442.0	1,257.6

Key to hydroprocessing: HDS -- Catalytic hydrodesulfurization
HDT -- Catalytic hydrotreating

Sources: Oil and Gas Journal surveys
Petroleum Times, January 24, 1975
Hydrocarbon Processing, February 1975
Trends in Refinery Capacity and Utilization, FEA, June 1975

the Caribbean refiners were in a position to supply the East Coast residual fuel oil requirements at lower prices than domestic East or Gulf Coast refiners running price-controlled U.S. crudes through expensive conversion refineries. Domestic refiners preferred to maximize gasoline yields at the expense of heavier products due both to the greater profit margins available from gasoline sales and their investment in conversion refining facilities. As a result, Caribbean refining capacity emphasized residual fuel oil yields (typically 50-60% of crude throughput) and total refining capacity in the area developed rapidly at rates far in excess of growth in local Caribbean petroleum consumption.

Over the period 1973-1975, Caribbean refiners have found themselves severely affected by, first, the drop in U.S. and European demand for residual fuel oil and, second, by the increased domestic residual fuel oil yield prompted by lowered average domestic crude costs under the Entitlements Program compared to the now very high foreign crude prices. As a result, Caribbean refiners have been forced to operate at rates well below capacity or, in some cases, cease operations entirely for certain periods. Certain refiners, particularly Amerada Hess in the Virgin Islands and, at times, NEPCO in the Bahamas, have found some relief from their current predicament in the form of special entitlement grants allowing them some relief from the higher costs of foreign crude. However, if these special entitlement grants are not continued in 1976 under the FEA regulations stemming from the new Energy Policy and Conservation Act, the Caribbean refiners will be at a considerable disadvantage in selling residual fuel oil to U.S. East Coast markets.

C.5.3.4 <u>Present Government Policies and Programs Influencing Growth In Refining Capacity</u>

C.5.3.4.1 <u>Import Fees</u> - At the time of the signing of the Energy Policy and Conservation Act, President Ford removed the supplemental license fees of $2.00/Bbl on imported crude. Thus, at present, there remain two types of fees on imported crude and product. The first is an <u>import</u>

tariff levied on the following schedule:

Type of Import	Source of Import: Most-Favored Nations (Tariff)	Source of Import: Other Nations (¢/Bbl)
Crude under 25° API Gravity	5.25	21
Crude 25° API Gravity and Over	10.50	21
Residual Fuel Oil Under 25° API	5.25	21
Residual Fuel Oil Over 25° API	10.50	21
Motor Fuels (inc. gasoline, diesel, and jet fuel)	52.5	105.0

These tariffs, which are collected by Customs, may be deducted from any of the second type of import fees--the import license base fees--that may be due the FEA. There are no proposals to modify the current level of import tariffs.

The second type of import fees which are in force are the import license base fees. In April, 1973, President Nixon initiated a system of import license base fees. These import license base fees have escalated over time to their current and maximum level of $0.21/Bbl of crude and $0.63/Bbl of product. These base license fees applied initially to a small proportion of imports, but over time the proportion of imports subject to the base license fees will be expanded, until 100% of imports will be covered in May 1980. The following is the schedule by which the volume of imports subject to the import license base fees is calculated:

For the year commencing May:	Percent of 1973 Imports Subject to Fees
1974	10%
1975	20%
1976	35%
1977	50%
1978	65%
1979	80%
1980	100%

Any volumes above the 1973 import levels are automatically subject to the import license base fees. The importer is allowed to credit any Customs tariffs paid against the import license base fees owed under the above schedule.

The base license fees were originally conceived as a means of encouraging domestic oil production and refining by making imported crude and, particularly, imported products, pay a substantial import penalty. The base license fee did result in an initial flurry of interest in expanded refinery capacity; however, the Arab oil embargo and OPEC price hikes of 1973/1974 instigated a period of such uncertainty about the future that many of the initial positive effects on refining capacity were overridden. The feeling of uncertainty about the future outlook for domestic refining was not alleviated during 1974 and 1975 under the various FEA programs such as the Buy/Sell and Entitlements Programs, even though these programs were established to assure all refiners adequate crude supplies at approximately equal costs. The uncertainty has recently been reduced for the next 3-1/4 years with the signing of the Energy Policy and Conservation Act, which provided for the continuation of FEA controls on domestic crude acquisition and costs (see analysis of impact below). However, most of the longer-term uncertainties remain unresolved and this environment may continue to obstruct refinery expansion.

C.5.3.4.2 Impact of Energy Policy and Conservation Act (EPCA) - In December 1975, the Administration ended the long struggle between itself and Congress over the future course of U.S. energy policy by signing into law the Energy Policy and Conservation Act (EPCA) or Omnibus Energy Bill. The passage of the EPCA represents a considerable compromise of the Administration's position that higher energy prices are necessary to encourage conservation and stimulate production. Instead of the gradual decontrol of domestic oil prices which the President desired, the EPCA provides for the maintenance of an average controlled price for domestic oil (initially $7.66) which can be raised a maximum of 10%* per annum over the 40-month life of the EPCA. According to the implementation regulations currently proposed by the FEA, the average domestic oil price would be realized by holding old oil (i.e., the proportion of domestic oil equivalent to average 1973 production) at the controlled price of $5.25 per barrel and allowing new oil prices (i.e., price of oil volumes produced in excess of 1973 average production) to be at a level such that the weighted average of the two is equivalent to the mandated domestic average. This has the effect of rolling back current new oil prices by about $1.30 per barrel. In effect, the current FEA implementation strategy would indicate a three tier pricing system in the U.S.: old domestic oil, controlled at $5.25; new domestic oil, initially priced at $11.28; and foreign oil, at international levels.

The result of the domestic three tier pricing structure is that U.S. refiners will, on average, obtain their supplies at prices below international oil parity. According to current FEA plans, the benefits of these lower average crude costs will be spread equally among all refiners as a modified version of the Entitlements Program is perpetuated. Other FEA programs initiated under the Emergency Petroleum Allocation Act (1973), such as the Buy/Sell Program (which assists all refiners to have physical access to sufficient crude supplies) and the dollar-for-dollar cost increase pass-through to products, are also expected to continue in some form under the EPCA. Thus, at least for the 40-month duration of the EPCA, there would appear to be a strong incentive for domestic refiners to maximize their output and reduce supplies from traditional import sources. This incentive for domestic refiners to address the whole domestic demand barrel rather than just meet gasoline demand was already evident under the original Entitlements Program. Domestic refiners'

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*The amount of the annual increase includes a factor for inflation (as measured by the GNP deflator) plus a 3% oil industry incentive increase. If the situation arises in which those two factors together exceed the annual 10% increase or if the President wishes to increase the percentage for industry incentive, Congressional approval can be sought.

yields of residual fuel oil have increased over the last year or so as refiners modified their gasoline-maximizing yield strategies in favor of a more balanced outturn. Other evidence of this incentive is the fact that U.S. refiners are building refineries or considering refinery projects involving high fuel oil yield processing schemes. For example, the Energy Company of Louisiana's (ECOL) new 200 MBCD refinery at Garyville, Louisiana, which is scheduled to be completed in 1976, will have a 67% fuel oil yield on crude input, as compared to a historic average residual fuel oil yield on crude for the U.S. Gulf Coast refineries of 4.5%.

In summary, the EPCA provides that over the next 3-1/4 years, crude costs to domestic refiners will be subject to continued FEA regulations and will likely, as a result of the EPCA requirement for a controlled domestic crude price, be lower than those prevailing on the international market. Over this period, there will, therefore, be an economic incentive for increased domestic refining activity, and also for an inducement for domestic refiners to lower gasoline yields and increase fuel oil yields.

C.5.3.5 Domestic Refining Trends

Beyond the purview of the Omnibus Bill, it is difficult to forecast the forces which influence domestic refining. If domestic crude prices continue to be regulated at a level below international market prices and the level of domestic product demand warrants, the incentives for domestic refiners would presumably hold and Caribbean refineries would be at a disadvantage. If domestic crude prices are completely decontrolled with the expiration of the EPCA, the current motivation for increased U.S. activity would evaporate. In large part the longer-term outlook will depend upon the relative levels of domestic and foreign crude costs and U.S. Government policy.

It is expected, however, that U.S. refining capacity will continue to expand over the next decade and that the expansions will favor the production of fuel oil over conversion processing to make gasoline. In addition, new refining capacity will probably be designed to accept sour crude oils, so will include desulfurization equipment. U.S. refinery growth may not keep up with increases in petroleum demand, but offshore refining capacity (see Chapter C.6 for a more detailed analysis) appears more than adequate in the next decade to handle new U.S. petroleum product demands, especially for residual fuel oil.

C.5.4 EPA AIR QUALITY REGULATIONS

C.5.4.1 Introduction

Air quality has become a prime concern in the United States since air quality directly affects human health and the biosphere in which we live. Regulations to control air pollution have been developed primarily in the last decade and it is not yet clear what the final rules and regulations will be or how they will affect fuel consumption patterns. Here we look at the development of current air quality laws both at a federal and state level and look at some of the current issues regarding air pollution control in order to draw some conclusions about probable future air quality control measures.

C.5.4.2 Development of Current Air Quality Regulations

Prior to 1955 the responsibility for maintenance of air quality rested with state and local governments. For the most part, the control measures initiated in these early years were smoke abatement measures since smoke was the most evident form of air pollution. However, beginning in 1955, the federal government began increasingly to involve itself in air pollution control programs. Initially, federal efforts were confined to research programs and counseling to assist state pollution control programs. In 1963, Congress passed the landmark Clean Air Act, which authorized more massive federal financial assistance for the establishment and improvement of state and local control programs, sanctioned federal interstate abatement actions and provided for a massive federal research effort to study and publicize the effects of pollution. In

1965, the original Clean Air Act was amended to give the federal government the authority to curb auto pollution emissions.

The Air Quality Act of 1967 signaled a new and more comprehensive approach to air pollution control. It mandated the federal government (through the National Air Quality Control Administration) to designate air quality regions on the basis of meteorological and urban factors and to publish documents describing the effects of various pollutants accompanied by analyses of the types and costs of available source control techniques. On the basis of the federally-generated information, the states were required to establish air quality standards and prepare plans for meeting such standards.

In 1970, the role of the federal government in air pollution control became even broader with the passage of the Clean Air Act Amendments directing the newly created Environmental Protection Agency (EPA) to set national ambient air quality standards. The states, in turn, would be required to submit for EPA approval their control plans for achieving the national air quality standards. In accordance with the 1970 amendments, EPA published, in April 1971, the national standards for six types of air pollutants: sulfur oxides, particulate matter, carbon monoxide, photochemical oxidants, nitrogen oxides, and hydrocarbons. These standards were stated for two levels: the primary standards were designed to prevent hazardous health conditions; and the secondary standards were intended to prevent any other detrimental effects (on animals, vegetation, visibility, aesthetics, etc.). It is important to note that these federal standards are stated for ambient air quality measured at ground level. They are not emission standards which measure pollution levels at their source (e.g., at the stack tip). The compliance strategies submitted by the states were to include plans for attaining and maintaining the primary standards within three years and the secondary standards within five years. As a part of their compliance programs the states had the right to set emission levels which they thought would enable them to meet federal ambient air quality standards.

The structure of the U.S. federal air pollution control laws as described above has always allowed the state and local governments the ultimate discretion to determine what control action would be appropriate for their particular pollution levels, meteorological conditions, fuel supply options, etc. As a result, the current regulations regarding the quality specifications for fuels which may be burned vary widely throughout the country, and even within individual states. Also, because the federal regulations do not restrain the state and local authorities from enforcing air quality standards superior to the national standards, many state and metropolitan areas have promulgated more stringent standards and control requirements than enacted by the EPA. In particular, the densely populated urbanized regions along the East Coast have passed very strict regulations regarding emission levels of pollutants.

C.5.4.3 State Regulations

According to the EPA's charter, the authority to establish specific pollution control measures was delegated to individual states rather than to the regional or federal EPA officials. These state regulations were intended to translate the EPA's primary air quality standards into practical operating guidelines for potential pollutors. Typically, for existing stationary sources, the states chose to stipulate the maximum quantity of pollutants that could be emitted from a source over a particular time period--the reading of emission levels taking place at the stack tip. With experience, these stack-tip readings were translated into fuel input standards; for example, maximum sulfur concentrations in fuel oils, ash content for coals, etc. Large new boilers (with capacities greater than 250 MMBTU/hr. [263.7 Gigajoules/hr.]), however, were required to meet federally set fuel standards which translated into approximately 0.8% sulfur in residual fuel oil burning boilers. All state regulations were subject to review and final acceptance by regional and federal EPA authorities to certify that, at a minimum, federal air quality standards were being met.

Beginning in mid-1970 and carrying through 1971, the first state implementation strategies became effective. As might have been expected, the densely-populated areas were generally the first to act. As early as October 1, 1971, the greater New York and Boston metropolitan areas required residual fuel oil users to burn fuel oil with less than 0.5% sulfur, while Philadelphia and Washington, D.C. limited sulfur content to under 1%. Congested West Coast areas were also quick in establishing stringent sulfur specifications for residual fuel oils--with both Los Angeles and San Francisco restricting sulfur in fuel oil to less than 0.5% in the fall of 1971. Other less populated or developed areas tended to set more lenient sulfur restrictions or to establish standards applicable only to new equipment or to ignore sulfur limitations in their immediate implementation regulations. Sulfur restrictions in critical air pollution areas--primarily, the metropolitan areas of the East and West Coasts--gradually become more comprehensive and stringent, so that virtually all the fuel oil consumed in these areas was below 1% sulfur and much of it below 0.5% sulfur.

The regulations devised by the states were not and still are not necessarily uniform throughout each state. More stringent sulfur specifications tend to apply to fuel oil burned in metropolitan areas than to oil burned in the more rural areas. Table C.5-4 describes in detail the sulfur specifications which currently apply in individual states within PAD Districts for the burning of residual fuel oil and indicates each state's proposed revisions (if any) to current regulations.

C.5.4.4 Current Issues Surrounding Air Pollution Control

Largely as a result of the higher oil prices, the Arab Oil Embargo and the subsequent policy of U.S. energy independence, U.S. energy consumers have begun to question the stringency of local air pollution regulations, particularly as they dictate the use of very low sulfur, and typically foreign-produced, fuel oils (or natural gas) as opposed to less costly and domestically available coal. In the wake of the recent upheaval in the world energy market, some of the larger fuel consumers are either

Table C.5-4

Detailed Federal, State and Local Sulfur Regulations

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Alabama	Category I Counties and Jefferson County	Oil	All	1.75 (1)	1-31-75
				1.66 (2)	1-31-75
		Coal		1.08 (3)	1-31-75
	Category II Counties	Oil	All	3.9 (1)	1-31-75
				3.7 (2)	1-31-75
		Coal		2.4 (3)	1-31-75
Alaska	All	Oil	All	1.00 (4)	5-26-72
		Coal	All	0.85 (5)	5-26-72
Arizona	All	Oil	Existing	0.98 (1)	5-30-72
				0.93 (2)	5-30-72
		Oil (high sulfur)	Existing	2.15 (1)	*
				2.04 (2)	*
		Coal	Existing	0.60 (3)	5-30-72
		Oil	New	0.78 (1)	5-30-72
				0.74 (2)	5-30-72
		Coal	New	0.48 (3)	5-30-72

*Proposed 10-15-75. Hearings held 12-75. Now awaiting State certification. High Sulfur Oil = Fuel Oil containing 0.90% or more by weight of sulfur.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Arkansas	All	The only regulations adopted by the State require that SO_2 concentrations do not exceed 0.20 ppm in the ambient air at any places beyond the premises on which the source of the emissions is located.			
California	Air Basins:				
	North Coast: (Less Mendocina & Sonoma Counties)	All	All	1.9	1-1-75
	San Francisco Bay	Oil	Existing	0.60 (4)	11-5-71
		Coal	Existing	0.51 (5)	11-5-71
		Oil	New: > 250 MBTU/hr.	0.78 (1)	12-74
				0.74 (2)	12-74
		Coal	New: > 250 MBTU/hr.	0.72 (3)	12-74
	North Central Coast	All	All	0.5	11-5-71
	South Central Coast	All	All	0.5	11-5-71
	South Coast	All	All	0.5	11-5-71
	Northeast Plateau: (Lassen County only)	All	All	0.5	11-5-71
California (continued)	Air Basin: (continued)				
	Sacramento Valley: (Tehama County only)	All	All	0.5	11-5-71
	San Joaquin Valley	All	All	1.9	1-1-75
	Southeast Desert: (Less eastern & southern portion of Kern County)	All	All	0.5	10-18-71
	San Diego	All	All	0.5	11-5-71
	Mountain Counties: (Tuoleme County only)	All	All	1.9	1-1-75
	Other Counties: (Less Madera & Mariposa Counties)	All	All	3.6	1-1-75
Colorado	All	Oil	All	0.78 (1)	4-5-75
				0.74 (2)	4-5-75
		Coal	All	0.72 (3)	4-5-75
Connecticut	All	All	All	0.5	4-1-73
Delaware	All	Distillate	All	0.30	1-7-72
	New Castle County	All	All	1.00	1-7-72
District of Columbia	All	All	All	0.5	7-1-75
Florida	All		> 250 MBTU/hr.*		
		Oil	Existing	1.07 (1)	7-1-75
				1.02 (2)	7-1-75
		Coal	Existing	0.90 (3)	7-1-75
		Oil	New	0.78 (1)	1-18-72
				0.74 (2)	1-18-72
		Coal	New	0.72 (3)	1-18-72

*Units with a heat input of less than 250 MBTU/hr. must use "latest reasonably available technology."

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Georgia	All	All	< 100 MBTU/hr.	2.50	11-30-75
			> 100 MBTU/hr.	3.00	11-30-75
			> 250 MBTU/hr.		
		Oil	New	0.74 (2)	11-15-74
		Coal	New	0.72 (3)	11-15-74

Notes: (1) Sulfur content greater than the above may be allowed provided that the source utilizes SO_2 removal and the SO_2 emission does not exceed that allowed by the above sulfur content limitations utilizing no SO_2 removal.

Table C.5-4 (Cont'd)

Detailed Federal, State and Local Sulfur Regulations

(2) Large fuel burning sources are limited by a maximum allowable SO_2 emission level expressed in pounds per hour. The allowable level varies with size and location of the facility and with stack height.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Hawaii	All	No. 1 & No. 2	All	0.5	Proposed
		No. 4	All	1.0	Proposed
		All	All	2.0	6-1-74
		All	> 250 MBTU/hr.	0.5	6-1-74
Idaho	All	No. 1	All	0.30	1-1-73
		No. 2	All	0.50	1-1-73
		Residual	All	1.75	1-1-74
		Coal	ALL	1.00	1-1-73
Illinois	All	Distillate	New	0.29 (1)	12-20-73
			Existing	0.29 (1)	5-30-75
		Residual	New		
			< 250 MBTU/hr.	0.93 (2)	12-20-73
			> 250 MBTU/hr	0.74 (2)	12-20-73
			Existing	0.93 (2)	5-30-75
		Coal	New		
			< 250 MBTU/hr.	1.08 (3)	4-14-72
			> 250 MBTU/hr	0.72 (3)	4-14-72
	Chicago, St. Louis and Peoria Regions	Coal	Existing	1.08 (3)	5-30-75
	Rest of the State	Coal	Existing	3.60 (3)	5-30-75
				1.08 (3)	6-1-75*

*If annual arithmetic average SO_2 level is greater than 0.02 ppm for any year ending prior to 5/30/76 or 0.015 ppm for any year ending on or after 5/30/76.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Indiana	All	Indiana has stack emission limits set for each site on the basis of unit size, stack height, number of stacks, etc. The most restrictive limit would be about 1.11 (2) wt.% S in fuels.			
	East Chicago	Oil	All	1.66 (2)	7-1-72
		Coal	All	1.08 (3)	7-1-72
	Hammond	All	All	1.50	10-13-74
Iowa	All	Oil	All	2.4 (1)	7-31-75
				2.3 (2)	7-31-75
		Coal		3.6 (3)	7-31-75
				3.0 (3)	7-31-78

Note: Less stringent standards for solid fuels have been proposed to become effective 7-1-76.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Kansas	All		> 250 MBTU		
		Oil	New	2.78 (2)	1-1-72
		Coal	New	1.80 (3)	1-1-72
Kentucky	Note: Fuel sulfur regulations are expressed on a sliding scale based on size of the facility. Values for typical units are given below:				
	All	Oil	New		
			≤ 10 MBTU/hr.	2.31 (2)	4-9-72
			50 MBTU/hr.	1.29 (2)	4-9-72
			100 MBTU/hr.	1.02 (2)	4-9-72
			≥ 250 MBTU/hr.	0.74 (2)	4-9-72
		Coal	New		
			≤ 10 MBTU/hr.	2.40 (3)	4-9-72
			50 MBTU/hr.	1.44 (3)	4-9-72
			100 MBTU/hr.	1.02 (3)	4-9-72
			≥ 250 MBTU/hr.	0.72 (3)	4-9-72
	Priority I (Louisville Area)	Oil & Coal	Existing	Same as New	7-1-77
	Priority II (Cincinnati, Paducah-Cairo, Evansville-Henderson)	Oil	Existing		
			≥ 500 MBTU/hr.	1.39 (2)	7-1-78
			< 500 MBTU/hr.	Same as New	7-1-78
		Coal	Existing		
			≥ 500 MBTU/hr.	1.20 (3)	7-1-78
			< 500 MBTU/hr.	Same as New	7-1-78
	Priority III (Huntington-Ashland, Bluegrass, Appalachian, North Central, South Central)	Oil	Existing		
			1000 MBTU/hr.	1.85 (2)	7-1-79
			< 1000 MBTU/hr.	Same as New	7-1-79
		Coal	Existing		
			1000 MBTU/hr.	2.10 (3)	7-1-79
			< 1000 MBTU/hr.	Same as New	7-1-79
Louisianna	All	Oil	All	4.00 (4)	1-30-72
		Coal	All	3.40 (5)	1-30-72
Maine	Portland Peninsular AQCR	All	All	1.50	11-1-75
	Rest of State	All	All	2.50*	11-1-73

*Limit does not apply to any emission source which through use of SO_2 collecting devices or other equipment reduces the emission of SO_2 to the equivalent of burning such fuel with a sulfur content of 1.50%

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Maryland	Areas I, II, V and VI	Distillate	All	0.3	8-16-75
		Residual	All	2.0	8-16-75
		Coal	All	2.1	8-16-75
	Areas III* and IV	Distillate	All	0.3	8-16-75
		Residual	All	1.0	8-16-75

Table C.5-4 (Cont'd)

Detailed Federal, State and Local Sulfur Regulations

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Maryland (continued)				0.5	7-1-80
		Coal	All	1.0	8-16-75

*Major fuel burners in Area III (Baltimore Metropolitan Area) are permitted to use one per cent limit sulfur oil until July 1, 1976.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Massachusetts					
	All	No. 2	All	0.33 (1)	10-1-70
		Residual	All	1.02 (2)	10-1-71
		Coal	All	0.66 (3)	10-1-71
	Boston Area*	Residual	All	0.52 (2)	10-1-71
		Coal	All	0.34 (3)	10-1-71
	Berkshire County APCD	All	All	2.26	10-1-71

*No residual to be used in units of 6 MBTU/hr heat input or less after 1-74.

NOTE: Amendments have been proposed and are under consideration for the Boston, Pioneer Valley, Southeastern Massachusetts, Merrimack Valley, and Central Massachusetts APCD's

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Michigan	Wayne (Detroit Area)	Distillate	All	0.30	8-1-72
		Residual	All	1.00	8-1-73
				0.70	8-1-76
		Coal-pulverized	All	1.25	8-1-75
				1.00	8-1-76
		Coal-other	All	0.50	8-1-74
	All	All	< 500 M lbs steam/hr.	2.0	7-1-75
				1.5	7-1-78
			> 500 M lbs steam/hr.	1.5	7-1-75
				1.0	7-1-78
Minnesota	Minneapolis-St. Paul AQCR	Oil	> 250 MBTU/hr	1.50	6-1-74
			< 250 MBTU/hr	2.00	6-1-74
		Coal	> 250 MBTU/hr	1.50	6-1-73
			< 250 MBTU/hr	2.00	6-1-74
	Rest of State	All	> 250 MBTU/hr	2.00	6-1-74
Mississippi	All	Distillate	< 250 MBTU/hr.	2.34 (1)	5-11-72
			> 250 MBTU/hr.	4.68 (1)	5-11-72
		Residual	< 250 MBTU/hr	2.22 (2)	5-11-72
			> 250 MBTU/hr	4.44 (2)	5-11-72
		Coal	< 250 MBTU/hr.	1.44 (3)	5-11-72
			> 250 MBTU/hr.	2.88 (3)	5-11-72
Missouri	All except cities of St. Louis and St. Charles and St. Louis, Jefferson, Franklin, Clay, Cass, Buchanan, Ray, Jackson, Platte and Green Counties	Oil	Existing	4.00 (4)	2-9-72
		Coal	Existing	3.40 (5)	2-9-72
		Oil	New	1.00 (4)	2-9-72
		Coal	New	0.85 (5)	2-9-72
Missouri (continued)	St. Louis AQCR	All	< 2000 MBTU/hr.	2.0	12-68
		Oil	> 2000 MBTU/hr.	2.13 (2)	3-24-70
		Coal	> 2000 MBTU/hr.	1.38 (3)	3-24-70
	Green	Coal	Existing	3.6 (5)	current
		Coal	New	0.8 (5)	current

Note: The sulfur limits for facilities < 2,000 MBTU/hr. are effective only for the period October through April.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Montana	All	Oil	All	1.85	7-1-72
		Coal	All	1.20	7-1-72
Nebraska	All	Oil	All	2.4 (1)	2-26-74
				2.3 (2)	2-26-74
		Coal	All	1.5 (3)	2-26-74
Nevada	Washoe County: Cities of Reno and Sparks.	All	< 250 MBTU/hr.	1.0	7-1-70
		All	> 250 MBTU/hr.	*	8-19-75

*Allowable emissions calculated by use of the Formula, y = 0.105x, where x = minimum heat input, number of millions of BTUs per hour, and y = allowable rate of sulfur dioxide emission in pounds per hour.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
	Rest of State	All	All	*	

*Maximum allowable rate of SO_2 calculated by use of the formula Z = 0.15x, where Z = allowable rate of SO_2 emission in pounds per hour and X = maximum heat input in MBTU/hr.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
New Hampshire	All	No. 2	All	0.40	10-1-72
		No. 4	All	1.00	10-1-72
		No. 5 & 6*	All	2.00	10-1-73
		Coal	Existing	1.68 (3)	10-1-70
			New	0.90 (3)	4-15-70

*New Hampshire portion of the Androscoggin Valley AQCR is permitted to use No. 5 & 6 oil with a 2.20 wt% sulfur.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
New Jersey	Atlantic, Cape May, Cumberland, Hunterdon, Ocean, Sussex and Warren Counties	No. 2	All	0.3	5-1-68
		No. 4	All	0.7	5-1-68
		No. 5&6	All	1.0	5-1-68
		Coal	All	0.2	10-1-71

Table C.5-4 (Cont'd)

Detailed Federal, State and Local Sulfur Regulations

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
New Jersey (continued)	Rest of State	No. 2	All	0.2	10-1-71
		Residual	All	0.3	10-1-71
New Mexico	All	Oil	>1,000,000 M̄BTU/hr.	0.31 (2)	1-10-72
		Coal	> 250 M̄BTU/hr.		
			New	0.20 (3)	3-25-72
			Existing	*	7-31-77
		Coal	> 3000 M̄BTU/hr.		
			Existing	**	7-1-77

*SO_2 emissions to the atmosphere may not be in excess of 35% by weight of the SO_2 which would be produced upon combustion of the coal prior to any pretreatment.

**SO_2 emissions to the atmosphere may not be in excess of 15% by weight of the SO_2 which would be produced upon combustion of the coal prior to any pretreatment.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
New York*	New York City	Distillate	All	0.20	9-26-74
		Residual	All	0.30	9-26-74
		Coal	All	0.20	9-26-74
	Nassau, Rockland and Westchester Counties	Oil	All	0.37	9-26-74
		Coal	All	0.20	9-26-74
	Suffolk County—towns of Babylon, Brookhaven, Huntington, Islip & Smithtown	Oil	All	1.0	9-26-74
		Coal	All	0.6	9-26-74
	Erie & Niagara Counties	Oil	All	1.1	10-1-75
		Coal	All	1.7	10-1-74
	Rest of State	Oil	All	2.0	9-26-74
		Coal	All	2.5	9-26-74
	All except New York City, Nassau, Rockland and Westchester Counties)		> 250 M̄BTU/hr.		
		Oil	New	0.75	9-26-74
		Coal	New	0.72 (3)	9-26-74

*It is anticipated that sulfur limits will be amended in 1976.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
North Carolina	All	All	New	1.55 (1)	7-1-71
				.93 (2)	7-1-71
				.96 (3)	7-1-71
		All	Existing	2.24 (1)	7-1-71
				2.13 (2)	7-1-71
				1.38 (3)	7-1-71
		All	Existing	1.55 (1)	7-1-80
				.93 (2)	7-1-80
				.96 (3)	7-1-80

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
North Dakota	All	No. 1&2	All	0.5	7-1-70
		Residual	All	2.78 (2)	7-1-70
		Coal	All	1.80 (3)	7-1-70
Ohio	Priority I Regions (Cleveland, N.W. Ohio, Steubenville, Toledo, & Zanesville Regions)	Sources	> 250 M̄BTU/hr.		
		Oil	Existing	0.98 (1)	7-17-72
				0.92 (2)	7-17-72
		Coal	Existing	0.60 (3)	7-17-72
	*Priority II Regions (Dayton, Marion-Mansfield, Marietta, Cincinnati, & Youngstown Regions)	Oil	Existing	1.56 (1)	7-17-72
				1.48 (2)	7-17-72
		Coal	Existing	0.96 (3)	7-17-72
	*Priority III Regions (Columbus, Portsmouth, Sandusky & Wilmington-Chillicothe Regions)	Oil	Existing	3.12 (1)	7-17-72
				2.96 (2)	7-17-72
		Coal	Existing	1.92 (3)	7-17-72

*Effective 7-1-75 Pri. II & III Regions must meet the limits currently established for Priority I Regions.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
	All	Oil	New	0.98 (1)	2-1-74
			≥ 100 M̄BTU/hr.	0.92 (2)	2-1-74
		Coal		0.60 (3)	2-1-74
	Allen, Ashtabula, Columbiana, Cuyahoga, Jefferson, Lucas, Summit and Trumbull Counties	Oil & Coal	New < 100 M̄BTU/hr.	0.92 (2)	2-1-74
			Existing ≤ 250 M̄BTU/hr.	0.96 (3)	2-1-74
	Belmont, Butler, Coshocton, Erie, Hamilton, Henry, Lake, Lawrence, Lorain, Mahoning, Monroe, Montgomery, Pickaway, Richland, Tuscarawas, Washington and Wayne Counties	Oil & Coal	New < 100 M̄BTU/hr.	1.48 (2)	2-1-74
			Existing ≤ 250 M̄BTU/hr.	0.60 (3)	2-1-74
	Franklin, Hancock, Hocking, Holmes, Knox, Licking, Morgan, Ross, Seneca and Shelby Counties	Oil & Coal	New < 100 M̄BTU/hr.	2.96 (2)	2-1-74
			Existing ≤ 250 M̄BTU/hr.	1.92 (3)	2-1-74
	Athens, Auglaize, Carroll, Clinton, Defiance, Fairfield, Fayette, Greene, Hardin, Harrison, Highland, Huron, Jackson, Marion, Mercer, Miami, Muskingum, Paulding,	Oil & Coal	New < 100 M̄BTU/hr.	3.70 (2)	2-1-74
			Existing ≤ 250 M̄BTU/hr.	2.40 (3)	2-1-74

Table C.5-4 (Cont'd)

Detailed Federal, State and Local Sulfur Regulations

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Ohio (continued)	Sandusky, Union, Vinton, Williams and Wood Counties				
	All remaining counties	Oil & Coal	New < 100 MBTU/hr.	4.44 (2)	2-1-74
			Existing ≤ 250 MBTU/hr.	2.88 (3)	2-1-74
	Cincinnati & Toledo	All	All	1.00	11-22-72
	Akron	Oil	> 10,000 MBTU/hr	0.78 (1)	1-1-75
			10-10,000 MBTU/hr.	1.9 to 0.78 (1)	1-1-75

Note: Hearings will be held in January 1976 on proposed changes to make standards generally less stringent.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Oklahoma	All	Oil	New	0.74 (2)	7-1-72
		Coal	New	0.72 (3)*	12-1-74

*The regulation prohibits any emission of SO_2 from existing equipment which results in an ambient air concentration of SO_2 at any given point in excess of 0.52 ppm in a five minute period of any hour.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Oregon	All	No. 1	All	0.3	7-1-72
		No. 2	All	0.5	7-1-72
		Residual	All	1.75	7-1-74
		Coal	All	1.0	7-1-72
			> 150 < 250 MBTU/hr.		
		Oil	New	1.37 (1)	1-1-72
				1.30 (2)	1-1-72
		Coal	New	.96 (3)	1-1-72
			> 250 MBTU		
		Oil	New	.78 (1)	1-1-72
				.74 (2)	1-1-72
		Coal	New	.72 (3)	1-1-72
Pennsylvania	Pittsburgh area (Allegheny County, Beaver Valley, & Monongahela Valley Air Basins) and Southeast Pennsylvania Air Basin (Bucks, Chester, Delaware, Montgomery, & Philadelphia Counties)	Oil & Coal	< 2.5 MBTU/hr	3.70 (2)	3-19-72
				2.40 (3)	3-19-72
			2.5-50 MBTU/hr.	0.92 (2)	3-19-72
				0.60 (3)	3-19-72
			50-2,000 MBTU/hr	Use Formula:	
			$A = 1.7E^{-0.14}$ where		
			A = allowable emission in pounds SO_2 per million BTU heat input.		
			E = heat input in MBTU's per hour.		
			> 2,000 MBTU/hr	0.55 (2)	3-19-72
				0.36 (3)	3-19-72
	All other	Oil & Coal	< 2.5 MBTU/hr.	3.70 (2)	3-19-72
				2.40 (3)	3-19-72
			2.5-50 MBTU/hr.	2.78 (2)	3-19-72
				1.80 (3)	3-19-72
			50-2,000 MBTU/hr	Use formula:	
Pennsylvania (continued)			$A = 5.1E^{-0.14}$ where		
			A = allowable emission in pounds SO_2 per million BTU heat input.		
			E = heat input in MBTU's per hour.		
			> 2,000 MBTU/hr.	1.67 (2)	3-19-72
				1.08 (3)	3-19-72
	Philadelphia	No. 1&2	All	0.3	5-1-70
				0.2	10-1-76
		No. 4	All	0.4	10-1-72
				0.3	10-1-76
		No. 5&6	All	0.5	10-1-72
				0.3	10-1-76
		Coal	All	0.3	10-1-72
Puerto Rico	All	All	< 8 MBTU/hr.	2.5	1-1-75
			≥ 8 MBTU/hr.		1-1-75

*Actual percentage value, not to exceed 3.1% is assigned through the permit system.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Rhode Island	All	Distillate	All	1.07 (1)	5-8-74
		Residual	All	1.02 (2)	5-8-74
		Coal	All	.66 (3)	5-8-74
South Carolina	Class I (Charleston County)	Oil	≤ 10 MBTU/hr.	3.41 (1)	1-30-74
				3.24 (2)	1-30-74
		Coal	≤ 10 MBTU/hr.	2.10 (3)	1-30-74
		Oil	> 10 MBTU/hr.	2.24 (1)	1-30-74
				2.13 (2)	1-30-74
		Coal	> 10 MBTU/hr.	1.38 (3)	1-30-74
	Class II (Aiken and Anderson Counties)	Oil	< 1000 MBTU/hr.	3.41 (1)	1-30-74
				3.24 (2)	1-30-74
		Coal	< 1000 MBTU/hr.	2.10 (3)	1-30-74
		Oil	≥ 1000 MBTU/hr.	2.24 (1)	1-30-74
				2.13 (2)	1-30-74
		Coal	≥ 1000 MBTU/hr.	1.38 (3)	1-30-74
	Class III (All remaining Counties)	Oil	All	3.41 (1)	1-30-74
				3.24 (2)	1-30-74
		Coal	All	2.10 (3)	1-30-74

Note: Variances granted on a case by case basis.

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
South Dakota	All	Oil	All	2.78 (2)	7-10-73
		Coal	All	1.80 (3)	7-10-73
Tennessee	Class I (Sullivan, Roane, Maury and Polk Counties)	Oil	New < 250 MBTU/hr.	1.48 (2)	1-1-73
		Coal	New < 250 MBTU/hr.	0.96 (3)	1-1-73

Table C.5-4 (Cont'd)

Detailed Federal, State and Local Sulfur Regulations

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Tennessee (Continued)		Oil	Existing	1.48 (2)	7-1-75
		Coal	Existing	0.96 (3)	7-1-75
	Class II (Humphrey's County)	Oil	New < 250 MBTU/hr	2.78 (2)	1-1-73
		Coal	New < 250 MBTU/hr.	1.80 (3)	1-1-73
		Oil	Existing	2.78 (2)	7-1-75
		Coal	Existing	1.80 (3)	7-1-75
	Class III (Remaining Counties)	Oil	New < 250 MBTU/hr	3.70 (2)	1-1-73
		Coal	New < 250 MBTU/hr	2.40 (3)	1-1-73
	All	Oil	New > 250 MBTU/hr.	0.74 (2)	1-1-73
		Coal	New > 250 MBTU/hr	0.72 (3)	1-1-73
	Roane & Humphrey Counties	All	> 1000 MBTU/hr.	1.11 (2)	9-9-74
	Class I (Polk County)	Distillate	> 1,000 MBTU/hr.	1.17 (1)	*
			< 1,000 MBTU/hr.	1.56 (1)	*
		Residual	> 1,000 MBTU/hr	1.11 (2)	*
			< 1,000 MBTU/hr	1.48 (2)	*
		Coal	> 1,000 MBTU/hr	.72 (3)	*
			< 1,000 MBTU/hr.	.96 (3)	*
	Class II (Humphreys, Maury, Roane Counties)	Distillate	> 1,000 MBTU/hr	1.17 (1)	*
			< 1,000 MBTU/hr.	4.88 (1)	*
		Residual	> 1,000 MBTU/hr	1.11 (2)	*
			< 1,000 MBTU/hr.	4.63 (2)	*
		Coal	> 1,000 MBTU/hr.	.72 (3)	*
			< 1,000 MBTU/hr.	3.00 (3)	*
	Class III (Sullivan County)	Distillate	All	2.34 (1)	*
		Residual	All	2.22 (2)	*
		Coal	All	1.44 (3)	*
	Class IV (Shelby County)	Distillate	All	.49 (1)	*
		Residual	All	2.50 (2)	*
		Coal	All	2.40 (3)	*
	Class V (Anderson, Davidson, Hamilton, Hawkins, Knox, Rhea)	Distillate	All	3.90 (1)	*
		Residual	All	3.70 (2)	*
		Coal	All	2.40 (3)	*
	Class VI (All other Counties)	Distillate	All	4.88 (1)	*
		Residual	All	4.63 (2)	*
		Coal	All	3.00 (3)	*
	Class IV (Shelby County)	New Facilities			
		Distillate	< 250 MBTU/hr.	3.90 (1)	*
		Residual	< 250 MBTU/hr	3.70 (2)	*
		Coal	< 250 MBTU/hr.	2.40 (3)	*
	All	New Facilities			
		Distillate	> 250 MBTU/hr	78 (1)	*
		Residual	> 250 MBTU/hr	.74 (2)	*
		Coal	> 250 MBTU/hr	.72 (3)	*
Texas	All	Oil	All	0.88 (4)	3-5-72
		Coal	Steam Generators	1.80 (3)	3-5-72

*Recently adopted by the Tennessee Air Pollution Control Board. Expected to become effective in early 1976

State	Portion of State	Fuel Type	Fuel Use	Sulfur Limit (Wt.%)	Effective Date
Utah	All	Oil	All	1.50	9-26-71
		Coal	All	1.00	9-26-71
Vermont	All	All	All	2.0	3-16-75
Virginia	AQCR 7	Oil	All	1.03 (1)	6-1-75
				0.98 (2)	6-1-75
		Coal	All	0.63 (3)	6-1-75
	Rest of State	Oil	All	2.57 (1)	6-1-75
				2.44 (2)	6-1-75
		Coal	All	1.58 (3)	6-1-75
Washington	Puget Sound Area: King, Kitsap, Pierce & Snohomish Counties	No. 1	All	0.30	2-21-74
		No. 2	All	0.50	2-21-74
		Oil-Other	All	2.00 (4)	2-21-74
		Coal	All	1.00	2-21-74
	Rest of State	Oil	New	2.00 (4)	2-24-72
			Existing	2.00 (4)	7-1-75
		Coal	All	1.70 (5)	7-1-75
West Virginia	The State of West Virginia Regulation 16-20, Series x, Section 3 sets SO_x weight emission standards for fuel burning units by Priority Regions. In addition the West Virginia Air Pollution Control Commission "strongly recommends" that the *following fuel sulfur contents be met by fuel suppliers:*				
	All	Oil	All	1.50	6-30-75
				0.50	6-30-78
		Coal	All	2.00	6-30-75
				1.00	6-30-78
Wisconsin	Southeast Wisconsin Intrastate AQCR	Standby Fuel: *			
		Distillate	All	0.70	4-1-72
		Residual	All	1.00	4-1-72
		Coal	All	1.50	4-1-72
	Racine County	Oil	All	2.31 (2)	12-15-70
		Coal	All	1.50 (3)	12-15-70
	All	New or modified Facilities:			
		Distillate	> 250 MBTU/hr.	0.76	4-1-72
		Residual	> 250 MBTU/hr.	0.74	4-1-72
		Coal	> 250 MBTU/hr.	0.72	4-1-72
Wyoming	All			None	

*Standby fuel is defined as a fuel normally used less that 15 days per year.

Table C.5-4 (Cont'd)

Detailed Federal, State and Local Sulfur Regulations

NOTES

(1) No. 1 & 2 Oil — Regulastion expressed as lbs. S or SO_2/M BTU. Equivalent weight percent sulfur calculated using 19,500 BTU/lb.

(2) No. 4, 5, & 6 OIL — Regulation expressed as lbs. S or SO_2/M BTU. Equivalent weight percent sulfur calculated using 18,500 BTU/lb.

(3) Coal — Regulation expressed as lbs. S or SO_2/M BTU Equivalent weight percent sulfur calculated using 12,000 BTU/lb.

(4) Oil — Regulation expressed as parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 25% excess air.

(5) Coal — Regulation expressed as parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 25% excess air.

(6) Oil — Regulation expressed as parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 10% excess air.

(7) Coal — Regulation expressed as parts per million SO_2 in the flue gas. Equivalent weight percent sulfur calculated using 10% excess air.

burning lower quality fuels on a variance from existing air pollution regulations or are attempting to obtain variances or to revise the regulations.

In a recent survey of the major residual fuel-oil burning utilities (primarily East Coast utilities), Arthur D. Little discovered some common attitudes and recommendations regarding current air pollution control regulations:

- State or local standards (largely expressed as emission standards at stack tip) are excessively stringent in relation to the federal ambient air quality standards (measured at ground level). As a result, local and state regulations should be relaxed.
- Now that air quality control authorities have had several years of experience and data on the effects of emission and fuel quality regulations, a review of existing regulations should be carried out with an idea to determining if the current controls are more stringent than necessary.
- Since meteorological conditions vary over time, perhaps fuel quality standards should be stringent in times of adverse conditions and more lenient during normal conditions. To realize such a fluctuating standard, constant air quality monitoring would be required and fuel burners would be required to maintain adequate supplies of high quality fuel for use when measured air quality deteriorates.
- There is a general aversion to installing stack gas removal systems both because of the high costs and the perception that the current stringent emission standards may eventually be relaxed.

C.5.4.5 Air Quality Control Trends

At this point in time, the outcome of the present debate over air quality regulations is uncertain. However, it is possible to speculate about the broad economic and political trends which are likely to influence the outcome. For example, in the new era of high oil prices, the added costs of burning very low sulfur fuel oils may well trigger reviews of the necessity for such stringent regulations. At the same time, the country is currently very concerned with the issue of domestic energy independence. Given the declining domestic oil and gas reserves, greater independence implies a greater reliance on coal. To the extent that air quality regulations prohibit the burning of coal or make it uneconomic as a result of costly stack gas removal requirements, it is likely that political pressure will be exerted to reexamine the necessity for current restrictions.

None of the above comments are meant to imply doomsday for environmental concerns. Most of the existing variances from air quality regulations are temporary and there are areas of the country (particularly, the East and West Coasts) which are unlikely to grant or renew further exemptions due to the more critical nature of air pollution problems in those areas. However, on the whole, a gradual relaxation of air pollution regulations in areas not presently experiencing significant air pollution conditions will likely occur over the next five years. For some areas, this trend will mean that the regulations intended to implement secondary standards will simply not be implemented. In other areas, current regulations will actually become less stringent, and these more lenient regulations may be accompanied by better monitoring systems to assure timely response to unfavorable meteorological developments. The air quality control regulations will probably become more sophisticated and tailored to particular locations to maximize clean air while minimizing the cost of maintaining it.

C.5.5 MANDATORY FUEL CONVERSION PROGRAM

In June, 1974, Congress passed the Energy Supply and Environmental Coordination Act (ESECA). This act provided for the creation of the Office of Fuel Utilization (OFU) and empowered that office to order the conversion of electric utilities and other major fuel burning installations to the use of coal instead of oil or gas. In its initial one-year life span, the OFU ordered the conversion to coal of some 74 power plants in 25 different states. On June 30, 1975, the original charter of the OFU expired. However, with the passage of the Omnibus Energy Bill in December, 1975, the operating lifetime of the Office has been extended through June, 1977.

In its initial conversion orders, the OFU adhered to the following criteria in selecting utilities for conversion:

- the utility must have a demonstrated capacity to burn fuel other than oil or gas (i.e., the utility must actually have burned coal in the past);
- there must be a source of supply for coal which is reasonably accessible to the utility's generating site (for example, there must be rail or barge receiving facilities on the generating site);
- the conversion must be "economically feasible" (here the impact on the individual utility of not only the conversion costs but also future fuel costs associated with coal were taken into account); and
- the conversion to coal must leave the utility in conformity with EPA regulations.

The first conversion orders, issued to 25 utilities covering some 32 generating stations, were subject to EPA verification that such conversion would not cause the utilities to be in violation of primary EPA air quality standards. Since EPA verification of compliance with air quality standards takes three to six months from the date of issue of the original conversion order and since most of the conversion orders were issued in the final months of ESECA charter, the EPA certification process has been going on since July 1975, and is expected to carry on into 1976. It is by no means certain that the EPA will grant approval of all of the conversion orders issued by the OFU. In addition, there is an appeals provision where the utilities or other large fuel users may request exemption from the conversion order if they feel that compliance would be too costly or arduous. After the utilities have received the conversion notice and EPA certification, they will be required to begin the actual conversion process which, it has been estimated, may take as long as two years to accomplish.

If all of the conversions which were ordered by the OFU prior to the expiration of that office's initial charter in June, 1975, are eventually complied with (a very large if), it will mean an estimated savings of some 64 million barrels per year of residual fuel oil and 88 billion cubic feet (2.5 billion cubic meters) of natural gas. Given that utilities accounted for 475 million barrels of residual fuel oil consumption in 1974 (or 50% of total residual fuel oil demand) and 3429 billion cubic feet per day (97.1 billion cubic meters per day) of natural gas (or 18% of total marketed natural gas production) in 1974, the quantities of those premium fuels potentially saved by the mandatory coal conversion program to date are relatively small. However, in addition to the conversion orders issued to operating generating plants, the OFU singled out 41 utilities planning to build new generating stations and ordered them to install coal burning capability, either as the only capacity or as dual-burning capacity.

With the passage of the Omnibus Energy Bill in December, 1975, the OFU received an additional 18 month charter. This additional time will be utilized to expand the conversion program to include not only utilities but other large fuel users (primarily large industrial customers). As with the initial conversion orders, the conversions which are mandated during the extension period will also require EPA approval.

These mandated conversions will have the effect over the long-term of reducing residual fuel oil demand. Whether the reduced demand is for low or high sulfur fuel oil depends on the physical location of the converted plants, so that there is no method to estimate the actual impact of such conversions. It is likely that by 1985, the net effect will be small and will be overshadowed by other fuel considerations, such as the loss of natural gas for use by utilities.

C.5.6 PROMOTION OF FUEL USE RESEARCH

The Energy Research and Development Administration (ERDA) was established under the Energy Reorganization Act of 1974 to bring together federal activities in energy research and development and to assure coordinated and effective development of all energy sources. The main impetus for its creation was the Arab oil embargo of 1973 and the heightened realization of the serious national security implications of such a heavy reliance on imported energy. The national goal stated by Congress in starting ERDA, which officially came into being on January 19, 1975, was

> *"...effective action to develop, and increase the efficiency and reliability of use of, all energy sources to meet the needs of present and future generations, to increase the productivity of the national economy and strengthen its position in regard to international trade, to make the nation self-sufficient in energy, to advance the goals of restoring, protecting, and enhancing environmental quality, and to assure public health and safety."*

In June 1975 ERDA outlined its national plan, urging five major changes in this country's energy R&D program:

(1) Increased efforts to overcome the technical problems inhibiting expansion of presently available energy forms, notably coal and light water reactors.

(2) An immediate focus on conservation efforts. Primary initial

targets to be automotive transportation, buildings and industrial processes.

(3) Acceleration of commercial capability to extract gaseous and liquid fuels from coal and shale.

(4) Inclusion of solar electricity generation among the "inexhaustible" resource technologies to be given high priority.

(5) Increased attention to the commercialization of under-used technologies which can be rapidly developed, principally solar heating and cooling and geothermal power.

A national ranking of R&D technologies was developed to identify priorities for emphasis in the plan. These priorities are as follows:

- For the near-term (now to 1985) and beyond
  - To preserve and expand major existing domestic energy systems: coal, light water reactors, and gas and oil both from new sources and from enhanced recovery techniques.
  - To increase the efficiency of energy used in all sectors of the economy and to extract more usable energy from waste materials.
- For the mid-term (1985-2000) and beyond
  - To accelerate the development of new processes for production of synthetic fuels from coal, and for extraction of oil from shale.
  - To increase the use of under-used fuel forms, such as geothermal energy, solar energy for heating and cooling, and extraction of more usable energy from waste heat.
- For the long-term (past 2000)
  - To actively pursue those candidate technologies which will permit the use of essentially inexhaustible

resources: nuclear breeders, fusion, and solar electric energy from a variety of technological options, including wind power, thermal and photovoltaic approaches, and the use of ocean thermal gradients. (None of these technologies is assured of large scale application.)

- To provide the technologies to use the new sources of energy which may be distributed as electricity, hydrogen, or other forms throughout all sectors of the economy. (For example, long-term efforts are needed to develop a full range of electric vehicle capabilities.)

ERDA's programs are divided into six major areas: fossil energy; nuclear energy; environment and safety; conservation; national security; and solar, geothermal and advanced energy systems. These programs, which include research, development, demonstration, testing and (in the case of special nuclear materials and weapons) production, are conducted both at the more than 50 ERDA facilities and at industrial and university sites around the country. ERDA's capability for carrying out broad-based programs is based on funding and personnel transferred from R&D programs in other federal agencies: the Atomic Energy Commission, Department of the Interior, National Science Foundation, and Environmental Protection Agency. For fiscal year 1975, ERDA's budget estimate was about $3.7 billion of which about 50% was devoted to nuclear energy development (only 3% to fusion studies), 5% to fossil energy development, 10% to solar, geothermal and advanced systems. Conservation, environment and safety were to use 6% of the budget and 29% was to go for national security. It is evident that little federal research money is now being devoted to fossil energy problems, indicating that problems facing fossil energy usage will probably not be mitigated rapidly.

C.6 FOREIGN FACTORS AFFECTING RESIDUAL FUEL SUPPLIES IN THE U.S.

C.6.1 INTRODUCTION

During the first nine months of 1975, the U.S. imported some 1.21 MMBCD of residual fuel oil--this was 50% of total supply. Historical U.S. dependence on imports of foreign source residual fuel oil is summarized in Table C.6-1. As the table shows, domestic manufacture of residual fuel oil, which historically has been under 1.0 MMBCD, actually increased to 1.05 MMBCD in 1974 and to 1.23 MMBCD in 1975, largely as a result of federally mandated pricing policies which provided some price incentives for domestic refiners to maximize residual fuel oil sales. Peak output was over 1.4 MMBCD in January 1975, and between February and August 1975 domestic output either was equal to or slightly greater than imports. Besides large imports of residual fuel oil, the U.S. is also heavily dependent on crude oil imports, which accounted for 32% of crude input to refineries in the first nine months of 1975. This import dependency for crude oil has increased from 19% in 1972 to 26% in 1973 and 29% in 1974. Since residual fuel oil currently represents about 10% of refinery output, it is apparent that residual fuel oil availability in the U.S. is heavily dependent on a variety of foreign factors--over which the U.S. has little, if any, real control.

It is therefore important to review some of the foreign factors which affect crude oil and residual fuel oil in the foreign environment. These factors can be summarized as follows:

- Sources of U.S. Crude and Fuel Oil Imports
- Foreign Crude Oil Availability
- Foreign Refining Capacity
- Foreign Crude Prices

Table C.6-1

Residual Fuel Oil Consumption and Imports
(MMBCD)

	1969	1970	1971	1972	1973	1974	1975[A]
Domestic Demand	1.98	2.20	2.30	2.53	2.82	2.62	2.44
Was Met by							
Imported Oil	1.26	1.53	1.58	1.74	1.85	1.57	1.21
Domestic Oil	0.72	0.67	0.72	0.79	0.97	1.05	1.23
Import Dependency (%)	64	70	69	69	66	56	50

A - First nine months

C.6.2 CURRENT SOURCES OF U.S. CRUDE AND FUEL OIL IMPORTS

C.6.2.1 Crude Oil

Table C.6-2 shows U.S. imports of crude oil by country of origin for 1973, 1974 and most of 1975. Note that 78% of oil imports in the first nine months of 1975 derived from the OPEC countries. The principal exporter to the U.S. was Nigeria in this period, followed by Saudi Arabia and Canada. Canadian exports have declined steadily since 1973 and are now scheduled to phase out completely by 1981, indicating that U.S. dependence on the OPEC countries is likely to increase significantly in the years ahead. Dependence on OPEC exports has increased from 65% in 1973 to 78% in 1975. Other trends in future sources are likely to be a decline in Indonesian imports as Alaskan crude oil becomes available in 1977/78 with the completion of the Alyeska pipeline and an increase in imports from Africa. The light African crudes (produced principally in Nigeria, Libya, and Algeria) which in 1973 accounted for 0.70 MMBCD or 22% of imports, now account for 1.21 MMBCD or 30% of imports, as the result of not only pressure on low sulfur crudes for the manufacture of low sulfur residual oil but more importantly due to the declining availability of sweet light domestic crudes in Districts II and III. We anticipate that this trend will increase in significance in future years, as domestic production continues to decline in the lower forty-eight states, and imports must increasingly be directed towards refineries in Districts II and III. District I refineries are already heavily dependent on imported crude and District V will be the main beneficiary of Alaskan crude oil.

C.6.2.2 Residual Fuel Oil

During the last four years, the U.S. has increased its dependence on Western Hemisphere (particularly Caribbean) nations for imports of residual fuel oil. As shown in Table C.6-3, 93% of 1974 fuel oil imports originated in the Western Hemisphere, as compared to 89% in 1972. Over

Table C.6-2

Sources of U.S. Crude Oil Imports

	1973 (MMBCD)	1973 %	1974 (MMBCD)	1974 %	1975[A] (MMBCD)	1975[A] %
1. Arab OPEC	0.83	26	0.72	21	1.24	31
of which Saudi Arabia	0.46		0.44		0.61	
Algeria	0.12		0.18		0.27	
Libya	0.13		0.04		0.21	
2. Non-Arab OPEC	1.26	39	1.83	52	1.87	47
of which Nigeria	0.45		0.70		0.73	
Venezuela	0.34		0.32		0.40	
Iran	0.22		0.46		0.26	
Indonesia	0.20		0.28		0.37	
3. Toal OPEC	2.09	65	2.55	73	3.05	78
4. Other Western Hem.	1.07	33	0.86	25	0.76	19
of which Canada	1.00		0.79		0.58	
5. Other	0.08	2	0.07	2	0.10	3
TOTAL	3.24	100	3.48	100	3.97	100

Source: Bureau of Mines

A -First 9 months.

Table C.6-3

Sources of U.S. Residual Fuel Oil Imports[A] For Domestic Consumption

	1972		1973		1974		1975[B]	
	MMBCD	%	MMBCD	%	MMBCD	%	MMBCD	%
Western Hemisphere	1.442	89	1.487	87	1.359	93	1.033	92
of which Canada	0.079	5	0.091	5	0.075	5	0.054	5
Bahamas	0.146	9	0.122	7	0.107	7	0.132	12
Trinidad	0.148	9	0.127	7	0.106	7	0.063	5
NWI	0.287	18	0.394	23	0.343	24	0.250	22
Venezula	0.511	32	0.521	31	0.431	30	0.234	21
Virgin Is.	0.251	15	0.217	13	0.282	19	0.181	16
Other	0.020	1	0.015	1	0.015	1	0.119	11
Europe	0.138	9	0.135	8	0.055	4	0.019	2
Other Eastern Hem.	0.041	2	0.079	5	0.050	3	0.068	6
Total U.S. Imports for domestic consumption	1.621	100	1.701	100	1.464	100	1.120	100

A -Excludes military and bonded imports.

B -First eight months (243 days).

Source: Bureau of Mines, Fuel Oil Availability by Sulfur Levels.

the same period, imports from Europe declined from 9% to 4% of total imports. In this period, the Bahamas, Trinidad, and Venezuela reduced shipments to the U.S. from a combined total of 0.805 MMBCD to 0.644 MMBCD while imports from the Netherlands West Indies (NWI) and the U.S. Virgin Islands increased from 0.538 MMBCD to 0.625 MMBCD. Combined imports from the NWI refineries and Venezuela amounted to 50% of the total in 1972 and 54% in 1974, while the Caribbean as a whole provided 88% of U.S. residual fuel oil imports. The Canadian Maritimes export refineries supplied about 5% of residual fuel oil imports in each year.

Overall, imports into the U.S. dropped by 10% between 1972 and 1974 and apparently dropped by 23% from 1974 to 1975 if the total imports for the year remain at a level of 1.12 MMBCD. This has happened because overall residual demand has dropped from 2.6 MMBCD in 1974 to about 2.4 MMBCD in 1975 as a result of the economic downturn and because U.S. refineries increased residual fuel oil production by about 15% in 1975 over 1974 as a result of the price incentive caused by the federal government price policy.

It should be noted that Table C.6-3 excludes military and bonded imports which represent about 7-8% of total imports and come primarily from the NWI and Venezuela.

Most of the low sulfur (less than 1.0% sulfur) fuel oil imports and virtually all the high sulfur (greater than 1.0%) fuel oil imports originate in the Caribbean. The combined imports from the Virgin Islands, NWI, and the Bahamas accounted for 67% of 1975 (first 8 months) low sulfur imports and 56% of the 1974 total. Venezuelan exports alone were 36% of 1975 high sulfur imports (42% of 1974) and combined with shipments from the NWI and Virgin Islands totaled 79% of 1975 and 78% of 1974 high sulfur imports to the U.S.

C.6.2.3 Summary of Discussion

This review indicates the historic U.S. dependence on the Caribbean refineries as its major source of residual fuel oil. The reason for this is that U.S. refineries had been designed to manufacture light products. As demand for residual fuel oil increased on the East Coast, this product had to be imported, and the natural source was the Caribbean, initially the Venezuelan and NWI refineries operated by the major oil companies. Air pollution regulations, discussed elsewhere in this report, increasingly required East Coast industry and the utilities to burn low sulfur products. This demand prompted the construction of increased capacity in the Caribbean to use low priced foreign crude and the large refineries in the Bahamas (BORCO) and the Virgin Islands (Hess) plus some further capacity in Canada and Trinidad were built to supply this demand.

C.6.3 FOREIGN CRUDE OIL AVAILABILITY

C.6.3.1 Recent Import Forecasts

As is pointed out in Chapter C.7, the U.S. will, according to all forecasts, become increasingly dependent on foreign source oil. While there is some degree of disagreement between forecasters as to the level of dependence, there is fundamental agreement by all forecasters about the basic trend which can be clearly seen in a recent forecast by Exxon shown in Table C.6-4. Exxon's forecast shows that actual oil imports in 1974 amounted to 6.1 MMBCD and that estimated imports in 1975 will be at a level of 6.5 MMBCD. Exxon sees a tremendous increase in imports to 8.0 MMBCD in 1976 and 9.2 MMBCD in 1977, prior to Alaskan oil coming onstream. Thereafter, the growth in oil imports, although curtailed, increases by over 2% per year to reach 12.2 MMBCD by 1990. We should note that this forecast was made prior to the Energy Policy and Conservation Act of 1975 becoming law. Most observers feel the new law will have the effect of inducing increased oil demand because of the lower price levels mandated for domestic crude oil. Due to the entitlements provisions, lower domestic crude prices translate into lower oil product prices throughout the

Table C.6-4

Exxon's Forecast of U.S. Energy Demand
MMBCD Oil Equivalent

	Actual		Outlook			
	1973	1974	1975	1980	1985	1990
Total Energy Demand	37.4	36.7	36.3	41.9	47.8	56.0
of which:						
Natural Gas	11.7	11.4	10.7	9.4	9.6	9.7
Coal	6.6	6.5	6.5	8.3	9.7	11.4
Non-fossil	1.8	2.2	2.4	3.9	6.6	10.4
Oil[A]	17.3	16.6	16.7	20.3	21.9	24.5
of which:						
Domestic Production[B]	11.0	10.5	10.0	9.6	10.8	11.9
Oil Imports	6.2	6.1	6.5	10.5	10.8	12.2
Import Dependency (%)[C]	36	37	39	52	49	50

A - Local Demand excluding exports.

B - Crude condenstate, NGL and synthetics.

C - Imports divided by oil demand.

Note: Domestic production and imports do not add to oil demand because of net processing gain.

Source: Exxon Press Briefing, December 9, 1975.

country, thus increasing the likelihood of increased consumption. This incremental demand cannot be met quickly by domestic sources and must therefore add to the import burden so that the Exxon forecast could well be a conservative statement as to import needs. The levels of oil import dependency shown in the Exxon forecast increase from 36% in 1973 to 39% in 1975, 52% by 1980, and thereafter remain at or slightly below 50% through to 1990.

An alternate view of future dependency is provided in Table C.6-5 which is from a May 1975 study published by the Petroleum Industry Research Foundation, Inc. (PIRINC) entitled "Electric Power and U.S. Oil Import Dependency: An analysis of the President's targets for nuclear generating plants and oil imports in 1985". This study is much more optimistic about future domestic oil production than the Exxon outlook, in that it shows a potential 1985 production of 13.9 MMBCD versus only 10.8 MMBCD in the Exxon forecast. Note also that the PIRINC forecast of demand is 0.5 MMBCD less than that of Exxon. As a result of these two factors, PIRINC's imports are at 7.0 MMBCD, showing an import dependency level of only 33% in 1985.

In our view, the PIRINC forecast of domestic production is optimistic since it implies a heavy investment in secondary and tertiary recovery (implicitly assuming no effective price control on old oil from enhanced recovery) and the full development of the Gulf of Mexico's offshore areas. The forecast also assumes the commencement of production from the Atlantic OCS and new production from South Alaska and California offshore areas, as well as 2.5 MMBCD from the North Slope. We believe that most experts concur that 13.9 MMBCD of domestic production in 1985 is extremely optimistic given that price controls have now been continued for a further 40 month period. In our view, the import dependency is more likely to tend towards the 50% level seen by Exxon.

Another view on future imports is provided by a recent Library of Congress study by Dr. Herman T. Franssen which also gives an indication of where

Table C.6-5

PIRINC Forecast

Projected U.S. Oil and NGL Supply 1985

(million b/d)

Production from Existing Areas	10.0
Outer Continental Shelf (Atlantic and Pacific)	1.0
Prudhoe Bay and Other North Slope	2.5
Synthetic Oil Production (Shale oil and coal liquefaction)	.4
Total Domestic Production	13.9
Refinery Processing Gains	.5
Total Supply from Domestic Sources	14.4
Required Imports	7.0
Total Supply (Demand)	21.4
Oil Import Dependency	33%

Source: PIRNIC, May 1975.

future oil imports might come from. In this forecast, shown in Table C.6-6, dependence on the Arab countries of the Middle East and North Africa will increase from 1.05 MMBCD in 1974 (16% of total oil imports) to between 34% and 42% in 1985 representing between 2.9 and 4.2 MMBCD. By adding Venezuela, Iran, Nigeria and Southeast Asia (primarily Indonesia) to these totals, we can see that the U.S. was apparently dependent upon OPEC countries for 65% of 1974 product and crude imports, and by 1985 Dr. Franssen is forecasting a dependency on OPEC nations of between 76% and 80%. The Library of Congress study shows total imports of 8.5-9.9 MMBCD by 1985 which, coupled with the 21.0-22.4 MMBCD oil demand in 1985, indicates an import dependence of 40-44%.

C.6.3.2 World Oil Production Potential

Against these forecasts of potential imports, we can examine current and likely future trends in world oil production to determine whether these import levels are likely to be attained. The FEA monitors crude oil production in the major exporting countries and we reproduce in Table C.6-7 the statistics shown in the November 1975 FEA Monthly Energy Review. The table shows that most major exporting countries are currently producing at levels considerably below capacity, and that OPEC as a whole was about 25% under capacity in August 1975. Kuwait was estimated to have 40% of capacity shut-in in August, Libya 30%, Qatar 41%, Saudi Arabia 28.6%, Nigeria 29.6%, and Venezuela 26.5%. Other countries which can be characterized as those with greater relative income requirements, have much less capacity shut-in, with Algeria at 10% being the least affected.

Since the major price increases of 1973/74, the OPEC member states have faced severe strain in coping with the over-supply situation caused by reduced demand due to the price increases and the worldwide economic recession. As a consequence, the demand for OPEC crude has been much reduced. Certain countries such as Kuwait and Libya have voluntarily reduced production on the grounds of conservation and in pursuit of political ends. Others have lost volume because of disparate pricing

Table C.6-6

Forecast of U.S. Oil Imports
By Region
(MMBCD)

	1974	1977	1980	1985
Western Hemisphere	3.1	2.7	2.6	2.7
Canada	1.1	0.4	0.1	-
Venezuela	1.2	1.1	1.0	1.0
Other	0.8	1.2	1.5	1.7
Middle East & N. Africa	1.5	4.5 - 4.7	5.1 - 5.7	3.8 - 5.2
Iran	0.5	0.8	1.0	0.9 - 1.0
Arab Countries	1.0	3.7 - 3.9	4.1 - 4.7	2.9 - 4.2
Eastern Hemisphere	1.1	1.3	1.8	2.0
Nigeria	0.7	0.8	1.0	1.0
Other Africa	0.1	0.1	0.2	0.3
Southeast Asia	0.3	0.4	0.6	0.7
Total	5.7	8.5 - 8.7	9.5 - 10.1	8.5 - 9.9
By Comparison				
Exxon Totals	6.1	9.2	10.5	10.8

Sources: Dr. H. T. Franssen, Library of Congress Study

Note that total oil imports in 1974 do not agree with Exxon's assessment.

Table C.6-7

Crude Oil Production

Crude Oil Production for Major Petroleum Exporting Countries — August 1975

Country	Production 1973	1974	1975 (8 months)	August	Production Capacity August	Production Shut in August In percent
	In thousands of barrels per day					
Algeria	1,070	940	922	900	1,000	10.0
Iraq	1,964	1,820	2,211	2,260	2,600	13.1
Kuwait*	3,024	2,550	2,110	1,960	3,500	44.0
Libya	2,187	1,520	1,384	2,100	3,000	30.0
Qatar	570	520	423	410	700	41.4
Saudi Arabia*	7,607	8,480	7,014	8,210	11,500	28.6
United Arab Emirates	1,518	1,680	610	1,870	2,400	22.1
Subtotal: Arab OPEC	**17,940**	**17,510**	**15,674**	**17,710**	**24,700**	**28.3**
Ecuador	204	160	155	210	240	12.5
Gabon	147	180	210	210	250	16.0
Indonesia	1,339	1,380	1,266	1,380	1,700	18.8
Iran	5,861	6,040	5,441	5,510	6,500	15.2
Nigeria	2,053	2,260	1,695	1,760	2,500	29.6
Venezuela	3,364	2,970	2,475	2,280	3,100	26.5
Subtotal: Non-Arab OPEC	**12,968**	**12,990**	**11,242**	**11,350**	**14,290**	**20.6**
Total: OPEC	**30,908**	**30,500**	**26,912**	**29,060**	**38,990**	**25.5**
Canada	1,798	1,695	1,440	1,520	2,016	24.6
Mexico	465	580	785	840	840	0
Total: OPEC, Canada, Mexico	**33,171**	**32,775**	**29,141**	**31,420**	**41,846**	**24.9**
Total World	**55,715**	**55,855**	**52,869**	**55,360**		

*Includes about one-half of Neutral Zone production which amounted to approximately 530,000 barrels per day in August.
Source: Central Intelligence Agency.

Source: FEA Monthly Energy Review, November 1975.

practices--from time to time the liftings of Abu Dhabi, Algeria, Nigeria, Venezuela and Indonesia have been affected for this reason. Since mid-1974, OPEC members have been discussing how to institute a more formal method to achieve consistency between relative crude oil prices so as to ensure that income requirements can be met.

C.6.3.2.1 Relative Crude Oil Pricing Considerations - Relative crude oil prices are of importance because of their effect on OPEC and because of the relative merits of heavy and light crudes.

Unless OPEC members can institute a system to control the actions of individual states, there is the distinct possibility of rapid and uncontrolled price deterioration because of the current and projected crude oil over-supply position. A situation could emerge, in other words, in which individual producing countries, because of their short-term revenue requirements, would continually discount prices in order to achieve volume. Unless a major producer is prepared to act as a flywheel on production, increasing it with demand and decreasing it to equate supply to decreased demand, then pricing cohesion could fail. In practice, Saudi Arabia has informally acted as the flywheel on OPEC production, essentially enabling other members to produce according to national ambitions, and agreeing to slow down its own production, although as shown in Table C.6-7, other member countries have also voluntarily reduced production by significant amounts.

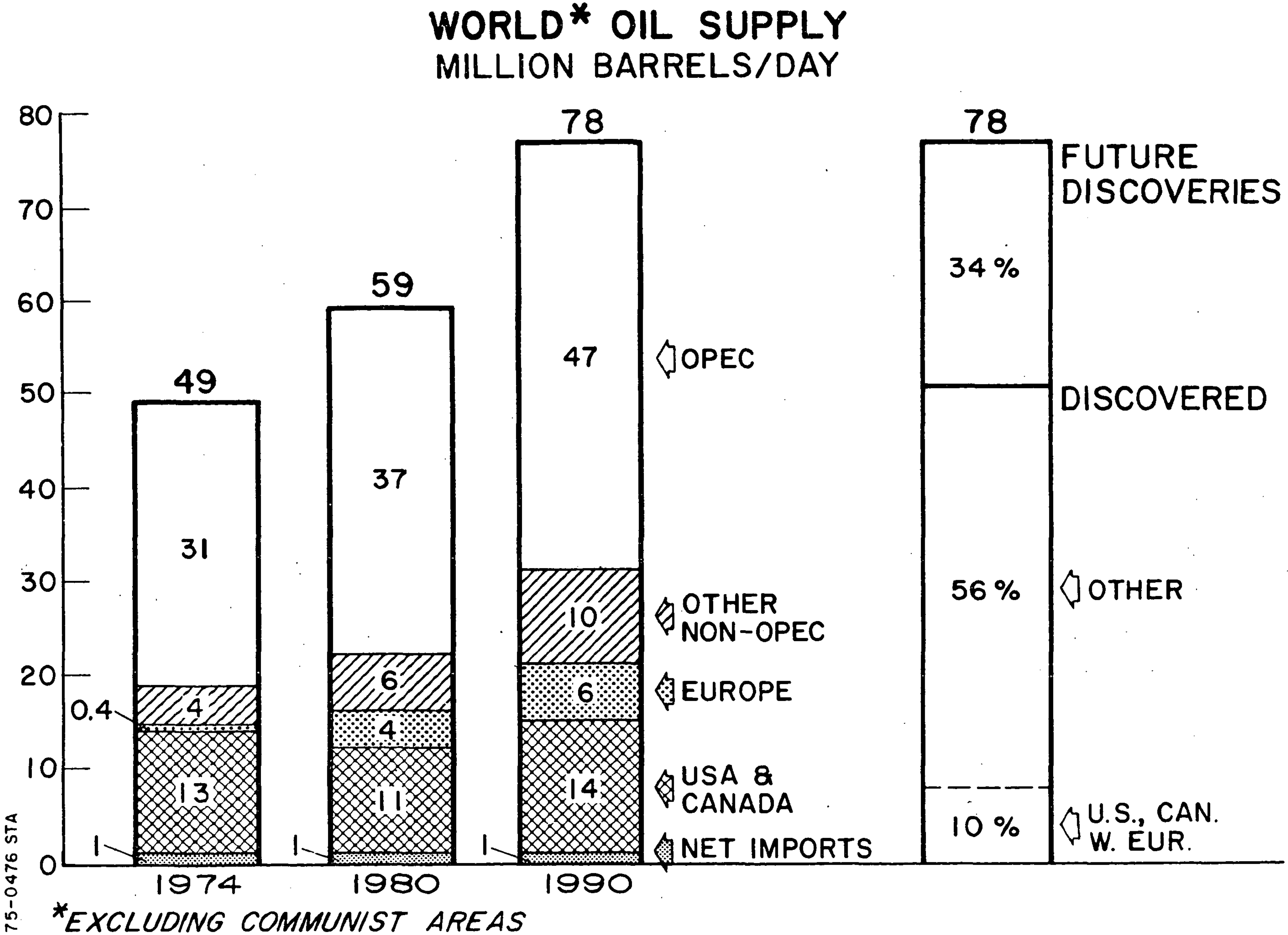
Relative crude oil prices must also by definition address the question of heavy crude prices versus light crude prices. This is vital to future product price relationships and in particular to future price trends for residual fuel oil, since the yield of fuel oil from a heavy crude is much greater than that from a light crude (for example, to take two extremes, 13° API Venezuelan Bachaquero crude has a residual fuel oil yield of almost 78% versus a 27% fuel oil yield from a 44° API Algerian crude oil). These considerations have been of great importance in recent price trends for residual fuel oil since the economic recession has selectively hit heavy industry and utility demand for residual fuel oil, thereby causing substantial oversupply of residual fuel oil and reducing the demand for heavy crudes. Meanwhile, light product demand has increased causing the value of light crudes to increase. OPEC members have in some instances been noticeably slow to react to these market trends, and Venezuela, for example, reportedly now holds large volumes of unsold residual fuel oil. Since further analysis of historic and future crude oil price trends follows in Section C.6.5, suffice it to say here that most observers believe that so long as Saudi Arabia, a producer of both light and heavy crude oils, is prepared to accept the balancing role, then OPEC will be able to hold prices at least at current levels, despite the current oversupply position.

C.6.3.2.2 Recent Foreign Crude Forecasts - Exxon's World Energy Forecast (referred to above) shows oil supply in the free world increasing from 49 MMBCD in 1974, to 59 MMBCD in 1980, and to 78 MMBCD in 1990. Exxon estimates that OPEC supplied 31 MMBCD or 63% of total world supplies in 1974, which will increase to 47 MMBCD (60%) in 1990. Thus, free world dependency on OPEC (as currently defined) will increase throughout this period, at the rate of 2.64% per year, slightly under the growth in oil demand estimated at 2.95% per year (which accounts for the slight decrease in dependence in % terms). The Exxon projection of oil availability is shown in Figure C.6-1. Note that this forecast is one of the few publicly available documents of this nature.

Exxon also estimates that of the total 78 MMBCD of oil required by the free world in 1990, about two-thirds will derive from existing reserves and about one-third will come from projected new discoveries. Known resources in the U.S., Canada, and Western Europe are expected to cover only about 10% of the world's needs in 1990.

In commenting on these future requirements, Exxon notes that OPEC's production peaked at about 32 MMBCD in the two quarters immediately preceding and following the 1973-74 embargo. By 1977, OPEC production

Figure C.6-1



Source: Exxon

is forecast to again surpass this peak level and by 1990, OPEC will be looked upon to supply 47 MMBCD. However, only a handful of countries have reserves which can support the increased production and most notably Saudi Arabia will be called upon to supply the bulk of this rapid increase in demand. Saudi Arabia is generally expected to have a production capacity of 16 to 18 MMBCD by the late 1970's. Exxon anticipates, however, that beyond 1985 the Arabian Gulf producers as a whole are likely to be approaching the upper limits of their resources and production capability may therefore become limited by the resource base. This leads directly to the question of future trends in crude oil prices which will be discussed later.

C.6.3.3 Summary

In summary, the future policies of the main producing countries will have a significant impact on oil availability and price. Because of its increasing oil dependency, and in particular because of historic and future residual fuel oil supply patterns, U.S. supplies of residual fuel oil will be particularly subject to OPEC oil supply and pricing actions.

C.6.4 FOREIGN REFINING CAPACITY

As was shown in C.6.2.2. 88% of the residual fuel oil imported into the U.S. in 1974 derived from Caribbean refineries. Apart from Venezuela, most of the crude oil currently processed in the Caribbean derives from OPEC countries in North and West Africa and the Middle East. With forecast declines in Venezuelan crude oil production, the Middle East and African crudes will form an increasing part of the crude slate for these refineries. In Table C.6-8, we have summarized the refining capacity available in the U.S. and its traditional product supply areas. The figures are based on assessed existing capacity plus an analysis of announced expansions.

Exxon estimates (Table C.6-4) total U.S. product demand in 1975 at 16.7

Table C.6-8

U.S. Domestic, Canadian Maritimes and Caribbean Exports[A]
Refining Capacity
(MMBCD)

	1975	1980
U.S. Domestic	14.75	17.49
Canadian Maritimes Export	0.22	0.29
Caribbean Export	3.68	3.85
Total	18.65	21.63

Source: FEA, Canadian National Energy Board
Petroleum Times Hydrocarbon Processing, Oil & Gas Journal, Platts and ADL estimates.

A - The figures shown for the Canadian Maritimes and the Caribbean are the result of an assessment of total refining capacity less local demand to give the capacity "available" for product exports.

MMBCD and 20.3 MMBCD in 1980. The forecast refining capacity in 1980 as shown in Table C.6-8 indicates that U.S. domestic refineries will be incapable of meeting U.S. product demand in 1980 by about 15% (versus 13% in 1975).

Thus the U.S. will continue to be heavily dependent upon foreign refinery capacity. Here we should note that the Administration has an announced intention to reduce U.S. dependency on refined product imports. In fact, the FEA is believed to be currently undertaking studies to determine the fee differentials to be applied to product imports which will discourage such imports, and consequently which will encourage the building of incremental domestic capacity to supply U.S. requirements. It is difficult to speculate about the effect of such policy changes since there is currently such a surplus of refining capacity worldwide. Further, it can be expected that many of the Caribbean refiners, who are U.S. companies, will vigorously oppose moves by the Administration which place them in an unfavorable competitive position. We should also note that current policy in fact favors onshore refining, without the imposition of any new fee differentials, because of the entitlements program and the discontinuation of the supplemental crude import fee.

Referring again to Table C.6-8, if we assume that U.S. refineries can produce a 10% residual fuel oil yield, that Canadian Maritimes exports are 50% residual fuel oil and the Caribbean 70%, then the potential capacity for residual fuel oil manufacture is over 4 MMBCD in 1975, against a currently estimated demand of about 2.5 MMBCD, indicating surplus refining capacity. In fact, Caribbean refineries have suffered severe capacity problems in 1975 and many are believed to have been operating at uneconomic throughput levels. By 1980 it is estimated that there will be 4.6 MMBCD of residual fuel oil manufacturing capacity which indicates that this area's residual fuel oil manufacturing capacity will also be adequate in 1980 to meet U.S. demand, which would have to increase at something over 12%/year to fully utilize the apparently available capacity of 4.6 MMBCD. We tend to feel that it will not be until towards the mid-1980's that new capacity will actually be required to meet U.S. product demand and the same would appear to be true of residual fuel oil. Note that the above excludes consideration of residual fuel oil imports from Europe or from the new export refineries which may be built in some Middle East and African exporting countries such as Saudi Arabia, Iran, Libya, Algeria, and Nigeria.

The forecast over-capacity in refining will have an impact on manufacturing costs in that refiners will presumably be unable to recover fully-allocated manufacturing costs (including capital costs) during this period. Until there is a capacity shortage, full cost recovery will not take place and product price trends are likely to reflect marginal manufacturing economics.

Besides refineries, the oil industry requires ships to move crude oil and refined products. The above conclusions about over-capacity in refineries and the consequent inability of refiners to pass on full costs appears to also be true of tanker freight rates (or costs). By the end of October 1975, the world oil tanker fleet* of vessels of over 10,000 deadweight tons (dwt)+ consisted of 3,457 ships with a total capacity of 278.4 million dwt. In addition, some 22.4 million dwt of combined carrier capacity which is actually used in the oil trades must be added to obtain a total oil carrier fleet capacity of 300.8 million dwt. Of this total oil-carrying fleet, 42.9 million dwt were currently laid-up and a large part of the remaining fleet was estimated to be under-utilized. Freight rates have reached extremely low levels and the current spot rate for transporting crude oil from the Persian Gulf to the Caribbean in a VLCC (very large crude carrier, i.e. a ship larger than 160,000 dwt) is of the order of $0.40/Bbl which can be compared to $2.50/Bbl in mid-1973 for the same movement. Moreover, there were 125 million dwt of tankers

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*Tanker tonnage statistics are from H. P. Drewry's "Shipping Statistics and Economics".

+A "deadweight ton" is one long ton of ship-carrying capacity and is equal to 1.016 metric tons. Since deadweight tons are used universally for ship size designation, such measures will not be converted to metric equivalents.

on order as of the end of October 1975, and almost 9 million dwt of combined carriers. This tremendous fleet expansion had been predicated upon expected exponential increases in oil demand, and on the premise that incremental crude oil would have to be moved from the Persian Gulf. The 1973/74 price increases and the slowdown in oil demand growth rates have thrown both these assumptions awry and most observers now feel that it will be at least the early 1980's (if not later) before tanker supply and demand are again in balance, indicating that there will be several years of very low freight rates in the interim. These low freight rates will, in turn, be reflected in relatively low product prices, including those for residual fuel oil.

C.6.5 CRUDE PRICE CONSIDERATIONS

The major component of the price of residual fuel oil is the cost of the crude oil, and since the U.S. is so dependent upon imports of residual fuel oil and on imported crude oil, a primary factor which needs to be considered is the foreign crude oil price. However, current price legislation means that the full cost of foreign crude oil is not necessarily reflected in residual fuel oil prices, because of the effect of the Entitlements Program. In this section, we shall look at (a) the potential effect on price of current U.S. legislation, (b) historic crude oil prices, and (c) possible future crude oil price trends.

C.6.5.1 The Effect of Current U.S. Crude Oil Price Legislation

The cost of fuel oil which would be calculated from consideration of foreign crude oil cost plus refining and transportation costs must be modified to reflect current U.S. policy. For example, the imposition by the U.S. of import duties, import license base fees and the like increase fuel oil costs above international levels; so also will the compulsory storage program which has been mandated to provide protection from short-term disruptions of supply. The cost of domestic fuel oil is also substantially affected by the crude oil Entitlements Program and price controls on domestic crude oils. The Energy Policy and Conservation Act of December 1975 will roll back U.S. crude oil prices from current levels and thereafter will allow crude prices to increase at up to 10% per year. Proposed detailed regulations for the administration of these provisions have just been issued by the FEA which administers these programs. As applied to residual fuel oils, the general effect of the new legislation, like the preceding regulations, appears likely to establish a raw material cost basis comprising a mixture of lower-priced domestic crude oil and higher-priced foreign crude oil.

By way of illustration of the impact of these governmental actions, the following figures have been developed. Imports currently account for about 35% of U.S. crude consumption and are delivered to the U.S. at about \$13.00/Bbl. Domestic crude oil accounts for 65% of U.S. crude runs and, under the new legislation, is price-controlled at an average of \$7.66/Bbl. This results in an average U.S. crude oil cost of \$9.53/Bbl (0.65 X \$7.66 + 0.35 X \$13.00). The Entitlements Program is designed to cause all U.S. refiners (with some exceptions for small refiners) to have essentially equal crude costs. Thus, a domestic refiner without access to any domestic crude oil sells 0.65 entitlements (he is 65% under the average usage of domestic crude), worth the difference between the domestic crude oil price and the foreign crude oil price (\$13.00 - \$7.66 = \$5.34), receiving \$3.47/Bbl (0.65 X \$5.34) in cash. This refiner's net crude oil cost then becomes the foreign crude oil price less the value of his entitlements (\$13.00 - \$3.47 = \$9.53). Conversely, the refiner who processes 100% domestic crude oil buys \$1.87/Bbl worth of entitlements (0.35 X \$5.34) and his crude cost becomes \$7.66 plus \$1.87 equal to \$9.53, or the same as the refiner processing 100% foreign crude oil. The effect is to set a crude oil cost for refiners covered by the Entitlements Program below that of a foreign refiner which is not covered. This advantage translates directly into lower-cost fuel oil as illustrated in Table C.6-9 which shows residual fuel oil costs calculations including and excluding entitlements when the fuel oil is produced in the Caribbean. It is very important to point out that the

Table C.6-9

Illustration of Delivered Cost of Residual Fuel Oil (2.8% Sulfur) With and Without Entitlements Based on Arabian Light Crude Oil Refined in the Caribbean ($/Barrel)

	With Entitlements	Without Entitlements
f.o.b. Crude Oil Price (Saudi Arabian light)	$11.51	$11.51
Tanker to Caribbean[A]	1.00	1.00
Delivered Crude Oil Cost	$12.51	$12.51
Entitlement Value[B]	3.47	-
Net Crude Oil Cost	$ 9.04	$12.51
Refining Cost[C]	(0.50)	(0.30)
Residual Fuel Oil Cost Ex-Refinery	$8.54	12.21
Tanker to East Coast[D]	0.40	0.40
Customs Duty[E]	0.05	0.05
Residual Fuel Oil Delivered Cost	8.99	12.66

A- Based on average (AFRA) rate for December 1975 for VLCC class Tankers (160,000 DWT Plus).

B- Using domestic crude price average of $7.66/Bbl.

C- Using full cost recovery for 1974 refinery; the negative refinery cost for 2.8% sulfur fuel oil reflects the allocation of a negative cost to this product by the LP simulation model, since high sulfur fuel is valued below crude oil cost.

D- Based on average (AFRA) rate for December 1975 for medium-size tankers (30,000 DWT).

E- Assumes fee free imports.

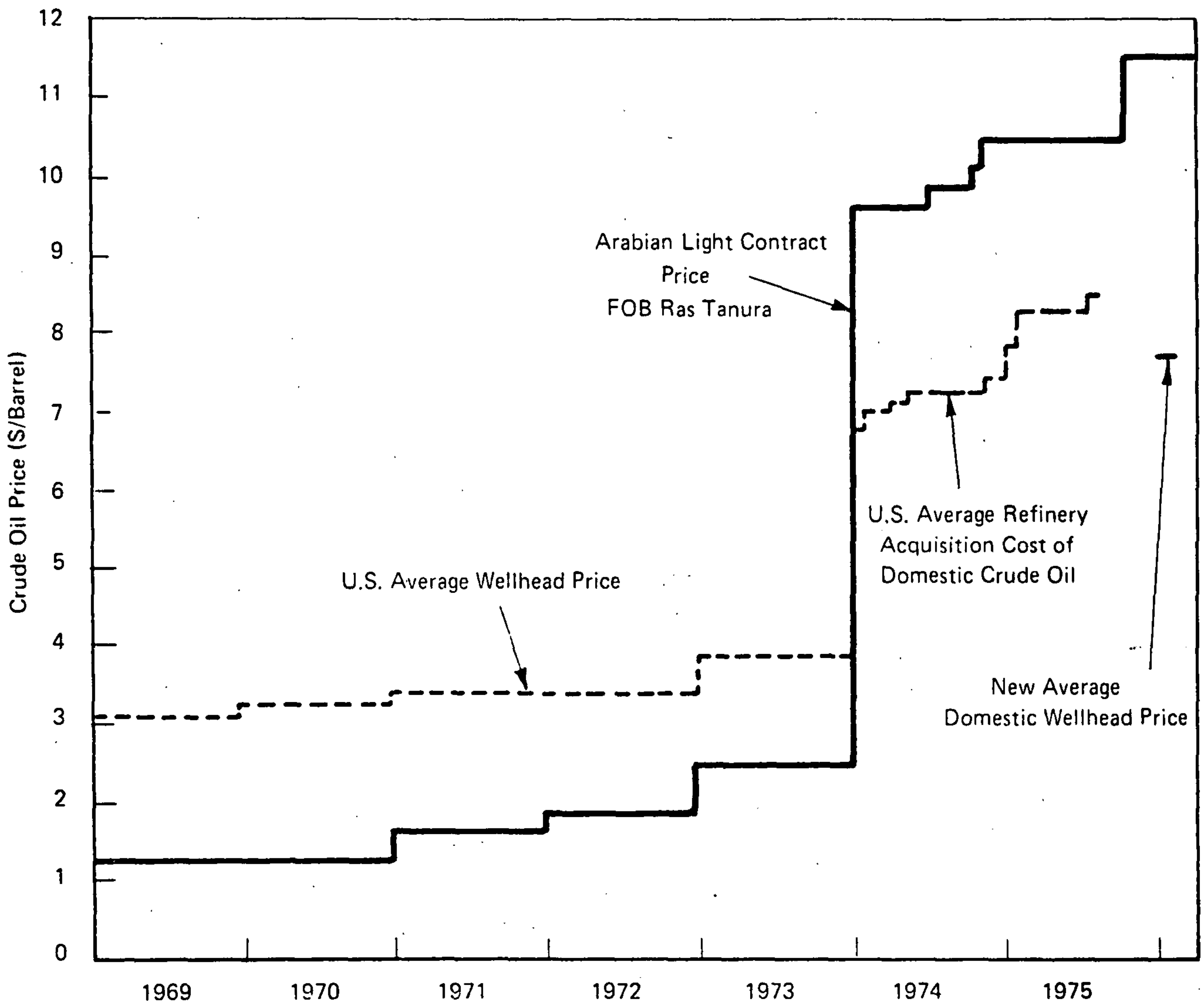
cost to the nation is not the entitlements-adjusted cost of crude oil but the full import cost. The Entitlements Program simply spreads this additional cost across all products and across all regions.

Clearly, a number of uncertainties surround how U.S. policy will evolve in the future, particularly when the federal legislation expires 40 months from now. Beyond this, however, there is the uncertainty as to how current legislation will apply to the historic suppliers to the U.S. East Coast fuel oil market. For example, will the benefits of the Entitlements Program be received by foreign Caribbean refiners which have been the major source of U.S. residual fuel oil supplies in the past?

C.6.5.2 Historic Crude Oil Prices

As shown in Table C.6-9, the cost of crude oil accounts for over 90% of the cost of producing 2.8% sulfur residual fuel oil. Although the costs of refining and tanker transportation have increased rapidly in recent years under the impact of inflation, crude oil price increases have been truly explosive. This is shown in Figure C.6-2, where the f.o.b. price of Arabian Light crude oil is compared with the average U.S. refinery acquisition cost of domestic crude oil.

Prior to 1971, the f.o.b. price of Arabian Light crude oil was about \$1.30/Bbl and the price delivered to the U.S. was about \$2.00/Bbl. U.S. crude oil prices were higher, a little over \$3.00/Bbl, and were maintained by a combination of import restrictions and individual state (notably Texas) production controls. International crude oil prices increased rapidly starting in late 1970. While there is some controversy over the role played by the various participants in the international oil scene which resulted in these price increases, there is little doubt that the price increases reflected the growing market power of the OPEC nations who currently control about two-thirds of free world published oil reserves and about 60% of free world production.



Source: U.S. Crude Prices: Bureau of Mines
Federal Energy Agency
Arabian Light Prices: Arthur D. Little, Inc., estimates.

Figure C.6-2 – HISTORY OF CRUDE OIL PRICES
(Annual Averages Prior to 1974, Monthly Thereafter)

The succession of crude oil price hikes in the post-1969 period were triggered off by rising prices for finished petroleum products which in turn reflected shortages in one or more of the elements in the integrated petroleum chain; these elements being production, transportation, and refining. In each case, the producing countries took advantage of the high product prices by raising taxes and later by partially or completely nationalizing the operations of the oil producing companies. The key events can be summarized as follows:

- In September 1970, following a rapid rise in spot tanker rates, which, in turn, reflected a shortage of tanker capacity, European product prices rose rapidly. Libya, which was in part responsible for the tanker shortage through having cut back production of its "short-haul" crude which then had to be replaced by "long-haul" crude from the Middle East, was able to negotiate a new fiscal package with the oil producing companies holding exploration and production concessions within its territory. The Libyan success led the Middle East countries to seek comparable tax increases and they successfully concluded the Teheran Agreement in February 1971, which called for, among other things, a 5-year built-in increase of taxes (the levels of which, in retrospect, now seem modest). Libya, in turn, dissatisfied with its increases in light of the new Teheran Agreement, went back to the table and successfully negotiated a new tax package, embodied in the Tripoli Agreement of March 1971. This was followed by a succession of agreements related to currency escalation, culminating in the participation agreements of 1973, in which the producing countries acquired partial ownership in their concessionary companies and the right and obligation to market increasing quantities of crude oil directly.

- In spite of what were then regarded as large increases in crude prices, which brought the f.o.b. price of the marker

Saudi Arabian Light crude to $2.30/Bbl by mid-1973, the rapid worldwide growth of oil consumption during 1973 again placed strains on tanker capacity (and, to a lesser extent, refining capacity). Tanker rates increased rapidly and product prices followed. The producing countries took advantage of this market development by unilaterally setting crude oil prices and virtually relegating their concessionary companies to contractor status. Following the October 1973 Arab-Israeli war and the Arab embargo which followed, product prices skyrocketed and the price of Arabian Light crude oil was subsequently fixed at $10.46/Bbl, about 8 times what it had been a little more than 3 years earlier.

- The combined effects of the high oil prices and the worldwide recession brought about a decrease in oil consumption during 1974 and 1975, at the same time as new refining capacity and tanker capacity were becoming operational to deal with anticipated but unrealized historic rates of growth in oil demand. Refinery margins (the difference between the weighted average price of finished petroleum products and the cost of crude), instead of being at cost-based levels, were barely able to cover out-of-pocket costs in many parts of the world. The same was true of tanker transportation. Freight rates dropped precipitously to levels which covered only fuel costs and port charges (i.e., not even enough to cover crew costs, insurance, finance and investment charges). Product prices, in relation to crude prices, dropped to historic lows. Residual fuel oil was particularly hard hit since demand for this product which is heavily dependent on industrial activity dropped the most sharply. In spite of the depressed demand conditions, however, the OPEC countries in October 1975 successfully raised the price of the marker crude by 10% from \$10.46 to \$11.51/Bbl using as one justification the continued inflation in the price of the goods and services they buy from the consuming countries.

Following the OPEC price increases, there was turmoil in U.S. crude oil markets and federal price controls were modified to recognize two categories of crude oil: "old oil" which was price controlled at \$5.25/Bbl and "new oil" which was free to rise to international levels. The intention of the regulations was to hold average domestic crude oil prices down while still providing an incentive to find additional oil in the new oil category. Based on FEA statistics as of August 1975, new oil represented about 40% of domestic supply and the average old oil/new oil price was \$8.48/Bbl. Under the new Omnibus legislation which reflects a compromise between Administration and Congressional views, the weighted average price of domestic oil has been fixed initially at \$7.66/Bbl (for the combination of old and new oil). This regulation, in effect, puts a limit on the new oil prices. The legislation also provides that the weighted average oil price can increase by up to 10% per year, at the President's discretion.

C.6.5.3 Possible Future Crude Oil Price Trends

The OPEC nations, in announcing their 10% price hike in October 1975, agreed to hold the marker crude price (for Saudi Arabian Light) constant at \$11.51/Bbl for the next 9 months. The OPEC nations are, however, becoming increasingly concerned about price relationships between the marker crude and crudes of differing quality and locations. Currently, heavy crudes (those containing a high proportion of residual fuel oil) are under pressure because of the decline in demand for fuel oil. Also, crudes closer to market have seen their geographical premium eroded by the decline in freight rates. Crude oil of all qualities is in abundant supply, given the failure of demand growth following the 1973/74 price hikes, and consuming countries have tended to become more complacent about security of supply. The major industrialized nations, within the context of the newly-formed International Energy Agency, have, however, agreed to a system of crude oil sharing in the event of supply interruptions and to protect investments in the development of alternative energy supplies, have agreed to institute policies creating a minimum domestic safeguard price of $7/Bbl for imported crude oil.

In general, the collapse of the international monetary system which some believed might result from a huge build-up of currency reserves by the OPEC members no longer seems to be a serious threat. The consuming countries have shown a surprising ability to absorb the OPEC price increases although their economies have been slow to recover from the 1974/75 recession. Many observers had projected that consuming countries would have much greater difficulty in absorbing the 1973/74 price increases than actually occurred. Thus, future oil price increases probably could be absorbed as well.

The availability of low sulfur crudes is ample and individual consuming countries are no longer bidding for supplies. However, a continuation of this situation is dependent on the production policies and political stability of one or two countries, particularly Libya and Nigeria, and could change dramatically if demand for low sulfur fuel oil increases or if production in these countries is cut back for any reason.

It is our view, in summary, that the OPEC nations, in spite of current conditions, will be able to hold the current level of prices. To some extent, this is dependent upon member nations reaching a concensus view on relative crude oil prices and on crude production balancing. Saudi Arabia and certain other nations appear to be able to balance production, and since we believe that world demand will increase, the problem of overcapacity will tend to be minimized. Thus, for the next several years, OPEC members will seek to achieve price increases which at least maintain the real price of oil. Given that international inflation is likely to be at least at a level of 5% in the next several years, we would anticipate prices increasing by this amount. We would expect these price increases to be fully reflected in residual fuel oil prices in the U.S. absent the effect of any mandated lower domestic price, and an averaging program such as is currently in existence. In the long-term, by the mid-1980's, we would anticipate that as oil reaches resource limits, and as one or more capacity constraints (in refining, production or transportation) becomes apparent, that OPEC will be able to capitalize this into a quantum increase in price. Of course, this could happen in the much shorter-term and as a result of unforeseen political events.

C.7 ENERGY PRODUCTION TRENDS

C.7.1 INTRODUCTION

In this chapter we discuss the future production trends for four energy sources

- Domestic crude oil
- Foreign crude oil
- Natural Gas
- Coal

We have included coal because it is in many ways the only alternate for fuel source to residual fuel oil. Our discussion of natural gas is included because it has been an important boiler fuel whose replacement in the future with other energy sources will impact heavily on the demand for residual fuel oil.

C.7.2 DOMESTIC CRUDE OIL PRODUCTION

In this section we first establish a framework for discussing crude oil production, then describe the current situation and end by discussing projections of future domestic crude oil production

C.7.2.1 Recent Statistics on U. S. Oil Production

United States year-end proved reserves and annual production are declining as is shown in Table C.7-1. With the Prudhoe Bay field discovery excluded from the totals, proved reserves in the U. S. have declined every year since 1966. Decreasing total U. S. reserves are the result of the general decline since 1965 of annual additions to reserves

Table C.7-1

Statistics on U.S. Domestic Crude Oil
(Excluding Prudhoe Bay in Alaska)

Year	Proved Reserves at Year End (Million Barrels)	Annual Additions to Proved Reserves	Annual Production (Million Barrels)	Indicated Year's Supply of Yr. End Proved Reserves
1965	31,352	3,048	2,849	11.0
1966	31,452	2,964	3,028	10.4
1967	31,377	2,962	3,216	9.8
1968	30,707	2,455	3,329	9.2
1969	29,632	2,120	3,372	8.8
1970	29,401 (1)	3,089 (1)	3,518	8.4 (1)
1971	28,463 (1)	2,318	3,454	8.2 (1)
1972	26,734 (1)	1,558	3,455	7.7 (1)
1973	25,700 (1)	2,146	3,361	7.6 (1)
1974	24,650 (1)	1,994	3,203	7.6 (1)
1975	NA	NA	3,055	NA

(1) Figures exclude 9,600 million barrels located at Prudhoe Bay, Alaska which cannot be produced prior to the 1977 completion of the Trans Alaskan Pipeline.

NA - Not available at time of writing.

Source: American Petroleum Institute

and the continued high production from existing reserves at the maximum efficient rate.* U.S. crude production continued to increase until 1970 but has declined since then. The ratio for the U.S. of proved reserves to production began to decrease over a decade ago as production exceeded reserve additions.

Five major oil producing areas in the U.S. collectively produced 82% of total U.S. production in 1974. Table C.7-2 shows annual production in each of the five major U.S. producing areas. The year production peaked and began to decline in each area has been underlined for emphasis. As can be seen, all five regions have already peaked in production anywhere from three to six years ago.

A disturbing aspect of the production trends shown in Table C.7-2 is that the only way to slow the production declines is by the addition of new oil reserves. However, the onshore portions of the five areas are the most thoroughly explored and drilled petroleum regions in the world, and there is little prospect for finding large amounts of new oil reserves.

Because of the extent of exploration and the history of production in each of the five major U.S. areas, regional production trends generally can be compared with a typical oil field production profile. Production profiles of oil fields are predetermined by engineers to maximize the total recovery of oil. Initially, production increases rapidly until it reaches a long-term plateau at the MER for the field. The field is produced for most of its life at the MER before a rapid production decline begins. Oil field facility equipment capacities are sized for production at the MER. When field production rates begin to fall below the MER, it indicates that the ability of the field to produce will decline rapidly until production becomes insignificant.

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*The maximum efficient rate (MER) of production is defined to be the maximum sustainable production from a field which will not decrease the total volume of oil recoverable from the field.

As a rough approximation, production trends in onshore portions of the five major producing regions are similar to the production profile of an individual field. During development of the areas, production increased and then stabilized before beginning a production decline corresponding to aging of the producing fields in the regions. Only discoveries of large, new fields will compensate for the regional production declines, and probably there are few, if any, large fields remaining undiscovered onshore in the lower 48 states.

As an indication of the intensity of previous exploration of the lower 48 states, Table C.7-3 compares the number of producing oil wells at the beginning of 1975 in Texas, Louisiana and the U.S. to the non-communist world and the Middle East. One third of the free world's currently producing oil wells are located in Texas and Louisiana, and 88% of the world's oil wells are in the U.S. This is in spite of the fact that in the last five years more than 90,000 U.S. oil wells have been abandoned. Another important fact to note from Table C.7-3 is that U.S. well productivities are significantly lower than those of other world areas due to reservoir characteristics and the length of time fields have been produced. Of the 494,352 oil wells in the U.S., 355,229, or 71.9%, are classified as stripper wells* which as a category averaged production in 1974 of 3 barrels of oil per day. This means that the rest of the wells averaged about 55 barrels per day, well below the world average. It should be noted that many U.S. offshore wells are very productive (some more than a thousand barrels per day) but these are the exception rather than the rule in the U.S.

C.7.2.2 Projections of Future U.S. Crude Oil Production

Future production depends critically on future additions to reserves since at current production rates present reserves would be totally exhausted in a little over seven years. Future reserves depend on how much oil is

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*A stripper well is defined as a well averaging 10 barrels or less of daily production.

Table C.7-2

Petroleum Production From the Five Major U.S. Producing Areas and Year of Peak Production

(MBBLS/Day)

Area	1968	1969	1970	1971	1972	1973	1974
Texas(1)	3,097	3,155	3,424	3,350	3,557	3,547	3,454
Louisiana(1)	2,234	2,314	2,485	2,562	2,437	2,278	2,018
California(1)	1,026	1,028	1,020	982	948	921	884
Oklahoma	611	616	613	584	567	524	487
Wyoming	394	424	439	406	382	389	386
Rest of U.S.	1,759	1,702	1,657	1,579	1,575	1,549	1,546
Total U.S.	9,121	9,239	9,638	9,463	9,466	9,208	8,775

(1) Includes both on- and offshore production

Source: American Petroleum Institute, "Annual Statistical Review", May, 1975.

Table C.7-3

Comparison of U.S. And World Numbers of Producing Oil Wells And Average Well Productivities
(January, 1975)

Area	Number of Producing Oil Wells	% of Wells in Each Area of World Total	Average Well Productivity (Barrels per Day)
Non-Communist World (excluding U.S.) of Which	67,288	12	501
Middle East	3,919	0.7	5,658
United States of Which			
Texas	159,090	28	22
Louisiana	28,000	5	83
Total U.S.	494,352	88	17
Total Non-Communist World	561,640	100	75

still left in the ground to be discovered.

C.7.2.2.1 Future Oil Reserve Forecasts - Predictions of undiscovered recoverable resources of oil are done using two major estimating approaches, geological and mathematical. Geological estimates relate past exploration and production statistics to the measured volumes of sedimentary rock strata which potentially could contain oil and gas reservoirs. The presumption is that unexplored, relatively unknown areas have general characteristics which are similar to areas which have been previously explored and developed. Mathematical predictions use historical statistical trends of geological and technical relationships to project future conditions. A number of such mathematical techniques, such as Gompertz curves and normal distributions, have been used in forecasting future oil production. Wide variations in resource estimates arise in part due to the different predictive techniques. In Table C.7-4 the Hubbert estimate was made using a mathematical approach while the other estimates in the table were derived using geological estimating methods. The table shows estimates of how much oil, presently undiscovered, will ultimately be found and produced in the United States. These projections essentially ignore the cost of such production and also assume that recovery techniques will be improved in the future.

The 1974 USGS estimate appeared to be overly optimistic and was downrated in 1975 by significantly more than half. The National Petroleum Council estimated range is in general agreement with other forecasts which have been made and is the one which we have assumed to be most valid. Hubbert's estimate appears conservative but, significantly, falls in the range of the latest USGS estimate so that the mathematical and geological techniques are beginning to converge on a reasonable range of values.

Recent major exploration failures, such as the $650 million invested in a non-productive exploration effort of the Dustin anticline of Florida, quickly influence geologist's opinions which are used in forecasts based on geological correlations and this may partly explain the large decline in the USGS prediction from 1974 to 1975. All the estimates in the table indicate that the bulk of undiscovered oil will be either offshore, or in Alaska.

The forecasts of future recoverable oil resources indicate that at roughly today's present level of oil production all the oil will have been produced in the United States within 35-55 years. Under actual conditions, the production level will not continue at the present rate but will continue to decline. Small quantities of oil will continue to be produced for many years, but all of the estimates predict that U.S. oil resources are finite and are being rapidly used up.

C.7.2.2.2 Future Oil Production Forecasts - Table C.7-5 presents four recent projections of future U.S. petroleum liquids* production. Although the projections are based on different assumptions about U.S. energy demand growth and about the production of alternative fuels, the forecasts rather uniformly predict that maximum production of domestic petroleum would occur under favorable government leasing and exploration policies. Assumptions about petroelum pricing are different among the forecasts.

Exxon's 1975 projection assumes U.S. oil prices will rise with inflation rates of 8% through 1977 and 6.2% through 1985. The Library of Congress projection assumes complete price decontrol while the Standard Oil of Ohio (SOHIO) projections are shown under both price decontrol and under the new Energy Policy and Conservation Act of 1975 (EPCA) regulations which permit the national weighted average composite price to be escalated at 10% per year. Thus, the Exxon and the SOHIO price regulated forecasts provide a low side to anticipated future production while the SOHIO price decontrolled and the Library of Congress forecasts provide a

*Including crude oil and natural gas condensates.

Table C.7-4

Various Estimates of Undiscovered Recoverable Resources of Oil
(Billions of Barrels)

Source	Date	Lower 48 States Onshore	Total
U.S.G.S.	1975	NA	50-127
U.S.G.S.	1974	110-200	200-400
Nat'l. Petroleum Council	1974	53-70	73-140
M. King Hubbert	1972	9	72

Table C.7-5

Projections of U.S. Petroleum Liquids Production
(MMBBLS/Day)

	1970	1973	1974	1975	1980	1985
Exxon (1975)	11.3	11	10.5	10.0	9.6	10.8
Exxon (1974)	11.3	11	10.5	10.6	10.8	10.5
Standard Oil of Ohio (1975)						
(1) Newly enacted price regulations	11.3	11	10.5	10.0	10.5	11.1
(2) Price Decontrol	11.3	11	10.5	10.0	12.2	14.3
Library of Congress (1975)	11.3	11	10.5	9.6	11.0	12.0

high side for future production. We assume that future crude oil production will fall somewhere between the low and high forecasts.

Projections of future domestic oil production must account for three factors: 1) the rate of the production decline from the lower 48 states onshore and the contribution of tertiary recover programs; 2) the scheduling of offshore lease sales and the rapidity of exploration of virgin acreage; and 3) the scheduled completion of the Trans-Alaskan pipeline and development of Prudhoe Bay and related fields.

The production decline of the lower 48 onshore will be slowed by increased drilling activities which will be directed primarily at further development and extension of existing fields. Wildcat drilling* has and will decrease; and new additions to reserves will most likely be in small increments.

Tertiary recovery programs in some areas of the country are and will be implemented but will create relatively insignificant production by the mid-1980's. Tertiary recovery techniques hold the promise of recovering almost as much oil from old fields as has previously been withdrawn during the primary and secondary production stages. Primary production depends on natural pressure or pumping to bring the oil to the surface. Secondary recovery techniques are used to repressure old fields and hence drive more oil to the producing wells. Gas or water injections into the formation are usually used to provide the pressure. Tertiary recovery techniques use chemicals or heat to force more oil out of the oil bearing formation by enabling the oil to move more easily within the formation. Primary and secondary recovery methods usually cannot recover more than about 30% of the oil originally in place while tertiary techniques can recover an additional 30%. Forty percent of the oil in the ground thus can never be recovered.

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*Wildcat wells are those drilled in areas which have not been previously explored.

The largest offshore areas of the U.S. have not been explored by drilling, although most of the areas have been surveyed using seismic profiling techniques. From the seismic studies large geologic structures are known to exist in the offshore areas which are expected to contain oil. The two largest factors affecting potential offshore development are whether the government will adhere to its accelerated leasing program and whether the petroleum accumulations are concentrated in large volume reservoirs.

At present several of the offshore areas most interesting to the industry, including the Gulf of Alaska and the Baltimore Canyon trough off of the U.S. East coast, are expected to be leased prior to mid-1977. Other areas such as the Georges Banks will not be offered for lease bids for several years. At present, the government leasing program is proceeding relatively slowly due to a lack of allocated funds to provide the manpower needed to handle the leases and due to the environmental impact statements which need to be written for each lease area. Of the two problems, the environmental constraints seems to be causing the longest delays.

Even with early leases of the offshore areas, however, it is estimated that exploration and development of the geologically complex and previously unknown areas will require from 7 to 10 years before significant volumes of oil will be produced.

A key consideration about the petroleum deposits to be found offshore will be their size. Small accumulations of oil simply are uneconomic offshore as a result of the high costs of developing fields which are in deep water and harsh operating environments. For example, in the North Sea, where water depths and weather conditions are similar to the conditions in the Gulf of Alaska and off the Northern U.S. East coast, a field must contain 300 million barrels or more before it can be developed under today's economic conditions. For contrast, only one field has been found in the Gulf of Mexico which contains more than 300 million barrels while many others of smaller size have been developed since the Gulf of Mexico has calmer weather and shallower water depths than the North Sea. Forecasts of the development of U.S. offshore areas are not constrained by manpower or equipment shortages since it is anticipated that both these factors will be in adequate supply. At one time it was thought that there would be a shortage of the type of rigs needed to do the work due to a high demand for such rigs in other parts of the world. That demand has slackened recently and no rig shortage is anticipated in the next decade.

Production of Alaskan oil from its southern fields has declined since 1972, but when the Trans-Alaskan pipeline begins delivering oil to the lower 48 states its production will increase dramatically. It is now estimated that in 1977 initial volumes of 600,000 B/D of oil will begin to flow southward through the pipeline. By 1978 up to 1.2 million barrels per day will become available from the Prudhoe Bay fields.

C.7.3 FOREIGN CRUDE OIL PRODUCTION

Although synthetic fuels, coal, nuclear power and other sources of energy are being developed to meet future world energy demands, oil production will continue through 1985 to be the only source of energy which will be able to respond significantly to the growth of world energy demand as well as absorb short-term demand fluctuations by the world economy. In this section we look at two recent forecasts produced by the Library of Congress and by a major oil company.

C.7.3.1 Exxon Forecast (December, 1975)

Using projections of growth rates of key world economies to establish future world energy demand, Exxon has forecast the contributions of oil and other energy sources to world energy supply. Three factors which form the basis of Exxon's world oil supply forecasts are: that economic and technical constraints will limit alternative energy sources to a relatively gradual development prior to 1985; that an average of an additional 15 billion barrels of crude oil reserves must be discovered every year; and that world markets will have continued access to OPEC production which will act as the supply balancing mechanism. Exxon's projection through 1985 of non-Communist world oil production is given in Table C.7-6. Note that the bottom line is Exxon's forecast of oil demand which means that the OPEC production level has been set to balance the difference between world demand and the ability of other areas to produce oil.

Exxon has based its projections on a non-Communist world energy demand growth of 4% per year through 1977 and a lower 3.3% per year from then until 1990. Non-oil energy annual growth rates of 3.6% through 1977 and 4.7% through 1985 are assumed, which implies that oil demand will grow 5.2% a year to 1977 and at 3.3% a year from then to 1990. See Table C.7-7 which shows the assumptions Exxon made about GNP and inflation and growth rates as well as showing the energy growth rates.

Exxon's production estimates indicate increased production from existing OPEC reserves will be needed to match world demand and discovery of additional world reserves will be needed to achieve the production rates shown. Since the 1940's, additions to crude reserves have averaged 15-20 billion barrels per year with the largest portion located in the Middle East and Exxon has assumed a continuation of that trend. Discoveries outside the Middle East have steadily increased during the past decade as higher oil prices have prompted supply diversification and stimulated exploration. This is offset somewhat by the fact that most of the major fields in the Middle East appear to already have been found.

Exxon assumes that aggressive exploration efforts stimulated by higher oil prices will be initiated on acreage provided through reasonable host government policies and consequently new world reserves can be found at an average of 15 billion barrels per year.

It should be noted that in the early 1970's world annual oil production

Table C.7-6

Non-Communist World Oil Production As Projected by Exxon
(MMBBLS/Day)

Production Source	1974	1980	1985
OPEC	31	37	43
Europe	0	4	5
U.S.A.	10.5	9.6	10.8
Other Non-OPEC	6.5	7.4	9.2
Net Imports from Communist Countries	1	1	1
Total World Demand	49	59	69

Table C.7-7

Exxon's Assumed Growth Rates
Non-Communist World

	1965-73	1973-75	1975-77	1977-90
Real GNP	4.7	(1.5)	4.2	3.9
Inflation	3.3	12.5	8.0	6.2
Energy Demand	5.1	(1.8)	4.0	3.3
(1) Non-Oil	3.3	1.9	3.6	4.7
(2) Oil	7.4	(2.4)	5.2	3.3

began to exceed annual additions to world reserves and, given Exxon's projection of reserve additions, by the late 1980's oil production will become limited by reserve availability just as the U.S. production became reserve limited in the early 70's.

According to Exxon's projections, oil production in Western Europe will go from almost zero in 1974 to over 5 MMBCD by 1985 as a result of North Sea development. Communist countries will also increase their production. Russia, currently the world's leading producing country, is expected to expand production, and China is projected to become a major oil producing nation by 1985. However, as a result of internal consumption, net exports from Communist countries are projected to stay at roughly 1 MMBCD through 1985.

North American production is expected to decline until Alaskan, offshore and Arctic areas are developed, but 1985 production levels are shown to be essentially the same as in 1974. Production in all other non-OPEC countries is projected to increase rapidly reflecting projected discoveries in Latin America, Africa and the Far East.

In order to balance total oil and energy requirements, increasing volumes will be needed from OPEC, rising from 31 MMBCD currently to 43 MMBCD by 1985. OPEC crude oil production reached a peak of 32 MMBCD in 1973 before declining to about 26 MMBCD in mid-1975 due first to the Arab embargo and later to the world economic recession. In 1975 OPEC had spare producing capacity of over 10 MMBCD. OPEC production now is increasing to meet the needs of the industrialized nations emerging from the recent recession. By 1985 OPEC as a whole could be supplying up to 45 MMBCD. However, because of limited long-term production growth by OPEC countries located outside the Persian Gulf area, the burden of balancing world oil requirements will fall increasingly on Saudi Arabia and to a lesser extent on Kuwait and the Arab Emirates.

The Arabian Peninsula producers are likely to approach maximum production capabilities sometime soon after 1985, indicating that at that point world oil production will have increasingly limited flexibility to adjust to world demand increases.

C.7.3.2 Library of Congress Forecast (November 1975)

Projections of world oil production given in a recent Library of Congress study are shown in Table C.7-8. These projections tend to agree with the Exxon forecast as the world demand estimates are approximately the same; however, there are several significant disparities between the assumptions made in the two forecasts.

The Library of Congress study does not include 1 MMBCD of Communist country exports, and the study bases its projection of U.S. production on a decontrolled price situation. Exports from the Communist countries appear to be a reasonable assumption for the future given China's proximity to the Japanese market, the use of western technology to develop China's resources and Russia's new position as the world's largest producing country. Thus the Library of Congress study may understate the free world's availability of oil somewhat.

Given the recently enacted EPCA it is likely that U.S. production of crude oil, condensate and natural gas liquids will not be able to sustain present production levels, and the addition of 1.2 MMBCD of Alaskan production will only partially compensate for production declines in the lower 48 states. Thus it may be difficult for U.S. production to reach the levels projected in the Library of Congress study.

C.7.3.3. Dependence on Arabian Peninsula Countries

If the future world oil demand as estimated in both the studies mentioned above is to be met, the major source of oil supplies through 1985 will be the three Arabian Peninsula countries shown in Table C.7-9. However, massive production from these areas probably will not serve the internal

Table C.7-8

Non-Communist World Oil Production
As Projected by Library of Congress
(MMBBLS)

Source	1980	1985
OPEC	36	40
Europe	4.5	5.9
U.S.A.	11.0	12.0
Other Non-OPEC	6.9	10.3
Total World Demand	58.4	68.2

Source: "Towards Project Interdependence: Energy in the Coming Decade", The Library of Congress, Dr. Herman T. Franssen, December, 1975.

Table C.7-9

Reserves and Productive Capacities of the Arabian Peninsula Countries

Country	Oil Reserves (Bil. of Barrels)	Percent of World's Oil Reserves	Estimated Current Prod. Capacity (MMB/D)	Ave. Daily Prod. Mid-1975 (MMB/D)	Spare Current Prod. Capacity (MMB/D)
Saudi Arabia	173.1	35	11.0	6.76	4.24
Kuwait	81.4	16	2.9	1.93	0.97
United Arab Emirates	33.9	7	3.7	1.7	2.0
Totals	288.4	58	17.6	10.39	7.21

Source: "Towards Project Interdependence: Energy in the Coming Decade", The Library of Congress, Dr. Herman T. Franssen, December, 1975.

interests of these three countries. These countries have small population bases and limited internal capital absorption capabilities and disproportionately large oil revenue surpluses. The long-range socio-economic and political interests of the countries probably would be best served by limiting production and thereby protecting the life of the finite oil reserves. Although other major OPEC producing countries have current capital needs in excess of oil revenues and will continue to maximize oil production, the Arabian Peninsula producing countries will have increasing oil payment surpluses which could accumulate to about $500 billion current dollars by 1985. Thus blind dependence on Arabian Peninsula countries to meet the world oil need may not be wise.

C.7.4 NATURAL GAS

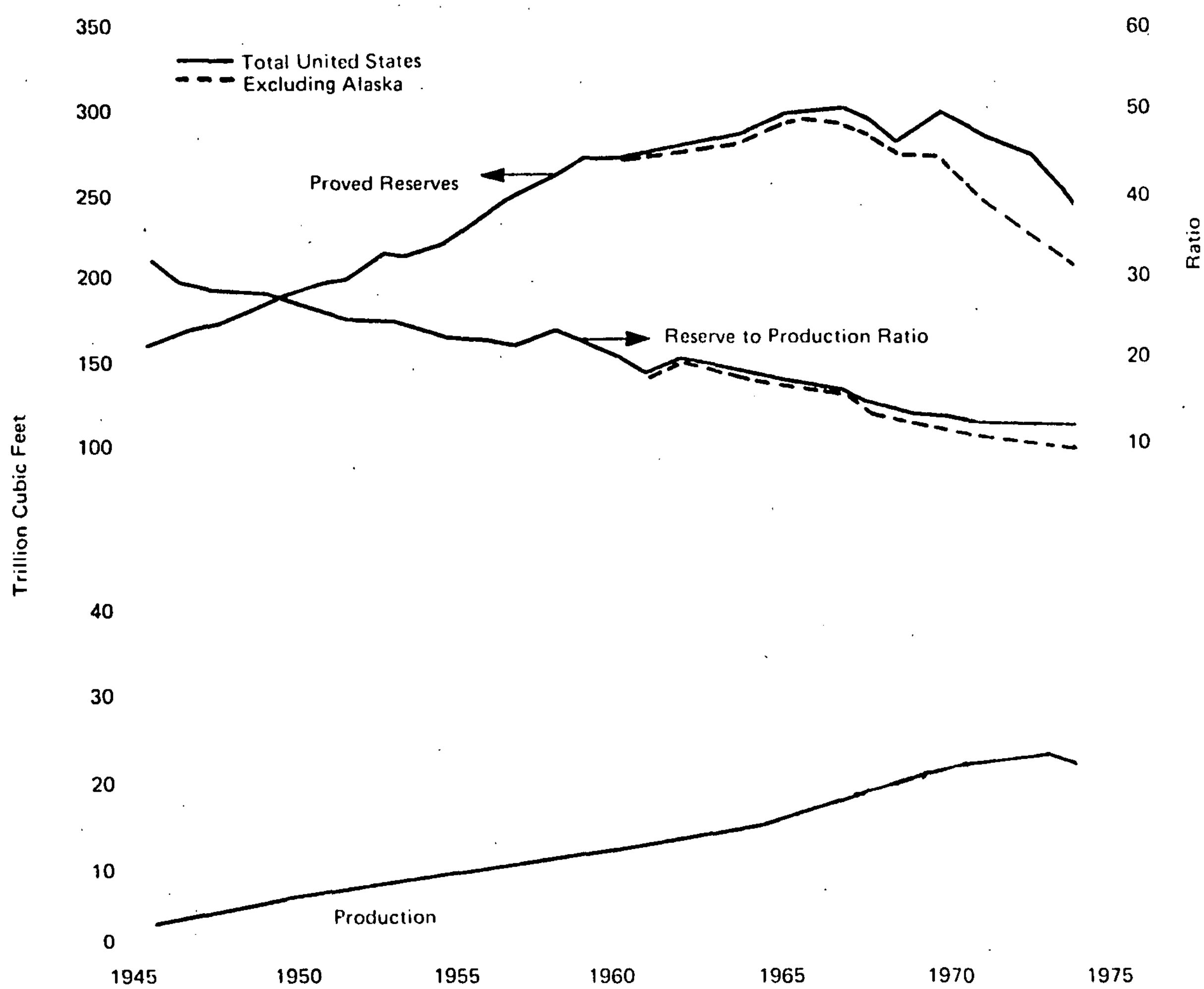
C.7.4.1 Natural Gas Supply in the U.S.

Annual natural gas reserve additions since 1967 have failed to keep pace with gas production so that proved reserves have begun to decline, especially since 1970. The reserve-to-production ratio--a measure of how many more years present reserves will last at current withdrawal rates--has declined steadily since 1945 and fell to 9.2 years in 1974; i.e., at current withdrawal rates only 9.2 years of natural gas reserves still remain. Figure C.7-1 graphically illustrates the decline in reserves and the R/P ratio and, in addition, shows that domestic production did not decline with the reserve addition trend line but continued to increase until 1973.

The Federal Power Commission's (FPC) exhaustive study, the "Natural Gas Survey", indicated a range of possible future proved reserve positions in their four alternate cases. Case 1 was to model business as usual conditions while Case 4 was a most optimistic case about exploration and development. We feel that Cases 1 or 2 are more realistic in the current situation and have used these in our forecasts of future production levels. We feel that, although the gas shortage has become acutely evident since 1973, government inaction and indecisiveness have prevented attainment

Figure C.7-1

U.S. Natural Gas Supplies, 1946-1974



Source: Federal Power Commission, *National Gas Survey.*

of the accelerated cases which the FPC had postulated would be needed to increase gas supplies by 1985. Table C.7-10 shows the range of possible additions to reserves which have been forecast plus the forecast production levels. Even given the high end of the forecast, by 1985 there will be less gas production than in 1975.

Table C.7-10 also shows our estimate of total gas availability (which includes natural gas production, supplements and imports) in the United States through 1985. Our estimate of potential alternate and substitute supplies of natural gas which will become available over time and that can be used in addition to natural gas production includes LNG, pipeline imports and SNG projects (from both coal and petroleum). It can be seen that these alternate sources are expected to have a significant impact on the total gas supply by 1985. The high side of our domestic production figures includes Alaskan gas arriving in the lower 48 states by the mid-1980's at a level of about 2 TCF by 1985. This is in line with the FPC Case 2 forecast although we are now less optimistic about such deliveries by 1985. We feel that the high side of this forecast range is less probable than the lower values due to uncertainties about Canadian gas imports and the continued lack of a national energy policy.

C.7.4.2 Potential Demand for Natural Gas

In 1973 the Future Requirements Committee (FRC) of the American Gas Association forecast a 1985 demand for natural gas of 39 TCF based primarily on historical demand growth rates. Now we know that such unconstrained demand will be impossible to meet but the difference between the FRC demand number and our estimate of future production points out the magnitude of the gas shortage which will occur. Demand forecasts thus must be supply-constrained and hinge on assumptions about supply allocations.

C.7.4.3 Probable Demand for Natural Gas

Since demand for natural gas is supply constrained, we must look to the

Table C.7-10

Future U.S. Natural Gas Year-End Proved Reserves and Production Levels
(Trillions of Cubic Feet)

	Year-End Reserves	Marketable[A] Production	Supplements and Imports	Total Gas Availability
1975	239 - 241	18.1	1.4	19.3
1980	204 - 222	16.4 - 17.5	2.2	18.6 - 19.7
1985	162 - 201	13.0 - 16.3	4.9	17.9 - 21.2

[A] 86% of production after field use, repressurization, and losses reduce gross withdrawals.

Source: F.P.C., Arthur D. Little, Inc.

potential supply as our maximum usage level and determine how the supply will be allocated among the users. In 1973, the Federal Power Commission issued a curtailment priorities list which is shown in Table C.7-11. We have assumed that this general priorities system will continue in effect in the future. The main point to be noted from Table C.7-11 is that large boiler use has a very low priority, especially if alternate fuels might be available. We conclude that, on a national basis, by 1985 large boiler use of natural gas will have been curtailed. This national assumption, however, is mitigated somewhat by the question of intrastate gas.

C.7.4.3.1 Intrastate vs. Interstate Gas Supplies - Since the FPC began regulation of interstate gas supplies in the mid-1950's, new supplies have increasingly gone to the *intra*state market, where the price has been unregulated. Table C.7-12 shows the prices of interstate and intrastate gas since 1966 and clearly demonstrates the wide gulf between the inter- and intrastate gas markets.

From previous work done by ADL, we conclude that without intervention by the federal government the intrastate market could probably absorb most new natural gas supplies which would become available, such that by 1985 there would be very little new gas moving in the interstate market. This would imply that the interstate market would be dependent on old gas supply contracts which would in turn be dependent on rapidly dwindling gas reserves. Currently, about the only new gas reserves being dedicated to the interstate market are those from offshore federal lease lands; almost all onshore new gas supplies are being dedicated to the intrastate market. The implication of this is that those regions with available intrastate gas would be far less impacted by gas shortages than those regions without gas production capabilities.

We feel that federal intervention will eventually force more gas into the interstate market to lessen regional inequities and this will mean that low priority uses, even in intrastate markets, will be curtailed

Table C.7-11

Federal Power Commission Natural Gas Curtailment Priorities

"The national interests in the development and utilization of natural gas resources throughout the United States will be served by recognition and implementation of the following priority-of-service categories for use during periods of curtailed deliveries by jurisdictional pipeline companies:

(1) Residential, small commercial (less than 50 MCF on a peak day).

(2) Large commercial requirements (50 MCF or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs, and pipeline customer storage injection requirements.

(3) All industrial requirements not specified in (2),(4),(5),(6),(7),(8),or(9).

(4) Firm industrial requirements for boiler fuel use at less than 3,000 MCF per day, but more than 1,500 MCF per day, where alternate fuel capabilities can meet such requirements.

(5) Firm industrial requirements for large volume (3,000 MCF or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements.

(6) Interruptible requirements of more than 300 MCF per day, but less than 1,500 MCF per day, where alternate fuel capabilities can meet such requirements.

(7) Interruptible requirements of intermediate volumes (from 1,500 MCF per day through 3,000 MCF per day), where alternate fuel capabilities can meet such requirements.

(8) Interruptible requirements of more than 3,000 MCF per day, but less than 10,000 MCF per day, where alternate fuel capabilities can meet such requirements.

(9) Interruptible requirements of more than 10,000 MCF per day, where alternate fuel capabilities can meet such requirements.

The priorities-of-deliveries set forth above will be applied to the deliveries of all jurisdictional pipeline companies during periods of curtailment on each company's system; except, however, that, upon a finding of extraordinary circumstances after hearing initiated by a petition filed under Section 1.7(b) of the Commission's Rules of Practice and Procedure, exceptions to those priorities may be permitted.

The above list of priorities requires the full curtailment of the lower priority category volumes to be accomplished before curtailment of any higher priority volumes is commenced. Additionally, the above list requires both the direct and indirect customers of the pipeline that use gas for similar purposes to be placed in the same category of priority."

Source: Federal Power Commission Statement of Policy on Utilization and Conservation of Natural Resources - Natural Gas Act, Docket #R-469, Order #467, Issued January 8, 1973 (modified March 2, 1973).

Table C.7-12

Prices Received by Producers for Natural Gas Sales, 1966-1975
(cents per thousand cubic feet)

	Average Wellhead Prices	New Long-Term Interstate Contracts	New Gulf Coast Intrastate Contracts
1966	15.7	17.7	15.1 - 19.5
1967	16.0	18.8	15.6 - 19.6
1968	16.4	19.6	16.1 - 20.2
1969	16.7	19.9	14.4 - 21.5
1970	17.1	22.3	18.5 - 23.0
1971	18.2	24.8	20.6 - 26.2
1972	18.6	35.1	23.5 - 30.0
1973	21.6	40.3	25 - 125
1974	26.7	43-51	125 - 195
1975	35.0		175 - 211

Sources: Foster Associates; U.S. Bureau of Mines, Natural Gas Annual, 1973; Federal Power Commission; Jensen Associates; and Arthur D. Little, Inc., estimates.

by 1985. The impact of this will be felt primarily in the major gas producing areas of Louisiana, Oklahoma and Texas, where utilities use large quantities of intrastate gas and do not have ready access to alternate fuel sources.

C.7.4.3.2 Impact on Utilities - We anticipate that, because of the lack of supplies, all interstate utility boiler use of natural gas will be eliminated by 1980. There may be a few circumstances of summer use of natural gas and some use in peakshaving units, but this will be of insignificant volume. In the intrastate market we feel that, by 1985, the same situation will apply, but that in 1980 the situation could still be very much undecided. The Texas Railroad Commission recently ruled that boiler use of natural gas in Texas would be reduced by 10% by 1981 and there would be a 25% mandated reduction in boiler use by 1985. Large utilities in that region, however, are planning to phase out all use of gas earlier than this in anticipation of federal controls on intrastate utility use of natural gas. We anticipate that, by 1980, intrastate natural gas usage will be limited to old contracts and that new gas supplies will not be available to utilities. By 1985, we assume that intrastate gas will not be used in utility boilers to a substantial degree.

C.7.4.4 Future Natural Gas Price

The current debate on deregulation of natural gas prices must be resolved before forecasts of future gas prices can be made with any accuracy, but we feel that future prices of new interstate natural gas supplies will primarily be a function of competing fuel prices and intrastate market conditions. The FPC has begun to allow private companies to make purchases in the intrastate market for movement through the interstate pipeline transmission system to the point where the company wants to use the gas. Such gas as is thus obtained will be bought in competition with intrastate industrial concerns who are buying gas for process use. This will increase the competition in the intrastate market. We anticipate that 1985 prices for natural gas will be equivalent on a BTU basis to the prices for fuel oil which means that gas prices might be in the range of \$3.50 - \$4.50/MMBtu. By 1980 parity with fuel oil prices will probably not be achieved for all supplies of intrastate gas but, for planning purposes, we can assume that the price will be \$2-3/MMBtu for such new supplies as are available.

C.7.5 COAL

The world's largest source of fossil fuel energy is contained in coal reserves. In 1973 world coal production was less than 1% of reserves but accounted for approximately 28% of the world's total energy consumption. In contrast, about 3% of the world's petroleum reserves were produced in 1975 and accounted for 45% of total world energy consumption.

About one-third of the world's recoverable coal reserves are located in the U.S.; and in 1973 the U.S. coal mining industry accounted for slightly less than a quarter of the total world coal production as shown in Table C.7-13.

C.7.5.1 U.S. Historical Coal Production

Because of large available reserves, U.S. coal production has been able to fluctuate in response to irregular growths in demand. As shown in Table C.7-14 the U.S. has a demonstrated coal reserve base of about 435 billion tons of which about 50% is economically recoverable under current conditions. The reserves are split roughly equally between East and West. Over two-thirds of the coal reserves are considered to be available only by underground mining methods.

U.S. coal production became significant and rose throughout the 1800's to a peak of 678 million tons in 1918 during World War I before falling to a low of 359 million tons in 1932 during the world business recession. Domestic production then increased again during World War II through 1947 reaching an all time peak of 688 million tons before falling as a

Table C.7-13

World Coal Statistics - 1973

Region	Reserves (Billion Short Tons)	Production (Million Short Tons)	% Of World Production
Sino-Soviet Bloc	307	1,266	51.0
United States	217	599	24.2
Western Europe	72	303	12.2
Far East + Oceania	46	207	8.3
Africa	17	74	3.0
Other Western Hemisphere	9	32	1.3
Total	668	2,481	100.0

Source: Energy Perspectives, U.S. Department of the Interior, February, 1975.

Table C.7-14

1974 U.S. Demonstrated Coal Reserve Base*
By Potential Mining Method
(Billions of Short Tons)

	Total U.S.					
	Billion Tons	%	Western	% of Total U.S.	Eastern	% of Total U.S.
Surface	137	32	103	24	34	8
Underground	298	68	129	30	169	38
Total	435	100%	232	54%	203	46%

*Note: Approximately 50% of Demonstrated Coal Reserve Base is economically recoverable.

Source: U.S. Geological Survey Bulletin 1412, "Coal Resources of the United States, January 1, 1974."

result of oil and gas penetration of transportation, home heating and industrial fuel markets. After decreasing to 420 million tons in 1961, coal production has increased substantially in response to the lower cost of coal resulting from the increasing size and efficiency of strip mining machinery and in response to increased demands of the electric utility industry. Since 1961 coal demand by utilities has risen at a rate which has more than offset declines in demand from all other consuming sectors. Highly productive strip mining has risen from 1% of production in 1917, a previous period of high coal demand, to over 50% of production in 1974. In addition to the trend towards increased production from strip mines, the coal industry has been moving westward so that in 1974 15.4% of all U.S. coal production came from the Western areas, as compared to 7.4% in 1970.

C.7.5.2 Projected Demand for Coal

Electric utilities are the major consumers of coal and will continue as such at least through 1985. Table C.7-15 shows projected demand for coal by user category. In 1974 utilities consumed 390 million tons, accounting for 63% of coal and lignite demand. Projections of electricity demand and utility consumption of primary energy sources indicate utility requirements will be 616 million tons and 741 million tons in 1980 and 1985, based on electric load growths of 6.2% per annum. The utility percentage of total coal demand is expected to decrease after 1980 as increased nuclear power generation reduces utility demand for coal at the same time as other coal markets begin to increase slightly.

Markets for coal other than that of electric utilities will begin to develop and increase slowly prior to 1985 but will not develop rapidly until later years. Demand for metallurgical grade coking coal by domestic and foreign steel industries will increase through 1985 but will be limited by improved efficiencies of blast furnaces. Use of coal as a feedstock and raw material by the chemical industry and as a fuel for industry will increase slowly prior to 1985 as natural gas becomes unavailable and petroleum prices rise. A significant new use for coal will be for gasification and liquefaction, and it is estimated that by 1985 63 million tons of coal will be thus used.

Table C.7-15

Projection of U.S. Bituminous Coal and Lignite Demand
(Million Short Tons)

Year	Electric Utilities	Industrial and Commercial[1]	Gasification, Liquifaction Feedstocks[3]	Retail & Railroads	Total Domestic Steam Coal Demand	Coke and Metallurgy[2]	Total Domestic Consumption	Exports[4]	Total Demand
1974	390.1	64.1	5.0	8.8	468.0	89.7	557.7	57.9	615.6
1975	405	65	5	8	483	87	570	67	637
1980	616	95	10	8	729	95	824	100	924
1985	741	127	63	5	936	105	1,041	110	1,151

1. Includes ship bunkers

2. Includes small quantities of non-coking coals used in steel and rolling mills.

3. Feedstocks for ammonia, methanol and non-energy uses.

4. Net exports: imports of coal, mostly from Canada, Poland and South Africa in 1974, have been small, totaling about 2,080,000 tons in 1974, and are expected to remain small.

Sources: U.S. Bureau of Mines and Arthur D. Little, Inc., estimates.

C.7.5.3 Projected Supply

Table C.7-16 shows several published projections of U.S. coal production, each of which is based on the assumption that environmental and federal leasing constraints will allow some further development of Western coal lands and continued operation of strip mines. Looking at all the projections the most probable U.S. production level in 1980 is expected to be 870 million tons and 1,150 million tons by 1985.

Until recently, U.S. demand has been met primarily by mining of eastern coal which has been responsive to demand fluctuations without the constraints of a federal leasing program and extensive environmental considerations. Most of the coal lands in the East, the Mississippi Valley region and the Appalachian basin are privately owned. However, as is shown in Table C.7-17, federal government ownership of coal rights and lands which will be developed in the Rocky Mountains and Northern Great Plains regions ranges from 82% in Utah to 25% in North Dakota and is in excess of 60% overall. These two regions contain over 50% of U.S. reserves so that future governmental actions will be critical to future coal production potential.

Severe environmental constraints imposed on surface operations issued in conjunction with a federal leasing program would have a major limiting effect on production prior to 1985. The U.S. has economically strip mineable reserves of 55 billion tons, but according to National Petroleum Council statistics, if contour mining bans are imposed amounts projected for production in 1980 and 1985 would be decreased by over 12%. If bans on all surface mining were imposed, projections of production for 1980 and 1985 would be reduced by over 40%.

Based on recent surveys by the Federal Energy Administration and the National Coal Association, ADL has prepared annual estimates of coal mine capacity through 1985 as shown in Table C.7-18. This table indicates the maximum expected production capability of the coal industry. Because

Table C.7-16

Actual and Projected U.S. Coal Production
(Million Tons)

Projection and Date Published		Actual* 1970	Actual* 1974	Projected 1975	Projected 1980	Projected 1985
ADL (1975)		602.9	603.4	636	870	1,130
EXXON (1974)	Eastern Production	558.0	510.6	578	650	700
	Western Production	44.9	92.8	92	220	514
	Total:	602.9	603.4	670	870	1,214
FEA (1975)	Eastern Production	558.0	510.6	587	710	NA
	Western Production	44.9	92.8	98	185	NA
	Total:	602.9	603.4	685	895	NA
Nat'l Petroleum Council (1973)						
	Case IV	602.9	603.4	695	830	1,004
	Case II/III	602.9	603.4	713	876	1,134
	Case I	602.9	603.4	754	1,023	1,570
Project Independence (1974)						
	Business as usual	602.9	603.4	685	895	1,100
	Accelerated	602.9	603.4	750	1,376	2,063
CONOCO (1975)		602.9	603.4	NA	NA	1,175

*Source: Bureau of Mines, "Minerals and Materials", 11/75.

Table C.7-17

Federal Ownership of Coal Lands and Rights

State	Total Reserves	By Potential Mining Method Underground	Surface	Percent Federal Ownership
Montana	107,727	65,165	42,562	75
Wyoming	51,228	27,554	23,674	65
North Dakota	16,003	NA	16,003	25
South Dakota	428	NA	428	NA
Utah	4,042	3,780	262	82
Colorado	14,870	14,000	870	53
Arizona	350	NA	350	small
New Mexico	4,394	2,136	2,258	59
Total	199,042	112,635	86,402	60%

Source: U.S.G.S. Bulletin 1412

"Project Independence, 'Coal'"

Table C.7-18

U.S. Domestic Coal Mine Capacity
(millions of short tons)

	Base[1]	Retirements[3]	New Mines and Expansions	Estimated Probable Capacity[4]
1974	638.0[2]	-18	46	666
1975	666	-18	53	701
1976	701	-18	35	718
1977	718	-18	50	750
1978	750	-19	57	788
1979	788	-20	60	828
1980	828	-20	62	870
1981	870	-20	66	916
1982	916	-21	70	965
1983	965	-21	73	1,017
1984	1,017	-22	77	1,072
1985	1,072	-22	80	1,130

1. January 1
2. Minerals Yearbook, 1974
3. Assumes 30-year mine lifetime (3.3% annual loss in capacity). Applicable only to eastern and midwestern capacity -- 536 million tons/year in 1974.
4. December 31

Sources: Arthur D. Little, Inc., estimates based on Federal Energy Administration and National Coal Association surveys of new coal mine plans.

it takes two to six years to develop mining operations, major commitments have already been made for 1980 output; but major new mines which will be operating by 1985 need not have been announced yet. Thus, the projection as shown is relatively accurate through 1980 but becomes increasingly uncertain after that.

C.7.5.4. Supply/Demand Balance

In Table C.7-19, which is based on the demand projection in Table C.7-15 and the ADL supply forecast in Table C.7-16, shortfalls in supply are indicated to occur throughout the time period. The 1974 shortage was caused by the mine workers strike while 1975 production and demand are essentially in balance. Shortages are expected to increase and to amount to 5% in 1980. The shortfall is expected to lessen somewhat by 1985. While actual conditions through 1985 may not produce a real shortfall, this analysis suggests that coal will not be able to be substituted freely for oil or gas usage due to a tight supply/demand situation using a rather conservative demand forecast. Ignoring import problems, this shows that in 1985 only oil will be essentially unconstrained by supply considerations while natural gas and coal will both be supply constrained.

Table C.7-19

Projected Short Falls of U.S. Coal Supply
(Millions of Short Tons)

Year	Total Demand	Total Supply	Short Fall	Short Fall as Percent of Demand
1974	615.6	603.4	(12.2)	2%
1975	637	636	(1)	Nil
1980	924	870	(54)	5%
1988	1,151	1,130	(21)	2%

Source: Tables C.7-15 and C.7-16

C.8 DEMAND TRENDS FOR RESIDUAL FUEL PRODUCTS

C.8.1 OVERVIEW

Over the period 1970-1973, demand for residual products grew at an average annual rate of 8.0%, while demand for all petroleum products increased at an average of 5.5% per annum. In the future the demand for all petroleum products is expected to increase at rates below recent historic averages as a result of several interrelated and reinforcing trends: slower rates of national economic growth, higher energy prices and conservation incentives. A concensus of recent forecasts of U.S. oil demand suggests that total product demand will grow at an average of 2% per annum. Residuum products other than residual fuel oil could be expected to follow the national growth pattern for petroleum products, since the demand level for these products is closely related to the national industrial outlook. However, the growth in demand for residual fuel oil may well exceed the national average for petroleum products generally.

Consumption of residual fuel oil will grow at rates in excess of other petroleum products for three primary reasons: the level of natural gas curtailments to utilities and large industrial customers; the inability of coal to substitute for curtailed gas supplies; and, finally, the increase in fossil fuel requirements by utilities resulting from delays in the scheduled operation of nuclear capacity. Since 1971, U.S. production of natural gas has been declining. Furthermore, the rate of discovery of new natural gas reserves has been below production levels since 1967, so that the outlook for increased domestic production of natural gas in the Lower 48 states is bleak. The only relief from this domestic decline trend is expected to come from production of Alaskan North Slope gas in the early to mid-1980's. The decreased availability of natural gas (see the previous chapter for more details) will have a significant impact on the demand for oil in general and residual fuel oil in particular.

In early 1973, the Federal Power Commission (FPC) issued a priority list of types of gas consumers which interstate pipelines were obliged to observe in curtailing their customers. This list basically gave preferential status to residential and small commercial customers and certain special industrial process users of gas, while according use of gas under boilers the lowest priority. Thus, as gas supplies have dwindled, it has been the utility and large industrial customers of interstate pipelines who have been most heavily curtailed. Also affected were the refineries, which have traditionally obtained a large fraction of their fuel from natural gas. Once curtailed, these large volume users had little choice in their fuel substitution, since the conversion from natural gas to residual fuel oil is more feasible from technical and cost viewpoints than conversion to coal. In addition, many of these curtailed interstate pipeline customers were located in areas remote from the country's coal producing regions, so that coal transportation logistics and costs would have ruled out conversion to coal. To date, most of the conversions to residual fuel oil have occurred along the East and West Coasts, and in the upper Midwest. In the near-term future, the trend will be for continued conversions to oil as a result of gas supply shortages; over the longer term (early to mid-1980's onward), the increased availability of nuclear power for utilities and the increased burning of coal by large industries is expected to gradually halt the present conversion trend.

Coal has been unable to offset the declining natural gas supplies in the short-term for three principal reasons: (1) the difficulty of quickly gearing up coal production capacity to meet higher demand levels; (2) transportation problems in getting coal from the mines to the end user; and (3) environmental objections to the burning of coal. During the 1960's and early 1970's, when oil products were relatively cheap compared to coal and when there was an awakening of environmental concern over air pollution, many large volume energy users, located away from coal deposits (and often near ports), switched from coal to oil or gas. With demand declining, coal producers dropped their production capacity. Then when the OPEC price hikes and Arab oil embargo launched a movement for U.S. energy independence, which implied a resurgence for coal as the country's most abundant energy resource, the coal industry found itself without the manpower and physical goods, not to mention a transportation network, to bring about the rapid increase in production implied in energy self-sufficiency.

In addition to the physical production and transportation constraints, coal faced environmental obstacles. With large metropolitan utilities on the East Coast restricted to burning residual fuel oil of less than 0.5% sulfur, the only comparable domestic coal supplies were, in general, expensive metallurgical grade coal or Western low-sulfur deposits. Some utilities did convert to coal during 1973-1974, but for the most part they had to be granted variances to existing local air pollution regulations in order to do so. In the short term, it is likely that some coal burning will continue at variance with local ordinances, but the difficulties in obtaining coal supplies and the uncertain outlook for air pollution restrictions, will keep down the number of conversions. For the longer term, when coal production capacity has expanded, permanent resolutions to the environmental conflicts are expected.

The third major factor impacting differentially on the demand for residual fuel oil is the delays in nuclear power plant construction. These delays have been blamed on financing difficulties, licensing and siting problems, equipment delivery schedules, public intervention in opposition to nuclear power and, most recently, changes in forecast load levels. Whatever the individual explanation for the delays, which have lengthened the average nuclear generating plant construction time to 8 to 10 years, the effect of the delays is to increase the short-term demand for oil. For some utilities the short-term solution has been the installation of gas turbine units, which require short lead times. These turbine units typically burn diesel fuel and are designed for peakload usage rather than base load applications. However, for other utilities, the delays in nuclear power plant construction have led to the need for additional residual oil-fired units or for the continued use of old oil-fired units which were scheduled for retirement. In addition, the extremely high capital costs of nuclear generating plants--particularly viewed from the present period at the end of a two year hiatus in electricity demand growth--have caused several utilities to postpone the start-up dates for their nuclear units.

In the following section the expected impact of these national trends on individual end-use consumption of residual fuel oil will be discussed.

C.8.2 TRENDS IN END-USE CONSUMPTION OF RESIDUAL FUEL OIL

As described in Chapter C.4 the two major end uses, electric utilities and industrial (including oil company usage), accounted for 60-70% of total residual fuel oil usage over the 1970-1974 period. Because of their prominence among residual fuel oil uses, demand trends in these two sectors will be critical in determining the rate of growth (or decline) in residual fuel oil consumption. Trends in utility and industrial fuel demand will, therefore, be covered in greater detail below. Among the three remaining end-use categories reported by the Bureau of Mines, only the Residential/Commercial Heating sector is significant in terms of volume. This classification refers to large apartment and commercial building and, therefore, it might be expected that growth in fuel demand by this sector would be related to changes in such independent variables as population growth, GNP and rate of urbanization. At the same time, electricity has been assuming an increasing proportion of this market, given the emphasis on year-round comfort, including air conditioning as well as heat. Thus, for the future, the growth in residual fuel oil consumption in the Residential/Commercial sector is expected to be minimal, certainly below the 2% per annum concensus forecast for all products.

Residual fuel oil usage for transportation (almost exclusively ships and bunkers) is extremely difficult to forecast due to the inherent nature of ship bunkering habits. Where ships bunker is a function not only of bunker prices, but of trade routes, which are likely to vary from one year to the next. Thus, for present purposes, it is sufficient to state that transportation uses are unlikely to expand very rapidly and, in fact, considering the small railroad component, may actually decline.

C.8.2.1 Utility Demand

Prior to the OPEC price hikes in 1973-1974 and the Arab oil embargo, it was a utility axiom that peak demand for electricity would grow an average of 7% per annum or double every 15 years. Subsequent to the rises in OPEC oil prices, which utilities were forced to pass along to their customers in the form of massive rate hikes, consumer demand for electricity dropped to below 1973 levels in 1974 and generally did not accelerate appreciably during 1975. This dramatic leveling off of the demand curve has lead to utility industry revisions of their hallowed 7% per annum figure. Most industry spokesmen now forecast that growth in demand will be more moderate--4.5% per annum--over the next five to ten years, although they typically express greater optimism about the longer term, when significant quantities of nuclear base load capacity are slated to be onstream. The slower than historical growth projections imply a reduction in the rapid rate of growth of utility consumption of residual fuel oil.

However, as discussed above, acting to offset the slowdown in consumer-induced utility expansion will be the conversions of curtailed gas-burning utilities to residual fuel oil and the delays in nuclear plant construction. Both of these trends will combine to cause at least a short-term spurt in residual fuel oil demand. To the extent that the gas curtailments and nuclear setbacks of the future occur in the Gulf Coast and Midwest areas, these trends will tend to lessen the concentration of residual fuel oil consumption on the East and West Coasts. Over the longer-term, utility demand for residual fuel oil should peak out and then decline gradually as other fuels (primarily coal and nuclear) take over this market.

C.8.2.2. Industrial Demand

Over the long-term, growth in the fuel consumption of the industrial sector can be expected to parallel the growth in the national economy. In the recent past, residual fuel oil consumption by the industrial sector has increased at a rate slightly in excess of GNP, reflecting the impact of gas curtailments. In the near future, residual fuel oil demand in the industrial sector is expected to continue to expand more rapidly than indicated by the rate of general domestic industrial activity as natural gas curtailments proceed to strand more industrial gas customers.

However, partially offsetting these gains in residual fuel oil customers will be the effects of price-induced conservation efforts of all residual fuel oil users. In the short-term, industry's conservation programs will be limited to non-capital intensive measures--curtailing wasteful practices and improving maintenance. Over the longer term, the results of industrial conservation efforts will be enhanced by the introduction of more energy efficient equipment and processes, so that the effects of energy conservation in the industrial sector can be expected to impact gradually over the next decade.

C.8.3 DEMAND TRENDS FOR OTHER RESIDUUM PRODUCTS

Besides the trends on residual fuel oil demand, brief mention should be made about future cat cracker feed demand, coke consumption and lubes, waxes and asphalt demand. These residuum uses constitute the balance of residuum demand with the exception of refinery fuel usage.

As discussed in Chapter C.3, future refinery usage of residuum as fuel will certainly increase in the future and would be expected to represent up to

3-4% of total crude charged by 1985 when it is anticipated that all natural gas will have been withdrawn from refinery boiler use.

Future gasoline demand will affect how much residuum is used as feed for the cokers, catalytic crackers and hydrocracking units. We anticipate that gasoline demand may increase slightly for a few more years (though at rates much below historic trends) then become static or actually decline in the early 1980's as federally mandated fuel efficiency standards for automobiles begin to have an impact. We anticipate that gasoline demand will commence a declining growth pattern in the 1980's as the proportion of more efficient, small engine cars in the total car population increases and as alternative transportation forms (largely mass transit) reduce reliance on the private automobile.

Since converting residuum into gasoline is one of the most costly operations in a refinery, it is reasonable to assume that static or declining gasoline demand will selectively impact first on gasoline produced by cracking residuum, thus freeing up supplies of residuum for use as residual fuel oil. Through 1985, however, this effect will be minimal.

In addition to producing gasoline blending stock the coking operation produces a salable by-product--petroleum coke. Petroleum coke produced in PAD Districts I-III is generally used in the steel and electric utility industries. Some coke that is of superior quality (i.e. of very low sulfur content and from particular types of coking operations) is used by the carbon products industry for such things as electrodes. Much of the coke produced on the West Coast is exported to Japan. In Japan some of the coke is used in the steel industry, but mostly it is blended with coal for utility boiler fuel. These uses of coke generally require a fairly low sulfur content so that coke cannot be treated as a sulfur sink. In addition, the EPA is beginning to regulate the sulfur content of coke sales to utilities, since high sulfur coke can result in higher than desired sulfur emissions.

In the late 60's petroleum coke was in oversupply and was sold at distress prices. Now sales keep up with production. Coke production, however, is not an independent variable--it is the result of conversion processing of residuum to gasoline. Thus, coke availability will probably follow gasoline production trends. Since we do not anticipate long-term continued growth in gasoline demand (as described above) no marked growth in petroleum coke production is likely in the future.

Lubes and waxes are very specialized products from residuum and they represent a very small part of the residuum usage. We assume that these products, which are premium uses of oil, will continue to be supplied in sufficient quantity to meet demand, which will probably grow at or above the deemed average growth rate of 2% per year.

Asphalt, which goes primarily into road construction and building construction, would appear to have relatively good growth potential in the future. However, the significant price increases, prompted by crude price increases, may impede further product demand growth. Road construction and repair depend on low cost bulk materials, and the recent crude oil price increases have forced asphalt prices upwards, causing users to begin seeking substitutes. Unless suitable substitutes are found, and there do not appear to be very many of them, asphalt will continue to be used in spite of higher prices. Thus we expect asphalt demand to grow at about 2% per year.

C.9 TECHNOLOGICAL TRENDS IN SULFUR REMOVAL PROCESSES

C.9.1 INTRODUCTION

Air pollution regulations limit the emission of SO_x gases in the flue gas from power boilers (steam boilers). These regulations are predicted on a maximum allowable emission of SO_x per heat input to the boiler. The Federal EPA regulations limit SO_2 emissions from new boilers having a capacity greater than 250 MMBTU/HR* (263.7 GJ/HR) as follows:

- For liquid fuel - 0.8 lb $SO_2/10^6$ Btu heat input [(0.34 kilogram (kg) SO_2/GJ)]
- For solid fuel - 1.2 lb $SO_2/10^6$ Btu heat input (0.52 kg SO_2/GJ)

Emission limitations for existing boilers were set by state and local codes, as developed in the implementation plans aimed at achieving the primary and secondary air quality standards on schedule. There are no federal emission requirements for existing boilers, only for new units. State regulations for new units can be more stringent than the minimum federal performance requirements as discussed in Chapter C.5.

Meeting these sulfur emissions regulations can be accomplished by a variety of methods including:

- Switching to low sulfur fuels
- Precombustion sulfur removal
- Post-combustion sulfur removal (flue gas desulfurization)

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*One BTU is the same as 1054.8 Joules so that to convert from millions of BTU's (MMBTU) to Gigajoules (GJ) one multiplies by 1.0548. One pound is equal to 0.4536 kilograms.

Pre-combustion sulfur removal can be accomplished either during the refining of the fuel products or just prior to use, as is the case with the CAFB process. Switching to low sulfur fuels is the easiest option to implement and requires minimal capital investment. However, it is not a universal solution because there is not enough low sulfur fuel available to satisfy the potential demand. Hence, pre-combustion or post-combustion sulfur removal must be employed to satisfy the sulfur emission requirements.

Various sulfur removal processes have been, or are being, developed in each of the categories mentioned above. We shall discuss the advantages and disadvantages of each category, concentrating on processes designed for oil.

C.9.2 POST-COMBUSTION SULFUR REMOVAL

Flue gas desulfurization (FGD) refers to removal of sulfur compounds after combustion of the fuel. Sulfur is present mainly in the form of SO_2 although some SO_3 is generally present. The advantages of FGD systems are the flexibility of fuel supply, lower operating cost and lower energy consumption than other available sulfur removal systems.

The disadvantages of FGD systems are that it adds the responsibility of controlling and managing an additional process on the user and that the user must sell or dispose of the final sulfur compound. Also, the economics may not be favorable for very small installations (generally below 100 megawatt capacity).

C.9.2.1 Current Status of FGD Systems

It now appears that reliable SO_2 control technology is finally emerging. Its use is being encouraged by the EPA which is adopting an enforcement strategy that requires boiler operators in areas where primary air quality standards are not being met to file compliance plans to meet emission codes as rapidly as possible by installing control systems or by converting to low-sulfur fuel.

Table C.9-1 summarizes the current status of commercial-scale SO_2 emission control systems as applied to electric utilities. The table indicates that roughly 50,000 megawatts of generating capacity are in various project stages, ranging from preparation of system bid specifications, through construction, to the 3,300 megawatts currently in operation with SO_2 control. Almost all of the capacity represents coal-fired boilers with well over 90% of the control systems involving production of a waste form of the sulfur rather than recovering by-products. The total U.S. generating capacity from all utility boilers in 1975 was about 500,000 megawatts.

All systems in the bid evaluation stage or in more advanced stages of contracting or construction should be in operation by the end of 1978. Systems in the pre-bid stage should be in operation by the end of 1980, as will additional systems not yet listed but committed by the end of 1977. Thus, the total capacity under SO_2 control should be on the order of 50,000 megawatts by 1980, or about 10% of total U.S. generating capacity in 1975.

It should be mentioned that no changes are required in the FGD system or the cost of the system between coal and oil-fired boilers. Oil has a higher Btu/lb (GJ/KG) content but lower acceptable emission rates in terms of lb SO_2/MMBtu (KG SO_2/GJ). Thus, 0.7% coal or 0.7% oil meets the federal regulations and 0.3% coal or 0.3% oil meets the regulations in the metropolitan areas (these percentages are weight percent of sulfur).

C.9.2.2 Types of Flue Gas Desulfurization Processes

FGD sulfur dioxide control processes may be classified according to the final form of the sulfur removed from the flue gas:

- Waste salts
- Concentrated SO_2
- Direct sulfuric acid
- Elemental sulfur

Table C.9-1

U.S. Utility SO_2 Control System Commitments

Status	Number of Units	Generating Capacity (MW)
Operational	21	3,300
Under Construction	23	7,500
Contract Awarded	9	3,800
Letter of Intent	11	4,700
Requesting/Evaluating Bids	8	3,900
Pre-Bid Period	46	24,000
TOTAL	118	47,200

A few processes have had important commercial-scale experience in coal-fired applications; most significant experience has been with processes that produce a waste form of the sulfur for disposal, rather than a by-product for recovery. Most of the leading by-product recovery processes have yet to be tested on long-term basis in coal-fired applications. However, a few processes, such as the Wellman-Lord concentrated SO_2 process, have been well demonstrated in industrial applications in the United States and in utility boiler applications in Japan. Four of these units are in operation in Japan on oil-fired boilers and on the tailgas stream coming from Claus plants. (A Claus plant converts SO_2 into elemental sulfur.)

The status of each of the processes is discussed briefly below:

C.9.2.2.1 <u>Waste Salt Processes</u> - These processes produce varying types of sulfite and sulfate salts which must be disposed of in an environmentally acceptable manner. These processes account for over 90% of the systems currently committed for SO_2 control and can be expected to maintain this dominant position in applications which will become operational over the next ten years. Of these waste salt or "throw-away" processes, a very large fraction involve some version of lime or limestone slurry scrubbing to produce a solid waste calcium sulfite/sulfate for disposal. The most prominent waste salt processes are based on lime, limestone and double alkali reactants.

C.9.2.2.2 <u>Concentrated SO_2 Processes</u> - These processes produce concentrated SO_2 gas streams from dilute flue gas SO_2. Conventional, commercially proven technology is available for the further conversion of the concentrated SO_2 produced by these processes into either liquid SO_2, sulfuric acid, or elemental sulfur.

Liquid SO_2 is produced by compression of the SO_2 stream after the gas from the process has been concentrated and dried. Sulfuric acid is produced by oxidizing the SO_2 to SO_3 and absorbing the gas in water.

Elemental sulfur is produced from concentrated SO_2 by direct reduction or by reactions involving other chemicals.

The main direct reduction process employs natural gas (methane) using technology offered by Allied Chemical and commercially demonstrated in a smelter application at Falconbridge Nickel on a 500-ton/day sulfur plant. The demonstrated capacity of this process is about the equivalent of the potential sulfur production from a 1500-megawatt utility plant running on high-sulfur coal.

Other conventional conversion technology, involving reaction of H_2S and SO_2 to produce sulfur (Claus process), can also be used. Such an approach requires generation of hydrogen for the production of H_2S and the reduction of the SO_2 instead of direct reduction with natural gas. Hydrogen can be generated by several approaches that differ in capital cost and from several feedstocks that differ in availability and cost.

The leading processes in this category are the Wellman-Lord process and the Magnesia Scrubbing process.

C.9.2.2.3 Direct Sulfuric Acid Processes - In these processes, sulfuric acid is produced directly with no intermediate concentrated SO_2 gas stream. A more dilute acid is produced than the normal commercial 98% acid grade. Operations involving this approach are still in the experimental stage. The outlook is not promising for this process category because no successful applications have been developed after several years research.

C.9.2.2.4 Elemental Sulfur Processes - These processes produce elemental sulfur or hydrogen sulfide directly, with no intermediate production of concentrated SO_2. Hydrogen sulfide can be converted directly to elemental sulfur using commercially available technology (Claus process). The EPA is currently reviewing proposals based upon some of these processes for funding of a 100-megawatt coal-fired demonstration plant for a sulfur recovery process. Processes in this category include:

- Charcoal absorption - Westvaco, Foster-Wheeler
- Citrate process - Arthur G. McKee
- Potassium thiosulfate system - Conoco Coal Development
- Sodium phosphate process - Stauffer Chemical/Chemico
- Dry carbonate process - Atomics International
- Ammonia process - Catalytic

All of these processes require some type of reducing gas (hydrogen, carbon monoxide or natural gas) to produce the elemental sulfur, with the exception of the Foster-Wheeler process, which uses a special char for the reduction of SO_2 to elemental sulfur.

All of these processes are in the earlier stages of development, and cannot be expected to have any important commercial impact until about the mid-1980's.

C.9.2.3 Present Work in FGD Systems

The FGD technology is considered a proven technology by the EPA. Thus present work includes removing operational problems and improving the reliability of the systems. The current work includes the following:

- Problems associated with reheat
- Operation of mist eliminator
- Scaling and plugging of the system
- Disposal of waste sludge in environmentally acceptable manners

It is now necessary that utility people gain experience in the operation of these systems. It is expected that the reliability of these systems will improve with increased familiarity of the systems by utility personnel.

C.9.2.4 FGD Process Economics

Over the past few years the costs for construction and operation of SO_2 control systems for utility boiler applications have increased markedly, because of:

- Improvements in systems to achieve greater reliability.
- Revisions of costs for systems as processes emerged from the development stage to full-scale installations and actual capital cost information based on operating experience became available.
- General escalation in the cost of materials, equipment and labor.

Capital costs have increased from \$20-30/KW of boiler capacity to \$50-80/KW, depending upon the application. Costs have more or less stabilized in 1975.

Table C.9-2 contains a summary of generalized, relative economics of the process types which have achieved the most advanced stage of development and demonstration and which are likely to have the greatest level of acceptance and application by the utility industry over the next ten years. Table C.9-3 gives the detailed cost breakdown for a double alkali (same cost for lime scrubbing) method.

Capital costs, given as dollars/KW of installed boiler capacity, are consistent on a relative basis for the process types and on an absolute basis are 1975 bid prices (with no inclusion of escalation over the course of the project) for a new 800-megawatt, high-sulfur, coal-fired application. The capital costs would not change appreciably on a \$/KW basis on larger applications or on applications down to about 150 megawatts because of the modular nature of the systems at and above the 150 megawatt level. The costs are also consistent with relatively simple retrofit situations; more difficult retrofit situations could increase the costs very significantly. The capital costs include on-site disposal ponds (for solid waste disposal), but do not include any treatment facility for fixation of the wastes or plants for conversion of the concentrated SO_2 to elemental sulfur or sulfuric acid; these are all handled as separate items under disposal and conversion costs.

The operating costs are on an annualized basis at an 80% load factor, include capital charges and are given in cents/MMBtu of fuel input to the boiler.

Table C.9-2

Utility SO_2 Control Process Economics

Process	Capital Cost[A] ($/KW)	Annual Operating Cost[B] (¢/MMBtu)
Lime Scrubbing	60	35.4
Disposal Cost[C]	-	6.5
Total Cost (with Disposal)	60	41.9
Concentrated SO_2 Operations	70	42.6
Acid Conversion Cost	7	2.5
Acid By-product Credit	-	(2.1)
Total Cost (to Acid)[E]	77	43.0
Sulfur Conversion Cost[D]	9	8.6
Sulfur By-product Credit	-	(3.0)
Total Cost (to Sulfur)[E]	79	48.2

A - 800-megawatt base load plant burning 2.6%S coal to produce 70,000 ton sulfur/year (80% load factor, 80% removal SO_2). New Unit or simple retrofit.

B - Includes capital charges (at 18% capital investment/year), labor, maintenance plus variable costs (including lime at $30/ton CaO).

C - Disposal @ $10/ton dry solids

D - Natural Gas @ $2.00/Mcf

E - Total annual cost (including all capital charges) to final form of sulfur removal from flue gas.

Note: The capital cost and the operating cost will be approximately 15% higher for 91% removal efficiency (giving sulfur emissions in flue gas equal to emissions from burning 0.3%S fuel).

Table C.9-3

Double Alkali FGD Systems

Capital Cost, \$/kw		60.0
Operating Costs (¢/MMBtu)		
Capital Charges, @ 22%	15.8	
Lime	5.3	
Na_2CO_3	1.8	
Operating Labor Cost	2.7	
Maintenance Cost	2.7	
Electricity, @ \$0.02/kwh	1.0	
Reheat, @ \$2.00/MMBtu	3.2	
Materials	2.7	
Total Operating Cost (¢/MMBtu)		35.4
Waste Disposal Cost		6.5
TOTAL DOUBLE ALKALI PROCESS COST		41.9

BASIS:

- 2.6% S fuel
- 88% efficiency of FGD system
- December 1975 dollars
- Plant size - 150 x 10^6 watts or larger
- Load factor - 0.80

Where waste treatment and disposal of waste solids by fixation processes are required, the cost is shown as a separate cost, which is added to the annual operating cost, to give a total annual operating cost.

The conversion of concentrated SO_2 to sulfuric acid and elemental sulfur (using either natural gas, if available, or else hydrogen or carbon monoxide) is shown separately. The conversion costs include capital charges on the investment (at 22%/year) for the conversion facility as well as other operating costs for the conversion to the final product. By-product credits, as indicated, are used to reduce the conversion costs and the net conversion cost (or credit) is added to the annual operating cost to produce concentrated SO_2, giving the total annual costs to produce the final by-product form.

Flue gas desulfurization cost varies from 40 to 45¢/MMBtu (37.9 to 42.7¢/GJ). This represents $2.35 to $2.65/bbl additional cost when using high sulfur fuel oil. The current cost of 2.8%S residual oil is roughly $10.00/bbl. Thus, the cost of desulfurization adds about 25% to the oil cost.

The cost of energy used in flue gas desulfurization is about 10% of the total cost. Thus, a 10% increase in energy cost will cause a 1% rise in flue gas desulfurization cost, and thus an 11% overall cost of obtaining flue gases meeting the applicable standards.

C.9.2.5 Application of FGD Systems to Industrial Boilers

Industrial boilers differ from the utility boilers primarily in their average capacity with the industrial boilers being generally fairly small. While the FGD technology for industrial boilers and utility boilers is the same, the application of FGD systems to industrial boilers has so far been limited to only a few installations. This is due to the fact that the industrial boilers represent a secondary small sized market for FGD systems which has been relatively neglected to date in favor of concentrating on utility boilers.

The cost of SO_2 control on small boilers is expected to be high. A six-tenth rule generally may be applied to determine the capital investment for a FGD system for a boiler having a capacity less than 150 megawatts. That is, the ratio of the capital investments for two different sized boilers varies as the six-tenth power of the ratio of their capacities. Thus, a 100 megawatt double Alkali FGD system would cost about $47 million to install.

C.9.3 PRE-COMBUSTION SULFUR REMOVAL

An alternate approach for meeting SO_x limitations in the flue gas is to desulfurize the residual fuel oil before it is used in the boiler. The sulfur removal may occur during the manufacture of the fuel oil, in which case the refiner provides the capital investment for the equipment, maintains the operations and pays for the processing; or it may be done by the fuel user, in which case it is the user who provides the capital investment, etc. Below we discuss catalytic desulfurization of residual fuel oil as part of the refining process and the CAFB process.

C.9.3.1 Catalytic Desulfurization of Residual Fuel Oil

The applicability of catalytic desulfurization in a petroleum refinery is determined principally by the characteristics of the crude oils to be processed and the end-product sulfur specification, as 90+% sulfur removal is technically feasible for most residual stocks. Most of the fuel oil desulfurization facilities installed to date have been based on the "indirect" route, but six direct desulfurization units have been installed since 1967 (five in Japan), and this route will be applied to a much greater extent as sulfur specifications become more stringent.

Before describing the differences between direct and indirect catalytic desulfurization, the properties of crude oils which make these two processes necessary are described.

C.9.3.1.1 Feedstock Properties Affecting Desulfurization - The most important feedstock property with respect to influence on the desulfurization of crude oil is the metals content. Organometallic compounds, principally porphyrins containing nickel and vanadium, will usually decompose on the catalyst surface resulting in metal deposition. Although catalysts can tolerate substantial metal deposits, ultimate deactivation is irreversible. The effect on economics of catalyst replacement cost, catalyst inventory and/or reduced operating efficiency due to catalyst changeouts is substantial for high-metals stocks. The concentration of metals in reduced crudes varies widely, from around 35 ppm Ni + V (nickel and vanadium) in Light Arabian and 60 ppm in Kuwait to about 250 ppm in Iranian Heavy and nearly 700 ppm in Venezuelan Bachaquero. In addition to the inherent metals content of the feed, the severity of processing (the degree of desulfurization and difficulty of processing), affects the amount of metals deposited on the catalyst.

The asphaltenes content of the residue reflects the type of structure in which the sulfur is bound, i.e., a high asphaltenes content indicates multi-ring, sulfur-containing hydrocarbon structures which require high processing severities for sulfur removal. Further, asphaltenes are thermally unstable and thus easily convert to coke on the catalyst surface which reduces the activity of the catalyst. Asphaltenes generally correlate positively with asphalt yield and sulfur content and direct desulfurization may be required to produce low-sulfur fuel oil from high-asphaltene residue. The sulfur content of the end-product would be significantly greater if the large proportion of asphalt were bypassed around the catalytic section as in indirect desulfurization.

Table C.9-4 (see also Table C.3-5) shows a classification of some widely available crude oils according to direct catalytic desulfurization processing characteristics:

- Type I (low metals, low asphaltenes). Can be desulfurized relatively readily by direct hydroprocessing.
- Type II (moderate metals, low asphaltenes). Can be desulfurized directly, but catalysts costs will be a more important factor in

Table C.9-4

Properties of Atmospheric Residues From Widely Available Crudes

	Crude Production $x10^3$ B/SD[A]	Residue Properties		
		Sulfur, Wt.%	Ni + V, ppm	Asphaltenes, Wt. %
Type I				
Murban (Abu Dhabi)	800+	1.6	1	0.1
Zakum (Abu Dhabi)	300	2.0	5	0.2
Qatar	555	3.0	30	~1.4
Arabian Light	5,300	3.0	34	~2.5
Kuwait	2,800	3.9	60	2.6
Type II				
Iranian Light	2,800+	2.4	102	~1.5
Kirkuk	500	3.8	80	3.3
Type III				
Arabian Heavy	960	4.3	102	7.6
Khafji (Arabian)	330	4.1	90	6.4
Type IV				
Iranian Heavy	2,400+	2.5	230	3.3
Tia Juana (Venezuela)	330	2.2	300	~11
Bachaquero (Venezuela)	600	3.1	680	8-9

A - 1973 approximate production, derived from Oil & Gas Journal.

Source: See Table C.3-5 for source reference.

scheme selection than for Type I.

- Type III (moderate metals, high asphaltenes). May be processed by direct desulfurization, but processing severity (hydrogen partial pressure, catalyst inventory) and/or product sulfur level will be higher than when processing Type I stocks.
- Type IV (high metals contents). Catalyst life will be low with direct processing; the impetus to follow an alternative scheme is very strong.

C.9.3.1.2 <u>Direct Versus Indirect Desulfurization Processes</u> - The expected properties of the crude oils to be used in a refinery determine what processing units will be used once a particular set of desired end-products has been chosen. To produce low-sulfur residual fuel oil from high-sulfur crudes, desulfurization units must be used: direct or indirect desulfurization is chosen depending on the expected crude types. Figure C.9-1 is a simplified illustration of these two processes.

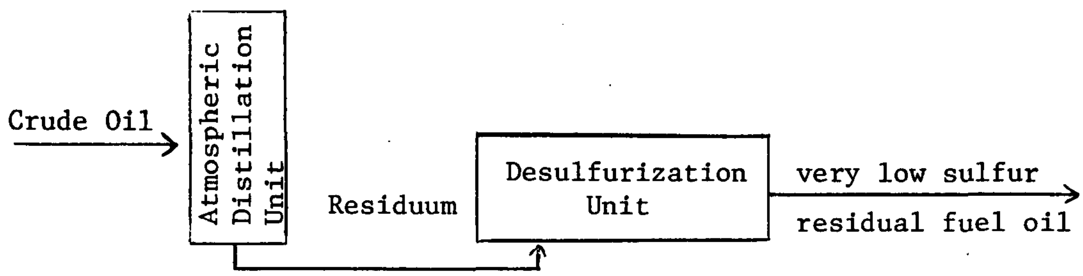
In direct desulfurization reduced crude from the atmospheric distillation unit is charged, along with makeup hydrogen, to the desulfurization unit, which yields low-sulfur fuel oil and small quantities of naphtha and light gases. Hydrogen sulfide is removed from the gases and converted to elemental sulfur. The hydrogen generally would be produced from light gases or naphtha since sufficient hydrogen usually would not be available from catalytic reforming of naphtha in the refinery and the quantity of hydrogen required for desulfurization will not justify the installation of a partial oxidation unit. The output from the desulfurization unit is a very low sulfur fuel oil with a sulfur content of 0.3% by weight. This very low sulfur content can be reached even when using a residuum containing 3.8% sulfur (such as from Saudi Arabian crude)--i.e. 3.5% by weight of the residuum charged to the unit is removed as sulfur.

Such a removal of sulfur is not possible with indirect desulfurization which in general can only produce a low sulfur (0.7% by weight) residual fuel oil. The word "indirect" is slightly misleading and the process could

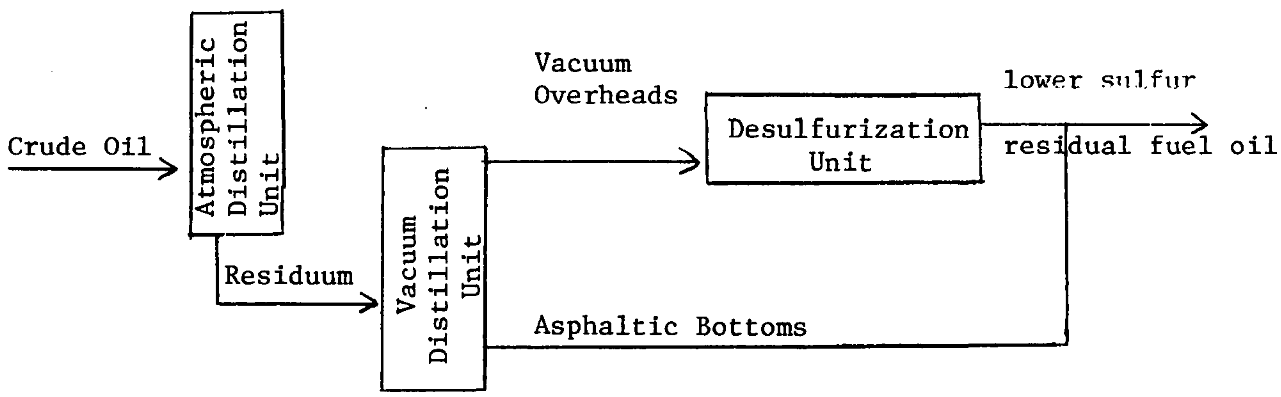
Figure C.9-1

Simplified Illustration of Direct and Indirect Desulfurization Units

Direct Desulfurization



Indirect Desulfurization



be better described as a "partial by-pass" process, as is shown in the bottom part of Figure C.9-1. In indirect desulfurization the residuum stream from the atmospheric distillation unit is sent to the vacuum distillation unit where the asphaltic compounds (along with most of the metals and a fair proportion of the sulfur) are separated from the rest of the stream. The vacuum overheads stream is sent to the desulfurization unit where the same process as for direct desulfurization takes place. After the desulfurizer the asphaltic bottoms are added back in to produce low sulfur residual fuel oil. It should be noted that any asphalt product production would be from the asphaltic bottoms and would lower the sulfur content of the residual fuel oil, but for a comparison of the two processes we have recombined the two streams.

The output from the indirect desulfurization process is usually about 0.7% sulfur fuel oil. This can only be accomplished if medium sulfur content residuum is used such as from Iranian Heavy oil which contains 2.5% sulfur. Indirect desulfurization cannot remove as much sulfur as direct desulfurization so is limited in application if very low sulfur fuel oils are needed.

C.9.3.1.3 <u>Comparative Costs of Residuum Desulfurization</u> - Some indication of relative costs can be obtained by considering economics based on two types of Middle East crudes. For this purpose, we have studied the processing of residues derived from a 50/50 blend of Arabian Light and Arabian Heavy crudes and from Iranian Heavy crude, representing, respectively, a high-sulfur, moderate-metals (Type I or II) stock and a moderate-sulfur, high-metals (Type IV) stock. The direct desulfurization processes have been set to produce 0.3% sulfur fuel oil so as to facilitate economic comparison with the CAFB process. The indirect desulfurization process is shown producing 0.7% sulfur fuel oil since it cannot produce a 0.3% product.

We have shown costs for Saudi Arabian crude since it is the benchmark crude oil for OPEC. However, for comparison with the CAFB process we have used Iranian Heavy since it has high sulfur and high metals, both of which properties are similar to what the CAFB process will accept.

We have chosen the Unibon process (licensed by UOP Process Division) as the basis for developing our cost estimates. The Unibon process is more limited than the H-Oil process in its ability to treat high metal vacuum residues without a prior deasphalting step; however, the costs for the processes are comparable.

"Typical" costs of process utilities for project assessment are unpredictable, considering the uncertainty of future energy values, but the values used in our comparisons are:

Power	\$0.02/kwh
Cooling Water	$\$0.03/10^3$ gal
Condensate	$\$0.30/10^3$ gal
Boiler Feedwater	$\$1.00/10^3$ gal
Steam (high pressure)	$\$3.00/10^3$ lb
Fuel	$\$2.00/10^6$ Btu

All costs reflect integration of the desulfurization unit into a grass-roots refinery or power plant. A nominal refinery on-stream efficiency of 330 stream days per year was applied. The cost figures were obtained from Conser* (1974) and updated to December 1975 dollars.

C.9.3.1.3.1 Arabian residuum - Table C.9-5 summarizes investment and operating costs for the desulfurization of Arabian Light/Arabian Heavy reduced crude. The Arabian reduced crude blend, having relatively high sulfur and relatively moderate metals contents, is a favorable stock for direct desulfurization. Table C.9-5 costs are shown for the production of 0.3% sulfur fuel oil when processing 20,000 and 40,000 B/SD of charge. The costs range from 52 to 57¢/MMBtu (49 to 54¢/GJ) depending on the size of the desulfurization unit.

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*Conser, R. E., "Management of Sulfur Emissions," presented at the NPRA, 72nd annual meeting, Miami, 1974.

Table C.9-5

Desulfurization Costs for Arabian Reduced Crude Mixture (3.8% S)
(Direct Desulfurization to 0.3% S)

Plant Capacity, B/SD	20,000	40,000
Capital Investment[A], $	48.7×10^6	81.7×10^6
Operating Costs, $/bbl		
H_2 Plant Feed + Fuel (net)	0.92	0.92
Other Utilities	0.51	0.51
Catalyst/Acceptor/Chemicals	0.27	0.27
Labor/Overhead	0.15	0.12
Maintenance @ 3% of Investment	0.25	0.21
Fixed Charges, @ 18% of Investment	1.50	1.26
TOTAL, $/bbl	3.60	3.29
TOTAL, $\$/10^6$ Btu	0.57	0.52

BASIS:

- 3.8% S fuel
- 92% S removal efficiency (0.3% S in final product)
- December 1975 dollars
- Operating factor - 7,000 hr/yr

A - Includes HDS unit, hydrogen and sulfur plants.

B - 6.3×10^6 Btu/Bbl of desulfurized oil (HHV).

C.9.3.1.2.2 Iranian Heavy residuum - With Iranian Heavy residuum it is less expensive to produce 0.3% sulfur fuel oil than with Saudi Arabian crude because less sulfur must be removed from the Iranian crude. As Table C.9-6 shows, using direct desulfurization with Iranian Heavy residuum costs 44.5 to 50¢/MMBtu (42 to 47¢/GJ) which is about 7-8¢/MMBtu (6.6-7.6¢/GJ) less than for the same end-product using a Saudi Arabian crude mix. But looked at on a cost per percent sulfur removed basis the Iranian crude is more expensive to desulfurize: at the 40,000 barrels per day level the Saudi mix costs 17.3 cents per percent sulfur removed while the Iranian oil costs 20.2 cents per percent sulfur removed. This is important because Iranian Heavy crude oil costs more to purchase due to its lower sulfur content so that the total cost of producing 0.3% sulfur fuel oil from Iranian Heavy will be higher than from Saudi crude. The higher cost of producing very low sulfur fuel oil from Iranian crude by direct desulfurization is due primarily to its high metal content which increases catalyst costs substantially. A fuel oil product having a sulfur content of 0.7% may be produced by indirect desulfurization, and we assume for comparison that no high-sulfur asphalt is made. Table C.9-7 shows the costs associated with the indirect desulfurization of Iranian Heavy residuum. The cost ranges from 33.5 to 38¢/MMBtu (32 to 36¢/GJ) and the cost per percent sulfur removed at the 40 MBCD processing capacity is 18.6 cents per percent sulfur removed.

C.9.3.1.2.3 Summary cost of residuum desulfurization - The residual oil desulfurization costs shown in Table C.9-6 vary from 2.67 to 3.43 $/bbl. With a current cost of high sulfur residual oil being about $10.00/bbl, the oil desulfurization cost represents 27-34% of the oil cost.

The cost of the energy used in the oil desulfurization process is 30-38% of the total cost. Thus, a 10% increase in energy cost will represent a 3-4% rise in oil desulfurization cost.

C.9.3.2 The CAFB Process

The Chemically Active Fluid Bed (CAFB) gasification/desulfurization of

Table C.9-6

Desulfurization Costs for Iranian
Heavy Reduced Crude (2.5% S)
(Direct Desulfurization to 0.3% S)

Plant Capacity, B/SD	10,000	20,000	40,000
Capital Investment, $\$10^6$	25.4	41.9	69.2
Operating Costs, \$/bbl			
H_2 Plant Feed + Fuel (net)	0.59	0.59	0.59
Other Utilities	0.43	0.42	0.41
Catalyst/Acceptor/Chemicals	0.35	0.35	0.35
Labor/Overhead	0.23	0.12	0.07
Maintenance @ 3% of Investment	0.26	0.22	0.18
Fixed Charges @ 18% of Investment	1.57	1.29	1.07
TOTAL, \$/bbl	3.43	2.99	2.67
TOTAL, $\$/10^6$ Btu	0.57	0.50	0.445

Basis:
- 2.5% S fuel
- 88% S removal efficiency (0.3% S in final product)
- December 1975 dollars
- Operating factor - 7,000 hr/yr

Table C.9-7

Desulfurization Costs for Iranian
Heavy Reduced Crude (2.5% S)
(Indirect Desulfurization to 0.7% S)

Plant Capacity, B/SD	20,000	40,000
Capital Investment, $\$10^6$	32.3	53.3
Operating Costs, \$/bbl		
H_2 Plant Feed + Fuel (net)	0.35	0.35
Other Utilities	0.57	0.56
Catalyst/Acceptor/Chemicals	0.07	0.07
Labor/Overhead	0.12	0.07
Maintenance @ 3% of Investment	0.17	0.14
Fixed Charges @ 18% of Investment	1.00	0.82
TOTAL, \$/bbl	2.28	2.01
TOTAL, $\$/10^6$ Btu	0.38	0.335

Basis:
- 2.5% S fuel
- 72% S removal efficiency (0.7% S in final product)
- December 1975 dollars
- Operating factor - 7,000 hr/yr

residual oil offers an alternate to the processes discussed earlier. Westinghouse Research Laboratories have prepared a process evaluation and demonstration plant design. The following evaluation of the CAFB processes is summarized from work done by Westinghouse* in 1975. Specific evaluation of the CAFB process was outside the scope of the ADL study.

C.9.3.2.1 Conclusions From Westinghouse Report - The conclusions and recommendations based on the results of the Westinghouse evaluation are quoted below:

"*Market*

- *Atmospheric-pressure operation of the CAFB process is most applicable to the electrical utility industry as a boiler retrofit for oil- or gas-fired boilers. The atmospheric-pressure process is not generally attractive for new boilers or retrofit of coal-fired boilers because of the current trend toward coal. The largest market is for boiler sizes ranging from 50 to 400 MW.*
- *Vacuum bottoms or other low-grade high metals content fuels are the fuels most likely to be available for the CAFB process.*
- *Limestone availability for CAFB may be more restricted than for slurry scrubbing processes due to more stringent requirements on sorbent physical properties with CAFB.*
- *Potential markets for CAFB by-product/waste stone are uncertain.*

Technology

- *Environmentally, CAFB appears superior to lime and limestone slurry flue-gas scrubbing because of the reduced impact of nitrogen oxide, solid waste, and process water requirements.*

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*"Fluidized Bed Combustion Process Evaluation," EPA-650/2-75-027-a, study conducted by Westinghouse, March 1975.

- *Higher fuel efficiencies are realized with CAFB than with HDS.*
- *The ability of CAFB to utilize low-grade petroleum or synthetic fuel fractions with high metals content provides the potential for a fuel source which may not be feasible with HDS or stack-gas cleaning processes.*
- *CAFB is in a much earlier state of development than is lime/limestone slurry scrubbing or HDS, although major development work is still required in slurry scrubbing processes to demonstrate reliability.* [See also section C.9.2. in this report on FGD.]
- *CAFB has the potential to offer high reliability and lower space requirements than lime/limestone slurry scrubbing.*
- *It has not been established whether there is, in general, sufficient physical space at a majority of boiler plant sites for either CAFB or slurry scrubbing retrofit.*
- *The utilization of a clean fuel, such as from HDS, is the most convenient technological option available to the utility.*

Economics

- *The capital cost of CAFB is 25 to 50 percent greater than that of limestone scrubbing and is comparable to regenerative stack-gas cleaning costs.* [ADL note--Table 8 in Westinghouse EPA 650/2-75-027-a--Summary Report--suggests the range is more like 100-120 percent greater.]
- *The fuel adder for CAFB is competitive with limestone scrubbing if low-grade fuels available to CAFB are 10 to 20¢/10^6 Btu cheaper than fuels suitable for firing in a plant with limestone scrubbing.*
- *HDS of vacuum bottoms with low metals content is not competitive, even though operating at a higher load factor,*

unless a unit larger than 25,000 bbl/d is built to supply more than three 200 MW boilers, or a unit larger than 35,000 bbl/d is built to supply two 500 MW boilers. Thus, HDS requires more immediate commitment of capital than would a single CAFB unit."

C.9.3.2.2 <u>Cost of CAFB Process</u> - Using the Stone & Webster/Westinghouse design and cost analysis as a basis, the economics of the CAFB process were adjusted to conform to the basis used in the FGD and HDS cost evaluations presented earlier. In addition, the CAFB costs are based upon a twenty percent air/fuel ratio, which corresponds to the ratio existing in most of the pilot plant runs. Desulfurization costs for CAFB are shown in Table C.9-8. Electric power consumption is the largest variable cost factor. The capital charge per million Btu's is relatively high compared to other processes discussed.

C.9.4 SELECTION OF THE DESULFURIZATION PROCESS

Up to now our discussion has focused on the various methods available to produce low sulfur emissions in the flue gases of an oil-fired boiler. In each case we have developed a cost for comparable sulfur removal by each process. Before making a cross-comparison among the processes we need to point out some of the other factors beyond the pure "cost per million Btu's" which need to be, or will be, considered by decision makers.

C.9.4.1 <u>Selection Criteria</u>

These selection criteria affect both the pre- and post-combustion desulfurization alternatives. Some of the major considerations are:

1. The user may wish to maintain flexibility of fuel supply by using a post-combustion process rather than be dependent on petroleum refiners marketing low-sulfur fuel oil.

2. A petroleum refiner installing direct desulfurization facilities for use with Arabian crude stock, for example,

Table C.9-8

Desulfurization Cost for CAFB (2.6% S Fuel)

Capacity		50	200
Capital Investment (C.I.) (1975), $\$10^6$		9.5	28.2

Operating Costs

	Unit Costs	¢/10^6 Btu	
Electric Power	\$0.02/kwh	11.8	11.8
Limestone	\$30/ton	1.8	1.8
Labor and Overhead	\$8/man-hr	8.5	2.1
Maintenance (L&M)	4% C.I.	5.9	4.7
Solid Waste Disposal	\$10/ton	0.7	0.7
Capital Charges, 18% of C.I.		48.9	36.3
Total Operating Cost, ¢/10^6 Btu		77.6	57.4

Basis: • 20% Air/Fuel ratio

• Operating Factor - 7,000 hr/yr

would incur significant additional costs and lower operating efficiency when processing other stocks which had higher metals contents. The same alternate stocks would not create similar problems for the fuel oil user with flue gas desulfurization or CAFB facilities where the costs relate more closely to sulfur content than to metal content.

3. A petroleum refiner installing indirect desulfurization facilities for use with Iranian crude oil, for example, could be limited in the amount of high-sulfur crudes that he could process while meeting product sulfur specifications since indirect desulfurization is inherently limited in the amount of sulfur which it can remove. A fuel user with flue gas desulfurization or CAFB facilities enjoys more flexibility in this respect.

4. The comparisons have been based on an equivalent rate of return on desulfurization facilities installed by the petroleum refiner and the user. The user might be able to include a relatively lower rate of return (utility basis) in his assessment of a flue gas desulfurization or CAFB installation as the alternative to paying for the petroleum refiner's full charges for risk and profit in the price of the low-sulfur fuel oil.

5. Pre-combustion desulfurization is less efficient with respect to overall energy considerations than flue-gas desulfurization--i.e., less energy is consumed for an equivalent degree of flue gas desulfurization than for residuum desulfurization. Increased energy costs or government policy with respect to energy conservation could enhance the influence of this factor.

6. The user may prefer not to take on the responsibility of a processing step involving the sale or disposal of sulfur and thus may prefer to shift the responsibility for desulfurization to his supplier if other economic and technical factors

are a standoff.

The economics of heavy oil catalytic desulfurization are more favorable in comparison with stack gas desulfurization for Type I crudes (Arabian) than for Type IV crudes (Iranian Heavy). Processing costs for either kind of residual fuel oil catalytic desulfurization and flue gas desulfurization are sufficiently close that individual decisions will be made in the context of the processing characteristics of the range of residuums expected to be available, the flexibility required in the proportions and types of these stocks, government policy, and individual approaches to the assessment of capital projects.

C.9.4.2 Comparison of Operating Costs of Desulfurization Alternatives

The above selection criteria will be very important in deciding which particular process will be selected by an individual user. But the decision must also look to economics and to that end we have prepared Table C.9-9 which summarizes the operating costs for the CAFB, FGD and catalytic desulfurization processes. The economics for FGD are based upon the Double Alkali process while the particular catalytic desulfurization costs shown are for the RCD Unibon process.

The CAFB information on Table C.9-9 is generally in agreement with the Westinghouse assessment but with some shifting in the ranges. For example, this comparison indicates that catalytic desulfurization would be competitive down to a capacity of 250 MW (10,000 Bbl/day).

The results of our technical assessment are summarized as follows:

- Flue gas desulfurization is the lowest cost option for sulfur control. The technology is further advanced than CAFB, but is not particularly effective for NO_x control, and offers no protection against ash deposition on boiler tubes and supports.

Table C.9-9

Comparative Desulfurization Costs

	CAFB		FGD (Double Alkali)	Catalytic Desulfurization (RCD Unibon)[A]		
Plant Capacity, MW	50	200	150	250(10)[B]	500(20)	1000(40)
Capital Investment, \$/kw	190	141	60	102	84	69
Operating Costs, ¢/10^6 Btu						
Electric Power	11.8	11.8	1.0	--	--	--
Other Utilities	--	--	3.2	7.1	7.0	6.8
Catalyst/Chemical	1.8	1.8	7.1	5.8	5.8	5.8
H_2 Plant Feed + Fuel	--	--	--	9.8	9.8	9.8
Labor & Overhead	8.5	2.1	2.7	3.8	2.0	1.2
Maintenance (L&M)	5.9	4.7	5.4	4.3	3.6	3.0
Solid Waste Disposal	0.7	0.7	6.5	--	--	--
Capital Charge @ 18% CI	48.9	36.3	15.8	26.2	21.5	17.8
TOTAL OPERATING COST, ¢/10^6 Btu	77.6	57.4	41.9	57.0	49.7	44.4

Basis: 2.6% Sulfur Residual Oil; ~90% sulfur removal
Operating Factor - 7000 hrs/yr

A - Licensed by UOP Process Division

B - Value in parenthesis is volume in MBCD.

Source: Westinghouse Research, Universal Oil Products and ADL Estimates.

- Catalytic desulfurization is less costly than CAFB in the capacity range above 250 MW (10,000 Bbl/day) which is generally the capacity suitable for a large modern refinery.
- When compared to catalytic desulfurization, CAFB appears to have a cost advantage in the capacity range from 50 to 250 MW, and is less sensitive to resid quality than catalytic desulfurization.

Although the CAFB process is currently shown to have a cost advantage for a certain capacity range, its status of development is less advanced than the competing alternatives. Historically, the cost of flue gas desulfurization increased as the various processes approached commercialization. Consequently, it would be unusual if the costs associated with CAFB do not escalate before the first commercial system is installed.

C.10 RESIDUAL FUEL OIL HANDLING PROBLEMS

C.10.1 INTRODUCTION

Much residual fuel oil is consumed at locations which are accessible to water-borne transports because residual fuel oil requires special handling in transportation and water-borne transports are the most convenient way of moving resid. For residual fuel oil to be used at locations remote from waterways special problems must be considered and overcome. This chapter discusses the specific handling problems associated with residual fuel oil and mentions several of the ways these problems have been overcome. The chapter begins with a brief description of the relevant physical properties of residual fuel oil, then discusses the various modes of transportation and finally discusses problems of resid storage.

C.10.2 PHYSICAL PROPERTIES

The main physical properties of concern for the transportation of residual fuel oil are its viscosity and pour point. Also briefly discussed are several other properties.

C.10.2.1 Viscosity

Viscosity is a measure of the resistance of a fluid to shear or flow and can be reported or measured in a number of ways.

In the case of fuel oils it is commercial practice in the U.S. to quote the viscosity as measured on the Saybolt viscometer, where the time, measured in seconds, for a given volume of oil at a constant temperature to flow through an orifice of standard size is given as a measure of the viscosity of the oil. Thus, the higher the viscosity value reported, the longer it took for the oil sample to flow through the orifice. Clearly, a viscosity of "infinity" indicates the oil will not flow at the test temperature.

The viscosity of more mobile oils is recorded as Seconds Saybolt Universal (SSU) at 122°F (50°C) but for more viscous oils similar instruments with larger orifices are used so that the time of flow is reduced to about one tenth of that taken with a smaller orifice. The viscosity is then given as Seconds Saybolt Furol (SSF) at 122°F. Other scales of viscosity which are regularly used are Seconds Redwood 1 at 100°F (38°C) and Engler Degrees.

The viscosity of an oil depends on its temperature. Hence, the viscosity is always recorded together with the temperature of the oil. Residual fuel oil which has a viscosity of 3,000 SSU at 122°F (50°C) will have a viscosity of 1,700 SSU at 140°F (60°C) and a viscosity of only 650 SSU at 180°F (82°C).

Viscosity is most important to the users of residual fuel oil. Too low a viscosity and the pumps used to move the oil about will not work properly (mainly a loss of lubrication for the pumps and a loss of pumping efficiency). Too high a viscosity may lead to premature pump failure as the pumps are overworked by trying to force the oil through the pipes.

C.10.2.2 Pour Point

Wax crystals (n-paraffins) contained in residual fuel oils can cause the fuel oil to gel and plug the pipelines if the temperature of the oil is permitted to fall below a certain level. As the temperature of the oil in the pipeline falls below a certain point called the cloud point, the wax crystals begin to form. As the oil continues to cool, the oil becomes a slurry of wax crystals in oil which tend to build up on pipe walls, valves, etc. When the oil cools to a temperature called its pour point, the crystals become so numerous that they interlock and the oil gels, stopping the flow.

The pour point of an oil thus represents the lowest temperature at which an oil can be stored or handled without it congealing in the tanks or pipe lines, and is thus a value of critical importance for handling residual fuel oil.

The pour point of residual fuel oils is an inexact measurement and is only measured to the nearest 5°F (2°C). For a given oil, the pour point is dependent upon the temperature to which the oil has been previously heated. Also, the pour point test does not indicate the behavior of the product under pressure, as in the case of the oil under pipeline pressure. The static conditions of storage of a large amount of oil are different from the laboratory test conditions. Hence it is general practice to keep a safety margin of several degrees between the measured pour point and the operating temperature of the fuel oil. Typically, residual fuel oils are handled at about 125-130°F (52-54°C), while most residual fuel oils have a measured pour point of 60-100°F (16-38°C).

In general, pour point is a less critical specification for residual fuel oil because users of resid are set up to handle it. For a user in the U.S. without heating equipment in the storage tanks pour point is all critical since he will not be able to use resid because the likelihood of the oil temperature occasionally falling below the pour point is overwhelming. But once the heating equipment is installed, pour point generally ceases to be a problem affecting storage or usage.

Residual fuel oil which requires special heating equipment before it can be handled is called "high pour resid" and usually sells at a slight discount from "low pour resid" which can be used without special heating equipment. The pour points associated with these two classes of resid vary with the seasons and by different oil companies, but generally any oil with a pour point over 60°F (16°C) would be considered high pour.

Clearly, pour points can go quite low--residual fuel oils with pour points of as low as -20°F (-29°C) can be obtained. It should also be pointed out that the pour point of an oil affects its viscosity. As the oil cools down towards its pour point the viscosity increases normally until the oil is within 5° to 10°F (2 to 5°C) of the pour point. As the wax crystals begin to form the viscosity begins to increase very rapidly and reaches infinity at, or near, the pour point.

C.10.2.3 Specific Gravity

Most residual fuel oils have a specific gravity between 0.94 and 1.00, i.e. almost as heavy as water. When an installation is designed to handle residual fuel oil, the equipment is dimensioned accordingly and hence the relatively high specific gravity of this product does not create any problems.

C.10.2.4 Sulfur Content

Although high sulfur content in residual fuel oils can cause severe problems as far as its use as a fuel is concerned, it has no effect on the storage or handling problems. All metal surfaces that come in contact with the residual fuel oil and are likely to corrode are usually coated and thus protected.

C.10.2.5 Minimum Operating Temperature

Utility grade residual fuel oils typically have pour points of 60-100°F (16 to 38°C). It is necessary to maintain the oil above this temperature, usually around 125-130°F (52-54°C) so that it can be handled at reasonable pressures at the lowest cost and so that problems with its pour point will not be encountered.

When transporting these oils special care has to be taken to ensure that their temperature at arrival is well above the pour point. This is achieved by:

- heating the oil to about 160°F (71°C) before it is transported

- reducing the heat loss by insulating the tanks, pipelines, etc.
- heating the oil intermittently during transportation, or
- a combination of two or more of the above mentioned methods.

C.10.3 TRANSPORTATION OF RESIDUAL FUEL OIL

This section will look at water transports, pipelines, railroads and trucks as means of moving residual fuel oil. Since sites remote from water will have special problems in obtaining resid, the emphasis of this section is on pipelines for heavy oil.

C.10.3.1 Water-Borne Transport of Residual Fuel Oil

C.10.3.1.1 Coastal and River Transport - Over a short distance in protected waters residual fuel oil is generally carried in barges or in tanks mounted on barges. The barges do not contain heating coils but in some cases the deck mounted tanks are insulated.

The oil is loaded at a temperature much higher than the pour point. Usually the total voyage time is short and hence the oil arrives at the users location at a temperature at which it can be handled normally.

C.10.3.1.2 Ocean Transport - Residual fuel oil is transported in ocean tankers which are specially designed to carry and handle high viscosity, high specific gravity products in bulk. The cargo tanks, which form an integral part of these tankers are not insulated, though in some cases they do contain steam-tracings to maintain the temperature of the product above its pour point. The cost of transporting the product in tankers with heating coils is higher because the capital costs, repair and maintenance costs and voyage costs of such tankers are higher than those of a tanker without the heating elements. Hence, such tankers are generally used only when the product and voyage specifications require them and where their full utilization is assured in a dedicated trade.

When residual fuel oil is transported in tankers without heating coils, the product is loaded at a temperature sufficiently high so that in spite of the natural cooling down that occurs during the voyage at sea the temperature of the oil, on arrival, will still be well above the pour point.

The cargo handling system of these tankers is specially suited to handling hot, viscous liquids and the deck pipelines, along which cargo to or from shore flows are insulated and steam-traced.

C.10.3.2 Pipelines for Residual Fuel Oil

C.10.3.2.1 Hot Oil Pipelines - Over a short distance residual fuel oil can be transported in an uninsulated pipeline. Typical examples of such installations are pipelines at tank farms, storage terminals, etc. where the pipeline is used infrequently for a short period. In some cases these pipelines are heated by steam-tracing or electricity. Over longer distances residual fuel oil must be transported in special pipelines. The oil is preheated to about 180°F (82°C) before it is pumped through the pipeline which, in order to reduce the heat loss, is insulated. Depending upon such operating factors as the velocity, pressure and viscosity of the oil in the pipeline, insulation of the pipeline, ground temperature, and the distance between the initial pumping station and the terminal, the pipeline system may include a number of pumping stations and/or reheat stations. Normal design conditions include an inlet temperature of 180°F (82°C) and outlet of 130°F (54°C), with 1200 psi maximum operating pressure.

C.10.3.2.1.1 Design and construction - The design of a "hot oil pipeline" is much more complicated than that of a pipeline for crude oil or other low viscosity products. During the design stage, several factors such as the physical properties of the residual fuel oil (viscosity, specific gravity), the insulation system and the selected equipment have to be balanced in order to obtain the most economical operating conditions such as inlet and outlet temperatures, maximum operating pressure and flow rate and the distance between reheat/pumping stations.

The construction of a residual fuel oil pipeline is also elaborate and expensive, mainly due to the fact that the insulation system has to be protected against damage during construction.

A typical cross section of a residual fuel oil pipeline will have an inner steel pipe which actually carries the oil. Its size will depend on the volume of oil to be transported. Surrounding the pipe is an anti-corrosion coating which generally will have been applied at the steel mill. Completely covering the pipe will be insulating material and an outer protective jacket must be applied to protect the insulation and permit the pipe to be handled during construction without too much difficulty. Depending upon the type of insulation selected, it is applied "in situ" or factory applied before the pipe is delivered at site. The outer protective jacket thickness can be reduced to about 40 mil. (0.1 mm) if the pipeline is bedded in a soft soil, but where the soil includes hard materials like rock, a steel casing with bulk-heads and support systems may have to be used.

Thermal expansion will take place in a steel pipeline carrying heated oil. This expansion has to be taken up by bellows in the pipe joints or by making U-shaped loops in the pipe. If the expansion movements are to be resisted, special anchor blocks have to be incorporated in the system and the resulting stresses must be within tolerable limits.

C.10.3.2.1.2 <u>Operations</u> - The most significant difference between the operating procedures of a hot and a normal oil pipeline is the routine shut-down procedure which must be established.

Short stoppages (e.g. power failures) can be tolerated on a hot line without the need to clear the line or take steps to prevent plugging. Pumping normally may be stopped for 3 to 12 hours, depending on the line size, without undue cooling. When pumping ceases, any heated fuel oil in the pipeline begins to cool down, and although an insulated line cools more slowly than a bare line, eventually ground temperature will be reached.

If the pour point of the oil is higher than the ground temperatures, the oil could gel and plug the line. Several methods may be used to overcome this difficulty, among them:

- flushing the line
- providing in-line heating elements
- using very high pressure pumps

Clearing the line of high pour material with a low pour flushing oil requires a ready supply of flush oil. Approximately twice the pipeline content must be made available for insulated pipelines [one content for line clearing and one content (or less) for pre-heating after prolonged shut-down]. If the flush oil cannot be used at the destination, a separate tank will be required for its collection and a pump to return the flush oil to the originating station during the next shut-down (the same oil can be used a number of times before its pour point becomes too high). When this stage is reached, it can be disposed of by degrading into a heavier fuel oil.

To ensure the removal of all the high pour point oil from the pipeline and to prevent any unnecessary amount of contamination of the flushing oil if it is not to be consumed, separator elements are used between the high and low pour oils.

Where normal pumping is by electrically-driven units, the stand-by pump or pumps should be provided with diesel engine or gas turbine drive, so that in the event of a power failure, the stand-by pump can be used to put flush oil into the system.

An electric heating cable may be installed within the pipe, the heating capacity being calculated so that the temperature of the oil may be raised from ground temperature to the minimum temperature required to pump the oil within a reasonable time. When pumping recommences, the heating may be switched off. This method would be very costly to install in long pipelines, as power feeder cables would be required along the pipeline to supply the sections of heating cable. Additional costs will be involved in areas where no main electricity supply is near at hand.

Providing a high pressure pump to move the gelled oil at a gradually increasing rate as hot oil is pumped along the pipeline may be economic, in certain circumstances, particularly for short lines. An accurate determination of the pressure required to move the oil is essential, and pipe-wall thickness and pressure rating of fittings must be suitable for this "cold" pumping duty. With this method it may take a considerable time to build up to the full flow rate--a time factor which should not be forgotten when comparing with other methods.

C.10.3.2.1.3 <u>Estimated transport costs</u> - Table C.10-1 is a rough cost estimate for a 600 mile long insulated hot oil pipeline, based on the following assumptions:

Flow:	100,000 B/d
Location:	Midwest
Cost Base:	Mid-1974 Costs
Line Length:	600 miles (966 Km)
Line Size:	16" Outer Diameter (40.3 cm)
	0.375" Wall thickness (0.945 cm)
Line Position:	Buried 4' (1.22 m) below ground
Insulation:	Polyurethane of 2" (5 cm) thickness

Ground Surface Temperature: 0°F (-18°C) (minimum)
Minimum Oil Temperature: 120°F (49°C)
Oil Temperature at Inlet: 140°F (60°C)
Oil Temperature at Outlet: 120°F (49°C)
Distance between reheat stations: 70 miles (113 km)

<u>Properties of Oil</u>:

Density: 28° API (0.885 units at 15°C)
Pour Point: 110°F (43°C)

Of the almost \$1/Bbl operating cost, about 20¢/Bbl is accounted for by the cost of heating the oil plus the capital charge associated with the one-third of the capital cost accounted for by the insulation requirements.

Table C.10-1

Capital and Operating Costs
for a Hot Oil Pipeline

		$ Million
Capital Cost:		
Basic pipeline plus equipment, land, etc.		100
Heating stations		1
Insulation		48
Total		149
Operating Costs:		
Capital charge		25
Operating costs		7
Power and heating		4
Total		36
Total in $/Bbl		0.98
Of which:		
Regular Pipeline	0.73	
Hot Oil Cost	0.25	
	0.98	

C.10.3.2.2 Residual Fuel Oil Pipelines Without Insulation - Over a short distance, residual fuel oil can be moved in uninsulated lines, although as the cost of energy continues to escalate these uninsulated lines begin to incur substantial energy costs. Because of the high cost penalty (as shown in Table C.10-1) incurred by hot oil lines, studies are being carried out to investigate the possibilities of transporting residual fuel oil over long distances in ordinary product pipelines. In this case the viscosity of the residual fuel oil would have to be reduced to an acceptable level by blending it with a diluent with a very low viscosity. The viscosity of the diluent will determine the ratio of blending.

Below are some rough estimates of the blending ratios required for some diluents so that the mixture has a viscosity of 400 SSU at 30°F (-1°C), a level at which it can be handled easily.

Cold Residual Oil Line Diluents

Product	Viscosity SSU at 35° F	Percent Product in Blend
Gasoline	32.5	26-40
Kerosene	33.7	37
Diesel #2	59.0	55
Solvent #1	33.6	38
Toluene	33	36
Xylene	33	36

The blending alternative has several problems linked with it, the main one being what to do with the mixture at the point of arrival. There can be two ways of treating this:

- use the mix as is
- separate the components

If mixed with #2 oil, residual fuel oil (#6) can be used as #4 fuel oil, This would eliminate the need for investment in a separating plant, storage, etc. but would carry a penalty of the cost differential between the #2 and #6 oil.

When mixed with gasoline or with hydrocarbon solvents, the constituent elements will have to be separated. This method has the following problems:

- Additional investment and operating costs for the separating plant and storage
- Problems of demand and marketing the diluent product at the point of arrival.

C.10.3.3 Other Transportation Modes

C.10.3.3.1 By Railroad - When residual fuel oil is transported by rail cars, this is usually done by unit trains which run a shuttle service between a refinery or tank farm and the industrial user or utility. Unit trains often consist of up to 50 cars of tank capacities of about 22,000 gallons each (about 525 Bbl, 80 LT).

The rail car tanks are insulated and the oil is loaded at temperatures well above its pour point. After loading the train proceeds to the destination with as few stops as possible, and in order to reduce the turnaround time both the loading and discharging operations are usually highly automated.

Most unit trains are dedicated to a project and form an integral part of the user's operations. Hence their capacity and scheduling is designed to suit the consumption pattern and storage tank capacities at the terminals. One such unit train operation in Canada delivers 25 million barrels of oil annually over a distance of 375 miles (604 Km).

C.10.3.3.2 Trucks - Residual fuel oil is transported by road tankers to the smaller users. The truck's fuel oil tanks do not contain any heating elements and are generally not insulated. Hence the transport of this product by trucks is limited to short distances and comparatively small quantities. Most truck transport operations service small industrial and commercial operations. Due to road traffic problems trucks are not a reasonable supply system to be used for a large volume residual oil user.

C.10.4 STORAGE OF RESIDUAL FUEL OIL

The main problem affecting storage of No. 6 fuel oil is to maintain the oil at a temperature above its pour point. This is done by

- heating the oil by steam fed heating coils, and/or
- by insulating the tanks to reduce the heat loss.

In the past, when the cost of energy was lower, heating the oil was preferred to insulating the tanks. In addition to the heating costs, the heating coils incur a higher maintenance cost due to corrosion from the sulfur content of the oil. With the higher cost of energy there is an increasing tendency to insulate tanks storing residual fuel oil or crude in order to reduce the heat loss.

The following table illustrates the savings achieved by insulating the tank.

Costs of Fuel Oil Storage Tanks

Parameter	Uninsulated Tank	Good Insulation
Heat Loss (BTU/ft^2 - hr.)	155	7
Fuel Cost per yr.	$ 95,000	$ 4,300
Insulation Cost	-	$50,000
Five Year Cost	$475,000	$71,500

One other problem in the storage of residual fuel oil is that the wax contents could cause a problem if the wax were permitted to build up on the tank sides. Stratification of tank contents could allow this to happen and, even when tanks are heated, mixers are considered necessary to prevent such stratification. Furthermore, mixers keep water and sludge stirred up and in motion, helping to prevent bottom sedimentation.

C.11 FUTURE RESIDUAL FUEL OIL DEMAND

C.11.1 INTRODUCTION

The level of future demand for residual fuel oil will ultimately depend on the outcome of the factors discussed in the previous chapters. However, in order to provide an estimate of the quantitative impact of these factors, we tried to review recently published forecasts to obtain a consensus view of future demand on a PAD district basis. Unfortunately, the publicly-available forecasts were deficient on two important counts: the data was presented only on an aggregate national basis (i.e. no regional or PAD district breakdown) and/or no product breakdown was given. In fact, we were unable to locate any reliable recent public forecasts which split national oil or product demand out by PAD districts or regions. Only one forecast, the Exxon forecast of December, 1975*, indicates an estimate of residual fuel oil usage, and that estimate is limited to the residual fuel oil consumed by electric utilities.

The lack of recent published forecasts on a regional or product basis leaves only the more general primary energy forecasts for the total U.S. In the following section we present the conclusions of a representative sampling of these primary energy forecasts and comment as to how we would expect residual fuel oil demand to be related to the oil growth indicated in the forecasts. We will also discuss briefly the extent to which we believe that residual fuel oil demand might be met from domestic refining sources.

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*"Energy Outlook, 1975-1996", December, 1975, Exxon Company, U.S.A. (including press release documents dated December 9, 1975).

In the event that the EPA decides to do further analysis of the potential demand for the CAFB process, it would be advisable to obtain a specific regional forecast of residual fuel oil consumption. The undertaking of the creation of such a forecast is clearly outside the scope of the present contract. However, in the event that EPA should proceed with their analysis of the feasibility of the CAFB process, a forecast should be made involving specific consideration of growth in demand by end-use sectors on a regional basis, as well as a thorough study of the regional impact of natural gas curtailments and nuclear plant delays. On the supply side, the forecast should focus on the changes in average yields of residual fuel oil by domestic refiners, and on the availability of residual fuel oil from foreign refining sources.

C.11.2 RECENT FORECASTS OF PRIMARY ENERGY BALANCES

Table C.11-1 summarizes the projections of primary energy balances as stated in a representative sample of recent public forecasts. It is necessary to be cautious in comparing these forecasts directly one with another since the underlying assumptions behind each forecast tend to differ. However, some general trends are revealed by reviewing these forecasts. Total energy demand is projected to reach 96.1 to 103.6 quadrillion Btu's by 1985, giving an average annual growth rate of 2.5% to 3.2% from 1974 to 1985. Projected growth in total energy consumption to 1985 compares with an average of 4.3% per annum over the period 1965-1972. The projected demand for oil in 1985 shows a consensus range of about 2 million barrels per day*, from 20.6 to 22.7 million barrels per day (42.1 - 46.5 quadrillion Btu's). These projections imply an average rate of growth over the period 1974 to 1985 of 2.1 to 3.0% per annum, as compared to an average of 4.9% in the period 1965-1972. Thus, not only is growth in overall energy consumption expected to fall off, but oil demand growth is projected to drop even more sharply in most cases. The projections reflect the higher price of energy generally and the

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*Ignoring for the moment the Sherman Clark estimate which is exceptionally high due primarily to a low coal production forecast.

Table C.11-1

A Comparison of
Recent Forecasts of Total U.S. 1985 Energy Demand
(Quadrillion Btu's)

Forecast Source and Date	Oil** Total	Oil** Domestic Conventional	Oil** Domestic Shale	Oil** Domestic Other	Oil** Imported	Coal	Nuclear	Natural Gas Total	Natural Gas Lower 48 Conventional	Natural Gas Alaskan	Natural Gas Imported LNG	Natural Gas Syngas	Natural Gas Other Not Specified	Other	Total
Sun Oil (Dec. 1975)	42.1	17.9	?	4.1 (Alaskan)	20.1	18.1	9.0	24.1	23.0	None	1.1		—	3.9	96.1
Exxon-"World Energy Outlook" (Dec. 1975)	44.8	21.6	0.5	0.6 (Proc. gain)	22.1	19.8	9.6 Est.	19.6	17.6	Inc.	1.0		1.0	3.9	97.7
U.S. Dept. of Interior, Bureau of Mines--"United States Energy Through the Year 2000" (Jan. 1976)*	46.5	NA	0.9		NA	21.3	11.8	20.1	17.3	1.5	0.6	(Syngas 0.4 counted under oil)	(Canada) 0.7	3.9	103.6
Mobil Oil-"U.S. Energy Sources: The Next Decade" (May 1975)	43.0	26.6	1.0	Some Syncrude	15.4 Est.	18.4	12.3	22.5	21.5	NA	1.0 Est.	NA	NA	4.1	100.3
PIRINC-"Electric Power and Oil Import Dependency" (May 1975)	43.8	22.5	Shale & Coal Liq. 0.8	Alaska 5.1 Proc. gain of 1.0	14.4	21.0	8.2	22.7	21.2	NA	1.5	(Syngas-coal 0.5; pet. 0.6; counted as primary fuels)***	NA	3.6	99.3***
Sherman H. Clark Assoc., July 1975	49.3	15.7 (range to 19.6)	0.2	3.9 (Alaskan)	29.5 (range from 25.6)	16.1	9.2	19.4	16.1 (could be 18.0 with deregulation)	1.0	1.5	(Syngas-coal 0.9; pet. 0.4)	0.5 Ca.; 0.3 other Alaska	3.7	97.7

*Only press release available to date.
**Includes NGL's and condensate unless noted.
***It is unclear in original report as to whether double counting of primary fuels used as feedstocks for syngas manufacture has occurred. The present account assumes that feedstocks were included in primary fuel demand figures.
Note: Forecasts may not be quoted in their original units. The following assumptions were made in converting forecasts to Btu's: 5.6 million Btu's/barrel of crude oil equivalent; 1.03 million Btu's/MCF of natural gas.

quadrupling of oil prices in particular. Table C.11-2 shows a tabulation of the growth rates for consumption of each primary fuel which are implied in the forecasts in Table C.11-1. Note that nuclear energy is expected by all the forecasts to be growing very rapidly in the next decade while natural gas is assumed to be a stagnant or even declining energy source.

In most of the forecasts reviewed, oil was assumed to be the balancing fuel. That is, a level of total energy demand was forecast and then supplies of all fuels other than oil were projected (assuming that non-oil fuels would be supply- rather than demand-constrained in the coming decade). The difference between total projected demand and projected supplies of non-oil fuels was assumed to be absorbed by oil, which was not considered supply-constrained during the forecast period. This methodology makes total oil demand extremely sensitive to the supply projections of the other primary energy forms (notice, for example, the effect of Sherman Clark Associates' low projection of coal supply on their oil demand). Any slippage in assumed contributions by non-oil fuels (such as nuclear) which is not matched by compensating declines in total energy demand will result in increased oil consumption.

C.11.3 IMPLICATIONS FOR RESIDUAL FUEL OIL DEMAND

While none of the current public forecasts provide breakdowns of oil consumption by product, it is possible to estimate the relative growth rates which might be inferred for residual fuel oil. In general, slower total oil demand growth is expected to be achieved by significantly less growth in light products (particularly gasoline) which is partially offset by increased demand for certain heavy products (i.e., residual fuel oil and, to a lesser extent, distillate fuel oil).

Gasoline demand, which currently accounts for approximately 40% of total product demand, is expected to depart markedly from historic high growth trends over the next decade. The declining rates of growth, and perhaps zero or negative growth in the early 1980's, will result from more efficient cars (efficiency standards are explicitly mandated by the new

Table C.11-2

A Comparison of Growth Rates Assumed In Recent Forecasts of U.S. Energy Demand
(Average % Per Annum, 1974-85*)

Source	Oil	Coal	Natural Gas	Nuclear	Other	Total
Sun Oil (Dec. 1975)	2.1	2.9	0.7	20.2	2.3	2.5
Exxon (Dec. 1975)	2.7	3.8	(1.1)	21.0	2.3	2.7
U.S. Dept. of Interior (Jan. 1976)	3.0	4.5	(0.9)	23.5	2.3	3.2
Mobil Oil (May 1975)	2.3	3.1	0.1	23.8	2.7	2.9
PIRINC (May 1975)	2.5	4.4	0.2	19.3	1.5	2.8
Sherman H. Clark Assoc. (July 1975)	3.6	1.8	(1.2)	20.4	1.8	2.7
Sohio (Dec. 1975-oil only)	2.8					

*1974 base data from U.S. Department of Interior, Bureau of Mines.

Energy Policy and Conservation Act of 1975), from consumer sensitivity to higher gasoline prices, and from a projected slower rate of growth in the total car population. Because of the importance of gasoline in relation to total petroleum product consumption, the projected decline in future growth rates will have a significant effect on growth in oil consumption as well as on the proportions of light and heavy products consumed. Partially offsetting the gasoline declines will be rapid increases in the petrochemical industry's demand for naphtha as a feedstock. However, in the period to 1985, increased petrochemical naphtha demand is not expected to alter the basic demand trend for more heavy products.

For all the reasons about natural gas problems, delays in nuclear plant construction and licensing, and the inability of coal production to increase sufficiently to absorb all deficits created by natural gas shortages and nuclear delays--residual fuel oil consumption is expected to grow more rapidly than total oil consumption during the coming decade.

Between 1970 and 1973, residual fuel oil demand increased at an average rate of 8.6% per annum. But there has been a two-year hiatus in the upward growth pattern of residual fuel oil. Following the OPEC price increases and Arab oil embargo, residual fuel oil demand actually declined 8% in 1974 over 1973 and early estimates place 1975 consumption lower than 1974 levels.

Over the next ten years it is possible that nationwide residual fuel oil demand will grow at the rapid historic rates; individual regions where gas curtailments are most severe and where residual fuel oil may have previously been of minor importance, may experience dramatic surges in demand. On average, we would expect residual fuel oil consumption to increase at annual average rates two to three percentage points above the averages for total oil demand. These future growth rates are expected to begin to decline in the mid-1980's as nuclear and coal energy sources become prepared to assume some of the electricity generation and large industrial demand loads.

C.12 FUTURE SUPPPLY OF RESIDUUM

C.12.1 INTRODUCTION

As discussed in C.11 no detailed forecasts of future petroleum product supply/demand balances have been available for this study. Thus, these conclusions are a consensus of the data we have developed in this study, rather than a publicly available forecast.

This chapter first presents a range of estimates of future residuum supply and next discusses its derivation. The sensitivity of residuum supply to various factors is discussed and some conclusions as to future residual fuel oil supply/demand balances are reached.

C.12.2 POTENTIAL FUTURE RESIDUUM SUPPLY

With the exception of residual fuel oil imports, virtually all residuum demand in the United States must be met by supplies from domestic refining. In a sense then, residual fuel oil production is a balancing element which is the net result of residuum production less all other uses of residuum. Table C.12-1 shows actual 1973 and potential 1985 refinery supply of residuum and imports of residual fuel oil. These potential supply situations should not be thought of as "forecasts" but rather are being used to illustrate a range of possible future outcomes.

Refinery capacity is expected to continue to expand in the United States to 1985, but whether it will do so at the rate shown in Table C.5-2 (about 3.7% per year) is not certain. Environmental constraints and uncertainty over government policies may slow refinery growth substantially. We show in Table C.12-1 a low range of refinery growth which has been set

Table C.12-1

Future Supply and Use of Residuum in the United States
(MMBBL)

		1985 Potential Supply/Demand	
	1973	Low	High
Crude Run to Stills	4,537	5,755	6,645
Residuum Yield	1,946	2,465	2,850
Less:			
Refinery Fuel	44	230	265
Asphalt & Road Oil	175	220	220
Lubes & Waxes	76	100	100
Coker Feed	250	250	280
Conversions	1,045	1,045	1,175
Subtotal	1,590	1,845	2,040
Residual Fuel Oil	356	620	810
Residual Fuel Oil Demand	1,016	1,655	1,865
Imports	660	1,035	1,055

to our average petroleum demand growth rate of 2% per year, while the high case uses 3.2% per year refinery growth which is close to the rate of refinery growth shown in Table C.5-2 for the period 1976-1980. The values shown in Table C.12-1 are for crude runs to still so that future refinery capacity would be a larger volume. If capacity utilization were 90% in both cases, then the anticipated refining capacities are 17.5 and 20.2 million barrels daily for the low and high cases. This compares to a current refining capacity of about 15 MMBCD.

We have assumed that the mix of crudes available to U.S. refiners will continue to yield roughly the same amount of residuum. This assumption may understate the future availability of residuum as lighter domestic crudes decline in production and foreign crudes, which would tend to be heavier than domestic crudes, are imported. Thus over time natural residuum yield may increase as a percent of crude runs, but we have held it as a constant percent in Table C.12-1. Besides possible future residuum yield changes, the amount of sulfur in future imports of crude oil is likely to be higher than it is today. The international availability of sweet crudes is limited compared to the availability of sour crudes which indicates that the average sulfur content of imported crudes will tend to increase. This will increase the need for sulfur removal processes.

From the residuum yield we have subtracted other residuum uses to derive the potential residual fuel oil supply. We have assumed that the needs for asphalt, road oil, lubes and waxes will grow at 2% per year in both cases, while we have shown static coker and conversion uses for residuum in the low growth case and a minimal 1% per year growth in the higher case. Refinery use of residuum as fuel is shown to expand dramatically under the assumption that residuum will replace lost natural gas supplies and become the main refinery fuel source.

Refinery gas, coke and other fuel sources will continue to be used for refinery fuel, but residuum is expected to become the main fuel. This high use of residuum for fuel could be reduced if more refineries use coal as a fuel. Such a situation is not expected to develop within the next decade, however.

Coker and conversion uses of residuum have been shown with no or very low growth between 1973 and 1985 to demonstrate the impact of gasoline demand on residuum use. It should be noted that we expect absolute gasoline demand to increase between now and 1980, but then begin to remain level or decline so that by 1985 residuum used in gasoline production could be expected to have grown only minimally. The no-growth situation is probably too low an estimate of what will happen by 1985 but is not totally unlikely.

The net result of meeting all other uses for residuum leaves residual fuel oil as the balancing element. Residual fuel oil production is shown to expand either at 4.8% per year or at 7.1% per year between 1973 and 1985. The low rate has domestic residual fuel oil supply growing at a slightly higher rate than demand which has been assumed to grow at 4.1% per year from 1973 to 1985 in the low case. The high rate assumes refinery residual fuel oil production will expand at a much higher rate than the 5.1% per year shown for growth in residual fuel oil demand from 1973 to 1985.

Even at the higher growth rate of residual fuel oil production, imports of residual fuel oil will still be higher than at present. A production expansion rate of about 14% per annum between 1973 and 1985 would be required to eliminate residual fuel oil imports by 1985. Such a growth rate appears impossible to attain. In Table C.12-1 imports of residual fuel oil are shown expanding at between 3.8 and 4.0% per year for the two cases. Imports of residual fuel oil in this potential situation are about 2.9 MMBCD which compares to current imports of about 1.8 MMBCD. These imports, of course, are in addition to imports of crude oil or other products. The spread between low and high case import levels shown on Table C.12-1 appears unrealistically narrow and is due to the assumptions which have been made rather than to any particular preciseness in forecasting imports.

In general agreement with our conclusions that there is now more of an incentive for refiners to produce residual fuel oil relative to other products and that such conditions may continue in the future, the 1985 figures on Table C.12-1 show residual fuel oil production being 10.8% and 12.2% of crude runs for the low and high cases while the 1973 actual runs showed that resid production was equal to 7.8% of crude runs. It should be noted that in March 1976 the FEA proposed rulings that would lessen the incentive for domestic refiners to produce residual fuel oil, especially for the East Coast market. The final FEA rulings could materially affect future production levels.

C.12.3 SENSITIVITY OF RESULTS TO VARIOUS FACTORS

C.12.3.1 Government Product Import Controls

The high side of the potential supply picture presented in Table C.12-1 is based on high refinery capacity growth and yet still requires large volumes of product imports. Without strong government assistance to the refinery industry, it is unlikely that product imports could be wholly eliminated by 1985. Indeed with most of the refining capacity in the Caribbean area designed for and dependent on U.S. markets, it could be politically difficult to eliminate those refineries from the U.S. supply situation as well as being difficult purely from supply oriented considerations.

Holding product imports to their present level would require substantial refinery growth above the high case rate. Such growth, again, would require government incentives. Proposed FEA rules would seem to act in the opposite direction, so it is not clear that the government is necessarily trying to reduce imports by encouraging the domestic refining industry.

C.12.3.2 Crude Oil Prices

Since the inception of the Entitlements Program, U.S. refiners have enjoyed a substantial crude cost benefit as compared to foreign refiners due to the lower average domestic crude prices. This benefit can last as long as domestic crude production is set less than world oil prices and should encourage refinery growth and increase domestic supplies of residuum. Such increases in supplies, however, must use foreign crudes since domestic crude production is not adequate to meet current demand. Thus, any marginal increases in residual fuel oil supplies will come from foreign crudes, whether or not the crude is refined domestically.

C.12.3.3 Residuum Product Prices

Residuum products supply a variety of markets and thus are sensitive to price changes in different ways. Refinery fuel usage of residuum in the long run must compete with any other available energy source. If those energy sources, for example coal, were available at lower cost than residuum, then they could be substituted for residuum usage in the long run. In the shorter run, it may be physically difficult for refineries to use fuels other than liquid or gaseous hydrocarbons. Thus to 1985 we feel that refinery fuel usage is relatively insensitive to end product pricing.

Asphalt and road oil have always been low value products and their usage is relatively sensitive to price changes. But with all competing products also facing cost increases due to increased oil prices, it is unlikely that asphalt and road oil market shares will be seriously eroded by price increases which are consistent with general energy cost increases.

Lubes and waxes are highly specialized, premium products whose use is relatively insensitive to price. Their prices generally are not set by raw material costs but rather by manufacturing and distribution costs, and their cost is a relatively small component of the product or service in which they are incorporated. Thus we would expect lube and wax demand to be relatively insensitive to price change.

Coker feed and residuum to conversion units basically depend on gasoline demand and prices to determine the volume so used, although petroleum coke does have specific market demand as an end product. Gasoline is a premium product compared to residual fuel oil so that residuum will selectively go to gasoline, but the conversion incurs substantial costs. As gasoline demand stops growing and refining capacity continues to expand, a larger fraction of gasoline demand can be met by the naturally occurring gasoline fractions and less conversion processing will be needed. Thus residuum will be freed for other end-product use. We expect that gasoline will continue to be a premium product so that residuum conversions will still be economically rational in the future.

C.12.3.4 Fuel Substitutability

Residual fuel oil must compete with other energy forms but as we have discussed previously, we expect oil to be the "swing" fuel at least for the next decade. This implies that oil price increases could be higher than for other fuels and oil demand would still increase. In addition, fuel cost is generally still a relatively small part of the cost of a finished product so that some price insensitivity in the manufacturing sector is evident. Thus we expect residual fuel oil demand will be relatively insensitive to normal price increases.

C.12.3.5 Product Quality Variations

Of concern to this study is the sensitivity of residual fuel oil price and supply to two quality parameters, sulfur and metals content.

We have not found any evidence to lead us to conclude that metal content directly affects today's price of residual fuel oil. Generally, product specifications list a maximum allowed metals content which is based on boiler requirements and the metals content specification is usually a relatively minor item in the product quality listing. These metals limitations have been developed over the years and the oil industry already operates to accommodate industry requirements. Some fuel oil uses, such as ship bunkers, can take fairly high metals content and we believe that the oil industry is able to divert high metal content oils to uses which are unaffected by those metals. It is doubtful whether oil suppliers would supply a high metals fuel oil to a user at a price discount. This would be especially true if the user needed relatively small volumes of such oil. That is to say, the oil supplier would have to set up a dedicated transportation and storage system to handle a high metals product and would not do so unless the volumes involved would justify such expenses. The oil supplier would be unlikely to give a price discount for the high metals product in such a situation, although to the extent that high metal and high sulfur contents go together, a price discount would be observed but would be attributed to the sulfur content.

Metal content probably does affect residual fuel oil price indirectly by making some crude sources not suitable currently for use in making resid. Such effects cannot be detected in current fuel oil market prices. We conclude that metal content currently has a very minor effect on residual fuel oil prices and supplies. In the future, metal content specifications may become more important but still will probably not be a sensitive element in price or supply decisions.

The sulfur content of residual fuel oil is the main variable in determining prices charged for the different grades of residual fuel oil. In the United States the New York Harbor area is the most active residual fuel oil market. In March 1976 2.8% sulfur residual fuel oil could be obtained on a contract basis for $10.00 per barrel while 1.0% sulfur fuel oil cost $11.70 per barrel, 0.5% sulfur fuel oil cost $12.45 per barrel and 0.3% sulfur, the lowest sulfur content fuel oil regularly available in the market, cost $13.20 per barrel. The sulfur premium per percent of sulfur ranges from $0.94 per barrel for 1.0% sulfur fuel oil to $1.28 per barrel for 0.3% sulfur fuel oil which reflects the increasing difficulty of obtaining ever-lower sulfur contents. These premia vary over time to reflect market conditions, but from the beginning of 1973 to 1976 the premia have all risen about 30-40 cents, reflecting increases in crude oil sulfur premia. These sulfur premia are about the same as the additional cost to desulfurize high sulfur oil. Table C.9-5 showed that desulfurization of an Arabian mix oil to 0.3% sulfur content cost 52 to 57 cents per million BTU's which is equal to $3.29 to $3.60 per barrel of resid. Since the oil mixture went from 3.8% to 0.3% sulfur content the cost was shown to be $0.94 to $1.03 per percent of sulfur removed. For the Iranian oil the lowest cost for obtaining 0.3% sulfur fuel oil was shown in Table C.9-6 to be $1.21 per percent sulfur removed. Thus sulfur premia in the marketplace reflect the cost of desulfurization but apparently provide no incentive for any process which costs more than current processes. Current sulfur premia are generally not large enough to encourage the construction of new desulfurization facilities.

Market conditions in Europe and the United States have lately been tending to reduce further the sulfur premia as there has been some relaxation of sulfur restrictions. Coupled with the slight easing of sulfur restrictions has been a general oversupply of fuel oil in the market which has resulted in relatively weak prices.

We anticipate, as discussed in C.6.5.3, that residual fuel oil prices will probably remain relatively steady in <u>real</u> terms for most of the next decade and that oil supplies will generally not be tight. We also anticipate these same conditions to apply to low sulfur oils so that sulfur premia will not be excessive. In fact, sulfur premia will probably continue to be as low as the lower cost desulfurization processes which will have a dampening effect on the installation of desulfurization facilities.

C.12.3.6 Technological Trends

The result of technological trends which would allow the environmentally sound use of high sulfur residual fuel oil without prior removal of the sulfur content would be to reduce the need for low sulfur fuel oils and increase the demand for high sulfur oils. If this shift in demand were of a significant size it could have the effect in theory of lowering the price differential between the two categories of oil until a user would be indifferent as to installing a system to use the high sulfur oil or as to buying the low sulfur oil directly, i.e. the sulfur premium would become equal to the additional cost of using the high sulfur oil directly.

Several conditions will cause problems with the above scenario. First, as shown above, sulfur premia are already as low as the cost of desulfurization so that end users are already indifferent as to whether to use low sulfur oil or some sulfur removal process and we do not anticipate a major change in this situation. Next, the assumption made above that a new process would affect the price of available oil is probably not valid until such time as the new process affects the use of a significant quantity of fuel oil. With current U.S. demand for residual fuel oil at about 2.5 million barrels per day a single installation, or even ten or twenty separate facilities, each using 10 MBCD, would be unlikely to affect the price of oil to any significant degree. If twenty facilities were to utilize common purchasing arrangements then some impact on price might be effected. However, and this is the final problem with the scenario posed above, all of this assumes an essentially elastic supply of oil which can continue to match demand. Oil supplies can appear infinitely elastic to an individual user, but when viewed from a national or global perspective there are definite limitations on availabilities of low sulfur, high sulfur, or any grade, oils. Thus in the future the ability to shift between grades of oil may become less important than being able to shift away from oil to coal or other energy sources.

In summary, environmentally sound uses of high sulfur fuel oils will probably not be able to affect overall oil prices or supplies and over the next decade may face price competition from available oil supplies. Such uses of high sulfur fuel oil could be useful in lowering sulfur emissions, so cannot be considered strictly from an economics standpoint.

C.12.4 CONCLUSIONS

Demand for residual fuel oil which in 1975 was about 2.5 million barrels per day could reach 4.5 - 5.0 MMBCD by 1985. Imports of residual fuel oil probably will continue to supply 60-65 percent of U.S. demand although a high rate of refinery expansion coupled with a slow growth in gasoline demand could reduce imports requirements.

The declining U.S. domestic production of crude oil will require increased imports of crude oil. Assuming world economic and political stability, such import requirements will be met mainly by the OPEC petroleum exporting countries and the effect on the United States will be primarily felt in the balance of trade.

Rising imports by the U.S. and other consuming countries will enable oil producing countries to continue to raise prices, although we expect prices in real terms to remain fairly stable for most of the next decade. By or before 1985, however, we would expect supply constraints to have developed to the point where oil prices could be expected to jump significantly in real terms. When that happens, additional incentive will be added for oil users to switch to other fuels.

Residual fuel oil will continue to be used primarily in areas convenient to water transport since that is the most economic method to transport residual fuel oil over any distance. Other transportation modes, such as pipelines or unit trains, will enable some users to be located away from water transport access. This may be important in allowing current natural gas users to shift to using residual fuel oil.

Residual fuel oil production in the United States will mainly be concentrated in areas with access to water transport: refineries located away from water routes will probably continue to convert most residuum into lighter products. The Gulf Coast region will probably expand its residual fuel oil production rapidly as the need to replace dwindling natural gas supplies increases.

In 1973 domestic residual fuel oil production was 7.8% of crude runs to stills or 18.2% of residuum yield which in turn was 42.9% of total crude runs. Most of the residuum was used for feedstock to conversion units (66.5%) with smaller volumes going to refinery fuel (0.2%), asphalt and road oil (9.0%), and lubes and waxes (3.9%).

By 1985 it is anticipated that some major shifts will have taken place in residuum yield. Refinery fuel usage will increase as natural gas supplies are lost. It is expected that residuum used for feedstock to conversion units will decline primarily as a result of gasoline demand becoming static under the impact of higher prices, increased mass transportation availability and increased automobile fuel usage efficiencies. Less residuum being used for conversion units will permit more residual fuel oil production and it is expected that domestic residual fuel oil production could increase to 25-28% of residuum yield or 11-12% of total crude runs.

It is not anticipated that major changes will occur in the next decade in the supply of or demand for residual fuel oil due to technological changes which would make the fuel oil more environmentally acceptable for use without further processing in the manufacturing stages. In other words, the normally anticipated demand increases for residual fuel oil of all sulfur levels will be high enough to overshadow any additional increase in demand which would result from being able to burn high, rather than low, sulfur resid. This is due mainly to the long lead times required to prove and install new technology which suggests that relatively few improved installations will have been made in the next decade. Another reason for this conclusion is that the cost to install such technological systems plus the cost of high sulfur fuel oil has been shown to be currently as high or higher than the cost of buying very low sulfur fuel oil. This has dampened any efforts to install new desulfurization equipment in refineries and would probably have an effect on any decision to install technological systems to control sulfur problems at the point of use. Such incentives could reemerge if a shortage of low sulfur crude oils were to develop. The EPA should keep this subject under particularly close review.

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16. ABSTRACT The report gives results of a study of the supply and demand of petroleum residuum in the United States, now and in 1985, with particular emphasis on residual fuel oil. The report details the historical residuum balance, then examines the major factors which affect the supply and demand. Factors include governmental influences, foreign factors, energy production trends, demand trends, technological innovations in sulfur removal processes, and residual fuel oil handling problems. Based on these factors, a potential 1985 residuum supply scenario is formulated and discussed. The sensitivity of the future scenario to the influence of the various factors is also examined.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Desulfurization	Air Pollution Control	13B	07A, 07D
Petroleum Industry		Stationary Sources	05C	
Residual Oils		Petroleum Residuum	21D	
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