

Chapter 5

The Petroleum Refining Industry

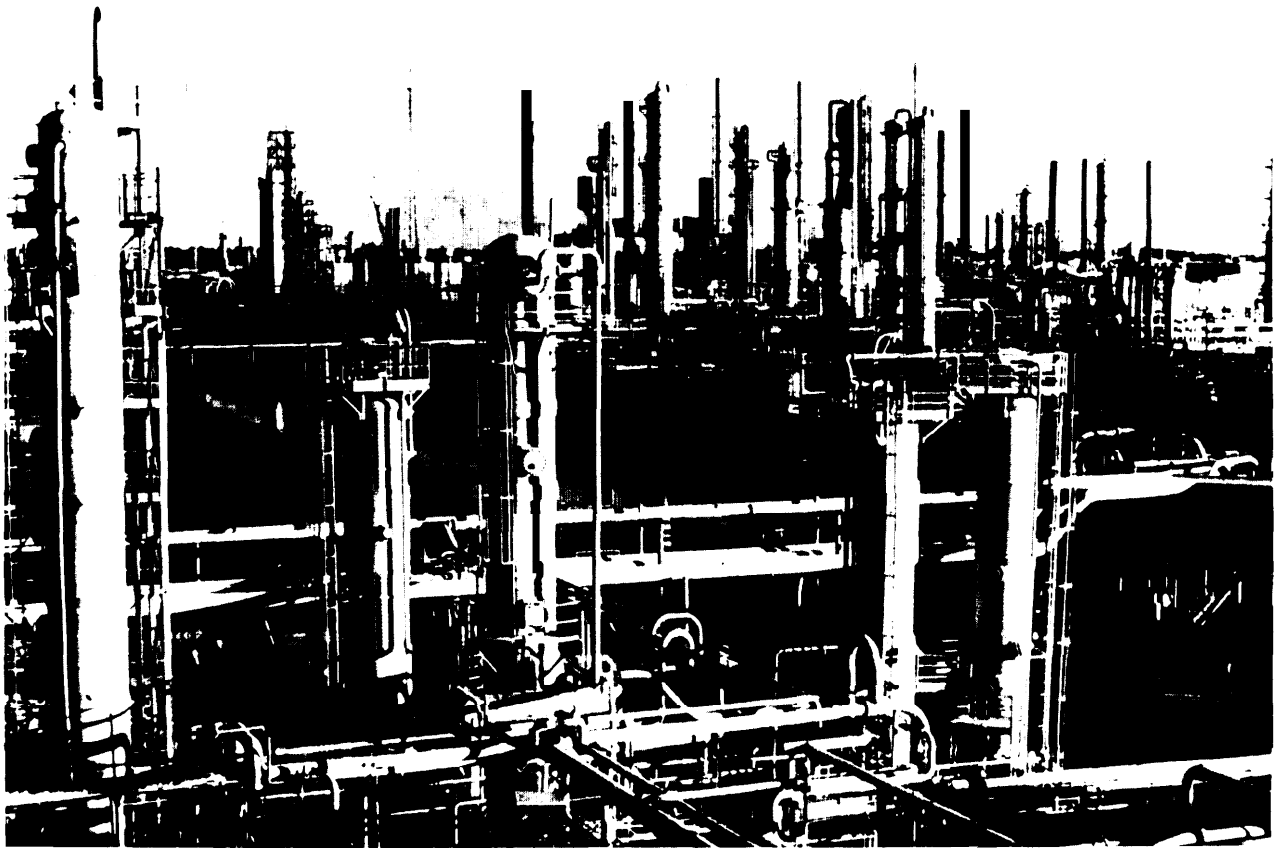


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INDUSTRY OVERVIEW

The petroleum refining industry uses the largest quantity of premium fuels in the industrial sector, amounting to 2,7 Quads in 1981. ¹ It is second only to the chemicals industry in the total amount of energy it consumes. Classified under SIC 29, the petroleum refining industry is defined as the group of establishments engaged in refining petroleum, producing paving materials, and manufacturing lubricating oils. Its official description is shown in table 21.

This industry faces a future that bears little resemblance to its past. Previously, the firms that made transportation fuels for the United States had access to large quantities of high-quality crude oil. Now, they must use less desirable high-sulfur crude oils as feedstocks. The petroleum product market is changing as well. Environmental considerations require production of high-octane, unleaded gasoline, instead of gasoline with lead added to improve fuel quality.

In addition, the costs of fuel have risen to such levels that overall demand for refining products is projected to decline over the next two decades. Thus, the management of firms in SIC 29 finds itself in the unenviable position of having to make sizable capital investments in an industry whose product will be in less demand.

¹ American Petroleum Institute, *Energy Efficiency Improvement and Recovered Material Utilization Report to U.S. Department of Energy*, June 10, 1982, p. 2.

Table 21.—Definition of SIC 29—The Petroleum Refining and Related Industries

This major group includes establishments primarily engaged in refining petroleum, manufacturing of paving and roofing materials, and compounding lubricating oils and greases from purchased materials. This SIC group contains the following subcategories:

SIC	Title
291	Petroleum refining
295	Paving and roofing materials
299	Miscellaneous products of petroleum and oil

SOURCE Office of Management and Budget, *Standard Industrial Classification Manual*, 1972

Finally, the refining process is becoming more complex as demand increases for high octane, unleaded gasoline. Crude petroleum, as found in nature, must be processed (refined) to remove impurities and to manufacture such useful materials as gasoline, jet fuel (kerosene), and fuel oil. In the early days of the petroleum refining industry, simple distillations were used to produce desired gasoline and kerosene products, with up to so percent of the crude oil feedstock being discarded. In recent years, this industry has made a great deal of effort to increase the yield of high octane products, minimize waste, and improve the overall quality of the product produced.

Industry Structure

The U.S. petroleum refining industry now consists of approximately 270 refineries owned by 162 companies.² Refineries are located in 40 of the 50 States. Refining capacity is located in areas known as Petroleum Administration for Defense (PAD) districts. Major concentrations of refining capacity exist in PAD districts 2 (Great Lakes and Midwestern States), 3 (Gulf Coast), and 5 (Pacific Coast). PAD district 1 (East Coast) has less refining capacity, a deficiency made up for by pipeline and tanker shipments from the Gulf Coast and by imports, primarily of residual fuel oil, from foreign Western Hemisphere refineries.³

As of January 1, 1982, the operating refineries in the United States had a total crude-running capacity* of about 17.7 million barrels per day (bpd), representing about 27 percent of the refining capacity of the non-Communist world.⁴ Processing from around 1,000 bpd to over 600,000 bpd, refineries range from "fully integrated" com-

²Ibid., p. 6.

³*International Petroleum Encyclopedia*, J. C. McCaslin (ed.) (Tulsa, Okla.: The Petroleum Publishing Co., 1981).

*The size of a refinery is normally expressed as its "crude capacity," meaning the number of barrels that can be "run" each day through its atmospheric distillation units.

⁴American Petroleum Institute, *Basic Petroleum Data Book*, January 1983.

plex plants, capable of producing a complete range of petroleum products, to small, simple refineries that can produce only straight-run distillates, heavy fuel oils, and sometimes asphalt. Small (less than 75,000 bpd) refineries make up about 60 percent of the total number of refining units, but their combined capacity is only about 24 percent of the total throughput. * In terms of ownership, the four largest companies have about 38 percent of the total refining capacity, and 20 companies have about 77 percent of the total refining capacity.⁵ The top 10 firms are shown in table 22.

There is no single, accepted method of categorizing the structure of the U.S. petroleum refining industry that captures the similarities and differences in refineries related to processing capabilities, access to feedstock supplies, ability to market, and the like. One grouping is:

1. **Large, integrated, multinational companies** typically have worldwide production, refining, and marketing operations in addition to their activities in the United States. A number of these firms are descendants of the Standard Oil companies created when Rockefeller's Standard Oil trust was dissolved in 1911.⁶ These major oil producers have typically had access to assured supplies of crude oil from the Middle East and other producing areas of the world. Such guaranteed sup-

plies of crude oil are diminishing as governments of the producing countries increasingly take over responsibility for disposing of their crude production. As a consequence, many of the U.S. multinational oil producers find that their domestic activities—including refining—are becoming more important to their financial health. These companies, with their sophisticated high-volume refineries, provide the bulk of the products manufactured through complex processing steps.

2. **Large- and medium-sized domestic refiners** make up a diverse group of companies. Some are fortunate in being largely self-sufficient in domestic production of crude oil. Others depend for their crude supply on some combination of long-term contracts and "spot" purchases. * They have much less total refining capacity than do the major firms, but a number of them are significant marketers in their own regions.
3. **Independent refiners** form the most diverse group of all. Most independent refiners are small, domestic companies. Refining is their principal operation; most do not produce crude oil and do not market their products under their own names.

Product Mix

A petroleum refinery is a complex assembly of individual process plants interconnected with piping and tanks. Each plant has a specific function,

*Throughput—the total amount of crude oil initially processed.
⁵*Oil and Gas Journal*, "Refining Capacity Dips on Broad Front," vol. 81, No. 12, Mar. 21, 1983, p. 84.

⁶U.S. House of Representatives, Committee on Energy and Commerce, *U.S. Refineries: A Background Study*, July 1980.

*Spot purchases are those made by refiners on the open market and without benefit of a contract.

Table 22.—Petroleum Refining Corporations Earning More Than \$16 Billion in 1981

Corporation	Revenues (in billions)	Employees
Exxon	\$110.06	137,000
Mobil Oil	60.33	82,000
Texaco	57.63	66,728
Standard Oil of California (Chevron)	46.61	43,000
Standard Oil (Indiana) (Amoco)	31.73	58,700
Atlantic Richfield	28.75	54,200
Gulf Oil Corp.	21.17	53,300
Shell Oil Co.	21.60	37,273
Conoco	16.29	34,500
Phillips Petroleum Co.	16.29	34,500

SOURCE" Standard and Poor's *Register of Corporations, Directors and Executives*, vol. 1, 1983

and each refinery has been built to process a certain type of crude oil (or "slate" of crudes) to produce the products required for a defined market.⁷ Markets for specific products change constantly, and existing refineries are modified or new refineries are built to accommodate such changes. In recent years, Government regulations, subsidies, and other influences (to be described later) have greatly affected both refinery operations and the construction of new refineries.

Refineries convert crude oils into a broad spectrum of products, most of which are fuels. A simple grouping of refinery fuels would include liquefied petroleum gases, gasolines, jet fuels, diesel fuels, distillate heating oils, and residual fuel oils. Refineries processing heavy crude oils may also produce asphalt and coke (see table 23). Refineries vary greatly in their size, processing complexity, and ability to use crude oils of differing characteristics.

⁷The Mellon Institute, *The Industrial Sector Technology Use Model*, final report, vol.3, *The Petroleum Refining Industry*, April 1982

An important aspect of the U.S. refining industry is its ability to produce basic petrochemicals—feedstocks for the manufacture of a wide variety of plastics, synthetic fibers, paints and coatings, adhesives, piping, and other products of modern society. Basic petrochemical materials manufactured by the U.S. refining industry from petroleum fractions and natural gas include such large-volume commodities as ethylene, methanol, and benzene and other aromatics. Until recently, it appeared that U.S. refineries could look forward to increasing markets for these materials. Now, however, the picture seems much less bright because the industry appears to be "overbuilt" for current market demands.⁸ Recent studies have concluded that current worldwide ethylene capacity is adequate to meet demands at least through 1985.⁹

⁸*Oil and Gas Journal* Mar. 21, 1983, op. cit., p. 85.

⁹*Chemical and Engineering News*, "Saudi Arabia Set To Emerge as Factor in World Marketplace for Chemicals," Dec. 20, 1982, p. 65.

Table 23.—Products Manufactured in SIC 29

Product manufactured	Percentage of total 1980 production	Definition of product and uses
Gasoline	39	A refined petroleum distillate, normally boiling within the ranges of 30 to 300 C, suitable as a fuel in spark-ignited internal combustion engines.
Distillate fuel oils	18	A general term meaning those intermediate hydrocarbon liquid mixtures of lower volatility than that of kerosene, but still able to be distilled from an atmospheric or vacuum distillation petroleum refining unit. Used as boiler fuel in industrial applications, and as home heating fuel.
Residual fuel oil	15	The material remaining as unevaporated liquid from distillation or cracking processes. Used mainly as boiler fuel in powerplants, oceangoing ships, and so forth.
Aviation jet fuel	6	Specially blended grades of petroleum distillate suitable for use in jet engines. These fuels have high stability, low freezing points, and overall high volatility.
Petrochemical feedstocks	5	A broad term encompassing those refinery products, having typically low molecular weight and high purity (ethylene, propylene, and acetylene, which are used as feedstocks in chemical production of everything from food additives to textile fibers.
Liquefied petroleum gases	4	Light hydrocarbon material, gaseous at atmospheric pressure and room temperature, held in liquid state by pressure to facilitate storage, transport, and handling. CONSISTS primarily of propane and butane. Used in home heating.
Kerosene	2	A refined petroleum distillate, intermediate in volatility between gasoline and heavier gas oils used as fuels in some diesel engines. Often used as home heating fuel.
Other products	11	Includes items such as petroleum coke, petroleum solvents, lubricating oils and greases, asphalt, and the like.

SOURCE *American Petroleum Institute Data Book*, published 1979, and *National Petroleum News*, December 1980

Economics of Refining

The economics of refining is now undergoing major changes. Existing refineries were built and expanded during a period of steady increase in market demand, accompanied by continuous, but moderately paced developments in refinery technology. The large integrated companies profited by the total price spread between their low-priced crude oil and the sales of refined products. Non integrated companies with access to crude oil supplies profited by refining this crude oil and disposing of the products in largely "unbranded" bulk markets. Others, without crude oil supplies of their own, but able to purchase crude oil on favorable terms, developed specialized refineries to supply regional markets, such as an Air Force base or commercial airport.

During these years of expansion, refinery operating costs were not considered critically important. Many in the industry were content to look at the "big picture" of the total spread between cheap crude costs and income from finished product sales. The cost of the refining operation, although certainly not insignificant, was only one of many costs in the series of steps between crude oil exploration and production and the delivery of products to the final consumer. The industry's profits came from high volumes of oil moved through the entire system, and refineries did what was necessary to keep this flow going.

Now the picture is changing. Some essential features of these changes can be summarized:

1. As product demand has leveled off or even decreased, the refining industry finds itself with more capacity than it can use. Many predict that this decrease in demand reflects a long-term trend.
2. Existing refineries, faced with the recent escalation in energy costs **and** the increasing need to break even or show an operating profit, are being forced to look much harder at ways to decrease operating costs, such as the more effective use of energy in refining processes.
3. "Margin a]" refineries, those that are expensive to operate or are poorly located with

respect to crude oil or markets, are being shut down—some temporarily, others for good. Although some employees will be transferred, most will be permanently laid off when a refinery closes.

4. Even if an individual company's market prospects or improvements in technology suggested that major new refinery process plants should be built, construction costs have escalated to the point that such new facilities in the United States would face capital carrying charges that would make it difficult to compete with existing refineries having surplus capacity. The increase in construction costs in the past 10 years for the three types of refineries are illustrated in table 24.
5. As a final deterrent to new "grass-roots" construction, siting problems—including the inevitable vigorous local environmental concerns—when coupled with increased costs, make it unlikely that a new refinery could be built in marketing areas where the capacity is needed (such as the Northeastern United States).

From the foregoing it appears safe to conclude that construction of a major new U.S. refinery is unlikely in the foreseeable future. Instead, the emphasis will largely be on adapting existing refineries to the changing patterns of crude supply and product markets (described in a subsequent section).

Employment

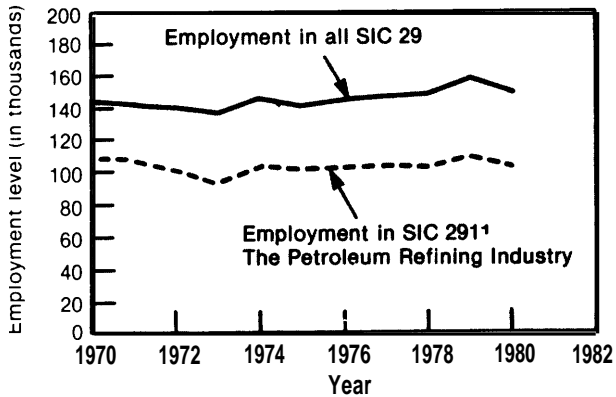
Employment in SIC 29 as a whole, or in SIC 2911, the petroleum refining industry itself, has been remarkably stable over the past decade. The trend, as shown in figure 19, exhibits the slight decrease during the 1972 and 1979 oil disruptions, but overall employment has been maintained at approximately 150,000 jobs.

Table 24.—Process Plant Construction Costs, 1972 and 1982 (thousands of dollars/bpd)

	1972	1982
Topping refineries	540	1,600
Hydroskimming refineries.	940	2,800
Complex refineries.	1,600	4,800

SOURCE Refinery Flexibility—An Interim Report of the National Petroleum Council, VOI 1, December 1979

Figure 19.—Employment Trends in Petroleum Refining Industry, 1970-82



SOURCE Annual Survey of Manufacture and Census of Manufacture.

Production Costs

The operating costs of refineries are generally closely held figures. These costs depend greatly on the size and complexity of a specific refinery. They are normally expressed in terms of dollars per barrel of crude unit throughput. Such figures can be misleading, however, because larger, more complex refineries will incorporate process plants used for the relatively expensive processing required to make a few specialty or highly refined products. Simple topping refineries—and especially those of medium to large size—will have relatively low processing costs per barrel, but the value of their products will be correspondingly low in comparison to the much broader range of products from a more complex refinery.¹⁰

Capital Investment

For a further perspective on the economics of the oil industry, it is important to recognize that about 70 percent of capital spending in a typical SIC 29 firm goes for exploration and production activities. "Petroleum refining capital budgets must compete for the remaining 30 percent of available funds with petrochemicals manufacturing, marketing, oil and gas pipelines, and other activities.

In considering the ability of the refining industry to raise funds for new capital expenditures, including those for energy conservation, it should also be recognized that the profitability of the refining industry appears to be very questionable in the immediate future.¹² Because U.S. refineries are operating well below capacity, there is a downward pressure on refined product prices that will prevent many refiners from passing on to their customers all their costs, including crude cost.

As a final observation on the subject of oil refining economics, it should be recalled that since the early 1960's, the industry has been under various types of controls intended to aid—i e., subsidize—small refiners. Under the original crude import control system of the 1960's, small refiners were given special allocations of "import tickets" that they could sell to large refiners who import their own foreign crude. In August 1971 additional subsidies for small refiners were put into effect.¹³ These included price controls on domestic crude oil, crude entitlement biases, small refinery set-asides for military businesses, guaranteed small business loans, U.S. royalty crude preference sales, naval petroleum reserve set-asides, mandatory crude allocations, and exemptions of small refiners from the scheduled phasedown of lead-octane additives.

As one result, this subsidy program established extremely attractive investment opportunities for very small, simple refineries, and many were quickly built. Very few of them could produce gasoline, and many used high-quality crude in the simple production of fuel oil instead of producing higher quality products. However, as of January 1981, all price and allocation controls were removed from crude oil and petroleum products.

Imports and Exports

Prior to the removal of price and allocation controls in January 1981, U.S. refiners were largely protected from foreign competition by a **system** of crude oil and product price controls.¹⁴ This

¹⁰National Petroleum Council 1, *Refinery Flexibility*, prepared for the U.S. Department of Energy, Washington, D. C., 1980, p. 18.
¹¹Standard Oil Co. of California, *1980 Annual Report*.

¹²*Oil and Gas Journal*, Mar. 21, 1983, op. cit., p. 85.

¹³National Petroleum Council, op. cit., p. 24.

¹⁴U.S. House of Representatives, Committee on Energy and Commerce, *U.S. Refineries: A Background Study*, July 1980.

program resulted in an average raw material cost for U.S. refiners that was below the price foreign refiners had to pay for their crude. As domestic crude oil price controls were phased out, the raw material cost advantage of the U.S. refiners began to disappear. The decontrol action eliminated the remaining advantage.

With its access to crude oil at worldwide competitive prices and an efficient domestic product distribution system, a vigorous U.S. refining industry should have little reason to fear foreign competition. All that seems to be required at this point is close monitoring by both Government and industry of the expansion of export refineries around the world, together with a continuing evaluation of how they might affect the U.S. refining industry if no control were exercised.

Refineries in Venezuela and the Caribbean area, for example, now supply somewhat over 1 million bpd of product to the U.S. market.¹⁵ However, residual fuel oil makes up most of these imports. These refineries have relatively little capacity to make gasoline and other light products, and it seems unlikely that they will invest in the very considerable conversion programs necessary for producing significant amounts of gasoline, jet, and diesel fuel to be marketed in competition with underutilized U.S. refineries.

Existing European refineries have considerable unused processing capacity, but to reach the U.S. market they must face the expensive transportation of refined products in small tankers. (The vessels of "supertanker" and larger size cannot practically be used to transport the mixed cargoes of light products that would be required in such movements.) Another major disadvantage faced by European refiners is the growing predominance of unleaded gasoline in the U.S. markets.

Unleaded gasoline of high octane is manufactured only in the United States. It appears most unlikely that European refiners could afford to invest in the additional catalytic reforming and other processes necessary to provide unleaded gasoline just for their share of the U.S. market.

In the long run, a more serious threat is production from very large petrochemical plants be-

ing built in areas where the basic raw materials are less costly (or will be made available by local governments at prices well below U.S. costs). Such plants are being built in Canada, Mexico, and—most significantly—the Middle East.¹⁶ Several such plants are being built at Jubail and Yanbu, in Saudi Arabia, by Saudi Government agencies and by joint ventures between these agencies and large foreign firms. These plants have been promised feedstocks and fuel at costs of only a fraction of world market prices. Although the plants are remote from current world markets, the industry anticipates that their low manufacturing costs will permit them to enter such markets, to the detriment of current producers. An analysis of transportation costs and potential markets indicates that finished products from newly constructed Middle East refineries will go primarily to Western Europe, presenting additional problems to the already depressed European refining industry. Another possibility is that the Middle East governments (notably Saudi Arabia) may require their crude oil purchasers to buy some refined products in order to be allowed access to crude oil.

Trends and Uncertainties

Refineries in the United States are experiencing drastic changes in the business atmosphere in which they operate. Available crude oil supplies are deteriorating in quality, motor gasoline use has been dropping sharply from historic highs, markets for many products are leveling out or declining, and Government-mandated changes (e.g., requirements for low-sulfur fuel oil, increasing use of unleaded gasoline, and the ultimate phaseout of leaded gasolines) require increasingly sophisticated and costly refining operations.

Refining capacity has probably peaked for the foreseeable future. Investment in refinery process plants will continue to be made, as necessary, to handle the growing amounts of heavy crude oil and the greater relative demand for unleaded gasoline of (perhaps) steadily rising octane number. The additional energy requirements of these

¹⁵National Petroleum Council, *op. cit.*, P. 223.

¹⁶*Chemical and Engineering News*, *Op. cit.*

new processes may affect the industry's ability to continue the recent trend toward more energy-efficient processing.

Details of these trends are discussed under the following topics and in subsequent sections of this analysis.

Crude Supply Uncertainties.— If the volumes of foreign crude oil imported into the United States continue to decrease, the industry and the Nation may become unjustifiably complacent about the perceived diminishing dependence on foreign crude oil. Short-term or even longer interruptions in the availability of Middle Eastern crude always remain a possibility.

Crude Oil Prices.—Crude oil prices quadrupled during the Arab oil embargo of 1973-74 and more than doubled again during the Iranian crises of 1978-80, in the early 1980's, worldwide crude oil prices declined as a result of production overcapacity and lowered demand.¹⁷ It is not clear what will happen to crude oil prices. Political upsets in the Middle East could result in crude oil embargoes or physical interruptions in crude oil availability, with consequent skyrocketing of prices worldwide. Also, reductions in crude oil prices, if unaccompanied by significant increases in production, could have a shattering effect on the economies and possibly on the internal stability of several of the highly populated, oil-producing nations.

Changing Crude Mix.—Much of the older refining capacity in the United States was designed to process crude oil of low sulfur content and medium-to-high quality. Available supplies of these crude oils are dwindling, both in the United States and elsewhere. Those OPEC countries having reserves of both light and heavy crudes are requiring their customers to take quantities of both types, instead of merely "lifting" predominantly the more desirable light crudes.¹⁸

As a consequence of this changing crude oil mix, U.S. refiners are being forced to make major investments in additional processes and new

facilities. These facilities involve heavy fuel oil desulfurization and coking, together with processes to recover the light ends given off in the coking operation. Modifications to permit processing heavy crude oil can be quite costly and energy-intensive. One U.S. refiner, for example, has announced a \$1 billion program to modify its Gulf Coast refinery so that it can process the Arabian heavy crude oil that it will be required to take as part of its share of ARAMCO* production.²⁰

Changing Product Demand.—The declining demand for refined products in the United States since 1978 seems permanent and is primarily a response to higher prices, the current lower level of economic activity, and the gradual introduction of more fuel-efficient small cars.²¹ Also, the trend of the refinery process mix will probably be away from motor gasolines and toward middle-distillate fuels. Yet it is not at all clear how much the U.S. demand for refined product will decline before it rises again (if it does). One major uncertainty is the response of the American motorist to the belief (not necessarily valid) that the days of skyrocketing motor fuel prices are over. It has been suggested that: 1) a period of level motor fuel prices will result in an increase in driving, with a correspondingly greater demand for fuel; and 2) motorists will not accept the small, fuel-efficient automobiles predicted for the next decade, but will instead turn back to larger, more comfortable and more powerful vehicles.

Residual Fuel Oil Demand.—Since residual fuel oil, as normally produced, is high in sulfur, environmental restrictions have reduced its use by utilities and industry. Its place has been taken by natural gas, distillate fuel oil, and coal. Thus, the demand for residual fuel oil is now declining. Current demands are for about 1.8 million bpd, resulting in increased needs for refinery fuel oil desulfurization and coking.²² The rate at which

¹⁷U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, Washington, D. C., February 1983, p. 5.

¹⁸*Oil and Gas Journal*, "Surviving the Shakeout: Refining and Marketing in the Eighties," Oct. 26, 1981.

¹⁹*Oil and Gas Journal*, "Petrochem Units Benefit From Integration, Flexibility," Apr. 11, 1983, p. 100.

*Arabian American Oil Co.—consortium of American and Saudi Arabian oil companies, formed in the 1920's to find and process crude oil in the Middle East.

²⁰Standard Oil Co. of California, 1981 *Annual Report*.

²¹U.S. Department of Energy, Energy Information Administration, *Short-Term Energy Outlook*, Washington, D. C., February 1983, p. 24.

²²*ibid.*, p. 26.

the demand for residual fuel oil decreases will be affected by natural gas usage policy and prices and by the rate at which major users of residual fuel oil can convert to coal in environmentally acceptable ways.

Motor Gasoline Upgrading.—Regardless of how the demand for motor gasoline changes, it is expected that unleaded gasoline—now over 50 percent of the refinery gasoline output—will comprise 100 percent of the market within 10 years.²³ It is also possible that gasoline octane numbers will continue to inch up in response to requirements for more efficient automobile engines, as well as to motorists' desires for better performance. The production of high-octane, unleaded

gasoline requires more complex and energy-intensive refinery processing. These complex facilities often require significant investments, while contributing nothing to the crude throughput of a refinery. In fact, the gasoline yield per barrel of crude oil may be lowered as a result,

Environmental Constraints.—Environmental restrictions designed to control gaseous emissions and the release of liquid pollutants have greatly affected refinery investments and operating costs, as well as the ability of refiners to install new process units or modify existing facilities. Although it seems unlikely that environmental regulations and emission controls affecting refineries will be stricter in the next few years, the present regulatory framework can make it very difficult to modify or replace existing facilities.

²³National Petroleum Council, op. cit., p. 52.

ENERGY AND TECHNOLOGY

Production Processes

To understand how refineries use energy and what the possibilities are for more efficient use of such energy, it is useful to review the principal processes of a modern refinery.²⁴

Atmospheric Distillation

Incoming crude oil is first treated to remove inorganic salts and then dehydrated. Under slight pressure it is then heated to a boil in a column where the various components of the crude oil are separated according to their boiling temperatures. Distillation, sometimes called "fractionation," is carried out continuously over a range of boiling temperatures, and at several points hydrocarbon streams within specific boiling ranges are withdrawn for further processing.

Vacuum Distillation

Some crude oil components are too heat-sensitive or have boiling points that are too high to be distilled at atmospheric pressure. In such cases the so-called "topped crude" (material from the

bottom of the atmospheric column) must be further distilled in a column operating under a vacuum. This operation lowers the boiling point of the material and thereby allows distillation of the heavier fractions without excessive thermal decomposition.

Fluid Catalytic Cracking

Through fluid catalytic cracking, crude petroleum whose lighter fractions were removed by atmospheric or vacuum distillation is entrained in a hot, moving catalyst and chemically converted to lighter materials. The catalyst is then separated and regenerated, while the reaction products are fractionated into their various components by distillation. This is one of the most widely used refinery conversion techniques.

Catalytic Reforming

Reforming is a catalytic process that takes low-octane materials and raises the octane number to approximately 100. Although several chemical reactions take place, the predominant reaction is the removal of hydrogen from naphthenes (hydrogen-saturated, ring-like compounds) and the conversion of naphthenes to aromatics (benzene-ring compounds). In addition to markedly in-

²⁴Process descriptions are adapted from Argonne National Laboratory publication *Energy and Material Flows in Petroleum Refining*, AN L/CNSV-10, February 1981. Available from National Technical Information Service, Springfield, Virginia.

creasing the octane number, the process produces hydrogen that can be used in other refinery operations.

Alkylation

In the alkylation process, isobutane, a low-molecular-weight gas is chemically added to the carbon-to-carbon double bonds that occur in certain hydrocarbons. The resulting product, now containing many isobutyl side groups, has a much higher octane number compared to the original straight-chained substance, and is therefore a better motor fuel. Branched-chain hydrocarbons, such as those with isobutyl side groups, are able to have their octane rating increased even further with lead additives, but with the increasing consumer need for unleaded gasolines, this type of alkylation will be less and less used.

Hydrocracking

Hydrocracking is a catalytic, high-pressure process that converts a wide range of hydrocarbons to lighter, cleaner, and more valuable products. By catalytically adding hydrogen under very high pressure, the process increases the ratio of hydrogen to carbon in the feed and produces low-boiling material. Hydrocracking is especially adapted to the processing of low-value stocks that are not suitable for catalytic cracking or reforming because of their high content of trace metals, nitrogen, or sulfur. Such feedstocks are used to produce gasoline, kerosene, middle-distillate fuels, and feedstocks for other refining and petrochemical processes.

Hydrotreating

A number of hydrotreating processes use the catalytic addition of hydrogen to remove sulfur compounds from naphthas and distillates (light and heavy gas oils). Removal of sulfur is essential for protecting the catalyst in subsequent processes (such as catalytic reforming) and for meeting product specifications on certain "mid-barrel" distillate fuels. Hydrotreating is the most widely used treating process in today's refineries. In addition to removing sulfur, it can eliminate other undesirable impurities (e.g., nitrogen and oxygen), decolorize and stabilize products, correct

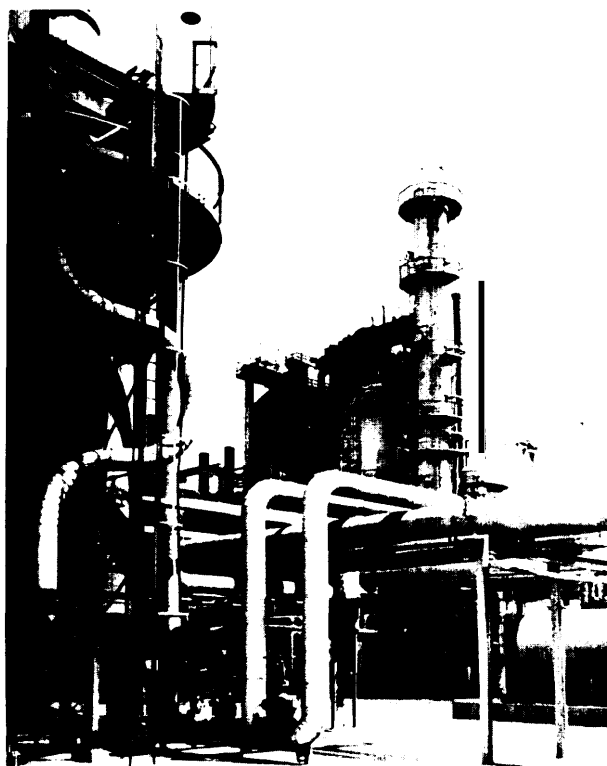


Photo credit: Phillips Petroleum Co. and American Petroleum Institute

A portion of Phillips Petroleum Co.'s refinery near Borger, Tex. In the background is one of two huge catalytic cracking units at this refinery. A large part of the refinery output is moved by four long-distance product pipelines, radiating in all directions from the refinery and serving markets as far away as Denver and Chicago

odor problems, and improve many other deficiencies. Fuel products so treated range from naphthas to heavy burner fuels.

Residuum Desulfurizing

With the increasing need to use the heavier, higher boiling components of crude oils (the "bottom of the barrel"), a number of processes are being offered for the desulfurization of residuum, the material remaining after atmospheric and vacuum column distillation. These processes operate at pressures and temperatures between low-severity hydrotreating and the much more severe hydrocracking previously described. Depending on the market, the desulfurized "resid" can be used as a blending component of low-sulfur fuel oils or as a feedstock to a coke producing unit (if a low-sulfur coke were to be made).

Coking

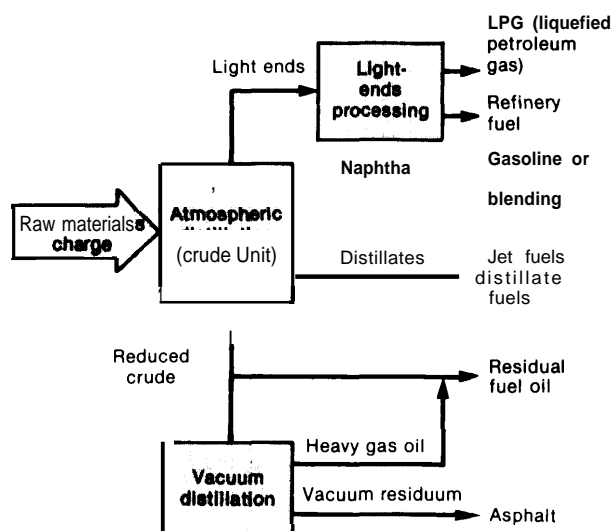
In the past, the residual bottoms from the crude unit have been blended with lighter oils and marketed as fuel oils of low-quality and often high sulfur content. These residues do, however, contain lighter fractions (naphthas and gas oils) that can be recovered if the residual oil is "coked" at high temperatures. It is becoming economically worthwhile to recover these remaining light ends for further processing. Petroleum coke is used principally as a fuel. Coke derived from untreated residues may have a high sulfur content and hence be of limited commercial value.

Kinds of Refineries

Refineries can be considered under the following three broad classifications:

Topping Refineries.—A topping refinery (fig. 20) is usually small, often having less than 15,000 bpd capacity (although some are much larger). It relies entirely on crude oil distillation to provide various product components, primarily liquefied petroleum gases, gasoline blending stocks, and distillate fuels (jet and diesel fuel and heating oils). Residuum would be sold as a heavy fuel oil or, if vacuum distillation were incor-

Figure 20.—Topping Refinery Model Configuration



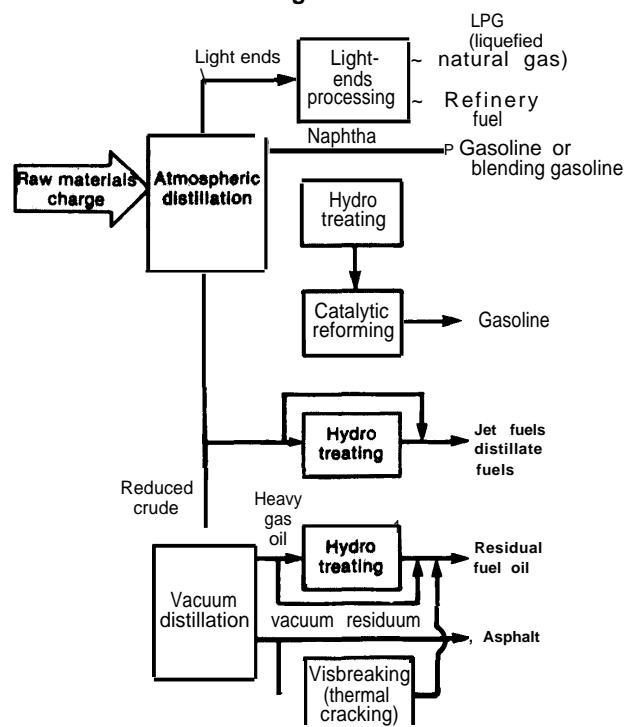
SOURCE: California Oil Scenario (Houston, Tex.: Bonner & Moore Associates, Mar 29, 1980)

porated, would be partly made into asphalt. Since a topping refinery, as described, has no cracking, hydrotreating, or reforming processes, its range of products is almost entirely dependent on the characteristics of the crude oil feedstock.

Hydroskimming Refineries.—Hydroskimming refineries (fig. 21) make extensive use of hydrogen treating processes for cleaning up naphthas and distillate streams. Thus, a refinery of this type is less dependent on the quality of the crude oil run, but it is still limited in its ability to produce high-octane, unleaded gasoline, and its product streams are heavily weighted toward fuel oils. Such a refinery would normally include catalytic reforming to increase its yield of high-octane finished gasoline.

Complex Refineries.—Most of the refining capacity (but not the number of refineries) falls into the category of complex refineries (fig. 22). A typical complex refinery uses most of the processes previously described. By virtue of its cracking

Figure 21.—Hydroskimming Refinery Model Configuration



SOURCE: California Oil Scenario Bonner and Moore Associates, Mar 29, 1980

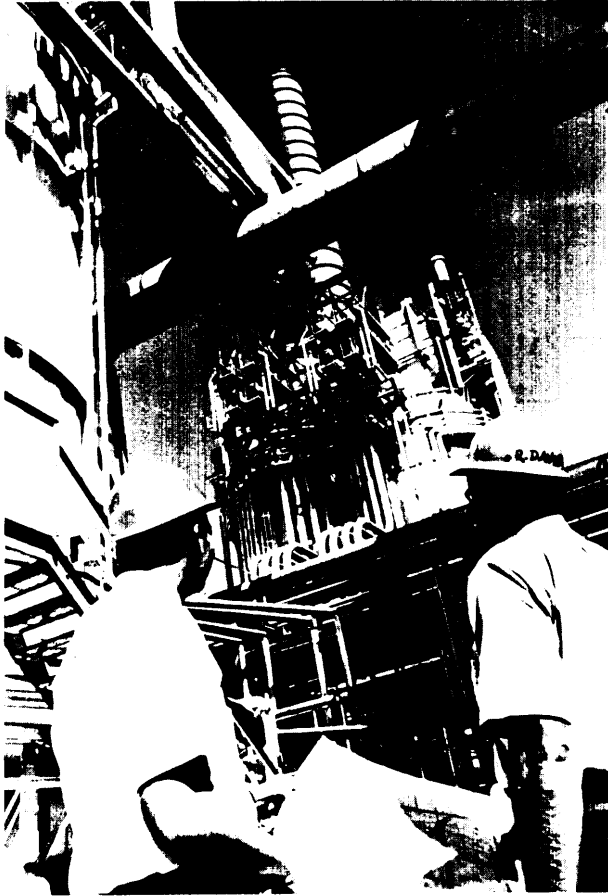


Photo credit Marathon Oil Co. and American Petroleum Institute

A portion of Marathon Oil Co.'s refinery near Robinson, Ill. In the background is the crude distillation unit which has a charging capacity of 110,000 barrels of crude oil per day

capacity, the refinery can convert high-boiling crude oil fractions (otherwise suitable only for heavy fuels) into lower boiling fractions suitable for gasoline and distillate fuels. By alkylation and other processes it can convert materials that are too light for gasoline into stocks that can be blended into gasoline. A typical complex refinery would thus be able to run a wider range of crude oils than would either a topping or a hydroskimming refinery. In addition, many—but not all—of the larger complex refineries will have distillation units designed to permit running crude oil of moderately high sulfur content (e. g., from the Alaskan North Slope).

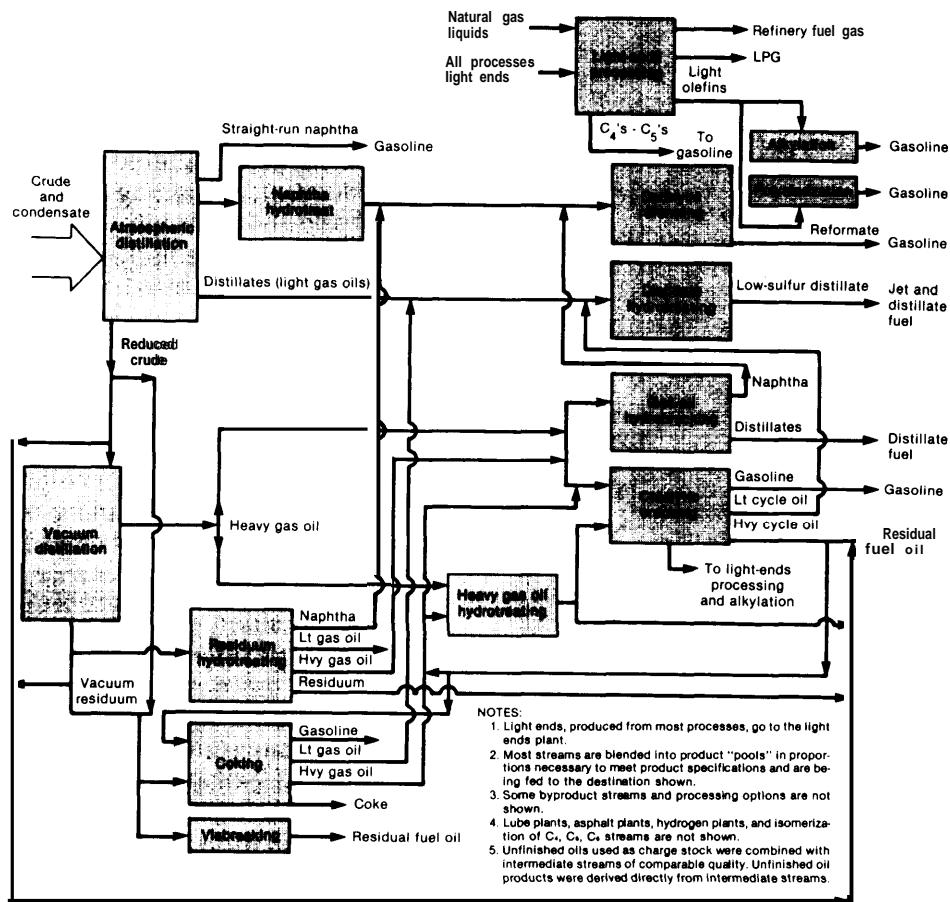
Energy Use

The petroleum refinery has not traditionally been looked on as a major "profit center." Profits in the oil industry come instead from producing crude oil and from marketing the products or, in the large, integrated companies, from the total operation of getting crude oil out of the ground and products into the hands of the consumer. Refineries themselves were (and continue to be) expensive to build and operate. Refiners sought efficiency improvements primarily to obtain a greater output of more uniform products from existing equipment. They studied and improved processes and installed expensive instrumentation and control systems to eliminate as much as possible of the uncertain "human element." As a result, oil refining now has one of the highest capital costs per employee of any U.S. industry.

Although refinery managements and their technical staffs had other priorities, they have taken measures to use energy efficiently. In many refineries, periodic efforts were made to improve the steam balance and eliminate obviously wasteful plumes of exhaust steam. Where large volumes of surplus low-pressure steam were available, consideration was given to investing in a condensing turbine driving a continuously operating pump or blower. Many refineries at one time supplied their electrical energy needs by "topping" turbines exhausting to the refinery steam system, a highly efficient use of fuel energy. However, as refinery electrical loads increased and the cost of electrical energy available from local utilities continued to decrease, investments in additional refinery electrical generating capacity appeared less attractive when viewed by the standards applied to other investments in the oil industry. In time, purchased electrical energy came to supply most of the refinery load.

At a few locations, a refinery and a local utility were able to collaborate on a large powerplant in or adjacent to the refinery. Typically, the powerplant would obtain heavy fuel oil from the refinery. The utility, in turn, might supply steam to the refinery. However, many utilities were reluctant to lose their expensively treated boiler

Figure 22.—Complex Refinery Model Configuration



SOURCE: California Oil Scenario (Houston, Tex.: Bonnar & Moore Associates, Mar. 29, 1980).

feedwater in the form of steam that would not be returned (or would come back contaminated). These early attempts at cogeneration were not very successful because to be of interest to the utility, the electrical capacity of the refinery had to be much greater than the refinery's demand. Also, the utility's need for fuel and the refinery's for steam were normally not in thermal balance, and the overall economics of the joint venture were usually not attractive.

A rule of thumb used by some refiners is that it takes 1 barrel of oil-equivalent energy to process 10 barrels of crude oil. In other words, using an average heating value for crude oil, processing a barrel of crude through a typical refinery results in the use of about **580,000 Btu of energy**. **This is a good approximation of energy use. Small**

topping refineries use less energy per barrel, and complex refineries with a wide spectrum of finished products probably use more.

In typical refining processes, feed streams are normally heated, either to effect a physical separation (crude unit fractionation) or to provide energy for a heat-absorbing reaction (e. g., catalytic reforming). Although heat exchange is used to preheat feed streams to the highest economically feasible temperatures, additional heat is usually needed. Specifically, petroleum refining processes use energy in the form of fuel, steam, or electrical energy for the following functions:

- To heat crude units and other process feed streams.
- To make steam for mechanical-drive turbines to power major compressors and some large

pumps; for process heating, steam-stripping, and steam-jet vacuum ejectors.

- To heat reboilers (steam-fired or fuel-fired).
- To power most pumps and the fans in air coolers (usually with electric motors.)

Energy losses from petroleum refining operations are primarily the result of the following:

- Heat rejected by (lost to) air- and water-cooled heat exchangers used to cool recycle and product streams. (This equipment is estimated to account for up to 50 percent of refinery heat losses.)
- Unrecovered heat in flue gases from furnaces and steam boilers (perhaps 25 percent of refinery energy losses).
- Convection and radiation losses from hot equipment and piping.
- Steam system losses.

Although most refineries maintain summary records of energy use by their process plants and

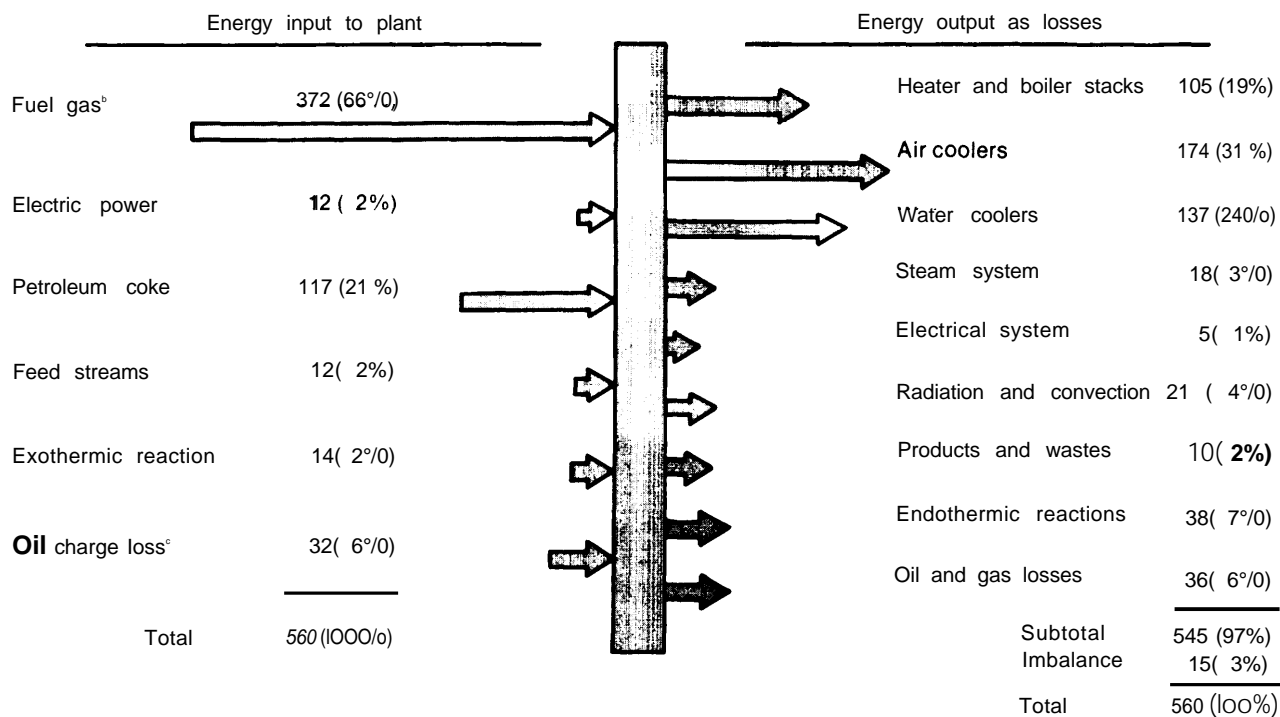
of energy purchased from utilities or sold offsite to other energy users, the only complete public, nonproprietary analysis of a "refinery energy profile" is the study of Gulf Oil Co.'s Alliance refinery carried out by Gulf Research & Development Co. under contract to the Department of Energy's (DOE's) Office of Industrial Programs.²⁵ Alliance is a typical complex refinery incorporating all the principal refining processes described earlier, with the exception of hydrocracking. Figure 23, reproduced from the Gulf Research report, illustrates the flow of energy into the total refinery, as well as the form and amount of energy losses from the system.

Energy Conservation

For this report, the basis for reviewing the energy conservation record of the petroleum refin-

^aGulf Research & Development Co., *Refinery Energy profile—Final Report*, prepared for DOE, report No. ORO-5262-5, January 1979,

Figure 23.—Alliance Refinery Energy Profile
(M Btu/bbl of oil charge to refinery and percent)^a



^aBased on period 9126177. 1016177 at 214,636 bpd Oil charge to refinery.

^bIncludes 2713 (487.) of refining gas and 102 (18%) of natural gas.

^cEnergy value of combustible portion of stock losses.

SOURCE: Department of Energy, *Refinery Energy Profile-Final Report*, prepared for DOE by Gulf Research & Development Co., Report No. ORO-5262-5, January 1979.

ing industry is the energy efficiency report made by the American Petroleum Institute (API) to DOE's Office of industrial Programs. Table 25 presents the petroleum refining industry's report to DOE on energy consumption for the year 1981.

As part of DOE's energy efficiency program, the petroleum industry adopted a voluntary goal of improving efficiency by 20 percent by 1980. A measure of industry progress toward this goal is shown in figure 24. Electricity and petroleum use remained approximately constant over the time period. However, natural gas use is now less than two-thirds of what it was in 1972. Production decreased by less than 1/2 percent over the same time period.

Potential for Energy Saving

It is to be expected that refinery managements and their technical staffs will continue to look for energy-saving opportunities and to implement those that appear to be economically justified. However, in evaluating progress the refining industry has made in energy conservation, as well as the potential for further savings, it is essential to keep several considerations in mind.

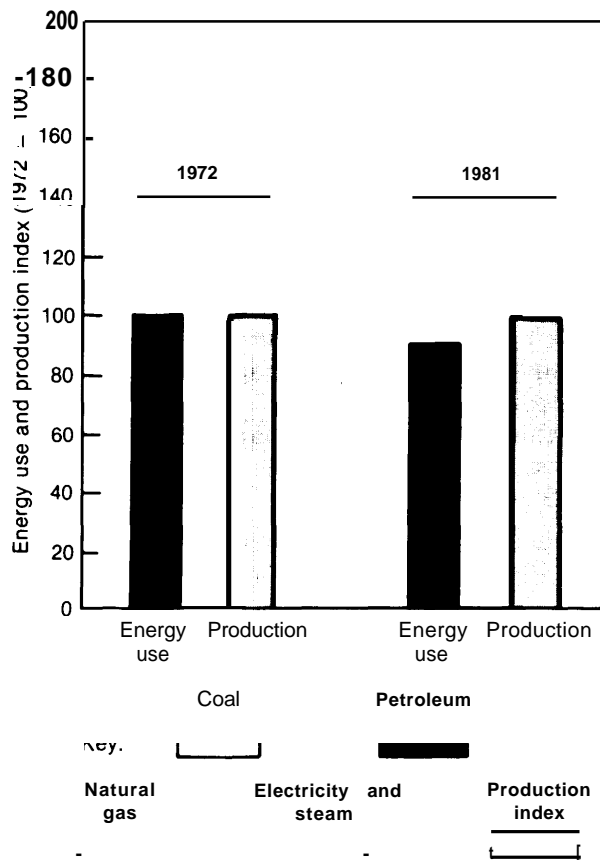
First, competition for capital funds in the petroleum industry is intense and likely to remain so.

Table 25.—Comparison of 1972 and 1981 Energy Consumption in Petroleum Refining Industry

Energy type	1972 consumption	1981 consumption
1. Electricity	200,525	250,193
2. Natural gas	1,034,006	686,277
3. Propane	9,850	6,979
4. LPG	28,438	24,852
5. Bituminous coal	4,850	4,823
6. Anthracite coal	38	0
7. Coke	0	0
8. Gasoline	107	112
9. Distillate fuel oil	22,183	8,425
10. Residual fuel oil	257,606	177,028
11. Petroleum coke	441,512	427,569
12. Purchased steam	37,128	27,629
13. Refinery gas	1,030,162	1,162,453
14. Other liquids	6,692	2,487
15. Other (specify)		
16. Total energy consumption	3,073,098	2,778,827

SOURCE: American Petroleum Institute, 1981 Report to the U.S. Department of Energy, "Energy Efficiency Improvement and Recovered Material Utilization Report."

Figure 24.—Comparison of Petroleum Refining Industry Energy Use and Production Output 1972 and 1981



SOURCE American Petroleum Institute and Federal Reserve Board

Thus, corporate management may see currently underused refineries as less desirable for investment than are the exploration and production activities that are rightly considered to be essential for the future well-being of the industry.

Second, many of the easy and obvious opportunities for energy savings have been taken. Additional opportunities, although certainly present, will be more difficult to identify and justify economically. In part, these energy savings will be difficult to make because environmental regulations have affected the industry's energy use in terms of the need for energy-consuming pollution abatement equipment and also in terms of the mandate to produce unleaded gasoline.

Technologies for Increased Energy Efficiency

Numerous energy conservation opportunities have been identified in the petroleum refining industry.²⁶ The most productive energy-conserving measures appear to be in the areas of improved combustion, the recovery of low-grade heat, and the use of process modifications.

However, there are several barriers to improving the efficiency of energy use in refineries. First, there are operational limits. Energy efficiency measures to achieve energy savings cannot often be put into effect just by a plant's operating organization when it is primarily concerned with running the equipment, maintaining safe conditions, and producing the desired amounts of specification products. An effective energy conservation program requires a sustained technical effort having the consistent support of the company's management.

Second, there are thermodynamic limits to the amount by which heat input into the processing "system" can be reduced. Many of the chemical reactions in refining processes require heat (i. e., they are endothermic). Other operations, such as fractionation, require that fluid streams be heated to high temperatures. It is not possible to obtain all this heat by exchange with other streams. Even more fundamentally, the great amounts of heat present in refinery lines, vessels, and tanks at low or moderate temperatures cannot be upgraded to higher temperatures by any techniques now available. Fired furnaces must usually provide such heat.

Finally, there are economic limits to the investments that can be justified to achieve specific energy savings. The amount of energy saved does

not justify the capital required. Some of these limits will be apparent in the following discussion.

Proven Technologies for Energy Conservation

Considering only proven technologies, the most significant opportunities for energy savings in refineries are likely to be found in the following operations and systems.

Air and Water Cooling of Process Streams

As indicated previously in figure 23, the final cooling of process streams in air- and water-cooled heat exchangers can represent the greatest single loss of heat in the refinery. Where feasible, heated streams can first be used to heat other process streams and thus minimize the amount of heat rejected to air or water. Cold streams suitable for this exchange must be available. The Gulf Research study showed that the total energy input requirements of the refinery could be reduced by about 18.7 percent if all such streams could be brought down to a temperature of 2000 F by process heat exchange before being cooled further. Such an extreme reduction is unlikely to be feasible, but the Gulf study showed that reductions to 250° or 300° F would reduce energy requirements by 8.6 and 3.7 percent, respectively. (Recovery of low-grade heat as mechanical energy is discussed under "New Concepts" in the next section.)

Process Heaters and Steam Boilers

These direct-fired units offer many opportunities for energy savings. With fired heaters, some of the options are: 1) reducing excess air and improving combustion by using stack gas analyzers and combustion control instrumentation, 2) reducing stack gas temperatures by using air preheater to heat incoming combustion air, and 3) installing convection sections at the heater outlets to heat incoming feed or to generate steam. (A constraint on the last two options is the need to keep stack gas temperatures above the sulfur content "dew point," below which serious corrosion of carbon steels can be anticipated.) Steam boilers, although many commonly incorporate such heat-conserving devices as air pre-

²⁶ *The Potential for Energy Conservation in Nine Selected Industries: The Data Base, Vol. 2, Petroleum Refining*, Gordian Associates, Inc., for the Federal Energy Administration, NTIS order No. PB-243-613, June 1974; *Energy Efficiency Improvement Targets, Vol. 1, Petroleum and Coal Products*, Gordian Associates, Inc., for the Federal Energy Administration, contract No. FEA/D-77/244, June 25, 1976

heaters and “economizers,” can also often benefit by improved combustion controls and perhaps by boiler blowdown heat recovery.

Steam System Improvements

In most refineries, steam is generated and then distributed at moderately high pressure (often 600 psi), as well as at medium or low pressures, such as 150 and 50 psi. The steam is used for heating and for mechanical drives (usually turbines) at many locations in the refinery. Ideally, the steam generated and distributed at these pressure levels is used at such levels, and is reduced or “let down” to a lower level only while doing useful work. At the lowest pressure level, all steam is ideally used for heating (or perhaps driving a condensing steam turbine) so that no steam is wasted by being vented to the atmosphere. Such a system represents the ideal goal of being “in balance.”

Inevitably, though, process plants are modified, and their uses of steam change. Steam systems get out of balance, and frequently no juggling of steam turbine and motor drivers can prevent wasteful let-downs of high-pressure steam or venting to the atmosphere of excess low-pressure steam. When steam systems become acutely imbalance, many refineries achieve significant savings by changing major drivers; installing large, low-pressure, condensing turbines; and using other means to minimize loss in the system. Since it is almost never economical to generate steam for a turbine driver if its exhaust steam will be wasted, replacement of such turbines by motors often represents an attractive investment.

Improved Process Heat Exchange

A refinery will contain many heat exchangers for transferring heat from one process to another. A great number of heat exchanger arrangements are usually possible, and the optimization of heat exchange—especially in the crude preheat train—is an important aspect of plant design. In the design of many U.S. refineries, low fuel prices (and hence low energy costs) resulted in a minimum amount of heat exchange being installed originally. Although a major revamp of heat exchange systems can be quite expensive, and sometimes impossible because of space limita-

tions, such an investment will often show a very good return.

Improved Instrumentation and Controls

Most refiners have steadily improved their instrumentation and control systems, even to the extent of using closed-loop computer controls. The economic benefits from such systems are primarily in improved performance of the process units, but consistently higher outputs and closer product specification tolerances can also result in significant energy savings per barrel of finished product.

Improved Insulation

As with heat exchange systems, insulation standards in many refineries were developed during the earlier era of cheap energy. Substantial heat losses from lines, vessels, and other equipment were anticipated. Many engineering design practice standards called for no insulation of surfaces at temperatures below 200° F unless a surface represented a hazard to operating and maintenance personnel who could inadvertently touch it from grade or operating platforms. In such cases, the hot surface was often insulated only as far as a person could reach. With increased energy costs, insulation of surfaces at much lower temperatures can now be justified. This justification is especially apparent for large, bare storage tanks operating at temperatures well above that of their surrounding environments.

Energy Recovery From Process Streams

Many high-pressure, gaseous, and liquid process streams are “throttled” by control valves, with significant energy loss. In some applications, hydraulic turbines and power recovery turbines (turboexpanders) can be used to extract considerable energy from such streams.

Pump Efficiency Improvement

Since refinery motors (and most mechanical-drive steam turbines) operate at constant speed, control of output from the pumps they drive must be achieved by throttling through a control valve. If the characteristic curve of the pump essentially matches that of the piping system, this throt-

ting dissipates only moderate amounts of energy and can usually be ignored. Unfortunately, mismatches of pump and system are all too common, and often intentional. Design engineers have been encouraged to specify pump impellers of greater diameter (which often need larger motors) than the hydraulic design actually requires. Thus, the engineer is protected against charges of having “underdesigned,” and the operator is assured of immediately available extra capacity in case he ever wishes to operate the plant above the original design limits. As a result, during its entire lifetime the pump wastes energy by discharging against a partially closed control valve, while the unnecessarily large motor driver, operating below its rated output, wastes even more energy because it is well below its point of maximum efficiency. Although the principal savings in this area can be achieved by proper selection of pumps and drivers initially, simply changing pump impellers can often achieve significant savings in an operating plant.

Fractionation Efficiency Improvements

The operating characteristics of a fractionating column are largely established in initial plant designs. Once the column has been installed, relatively little modification is feasible, and specific opportunities for energy savings are limited. However, many columns are operated at considerably higher reflux rates than necessary for proper fractionation. Reducing these reflux rates to the minimum required for proper functioning of the column can result in significant savings.

Refinery Loss Control

Many potential types of refinery losses include losses from flares, relief valve leaks, tank filling, evaporation from tanks and from oil-water separators, other leaks of all types, tank cleaning and vessel draining, and spillages from all forms of loading operations.

Housekeeping Measures

Potential savings by vigilance in policing and correcting such energy wasters as faulty steam traps, damaged insulation, careless steam depressurizing and venting, and the like. The possible

energy-saving measures discussed to this point involve well-understood technologies and operating and maintenance practices. The challenge to refineries comes from the need to identify such opportunities in specific plants, evaluate them to determine what corrective measures can be justified, and then proceed to take the necessary action.

New Concepts in Refinery Energy Use

Beyond the existing technologies discussed above there appear to be some significant, long-term opportunities for improving in energy efficiency by the use of certain new—or at least unproven—technologies. Refineries may be able to use other sources of energy, and otherwise wasted heat, to reduce the combustion of gaseous and liquid fuels. OTA considers that fuel substitution (such as the use of coal in refineries) is an important goal, even though the calculated efficiency of fuel energy use may not be improved or may even be lowered as a result of such a change in fuel.

The majority of refinery process heaters now burn only gaseous and liquid fuels derived from petroleum. In some heaters, tube configurations and the need for close control of process reactions permit only gas to be burned. Since it is perhaps not entirely clear why coal-burning refinery process heaters have not been developed, it may be useful to summarize the principal demands made on refinery process heaters:

1. In many heaters, the fluids undergo process reactions in the tubes, often at high pressure and temperature. Careful monitoring and precise control of such reactions are essential, since the process fluid will decompose if heated above the intended temperature.
2. Precise firing control is necessary for rapid, even instantaneous, control response necessary because of the need to shut down firing immediately if the instrumentation or operators detect tube failures, dangerously reduced flow rates in any tubes, or a power failure.
3. In addition to the required, precise control of temperature of the process streams being heated, measurement and control of tube

wall temperature in many furnaces is necessary to prevent overheating and rupture of the tube, with the resulting prospect of a serious fire.

Coal as a Refinery Fuel

Coal-fired furnaces are perceived by refiners as unable to meet any of the above requirements because they have considerable "thermal mass" and respond relatively slowly to control changes. Also, coal firing results in molten ash deposition on tubes at some temperatures. Lower heat-release rates for coal burning require larger (and hence more expensive) furnaces. Large volumes of ash must be dealt with and—as always with conventional coal burning—the stack gases must be cleaned of particulate and perhaps even scrubbed to remove sulfur acid compounds. In view of the historically small differential between the costs of coal energy and those of petroleum, it is understandable that little pressure has existed for the development of coal-fired refinery process heaters. Now, however, with increasing energy costs and potential restrictions on the use of petroleum-derived fuels, renewed emphasis is being placed on coal as a potential refinery fuel. Some of these developments are discussed in the following paragraphs.

CONVENTIONAL FIRING

Several attempts have been made to design process heaters in which coal would be fired directly. Furnace "geometry" would of course be different; provisions for ash collection and removal would be provided; and other changes would be made to use the electric utilities' experience with burning coal. Pulverized coal (rather than stoker firing) would be necessary to permit faster response to combustion controls. Although some progress reports have appeared in the technical press, the refining industry's apparent conclusion is that no coal-fired heater designs are yet available to meet the exacting demands of process heater service.

FLUIDIZED-BED COMBUSTION

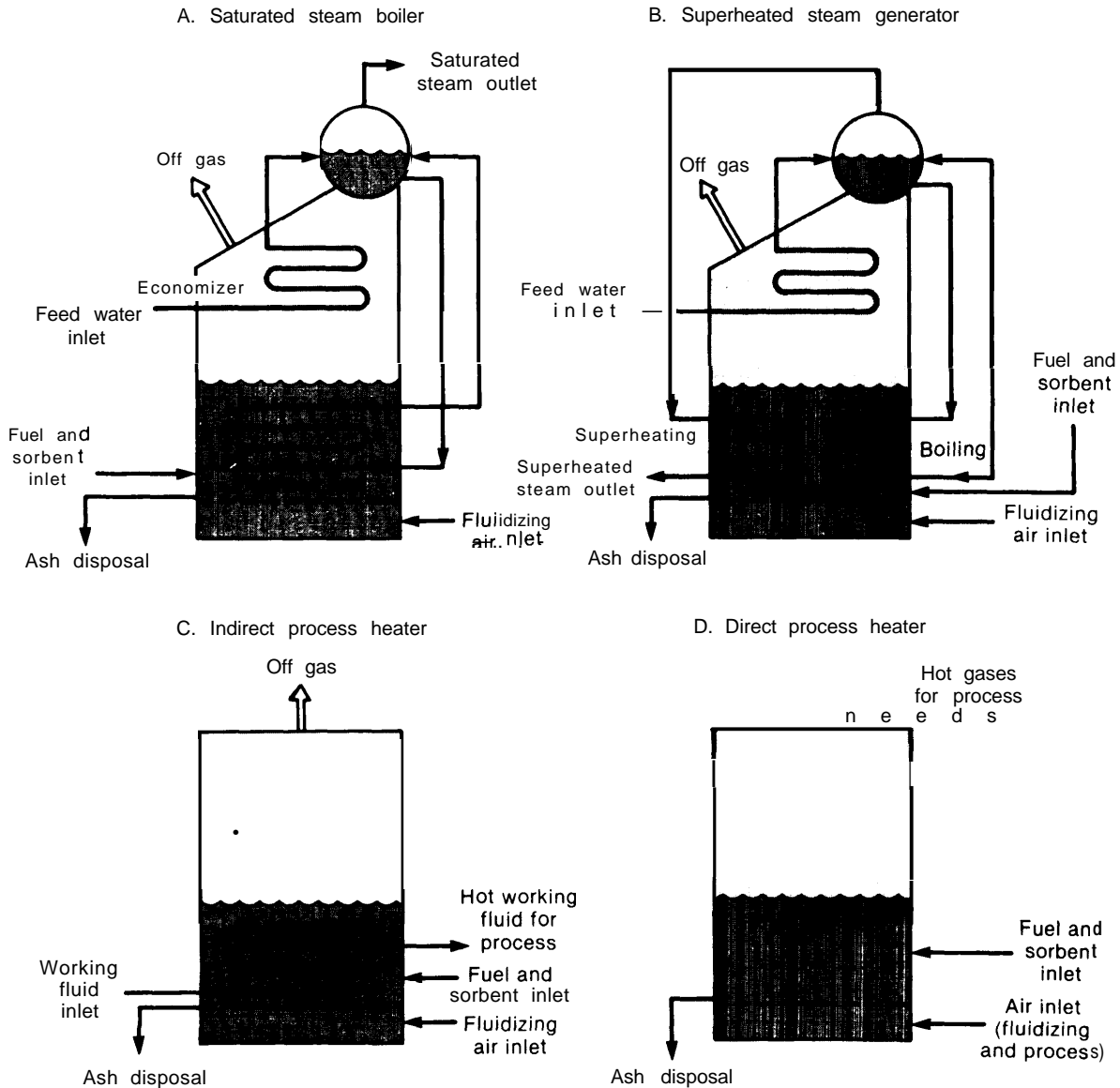
Fluidized-bed combustion is a process by which a fuel is burned in a bed of small particles that are suspended, or "fluidized," in a stream

of air blown upward from below the bed. Almost any type of properly dispersed fuel can be burned in a fluidized bed, but most of the technology of interest relates to the combustion of coal in a "clean" manner that eliminates the need for stack gas scrubbing devices to remove sulfur oxides. This result can be achieved by feeding crushed limestone or dolomite into the fluidized bed along with the coal. The sulfur in the coal combines with the calcium in the crushed rock to form calcium sulfate. Sometimes identified as "spent sorbent," this material is removed with the ash, and the combined solid waste is disposed of as landfill or used in some other manner.

The concept of a fluidized bed is not new. Since the 1940's, various forms of catalytic crackers, using fluidized beds, have evolved. The fluid catalytic cracking process is the result of this development. The petroleum refining industry has been following the development of fluidized-bed combustion with great interest. Although it was originally thought to be just a clean method of burning coal for refinery steam generation, fluidized-bed combustion could ultimately develop into a technology for providing a large part of the total heat required by a refinery. As an illustration, figure 25 shows, in elementary form, a conceptual comparison between steam boilers and process heaters using atmospheric, fluidized-bed combustion (AFBC) techniques. In this concept (diagram C), the process fluid to be heated would be immersed in the fluidized bed.

Since coal-burning equipment of any type requires large areas for coal storage and handling, as well as for ash disposal, it would not be feasible to replace individual process heaters throughout a refinery with coal-burning, fluidized-bed units. Instead, it is possible to visualize large fluidized-bed process heaters made up of several cells. Steam would be generated from coils in some parts of the bed, and process heat could be generated in coils in other parts of the bed. Because of the distances involved and the characteristics of process fluids, it seems unlikely that many process steams would be heated directly by means of coils in fluidized beds. Instead, heat might be transferred to the process areas by hot-oil systems and heat exchangers, and perhaps also by high-temperature, pressurized water sys-

Figure 25.— Diagram of Atmospheric Fluidized-Bed Combustion (AFBC) Boiler/Combustor Arrangements



SOURCE U S Department of Energy 1977 Annual Report

terns. Since some process streams must be heated to temperatures higher than a hot-oil system could feasibly deliver, some process heaters would still be required.

In view of the foregoing, it seems necessary to conclude that fluidized-bed combustion of coal, although perhaps an eventual means of reducing the combustion of petroleum-derived fuels in refineries, will not be a significant process

energy option in the immediate future. It very likely will, however, find increasing application for steam generation in refineries.

COAL GASIFICATION

It has been suggested that refineries might install coal gasification units to obtain energy from coal. Coal gasification could most logically produce a medium-Btu industrial "syngas" com-

posed primarily of hydrogen and carbon monoxide. However, it seems unlikely that such an installation would now be attractive to refiners. The gasifiers being offered are in various stages of development, and none can be considered reliable. Likewise, the relatively low conversion efficiency of the process, the problems of handling coal and ash, the need to build and operate an adjacent oxygen plant, and the complications of converting refining furnaces to use a fuel of much lower Btu than now used all argue against considering coal gasification a reasonable option. If done at all, it seems most likely that coal gasification will be undertaken by a major utility serving refineries along with its many other industrial customers.

Thermal Recovery of Low-Level Heat

As might be expected from the magnitude of losses to air- and water-cooled heat exchangers, refinery management and its technical staff see thermal recovery of low-level heat as a prime opportunity to save energy. They are also aware that opportunities for recovering significant amounts of this wasted heat are unlikely to be found in existing operating plants, but must await instead the design of new facilities where heat balances can be developed with consideration for the true values of heat at all temperatures and pressure levels.

One major refining company is designing a new lubricating-oil manufacturing plant to take advantage of low-level heat recovery. In this plant, the process streams being "run down" for final cooling first generate 45-lb steam and then provide heat to a pressurized, "tempered" water system operating at about 2850 F. The tempered water is used for process reboilers and also as the heat

source for the aqua-ammonia absorption refrigeration system, a key part of the plant. Finally, the process streams are cooled in the conventional manner. Although these streams are still at temperatures of approximately 300° F when finally cooled, considerable energy that would otherwise be wasted is recovered.

Most of the many opportunities for using low-level heat from rundown streams will appear in the design of new facilities whose energy requirements are not circumscribed by existing systems.

Mechanical Recovery of Low-Level Heat

Low-level waste heat might be used to vaporize a fluid, use the vapor to operate a mechanical-drive turbine, and then condense the vapor for recycling to the heat source. Although the concept is straightforward, its practical application is not. Organic fluids must be used instead of water because of the size of the required equipment and the complexity of operating under a vacuum. * Selection of a working fluid involves considerations of toxicity, environmental acceptability, cost, and the thermodynamic properties needed for the cycle. Although the various fluorocarbons are leading contenders, increasing restrictions may make their use inappropriate. Other typical refrigerants have been considered, and one, toluene, is used in one experimental application reported in the literature. Finally, **in addition to other limitations of this method, the low level of heat involved limits energy** recovery to perhaps 10 percent, making this form of energy conservation generally unattractive economically.

*The term "organic rankine cycle" is used to refer to this low-level heat recovery technology.

INVESTMENT CHOICES FOR THE REFINING INDUSTRY

In this section OTA examines certain broader aspects of the petroleum industry, including: 1) competition for capital investment dollars within the industry as it is now structured, and 2) possible investment opportunities in largely nonoil operations. OTA then relates the alter-

native investments discussed to those for energy-saving options in refineries.

Capital Expenditures in the Oil Industry

In considering investment opportunities and incentives for energy-saving measures in refineries,

it is essential to keep in mind the magnitude of other demands for capital in the entire industry. For example, the *Oil & Gas Journal* summarizes the 1982 budget for the U.S. oil industry as:

Exploration and production\$66.8 billion
Refining	6.4 billion
Other	22.1 billion
Total 1982 budget\$95.3 billion

The Standard Oil Co. of California capital expenditure record (shown below) for 4 years is consistent with the *Journal's* report and is believed to be representative of similar expenditures by other major U.S. oil companies.

Capital and Exploratory Expenditures (millions of dollars)				
	1977	1978	1979	1980
Producing and exploration	.\$ 891	\$1,163	\$1,603	\$2,230
Manufacturing: Chemicals	60	26	57	91
Refining	168	149	187	328
M a r k e t i n g	76	92	102	272
Transportation	84	50	96	134
O t h e r	150	212	213	544
Total expenditures\$1,429	\$1,692	\$2,258	\$3,599

A very significant aspect of the foregoing figures is the magnitude of the financial resources needed to discover and produce crude oil and natural gas. These expenditures have increased rapidly in recent years, partly because of the anticipated (and then actual) decontrol of oil prices and because of the urgent need seen by the industry to reduce its dependence on foreign sources of crude oil. In addition, even though geophysical techniques are constantly improving, exploration operations produce many more "dry holes" than wells promising commercial production. As the potentially hydrocarbon-bearing geologic structures now being explored are at increasingly greater depths, the exploratory wells and those drilled for production of commercial discoveries are becoming increasingly expensive.

Another drain on the capital resources of the industry is the previously mentioned restructuring of processing systems to permit running heavy, high-sulfur crude oil and producing the increasing share of unleaded gasoline that must be provided for the motor fuels market.

Other Investment Opportunities

Corporate planners in the oil industry work in an atmosphere of great uncertainty. They know

that supplies of crude oil and natural gas will become increasingly scarce, but they do not know whether a serious availability "crisis" will occur within a decade, a generation, or at some time in the next century. More immediately, they cannot assess political conditions in the troubled areas of the oil-producing world accurately enough to forecast either worldwide price trends or the amounts of imported crude oil the Western world can safely count on. They can be certain, however, that their past world of steadily increasing crude runs and product sales has come to an end; they must now do the best they can to plan for an uncertain future. Two options—not mutually exclusive—seem open to the industry:

- Concentrate on employing the resources and special skills they now have available, including searching out long-term investment opportunities in areas of technology that can be developed without major shifts in corporate structure, personnel, or markets.
- Use their great financial resources and presumed managerial and technical expertise to enter any field of endeavor that promises financial rewards, regardless of its relation to existing operations.

In considering options of the second type, oil industry corporate management may find itself confronted with what might be termed an "identity crisis." As repeated public opinion polls demonstrate, the industry is now held in low esteem by much of the U.S. public. In spite of clear factual evidence to the contrary, a large segment of the public seems to believe that the much publicized oil shortages and the gasoline lines of the recent past—and for many, perhaps, even high gasoline prices—have been contrived by the major oil companies for their own financial benefit. Although legislative proposals for break up or nationalization of the industry appear to have subsided, such proposals are very much **in the background and would probably be reintroduced if their sponsors felt the political climate were right.**

The public can likewise be expected to recall that much of the industry vigorously campaigned for decontrol of oil prices, giving as a principal justification the need for more revenue to increase oil and gas exploration in the United

States. Now that oil price decontrol has been achieved, public opinion and editorial comment could be most unfavorable to announcements by major oil companies of large investments in activities unrelated to the oil business or to takeover attempts within the industry by companies already perceived to be "big enough."

Given this background, corporate management might seek several types of investments to guide their companies during the uncertain transition period.

Energy Investments

The most obvious area of oil industry expansion involves investments in other forms of energy. Although not all investment decisions use oil industry expertise directly, most do follow the sequence, "research-development-marketing," to which the industry is accustomed. Examples would include the following:

Synfuels: Liquefaction of Coal.—Liquefaction of coal is perceived by many industry analysts to be one of the best long-term opportunities for major refiners. In direct liquefaction processes, liquids are obtained directly by hydrogenation of coal. Liquefaction processes are being developed in many of the major oil industry process laboratories, and several processes are felt to be approaching commercial development—examples are SRC-11, Exxon Donor Solvent, and H-Oil. Unfortunately, all these processes still appear to be plagued by mechanical problems as well as by process uncertainties. Moreover, recent declines in crude oil prices, together with the great reduction in Federal subsidization of demonstration energy projects, make it unlikely that direct liquefaction plants of commercial size will be built in the near future. Nevertheless, these processes represent a long-term source of liquid fuels that could supplement and perhaps ultimately supplant crude oil in the manufacture of liquid fuels and a wide range of other products. It is to be expected that the industry will continue to work on their development.

Indirect processes of coal liquefaction are those in which coal is first gasified to produce a medium-Btu syngas. This gas can be converted to liquid fuels or to chemical feedstocks, as done in

the South African Government's large "Sasol" plants. Alternatively, the syngas can be converted to methanol and then to gasoline, using Mobil's proprietary process. Although the indirect liquefaction technologies are considerably further along in development than are the direct processes, they seem to be less attractive to the oil industry. Their conversion efficiency is significantly lower, and they do not produce the wide range of products required by oil industry markets. Oil industry R&D appears to be concentrated on direct liquefaction processes, but considerable effort is also being devoted to the indirect approaches.

Geothermal Energy production.—Some geothermal energy resources (steam and hot water) can be identified by surface geologic conditions, others by exploratory drilling for oil and gas. Typically, an oil company exploiting a geothermal resource will top the steam or hot water and then sell it to a utility for power generation. Cooled water may be returned for injection into the formation. In spite of many optimistic assessments, use of geothermal energy resources presents many technological and environmental problems that can be expected to slow development. Nevertheless, geothermal energy resources in the United States are of very great magnitude. It is expected that oil industry participation in their use will continue.

Petrochemicals.—Most U.S. manufacture of petrochemicals (including basic feedstocks) is not especially profitable at present. Although it is a basic activity of the refining industry, petrochemical manufacture would not appear to be an attractive investment area until the potential problems of foreign competition are resolved and the U.S. market improves.

Alternative Energy Sources.—Many oil industry laboratories conduct intensive research programs in such fields as fuel cells, solar photovoltaics, and other forms of solar energy utilization. Most of these activities are considered to be very long range. It is hoped that some will result in new and economical sources of energy, but none is believed to be at a point where a major capital investment in the technology would be considered.

Oil Shale Mining and Processing.—Many of the major oil companies are undertaking oil shale projects, and others have been preparing to do so. Some acquired their own oil shale properties many years ago. Others operate under Federal leases. The hydrocarbon reserves in Colorado and other oil shale deposits are of very great size, and much informed opinion in the oil industry holds that oil from shale will be developed and on the market long before synfuels from coal can be produced. Nevertheless, billion-dollar investments will be required for shale production and retorting, and few companies appear to be willing (or able) to proceed with such developments without Federal product purchase contracts or loan guarantees. As with many other energy proposals, softening prices of crude oil are dampening the recent enthusiasm for shale oil, and several cutbacks and postponements of these developments have already been announced. Although ultimate use of these shale oil resources

seems certain, the firms making investments now are doing so because of the long-range potential, and not in expectation of immediate profits.

Nonoil-Related Investments

Although many nonoil-related investments are initially profitable—and others may prove so after initial difficulties—several have already caused unfavorable comment in the financial press. Among the best known examples of investments that apparently have not been profitable are Mobil's acquisition of Marcor (including Montgomery Ward), Exxon's Office Systems Co., and Exxon's acquisition of Reliance Electric. It would appear that such investments are appropriate only when oil industry management is confident that no reasonably equivalent opportunities can be found in its own industry—including the often overlooked possibilities of investments to achieve more efficient refinery operations.

IMPACTS OF POLICY OPTIONS ON THE PETROLEUM REFINING INDUSTRY

Having examined the energy use characteristics of the petroleum refining industry, including the specific unit operations where energy is used and the technological opportunities that can improve the efficiency of energy use, the rest of this chapter will be devoted to an examination of the effect of a series of policy options as they would influence energy use.

This analysis is based on a trio of analytical methodologies. In each policy option case, OTA has projected fuel use between 1980 and 2000 using the Industrial Sector Technology Use Model (ISTUM). Second, OTA has assembled a list of eight typical projects in which a petroleum refinery management could invest its capital funds. The projects are ranked according to their internal rate of return (IRR) under both the reference case and the policy option. Any changes in the ranking are then examined and discussed. Finally, the observations and analyses of OTA's consultants, advisory panelists, and workshop participants are noted.

The projects used to illustrate the IRR calculations are described in table 26. Four of the projects are specifically oriented toward the petroleum refining industry. The remaining four are generic—i. e., they are applicable throughout the industrial sector.

A graphical illustration of the impact of each policy option on energy use in the industry is presented in figure 26. The analysis begins with a discussion of the reference case.

The Reference Case

The reference case is predicated on the economic and legislative environment that exists today. It includes the following several general trends that can be identified at present and which should continue over the next two decades:

- **A general decline in the total amount of refined product produced between 1980 and 2000.**

Table 26.—Petroleum Refining Industry Projects To Be Analyzed for Internal Rate of Return (IRR) Values

- | | |
|--|--|
| <p>1. Inventory control.—A computerized system that keeps track of product item availability, location, age, and so forth. In addition, these systems can be used to forecast product demand on a seasonal basis. The overall effect is to lower inventory yet maintain the availability to ship products to customers with little or no delay. In typical installations, working capital costs are dramatically reduced.
Project life—5 years.
Capital and installation costs—\$560,000.
Energy savings—0 directly, but working capital could be reduced by \$1.2 million.</p> <p>2. Electric motors.—The petroleum refining industry uses electrical motors for everything from vapor recompression to mixing, pumping, and extruding. In this analysis, OTA has assumed that five aging electric motors will be replaced with newer, high-efficiency ones.
Project life—10 years.
Capital and installation costs—\$35,000.
Energy savings—\$16,000 per year at 4¢/kWh.</p> <p>3. Catalytic reformer air preheater #1.—A typical energy conservation project in the petroleum refining industry wherein hydrogen is removed from certain organic compounds, thereby increasing the octane rating of the remaining aromatic material.
Project life—10 years.
Capital and installation costs—\$2 million.
Energy savings—\$894,000 at 30 million Btu saved per hour.</p> <p>4. Catalytic reformer air preheater #2.—Same as above, except that major structural changes are necessary in the furnace configuration, thereby increasing installation cost.
Project life—10 years.
Capital and installation costs—\$3 million.</p> | <p>Energy savings—\$1394,000 at 30 million Btu saved per hour of operation.</p> <p>5. Computerized process control.—One of the most ubiquitous retrofit purchases being made for industrial systems is to add measuring gauges, controlling activators, and computer processors to existing machinery. The main accomplishment of such a process control system is to enhance the throughput and quality of a refinery with only materials and small energy inputs.
Project life—7 years.
Capital and installation costs—\$500,000.
Energy savings—\$150,000 per year.</p> <p>6. Crude oil atmospheric distillation unit.—It is assumed that two major crude oil distillation furnaces have been in operation for many years. While relatively inefficient in energy use, the two furnaces are nevertheless still serviceable. Can their replacement be justified in energy savings alone?
Project life—10 years.
Capital and installation costs—\$12 million.
Energy savings—\$3.2 million per year.</p> <p>7. Counterflow heat exchanger.—Installation of a counterflow heat exchanger to preheat air entering a furnace with the exhaust stack gases from the same kiln.
Project life—10 years.
Capital and installation costs—\$200,000.
Energy savings—\$53,000 per year.</p> <p>8. Refinery boiler control system.—Installation of a computer control system to optimize burner efficiency in a boiler furnace.
Project life—10 years.
Capital and installation costs—\$3.75 million.
Energy savings—\$820,000 per year.</p> |
|--|--|

SOURCE: Office of Technology Assessment

- A shift in product mix produced by the petroleum refining industry.
- A deterioration in the quality of crude oil feedstock available to the petroleum refining industry.

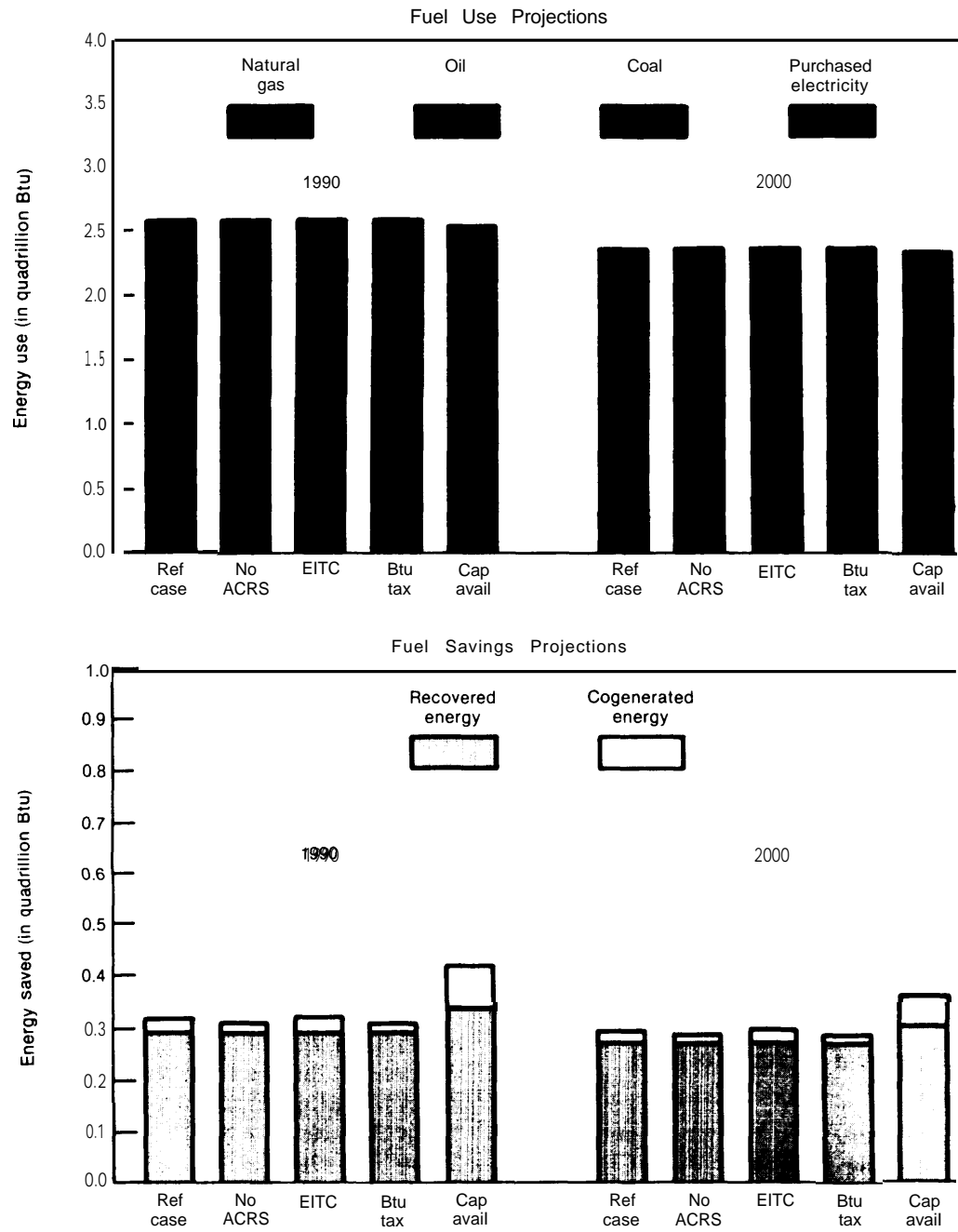
As mentioned before, these trends place SIC 29 corporations in the unenviable position of having to make substantial investments to accommodate changing feedstocks and product markets in an industry whose overall growth will be negative.

These trends can be clearly seen in the modeling analyses carried out under OTA direction. Table 27 presents the OTA projection for total production in SIC 29. As shown, it decreases from a high of 14.2 million bpd in 1980 to 13.9 million bpd in 2000. At the same time, the product mix is forecast to change from a preponderance of

gasoline to an equality between gasoline and middle distillates.

The decline in energy intensity will be most rapid in the 1980-90 decade owing to projected improvements in operations and retrofit additions to enhance heat recovery (see fig. 27). Computer controls and process units, heat exchangers, re-generators, waste heat boilers, and the like are expected to improve the efficiency of existing units and fired heaters. In the following 10 years (1990-2000), new, more efficient processes should be added to refinery operations to help reduce energy intensity. These should be **processes** such as fluid coking with gasification, polymerization, and so forth. It is interesting to note that, given the projected decline in consumption of refined petroleum products, 80 percent of the expected improvement in energy efficiency in SIC

Figure 26.—Petroleum Refining Industry Projections of Fuel Use and Energy Savings by Policy Options, 1990 and 2000



SOURCE Office of Technology Assessment

Table 27.—Projected Changes in Petroleum Refining Production Between 1985 and 2000^a

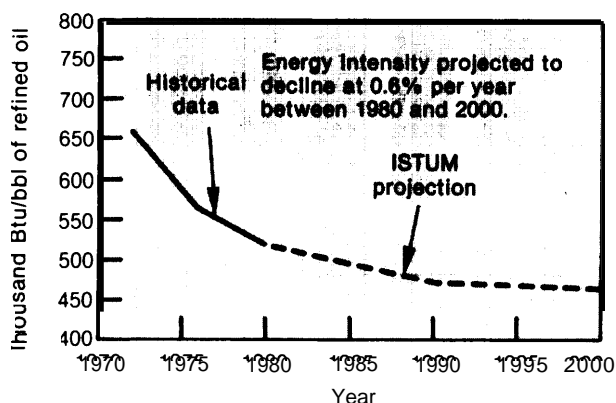
	1980	1985	1990	2000
Gasoline	6.4	6.4 (42%)	5.7 (380/.)	4.9 (350/o)
Middle distillates	4.0	4.4 (290/o)	4.7 (32%)	4.7 (34°/0)
Naphtha	0.5	0.6	0.7	0.9
Petrochemical feedstocks ^b	0.6	1.0	1.2	1.3
Residual oil	1.4	1.5	1.4	1.0
Others ^c	1.3	1.2	1.2	1.1
Total	14.2	15.1	14.9	13.9

^aIn million barrels of oil refined per day and percent.

^bOther than naphtha.

^cIncludes asphalt paving materials, Petroleum coke, lubricating oils, and the like.

SOURCES: Department of Energy, *Petroleum Supply Annual Report, 1991*; and Office of Technology Assessment projection using ISTUM.

Figure 27.—Petroleum Refining Industry Energy Intensity Projection, 1970-2000

SOURCE Office of Technology Assessment

29 will be attributable to add-on energy conservation units over the next two decades. Only 20 percent will be attributable to new processes.

Projected Effects of Policy Options

Option 1: Removal of Accelerated Depreciation

OTA projects very little change in petroleum refining energy use patterns if the ACRS is removed, as shown in figure 26. There should be a slight increase in natural gas used (1 percentage point or less) and a slight increase in coal used. Cogenerated electrical energy production would be down because the depreciation in newly installed equipment would not be as rapid and would therefore be less attractive. Overall energy use is projected to increase less than 1 percentage point above that of the reference case.

This analysis is corroborated by an examination of table 28. There are no changes in any of the IRR values that are greater than 1 percentage point, nor are there any changes in the ranking of any project.

The top three projects are obviously attractive investments. They represent the type of projects corporations readily take on when energy costs begin to approach 1981 levels. And these projects maintain their attractiveness even without the added incentive of ACRS depreciation. These projects will be done, assuming capital is available, because energy, along with materials and labor, is expensive, and each of the top three projects represents a means of reducing costs without changing the nature of the products produced.

Option 2: Energy Investment Tax Credits

OTA analysis suggests a less than 1-percent change in overall energy use as a result of a 10-percent targeted **energy investment tax credit** (EITC). And, perhaps surprisingly, the change is projected to be a slight increase, as shown in figure 26. This result arises from a projected increase in cogeneration, which comes about primarily from using natural gas to produce both steam and mechanical or electrical energy. Coal use is also projected to increase by several percentage points as coal-fired boilers are used to raise steam, and coal is used for process heat.

Table 28 shows the impact of an EITC on the IRR values of representative petroleum refining

Table 28.—Effects of Policy Options on IRR Values of Petroleum Refining Industry Projects

Project	Reference case	IRR with policy option		
		ACRS removed	10-percent EITC	\$1/MMBtu tax on natural gas and petroleum products
1. Inventory control	87	87	87	87
2. Electric motors	43	43	48	51
3. Catalytic air preheater #1	30	30	34	37
4. Catalytic air preheater #2	20	20	23	25
5. Crude unit furnace replacement	17	17	21	24
6. Computerized process control	16	16	22	19
7. Counterflow heat exchanger	15	15	18	19
8. Boiler plant control system	14	14	17	18

SOURCE: Office of Technology Assessment.

industry projects. As shown, the impact on the project was modest. Most IRR values increased by 3 to 5 percentage points, and only one project, the computerized process controller, moved **up in ranking, but only by 1 point. It is unlikely that this change in ranking would affect management's decision to take on, for example, the crude unit furnace replacement. Such factors as total cost, age of the furnace, perceived reliability of the computer process controller, and the like, would** have more impact on the decision.

in evaluating the potential effect of energy tax credits, it is necessary to recognize that applicability of such credits is not guaranteed. In order to avoid having such credits treated as just one more general investment tax credit, the Internal Revenue Service (IRS) can be expected to examine proposed applications of an energy tax credit closely. To judge from experience, IRS examinations and rulings may be expected to delay the application of such credits and to limit their use to a perceived energy-saving portion of an investment, even though the entire investment must be made in order to achieve the energy savings.

Option 3: Tax on Premium Fuel

OTA analysis suggests that a fuel price increase of \$1/MMBtu, whether in the form of a tax or market-dictated increase, would have the effect of slowing the penetration of cogeneration technology into SIC 29 relative to what is projected

to occur in the reference case. And because cogeneration is slowed, natural gas use will be less and purchased electricity will be greater than that in the reference case.

However, the greatest effect would be to promote fuel switching away from premium fuels and toward coal for both coal boilers and for hydrogen production. The combined effect of the use of more coal technologies with the decrease in cogeneration and increased purchase of electricity from utilities leads to a slight increase in total energy demand.

Table 28 presents the projected impact on IRR values of the petroleum refining projects. The fuel price increase does increase IRR values by 5 to 7 points, except for the inventory control **option, which is a project with no premium fuel use. However, none of the projects changed its relative ranking.** While the list of projects may not be all inclusive of those available to a refinery's management, it does illustrate that other factors besides IRR would be needed to change the ranking of a project.

An energy tax can have undesirable effects on the refining industry. Refining costs would increase, and product prices would necessarily follow. Imported products would become more competitive, perhaps necessitating specific *tariffs* or other measures to protect U.S. refiners and their industrial customers. And refiners would have less ability to invest in energy-saving equip-

ment to the extent that they couldn't pass on their increased costs.

Option 4: Low Cost of Capital

OTA analysis suggests that of all the legislative options examined, the low cost of capital would cause the greatest change **in energy use compared to the reference case. The low cost of capital** would promote the use of cogeneration and retrofit conservation technologies, thereby producing more self-generated electricity and a reduction in waste energy. The most significant shift in fuel mix would occur **in steam methane reforming, where partial oxidation of coal** to produce hydrogen displaces the use of natural gas.

Table 29 presents the OTA analysis of the impact of a decrease in interest rate on moneys borrowed to undertake the representative petroleum refining projects. In this instance, the reference case figures have been changed to reflect a situation where two-thirds of the money needed to finance the project is borrowed at a 16-percent interest rate. One-third of the cost would come from funds already in hand in the firm. When the interest rate is lowered to **8** percent, two of the

projects move up in ranking. Although the catalytic air preheater # 1 project would advance to the second place, it was already very attractive. Even without borrowing, the IRR value was above 30 percent with borrowing, it soars to 83 percent. The shift to above 100 percent will not significantly increase the attractiveness of an already desirable project,

Because of the decline in interest rates, all the projects have become more attractive, at least as measured by IRR values. Other factors such as total cost, plant downtime, and the like, however, would also affect the decision about whether to invest **in these projects. It must again be emphasized that investments** for energy savings have no special priority over the petroleum industry's need to spend vast amounts of capital **in essential exploration and producing activities and to adapt refineries to the changes in available crude types and to the changing demands of the products market. Many such investments will be considered necessary by industry management and thus will take priority** in discretionary capital expenditures.

Table 29.—Effect of Lower Interest Rates on IRR Values of Petroleum Refinery industry Projects^a

Project	Reference case IRR with 16 percent interest rate	IRR with policy options: interest rate of 8 percent
1. Inventory control	385	370
2. Electric motors	93	97
3. Catalytic air preheater #1	83	107
4. Crude unit furnace replacement	76	90
5. Catalytic air preheater #2.	70	89
6. Computerized process controller	36	44
7. Counterflow heat exchanger	33	38
8. Boiler plant control system	413	59

^aAll projects are assumed to be two-thirds debt financed and one-third equity financed

SOURCE: Office of Technology Assessment.