HYDROCARBONS PROCESSING
A PRIMER FOR ALASKANS

by Arlon R. Tussing and Lois S. Kramer

INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH
UNIVERSITY OF ALASKA
PREFACE

This primer on fuels refining and petrochemicals manufacturing is intended to illuminate a continuing debate among Alaskans over the economics and potential benefits of processing hydrocarbons in the state. The recurring policy issue toward which the report was initially directed was the question of what to do with the State's royalty share of the crude oil, natural gas and natural-gas liquids (NGL's) produced at Prudhoe Bay. The uses and implications of our report will extend far beyond decisions regarding the disposition of State royalty hydrocarbons, but this issue provides a convenient focus for reviewing:

- How the refining and petrochemical industries are organized.
- The role of petroleum and the petroleum industry in Alaska.
- Elementary hydrocarbons chemistry.
- Refining and petrochemical-manufacturing technology.
- Health and safety issues.
- The economics of hydrocarbons processing.
- The outlook for refining and petrochemicals investment in Alaska.

The first stage in the debate over disposition of State hydrocarbons royalties ended in 1977, when the Alaska Legislature conditionally approved the sale of the State's Prudhoe Bay royalty gas to subsidiaries of the El Paso Company, Tenneco, and Southern Natural Gas Company, hoping that the political influence of these firms would lead the federal government to select an "all-Alaska" pipeline route for the Alaska Natural Gas Transportation System (ANGTS). Under this plan, a plant producing liquefied natural gas (LNG) and possibly other gas-processing facilities would have been built at the pipeline's Gulf of Alaska terminal.
The royalty-gas sales contracts lapsed later in 1977, when the President and Congress and the Canadian government chose the Alaska Highway ("Alcan") pipeline, sponsored by Northwest Energy Company and the Foothills group, over El Paso Alaska's proposed LNG system and the Mackenzie Valley pipeline proposal advanced by the Arctic Gas group.

The second stage of the debate opened in 1978, when the Legislature considered a long-term contract to sell 85 percent of the State's North Slope royalty oil, up to 150 thousand barrels per day (mb/d), to the Alaska Petrochemical Company ("Alpetco") if the company built a "world-scale" petrochemicals plant in Alaska.

The Alpetco contract was later amended to permit the sponsors to build a 100 mb/d fuels refinery, which might or might not have produced petrochemicals. Several changes in the project's ownership structure led to its final sponsorship by the Alaska Oil Company, a subsidiary of the Charter Oil Company. In May of 1981, Charter abandoned its plan for a refinery at Valdez, stating that it had been unable to obtain outside financing, and gave up its right to purchase 75 mb/d of State royalty oil prior to completion of the refinery.

Most recently, in 1980, the Alaska Department of Natural Resources (DNR) entered into an agreement with the Dow Chemical Company, the Shell Oil Company, and a group of associated companies to study the feasibility of transporting and processing Prudhoe Bay NGL's in Alaska. The State, in turn, granted the participating companies an option to buy its royalty share of the NGL's and agreed to use its influence with the North Slope producing companies to obtain additional feedstocks for the petrochemicals complex, should it prove feasible. This study is scheduled for completion and delivery to the State in September, 1981.

Concurrently with the Dow-Shell study, the Exxon Chemical Company has independently been studying the feasibility of petrochemicals manufacturing based on North Slope NGL's. Earlier in 1981, Arco made its own assessment
Preface

of Prudhoe Bay methanol production as an alternative to construction of a natural-gas pipeline.

The several projects have been quite different technically, but all of them tend to evoke similar hopes, fears, and controversy among Alaskans. The hopes and arguments favoring such ventures have been: increased local "value-added" from the state's natural resources (as opposed to their export in unprocessed form), the contribution that this processing would make to the state's economic growth and economic diversity, a greater and more diversified tax base, new and more diverse job opportunities, and lower Alaska prices for fuels and other petroleum products.

At the same time, some Alaskans have been skeptical about the underlying economic soundness of the proposals and feared that one or more of these ventures might ultimately have to be rescued by the State treasury. Other concerns have been the possibility that long-term royalty-gas export contracts could foreclose future opportunities for residential, commercial, industrial or electric-utility use of the gas in Alaska, and that long-term royalty-oil sales to export-oriented new refineries could leave existing refineries that serve Alaska customers short of raw material, if the decline in Prudhoe Bay production made the oil producers less willing to sell crude oil to these refineries.

Other potentially adverse impacts are the prospects of deepening Alaska's already excessive dependence on petroleum-related industry, and of once more repeating the state's familiar boom-bust cycle; new sources of pollution and other health, safety, or aesthetic hazards; and unwelcome changes in community values and life-styles.

To aid the rational discussion of such issues, this primer tries to set in context the basic technical and economic facts, analytical concepts, and policy considerations relevant to hydrocarbons processing in Alaska. Many of the crucial questions have already found their way into public debate and set the stage for our discussion of the more technical aspects of fuels refining and petrochemicals processing. These questions, for example, include considerations of:
Feasibility. Is Alaska a realistic location for nationally or internationally competitive fuels refining or petrochemicals-manufacturing activity?

Type of industry. For what specific kinds of hydrocarbons-processing, if any, does Alaska have a special comparative advantage, and what kinds of facilities are especially unpromising for Alaska?

Interrelationships. What interrelationships exist among the projects that have been proposed? Are some of them mutually exclusive? How will decisions regarding ANGTS affect the viability of a gas-liquids pipeline or natural-gas liquids-based petrochemicals production, and vice-versa?

Influence of the State. What special ability does the State's ownership of royalty oil and gas, regulatory powers, taxing authority, or investment capability give it to encourage or discourage investment or to affect the character or location of facilities that process Alaska hydrocarbons? And, to what extent is it (1) proper or prudent in a society committed to private enterprise, or (2) in the interests of Alaskans, that the State government deliberately use its powers to influence the course of development?

Direct economic impacts. How many jobs, of what character, will each proposed project offer in its construction and operational phase respectively, and who will fill these jobs? How will construction and operation of the facilities affect the demand for services in other local industries?

Indirect development impact. To what extent will the existence of any of the projects in question stimulate (or discourage) investment in complementary (or competing) industries, and
what will be their total impact on the state's economy after taking into account all their short and long-term, direct, indirect, and multiplier effects?

Health, safety, environmental, and aesthetic considerations. To what extent do the proposed projects (or their indirect developmental effects) have unavoidable adverse impacts or create known or potential risks of adverse impacts on health, safety, the natural environment, or other dimensions of the quality of life in Alaska?

Conflicting objectives. To what extent do specific kinds of State efforts to attract refinery or petrochemical investments assist or conflict with other goals, such as maximization of royalty and tax revenue from oil and gas production, early completion of the natural-gas pipeline, or availability of low-cost energy for local residential, commercial, or industrial consumption?

Consequences. What are the likely consequences of making an early commitment or not making such a commitment of the State's Prudhoe Bay royalty gas and/or gas liquids? Are there additional costs that State and local governments may incur as a result of their aggressive pursuit of petrochemical investment in Alaska?

These questions, while not exhaustive, are the major issues in the current public debate over State policies toward petrochemical development. Although the authors have tried to give general answers to some of these questions, the main function of the present paper is to provide its readers with some of the background necessary to develop their own answers.
**Sponsorship.** Production of this study was supported by a contract between the University of Alaska's Institute of Social and Economic Research and the Alaska Legislature's Joint Gas Pipeline Committee with a matching grant from the Ford Foundation. The contract with the Legislature was administered by Susan Brody of the House Research Agency.

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The authors accepted many but not all of the suggestions and criticisms offered by these reviewers, and take full responsibility for any errors or deficiencies in this final version.
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Chapter 6

The Economics of Hydrocarbons-Processing and the Outlook for Refining and Petrochemicals in Alaska

Hydrocarbons-Transportation Economics

Fixed-Capital Costs

Feedstock Costs and Supply

Illustrations

Economies of Scale

Analyzing Project Feasibility

Coping with Uncertainty and Risk

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CHAPTER 1
OVERVIEW OF PETROLEUM
AND THE PETROLEUM INDUSTRY

Crude oil, natural gas, and natural-gas liquids are all "petroleum," which is the general term for hydrocarbons -- compounds found in the earth's crust that are composed mainly of hydrogen and carbon atoms. Hydrocarbons vary considerably in molecular size and structure, and each hydrocarbon compound can exist as a solid, a liquid, or a gas, depending on the pressure and temperature to which it is subjected.

"Crude-oil" fields or reservoirs are naturally occurring deposits containing hydrocarbons that are liquid at atmospheric pressures and temperatures, while "natural-gas" fields or reservoirs are deposits containing only hydrocarbons that are gases under the same conditions. However, most commercially recoverable petroleum deposits, including the Prudhoe Bay field, contain a mixture of liquid and gaseous hydrocarbons that have to be separated in the field for transportation and processing.

The petroleum industry, as we define it for the purposes of this primer, includes businesses engaged in finding and extracting hydrocarbons from the earth, and their storage and transportation; the refining, distribution, and sale of fuels and lubricants; and related service and support activities. It also includes a "petrochemical" sector --- the manufacture and distribution of organic chemicals based upon petroleum feedstocks, often by affiliates of petroleum production and refining companies.

Internationalism. Petroleum is the most important commodity in world trade in both volume and value, and a large part of the world's total production of petroleum liquids is transported and processed by a few multinational companies. The reason for the industry's exceptional internationalism is the widely differing locations of the chief petroleum-producing areas and the major markets for petroleum products. Figure 1 illustrates the geographic disparity between global oil production and consumption in 1979.
### Figure 1
Crude-Oil Production and Consumption of Refined Products By Area, 1979

<table>
<thead>
<tr>
<th>Area</th>
<th>Production (1,000 barrels)</th>
<th>Consumption (1,000 barrels)</th>
</tr>
</thead>
<tbody>
<tr>
<td>United States</td>
<td>3,111,625</td>
<td>6,728,410</td>
</tr>
<tr>
<td>Canada</td>
<td>545,675</td>
<td>691,675</td>
</tr>
<tr>
<td>Latin America</td>
<td>1,912,200</td>
<td>1,604,175</td>
</tr>
<tr>
<td>Middle East</td>
<td>7,803,700</td>
<td>542,025</td>
</tr>
<tr>
<td>Africa</td>
<td>2,901,700</td>
<td>478,150</td>
</tr>
<tr>
<td>Asia/Pacific</td>
<td>1,042,075</td>
<td>3,429,175</td>
</tr>
<tr>
<td>Western Europe</td>
<td>826,725</td>
<td>5,427,550</td>
</tr>
<tr>
<td>Communist Nations</td>
<td>5,120,950</td>
<td>4,688,425</td>
</tr>
</tbody>
</table>


**Size and capital intensiveness.** The world petroleum industry is both very large, and as a whole, exceptionally capital-intensive. Six of the ten largest firms in the 1980 *Fortune 500* were oil companies. Table 1 summarizes the
Chase Manhattan Bank's survey of the petroleum industry's 1975-77 capital expenditures. The industry's new investments over the three years amounted to about $62 billion in the United States and $168 billion worldwide.

Table 1
Domestic and Foreign Capital Expenditures of The World Petroleum Industry

<table>
<thead>
<tr>
<th>Production</th>
<th>Transportation</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S.</td>
<td>Foreign</td>
</tr>
<tr>
<td>$ bil</td>
<td>%</td>
</tr>
<tr>
<td>1975</td>
<td>9.4</td>
</tr>
<tr>
<td>1976</td>
<td>13.4</td>
</tr>
<tr>
<td>1977</td>
<td>15.2</td>
</tr>
<tr>
<td>U.S.</td>
<td>Foreign</td>
</tr>
<tr>
<td>$ bil</td>
<td>%</td>
</tr>
<tr>
<td>1975</td>
<td>3.7</td>
</tr>
<tr>
<td>1976</td>
<td>3.9</td>
</tr>
<tr>
<td>1977</td>
<td>2.3</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Refineries &amp; Chem. Plants</th>
<th>Marketing</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S.</td>
<td>Foreign</td>
</tr>
<tr>
<td>$ bil</td>
<td>%</td>
</tr>
<tr>
<td>1975</td>
<td>3.6</td>
</tr>
<tr>
<td>1976</td>
<td>3.8</td>
</tr>
<tr>
<td>1977</td>
<td>3.7</td>
</tr>
<tr>
<td>U.S.</td>
<td>Foreign</td>
</tr>
<tr>
<td>$ bil</td>
<td>%</td>
</tr>
<tr>
<td>1975</td>
<td>.6</td>
</tr>
<tr>
<td>1976</td>
<td>.6</td>
</tr>
<tr>
<td>1977</td>
<td>.8</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Other Capital Spending</th>
<th>Total Capital Spending</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S.</td>
<td>Foreign</td>
</tr>
<tr>
<td>$ bil</td>
<td>%</td>
</tr>
<tr>
<td>1975</td>
<td>.4</td>
</tr>
<tr>
<td>1976</td>
<td>.3</td>
</tr>
<tr>
<td>1977</td>
<td>.4</td>
</tr>
<tr>
<td>U.S.</td>
<td>Foreign</td>
</tr>
<tr>
<td>$ bil</td>
<td>%</td>
</tr>
<tr>
<td>1975</td>
<td>17.7</td>
</tr>
<tr>
<td>1976</td>
<td>22.1</td>
</tr>
<tr>
<td>1977</td>
<td>22.4</td>
</tr>
</tbody>
</table>


Table 2 shows that petroleum refining also had the highest ratio of assets per employee among the 29 industries included in the Fortune survey. The chemical industry ranked sixth. Petroleum was also in first place among all industries with respect to the ratio of assets to sales.

Not all phases of the industry are exceptionally capital-intensive, however. In the Middle East, for example,
capital costs for crude-oil production --- the cost of wells, gathering lines, and separating facilities --- tend to be relatively low, ranging from about $100 to $500 for the capacity required to produce one barrel of oil per day. At an oil price of $32 per barrel, even $500 per "daily barrel" implies that only 16 days of production would be needed to recover the fixed investment in field development.

Table 2
Assets per Employee for the Fortune 500
(Industry Medians)

<table>
<thead>
<tr>
<th>Industry</th>
<th>Median Assets per Employee</th>
</tr>
</thead>
<tbody>
<tr>
<td>Petroleum refining</td>
<td>$303,839</td>
</tr>
<tr>
<td>Mining, crude-oil production</td>
<td>254,336</td>
</tr>
<tr>
<td>Broadcasting, motion-picture production and distribution</td>
<td>108,772</td>
</tr>
<tr>
<td>Tobacco</td>
<td>81,937</td>
</tr>
<tr>
<td>Metal manufact'g</td>
<td>79,868</td>
</tr>
<tr>
<td>Chemicals</td>
<td>77,947</td>
</tr>
<tr>
<td>Paper, fiber and wood products</td>
<td>76,141</td>
</tr>
<tr>
<td>Pharmaceuticals</td>
<td>66,543</td>
</tr>
<tr>
<td>Publishing, printing</td>
<td>56,129</td>
</tr>
<tr>
<td>Glass, concrete abrasives, and gypsum</td>
<td>55,668</td>
</tr>
<tr>
<td>Industrial and farm equipm't</td>
<td>53,361</td>
</tr>
<tr>
<td>Office equipm't, computers</td>
<td>49,039</td>
</tr>
<tr>
<td>Food</td>
<td>49,488</td>
</tr>
<tr>
<td>Motor Vehicles</td>
<td>46,039</td>
</tr>
<tr>
<td>Shipbuilding, railroad &amp; transport equipment</td>
<td>43,941</td>
</tr>
<tr>
<td>Rubber and plastic products</td>
<td>42,563</td>
</tr>
<tr>
<td>Measuring, scientific and photographic equipm't</td>
<td>41,000</td>
</tr>
<tr>
<td>Aerospace</td>
<td>40,901</td>
</tr>
<tr>
<td>Musical instrum'ts, toys, sporting goods</td>
<td>37,666</td>
</tr>
<tr>
<td>Electronic appl.</td>
<td>37,594</td>
</tr>
<tr>
<td>Textiles &amp; vinyl flooring</td>
<td>26,431</td>
</tr>
<tr>
<td>Apparel</td>
<td>20,364</td>
</tr>
<tr>
<td>Leather</td>
<td>n.a.</td>
</tr>
<tr>
<td>Furniture</td>
<td>n.a.</td>
</tr>
<tr>
<td>Jewelry, silverware</td>
<td>n.a.</td>
</tr>
<tr>
<td>All industries</td>
<td>$ 55,505</td>
</tr>
</tbody>
</table>

Source: Fortune, May 4, 1981
The capital cost per daily barrel for new crude-oil production in the North Sea, the United States Outer Continental Shelf (OCS), or the Arctic is typically much higher than for Middle Eastern production — in the range of $5,000 to $25,000 per daily barrel. Synthetic oil and gas plants are expected to be even more capital-intensive, with capital costs of $50,000 or more for the producing capacity equivalent to one barrel of oil per day.

Refining and petrochemical plants also require very large capital additions, both absolutely and per unit of capacity: a completely new ("grass-roots") state-of-the art oil refinery may cost more than a billion dollars — at $5,000 to $10,000 or more per daily barrel of capacity — and a first-stage petrochemicals plant may cost even more. Even the extra equipment an existing refinery would need to process lower-quality ("heavy" or high-sulfur) types of crude oil tends to add new capital costs of $1,500 to $2,500 or more per daily barrel of capacity.

**High technology.** The search for natural hydrocarbons is reaching out to more remote and difficult locations: farther below the earth's surface, under deeper water, and into the Arctic. Construction of production platforms in the North Sea marked the first time engineers had installed permanent structures of any kind in such deep or wave-stressed waters, while the Trans-Alaska oil pipeline (TAPS) required radically new pipeline design and construction techniques to cope with tundra and permafrost conditions.

The production of unconventional hydrocarbons or even familiar resources in new environments (tar sands and oil shales, for example, or natural gas in coal seams, tight rocks, and pressurized brine solutions) is tied directly into technological advance as is progress in the refining and petrochemical sectors, where new end-products appear frequently and where both the demand mix and feedstock mix continue to change.

**Short- and long-term flexibility.** Petroleum-product demand changes constantly. Part of this change is short-term, determined by the seasons and the weather, or by
economic conditions. Gasoline consumption peaks in the summer, and heating oil consumption in the winter; a warmer-than-usual spring increases gasoline demand, while a colder-than-usual winter favors heating-oil demand. Consumption of all petroleum products and petrochemicals tends to fall off in recessions, though not in constant proportions. These fluctuations require that refiners be able to vary the mix of different products in their plant output, carry some surplus processing capacity, and maintain storage facilities.

Another part of the change in demand is longer-term. It appears that the total consumption of petroleum products in the United States and the world as a whole peaked in 1978, and the subsequent decline may well be permanent. Gasoline and residual oil demand, in particular, are expected to continue shrinking, but the consumption of "middle distillates" (diesel fuel, home-heating oil, and jet fuel) and the use of refinery products for petrochemical feedstocks may resume their growth or at least stabilize. At the same time that gasoline consumption as a whole is shrinking, the U.S. Environmental Protection Agency (EPA) is requiring refiners to phase out lead as a gasoline additive, compelling them to produce an essentially new kind of gasoline in order to obtain acceptable anti-knock ("octane") ratings.

These shifts in product demand are all occurring at a time when "heavy" crude oil containing a high proportion of residual oil is becoming a relatively larger part of the total oil supply. The continuing decline in Lower 48 natural-gas production from traditionally-exploited kinds of resources is also reducing the supply of natural-gas liquids (NGL's), a major feedstock source for the petrochemical industry. As a result, an overall decline in the demand for petroleum-processing capacity may not forestall the need for further investment in facilities to "upgrade" surplus residual oil into middle distillate fuels and petrochemical feedstocks like naphtha and gas oil.
**Long lead times.** Capital-intensiveness and high technology imply long engineering lead times and long construction schedules, with heavy capital outlays required far in advance of any return on investment. Refineries, petrochemical plants, frontier oil and gas development, and pioneering pipeline ventures like TAPS and ANGTS, tend to require 3 to 8 years or even longer for their planning, design, construction, and shakedown.

**Risk.** Risk and uncertainty pervade all segments of the petroleum business. Geological or exploration risk -- the low percentage of "wildcat" wells that lead to commercial oil and gas discoveries --- probably receives the greatest emphasis in public discussions of petroleum industry risks. But the most significant risks in the industry today tend, rather, to concern costs, markets, and political and regulatory treatment. The large absolute size of individual projects and the long time that typically elapses between the initial outlay and its return make the economics of new refineries, processing plants, or transportation systems extremely sensitive to future raw materials costs, product markets, tax treatment, and government policies for long periods into the future. Such investments are therefore exceptionally vulnerable to cost overruns, unforeseen changes in raw materials costs or supply interruptions, and to changes in product demand, tax treatment, regulation and other government policies.

**Vertical integration.** Vertical integration is primarily an attempt to reduce the supply and market risks faced by the various sectors of an industry. Primary raw materials producers are likely to integrate "downstream" into refining, chemical manufacturing, and distribution, in order to assure themselves a long-term market. At the same time, refiners and processors try to obtain "upstream" control over producing properties in order to stabilize their raw materials costs and reduce the possibility that expensive plants will become idle or customers go unserved in some future feedstock shortage. Crude-oil pipelines are typically built and operated by major producers and/or refiners, because only they can assure that the pipeline will be used.
As a result, a relatively small number of multinational firms produce, transport, refine, and market most of the petroleum liquids in the United States, but these major companies share the stage with independent and partially-integrated producers, refiners, resellers, and marketers of all sizes.

The chemical industry is more concentrated than the oil industry: the five top companies accounted for 60 percent of total U.S. chemical sales in 1979, in contrast to the five top refiners' 48 percent of petroleum-product sales. In the last five years, however, growing downstream integration by major oil companies has given them a dominant role in production of primary petrochemicals, such as ethylene and benzene.

**Government involvement.** Governments powerfully influence the structure and performance of the petroleum industry through their roles as landlords and royalty-owners; tax collectors; protectors of investors, consumers, and competitors, and of health, safety and the environment; price regulators and allocators; statisticians; traders; and promoters or investors.

Some government programs or policies have encouraged vertical integration. Examples have been percentage depletion allowances and the windfall profits tax, both of which permit integrated companies to reduce their federal tax burden by means of crude-oil "transfer prices" that shift book profits to the stage of production where the tax rate is lowest. Other programs have penalized integration: The import quota system that existed between 1958 and 1974, for instance, had a "sliding scale" that favored small refiners, while the "small refiner bias" in the crude-oil "entitlements system" under the Emergency Petroleum Allocation Act had a similar effect between 1974 and 1980.

The government of Alaska is distinctive among the states because of the size of the petroleum resource it controls and particularly because of the disproportion between this resource base and the state's present population. At the end of 1980, the State's royalty interest in just
proved reserves amounted to about 1.1 billion barrels of crude oil and NGL's, and 3.9 trillion cubic feet (tcf) of natural gas. Its taxing authority extended to another 8.6 billion barrels and 32.8 tcf of proved reserves. Further oil and gas discoveries will surely add to these totals.

With a 1980 Alaska resident population of about 400 thousand persons, these supplies exceed by many times any reasonably foreseeable demand by the State's existing residential, commercial, or industrial consumers. The expected revenues from extracting these resources will likewise far surpass the population's need for the ordinary services of State and local governments, leaving a large current revenue surplus available for long-term investments, industrial development projects, or direct distribution.

Thus, Alaska's discretionary powers over the oil and gas itself, and over the revenues they generate, are exceptional. The role of State government as resource owner, manager, regulator, and potential investor plunges the issues of refinery and petrochemical development squarely into the political arena. As Alaska's oil and gas industry is already a quarter-century old, a brief overview of its existing and contemplated developments will shed some light on how and where the industry may develop in the future.
CHAPTER 2

THE PETROLEUM INDUSTRY IN ALASKA

The kind, size, and location of existing petroleum-related activity in Alaska will doubtless have a large influence on the kind, size, and location of future refining and petrochemical investments.

Hydrocarbon Resources, Reserves, and Production.

Cook Inlet. In the modern era, the first commercial discovery of petroleum occurred in 1957 at Swanson River on the Kenai Peninsula, 100 kilometers southwest of Anchorage. The last major oil discovery in the upper Cook Inlet region was in 1965, and the last important gas discovery was in 1966. Oil production peaked in 1970 at 229 thousand barrels per day (mbpd), averaged 85 mbpd in 1980, and is continuing to decline rapidly. Industry geologists believe it is unlikely that new discoveries in the Upper Cook Inlet area will reverse this trend.

Natural-gas production, other than volumes reinjected to maintain oil-field pressures, averaged about 600 million cubic feet (mmcf) per day in 1980. At the end of 1980, Cook Inlet's proved natural-gas reserves totalled more than 3.5 trillion cubic feet, about 16 years' production at the current rate. Exploration of the area is continuing to produce promising "shows" of natural gas. Because about half of the area's proved reserves are still not firmly committed to production, however, there is little incentive for the industry to develop new discoveries, and thus to add them to the proved reserves category. In any event, given a growing market, it is likely that Cook Inlet gas production could continue to increase for, say, another decade before beginning to fall off.

Prudhoe Bay area. The Prudhoe Bay oil and gas field in Arctic Alaska, discovered in 1968, is relatively small compared to a few fields in the Middle East (and perhaps in the U.S.S.R.) but it is the largest crude-oil deposit yet discovered in the United States or Canada, and one of the Continent's three or four largest natural-gas deposits.
The main reservoir at Prudhoe Bay (the "Sadlerochit" formation) began producing crude oil in commercial quantities when TAPS was completed in 1977. Current production is at the reservoir's maximum allowable offtake of 1.5 million barrels per day, about 18 percent of the total U.S. production of crude oil, and 15 percent of domestic petroleum liquids production.

Table 3
(thousands of barrels per day; percentage confidence intervals)

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Table 3 shows the range of likely crude-oil production figures from all North Slope fields through the year 2000. The "Kuparuk" and "Lisburne" formations in the Prudhoe Bay area and other discoveries nearby, at Point Thompson-Flaxman Island, Sag Delta-Duck Island, and Gwyrdyr Bay will probably contribute an additional one or two hundred thousand barrels per day by the time that production from
the Sadlerochit reservoir begins to fall off in the mid-to-late 1980's. Without very large additional discoveries, however, there is little chance that production from new fields on the North Slope will fully offset this decline.

Commercial production of natural gas from Prudhoe Bay awaits completion of the Alaska Highway gas pipeline ("Alaska Natural Gas Transportation System" or ANGTS), no sooner than 1986. Gas producers and pipeline sponsors are counting on the Sadlerochit formation to produce at least 2.7 billion cubic feet (bcf) of raw, unprocessed gas per day, the equivalent of about 2.0 bcf per day of pipeline-quality gas, for 20 to 25 years. There are no authoritative public estimates of potential production from the other known reservoirs and recent discoveries in or around the Prudhoe Bay field, but they might increase these figures by another 25 to 50 percent by the time the gas transportation system is in place.

The outlook for further discoveries. Alaska and its offshore margins contain the bulk of the remaining unexplored petroleum-producing prospects in the United States, and major additional oil and gas discoveries are inevitable. Some areas in and adjacent to Alaska are regarded as the most promising acreage for petroleum exploration under the American flag. Three examples of such Alaska areas are (1) portions of the Beaufort Sea where the State and Federal governments held an oil and gas lease sale in December 1979, (2) the St. George Shelf South of the Pribilof Islands in the Bering Sea, and (3) the Arctic National Wildlife Range (ANWR) in the extreme Northeast corner of Alaska.

On the basis of surface investigations and inferences from drilling elsewhere, geologists believe that each of these areas contains one or more geological structures capable of containing a "supergiant" oil and/or gas reservoir. (A supergiant is an oil field with recoverable crude oil reserves of one billion barrels or more, and a supergiant gas field is one with an equivalent amount of energy in the form of natural gas --- roughly 1.8 tcf.)
Supergiant oil and gas discoveries are rare and random events, however, and the probability that another field the size of Prudhoe Bay will be discovered in this century is very slim. Moreover, there is still no way short of drilling to find out for sure whether even the most promising structure identified from the surface contains petroleum rather than, say, salt water.

The location and current status of these three exploration prospects illustrate the problems of developing oil and gas production in frontier areas of Alaska generally. Many petroleum geologists consider the Beaufort Sea the nation's most promising exploration frontier. The first exploration well in the Beaufort Sea was "spudded" — i.e., began drilling — in November 1980, less than one year after the 1979 lease sale, and at least one major oil discovery has already been announced (in the Duck Island - Sagavanirktok Delta area).

Nevertheless, it is not reasonable to expect any commercial oil or gas production in less than 6 to 10 years. Local villages, whaling interests, and environmental groups have filed lawsuits against drilling on both State and Federal acreage, and the resulting possibilities for delay are substantial. Even after all legal and regulatory obstacles are overcome, the short shipping season, the horrible weather, and the need to develop new engineering techniques for finding oil and producing it from under ice-stressed seas will contribute to further delays.

The area of the 1979 Beaufort Sea lease sale is under shallow water within about a 200-kilometer radius of Prudhoe Bay and can rely to a large extent on the infrastructure created to serve Prudhoe Bay — particularly on TAPS and ANGTS, should exploration be successful. However, the St. George Shelf in the Bering Sea, where a Federal OCS lease sale is scheduled for 1982, is far from the mainland. Any exploration effort there must cope with much deeper water and high waves as well as different but equally inhospitable weather. And the petroleum industry has yet to establish staging areas or even the beginnings of an oil or gas
transportation system in the area. Finally, the State government itself is on record opposing petroleum exploration in the Bering Sea, along with some communities and local interests, fishermen, and conservationists.

The ANWR is in the extreme Northeast corner of Alaska. Its most promising acreage is on land or in shallow seas immediately offshore, and although this area is considerably farther from Prudhoe Bay, TAPS, and ANGTS than the 1979 Beaufort Sea leases, exploration in the ANWR would benefit considerably from existing North Slope infrastructure development. It would, in addition, draw directly on proved engineering techniques for Arctic tundra areas developed for Prudhoe Bay operations.

No leases are yet scheduled for ANWR, however, and preservation of the wilderness status of the Range is one of the highest political priorities of national conservation organizations. As a result, the 1980 Alaska Lands Act closed most of the ANWR to exploration, except for a strip along the Arctic Coast, and even that parcel requires a 5-year geological and geophysical study by the government, followed by Congressional action, before any leasing would be permitted.

Every other prospective oil and gas exploration frontier in Alaska differs somewhat from the three we have used as illustrations, but almost all of them hold comparable obstacles to development in the form of remoteness, climate, novel engineering or environmental challenges, lack of an existing infrastructure, and/or local, statewide or national opposition.

In summary, therefore, Alaska doubtless has a great deal of undiscovered petroleum, and petroleum exploration will be an important activity in and offshore Alaska for many decades. Apart from the known deposits in and adjacent to the Prudhoe Bay field and in Upper Cook Inlet, however, how much oil and gas will actually be discovered and produced in the State, where, and when, are complete mysteries. In no case can these unknown resources be a basis for projecting the State's fiscal outlook, its future
population and economic activity, or future investment in refining or petrochemical manufacturing.

Royalty oil and gas. Lease contracts covering the established production at Prudhoe Bay and most of the Cook Inlet fields reserve a one-eighth royalty interest in the oil and gas produced, which the State may at its option take either "in value" (cash) or "in kind" (as oil and gas). On many State leases not yet under production, including the Beaufort Sea lease area, the State's royalty share is one-sixth or more. Taking royalty oil or gas in kind, in order to sell it to an established or prospective in-state hydrocarbons processor, has been and will likely continue to be one of the State's tactics in attempting to encourage refining and petrochemicals investment.

Outer Continental Shelf (OCS) oil and gas leasing is under federal jurisdiction, however, and the State has neither a royalty share nor the right to levy taxes on OCS production.

Hydrocarbons Processing in Alaska.

Estimates of 1980 Alaska petroleum-products consumption by five different authorities range from 63 to 89 mb/d, of which about 28.5 mb/d appears to be jet fuel, (much of it destined for international airlines and the military, and thus not strictly an in-state use). The remaining direct Alaska consumption of motor fuels, heating oil, and electric utility fuel in Alaska was somewhere in the range of 35 to 60 mb/d --- the most likely figure is on the order of 45 mb/d. Nearly half of this total was imported from the Lower 48, much of it to Southeast and Western Alaska.

Fuels refineries. The remainder of Alaska's petroleum requirements are served by three in-state refineries, operated by the Standard Oil Company of California (Chevron) at Swanson River on the Kenai Peninsula, by Tesoro Alaskan at Nikiski (Kenai), and by Mapco (formerly Earth Resources Company of Alaska) at North Pole near Fairbanks. Together the three refineries have been running slightly more than
100 mb/d of crude oil and producing about 44 mb/d of refined products, principally fuels. The balance of their output is residual oil, which is shipped to the Lower-48 for further processing or for sale as electric-utility fuel.

The Chevron refinery was built in 1963, has a crude-oil distillation capacity of 22 mb/d, and refined an average of 13.5 mb/d in 1980. Chevron is currently considering shutting-down this small and relatively inefficient plant because of excess capacity in the company's larger West Coast facilities. The Tesoro refinery was built in 1966 expressly to run sweet (low-sulfur), light (high gasoline-content) crude oil, which it obtains from the State in a long-term sale of Cook Inlet royalty crude. Because of the decline in Cook Inlet production, the refinery has been modified to run a feedstock mixture that includes about 15 percent Prudhoe Bay crude oil, which has a higher sulfur content and lower "gravity" (less gasoline and more residual oil). The Tesoro plant's crude-oil distillation capacity is 48.5 mb/d, and it ran essentially at full capacity in 1980.

Both the Chevron and Tesoro refineries export about half their total product to the U.S. West Coast --- mainly residual oil and crude gasolines for blending --- and sell middle distillates (diesel, home heating oil, and jet fuel), gasoline (Tesoro) and asphalt (Chevron) in Alaska.

The North Pole refinery is less complex than Tesoro's, with a crude-oil processing capacity of 47 mb/d. In 1980 the refinery processed an average of 43 mb/d of crude oil taken from TAPS; the output consisted of 16 mb/d of middle distillates sold in Alaska and 27 mb/d of residual oil, LPG's, and crude gasoline reinjected into TAPS for processing by Lower-48 refiners.

The refinery proposed for Valdez by the Alaska Oil Company (Alpetco) to use Prudhoe Bay royalty oil would have been much more sophisticated than the existing Alaska plants in that it would have processed its entire crude-oil input of 100 mb/d into light fuels (including high-octane unleaded gasoline) and middle distillates. The refinery was
designed to produce virtually no residual oil to sell in today's shrinking market.

Facilities using Cook Inlet natural gas. Three major producing fields in the Cook Inlet area are the main support of Southcentral Alaska's natural-gas industry. The gas from these fields is "sweet" gas, gas that contains hardly any hydrogen sulfide, carbon dioxide, or condensate (essentially the same thing as NGL's --- hydrocarbons that are liquid under atmospheric conditions), and production operations are therefore relatively simple.

The North Cook Inlet field was discovered in 1962, but the absence of a market delayed its development for several years. Eventually, the Phillips Petroleum Company arranged to sell production from the field as liquefied natural gas (LNG) to two Japanese utilities. In 1967, Phillips bought out the other leaseholders and developed the field from a single platform. The gas is piped to shore through two undersea lines and then moves in a single line to the LNG plant at Nikiski, where it is cooled and liquefied. The LNG is then loaded into special "cryogenic" tankers, which ship the equivalent of 140 mmcf/d to Japan.

The Beluga River gas field is not yet completely developed. The gas in this field has been sold to an Anchorage-based electric utility, the Chugach Electric Association (CEA), which uses it to fire combustion turbines at Beluga on the west shore of Cook Inlet.

The Kenai field is a large gas field immediately south of Kenai along the west shore of Cook Inlet. Most of the field is onshore, on acreage owned by CIRI (Cook Inlet Region, Inc., a Native corporation) as the result of a land-swap with the State. Some of the gas from the Kenai unit is produced for sale to the Alaska Pipeline Company (APC) which carries it to the Anchorage gas utility, an affiliate of APC. The balance is piped to Kenai, where it is used to manufacture aqueous ammonia and urea fertilizer at a plant operated by the Collier Carbon and Chemical Company (a Union Oil Company subsidiary) on behalf of itself and Japan Gas Chemical Company. Some of the Kenai gas is liquefied
at the Phillips LNG plant, some is sold directly to the local gas utility in Kenai, and the remainder is sent to the Swanson River oil field where it is used to repressurize that field to improve oil recovery.

The Pac-Alaska LNG project is a plan by two West Coast utilities to liquefy Cook Inlet natural gas and ship it as LNG to a terminal and regasification plant in California. Actual construction of the project is now doubtful, because of (1) the sponsors' inability thus far to get sales commitments for the full volume of gas necessary to support the plant, (2) a protracted contest before several regulatory agencies --- now over, but succeeded by lawsuits --- over the California terminal site, and (3) a growing abundance of Lower-48 and Canadian gas that the California utilities can obtain directly by pipeline.

Residential consumers, industry, and electric utilities in the Anchorage-Cook Inlet region currently enjoy some of the lowest natural-gas prices in the United States. The average wellhead price in 1980 was about 27 cents per mcf compared to a national average of $1.61 per mcf, and a $4.91 border price for Canadian imports to the United States. The provisions of the present sales contracts would raise most Cook Inlet gas prices to whatever levels are paid by the Pac-Alaska LNG plant, if that project is actually built.

Prudhoe Bay Natural-Gas Reserves and ANGTS

The Alaska Department of Natural Resources (DNR) in 1980 estimated the proved natural-gas reserves of the Prudhoe Bay Sadlerochit reservoir at 29 tcf, with 4.5 to 7.8 tcf in other nearby reservoirs. Thus far, the natural gas dissolved in the crude oil withdrawn from the Sadlerochit reservoir is all being reinjected, except for a very small quantity used as local fuel. After a natural-gas pipeline is completed, the gas stream will then be stripped of water, carbon dioxide, and most of its natural-gas liquids (NGL's), and shipped through the pipeline to gas-transmission companies in the Lower 48.
ANGTS --- The Alaska natural gas transportation system. In 1977, the President and Congress awarded the Alcan Pipeline Company, a subsidiary of Northwest Energy Company, the right to build the Alaska segment of ANGTS, which will consist of a pipeline laid parallel to TAPS as far as Fairbanks, whence it would follow the Alaska Highway into Southern Alberta. There, the system branches into a "Western Leg" to California, and an "Eastern Leg" into the Midwestern States.

Alcan has now been succeeded by the Alaskan Northwest partnership; the Canadian sections would be built by a group of companies operating under the name Foothills. The Eastern Leg, known as the Northern Border system, is now under construction by a partnership headed by InterNorth (formerly Northern Natural Gas); the Western Leg is being built by a subsidiary of Pacific Gas and Electric Company.

The ANGTS sponsors plan to design the system for an initial throughput of 2.0 bcf per day, beginning in 1986; they have already received a number of important regulatory approvals in both the United States and Canada, including final authorization to "pre-build" the Southernmost sections designed to carry Canadian as well as Alaska natural gas. The 1977 presidential decision selecting ANGTS, however, has several provisions that effectively block financing of the rest of the more-than-$30 billion system. The pipeline sponsors, the Prudhoe Bay gas producers, and their respective financial advisors have asked Congress for waivers to some of these provisions, but the fate of this request is now (August, 1981) uncertain. Moreover, even the proposed waivers would not solve all of the system's organizational and financial difficulties, and it is unlikely that the impasse will be resolved soon enough that the pipeline can actually be built and completed on schedule.

The sales gas conditioning facility (SGCF). Natural gas from the Sadlerochit reservoir is relatively "sweet" and "wet" --- devoid of hydrogen sulfide, but saturated with NGL's --- and has a high carbon-dioxide (CO2) content (about 13 percent). A "sales-gas conditioning facility"
(SGCF) would reduce the level of CO$_2$ in the "sales gas" (natural gas shipped through ANGTS) to a level consistent with "pipeline quality" standards. Preliminary designs for the SGCF, prepared for the gas producers and the ANGTS sponsors, would use a physical (rather than chemical) process called Selexol to remove CO$_2$ from the raw gas.

The Selexol process separates the components of the produced-gas stream according to their different boiling points. Two-thirds of the ethane that enters the conditioning plant stays in the sales gas to be shipped out in the gas pipeline. Because the boiling point of ethane (C$_2$H$_6$) is close to that of CO$_2$, however, some of the ethane remains mixed with the CO$_2$ in a "waste gas", about half of which would be used as plant fuel and the remainder returned to the field for other local fuel uses. As the SGCF and nearby pumps, compressors, and heaters must use some fuel or another in large quantities, this arrangement may be an excellent one if there is no better use for this portion of the ethane.

Prudhoe Bay ethane, however, may be most valuable as raw material for an Alaska-based complex to produce ethylene and its derivatives. This would be the case if the ethane could be delivered to an appropriate plant site at an acceptable cost after it has been extracted during or after the conditioning process. The CO$_2$-removal process could affect the amount of ethane available for petrochemical use if the ethane is recovered downstream from the conditioning plant instead of upstream. Even if the ethane were extracted downstream, however, its volume would be more than sufficient to supply a single "worldscale" ethylene plant.

A natural gas liquids (NGL's) pipeline and Alaska petrochemicals production. Prudhoe Bay natural gas contains other NGL's in addition to ethane (C$_2$): propane (C$_3$), butanes (C$_4$), and pentanes-plus (C$_5^+$), each of which has several alternative uses. Propane can be used directly as home heating or industrial fuels in the form of "bottle-gas", while propane and butane may be used along with ethane to produce "olefins", such as ethylene, propylene, butylene, and
their derivatives. Butane may be used as the principal raw material for methyl tertiary butyl ether (MTBE) and other synthetic high-octane gasolines. The Exxon Chemical Company and the Dow-Shell group are independently studying the economic feasibility of NGL's-based petrochemicals production in Alaska.

The outlook for such a chemical industry is intimately intertwined with decisions concerning Prudhoe Bay hydrocarbons production and ANGTS. For example:

1. If ethane and heavier hydrocarbons are to be recovered in sufficient quantities at Prudhoe Bay to justify building an NGL's pipeline and ethylene plant, the SGCF design may have to be modified.

2. If ethane and the heavier hydrocarbons are recovered for use as chemical feedstocks, the energy content of the recovered NGL's and the hydrocarbons used for fuel in the ethane-extraction facility will not be available for transportation through the natural-gas pipeline and therefore might have an adverse impact on the economics of ANGTS.

3. Exxon and ARCO, owners of the bulk of the Prudhoe natural gas and NGL's, are major chemical producers, and they must either be interested themselves in building (or participating in) an NGL's line and an ethylene plant, or be willing to sell other parties like Dow-Shell sufficient volumes of NGL's to support both the NGL's pipeline and the petrochemical facility.

4. Whatever the resolution of these three issues, the feasibility of building and operating an NGL's line and an Alaska-based worldscale ethylene plant has yet to be demonstrated; their operation raises some additional questions. For example ---

5. A single worldscale ethylene plant would require only about 35 mb/d of ethane; some additional ethane could conceivably be sold as electric utility fuel in Interior and Southcentral Alaska, but the total
assured demand within Alaska would be considerably less than the volume of liquids (at least 150 mb/d) necessary to justify construction of a new pipeline.

As shipment of surplus ethane beyond Alaska would require cryogenic tankers similar to those used to move LNG, large volumes of propane and butanes (which must also be shipped under pressure or refrigeration, but require less sophisticated tankers than LNG) would have to be saleable in export markets in order to cover the pipeline cost, at least until two or more ethylene plants were operating in Alaska.

Finally, production of ethylene generates its own problems. Ethylene remains a gas unless it is chilled to -155°F (-104°C); sometimes it is shipped by sea on a small scale in cryogenic vessels similar to those used for LNG, but costs probably rule out this strategy for a worldscale Alaska facility. The chemical companies that have expressed interest in producing ethylene from ethane in Alaska therefore contemplate processing the ethylene further into compounds such as polyethylene, ethylene glycol, or styrene, which are solids or liquids under normal atmospheric conditions and hence are easier to transport.
CHAPTER 3
FUNDAMENTALS OF HYDROCARBONS CHEMISTRY

General Introduction.

Fuels refining and petrochemicals manufacturing are both hydrocarbons-processing industries. They begin with mixtures of hydrocarbons from crude oil or natural gas as raw materials, separate them into components, and alter the molecules in various ways to produce a range of products for final consumers or for use as inputs to other industries.

The refining and petrochemical industries overlap technically, using many of the same processes and intermediate products. The chief distinction between them is in their respective "product slates". The greatest part of refinery output is made up of liquid hydrocarbon mixtures, along with certain solid byproducts of fuels refining, such as asphalt or petroleum coke. While some refinery products are sold for use as lubricants, solvents, or raw materials for the petrochemical industry, the main business of the refining sector is fuels production.

Petrochemicals manufacturing includes practically any hydrocarbons-processing operation whose principal output is not liquid hydrocarbon fuels. Petrochemical products may be liquid, gaseous, or solid: they include synthetic fibers, plastic, paints and varnishes, resins, food additives, medicines, industrial reagents, and much more.

Composition of Natural Hydrocarbons.

Natural hydrocarbons are complex mixtures of carbon and hydrogen that are usually found underground in combination with impurities such as water, sulphur, and carbon dioxide. Conventionally, hydrocarbons are grouped according to the number (n) of carbon atoms (C_n) in each molecule. However, the variations of hydrocarbon mixtures are vast and every accumulation of oil and gas is unique.

Table 4 lists the names of some simpler, smaller-molecule hydrocarbons found in crude-oil and natural-gas reservoirs, and alludes to the existence of others with dozens of carbon atoms in each molecule.
Table 4
Elementary Hydrocarbon Compounds

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<th>Compound</th>
<th>Chemical Formula</th>
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<td>CH₄</td>
<td>Natural gas.</td>
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<td>ethane</td>
<td>C₂H₆</td>
<td>Natural-gas liquids (NGL's) or condensate.</td>
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<tr>
<td>propane</td>
<td>C₃H₈</td>
<td>Pentanes-plus, natural gas-lines, or naphtha.</td>
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<tr>
<td>butane</td>
<td>C₄H₁₀</td>
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</tr>
<tr>
<td>pentane</td>
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<td>hexane</td>
<td>C₆H₁₄</td>
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<tr>
<td>heptane</td>
<td>C₇H₁₆</td>
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<tr>
<td>octane</td>
<td>C₈H₁₈</td>
<td></td>
</tr>
<tr>
<td>etc.</td>
<td>C₁₀₀H₂₀₀⁺</td>
<td>Oils, waxes, tars, bitumen, asphalt.</td>
</tr>
</tbody>
</table>

The lightest and most stable hydrocarbon is methane (CH₄), the chief component of natural gas and a building block for other hydrocarbons. Methane and ethane (C₂H₆) are usually transported from the field in gaseous form and sold to long-line gas transmission companies, which in turn sell them to local gas distribution companies, most of whose customers use gas directly as fuel without further processing. The methane of natural gas is, however, also frequently used as a feedstock to make synthesis gas for processing into methanol, ammonia, urea, amines, and their derivatives.

The bulk of the natural-gas liquids (NGLs), which may or may not include the produced ethane, is usually separated in the field and sold for fuel use as LPG (liquefied petroleum gas) or as feedstocks for petrochemical manufacturing.

The term "crude oil" usually refers to the heavier hydrocarbon fractions, composed of molecules with five or
more carbon atoms. Crude oils are very complex mixtures with many thousands of individual hydrocarbon compounds, and range in consistency from natural gasolines to viscous, semi-solid materials such as the bituminous tar sands of Northern Alberta.

Each hydrocarbon compound in crude oil has its own boiling temperature, with the heavier compounds (those having a greater number of carbon atoms in each molecule) boiling at higher temperatures and the lighter compounds boiling at lower temperatures. Table 5 illustrates the relationship between hydrocarbon boiling points and weights.

<table>
<thead>
<tr>
<th>Compound</th>
<th>Formula</th>
<th>Boiling Temperature</th>
<th>Pounds/Gallon</th>
</tr>
</thead>
<tbody>
<tr>
<td>Propane</td>
<td>C₃H₈</td>
<td>-44°F</td>
<td>4.2</td>
</tr>
<tr>
<td>n-Butane</td>
<td>C₄H₁₀</td>
<td>31°F</td>
<td>4.9</td>
</tr>
<tr>
<td>n-Decane</td>
<td>C₁₀H₂₂</td>
<td>345°F</td>
<td>6.1</td>
</tr>
</tbody>
</table>

Every crude oil contains a distinctive mixture of hydrocarbon compounds, ranging from very light mixtures with about 75 percent of the hydrocarbons in the gasoline/naphtha range (C₅ to C₁₀) to heavy oils that are solid or nearly solid at atmospheric temperatures.

Crude oils also contain small amounts of sulfur, nitrogen, heavy metals, and other contaminants. The percentage of sulfur varies from as low as 0.03 percent in some crude oils from Bolivia and Argentina, to as high as 7.3 percent in oil from the Qayarah field in Iraq. Alaska's Cook Inlet crude, with 0.1 percent sulfur, are regarded as "sweet," or very low-sulfur supplies. Other important sources of low-sulfur crude oil are Alberta, Indonesia, Nigeria, and Libya. Prudhoe Bay Sadlerochit crude oil, with about 1.0 percent sulfur, is described as medium-sulphur or intermediate-sweet. Quayarah crude oil is considered extremely "sour".
(Strictly speaking, only crude oils containing free hydrogen sulfide (H₂S) should be called sour, but the term is commonly used to refer to the presence in significant quantities of any compound containing sulfur.)

Chemistry.

The mixture of hydrocarbon compounds and the kind and amount of impurities in a crude oil generally determine its yield of gasoline, distillate fuels, lubricating oils, and petrochemical feedstocks. To obtain these products, refineries and petrochemical plants subject the hydrocarbon mixtures to a number of processes that separate the compounds into fractions or "cuts", remove the impurities, recombine or convert the hydrocarbons into other forms, and blend them into products for sale or further manufacturing. Equipment for altering the chemical structure of hydrocarbons varies, however, among different refineries and petrochemical plants, and will thus yield different product slates even from the same crude oil.

The differing chemical composition of various natural hydrocarbon supplies is reflected in different refining and processing techniques, differences in product quality, and in the manufacture of a wide range of different petroleum fuels, chemicals, and synthetic products. The chemistry of hydrocarbons is, therefore, an essential prelude to our discussion of fuels refining and petrochemical manufacturing.

Paraffins. Paraffins (also known as "alkanes") represent a large proportion of the hydrocarbons present in crude oil. The paraffin series is composed of "normal" compounds having straight chains of linked carbon atoms, and their corresponding "isomers" (or "iso-alkanes") --- compounds with the same numbers of carbon and hydrogen atoms, but with branched-chain molecules. Both have the general formula CₙH₂ₙ₊₂; the names of individual hydrocarbons in the series end with "-ane". Methane and ethane are the simplest paraffins, having the following structures:
Hydrocarbons containing more than three atoms of carbon in each molecule may form "isomeric," branched-chain forms. Contrast, for example, "normal" (n-) butane and "iso-" (i-) butane:

Butane has only these two isomers. As the number of carbon atoms increases, however, the number of possible
structural combinations increases geometrically. For instance, pentane \((C_5H_{12})\) has three isomers, nonane \((C_9H_{20})\) has 35, and dodecane \((C_{12}H_{26})\) has 355.

Although a paraffin and its isomers have the same number of atoms, they boil at different temperatures, have different specific gravities, and participate in different chemical reactions.

**Naphthenes.** Naphthenes are hydrocarbons with more than four carbon atoms arranged in ring-like central structures rather than straight or branched chains, and have the general formula \(C_nH_{2n}\). (For simplicity, we have omitted the H symbols in the following schematic diagrams.)

![Diagram of cyclopentane and cyclohexane]

At least one five- or six-membered ring is present in every naphthene. Cyclopentane and cyclohexane are the only hydrocarbons in the series that occur in nature. The more complex members of the series consist of one or more central rings, with one or more paraffin-like branches ("alkyl" groups) attached to them. The number of compounds which, in the course of refining processes, may attach in different combinations to the outside of the ring can be very large, however. One such compound is methyl cyclopentane:
Aromatics. The simplest member of the aromatic series and the building block for all other aromatics is benzene, composed of a six carbon-atom ring like cyclohexane, but with only six associated hydrogen atoms, and with three single and three double bonds alternating between the carbon atoms in the ring:

\[
\begin{array}{c}
\text{C} \\
\text{C - C} \\
\text{C - CH}_3 \\
\end{array}
\]

Benzene (C\textsubscript{6}H\textsubscript{6})

The aromatics include all compounds whose molecules contain at least one benzene ring. Some such compounds are formed by substituting paraffin units for one or more of the hydrogen atoms in the benzene molecule. These hydrocarbons are called alkyl benzenes; one example is toluene. Other compounds, like naphthalene, contain more than one benzene ring:
The substitution of double carbon bonds for hydrogen bonds is easy to understand if one remembers that each carbon atom in a larger molecule almost always has four links or bonds with other atoms. If hydrogen atoms are removed from a hydrocarbon molecule, the carbon bonds that are left empty tend to link with one another to create double bonds. The double bonds in the benzene ring are very unstable and chemically reactive, however, and thus the members of the alkyl benzene series are important building blocks for refined petroleum products and petrochemicals.

**Olefins.** The olefins are not found in crude oil, but are manufactured from oil, natural gas, or NGL's by one of several cracking processes. They resemble paraffins and naphthenes in structure, but like aromatics they have double (and sometimes triple) bonds between carbon atoms.

The double and triple bonds are deceiving because, contrary to appearances, these bonds are weaker than a single bond, making the compound unstable. If every carbon bond were linked to an atom of hydrogen (or some other element), the hydrocarbon would be "saturated" and therefore relatively stable. Olefins and aromatics are said to be "unsaturated" because they contain double or triple bonds.
The unsaturated hydrocarbons are valuable to the chemical industry precisely because they readily react directly with other chemicals to form more complex compounds. For instance, the olefin ethylene (C$_2$H$_4$) reacts with chlorine to form vinyl chloride monomer, (VCM), which in turn is used to produce polyvinylchloride (PVC) resin used for the manufacture of plastics.
CHAPTER 4
FUELS REFINING

The main business of the refining sector is fuels production. The manufacture of refined fuels begins with natural hydrocarbon compounds and separates them by distillation, tears them down, and rebuilds and restructures their molecules into produce saleable products. Before the 1900's, a typical refinery just distilled the crude oil into a series of "cuts" or fractions, which were sold as straight-run fuels. Today, almost all petroleum products are specially tailored in their physical and chemical properties and freedom from impurities to meet exacting market demands, thus requiring treatment that extends far beyond simple distillation.

Petroleum Industry Structure.

The refining sector is an integral part of a petroleum industry made up of thousands of companies that are exceedingly varied in size, functions, geographical sphere of operations, and structure.

The major oil companies. "Big Oil" consists of seven, twelve, sixteen, or twenty "major" or "multinational" corporations, depending upon the statistical authority. However many "Sisters" one chooses to count, the major oil companies are distinguished by both their great size and their vertical integration: They produce crude oil; own crude-oil and petroleum-product pipelines, tankers, and barges; refineries; tank farms and terminals; and operate retail outlets. Many of the majors are engaged in other related businesses, such as natural-gas production and processing, and petrochemicals manufacturing. These major companies vary greatly in size, and no two of them have the same mix of functions; some majors are net sellers and others net buyers of crude oil; some are net sellers of refined products at wholesale and others net buyers, and in many different degrees.

In 1979, the top 16 integrated companies produced about 60 percent of U.S. crude-oil output and accounted for about 12 million barrels per day (mmb/d) of refining capacity, or about two-thirds of the national total. The same
companies also marketed about two-thirds of the refined products sold in the United States.

The independents. A significant part of the business in each sector of the petroleum industry is conducted, however, by "independents" --- specialized or only partially-integrated firms that compete both with the majors and with one another. There are independent exploration companies and producers; independent oilfield service companies and gathering companies, independent oil-pipeline and tanker-transportation companies, independent refiners, resellers, and brokers; jobbers, marketers, and retailers.

The independent sector is deeply rooted in U.S. oil-industry history. From its earliest days, the production of crude oil in the United States was widely dispersed among many producing companies, largely because oil was discovered in fields of many sizes located on privately-owned tracts where farmers, ranchers, and other owners held the subsoil mineral rights as well as the surface estate. Although the top 20 integrated oil companies have acquired control of about two-thirds of the crude-oil output in the United States and three-fourths of the reserves, many fields have several operators and royalty owners. Data from Windfall Profits Tax collections reveal that the United States has literally tens of thousands of crude-oil producers and about two million royalty owners.

The majority of oil-field discoveries onshore in the Lower-48 appear to have been made by independent "wildcat" exploration companies, and they continue to contribute a smaller yet significant portion (about one-third) of the new crude-oil reserves added annually. Because their cost structures and exploration strategies differ from those of the majors, there is a tendency for independent explorationists to sell their discoveries to major producers, while the majors often sell off nearly depleted fields and high-cost "stripper-well" (wells producing less than 10 barrels per day production) properties to specialized independents.

The situation is somewhat different on the Outer Continental Shelf (OCS) and Alaska. There, the ownership
of prospective petroleum acreage is concentrated in the Federal and State governments, and lease tracts are much larger than the typical southwestern U.S. farm property. In these areas, the high costs of exploration tend to restrict activity to the major companies and joint ventures of the larger independents. Even so, OCS and Alaska State lease auctions typically attract 10 to 50 different bidding combinations, representing dozens of separate companies.

About 6 mmb/d or 34 percent of the total U.S. refining capacity were owned by non-integrated refining companies in 1979. As one might expect, the independent refiners depend far more heavily on crude oil from independent producers than do the refining divisions of the major companies. In retailing, the majors tend to sell their own refined products, or refined products exchanged with other majors, under their respective brands, while independent marketers buy their products at wholesale from major companies, independent refiners, and resellers.

Feedstocks and Petroleum Products

Within rather narrow limits, the characteristics of a refinery's crude-oil supply and its initial design determine the possible mix of its refined product output. Refineries are planned, therefore, to match their product slates as closely as possible to the mix of product demand in the areas the refinery serves. North American refineries, for example, have been generally designed to emphasize gasoline production, and secondarily, that of "middle distillates" (heating oil, diesel fuel, and jet fuel), at the expense of heavy fuel oils.

Closer to home, Chevron's Kenai refinery processes crude oil to serve local markets for jet fuel, diesel fuel, and home heating oil. Mapco's North Pole refinery near Fairbanks cuts the "tops and bottoms" (the lightest and heaviest fractions) out of the crude oil, in order to sell the middle distillates, and the Tesoro refinery produces gasoline and middle distillates. Each of them, however, exports a large part of each barrel to other states in the form of residual oil, for which there is no significant demand in Alaska. Had
it been built, Charter's proposed Alaska Oil Company refinery at Valdez would have been the state's first "complex" refinery, capable of processing all the residual oil from the distillation tower into lighter refined products.

Refinery design also reflects the grade and quality of crude oil to be processed. Refinery complexity, fixed costs, and operating costs depend principally upon the match or mismatch between feedstock characteristics and the products to be produced. Thus, light (high-gasoline) and sweet (low-sulfur) crude oils have long been preferred refinery feedstocks in North America, where motor fuels have been a relatively large part of total petroleum demand and where air quality has been a major concern. Fortunately, the grade and quality of North American crude oils (other than in California) have tended to be well matched to domestic product slates.

**Feedstock characteristics.** The characteristics of different crude oils determine, to a large extent, the refinery processes needed to make a particular product slate. Each crude oil is unique, yielding different amounts of and different mixtures of compounds within each fraction. These characteristics are ascertained by means of a **crude-oil assay** involving controlled fractionation in the laboratory and the chemical analysis of each fraction. The assay results typically describe a crude oil in terms of the proportion of its total weight falling into each straight-run fraction, and its density, sulfur content, viscosity, pour point, metal content, and often the proportion of straight-line paraffins, branched-chain paraffins, naphthenes, and aromatics.

**Density** is the ratio between the weight of a substance and its volume, for example, kilograms per liter or pounds per barrel. For crude oil, density serves as an index of the relative proportions of the different hydrocarbon fractions, with the compounds that contain the largest number of carbon atoms per molecule having the greatest density, and the smaller-molecule LPG's and natural gasolines the least. The density measure is also affected by the proportions of
the four major hydrocarbon types, as the individual densities of compounds with a given number of carbon atoms per molecule is greatest for the aromatics. Naphthenes, isoparaffins, and normal paraffins have progressively lower densities.

A low-density crude oil can yield more than half of its weight in light distillates (straight-run LPG's, gasoline, kerosene, and naphtha), while there are high-density California crudes in which these lighter fractions comprise as little as 6 percent of total weight. Alaska North Slope (Sadlerochit) crude oil is somewhere in the middle with about 30 percent light distillates. Density can be measured in terms of specific gravity (the ratio of the weight of a given volume of a substance to that of an equal volume of water), but the petroleum industry generally prefers to use "API gravity", a measure denominated in degrees in which lighter or low-density crude oil is referred to as having a "high API gravity", in a confusing violation of the layman's common intuition. A high-density crude oil is similarly referred to as having a "low API gravity." Some heavy California crudes have API gravities in the $10^\circ$ to $16^\circ$ range; Prudhoe Bay crude oil has an API gravity of $27^\circ$; and "light" crude oils from Cook Inlet have API gravities as high as $41^\circ$.

The total sulfur content of a crude oil is measured in terms of its proportion of sulfur(s) in the total weight of the crude oil, and thus the volume of sulfur compounds likely to be present in the products refined. Because sulfur atoms have an affinity for the heavier hydrocarbon molecules, the heavier crude oils generally (but not always) tend to have a higher sulfur content. Cook Inlet, Alberta, and Nigerian crude oils tend to be have a relatively low sulfur content of less than 0.3 percent; Prudhoe Bay crude oil is regarded as a medium-sulfur product at about 1 percent, while some "sour" California crudes contain more than 3 percent sulfur.

Since 80 to 90 percent of the sulfur typically remains in the "residuum", (the substance that remains in the bottom of the refinery fractionally lower after the lighter products have boiled off), the acceptability of heavy fuel oils under
prevailing air-quality standards depends chiefly on the sulfur content of the crude oil. High-sulfur crudes tend to leave impermissible amounts of corrosive and polluting sulfur compounds in the middle distillate as well, requiring costly hydrotreating before the products can be marketed. Processing high-sulfur crude oils also requires special catalysts and more sophisticated refinery metallurgy, meaning that a high sulfur content in the refinery feedstock makes it considerably more costly to convert into a given slate of refined products.

Generally speaking, crude-oil types and qualities are categorized as follows:

<table>
<thead>
<tr>
<th>Sulfur by Weight</th>
<th>Less than 15%</th>
<th>More than 15%</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 0.5%</td>
<td>light low-sulfur</td>
<td>heavy low-sulfur</td>
</tr>
<tr>
<td>0.5% to 1.0%</td>
<td>light medium-sulfur</td>
<td>heavy medium-sulfur</td>
</tr>
<tr>
<td>more than 1.0%</td>
<td>light high-sulfur</td>
<td>heavy high-sulfur</td>
</tr>
</tbody>
</table>

**Viscosity, pour point, and wax content** indicate how easily crude oil will flow through pipelines and into or out of tanks and tankers, and the degree to which solid deposits are likely to build up on pipeline or storage-tank walls. All of them are, therefore, crucial variables in designing pipelines and storage facilities. **Pour point** is the lowest temperature at which oil will pour or flow in response to gravity, under standard conditions. Examples of pour points are:

- Bonny Light (Nigeria) +50° F
- Prudhoe Bay Sadlerochit -50°
- Saudi Arabian Light -30°

**Viscosity** is a measure of the resistance to flow in a liquid at a given temperature and pressure, and increases as
the temperature increases. A high wax-content crude oil like Indonesian Minas crude tends to clog pipelines, so that they have to be "pigged" (scraped out by a special device sent through the line) frequently.

In addition to these characteristics, there are other features of crude oil that affect its product yield and cost of refining. The most important of these characteristics are the relative proportions of paraffinic and naphthenic hydrocarbons, and the metals content.

**Refinery Products.**

Refined products include a full spectrum of intermediate and consumer products:

**First-stage products.** Distilling crude oil into fractions is the first step in all petroleum-refining operations. This process yields a set of straight-run "cuts" or product mixes that are the intermediate building blocks for refined products. These fractions are characterized by their boiling ranges --- the hydrocarbons with the lowest boiling points being the lightest compounds.

Table 6 illustrates the relationships among cut points, straight-run fractions, and refinery end-products. Each of the various end products is composed of hydrocarbons having a rather broad range of boiling points, while different end products have boiling ranges that overlap. As a result, refiners are able to vary the proportions of different products made at a given refinery by varying the temperatures or cut-points. For example, adjusting refinery operations to raise the cut-point temperature at which straight-run gasolines are separated from naphtha means that (1) less gasoline and more naphtha will be produced (perhaps for use as military jet fuel), and (2) the produced gasoline and naphtha will both be lighter than before.

Distillation of two different crude-oil types in identical refinery facilities will, moreover, yield gasoline of different octane ratings and a light gas-oil fraction of different cetane ratings (a measure of diesel-fuel quality comparable to octane ratings for gasoline). Thus, the amount of
<table>
<thead>
<tr>
<th>Hydrocarbon type</th>
<th>Temperature cut-points</th>
<th>Distillation products</th>
<th>End-products</th>
</tr>
</thead>
<tbody>
<tr>
<td>C 1</td>
<td></td>
<td>methane</td>
<td>Natural gas</td>
</tr>
<tr>
<td>C 2</td>
<td>less than 1000 °F</td>
<td>LPG</td>
<td>LPG</td>
</tr>
<tr>
<td>C 3</td>
<td>1000 °F</td>
<td>LPG</td>
<td>Motor gasoline</td>
</tr>
<tr>
<td>C 4</td>
<td>100</td>
<td>Gasoline</td>
<td>Military jet fuel</td>
</tr>
<tr>
<td>C 5</td>
<td>150</td>
<td>Naphtha</td>
<td>Chemical feedstock</td>
</tr>
<tr>
<td>through</td>
<td>200</td>
<td>Light gas</td>
<td>Military jet fuel</td>
</tr>
<tr>
<td>C 10</td>
<td>250</td>
<td>Naphtha</td>
<td>Civilian jet fuel</td>
</tr>
<tr>
<td>C 10+</td>
<td>300</td>
<td>Kerosene</td>
<td>No. 1 diesel &amp; stove oil</td>
</tr>
<tr>
<td></td>
<td>400</td>
<td>Light gas</td>
<td>No. 2 diesel &amp; stove oil</td>
</tr>
<tr>
<td></td>
<td>450</td>
<td>Gas oil</td>
<td>No. 4 turbine fuel</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>Heavy gas</td>
<td>Gas-oil petrochemical feedstock</td>
</tr>
<tr>
<td></td>
<td>550</td>
<td>Gas oil</td>
<td>No. 4</td>
</tr>
<tr>
<td></td>
<td>600</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>650</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>700</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>750</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>800</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>850</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>900</td>
<td></td>
<td>Residual fuel oil</td>
</tr>
<tr>
<td></td>
<td>950</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1000</td>
<td></td>
<td>Bunker &quot;C&quot;</td>
</tr>
<tr>
<td></td>
<td>more than 1000 °F</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1000 °F</td>
<td>Coke</td>
<td>Asphalt</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Petroleum coke</td>
</tr>
</tbody>
</table>
reforming and other processing required to turn different crudes into marketable products varies widely.

**End products.** Refinery end-products can be grouped as follows:

**Motor gasoline.** At one time, light naphtha fractions direct from the distillation tower were sold as straight-run gasoline; however, today's cars would run very poorly on such fuels. Refiners have altered the composition of gasoline considerably by means of reforming, blending, and compounding with additives, in order to control premature ignition and detonation ("knocking"), vapor pressure, gum formation in the engine, odor, and overall performance.

For several decades, refiners have produced and marketed at least two octane levels of leaded gasoline (regular and premium). Since the early 1970's, changes in automobile design intended to reduce air pollution have forced refiners to offer, in addition, at least one grade of unleaded gasoline; the sale of premium leaded gasoline is now being phased out with the decline in the number of cars that require it. These changes in gasoline requirements result in more complex and expensive refining operations and reduce the amount of gasoline that can be obtained from a barrel of oil.

**Diesel fuel.** Refineries manufacture diesel fuel for high-speed stationary, highway and marine diesel engines from the middle-distillate fractions of the crude oil. Fuel-quality requirements depend largely on engine rotational speeds. Fuel for high-speed diesel engines is made from the lighter portions of the distillate cut, and overlaps to some extent with kerosene.

Engines used for electrical generation or marine propulsion run at lower rotational speeds than automotive engines and will accept a lower quality fuel. A marine diesel fuel, therefore, often consists of a blend of distillates and heavy gas oil.

Like motor gasoline, distillate diesel fuels for use in automotive engines have improved during the past several years to meet requirements imposed by changes in engine design and operation. The most significant change in diesel
fuels has been the use of hydrogen treating in refineries, primarily to reduce sulfur content. Fuels have also been improved to decrease engine deposits and reduce smoke and odor. The use of additives in diesel fuels has become common for the purpose of lowering "pour points" (insuring that the fuel continues to flow at low temperatures), increasing stability in storage, and improving the ease of ignition.

**Aviation fuel.** Aircraft fuels are of two quite different kinds: aviation gasoline ("Avgas") for piston-engined craft, and jet fuels for use in turbine engines. Aviation gasoline generally requires higher antiknock ratings than motor gasoline and, because of the greater range of atmospheric pressures and temperatures, more exacting vapor-pressure standards.

A satisfactory turbine fuel must ignite easily and burn cleanly; and because jet fuels are exposed to very high and low temperatures in use, they must therefore have low freezing points and at the same time be stable at high temperatures. These qualities are less demanding on refinery design and operation, however, than those that are critical in fuels for internal-combustion engines. As a result, marketable jet fuels can be produced even in relatively simple refineries, like Mapco's North Pole plant, and tend to be cheaper to manufacture than the same amount of energy in the form of Avgas.

An alternative jet fuel used mainly by the military is known as "wide-cut" gasoline and is, as its name suggests, a product blended from straight-run fractions ranging from the light naphthas to heavy gas oil (but mainly the former). This fuel, known as "aviation turbine gasoline" or JP-4, is easily manufactured, and because of its wide cut, refiners can obtain a high yield from each barrel of crude oil.

**Gas and LPG (liquefied petroleum gas).** Various refining processes liberate considerable volumes of gaseous hydrocarbons (methane, ethane, propane and butanes). These gases are typically used as fuel within the refinery itself. Refinery gases, particularly methane and ethane, are also important feedstocks for the manufacture of petro-
chemicals, including methanol, ammonia, ethylene and their derivatives. Butane and isobutane are blended directly into motor gasoline to increase its vapor pressure and, hence, to assure that it will ignite.

The butanes and propane ("liquefied petroleum gases" or LPG) released during refining also become feedstocks for certain intermediate processes in the manufacture of motor gasoline and additives like MTBE (methyl tertiary butyl ether), which raise the octane rating of gasoline. Under moderate pressure propane remains liquid at ambient temperatures, and can therefore be marketed safely as "bottle gas" for space heating and cooking. Gas utilities also mix propane and butane with air to form an additive or substitute for natural gas during peak-demand periods, and there are a large number of industrial uses for propane, including metal cutting and welding using oxy-propane torches, and as process fuels.

**Distillate fuel oil.** Distillate fuel oil includes the Nos. 1, 2, and 4 heating oils; and the term is often used to include diesel fuels as well, which are almost identical to distillate heating oils. No. 1 stove oil is the lightest of the distillates and, because it remains liquid and ignites readily at very low temperatures, is the main home-heating fuel in Alaska's interior. No. 2 heating oil is the most common home and commercial heating oil nationally and worldwide. The price of No. 2 fuel oil is a frequently used indicator of petroleum-product costs.

Since World War II, refiners have improved the quality of distillate heating oils by removing sulfur and nitrogen through hydrogen treating and reducing the quantity of ash or other deposits left when the fuel is burned. Just as they do for gasoline and diesel fuels, refiners adjust the hydrocarbon blend in each grade of distillate heating oil to match the particular season and location.

**Residual fuels.** Residual fuels are made from the heaviest hydrocarbon fractions and are commonly marketed as Nos. 5 and 6 heating oils, heavy diesel, heavy industrial, and Bunker C fuel oils. Residual fuel oil has a higher energy content per unit of volume (e.g., per gallon) than other
petroleum fuels, but it must be heated before it will flow through a pipe or burn in a furnace or turbine. Typically, therefore, these fuels are used to provide steam and heat for industry and large buildings, to generate electricity, and to power marine engines.

Residual fuel oil is therefore competitive with natural gas and coal as in industrial and electric utility fuel markets. While there are serious regulatory obstacles to using either gas or coal as an electric utility and industrial boiler fuel, the rapid runup in crude-oil prices since 1973 has tended to make residual oil more valuable as intermediate products for the manufacture of gasoline and distillate fuel oils. Relative prices therefore increasingly favor (1) substitution of coal, natural gas, and nuclear energy for residual oil as industrial fuel and, (2) petroleum-industry investment in new crackers and cokers to break up the residuum into lighter hydrocarbon mixtures that can be processed and sold for higher prices.

**Lubricants.** Lubricants are a diverse group of specially-blended products falling into three general categories: automotive oils, industrial oils, and greases. Engine oils, gear oil, and automatic transmission fluids are three major lubrication products used in automotive operations. These products function to lubricate, seal, cool, clean, protect, and cushion metal parts. Industrial oils are blended to perform a variety of functions, including lubrication, friction modification, heat transfer, dispersancy, and rust-prevention. Greases are basically gels and are composed of lubricating oil in a semi-rigid network of gelling agents such as soaps or clays.

**Petroleum solvents.** Although they represent a much smaller market than, say, motor fuels, petroleum solvents are made in many grades for a variety of uses. Solvents are a major component of paint thinner, printing inks, polishes, adhesives and insecticides, and are used for dry cleaning. The manufacture of these products requires careful refining to remove unwanted odors and maintain consistent product quality.
Asphalt. The heaviest fractions of many crude oils include natural bitumens or asphaltenes and are generally called asphalt. Long before its use as a fuel, petroleum was valued for its asphalt, which has been used throughout recorded history. Because of its adhesive, plastic nature and waterproofing qualities, it is widely used for road-making.

Product mix. Individual refineries have considerable discretion in the product slates they produce, even from a single mix of crude-oil feedstocks. For this reason, it is important to understand the factors that influence product-slate decisions; these factors include -- in no particular order of logic --

* Feedstock assay and straight-run fraction mix.
* Crude-oil supply conditions.
* Refined product market conditions.
* Refinery flexibility regarding product slate.
* Refinery flexibility regarding feedstock mix.
* Refinery size and affiliation.
* Finished-product specifications.

Feedstock assay and straight-run fraction mix. The discussion of first-stage products has already shown that the hydrocarbon composition of crude oil determines the volumes of different straight-run fractions into which the crude oil can be separated by simple distillation.

Crude-oil supply conditions also influence refinery design and product slates. For example, Mapco's refinery at North Pole runs medium-gravity (API 270) Prudhoe Bay crude oil into a simple atmospheric distillation facility. The straight-run gasoline distilled from this crude oil is not suitable for automotive use, but the straight-run naphtha and light gas oil can be blended to make marketable jet fuel, diesel oil, and home-heating oil. The lightest products, the heavy gas oil, and the residual oil are mixed with the remaining Prudhoe Bay crude oil flowing through (TAPS) and delivered to more complex refineries in the Lower 48 that can process these hydrocarbons into marketable products.
Elsewhere, a refinery like the North Pole plant would probably have a hydrocracker to convert most of the heavy gas oils coming from the fractionating tower into gasoline or middle distillates. But in Fairbanks, the processing and marketing of the heavy gas-oil fraction would leave the remaining residual oil with an API gravity lower than the 70° minimum established by the Alyeska Pipeline Service Company for shipments through TAPS. Thus, if Mapco wanted to convert more of its Prudhoe Bay feedstocks into products that are saleable in Alaska, it must either (1) process all of the gas-oil and residual-oil fractions into lighter products at a very high cost, or (2) develop currently nonexistent local markets for naphtha and heavy fuel oils.

**Refined-product market conditions** play a crucial role in determining product slates. A given volume of petroleum is generally cheaper to ship long distances in the form of crude oil than as a diverse and varying assortment of refined products. For this reason, transportation economics normally lead refineries to locate near their product markets and each refinery, in turn, is normally designed to produce a product slate that corresponds to local demand.

The mix of petroleum-product demand tends to vary geographically according to a region's climate, level of economic development, industrial character, and supply of competing fuels. U.S. West Coast refineries have been designed largely to produce transportation fuels such as motor gasoline and jet fuels, because of (1) the region's mild climate, (2) the mobility of its population, and (3) relatively abundant regional supplies of natural gas and hydroelectric energy. In the Northeast, on the other hand, climate, lifestyles, and energy costs combine to encourage relatively greater dependence upon heavy fuel oils. The design of refineries in the two regions reflects these differences in demand mix.

Product demand also varies seasonally. Gasoline consumption typically peaks in the summer, but winter is the peak season for home heating oil. Refineries are usually designed with only enough flexibility to accommodate a part of this seasonal swing in demand, because increasing the
product-slate flexibility beyond a certain level comes only at increasing costs. For this reason, the seasonal supply strategy of major refiners also involves "winterfill" and "summerfill" --- putting the products into storage for sale when the demand pattern reverses itself.

Different types of fuels require differing degrees of precision in their product specifications. The performance of industrial and electric-utility boiler fuels, for example, is relatively insensitive to the exact character or size of hydrocarbon molecules burned. Product specifications for middle distillates --- stove oil, diesel fuel, and jet fuels --- focus on easy ignition, clean burning, pour points and vapor pressures. The demands these specifications make on refinery design and operation are rather moderate, because there is a broad range of straight-run hydrocarbon blends that are able to meet the requirements for any of these fuels. Motor gasolines, however, have to be more closely controlled with respect to molecular structure and impurities in order to assure ignition and to avoid vapor lock, knocking, and unacceptable engine wear.

Aviation gasolines must meet the most severe product specifications of any petroleum fuel, both because of the extreme combustion conditions encountered in high-performance piston engines and the potentially disastrous consequences of engine failure. It is probably the risk of legal liability from alleged quality shortcomings that has so far deterred any Alaska refiner from producing Avgas for local consumption, despite the relatively high demand for the product in the state.

Refinery flexibility. Adding a hydrocracking or coking unit to an existing refinery enhances its processing flexibility by permitting the upgrading of straight-run residuum and heavy gas oils into gasoline and middle distillates.

Tesoro recently installed the first hydrocracker in Alaska at its Kenai plant. The refinery was originally designed to run light Cook Inlet crude, but as the supply of that feedstock declined, Tesoro was faced with the choice of (1) cutting back production accordingly, (2) running the heavier Prudhoe Bay crude oil, and thus producing less
gasoline and middle distillates and more residual oil to be exported from Alaska because of the lack of a local market, or (3) adding equipment to upgrade the greater quantities of residual oil produced by distilling Prudhoe Bay crude.

Tesoro chose the third alternative, installing a hydrocracker to process about 7,500 bpd of heavy gas oil --- about 11 percent of the crude oil input to the refinery --- into motor gasolines, jet fuel, and diesel fuel. Plunging demand for residual coupled with a fall in the average API gravity of crude-oil inputs is encouraging refiners to take similar action everywhere in the United States. The Oil and Gas Journal reported an increase in total U.S. hydrocracking capacity of close to 30 percent between year-end 1979 and year-end 1980.

**Refinery size and affiliation.** Independent refineries in the United States with less than 30 mb/d capacity --- especially the "bias-babies" spawned by the federal entitlements system between 1973 and 1980 --- are typically simple atmospheric distillation units producing a relatively large proportion of residual oil and heavy refined products. Not only do larger refineries tend to be more complex and more flexible with respect to both feedstocks and product slates but, all other things being equal, a large company with many refineries has greater system-wide flexibility because of its ability to produce different product slates in different plants equipped to complement one another.

Of all the refineries operating in Alaska, for example, the Chevron Kenai facility has from the beginning taken advantage of California standard's system-wide flexibility. Much of the heavy gas oil from Kenai is sent, along with the residual oil, to the company's Richmond plant, which already processes Prudhoe Bay crude oil that Chevron buys from Sohio. In the face of surplus system-wide capacity, moreover, Chevron recently suspended production of military jet fuel in Alaska, instead choosing to ship the straight-run gasoline from Kenai to its El Segundo refinery for conversion to benzene.
Refining of Petroleum

Distillation. All refinery operations begin with the distillation of a crude-oil feedstock into petroleum fractions. The crude oil can either be heated through a series of temperature steps and the vapors condensed at each step, or a large portion of the crude oil can be vaporized and the vapor cooled in a series of temperature steps. Either way, the crude oil is separated into fractions, each composed of hydrocarbons having similar boiling-points. The boiling point ranges of the more common products are shown in Table 7 below.

Table 7
Boiling Ranges and Distillation Products

<table>
<thead>
<tr>
<th>Boiling Range°F</th>
<th>Product</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 90</td>
<td>propane/butane</td>
</tr>
<tr>
<td>90-220</td>
<td>gasoline</td>
</tr>
<tr>
<td>220-315</td>
<td>naphtha</td>
</tr>
<tr>
<td>315-450</td>
<td>kerosene</td>
</tr>
<tr>
<td>450-800</td>
<td>gas oil</td>
</tr>
<tr>
<td>more than 800</td>
<td>residuum</td>
</tr>
</tbody>
</table>

In a typical refinery, the crude oil is heated to about 650°F as it enters the atmospheric distillation tower. The vapors rise in the tower, are cooled and condensed on trays at various levels and then withdrawn. Those heavy portions that do not vaporize are withdrawn at the base of the tower and sent to a vacuum distillation tower. Under reduced pressure, additional hydrocarbons vaporize, rise in the second tower, and are separated as the vapors cool. The heavy residue remaining is withdrawn at the base of the vacuum tower.

Restructuring hydrocarbon molecules. The separated fractions undergo further processing. Typically, the "light ends" from the top of the fractionating column go to the gas plant for further fractionation; the straight-run gasoline is
blended into motor gasolines and jet fuel; naphtha is sent to the reformer for processing, kerosene to a hydrotreater for clean-up, light gas oil to distillate-fuel blending, heavy gas oil to the cat cracker; and straight-run residue is fed to the flasher.

Beyond distillation, refiners restructure or "reform" the hydro-carbon molecules either by making the molecules smaller or larger or by rearranging the molecular structure of a hydrocarbon without changing the number of atoms. In restructuring molecules, extensive use is made of catalysts, substances that cause an acceleration of a chemical reaction without themselves being permanently affected. Some catalysts offer a surface structure that increases the rate of reaction, and others may cause certain reactions that would not otherwise occur. In many refining processes, the use of different catalysts results in a different yield, such as a different proportion of paraffins and aromatics. As a consequence, the refining and petrochemical industries are continually searching for new and superior catalyst materials.

Various processes have been given different names by their inventors, but basic refinery operations can be classified into the categories shown in Table 8:

**Cracking.** When hydrocarbons are heated to temperatures exceeding about 450° C (842° F), some molecules begin to break down or split. The reaction is very complex and a number of different products are formed, including heavier products as well as the predominantly lighter products.

In cracking, refiners heat a mixture of heavy hydrocarbons to a high temperature under pressure. This process causes the larger molecules to split; the result is a new mix of molecules, but one with a much higher proportion of lighter hydrocarbons, from methane through the gasoline, naphtha, and middle-distillate ranges.
Table 8  
Refinery Processes to Restructure Hydrocarbons

<table>
<thead>
<tr>
<th>Process</th>
<th>Basic Function</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRACKING:</td>
<td>Breaking (&quot;cracking&quot;) large molecules into smaller ones. (Cracking also produces some larger molecules.)</td>
</tr>
<tr>
<td>REFORMING:</td>
<td>Dehydrogenation --- removal of hydrogen --- for example, converting saturated straight-chain hydrocarbons into unsaturated aromatics.</td>
</tr>
<tr>
<td>POLYMERIZATION and ALKYULATION:</td>
<td>Combining smaller molecules into larger ones; polymerization combines identical molecules while alkylation combines different-type molecules.</td>
</tr>
<tr>
<td>HYDROGENATION or HYDROTREATING:</td>
<td>The addition of hydrogen to convert unsaturated to saturated hydrocarbons, or to replace various chemical radicals with hydrogen.</td>
</tr>
<tr>
<td>ISOMERIZATION:</td>
<td>Rearrangement of the structure within a molecule without changing the number of atoms.</td>
</tr>
<tr>
<td>TREATING:</td>
<td>Converting a contaminant into an easily removable or non-objectionable form.</td>
</tr>
<tr>
<td>COKING:</td>
<td>A form of thermal cracking conducted under high pressure, promoting the formation of coke as well as lighter products.</td>
</tr>
</tbody>
</table>
As large molecules break up through cracking, the lack of sufficient hydrogen atoms to saturate all the carbon bonds forces some of the carbon atoms to bond to one another, forming olefins, smaller aromatic and naphthenic rings, and coke. The lighter products of this process are important chemical feedstocks --- ethylene, propylene and butylenes. However, the majority of heavy distillates and residual fuels cracked in refineries goes into the production of gasoline. Crude oils that initially yield only 15 to 20 percent gasoline-range products through distillation can yield 60 to 70 percent gasoline when subjected to cracking.

There are basically three cracking processes: thermal cracking, catalytic cracking and hydrocracking. Thermal cracking is the oldest of the three, and simply heats the large hydrocarbon molecule to temperatures exceeding $450^\circ$ C. At one time, thermal cracking was widely used to improve the octane number of naphthas and to produce gasoline and gas oil from heavy fractions. However, because thermal cracking of heavy distillates for gasoline production produces substantial quantities of less valuable gases and low-quality gas oils, the process has largely fallen out of use.

About forty years ago, catalysts were introduced into the cracking process to produce a higher quality gasoline. Catalysts enable cracking to take place at lower temperatures and yield a heavier, more valuable gas as well. Higher volumes of C3 and C4 products (propane and propylene; and butane, butene, and butadiene) are produced, offsetting lower volumes of methane and ethane. Catalytically-cracked gasolines contain more branched-chain hydrocarbons, have higher yields, and are generally superior to thermally-cracked gasolines. As a consequence, most refineries that make gasoline from heavy distillates and gas oil use catalytic crackers.

The major problem with catalytic cracking is that the catalyst quickly becomes contaminated with coke deposits. Spent catalysts must be continually separated and regenerated.
Hydrocracking is a process designed to increase the yields of high-value gasoline components, usually at the expense of the gas-oil fraction. Hydrocracking involves cracking in the presence of both a catalyst and hydrogen gas. In thermal cracking, olefins (which have a lower hydrogen/carbon ratio than paraffins) are produced and in catalytic cracking, olefins are produced and carbon eliminated by deposition on the catalyst. In hydrocracking, most of the olefins that are produced immediately combine with hydrogen to form short branched-chain paraffins.

The cracking process is typically very flexible and can produce high yields of either gasoline or gas oil from the heavier crude-oil fractions. Tesoro Alaska has recently added a hydrocracker to its Kenai refinery in order to obtain an 11-percent increase in the yield of gasoline and middle distillates from each barrel of crude oil processed.

**Reforming.** Catalytic reforming, like cracking, is one of the most important processes in the production of gasoline. The process typically uses straight-run naphtha as feed and alters the chemical composition of the hydrocarbons by removing hydrogen. Major changes in the composition of the naphtha include conversion of:

* paraffins to isoparaffins
* paraffins to naphthenes
* naphthenes to aromatics

Sometimes paraffins, naphthenes, or side chains break up in the reformer to form butanes and lighter gases, but the principal object of reforming is to raise the octane number of the gasoline. Aromatics have higher octane numbers than paraffins and naphthenes; long-chain paraffins have low octane numbers.

An ideal catalyst for reforming gasoline would convert the long-chain hydrocarbon molecules in the naphtha feed to aromatics or branched-chain paraffins. Platinum catalysts appear to be the most selective in achieving this outcome and also, the most active in speeding the rate of reaction. They are also the most expensive. Other dehydration and
reforming catalysts include molybdena, chromia, and cobalt molybdate.

The main product from a reformer is called "reformate". The butanes and lighter gases released in the process are taken off overhead and used as fuel or processed elsewhere in the refinery. Hydrogen is also an important reformer byproduct that can be used in other parts of the refinery, for desulphurisation ("hydrotreating"), or for hydrocracking.

**Polymerization and alkylation.** When refiners pass crude oil through a catalytic cracker, the lighter olefins (butylenes and propylenes) produced are too unstable to stay dissolved in the gasoline blends. Polymerization and alkylation were invented to combine the smaller hydrocarbon molecules into larger ones. Polymerization combines identical molecules, while alkylation combines different types of molecules. Thus, butenes \((C_4H_8)\) are polymerized to octenes \((C_6H_{16})\); similarly propylene \((C_3H_6)\) becomes hexene \((C_6H_{12})\). Propylene and butene combine through alkylation to form heptene.

The use of alkylation has grown at the expense of polymerization, primarily because alkylation yields more product from the same quantity of olefin feedstock and the resulting alkylate has superior gasoline-blending qualities. Alkylation is also used to manufacture petrochemical derivatives. For example, benzene and ethylene may be combined to form ethylbenzene, which in turn, is used to make styrene and synthetic rubber.

**Isomerization.** Isomerization involves changing the structure of a hydrocarbon to yield a different, more valuable isomer. In most cases, normal paraffins are changed with the aid of a catalyst to branched-chain paraffins. An original application of isomerization was the conversion of normal butane to isobutane for use as an alkylation feedstock. However, with increased yields of isobutane from reforming operations, this application is limited. Most isomerization units now convert low octane-rated pentane and hexane into their high-octane isomers.
Hydrotreating. As petroleum fractions move through a refinery, impurities in the crude oil can have a detrimental effect on equipment, catalysts, and quality of the finished product. Hydrotreating removes most contaminants by mixing hydrogen with the crude-oil fractions and then heating the mixture under high temperature and pressure in the presence of a catalyst. Several reactions can take place:

- Hydrogen combines with sulfur atoms to form hydrogen sulfide (H₂S).
- Some nitrogen compounds are converted to ammonia.
- Metals entrained in the oil are deposited on the catalyst.
- Some of the olefins, aromatics, or naphthenes become hydrogen-saturated, and some cracking takes place, causing the creation of some methane, ethane, propane, and butane.

Hydrotreating is, therefore, used both to remove impurities and to alter the composition and characteristics of refined products. Gasoline may be treated in order to hydrogenate olefins and diolefins in order to reduce gum formation.

Reformer feedstocks and other feedstocks may be treated to remove sulfur, nitrogen, and other impurities that could otherwise "poison" and deactivate the catalysts. Kerosene and lube oils may be treated to reduce both sulfur and the proportion of aromatics. Many refineries have also added hydrotreating units to desulfurize residual fuels in order to meet environmental specifications.

Refinery Technology and Design.

Refinery design and the choice of refinery processes depend upon several factors, including the type of crude oil available as feedstock, the desired product slate, product quality requirements, and economic considerations such as relative crude-oil prices, product values, availability of electricity and water, air and water emissions standards,
and the cost of land, equipment, and construction labor, and the owners' access to capital.

Complexity of product slates adds to the complexity of a refinery and thus to its fixed and variable costs, as does a mismatch between the grade and quality of available feedstocks and the desired product slate. Thus, refinery capital and operating costs tend to be higher on the West Coast of the United States, where product slates emphasize lighter products; air-quality standards are more critical, and the typical crude oil is, unfortunately, of lower gravity and higher sulfur content than elsewhere in the United States.

A typical U.S. refinery that produces more than one grade of gasoline and several kinds of middle distillate products is likely to have a fairly complex array of processes, as indicated by the flow chart in Figure 2. This complexity has evolved over a period of many decades, in response to a growing diversity of petroleum-product demand and ever more critical product specifications generated by more sophisticated fuel-using equipment.

Although "downstream" process complexity, pressure and temperature controls, and other dimensions of refinery technology have advanced continually over the years, crude-oil distillation remains the heart of the refining business, and its technology remains much as it was decades ago. All refining operations begin with the separation of crude oil into various fractions with different boiling-point ranges. This is where the similarity ends. Some small refineries, like Mapco's North Pole plant and the Chevron Kenai refinery are simple "topping plants", that sell a narrow range of straight-run distillates as final products, exactly like the typical refinery of one hundred years ago. The essential difference is only that the "top" and "bottom" ends of the crude-oil barrel (the lightest and heaviest fractions) are no longer discarded, but are now sent on to more complex refineries for further processing or sold for electric-utility boiler fuel or ship's bunker-oil use, where product quality is not a critical factor.
Figure 2
Simplified Flow Chart of a Refinery
Other more complex refineries like Tesoro's Kenai plant process the straight-run distillation products much further and crack much of the heavier fractions into more valuable refined products. The state of the art today is represented by complex refineries like the one depicted in Figure 2 and that which Charter Oil contemplated for Valdez, in which the entire crude-oil barrel would have been processed into gasoline, middle distillates, and petrochemicals.

Forces for Change

The OPEC price revolution. The recent "energy crisis" began in 1973-74 with the Arab oil embargo. The embargo came (1) just at the peak of an unprecedented world-wide economic boom that had stretched global oil-producing capacity to its limit and (2) just as U.S. crude oil production had reached full capacity and peaked out. The Organization of Petroleum Exporting Countries (OPEC) seized upon the shortage caused by the embargo to increase world crude-oil prices more than fourfold. A second supply pinch, and a further threefold price increase came in 1979-80, when the Iranian revolution and the subsequent war between Iran and Iraq deeply curtailed production in both countries, which were the world's number-two and number-three exporters respectively.

Higher oil prices and the fear of future supply interruptions have created strong incentives for consumers to conserve energy or to change fuels (switching from oil to coal, for example), and for the oil industry to explore for petroleum outside the OPEC countries, and for various parties to develop alternative energy sources. The full adjustment of industrial economies to higher oil-price levels and supply insecurity would have been gradual under any circumstance. Fuel-use patterns are embodied in buildings, appliances, transportation equipment, and industrial processes that take several years to wear out, become obsolete, or in many cases, even to become economic to retrofit. It also takes several years to mobilize and carry out successful oil and gas exploration programs or to design and build substi-
tute-fuel production facilities (for shale oil extraction, synthetic fuels, etc.).

In the United States, the adjustment was delayed even further because the initial policy response to the events of 1973-74 was to impose price controls on domestically-produced oil in order to shelter consumers as much and for as long as possible from the impact of rising OPEC prices. The average inflation-adjusted retail price of gasoline, for example, was only 10 percent higher in 1978 than it was in 1973. Not only did crude-oil price controls maintain the level of U.S. petroleum-product consumption higher than it otherwise would have been, but the crude-oil price-averaging mechanism (the "entitlements" system) that went with it effectively subsidized the domestic refining sector and protected it from foreign competition.

The temporary fool's paradise that petroleum price controls and allocation created for consumers and refiners alike is now over. As a result, five interrelated factors are now pressuring the U.S. petroleum-refining industry --- (1) an overall decline in petroleum products consumption, (2) a shift in the mix of products demanded, (3) a worsening of the average quality of crude-oil supplies, (4) a less secure crude oil supply, and, of course, (5) higher crude-oil prices.

**Declining consumption.** Total U.S. consumption of petroleum products fell from 18.8 million barrels per day (MMB/d) in 1978 to about 17.0 MMB/d in 1980, and in April 1981 was less than 16.0 MMB/d. Declining product sales have resulted in redundant refining, storage, transportation, and distribution capacity. Consumer resistance to higher gasoline and fuel oil prices has joined with higher crude-oil costs to create an intense profit squeeze on refiners, distributors, and retailers alike.

**Changing market requirements.** Higher oil prices and federal regulations have combined to create a trend away from both the lighter and the heavier petroleum products (e.g., gasoline and residual oil) toward middle distillates (e.g., jet fuel, diesel fuel, and No. 2 heating oil) and from leaded to unleaded gasoline. Higher crude-oil prices have tended to shift petroleum product demand away from heavy
fuel oil, which can rapidly be supplanted by coal or natural gas in most of its uses. At the same time, voluntary conservation and more fuel-efficient cars (with some help from the economic recession) have already reduced overall U.S. gasoline consumption by more than 15 percent below its 1978 peak. The National Petroleum Council (NPC), nevertheless, forecasts demand for high-octane unleaded gasoline to double by 1990. Consumption of gas oil and naphtha as petrochemical feedstocks is also expected to increase as demand continues to grow for synthetic textiles, fertilizers, plastics, and other chemical products.

Declining crude oil quality. Light (high-gasoline) and sweet (low-sulfur) crude oils have long been preferred refinery feedstocks, particularly in North America, where motor fuels are an exceptionally large part of total petroleum demand and where air quality became a major concern earlier than in Europe and East Asia. Fortunately, the grade and quality of North American crude oils (other than in California) has tended to be well suited to the mix of domestic product demand.

Throughout the 1970's, however, crude-oil production from historical domestic sources declined. As a result, price premiums for light, sweet crudes have widened, and U.S. refiners have had to turn increasingly to heavier, higher-sulfur crude oil supplies, both domestic and imported. According to the National Petroleum Council (NPC) study cited earlier, 80 percent of the world's remaining crude-oil reserves are high in sulfur, but only 46 percent of the raw material run in U.S. refineries in 1978 came from high-sulfur stocks. NPC forecasts that high-sulfur crudes will increase their share in total feedstocks to between 55 and 59 percent in 1990. Most industry analysts appear to agree that the trend toward heavier, higher-sulfur feedstocks will continue, and will require refiners to make major modifications in existing plants, above and in addition to those investments needed to deal with the shifting demand mix.

Concern for feedstock security. For several decades before 1973, a large excess of oil-producing capacity existed in Texas, Louisiana, and other states, where production was
controlled and allocated by State oil-conservation authorities. Excess capacity in the oil-producing nations of the Middle East and the Caribbean was even greater, and the vast bulk of this capacity was controlled by the major multi-national (mainly U.S.-based) oil companies. As a result, many North American refiners were self-sufficient in crude oil or nearly so.

Domestic and world crude-oil markets were, therefore, normally buyers' markets, and access to crude oil was not a major concern for most refiners. The upheavals of the 1970's, however, made security of crude-oil supply of paramount interest to refiners as well as governments. First, U.S. domestic production peaked in 1970 and declined throughout the decade, while consumption continued to climb until 1978, leading to an ever-greater dependency on imported oil. At the same time, foreign oil-producing countries were in the process of nationalizing the concessions of the multinational companies. The combined effect of these two trends was to place almost every refiner in North America in a position of depending on other domestic or foreign producers for a large part of their refinery feedstocks.

Because of the two major interruptions of Middle Eastern production that occurred during the 1970's, markets for both foreign and domestic crude oil became dominated by political considerations. Not only has the world's overall supply become vulnerable to curtailment at the whim of a handful of governments or perhaps of a handful of terrorists, but even in the absence of an overall supply crisis, the price that different refiners have to pay for crude oil of a given grade and quality might vary by several dollars per barrel, depending on the refiner's relationship with the Saudi Arabian or other OPEC producer governments, or (at least until January 1981) on the company's regulatory status under U.S. oil price and allocation rules.

In the "seller's market" that prevailed during the 1970's, an assured supply of crude oil seemed to be very important to the long-term viability of existing refineries, an important precondition for financing the construction of
any new refinery, and an absolutely necessary condition for financing any independent refinery. Would-be independent refiners, like the various groups that promoted the Alpetco project at Valdez, seemed to center their entire investment strategy on the search for assured crude-oil supplies, on the apparent theory that such a supply was not only necessary but sufficient for project success.

As a result, there have consistently been companies willing to pay a premium over the benchmark price applicable to a given kind of crude oil, like the official Saudi government price or Alaska's "Exhibit B" price (the weight-average of prices posted by the North Slope producers), in order to secure captive reserves, long-term purchase contracts, or long-term allocations by governments.

Any large new source of secure domestic crude oil that was not yet under the control of a major refiner thus became a particularly attractive property, and was eagerly sought out by refiners or by speculators confident that control over crude oil would either make them into refiners or allow them to capture part of the premium that refiners would pay to be assigned the right to that crude oil.

In this situation, Alaska's right under its oil and gas lease contracts to take oil royalties either in money or in kind gave the State two special choices for using its North Slope royalty crude. This option could be used, on the one hand, to attract refinery and petrochemical investment in Alaska, seemingly even without any discount on royalty-oil or gas feedstocks below the "in-value" price --- the amount the State would have received if it took its royalties in cash from the North Slope producers. Alternatively, royalty oil taken in kind could be sold on long-term contract to existing Alaska refiners or to refiners elsewhere at a premium above its in-value price.

An example of the first strategy was the State's contract with a series of groups --- most recently a Charter Oil subsidiary (the Alaska Oil Company) --- to sell 100 mb/d of North Slope royalty oil at the "Exhibit B" price, conditional upon the company building a worldscale refinery in Alaska. The second strategy is illustrated by the State's
1980 auction of North Slope royalty oil in approximately 5 mb/d lots for a one-year term beginning in July 1981. The high bidders in this auction offered premiums ranging up to almost $3.00 per barrel above the price the state would have received if it had left the royalty oil under control of the North Slope producers and taken payment "in value" --- that is, in cash rather than oil.

Costlier crude oil. The average price U.S. refiners paid for crude oil increased more than seven-fold, from an average of $4.11 per barrel in 1973 to about $36.00 per barrel in early 1981. Because crude-oil costs are the major part of the wholesale price of petroleum products, large consumer-price increases were therefore inevitable. In the absence of government price controls, the rise in retail prices would have led to sharply curtailed consumption of petroleum products, refinery and distributor margins would have fallen nearly to zero, and there would have been little incentive for anyone to think of investing in new refinery capacity.

Until the beginning of 1981, however, ceilings on the domestic price of crude oil permitted U.S. petroleum consumption to keep growing through 1978. Despite the lip service that federal policy paid to energy conservation, the apparent demand for new refinery facilities in the United States continued to grow apace. Price controls, moreover, were augmented by an elaborate system of "entitlements", under which refiners who processed price-controlled domestic oil subsidized refiners who depended on imported crude-oil and major companies subsidized small refiners. Because U.S. refiners could buy crude oil at lower average prices than in any other advanced country except Canada, entitlements effectively insulated domestic refiners from competition with products refined abroad.

In addition, refiners and distributors were generally able to pass through the crude-oil price increases that the system did permit, and even to increase their markups, because domestic product-demand remained strong at the same time that domestic refiners were sheltered from worldwide competition. The strong profit outlook that this
situation generated combined with the subsidy element in the entitlements system to encourage the oil industry to invest in both "grass-roots" (entirely new) refineries and in the expansion or retrofitting of existing refineries.

Finally, and rather amazingly in retrospect, almost all of the concerned parties in industry and government seem to have expected these market conditions to continue forever. Throughout the 1970's, oil-company trade associations, the Department of Energy, and both liberal and conservative members of Congress deplored the growing "shortage" of refinery capacity in the United States (which each of them tended to blame on different parts of the federal regulatory apparatus), and sponsored legislation to create new incentives for domestic refinery investment.

The most important effect, for the purposes of our discussion, was the way in which the conditions we have described did, in fact, encourage industry to plan new domestic grass-roots refineries. One such proposal was, of course, the Alpetco project at Valdez.

Alpetco and other U.S. refinery-construction projects planned in the late 1970's rested on the assumption that the 1980's, like the 1970's, would be another decade of (1) growing petroleum-products consumption and (2) sellers' markets for crude oil. If these two assumptions had been valid, they would have meant that an assured supply of crude oil almost guaranteed the profitability of any new refinery. The absence of either condition, however, jeopardizes all current plans for domestic grass-roots refinery construction and also casts a shadow over many of the planned expansions and retrofits of existing refineries.

**Outlook for the 1980's.**

It is likely that the current (August 1981) oil "glut" foreshadows an entirely different kind of petroleum market in the 1980's from that which prevailed in the previous decade. World oil consumption may well have peaked-out in 1978, and world energy prices prices may have reached their long-term summit at the beginning of 1981, at least in
constant-dollar terms. The buyers' market that exists today could even, conceivably, become a rout in which OPEC prices collapse nearly as fast as they rose. More likely, prices will remain well above 1973 and even 1978 levels, but neither refiners nor governments will any longer seem desperate to obtain crude oil at almost any cost.

Other scenarios are also plausible. The current glut depends both on falling world consumption and on the decision of the Saudi Arabian government to maintain high production levels in order to assert its own control over OPEC. Saudi policy could change radically overnight, the present regime might be overthrown, or a wider war could sharply curtail exports from the entire Middle East. If any or all of these events came about, we would once more see world oil prices soar, until a new equilibrium (and a new oil glut) was established at the new price level.

If, as is more likely, oil is in fact plentiful enough during the 1980's to exert a continuing downward pressure on world oil prices, the consequences for oil-producing regions like Alaska would, of course, be profound. Not only would their oil-sales revenue be far lower than they now anticipate, but the attraction of long-term feedstock-supply security would no longer tend to override the transport and construction-cost handicaps of frontier regions as a site for worldscale refining operations.

Ironically, however, the resumption of real-price increases for crude oil would not improve the generally-dim outlook for new refinery construction in areas like Alaska, because higher prices would cause domestic and world oil consumption to shrink even more drastically. The present excess of refinery capacity in the United States and elsewhere would continue to grow, probably assuring that no new export refinery anywhere --- and certainly no such refinery in a comparatively high-cost environment --- would be profitable.

The impact of the new situation on the outlook to refinery modifications is less obvious, but even the drive to upgrade existing Lower-48 refineries in order to produce a
different product mix, or to run a different mix of crude-oil feedstocks may be a movement whose time has passed.

One way of viewing the impact of declining consumption on the need to modify existing refineries is to assume that refiners generally prefer to run lower-sulfur, higher-gravity feedstocks because they are cheaper to process, but that the refining industry is facing a steady decline in the physical availability of such crude oils. However, a one-percent annual decline in overall petroleum-product consumption, or even a one-percentage-point reduction in the expected rate of consumption growth, would more than offset the roughly one-percent annual decline expected in the supply of higher-quality crude oils.

At lower overall consumption levels, therefore, the need to run inferior feedstocks would be considerably less than expected. Moreover, with refineries operating at less than 70 percent of capacity in North America, and at even lower utilization rates elsewhere, the flexibility of the refining sector as a whole would be greatly enhanced. As a result, the ability to process heavy, high-sulfur crudes in existing equipment would improve at the same time the need to do so would be far less pressing. Circumstantial evidence of such a tendency has already appeared this year, in the form of lower world-market price premiums on light, low-sulfur crudes --- a significant reversal of the trend that dominated the 1970's.

The next few years may well be a period in which most refineries are merely holding on with their current design, with the least adjustable facilities being shut down. It is important to note that the most definitive studies of refinery flexibility were completed before the latter half of 1980 --- when it first became impossible to ignore the powerfully depressing effect on oil consumption of the 1978-79 round of crude-oil price increases.
CHAPTER 5
PETROCHEMICALS

Introduction

The manufacture of most organic chemicals relies on the general principles of chemistry that we summarized in Chapter 3 and on many of the same processes that fuels refineries use to transform hydrocarbons that we outlined in Chapter 4. The petrochemical industry's final product slate is far more varied than that of the refining sector, however, serving a global market with more than fifty thousand different chemicals used in the production of food, clothing, building materials, machinery, medicines, and many other goods.

Because petrochemical products appear in almost every aspect of daily life, they have become regarded as necessities, but they also occasionally become the focus of public consternation, as in the well-known controversies over DDT, urea-formaldehyde insulation, and TRIS. For this reason the development of either a new petrochemical product or a new petrochemical-industry facility can evoke both favorable and unfavorable public interest.

Table 9 shows that fabrication of consumer products from petrochemicals completes a complex chain of processes stretching back to production of primary petrochemicals from natural gas, ethane, LPG's, naphtha, and gas oil. Any intelligent consideration of the benefits and costs of petrochemical development in Alaska, including health and safety risks, requires some familiarity with these processes and their corporate setting.

Chemical Industry Structure

The boundaries of the petrochemical industry are rather fuzzy. On the "upstream" end, they blend into the petroleum refining sector, which furnishes a major share of petrochemical feedstocks; "downstream," it is often impossible to draw a clear line between petrochemicals manufacturing and other organic chemistry-based industries such as plastics, synthetic fibers, agricultural chemicals, paints and resins, and pharmaceuticals.
Table 9
Petrochemical Processes and Market Sectors

<table>
<thead>
<tr>
<th>Chemical Feedstocks</th>
<th>Primary Petrochemicals</th>
<th>Petrochemical Products</th>
<th>Major Consuming Industries</th>
<th>Major End-Uses</th>
</tr>
</thead>
<tbody>
<tr>
<td>Naphtha and Gas Oil from Crude Oil</td>
<td>Ethylene</td>
<td>Plasticizers</td>
<td>Fabricated Plastics</td>
<td>Packaging, Construc., Materials, Housewares; Furniture</td>
</tr>
<tr>
<td></td>
<td>Propylene</td>
<td>Dyestuffs, Pigments</td>
<td>Textile Products</td>
<td>Apparel, Tire Cord</td>
</tr>
<tr>
<td></td>
<td>Butadiene</td>
<td>Industrial Organic Chemicals</td>
<td>Soaps &amp; Detergents</td>
<td>Industrial, Household Cleaners</td>
</tr>
<tr>
<td>Ethane, Propane &amp; Butanes from Crude Oil</td>
<td>Benzene</td>
<td>Solvents</td>
<td>Rubber Products</td>
<td>Tires, Belting, Hose</td>
</tr>
<tr>
<td></td>
<td>p-Xylene</td>
<td>Rubber Processing Chemicals</td>
<td>Pharmaceuticals</td>
<td>Prescription &amp; Patent Medicines</td>
</tr>
<tr>
<td></td>
<td>Ammonia</td>
<td>Surf-actants</td>
<td>Agricultural Chemicals</td>
<td>Feed &amp; Fertilizers</td>
</tr>
<tr>
<td>Ethane, Propane &amp; Butanes from Natural Gas</td>
<td>Methanol</td>
<td>Plastic Resins</td>
<td>Prescriptions &amp; Patent Medicines</td>
<td>Feed &amp; Fertilizers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Synthetic Rubber</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Medicinals</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Nitrogen Fertilizers</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Pesticides</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Petrochemicals

The chemical industry is complex, no matter how narrowly its boundaries are drawn, and it is highly international. Petrochemicals are produced by (1) firms that specialize in the chemical business, (2) integrated oil companies, and (3) government enterprises and joint ventures between governments and international chemical or oil companies.

Four of the world's twelve largest chemical companies --- DuPont, Dow, Union Carbide, and Monsanto --- are headquartered in the United States, and each of these companies is among the 50 largest industrial corporations in the country, with total sales of more than $4 billion in 1980.

The chemical companies themselves generate many captive product streams for which no public sales occur. The chemical industry is its own best customer, particularly for the primary petrochemicals and their first derivatives. Dow Chemical Company and Union Carbide, for example, produce significant volumes of ethylene oxide, which serves as an intermediate product for making antifreeze, detergents, and a host of second- and higher-order derivatives. A large part of this output is used by the companies themselves, usually within the same plant or complex, and a significant amount is sold to other chemical companies, but very little ethylene oxide is marketed outside the chemical industry itself. The same pattern exists for propylene, ethylene dichloride, and a number of other primary petrochemicals and derivatives.

Most large integrated oil companies also manufacture chemicals; the worldwide chemical sales of Shell and Exxon, for example, would rank them among the top dozen chemical producers. The large-scale entry of the major oil companies into the chemical industry reflects the comparative advantage that control over hydrocarbon feedstock supplies gives them in relation to independent chemical producers. "Forward" or "downstream" integration by oil companies also stems from their desire to obtain assured markets for their future crude oil, natural gas, NGL's, and refinery production. The recent declines in gasoline and
fuel-oil consumption in the U.S. and elsewhere are giving refiners a special incentive to treat petrochemicals production as a potential outlet for surplus naphtha and gas oil.

### Table 10
**Worldwide Sales of Petrochemicals and Plastics**

<table>
<thead>
<tr>
<th>Company</th>
<th>1980 Sales ($ millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Royal Dutch/Shell¹</td>
<td>7,633</td>
</tr>
<tr>
<td>Exxon¹</td>
<td>6,963</td>
</tr>
<tr>
<td>Dow Chemical²</td>
<td>6,882</td>
</tr>
<tr>
<td>ICI</td>
<td>4,105</td>
</tr>
<tr>
<td>Union Carbide¹,³</td>
<td>3,665</td>
</tr>
<tr>
<td>Montedison</td>
<td>3,594</td>
</tr>
<tr>
<td>Hoechst⁴</td>
<td>3,476</td>
</tr>
<tr>
<td>BP¹</td>
<td>3,394</td>
</tr>
<tr>
<td>Veba</td>
<td>3,264</td>
</tr>
<tr>
<td>Bayer⁵</td>
<td>2,943</td>
</tr>
</tbody>
</table>

**Notes:**

1) Total chemical business, excluding inter-affiliate transfers.
2) Organic chemicals, hydrocarbons, and plastics.
3) Chemicals and plastics.
4) Organic chemicals, plastics, waxes, and resins.
5) Plastics, coatings, and polyurethanes.

**Source:** *Mike Hyde's Chemical Insight* (No.228)

Because vertical integration has advantages for both the feedstock producer and the processor, the forces favoring integration work in both directions: Chemical companies are also integrating "backwards" or "upstream" into hydrocarbons production, in order to reduce uncertainty about both the prices and availability of raw materials.
DuPont's apparently successful attempt to take over Conoco is a dramatic illustration of this trend.

The recent growth of government-affiliated petrochemical ventures in petroleum-producing states and other Third World countries reflects both a striving for industrial diversification and the opportunity that petrochemicals manufacturing offers some of them to utilize natural gas and NGL's that would otherwise be flared in the oil fields. One feature that distinguishes the government enterprises from most private petrochemical ventures is their relative lack of downstream activity. Chemical manufacturing in the less-developed countries has centered on producing a few primary petrochemicals --- first-stage olefins and aromatics, for example, and, to a lesser extent, first derivatives for sale to the chemical industry.

**Petrochemical Feedstocks**

The primary petrochemical feedstocks include (1) naphtha and gas oil from crude-oil distillation; (2) ethane, propane, and butane, mainly from natural-gas liquids (NGL's) but also from oil refineries; (3) methane from natural-gas wells; and (4) synthesis gas, a carbon monoxide-hydrogen mixture that can be produced from crude oil, natural gas, or coal. Any primary petrochemical can ultimately be made from any of these feedstocks, but raw-material and processing-cost differences encourage chemicals producers to choose particular feedstocks for particular products.

**Natural-gas liquids** (NGL's) are the principal raw material for ethylene manufacturing in North America, accounting for about two-thirds of total ethylene production. Ethane from NGL's is a particularly desirable feedstock not only because its processing is relatively simple, but also because few byproducts are generated in the process. Producers of ethylene from gas oil, on the other hand, are faced with a large variety of compounds formed in the cracker which, though valuable, make production facilities more costly and complicate products marketing.
Naphtha and gas oil are also important feedstocks for making olefins and for the production of aromatic hydrocarbons --- benzene, toluene and xylene (BTX). Much of the BTX produced in North America is, however, a byproduct of gasoline upgrading (naphtha reforming) in refineries, thereby reducing the need for special aromatics-producing facilities.

Natural gas is the principal raw material in North America for the production of synthesis gas which is, in turn, the main feedstock for producing ammonia, urea, methanol, formaldehyde, and chlorinated hydrocarbons (e.g., carbon tetrachloride and chloroform). Although natural gas is the preferred feedstock, synthesis gas is also produced from coal, oil, and vegetable matter.

Feedstock supplies. The differing availability and prices of different feedstocks have been important in shaping both the development history of the petrochemical industry and the regional variations in its evolution.

In the United States, the dominant factors governing the development of the petrochemical industry were cheap natural gas and natural gas liquids and elevated production levels for high-octane gasoline. Abundant methane and NGL's made possible the manufacture of low-cost ammonia, methanol, ethylene, and propylene. Demand for high-octane gasoline made aromatic naphtha less desirable for making gasoline, and thus benzene and xylene were available relatively low opportunity costs.

In Western Europe and Japan, however, gasoline has accounted for a smaller proportion of total petroleum consumption. Excess European refinery capacity has made naphtha abundant and as the petrochemical industry developed, naphtha was the main feedstock for production of olefins and aromatics, and even ammonia and methanol.

From the end of World War II to the early 1970's, the petrochemical industry grew rapidly and enjoyed steadily expanding markets and relatively stable raw-materials
costs. However, even before the 1973-74 oil embargo, concerns about feedstock availability were starting to emerge:

* In the United States, annual natural gas and oil discoveries during the 1960's were far smaller than the drawdown of reserves.
* In Europe, high standards of living increased gasoline consumption, leading to forecasts of naphtha shortages.
* All over the world, the new crude-oil reserves that were being proved tended to be heavier than in the past, causing concern over the long-range sufficiency of light distillate feedstocks for the petrochemical industry.
* And finally, developing nations wanted to start building their own chemical manufacturing capacity, particularly when they owned the low-cost hydrocarbons themselves.

These pre-1973 trends became the industry's major concerns of the mid-to-late 1970's, dominating the planning and development of new capacity in the chemical industry.

**Future feedstock developments.** The total world demand for petrochemical feedstocks and the factors that will affect feedstock choices in the 1980's and 1990's are subject to many uncertainties, including global and national economic growth trends, the overall world oil-supply outlook, and specific regional circumstances. The latter include, for example, the volume of new supplies of NGL's from the Middle East, Alberta, and Alaska.

Raw materials "availability" and supply security dominated industry planning in the 1970's, and they will remain important considerations in the choice of feedstocks. They may not loom as large in the investment decisions of the 1980's and 1990's, however. The reason is the appearance of a buyers' market for crude oil and the prospect of a buyer's market in North America for natural gas as well.
In these circumstances, excess refinery capacity is providing oil companies with the flexibility and added incentive to market and sell the otherwise surplus portions of the crude-oil barrel as petrochemical feedstock. The supply of natural gas liquids to existing U.S. plants has also remained ample thus far and, in fact, as Saudi Arabia and other oil-producing nations export ever-greater quantities of LPG's, competition to find markets for LPG supplies may intensify and seriously impinge on the marketability of relatively high cost NGL's from areas like Alaska.

In general, therefore, the physical supply of feedstocks does not seem to be a limiting factor for Lower-48 primary petrochemical production, but the relative costs of various feedstocks in the 1980's and 1990's remain uncertain, and are one explanation of an industry-wide reticence to announce construction plans for new petrochemical facilities. Nevertheless, oil and gas prices will remain substantially above the levels that prevailed in the early 1970's. As a result, costs rather than availability per se will probably play the critical role in the selection of future chemical feedstocks, plant locations, and processes for converting feedstocks to derivatives and end-products.

Fuel prices and processing economics will combine to determine which hydrocarbons are to be processed to petrochemicals and which are more valuable as fuels. The one most important influence on this decision --- and one of the greatest uncertainties --- is the relationship between natural gas prices and oil prices after the former are deregulated in 1985. If Lower-48 natural-gas supplies do not expand rapidly in response to higher prices, residential and commercial consumers could bid the price of gas substantially above that of oil-based fuels.

In this circumstance, methane would cease to be an attractive chemical feedstock in the United States, and the incentive of gas producers to extract ethane from the pipeline-gas stream would be greatly weakened. As a result, (1) new investment in ammonia and methanol production might shun the United States altogether, moving to Canada
or to Middle Eastern countries in order to take advantage of
natural gas that would otherwise be shut in or flared, and (2)
domestic olefins production would depend increasingly on
naphtha or gas oil as feedstock.

If No. 2 fuel oil prices rose faster than the prices of
other hydrocarbons, on the other hand, new olefins produc­
tion would move to countries with surplus LPG supplies,
while U.S. plants continued to make ethylene from both
naphtha and natural-gas liquids.

**Petrochemical Product Groups.**

Petrochemicals are conventionally classified according
to two features: (1) their sequence in the production
process (primary petrochemicals, intermediates or deriva­
tives, and final products), and (2) their chemical structure
(e.g., olefins, aromatics, alcohols, etc.).

**Primary petrochemicals** are compounds with relatively
simple molecules, made directly from hydrocarbon feed­
stocks. These compounds include ethylene, propylene, buty­
lenes and butadiene, benzene, para-xylene, ammonia, and
methanol. Most of them are relatively reactive --- as a
result of multiple carbon bonds except in the last two cases
--- and it is this quality that makes them useful for
processing into thousands of more complex chemical pro­
ducts.

**Olefins.** Olefins are the most important primary and
intermediate petrochemicals. They are not present in crude
oil or natural gas, but are obtained when hydrogen atoms are
removed from paraffin and isoparaffin molecules, usually by
cracking. Olefins are characterized by branched or
straight-chain hydrocarbons with double bonds between the
carbon atoms. The double bonds are less stable than single
bonds and thus the olefins will readily combine or react with
other compounds.

**Ethylene** is by far the most important olefin for the
manufacture of petrochemical products. A typical world­
scale ethylene plant manufactures more than one billion
pounds of ethylene per year and in 1980, 28 billion pounds were produced in the U.S. alone.

Ethylene is a colorless, flammable gas which, because of its extremely low boiling point (-155°F), cannot be shipped long distances except in high-pressure pipelines or very costly cryogenic (refrigerated) tankers like those used for liquefied natural gas (LNG). In the Lower 48 and Canada, ethylene is typically produced in separate plants and piped to other petrochemical producers. An elaborate pipeline system has evolved in the U.S. Gulf Coast region to connect ethylene producers and manufacturers of ethylene derivatives such as styrene and polyethylene.

\[
\begin{align*}
\text{Ethylene (C}_2\text{H}_4) & \quad \text{Propylene (C}_3\text{H}_6) \\
\begin{array}{c}
\text{H} \\
\text{H} \\
\text{H} \\
\text{H} \\
\text{C} = \text{C} \\
\text{H} \\
\end{array} & \quad \\
\begin{array}{c}
\text{H} \\
\text{H} \\
\text{H} \\
\text{H} \\
\text{H} \\
\end{array}
\end{align*}
\]

Aromatics. The "aromatic" hydrocarbons are a family of basic chemicals --- benzene, toluene and xylenes --- characterized by the "benzene ring" molecular structure, which has six carbon atoms and alternately-spaced double bonds. The group is named for the distinctive odors typical of this chemical family.

Toluene and benzene are colorless, flammable liquids, which, like ethylene, constitute building blocks for many chemical intermediates. Toluene and benzene are intimately related, not only because they are produced from the same processes, but also because the principal chemical use for toluene is the manufacture of benzene. Benzene, in turn, is used to make a number of products, the most notable and important of which is styrene.
Other outlets for benzene are phenol, an intermediate for resins; cyclohexane, an intermediate for nylon production; dodecyl benzene for detergents; aniline for dyestuffs and rubber additives; and maleic anhydride, a raw material for polyester glass-fiber plastics. Toluene is used to make plastic foams, TNT and solvents.

Xylene is available from refinery catalytic reforming processes in great abundance, but very few of the mixed xylenes from this source have chemical applications as yet. The major outlets for xylenes are polyester fibers, resins, and solvents.

Most aromatics for the U.S. petrochemical industry are made in refineries. It is not uncommon, therefore, to locate a petrochemical plant whose product slate includes styrene, polystyrene plastics and synthetic rubber near a refinery producing benzene.

**Synthesis gas.** The term "synthesis gas" refers to a mixture of carbon monoxide gas (CO) and hydrogen in any proportion. In the United States, synthesis gas is made primarily from the steam reforming of natural gas and then processed into three major intermediate chemicals -- ammonia, methanol and oxo alcohols.

**Ammonia** is one of the world's most important commercially produced chemicals. It is a colorless gas with a characteristically pungent odor and is used as the basic raw material for many different forms of nitrogen-containing chemical compounds. These products and end uses include fertilizers, refrigerants, nitric acid, water-treatment chemicals, synthetic plastics and fibers, animal feed, explosives, rocket fuels, and many others.

**Methanol** or methyl alcohol is one of the largest-volume organic chemicals produced synthetically. A liquid under all atmospheric temperature-pressure combinations, methanol can be produced from natural
gas, coal, or vegetable matter, and thus is an attractive substitute for liquid petroleum fuels in both stationary and transportation uses.

Synthesis gas, under special conditions and in the presence of a catalyst, will react with olefins to produce alcohols. The resulting oxo alcohols do not often find their way into consumer markets. Some are used to make solvents; but most oxy alcohols are used in manufacturing plasticizers that keep polyvinyl chloride and other resins soft and pliable.

**Intermediates or derivatives.** Because of their instability, primary petrochemical compounds are typically converted at the same plant or nearby into intermediate products or derivatives, most of which are not sold in final consumer markets, but serve as essential inputs to further processing operations.
Petrochemicals

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Figure 3 shows the relationships among the feedstocks and primary petrochemicals used to produce several of the most important petrochemical first derivatives. Chemical companies manufacture many primary and intermediate petrochemicals expressly for captive product streams. Twenty percent or more of all organic chemicals produced in the United States remain within the same company for further processing or are sold to other chemical companies on long-term "take-or-pay" contracts.

For example, all of the ethylene produced in the Alberta Gas Ethylene (AGE) No. 1 plant at Joffre was committed to Dow Chemical Company prior to construction. AGE's proposed Plant No. 2 plant already has customers ready to enter into long-term purchase contracts for the ethylene it will produce. Captive streams of primary petrochemicals and first derivatives are thus the rule, rather than the exception, and help to assure chemical companies manufacturing second- or higher-order derivatives and fabricated products a secure supply of raw materials.

Derivative products from ethylene are of particular interest to Alaskans because the proposed Dow-Shell petrochemical project features extraction of gas liquids from Prudhoe Bay natural gas and shipment of the NGL's by pipeline to tidewater in Southcentral Alaska. There the ethane would be separated and made into ethylene and ethylene derivatives and the remainder of the liquids exported by tanker, probably to other plants owned by the same companies. Table 11 summarizes the derivative products that Dow-Shell have mentioned for possible production in Alaska.

**Final Products**

End uses for petrochemicals are numerous. Petrochemical intermediates are converted into fertilizers; plastics; all varieties of rubber and urethanes; fibers, especially nylon, polyesters and acrylics; paints, drugs and pharmaceuticals (such as aspirin and thiamine); and detergents. Primary and intermediate petrochemicals are also key ingredients in making lubricating-oil additives, pesticides,
<table>
<thead>
<tr>
<th>Derivative</th>
<th>Product form</th>
<th>Intermediate and End-uses</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>ETHYLENE:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Low-density polyethylene (LDPE)</td>
<td>Resin sold as pellets, packaged in bags, hoppers, or containers</td>
<td>Film for food wrap, garbage bags; housewares, wire &amp; cable insulation, paper milk-carton coatings</td>
</tr>
<tr>
<td>High-density polyethylene (HDPE)</td>
<td>Same as LDPE</td>
<td>Blow-molded articles, injection-molded bottles, pipe &amp; films</td>
</tr>
<tr>
<td>Ethylene oxide (EO)</td>
<td>Gas in water solution</td>
<td>Intermediate for EG</td>
</tr>
<tr>
<td>Ethylene glycol (EG)</td>
<td>Liquid shipped in tanks and drums</td>
<td>Antifreeze, intermediate for polyester fiber, film, resins</td>
</tr>
</tbody>
</table>

| **ETHYLENE PLUS CHLORINE:**               |                                    |                                                                                          |
| Ethyl dichloride                          | Gas: seldom shipped                | Intermediate for VCM                                                                     |
| Vinyl chloride monomer (VCM)*             | Liquid shipped in tanks            | Intermediate for PVC                                                                     |
| Polyvinyl chloride (PVC)*                 | Solid sold as pellets, packaged in bags or in bulk | Irrigation and sewer pipe, electrical conduit, vinyl floor tiles, rigid sheet packaging material |

(continued)
Table 11
Primary Petrochemicals and Derivatives Considered
For Production in Alaska (continued)

<table>
<thead>
<tr>
<th>Derivative</th>
<th>Product form</th>
<th>Intermediate and End-uses</th>
</tr>
</thead>
<tbody>
<tr>
<td>ETHYLENE PLUS BENZENE:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ethylbenzene</td>
<td>Gas: seldom shipped</td>
<td>Intermediate for styrene monomer</td>
</tr>
<tr>
<td>Styrene monomer*</td>
<td>Liquid shipped by pipeline or in tanks</td>
<td>Intermediate for polystyrene, synthetic rubber</td>
</tr>
<tr>
<td>Polystyrene*</td>
<td>Solid sold in pellets, sheets, and blocks</td>
<td>Disposable drinking cups, resin for toys, football helmets, inc.</td>
</tr>
<tr>
<td>AMMONIA:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Urea</td>
<td>Solid, sold as prills in bags or in bulk</td>
<td>Nitrogen fertilizers; intermediate for urea &amp; melamine resins &amp; plastics, explosives</td>
</tr>
<tr>
<td>Acrylonitrile*</td>
<td>Liquid shipped in drums or tanks</td>
<td>Intermediate for acrylic resins and plastics, synthetic rubber</td>
</tr>
<tr>
<td>METHANOL:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liquid shipped by pipeline or in tanks</td>
<td>Direct fuel use, intermediate for formaldehyde</td>
<td></td>
</tr>
</tbody>
</table>

*) Not listed by Dow-Shell as proposed Alaska product.
solvents, and much more. It is unlikely that large quantities of intermediates manufactured in Alaska will remain in the state for processing into final products, however, both because Alaska will remain a relatively high-cost location for consumer-goods manufacturing, and because it is easier and cheaper to ship intermediates long distances than to ship a variety of fabricated products.

**Petrochemical Processes and Plant Design**

Petrochemical complexes are often laid out like large industrial parks. They can include plants that manufacture any combination of primary, intermediate, and end-use products. For example, some ethylene plants are single-purpose facilities that ship a single product via pipeline to other chemical companies for further processing. AGE's ethane-to-ethylene plant at Joffre is such an instance. Other petrochemical complexes are composed of a number of largely discrete, specialized plants and laboratories that manufacture a variety of chemicals and share common power generation and wastewater treatment facilities.

Product slates at petrochemical complexes evolve over time, reflecting changes in market conditions and technology. For example, in 1959, Dow Chemical Company of Canada purchased a 700-acre site at Fort Saskatchewan. Initial facilities included ethylene glycol, ethanolamine, chlorophenol, agricultural chemical and chlor-alkali plants. Within a few years, the site had more than doubled in size to 1,450 acres, and new plants were built to manufacture caustic soda, chlorine, ethylene dichloride, vinyl chloride monomer and ethylene oxide/ethylene glycol. The Dow Chemical Company facility in Midland, Michigan, a much older facility, manufactures approximately 400 chemicals in 500 plants and laboratories.

In general, petrochemical plants are designed to attain the cheapest manufacturing costs and as such, they are highly "synergistic". That is, product slates and system designs are carefully coordinated to optimize the use of chemical by products and to use heat and power efficiently.
Figure 4
Schematic Diagram of the Ethane-to-Ethylene Plant
At Joffre, Alberta
For example, exothermic (heat-generating) processes provide heat for endothermic (heat-absorbing) processes; hydrogen-producing processes are coupled with hydrogen-using processes; acid wastes are stored in lagoons with basic wastes to reduce the cost of neutralization; and plant fuel is provided in part by unmarketable hydrocarbon by products (e.g., methane) from various processing operations.

The Dow-Shell group would take advantage of this type of synergism in the design of an Alaska petrochemical complex, which might produce a variety of petrochemicals from several feedstocks --- natural gas from Cook Inlet, natural gas liquids from Prudhoe Bay, naphtha and light gas oil refined from Prudhoe Bay crude oil, and possibly Healy or Beluga coal. One distinctive feature of the petrochemical complex the Dow-Shell group contemplates for Alaska is the participation of several large companies with already-established markets for their respective chemical products. If an Alaska petrochemical complex should be built by this group, it would be patterned after an industrial park where companies operate individual plants, but they would also take advantage of economies of scale by sharing infrastructure and transportation facilities.

To help the reader understand how an Alaska complex might be designed and organized, the following section presents three examples of primary petrochemical operations.

**Natural-gas liquids to ethylene and its derivatives.** Ethylene is manufactured from feedstocks that range from ethane to heavy gas oil, depending on economic conditions. In North America, ethylene is most economically made from ethane. An ethane-to-ethylene plant consists primarily a large cracker whose output is mainly ethylene with small quantities of byproducts, mostly LPG's. A "worldscale" ethylene plant is one with a capacity on the order of 1 billion pounds per year.

Figure 4 shows the basic processes for ethylene manufacturing at the plant operated by the Alberta Gas Ethylene Company, Ltd., at Joffre, Alberta. These are described below:
* Ethane feedstock is vaporized and scrubbed to remove carbon dioxide, preheated, and sent to the cracking heaters.

* The ethane is then cracked to yield ethylene and byproducts. The cracked gas is cooled by direct contact with quench water and sent on to the cracked-gas compressor.

* The cracked gas is compressed, scrubbed with dilute caustic to remove any traces of acid gases, and dried to remove all traces of water.

* The dried gas is progressively chilled and partially condensed at progressively lower temperatures.

* The condensate from the chilling train is separated into its components by distillation. The condensate is first fed to a demethanizer where methane goes overhead to the fuel-gas system, and the remaining components go out the bottom of the column to a de-ethanizer.

* The bottoms from the de-ethanizer go to a depropanizer and debutanizer, where the material is split into C2, C3, and C4 fractions, which are either used as plant fuel or sold.

The overhead from the de-ethanizer goes to an acetylene-removal system where the acetylene is converted with hydrogen to ethylene or ethane.

The stream is dried again to remove any traces of water and sent on to a secondary demethanizer. High purity ethylene is taken overhead, condensed and stored for use by derivative plants.

Figure 5 illustrates the wide range of derivatives that can be manufactured from the primary petrochemical ethylene.
Figure 5: Derivatives of Ethylene

- (catalyst) → polyethylene

- +oxygen → ethylene oxide → +H₂O → ethylene glycol

- +alkali → polyglycols

- ethylene from refinery gases or cracker →
  - +hypochlorous acid → ethylene chlorohydrin → +alkali →
    - di- & tri-ethylene glycols
  - +chlorine → vinyl chloride → +alcohols or alkyl phenols
  - ethylene dichloride
  - ethylene dichloride + water → ethyl alcohol → acetaldehyde
  - ethyl chloride + water → esters
  - ethyl chloride
  - +hydrogen chloride
  - +water (catalyst) → styrene → poly-styrene
  - +sulfuric acid → sulfuric esters + water
  - +benzene → styrene
Natural gas to methanol. Methanol is produced from natural gas as indicated in Figure 6, and as described by the following process steps:

* First, the natural gas feedstock is desulfurized and the hydrocarbons are decomposed in a steam reformer. The synthesis gas thus obtained consists mainly of CO, CO₂ and H. The high-grade waste heat is used for generating steam, and some residual heat is dissipated to the air or cooling water.

* In the next process step, the synthesis gas is compressed to the synthesis pressure. Methanol synthesis is performed at pressures on the order of 50...
atmospheres and temperatures around 500°F, using a copper catalyst. The heat of the reaction is used for generating steam, and the methanol-gas mixture is further cooled with the aid of water and/or air, causing the methanol to condense. The unconverted gas is returned to the reactor.

* The resulting mixture of methanol, water, and traces of synthesis byproducts (such as higher alcohols and dissolved gases), is purified by distillation.

* The purified methanol is then stored ready for transportation or further processing.

Methanol made in this way can be used directly as fuel or it can be further processed into formaldehyde, methyl chloride, chloroform or carbon tetrachloride. Mobil Oil has developed a process to produce synthetic gasoline from methanol.

**Figure 7**

**Benzene, Toluene, and Xylenes**

**By Reforming and Extraction**

---

**Figure 7**

**Benzene, Toluene, and Xylenes**

**By Reforming and Extraction**

---

**Figure 7**

**Benzene, Toluene, and Xylenes**

**By Reforming and Extraction**

---
Naphtha to benzene. Mixtures of aromatic hydrocarbons --- benzene, toluene, and xylenes, are produced as coproducts or byproducts in several refinery and petrochemical plant processes, including cracking of ethane, naphtha, and gas oil to olefins. Most of the aromatics produced, however, come from catalytic naphtha reformers that convert paraffins to cycloparaffins and cycloparaffins to aromatics. A flow sheet for the process is presented in Figure 7.

Because the aromatics leave the reformer in a mixture containing other hydrocarbons of the same boiling range, the recovery process consists of extracting the aromatics using an organic solvent and subsequent fractionation of the individual aromatic compounds.

Benzene is obtained from the mixture of aromatics either by direct extraction or by the hydro-dealkylation of toluene. In this process, fresh toluene feed is combined with hydrogen and heated. The temperature rise resulting from the exothermic reaction is controlled by quenching with hydrogen-rich gas. The gas stream is drawn off, cooled, and recycled. The liquid is stabilized to remove light paraffins and olefins, treated, and sent to a fractionator where the benzene is separated out.

As Figure 8 suggests, benzene and the other aromatics are important primary petrochemicals for the manufacture of styrene, nylon, detergents, epoxy resins and more.

Petrochemical Complexes and Utility Requirements

Petrochemical complexes often combine the manufacture of several primary petrochemicals and derivative operations. Figure 9 lays out the different processes contemplated for Phase I and Phase II of the Dow-Shell Group project. At this time (August, 1981), the group is considering the following feedstocks: methane to make ammonia and urea; ethane for ethylene and its derivatives; naphtha for benzene; and coal for methanol.
FIGURE 8
Aromatics Derivatives

Source: Shreve and Brink, Chemical Process Industries
Figure 9
Dow-Shell Petrochemical Project

<table>
<thead>
<tr>
<th>PHASE I</th>
<th>PHASE II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>Ammonia 950</td>
</tr>
<tr>
<td>Ethane</td>
<td>Urea 1,280</td>
</tr>
<tr>
<td>Polyethylene</td>
<td>Ethylene 400</td>
</tr>
<tr>
<td>Propane, Butanes</td>
<td>Ethylene 1,200</td>
</tr>
<tr>
<td>Naphtha</td>
<td>Benzene 970</td>
</tr>
<tr>
<td>Coal</td>
<td>Methanol 4,000</td>
</tr>
<tr>
<td>Salt</td>
<td>Chlorine and Caustic Soda 1,150</td>
</tr>
<tr>
<td>Exort</td>
<td>Export</td>
</tr>
<tr>
<td>Exort</td>
<td>Export</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PHASE II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethylene 1,200</td>
</tr>
<tr>
<td>Ethylene oxide &amp; Ethylene glycol 600</td>
</tr>
<tr>
<td>Ethylene 1,200</td>
</tr>
<tr>
<td>Ethylene oxide &amp; Ethylene glycol 600</td>
</tr>
<tr>
<td>Ethylene 1,200</td>
</tr>
<tr>
<td>Chlorine and Caustic Soda 1,150</td>
</tr>
<tr>
<td>Ethylene di-Chloride 700</td>
</tr>
<tr>
<td>Polyethylene 200</td>
</tr>
<tr>
<td>Styrofoam</td>
</tr>
</tbody>
</table>
The utility requirements to operate a plant of the magnitude contemplated by Dow-Shell are substantial, as indicated by the project's forecast demand for electricity, steam, air, and water in Table 11.

**Table 11
Projected Utility Requirements: Dow-Shell Project**

<table>
<thead>
<tr>
<th>Utility</th>
<th>Phase I</th>
<th>Phases I and II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity</td>
<td>75 mw</td>
<td>245 mw</td>
</tr>
<tr>
<td>Steam</td>
<td>350 ton/hr</td>
<td>615 tons/hr</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>2,000 SCFM</td>
<td>3,500 SCFM</td>
</tr>
<tr>
<td>Air</td>
<td>7,500 SCFM</td>
<td>9,000 SCFM</td>
</tr>
<tr>
<td>Potable Water</td>
<td>300 GPM</td>
<td>500 GPM</td>
</tr>
<tr>
<td>Demineralized Water</td>
<td>2,500 GPM</td>
<td>4,600 GPM</td>
</tr>
<tr>
<td>Cooling Make-Up Water</td>
<td>8,000 GPM</td>
<td>12,000 GPM</td>
</tr>
</tbody>
</table>

SCFM = Standard cubic feet per minute  
GPM = Gallons per minute

**Water use.** Water supply is a very "site-specific" consideration, which affects not only the choice of plant location, but also plant design and operating costs. Water serves a variety of refining and petrochemical needs including cooling, processing, steam generating, potable water use and sanitation.

Relatively little water is actually consumed by refineries and petrochemical plants; however, huge quantities of water are used for cooling and condensing. In many chemical and refining processes, the feed is heated or vaporized to promote the desired reaction or permit the required separation of products. The products, in turn, must be condensed to a liquid and cooled to a safe temperature for storage or product blending.

A large amount of heat is recovered by the use of heat exchangers to transfer heat between fluids; e.g., heat contained in a hot product that must be condensed or cooled is
transferred to a cooler feed stream that must be heated. This arrangement conserves fuel and reduces cooling water requirements. Most cooling water, moreover, is pumped within a closed system, where it is generally not subject to contamination and thus can be reused repeatedly.

Refineries and petrochemical plants also require large quantities of water to generate steam for power, evaporation heating, and drying. Most of the steam is condensed in closed systems and is normally reused. Water suitable for **steam generation**, however, requires extensive treatment because as the water is evaporated, solids in the boiler water become concentrated and can cause overheating. Also, gases dissolved in the water or liberated from dissolved minerals will corrode pipes and fittings.

Much smaller quantities of water are required for **process purposes**. In refineries, crude oil normally contains salt and other matter that is removed by water-washing to avoid corrosion or fouling of process equipment. Where water is used to separate oil and water phases, to wash traces of treating chemicals from product streams, or to flush lines and other equipment, the possibilities for water contamination are high and for water reuse, relatively low. Finally, potable-water requirements for drinking and sanitation are relatively small compared to other water uses.

The quantity and quality of water needed for a petrochemical complex are not absolute. Dow-Shell estimate daily water requirements to be in the neighborhood of 24.6 million gallons, a staggering amount considering that the City of Kodiak, for example, uses only 10 to 12 million gallons daily at the height of the fish-processing season. If water is not available in these quantities at the chosen site, however, the requirement could be reduced substantially by the use of sea-water or air-cooled towers.

Water can be a significant cost factor where access to the water requires major investments in wells or pipelines, or when equipment must be installed to treat or conserve water. The Pac-Alaska LNG plant design illustrates the relative-cost tradeoffs. The sponsors considered piping
water 16 miles from the Kenai River, but found that an air-cooling system was less expensive. Because of the choice of air-cooling, the Pac-Alaska plant, if constructed, will require only about one percent of the water now used by the much smaller Phillips LNG plant.

Energy requirements. Both the chemical and refining sectors are substantial users of energy for boiler and process fuel, refrigeration, pumps and compressors, etc., in addition to their feedstock requirements. The chemical industry consumes more than one third of the energy used by all manufacturing industries in the United States. Because it is a significant cost factor, plants are carefully designed to use energy synergistically and are often located in places where fuel is relatively cheap.

Health and Safety Issues

Whatever economic interest Alaska may have in expanding the processing of locally produced hydrocarbons within the state, other issues have dominated public discussion, and will probably continue to do so. A recent survey by the Alaska Department of Environmental Conservation identified the largest public concerns with respect to petrochemical industry development as the transportation of chemicals, public health, air and water quality, and disposal of hazardous wastes, while employment, population growth, and the impact of public services seemed to be less important.

These issues were raised during the debate over the Alpetco proposal and will surely surface again if the Dow-Shell group or some other entity decides that petrochemicals development in Alaska is economically feasible and moves toward the design and construction of transportation and processing facilities.

Poisons and carcinogens. The acute toxic character of some naturally occurring chemicals is obvious, causing death, sickness, or readily detectible biological reactions in organisms that come into contact with them. Evolutionary adaptation, however, has made humans and other organisms
relatively immune to small internal doses or contact with most chemical substances they are likely to encounter in nature. There are a few well-known exceptions, including poisoning from heavy metals (e.g., lead, arsenic, mercury, and cadmium) that can accumulate in the body over many years from natural sources, and some natural "carcinogens" (cancer-inducing agents).

Synthetic organic chemicals create special hazards, however. Mid-stage petrochemical derivatives tend to be particularly active chemically (hence their usefulness as chemical intermediates). As a result, once they leave the controlled environment of the laboratory or chemical plant, they readily interact with many other kinds of molecules, including those that make up human cells.

Because they are highly reactive with other substances, moreover, these chemicals tend to be absent or infrequent in nature, even in minute quantities, and for that reason, evolution has had no occasion to create natural defenses against them in humans and other organisms (by permitting only the more resistant individuals to survive and reproduce).

The most pernicious of the bioactive substances may be those that have an affinity for the genetic materials in cell nuclei --- the proteins that control cell development and division. Today's view of cell biology implies that just one molecule of such a chemical coming into contact with one DNA molecule in one cell can alter the cell's "genetic code" and thereby initiate the production of cancerous cells or, if the DNA is part of a reproductive cell, cause a defective birth or an inheritable defect.

One implication of this mechanism would be that there is no safe dose for any such substance, just as there seems to be no safe dose for ionizing radiation (which includes the earth's natural "background" radiation and cosmic rays, as well as x-rays and the emissions from nuclear power plants). Controlling human exposure to carcinogens or teratogens (agents producing inheritable defects) without
eliminating it will only \textbf{reduce} the number of deaths, illnesses, or defective births caused by the substance, but can not completely eliminate them.

Not all authorities agree with this "one-shot" view of the way in which carcinogens and teratogens operate. Some scholars still hold to the classical theory in which there is a "threshold" of exposure for each substance below which harmful effects are unlikely. This older "pharmacological" view is, significantly, the assumption that underlies federal harmful-substances legislation and the regulations of the Occupational Health and Safety Administration (OSHA).

Whether or not one molecule is sufficient to initiate a cancer or a birth defect, poisoning by synthetic chemicals has other indisputably troublesome features, including long lags between exposure and the first appearance of symptoms. One famous instance is that of DES (diethyl silbestrol), which appears to produce cervical cancer in the grown daughters of women who took the drug two or three decades earlier.

Even without such delays in the occurrence of harmful effects from a chemical, moreover, it can be years or decades before a sufficient statistical base accumulates to warrant suspicion that the substance is harmful, much less to establish the fact conclusively. The first hint might appear, for example, only when a public health statistician noted that the last 25 years had seen three cases of a certain rare form of cancer among the more than seven thousand workers who had worked in a particular plant, while the average incidence in a national population sample of that size would have been less than one.

It is conceivable, indeed, that powerful synthetic poisons and carcinogens exist that will \textbf{never} be detected. A few kilograms of a given substance vented into the atmosphere or carried off in the drains and diluted throughout the world's oceans over a period of years might increase the worldwide incidence of cancer or, say, mongolism by tens of thousands of cases per year. If these cases were dispersed widely enough geographically and over time, they would be
overwhelmed statistically by the hundreds of other things that influence the world's mortality and morbidity trends.

There are now thousands of experts engaged in testing the effects of acute and long-term exposure to various chemicals, but little is really known. More than fifty thousand synthetic chemicals are currently produced in commercial quantities, and about four to six hundred new chemicals are introduced commercially each year. Only a tiny fraction of these substances were tested for cumulative toxicity or carcinogenic effects before being marketed. The chemical industry and federal regulatory agencies have been continually expanding their testing programs for newly introduced substances, but a considerably greater effort would be necessary in order to bring our knowledge of the thousands of untested but currently marketed chemicals up to the standards that apply to new products.

The development of a petrochemical industry in Alaska inevitably involves the production, handling, storing, transportation, and disposal of substances that are or may be hazardous to human life and health. Three of the chemicals the Dow-Shell group contemplates producing in Alaska are known carcinogens --- benzene, ethylene oxide, and ethylene dichloride. Two others are suspected carcinogens --- ethylbenzene and ethylene glycol. Moreover, most petrochemical complexes of the type that Dow-Shell are studying also produce vinyl chloride monomer and acrylonitrile, both of which are known to cause cancer.

Since World War II, sufficient evidence has accumulated to establish that some aromatic hydrocarbons produced in refineries and several aromatic products of petrochemical plants, pose health hazards when a major spill or accident occurs or when people are repeatedly exposed or receive prolonged contact with even minute amounts.

Prolonged exposure to high concentration of benzene is known to cause reversible damage to the bone marrow where red and white cells and platelets are formed. Benzene exposure can cause aplastic anemia, a form of leukemia, chromosome damage in white blood cells, and acute
myelogenous leukemia. Benzene is also a central-nervous-system depressant.

The federally regulated occupational exposure level for benzene is now 10 parts per million (ppm), averaged over an eight-hour day. OSHA regards this level of exposure to be too high and recommends a standard of 1 ppm, a standard that was recently rejected by the Supreme Court on a procedural technicality in a 5-4 decision.

These standards apply principally to refinery and chemical plant workers, but we know almost nothing about the health effects, if any, of the tons of benzene that are released into the atmosphere every day when automobile gasoline tanks are filled. Little consideration has yet been given, moreover, to systematically measuring, much less controlling, exposure to aromatics on the part of those who may conceivably comprise the most numerous and severely impacted occupational group --- filling-station attendants.

Ethylene dichloride is another chemical also in the midst of regulatory controversy. It is a major ingredient for manufacture of vinyl-chloride monomer (VCM --- one of the most active known carcinogens) and appears to pose some danger itself. The current regulated level of exposure to ethylene dichloride is 50 ppm; however, in 1975, the National Institute for Occupational Safety and Health (NIOSH) recommended a revised standard of 5 ppm because impairment of the central nervous system and increased morbidity (especially diseases of the liver and bile ducts) were found in workers chronically exposed to ethylene dichloride at concentrations below 10 ppm and averaging up to 15 ppm.

In addition to exposure problems within the petrochemical plants, there are also risks associated with the transfer and shipment of chemicals. Again, as with exposure in the workplace, the implications of and dangers posed by a chemical spill are not precisely known. Petrochemicals do, however, present a hazard to marine ecosystems both in terms of an acute spill situation and chronic exposure to small dosages. The acute toxicity of ethylbenzene to
marine organisms occurs at concentrations as low as 0.43 ppm, for example, but little is known about the toxicity to marine animals from chronic exposure to lower concentrations of ethylbenzene or other chemicals.

A petrochemical complex in Alaska may not by itself pose great health, safety, or aesthetic risks. Production of some first-stage petrochemicals such as ethylene and methanol is virtually odorless and, with the sometime exception of large quantities of water vapor and occasional flaring, the plants are fairly safe and quite inconspicuous.

The production of benzene, ethylene dichloride, and possibly VCM, however, presents a new dimension of risk for Alaska industry and to the communities in which the plants would be located. Acceptable levels of exposure are the subject of much dispute and debate even within the responsible federal agencies (OSHA and NIOSH).

The Policy Dilemmas. In summary, the hard facts about chemical health hazards are sparse, and even where the facts are known, their policy implications are not obvious or even easy to think about systematically. There is an undeniable statistical association between exposure to aromatic hydrocarbons or VCM, for example, and the incidence of certain degenerative diseases and cancer. If, as is likely, the "one-shot" view of carcinogens is correct, there is probably an inescapable risk of exposure and some increase in the risk of cancer for anyone working or residing in places where these products are produced, stored, transported, or used.

Society tolerates cigarettes, firearms, motorcycles, and a host of other products whose association with death and sickness is far more obvious than that of benzene or VCM. Public policy toward these products is just as controversial as are policies regarding hazardous chemicals or nuclear power, but they are tolerated in part because their risks are regarded as largely voluntary. The distinction is not an absolute one, as tobacco, handguns, and traffic accidents do claim "innocent" victims and, just as an individual can choose not to smoke, ride a motorcycle, or
associate with people who play with guns, he or she presumably can choose not to work in or live next to a petrochemical plant or nuclear reactor.

Fuzzy as the distinction is, however, it is a real one. Regulation of the health and safety risks --- known and unknown, real and imagined --- is a social and political task. The people of Alaska will have to make some hard practical decisions on how their government will deal with these issues.

Options for Regulation

Most States have adopted standards and regulations to govern the handling, processing, and storage of hazardous substances and wastes. These regulations attempt to address certain known workplace and environmental hazards.

For example, oil contamination is a serious problem in refining and some petrochemical operations. Hydrocarbons can enter the wastewater system directly from a spill, leaks from lines, vessels and valves, leaks around pump packing, or product-sampling. Contamination can also occur when oil and water are brought into direct contact as in crude-oil desalting operations or product washing following chemical treating. Remedies include special collection and segregation systems and processes for removing oil from ships' ballasts, wastewater, plant runoff, and the like.

Disposal of spent chemicals poses another set of environmental problems with special significance to people who live near hazardous-waste dumps established before there were federal regulations governing the disposal of toxic substances. Today, because feedstocks are expensive, hydrocarbon byproducts are generally recovered and recycled, so that new petrochemical facilities tend to generate a smaller volume of waste materials than older plants, while those waste materials that are produced are subject to increasingly stringent regulations regarding the sale of spent chemicals and disposal by chemical means, incineration, venting or flaring.
Finally, air pollution in the form of emissions and "fugitive" (unintended) leaks, is an important concern that is reflected in the current requirement for special permits as a condition of refinery and petrochemical-plant construction, and operational regulations intended to protect air quality. Major sources of air pollution are burning of fuel in boilers and process heaters. The greatest volume of discharge from other plant components typically occur at peak operating conditions, during plant upset or malfunctions, and during the startup or shutdown of operations. Atmospheric discharges of sulfur oxide, hydrogen sulfide, and mercaptans are, of course, a major problem for refineries processing high-sulfur crude oil.

The State of Alaska has adopted and strengthened EPA air-quality standards, and adopted and modified EPA and OSHA water-quality standards, waste-disposal regulations, and occupational-safety standards. The State's leasing and permitting processes provide vehicles for controlling discharges on, into, or under State lands, and into surface and ground water. In 1981, the legislature also passed a waste-disposal law that authorizes State agencies to write new standards for the handling and disposal of hazardous wastes.

The Federal regulatory machinery in Alaska is comparatively lean but is probably adequate to the relatively small chemical industry that exists in Alaska today. The prospect of large-scale petrochemical development in Alaska, however, suggests the wisdom of at least investigating and comparing additional measures that might be implemented at the State level to protect human life and the natural environment.

Prescriptive vs. Economic Remedies

There are two polar approaches to control of health and safety hazards and environmental quality, and a number of in-between measures. At one extreme are prescriptive and proscriptive regulations, which state in categorical terms what industry may or may not do, what facilities are acceptable, or exactly how certain equipment is to be designed. In a prescriptive system of regulations, remedies
for non-compliance can be either criminal penalties (including fines and imprisonment), civil penalties, suspension of operation, or orders by regulatory agencies or the courts directing specific performance. The other extreme leaves the individual or enterprise free, at least in principle, to decide how to operate, but relies on economic incentives in the form of graduated fees or penalties to discourage harmful activity, and tax-credits or other rewards for desired behavior.

**Prescriptive and proscriptive regulation.** Prescriptive regulations are of two general types, specifications and performance standards. Traditional building codes are typical of regulation by specification, attempting to limit fire hazards by prescribing lath-and-plaster walls, protecting sanitation by requiring cast-iron drain pipes of a certain diameter, and the like. Many of the Interior Department's stipulations governing the construction of TAPS were also of a prescriptive character. Effluent and emissions standards that set the maximum absolute volume or maximum concentration of some pollutant that may be released by a single plant or from a single point are examples of performance standards.

The ultimate proscriptive regulation is simply to forbid the activities that are deemed hazardous. One possible approach to the real and imagined hazards arising from the production, storage, and transportation of VCM or ethylbenzene, for example, would be for Alaska to ban their manufacture within the state.

It is likely that the federal courts would hold that a direct legal prohibition on the production of specific substances was unconstitutional, but it would not be difficult for the State to surround the industry with so many regulatory restrictions and so much red tape as to make it economically unattractive. The State of Alaska has, for all practical purposes, done this with respect to nuclear power.

The most direct and least vulnerable approach legally, however, would be to use the state's proprietary position and contractual ability rather than its police powers to prevent industrial activity it deems undesirable --- just as it uses
these powers to promote in-state processing of hydrocarbons, timber, etc., and preferences for employment of Alaska residents. The State, in other words, is free not to sell its royalty oil, gas, or NGL's; not to lease plant sites, and not to sell gravel from state lands unless the party stipulates that it will not produce, store, or transport specified chemicals within the State.

The advantages of prescriptive regulations are their relative and ease of enforcement. Their disadvantages are inflexibility and insensitivity to costs. Obsolete building codes, for example, have frequently delayed the introduction of cheaper, stronger, and safer building materials; a categorical Federal requirement for secondary treatment of municipal waste-water has imposed extravagant sewage-treatment costs on many small communities (including Alaska communities), where it makes no perceptible contribution to human health or environmental quality. Yet the same regulation allows serious water-quality hazards that could be resolved at comparatively low costs to persist in a number of more densely populated areas.

Economic incentives. At the other extreme from prescriptive and proscriptive regulation are purely economic incentives that leave design and operational details, and the risks attendant upon them, entirely up to management. The heart of this approach in its historical form is the right of injured parties to sue and recover damages for loss of life, or injury to persons or property.

Litigation. Traditional civil remedies rely on the threat of lawsuits and expensive court awards to induce industry to spend just about as much on health, safety, and environmental protection as the risks of measurable (and litigable) damage warrant. The effectiveness of litigation as a deterrent to (as well as a remedy for) private or public injury has been greatly enhanced in recent years by, (1) the possibility of "class action" suits, in which large numbers of parties claiming relatively small individual injuries can group together to litigate, (2) the increasing tendency of State and local governments to institute proceedings to
recover for alleged damages to public values in cases where it would be difficult to show or measure individual damages, and (3) the publicity accorded to a few huge settlements and awards of punitive damages in occupational-injury and product-safety proceedings.

**Strict liability.** Traditionally, civil remedies for injuries to health, safety, or the environment are available only to injured parties who can prove that there was misconduct or negligence on the part of the persons that caused the problem. The very existence of a refinery, tanker terminal, or petrochemical plant, however, creates a statistically certain risk of injury or damage to someone, sometime, even if there is no legally provable misconduct or negligence on the part of anyone. (Suppose a wholly unanticipated natural disaster ruptures a tank full of poisonous gas; or suppose that a chemical which was rigorously tested turns out to have horrible long-term effects that no one reasonably could have been expected to anticipate?)

Thus, for the possibility of litigation to be an adequate remedy, legislation is necessary to make the legal liability for certain kinds of damage "strict", or "absolute" --- not conditional upon proof of negligence, in other words. For example, Alaska law establishes strict liability for damages from marine oil spills.

Individual litigation is inadequate or totally inapplicable, even with strict liability, wherever damage is likely to be distributed randomly over a large and hard-to-define population (as is often the case with carcinogens), so that responsibility cannot clearly be assigned. It is also inadequate where the values to be protected are not privately owned (as in the case of a commercial fishery stock), or difficult or impossible to put a price on (air clarity, for example, or the ability of an area to support a wild bird population).

**Insurance.** Another problem with relying on the judicial process to motivate safe design and operation of industrial facilities is the cost of litigation, its overall
uncertainty, and the long time that typically elapses between the damage and its compensation. Insurance, and particularly insurance funds administered by an independent party, can benefit both industry and the public by cutting legal costs, delays, and the uncertainty of the outcome. Insurance can be either voluntary or mandated by law: There are a number of Federal, State, and cooperative insurance funds for clean-up after major accidents.

The Trans-Alaska Pipeline Liability Fund was the first Congressionally created entity of its kind, receiving a fee of five cents per barrel lifted at the Valdez terminal by the TAPS owner companies. The purpose of the fund is to pay legitimate claims for damages, including clean-up costs, resulting from oil discharges between Valdez and any other U.S. port; the Fund is liable without regard to fault for that increment of damages in excess of $14 million but not in excess of $100 million per oil-spill incident.

Insurance also has its shortcomings, however. As many readers who have had difficulty with an auto insurance claim may recall, it sometimes requires litigation to collect benefits, even from one's own insurer. Diluting the penalty a firm pays for a given injury also dilutes the incentive to avoid the injury. Premiums in private insurance programs are normally adjusted to the experience of the individual enterprise as well as the industry, but rigorous actuarially-based premiums seem to be the exception in compulsory, government-sponsored no-fault insurance programs.

A difficult issue in establishing mandatory insurance programs is whether to make them serve as a substitute for all other private remedies, or to allow those who are injured to retain all of the rights they would otherwise have under civil law. Workmen's compensation laws in most States prohibit lawsuits or any other remedy for job-related injuries. The federal insurance program for nuclear power plants (the Price-Anderson Act) also eliminates any other recourse on the part of individuals who might be injured in a nuclear accident. Details of the issue are beyond the scope
of this report, but either choice may create serious inequities.

**Effluent taxes and hybrid systems.** There are a variety of health, safety, and environmental regulation techniques that are not based purely on an economic assessment of risk, but neither are they purely prescriptive. Toward the economic end of the spectrum, there is a growing literature on the advantages of emissions and effluent taxes. Few such programs yet exist in North America, but they are common in Europe.

A regional air-quality board might, for example, establish a tax or penalty per kilogram of sulfur dioxide (SO₂) discharged into the air. This tax would allow each operator of an electrical generating plant or refinery to decide whether it was cheaper to reduce emissions or to pay the tax. The SO₂ tax rate could be adjusted periodically to create just enough pressure on industry as a whole to hold the concentration of SO₂ in the atmosphere below some target level. Since those firms with the cheapest options for reducing sulfur emissions are the ones that would choose not to pay the tax, this approach would theoretically achieve a given improvement in air quality at a considerably lower economic cost than prescriptive standards.

A related regulatory technique is to establish prescriptively based --- even arbitrary --- standards for some aspect of environmental quality, but to allow a "market" in pollution rights. A regional air or water quality agency might, for example, establish a maximum allowable rate of discharge or percentage concentration of certain pollutants for each plant or effluent source. A plant would be allowed to exceed its individual pollution quotas or even to establish a new source of pollution, however, if it could induce some other party to reduce its output of pollutants by a comparable amount.

California's Air Resources Board, for example, required Sohio to effect a net reduction in certain air pollutants in the region, as a condition of the Board's licensing of the tanker terminal that the company planned at Long Beach to
serve its proposed Pactex pipeline. Sohio's solution was to pay for smokestack scrubbers for electrical generating plants owned by the Southern California Edison Company.

The system that Alaska establishes to control the health, safety, and environmental risks of hydrocarbons processing will undoubtedly differ from the current mix of prescriptive, proscriptive, and economic regulation that exists in Federal law or in the laws of other States (or other nations). It is in order, however, for Alaska to begin a systematic review of these systems, their effectiveness, and their cost-effectiveness.
CHAPTER 6
THE ECONOMICS OF HYDROCARBONS PROCESSING
AND THE OUTLOOK FOR
REFINING AND PETROCHEMICALS IN ALASKA

Three cost factors dominate investment and location decisions for hydrocarbons-processing facilities: (1) transportation costs, (2) feedstock costs, and (3) plant-construction costs. It is the interplay among these three factors that determines whether export refineries or petrochemical plants will be built in Alaska.

Hydrocarbon Transportation Economics

Transportation cost is the most powerful economic influence on the location of refineries and petrochemical plants, and one of the most important considerations in choosing a product slate. Two fundamental axioms govern the relationship between transport costs and the choice of transportation systems and plant location:

(1) Light hydrocarbons cost more to ship per unit of weight or energy than heavy hydrocarbons. A corollary of this axiom is that gases cost more to ship than liquids.

(2) Tankers are the most efficient long-distance transportation mode for hydrocarbons that are liquid under atmospheric conditions, while pipelines are the most efficient mode for gases.

The first axiom and its corollary rest on elementary physical principles. At a given pressure and temperature, solids and liquids pack more matter and more energy into the same pipeline or tanker space than gases. A cubic foot of propane gas contains more energy than the same volume of methane gas, and a barrel of crude oil or residual oil contains more energy than lighter petroleum products like gasoline or naphtha, or light chemical derivatives such as methanol.
Waterborne bulk carriers. The second axiom reflects the fact that waterborne transport is generally the cheapest way of moving a given weight or volume of any bulk commodity. Crude oil, in turn, is almost an ideal cargo for large ocean-going vessels. It has just the right density — slightly lighter than water so that the entire hull-space can be filled with cargo and the vessel will have a low center of gravity, which improves its stability. A liquid at atmospheric pressures and temperatures, crude oil does not require closely-controlled conditions on board, is easy to load and unload, and is relatively insensitive to contamination.

Shipping gases by tanker is a wholly different matter. Vapors must be chilled and liquefied in costly facilities that consume substantial amounts of energy as well. The lightest hydrocarbons such as methane, ethane, and ethylene have especially low boiling points, and vessels designed to carry them feature expensive cryogenic (refrigerated or super-insulated) compartments.

The heavier propane and butanes (LPG) require less energy to liquefy, and will remain liquid at atmospheric temperatures if confined in tanks under only modest pressures. Thus, while ocean-transport costs for LPG are substantially higher per unit of energy than for crude oil, LPG is much less troublesome than natural gas, ethane, or ethylene.

Gas-pipeline transportation. Pipelines are the ideal transport mode for gases. In a pipeline, extremely high pressures can be used to squeeze even the lightest hydrocarbons into dense-phase fluids that contain nearly as much energy in a given space as liquids, and these fluids can be pumped long distances with a relatively modest loss of energy in the form of compressor fuel.

TAPS vs. ANGTS. In Alaska, these principles can be seen in the contrasting choices of transportation modes for North Slope oil and gas. Before deciding to build an oil pipeline across Alaska, the North Slope producers investigated the feasibility of a sea route directly from Prudhoe Bay to the U.S. East Coast. The all-tanker system was rejected
in favor of a pipeline only because of the delays that would have been involved in perfecting ice-breaking techniques.

While an all-pipeline system across Canada would have been the cheapest way to take Alaska oil to the Upper Midwest, the companies finally chose TAPS because it was the shortest land route to a year-round ice-free port (Valdez), from which tankers could carry crude oil for less than $1 per barrel to any Pacific Coast port in North America or Asia.

For Prudhoe Bay natural gas, in contrast, most parties favored an all-pipeline route across Canada over a liquefied natural gas (LNG) tanker system right from the beginning, because of the latter's greater capital cost and fuel consumption. Even now, if transportation of North Slope gas by means of the proposed Alaska Highway pipeline turns out to be so expensive that the gas cannot be marketed in the Lower 48, the gas producers are unlikely to reconsider an all-Alaska-pipeline/LNG system. Even the El Paso Company, which originally sponsored the LNG concept, has abandoned it as uneconomic.

If an overland pipeline from the North Slope turns out to be infeasible, the relative costs of transporting different hydrocarbons suggest that:

(1) There may be NO alternative transportation technology that is capable of moving North Slope methane to market at an acceptable cost.

(2) Such a system, if it does exist, is less likely to combine a Trans-Alaska gas pipeline with LNG tankers than to involve either ---

(a) processing the natural gas right on the North Slope into products like methanol or synthetic gasoline that could be shipped to an ice-free port through the existing oil pipeline or a new liquid-products pipeline; or
(b) shipping LNG directly from the Arctic Coast in icebreaking tankers or submarine barges.

Transportation costs and plant location. The two transportation axioms above can be applied directly to decisions that govern the location of refineries and petrochemical plants:

1. Petroleum refineries tend to be located near their markets.

2. Naphtha and gas-oil-based petrochemical plants tend to be located near refineries.

3. Natural-gas-based petrochemical plants tend to be located near their raw-materials sources.

Refined petroleum products are more costly to ship long distances than crude oil, and only partly because of their lower energy-density. Refineries produce a variety of products with different viscosities and vapor pressures, and with different degrees of flammability, toxicity, etc. Individual refinery products are therefore typically shipped in relatively small batches and tend to require specialized treatment to avoid loss or contamination, fire hazards, and the like. Thus, refineries are usually located to take advantage of the lower cost of crude-oil transportation, and designed to produce a product slate that matches a local or regional demand mix.

The same principles apply to petroleum (naphtha and gas-oil) -based petrochemicals manufacturing. Crude oil is cheaper to transport than the primary and intermediate petrochemicals or end-user products made from it. In addition, the initial distillation of crude oil and the subsequent cracking or reforming of naphtha or gas oil produce a great variety of hydrocarbons. Some of these products are suitable for petrochemical use, but others are more valuable as gasoline, jet-fuel, or fuel-oil blending stocks. Thus, petroleum-based petrochemical plants are generally planned
as a part of refinery complexes, or are at least located near refineries. As a result:

Transportation economics do NOT favor Alaska locations for petroleum refineries (except to serve in-state demand) or oil-based petrochemical plants.

These principles help explain why oil-industry personnel and energy analysts from the beginning almost unanimously doubted the economic viability and financeability of the Alpetco proposal, both in its original petrochemical-plant incarnation and in its later refinery version.

Natural gas and the lighter natural-gas "liquids" like ethane tend to be more costly to ship than their liquid or solid derivatives. Generally, therefore, it makes sense to convert methane and ethane to non-gaseous substances before shipping them long distances.

Accordingly, gas-based methanol plants and ethane-to-ethylene plants are almost invariably located in gas producing areas. As ethylene is itself a light gas, which can be moved by sea only as a chilled liquid in costly cryogenic tankers, it is usually processed further into liquid or solid petrochemical derivatives such as ethylene oxide or polyethylene before being transported to distant markets. As a result:

If Alaska natural gas and ethane are to be converted to petrochemicals anywhere, transportation economics favor an Alaska plant location.

This principle is the rationale behind the Dow-Shell group's strategy. Methane or ethane would have to be shipped by pipeline at relatively high unit costs, or by cryogenic tankers at even higher costs, to feed petrochemical plants in the Lower 48 or, say, Japan. Converting methane to methanol in Alaska, or ethane to ethylene and then to polyethylene, for example, would facilitate transportation and hence reduce the final cost of the chemical products.
Final-products manufacturing. The advantage of locating gas-based hydrocarbon-processing facilities near feedstock sources does not extend indefinitely "downstream". Just as in other Alaska resource-based industries — wood products and fisheries, for example — the state's comparative advantage in manufacturing ends with those kinds of processing that reduce shipping costs by decreasing the bulk, weight, or perishability of the product. For a long time to come, the more complicated, labor-intensive, and weight- or bulk-increasing manufacturing activities will be cheapest to carry out in populous areas close to major markets. For this reason:

Alaska petrochemicals manufacturing will probably end with first or second derivatives that can be shipped as liquids or solids for further processing and fabrication elsewhere.

High capital, labor, and transportation costs make it unlikely, in other words, that a petrochemical complex in Alaska would produce and package fibers, textiles, apparel, housewares, rubber or rubber products, pharmaceuticals, etc. Although the public-relations literature of the various chemical companies emphasizes the vast number of final products made from, say, ethylene derivatives, the Dow-Shell reports make it clear that the group is not actively considering processing Alaska hydrocarbons beyond the first form in which they can be shipped economically to other markets.

Fixed Capital Costs.

The foregoing principles in themselves do not guarantee that it is economically feasible to make petrochemicals in Alaska from North Slope hydrocarbon gases. Fixed capital costs — essentially plant construction costs — are also a crucial element in investment and plant-location decisions. It is conceivable, therefore, that the construction-cost disadvantages of an Alaska location might overwhelm its transportation-cost advantage. For the same reason, relative transportation expense alone does not
necessarily dictate where in Alaska a plant should be located.

Because refining and petrochemicals are unusually capital-intensive industries, however, production labor and other operating costs are relatively unimportant.

**Fixed costs vs. variable costs.** No new hydrocarbons-processing facility is likely to be built unless its sponsors and their lenders are convinced that project sales revenues will be sufficient to cover the full cost of production; that is, to recoup both (a) **fixed costs** --- the entire original investment plus a competitive return on that investment --- and (b) **variable costs** --- feedstock costs and other operating expenses.

Because an individual plant or complex costs hundreds of millions or even billions of dollars, cost overruns and mistaken product-market or feedstock-supply forecasts can be catastrophic, so that investors normally demand that their feasibility studies demonstrate a substantial safety margin. Therefore:

*Investors in a NEW plant will insist that expected sales revenues cover fixed as well as operating costs,*

*Nevertheless, once a plant is built, sunk costs do not affect operating decisions.*

Lumped together, these two propositions may seem confusing, but they are relatively simple concepts. An established plant will tend to operate at virtually full capacity so long as its product sells for more than its feedstock and other operating costs, even if it is not covering its depreciation or debt service, or generating any net profit.

In such a situation, in other words, the goal of plant management is to **minimize losses** rather than to maximize profits; refineries or chemical plants will stay in service whenever they would lose more money by shutting down than by continuing to operate. Such plants would never
have been built, however, if their sponsors had expected them to operate at a chronic loss.

**The outlook for refinery investments.** A huge overhang of excess refining capacity now exists both in the U.S. and worldwide. As a result, the current prices of petroleum products tend to represent little more than the cost of feedstocks, and contain no allowance for the amortization of fixed costs or any return to even the capital invested in existing facilities. Such a market is less likely yet to provide the substantial margin above operating costs that is necessary to justify building new refineries, unless they have some exceptional offsetting advantage in the form of low-cost feedstocks, captive markets, or a direct government subsidy.

Oil refining is thus a money-losing business almost everywhere, and it is likely to remain a money-losing business for many years. This situation probably would have been fatal to the Alpetco refinery scheme even if it did not have to face Alaska's transportation and construction-cost disadvantages.

**The outlook for petrochemicals investments.** New investments in facilities to produce ethylene and ethylene derivatives might seem to face the same difficulties as refinery investments, because great excess plant capacity now exists for olefins both nationally and worldwide. The crucial difference in outlook between refining and petrochemicals, however, is that there is little prospect that the expansion of oil-product consumption will resume in the foreseeable future, but most analysts believe that petrochemical consumption will begin growing again when the present economic slump ends. There is also a reasonable chance that the prices of gaseous feedstocks in remote producing regions like Alaska or Saudi Arabia will be sufficiently lower than world prices for competing oil-based feedstocks to make new gas-based plants profitable even in the face of idle capacity elsewhere.

**The "Alaska cost differential".** Big construction projects in Alaska are notorious for their high costs relative to
their counterparts in more developed temperate regions. Industrial facilities in Alaska must be designed to withstand more severe environmental stresses. At the same time, labor expense and transportation charges for equipment and materials are higher in Alaska, while labor productivity is lower than in the Lower 48, Europe, or East Asia.

Local construction expenses, chiefly site preparation and on-site labor costs, are usually assumed to be 50 to 60 percent higher at tidewater in Southcentral Alaska (e.g., at Anchorage, Kenai, or Valdez) than on the U.S. Gulf Coast; about 100 percent higher in Interior Alaska (Fairbanks or Big Delta); and about three times as high in the Arctic (Prudhoe Bay or Barrow). The Dow-Shell group has concluded that the cost differentials for petrochemical-plant construction in Alaska are even greater than these, projected plant costs in Southcentral Alaska ranging from 1.7 to 2.1 percent of the Gulf Coast cost. (These figures, incidentally, are comparable to the typical cost differential for refinery or chemical-plant construction in the Middle East.) Therefore:

If a processing plant in Alaska is to be competitive, the sum of its transportation and feedstock-cost advantages must be sufficient to overcome a large construction-cost disadvantage.

Feedstock Costs and Feedstock Supply.

The costs of feedstock and fuel (which are often but not always the same) are a crucial factor in deciding the feasibility of any refinery or petrochemical investment.

Oil-based feedstock costs. Low ocean-transport costs have created a single world market for crude oil, in which prices everywhere move more or less in unison, and in which differences in the price of crude oil between various tidewater locations around the world are relatively small.

Petroleum refining and petroleum-liquids-based petrochemicals manufacturing therefore tend to be "price-taker"
industries. Long-term crude-oil or petroleum-product sales contracts at fixed prices, or even at fixed formula prices (say, at the Saudi Arabian "marker-crude" price plus or minus a location and quality differential) are very rare. Individual operators of petroleum-liquids processing plants thus have little opportunity to control their raw-materials costs, but typically must accept whatever prices world markets (or government regulators) dictate. This is the case even for a refiner or chemical producer that owns and processes its own crude-oil supplies, because the true index of feedstock costs to such a producer is the price the oil might have commanded on the open market.

In assessing the economic feasibility of a fuels refinery or oil-based petrochemical plant, therefore, its sponsors have to make judgments about future oil prices and their relation to the market value of the fuels or petrochemicals derived from them. This task is not quite as hopeless as the turbulent history of world oil prices might suggest, because the market prices of petroleum-derived products from competing plants will also vary with the price of crude oil. And although substantial volumes of petrochemicals are produced from feedstocks other than crude-oil fractions, petrochemicals derived from oil constitute the "marginal" supply --- the strategic portion of world output whose costs will determine the product-price levels at which any new chemical plant must be competitive.

The feasibility analysis for a new hydrocarbon-liquids processing plant need not concentrate on the absolute level of oil prices, therefore, but only on:

The cost of feedstocks for the proposed plant, RELATIVE to the expected costs for its competitors (e.g., the difference between naphtha prices in region A and gas-oil prices in region B).

The effect of oil-price levels on total product demand.
The Alpetco project, for example, would clearly have lacked any advantage under the first test whether its product was to be petroleum fuels or petrochemicals. Unless Alaska were willing to sell royalty oil at less than market value, project sponsors had no reason to expect their oil feedstock costs to be decisively lower than those of Lower-48 or East Asian refiners or oil-based petrochemical manufacturers.

As a refinery, at least, Alpetco was handicapped under the second test too: Higher oil prices were persuading consumers worldwide to reduce oil consumption, idling a high proportion of existing refinery capacity in the United States, the Caribbean, Europe, and East Asia. The result has been --- and will continue to be --- petroleum-product price levels that reflect near-zero operating profits for refineries everywhere. Unless the State sold its crude-oil at a very deep discount, therefore, no hope would exist for Alpetco to recover its investment or earn any return on it.

Gas-based petrochemical feedstocks. Natural gas and natural-gas liquids markets are quite different from those for crude oil. Because of high costs for marine transport of liquefied gases, a single world market for methane or ethane does not exist as it does for crude oil and petroleum products, while the market for LPG's is far less developed than the crude-oil market. Even within North America, the huge investments necessary to bring Arctic gas to market would foster large regional differences in the wellhead value of natural gas and gas liquids.

Accordingly, gas-based petrochemical plants in remote producing areas like Alaska or the Middle East are likely to be "price-makers" rather than price-takers. This means, simply, that local petrochemical manufacturing may be able to offer gas producers a higher price than they would get by shipping the gas to distant markets by pipeline or as LNG.

Illustrations.

Natural gas is interchangeable with fuel oil in most of its end uses. Because more than half of the natural gas
currently sold in the United States is consumed by electric utilities and industry, the ultimate market value of additional gas to Lower-48 consumers is the price of the residual fuel oil that gas would displace.

Let us ignore for the moment the complications created by federal wellhead price controls and "rolled-in" pricing, and suppose that the value of North Slope natural gas used as fuel in the Lower 48 is roughly equal to the price of residual oil at $30.00 per barrel or $5.00 per million btu (mmbtu). If the cost of transporting North Slope gas to Lower 48 consumers is $4.00 per mmbtu, its netback value on the North Slope would only be $1.00 per mmbtu. Thus, the gas producers would gain if they could obtain any price above $1.00 for the North Slope hydrocarbons that would be worth $5.00 in the Lower 48. Figure 9 illustrates the way in which transportation costs determine the netback value of natural gas.

<table>
<thead>
<tr>
<th>Lower-48 Markets</th>
<th>Natural-Gas Pipeline</th>
<th>Prudhoe Bay</th>
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<tbody>
<tr>
<td>Natural-gas value ($5.00 per mmbtu)</td>
<td>less pipeline transportation cost ($4.00 per mmbtu)</td>
<td>Netback gas value ($1.00 per mmbtu)</td>
</tr>
<tr>
<td>Oil price ($30.00 per barrel)</td>
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**Figure 9**
Netback Value of Prudhoe Bay Natural Gas

**Methanol and MTBE at Prudhoe Bay.** In 1980, a group that included the Arctic Slope Regional Corporation (ASRC), Davy-McKee International (DMI), and Westinghouse proposed to study the feasibility of building an industrial complex at Prudhoe Bay that would produce methanol and MTBE (methyl tertiary butyl ether), a high-octane synthetic gasoline for shipment either through TAPS or through a new light-liquids pipeline.
The viability of a North Slope methanol/MTBE concept would depend on whether (1) the ability to obtain feedstocks for a small fraction of the Lower 48 price ($1.00+ vs. $5.00 in the preceding illustration) would offset (2) the higher cost of transporting the petrochemical products to market plus (3) the higher capital cost of construction in the Arctic. (Because of the highly-automated, capital-intensive character of the plants, higher operating costs would not be a major factor.)

**NGL-derived olefins in Southcentral Alaska.** Under the same assumptions as in the previous examples, the gas producers would have three options for selling the ethane from their North Slope natural gas liquids:

1. The ethane could be sold to gas-transmission companies for shipment to the Lower 48 as part of the pipeline-gas stream at a wellhead price of $1.00;

2. The ethane could be extracted from the pipeline-gas stream for use as plant fuel at Prudhoe Bay, thus freeing additional methane that is worth $1.00 when shipped through the gas pipeline, or

3. The ethane could be extracted from the natural gas either on the North Slope or at Fairbanks for shipment through a new pipeline to a petrochemical complex at Valdez, Anchorage, or Kenai.

Suppose further that the cost of moving the ethane from the North Slope to the petrochemical complex were $2.00 per mmbtu. If ethane were worth any more than $3.00 as a feedstock for petrochemicals manufacturing, a petrochemical-plant operator could afford to offer the North Slope gas producers a better price for their ethane than they would receive under either of their other two options.
This, basically, is the Dow-Shell concept. The economic viability of the proposed NGL's pipeline and olefins plant would depend on whether the plant's ability to get feedstocks at a cost significantly lower than the Lower-48 price would be sufficient to offset the capital-cost disadvantage of operating in Alaska and any transportation-cost disadvantage for the petrochemicals produced.

**Feedstock value vs. feedstock price.** The value of North Slope methane or ethane as pipeline gas (or conceivably, LNG) in distant markets typically establishes its opportunity cost in any sale for use as a petrochemical feedstock in Alaska, but this cost does not automatically determine the market price.

Figure 10 illustrates this situation. (Note: The figures in this illustration are wholly hypothetical, and not purported to be realistic.) Suppose as before, that a gas producer ("Exxon") could get $1.00 per mmbtu for ethane shipped to the Midwest via the natural gas pipeline, and that the same ethane would cost $2.00 to ship from Prudhoe Bay to an ethylene plant in the Cook Inlet region. And suppose further that a chemical company ("Dow") determines that it could produce petrochemicals worth $8.00 ($9.00 in the Lower 48, less $1.00 transportation cost) in that plant from each mmbtu of ethane feedstock at a manufacturing cost (including a normal profit) of $4.50 Thus the value of the ethane as petrochemical feedstock at Cook Inlet would be $3.50 per mmbtu ($8.00 less $4.50), and "Dow" would make an acceptable profit so long as it could get the feedstock for $3.50 or less.

"Exxon's" opportunity cost of $1.00 per mmbtu plus transportation costs of $2.00 would, therefore, establish a $3.00 floor price at the ethylene plant, while the $8.00 netback value of the petrochemicals less "Dow's" $4.50 manufacturing cost would establish a $3.50 ceiling price. Figure 10 asks at what price between the floor and the ceiling would "Exxon" be likely to sell its ethane to "Dow"; specifically, how would the extra 50 cents per mmbtu in potential profits be shared between them.

In the specific case at hand, there is reason to expect the actual sales price to be nearer to the ceiling (ethane's
Figure 10
Value vs. Opportunity Cost at Cook Inlet

<table>
<thead>
<tr>
<th>Lower-48 Markets</th>
<th>Prudhoe Bay</th>
</tr>
</thead>
</table>
| **Natural-gas value**
   ($5.00 per mmbtu)
   equals the oil price
   ($30.00/barrel) | Ethane opportunity cost
   equals the netback gas value
   ($1.00 per mmbtu) |
| less gas-pipeline transport cost ($4.00 per mmbtu) | |
| **Oil- or gas-based feedstocks**
   ($6.00 per mmbtu) | Ethane opportunity cost to "Exxon"
   ($3.00 per mmbtu) |
| plus manufacturing cost ($3.00 per mmbtu) | What is the ethane price? (Who gets the extra 50 cents per mmbtu profit?)
   ($3.50 less $3.00) |
| ** Petrochemical market value**
   ($9.00 per mmbtu) | Value to "Dow":
   ethane value as feedstock
   ($3.50 per mmbtu) |
| less ocean transport cost ($1.00 per mmbtu) | less petrochemical manufacturing cost ($4.50 per mmbtu) |
| plus NGL's pipeline transport cost ($2.00 per mmbtu) | netback value of petrochemicals
   ($8.00 per mmbtu) |
value to "Dow") than to the floor ("Exxon's" opportunity cost). The reason is that "Exxon" itself could become an Alaska petrochemical producer and reap the full profit if "Dow's" highest offer were less than the value of the ethane as a petrochemical feedstock.

The real-life Exxon is itself one of the world's biggest petrochemical producers, as are British Petroleum and Arco. If "Dow" determined that the most-likely value of North Slope ethane as feedstock for a Cook Inlet ethylene plant were $3.50 per mmbtu, it is reasonable to suppose that the chemical subsidiary of "Exxon" or some other North Slope gas producer would also conclude that ethane was worth about $3.50 as a feedstock for a Cook Inlet ethylene plant. It is not likely, therefore, that "Exxon" would "leave money on the table" by selling feedstocks to a competitor for less than this price.

Alternative scenarios. It is instructive to examine two variations on this scenario: (1) in which the Alaska gas pipeline is not built, and (2) in which wellhead price controls on Prudhoe Bay natural gas influence the producers' decision on the disposition of North Slope hydrocarbons.

(1) No gas pipeline. It is conceivable that North Slope natural gas will cost more to ship to the Lower 48 by pipeline than it would be worth as fuel when it arrived, so that its netback value at Prudhoe Bay would be close to zero or even negative. Or, alternatively, the gas pipeline may not be built for some financial or political reason. In either of these cases, it would not be the value of ethane as part of a gas stream destined for the Lower 48 that would establish the producers' opportunity cost for North Slope ethane. The absence of the gas-pipeline alternative would establish a floor price for ethane feedstocks at approximately the cost of extracting it from the produced natural gas, which would otherwise be reinjected or (if the law permitted) flared.

If "Exxon's" added out-of-pocket cost of extracting and gathering the ethane were 75 cents per mmbtu, the company's floor price for ethane at Cook Inlet would be $2.75 ($0.75 plus $2.00 transport cost). But so long as
"Exxon" itself had the option of processing the ethane into ethylene, the probable sales price of ethane would not be affected by "Exxon's" loss of the option to ship it out in the gas pipeline; that sales price would still reflect the $3.50 value of the ethane as petrochemical feedstock in Cook Inlet, just as it did in Figure 10.

This comparison illustrates our earlier remark that a gas-based petrochemical plant could be a raw-materials price-maker rather than a price-taker like an oil-based petrochemical plant. So long as ethane's feedstock value is higher than its opportunity cost or its out-of-pocket cost to the producers, that value will tend to determine the price.

(2) The effect of wellhead price controls: methane. The Natural Gas Policy Act of 1978 establishes a ceiling price for Prudhoe Bay natural gas. This price is a little bit higher than $2.00 per mmbtu in 1981 and is scheduled to escalate with general inflation.

Interestingly, the federal ceiling price may be considerably higher than the netback value of North Slope gas at the wellhead (its market value in the Lower 48 less processing, transportation, and distribution costs). Without the regulation of Lower-48 natural-gas prices, the North Slope producers probably could not hope to collect the ceiling price for their gas. The gas producers are nevertheless counting on price controls for Lower-48 natural gas plus "rolled-in" pricing to make North Slope gas marketable at the federal ceiling price.

Let us assume for the sake of illustration that these hopes are realistic, and that Alaska gas could be sold in the Lower 48 on a rolled-in basis at a price of $8.00 per mmbtu instead of the $5.00 we assumed in Figures 9 and 10. This instance is illustrated in Figure 11. The netback value of North Slope gas is now $4.00 per mmbtu ($8.00 in the Lower 48 less $4.00 transportation expense), in contrast to $1.00 in the earlier examples. If the wellhead price is subject to a federal ceiling of $2.00, however, the ceiling price (rather than the $4.00 netback value) would establish "Exxon's" opportunity cost for the gas.
Figure 11
Methane-to-Methanol Price Determination

**Lower-48 Markets**

- **Final-market gas value** ($5.00 per mmbtu) (not applicable)
- **Rolled-in gas value** ($8.00 per mmbtu) (not applicable)

**Prudhoe Bay**

- **Netback gas value** ($1.00 per mmbtu) (not applicable)
- **Netback gas value** ($4.00 per mmbtu) exceeds ceiling (not applicable)

**Cook Inlet**

- **Lower-48 market value of methanol** (= $7.00 per mmbtu of methane)
- **Cook Inlet methanol cost** (= $5.00 per mmbtu of methane)
- **Netback methanol value** ($6.00 per mmbtu of methane)

- **Netback gas value** ($4.00 per mmbtu)
- **Ceiling price** ($2.00 per mmbtu)
- **Netback methanol value** ($6.00 per mmbtu of methane)
- **North Slope methanol opportunity cost to "Exxon"** (= $4.50 per mmbtu of methane)

**North Slope methanol opportunity cost to "Exxon"**

- **North Slope methanol opportunity cost** ($4.50 per mmbtu of methane)
- **North Slope methanol opportunity cost** ($4.50 per mmbtu of methane)

**Extra profit to either "Exxon" or "Dow" is 50 cents:**
- "Exxon" is not indifferent between selling to "Dow" and selling to its own affiliate
Let us further assume that each mmbtu of methane could be converted on the North Slope into methanol at a manufacturing cost (including a normal profit) of $2.50, and shipped to Cook Inlet at a cost of $1.00, where the methanol would be worth $6.00. Thus, the netback value of North Slope methane would be $4.00 ($8.00 less $4.00) if it were shipped to the Lower 48 as pipeline gas, and only $2.50 ($6.00 less $2.50 manufacturing cost and $1.00 pipeline transportation cost) if shipped as methanol. "Exxon", however, would be forbidden to charge more than $2.00 for the feedstock in either case. How would the gas actually be used, and what would its actual sales price be?

Interestingly, the existence of a ceiling price would tend to favor using the gas as raw material for methanol production. Because the use could not itself affect the wellhead price, "Exxon" as producer of the gas would be indifferent to whether it was sold for shipment through ANGTS or for processing in Alaska. Because the gas is worth $2.50 as a chemical feedstock, however, any chemical company to whom Exxon sold its gas at $2.00 would reap a 50-cent windfall. The obvious course for "Exxon" would be to avoid arm's-length sales entirely, and to sell its North Slope gas to its own chemical subsidiary.

(3) The effect of wellhead price controls: ethane. If ethane and other NGL's were extracted from Prudhoe Bay natural gas in the field before they entered an interstate natural gas pipeline, they would not be subject to federal ceiling prices under the Natural Gas Policy Act or any other provisions of federal law governing "natural gas". However, any gas liquids shipped through ANGTS (and thereby "commingled" with methane) would lose their separate legal identity and become subject to the same price controls as the methane. Indeed, though the question is legally arguable, the Federal Energy Regulatory Commission (FERC) and the federal courts may deem ethane commingled with the sales-gas stream to be "commodities in interstate commerce" and, accordingly, subject them to even further federal regulation --- even if they are ultimately separated
from the pipeline gas and sold in Alaska for processing within the state.

The extent of federal regulatory jurisdiction over North Slope ethane can not be forecast precisely today, but it is possible that the Federal Energy Regulatory Commission (FERC) and the Department of Energy will try to claim some jurisdiction over their prices, transportation, and/or end-uses. Moreover, there will surely be some private parties and perhaps State agencies in the Lower 48 demanding that the Commission exert such jurisdiction.

All in all, it appears that shipment of NGL's through the gas pipeline would subject them to wellhead price controls and possibly to direct federal controls over their transportation logistics and ultimate disposition. If North Slope ethane shipped through ANGTS were extracted, say, at Big Delta for shipment through an NGL's pipeline to a petrochemical plant in Valdez or Kenai, federal regulation could create the same kind of incentive for the producers to avoid an arms-length sale (to Dow-Shell, for example) but rather to maintain control of the feedstock, just as we described with respect to price-controlled methane.

The foregoing scenarios have been for the purpose of illustration only. They hardly begin to exhaust the roster of economic and regulatory possibilities. The pricing assumptions in these examples, moreover, were not intended to be realistic (though the following section will explore some of the issues in understanding what constitutes realistic figures). And finally, the Prudhoe Bay gas producers may have considerably less control over the disposition of their natural gas than some of the examples suggest, because they have already sold that gas, at least conditionally, to Lower-48 gas pipeline companies. Nevertheless, these scenarios point to facts about the disposition of North Slope oil, gas, and NGL's that are often overlooked in Alaska:

(1) It is not clear that ANY system for marketing or processing North Slope gas and gas liquids --- be it ANGTS, LNG, the Dow-Shell
concept, or methanol --- will be organizational­
ly, legally, and economically viable in the fore­
seeable future.

(2) The ultimate disposition of the differ­
ent North Slope hydrocarbons and their alloca­
tion among pipeline sales gas, petrochemical feedstocks, and field fuels will be determined mainly by how the gas producers perceive their own interests, and how they view the viability of the various systems that might be proposed.

The Northwest Alaskan partnership, the State of Alas­
ka, potential outside purchasers like Dow and Shell, or the ventures of Alaska Native corporations can have comparatively little influence on either of these circumstances.

Economies of Scale

"Economies of scale" are another factor that combines with transportation economics, feedstock prices, and relative construction costs to influence owner decisions where to locate various kinds of industrial facilities. The term refers to the tendency of larger machines, plants, firms, and industries to have lower average unit costs of production, processing, or transportation than smaller units of the same kind. Several elementary physical principles contribute to technical economies of scale in the equipment and plants used for petroleum refining, pipeline transportation, and petrochemicals manufacturing. Three of most important of these principles are as follows:

The amount of steel in a pipe increases roughly in proportion to its diameter; but the volume of fluid it can contain increases with its cross-sectional area (which is proportional to the square of its diameter) and, because the amount of friction depends on the inner surface area (which is directly proportional to the diameter rather than to the cross-sectional area) the fluids-carrying capacity of the pipe increases more than proportionally to the square of its diameter.
The amount of steel in a refinery or chemical-plant processing vessel, and its heat-loss (or gain) by radiation, are proportional to its surface area (which increases with the square of its length or width), while the volume of fluids it can hold during processing is proportional to the cube of any one of its dimensions.

Increasing the size of a given piece of equipment does not necessarily require any increase (and almost never requires a proportional increase) in its operating and supervisory manpower, or in the investment in control-system equipment.

A common (if imprecise) rule of thumb with respect to both process equipment and pipelines is that fixed costs tend to increase with the six-tenths power of capacity. That is, if a 50 mb/d refinery costs $500 million, a comparable 100 mb/d refinery can be expected to cost about $760 million ($50 million \times 2^{0.6})

Thus, doubling the refinery's size reduces its fixed cost per unit of capacity 24 percent, from $10,000 per barrel per day, to $7,600.

Comparable rules of thumb are (a) that operating labor requirements vary by the one-fifth power of capacity, and that fuel consumption varies with its four-fifths power. If a 50 mb/d refinery needs 100 workers, therefore, a 100-mb/d refinery would need about 115 workers (100 \times 2^{0.2}); a doubling of capacity would increase total fuel requirements by about 76 percent (2^{0.8} = 1.76), meaning that average fuel costs per barrel would fall about 12 percent (1.76/2 = .88).

**Limits to economies of scale, and the optimum scale.**

Economies of scale always have upper limits dictated by physical, economic, or human factors. The size of refinery or chemical-plant process vessels, for example, is limited by the strength of materials, safety considerations, and the disruption that would be caused by the planned or unplanned shutdown of a single large unit rather than one of a series of smaller units.
Thus, there tends to be some optimum (or lowest unit-cost) size for each kind of facility. Actually, the optimum size in most cases tends to be a rather broad range of sizes, over which unit costs at a given rate of capacity utilization (say, 90 percent) are rather flat. There always seems to be a region, in other words, where the economies of scale in some parts of the system just about offset diseconomies in others.

The optimum scale for complex fuels refineries nowadays is in the 100-to-250 mb/d range. The optimum scale for oil tankers in intercontinental service (e.g., between the Persian Gulf and the U.S.) is 250 to 500 thousand tons (mt), but the optimum size on shorter hauls (e.g., Valdez to Puget Sound) is considerably less. The reason is that larger tankers take longer to load and unload. As a result, they would spend an uneconomic proportion of their total service-lives in port if they were used on short hauls, thereby dissipating the operating economies of scale that they achieve only while sailing.

The optimum size for ethane crackers is between 1 and 1.5 billion pounds per year, and the optimum size for oil and gas pipelines seems to be in the 42-to-56-inch range. Most of these figures tend to increase over time, as a result of the development of stronger steels.

"Worldscale" facilities are facilities built to the technically optimum size because they have not had to be scaled to a limited feedstock supply or product market. They are facilities, in other words, that have the entire world to draw on and/or to serve and which, because they are of the optimum size, are able to compete in world markets.

Collier Carbon and Chemical Company's ammonia/urea plant at Kenai is worlds; Alpetco proposed a worlds; refinery at Valdez; and the Dow-Shell study is considering a worlds; petrochemicals complex. Alaska's existing refineries, however, are not worlds; their design scale was keyed to the limited size of the Alaska market rather than to national or international competition.
Analyzing Project Feasibility

Refinery and petrochemical plant investment decisions depend on several variables, including the ones that this chapter has considered in some detail (transportation, construction, and feedstock costs, and economies of scale), plus a number of others that include:

- Feedstock requirements
- Feedstock characteristics
- Process engineering and operation
- Fuel and energy supplies and prices
- Labor, materials, utilities, and services needs and prices
- Product slates and volumes
- Product prices
- Capital structure
- Interest rates
- Inflation rates
- Federal, state, and local taxes
- Health, safety, and environmental regulation

A companion volume to this report, Zinder Energy Processing, "Preliminary Economic Evaluation of NGL-Based Petrochemical Production in Alaska", October 1980, provides a useful accounting framework for most of these variables, and a rudimentary economic model for relating them to one another with respect to a project similar to that contemplated by the Dow-Shell group.
The final product of most economic feasibility studies includes (1) a "pro-forma" income statement, and (2) a discounted cash-flow (DCF) or "internal" rate-of-return analysis. A pro-forma income statement lists and sums hypothetical figures for the major cost and revenue elements for each year over the project's economic life, usually 20 to 25 years. A DCF analysis calculates the rate of return on investment (ROI) implied by the whole stream of negative and positive cash-flow figures in the income statement. Judgments on project feasibility, then, depend upon the DCF rate-of-return estimate: Is the expected return high enough to justify the investment?

Economic feasibility reports vary greatly in sophistication and detail, depending on the project and sponsor on the purpose of the report. In general, a preliminary "reconnaissance" study will use far more general assumptions and simpler models than a report prepared for prospective lenders, who usually insist on a completed engineering design and detailed market analysis, among other things.

Assessing uncertainty and risk. Greater methodological sophistication and detail do not necessarily improve the quality of an economic feasibility study, however. The most critical factors determining the economic feasibility for refineries and petrochemical plants are often judgmental assumptions, for which the most rigorous engineering or econometric methods give little hope of precision. Worse yet, the very complexity and appearance of precision in a formal economic analysis tend to obscure the intuitive and imprecise insights about the key unknowns that are absolutely crucial to intelligent decision-making.

The most powerful variable in determining the outlook for new worldscale hydrocarbons-processing plants is the outlook for world oil prices. By influencing petroleum-product and petrochemical prices, oil prices determine the level of consumption and the rate of demand growth. Since the prices of crude-oil, natural gas, LPG's, coal, and other feedstocks do not necessarily move together, the outlook for crude-oil prices is central, not only to
deciding whether any new plants should be built, but to choosing the right combination of raw-materials and plant location.

Expert opinions about how crude-oil prices will change over a period as short as five years vary by a factor of two or even three. Certainly, the recent history of petroleum prices calls for some humility in forecasting the future. The weighted-average wellhead price of Prudhoe Bay crude oil has quadrupled since mid-1978, reaching an all-time peak of about $26 per barrel in March 1981; it has now (August 1981) fallen below $22, and few analysts would be startled by 1985 prices as low as $15 or as high as $50. Because of the crucial role oil prices play in determining both the costs and revenues of any new refinery or petrochemical plant, the range of uncertainty about oil prices probably overwhelms the influence of all other economic assumptions combined.

The level of oil prices and the many other variables that are powerfully influenced by oil prices are not the only factors that are essential inputs to any feasibility analysis yet subject to horrible uncertainties. Capital-cost estimates for large construction projects are notoriously unreliable --- TAPS would have been the largest economic debacle in U.S. history if its huge cost overruns had not been offset by an even larger, unanticipated, leap in the price of imported oil. There is, likewise, no scientific way to determine future inflation rates.

Unfortunately, the feasibility reports of major energy projects that are offered to investors, government officials, and the public, are usually designed primarily as means of persuasion rather than business-decision tools. Most such reports present a single pro-forma income table and DCF-return-on-equity figure, concluding that the most-likely return-on-equity (ROE) from the project in question is, say, 15 percent. At most, the authors will offer several "scenarios" that correspond to different prepackaged sets of assumptions and show different ROE's, but which give the reader little basis for choosing one scenario over another.
Sensitivity analyses. A relatively simple device for improving the usefulness of feasibility analyses, but one which has been absent in the public literature regarding Alpetco, the Alaska Highway gas pipeline, and the like, is a sensitivity analysis that tells the reader which assumptions are truly critical and how critical they are. Even the Zinder report regarding NGL-based petrochemicals in Alaska, cited above, fails to tell its readers how its final results would be affected by a $5.00 per barrel change, plus or minus, in world oil prices; by a given percentage construction-cost overrun; or by a specified change in the project's capital structure, or in interest rates, etc. The Zinder model does allow users in state government to vary inputs one by one and to observe any change in the result, but this computing capability is no substitute for a clearly presented sensitivity analysis.

Risk analysis. One step in sophistication beyond sensitivity analysis is risk analysis, which explicitly incorporates uncertainty into its calculations. If experts are willing to attach probability figures to their assumptions, a "Monte Carlo" or "decision-tree" risk-analysis program will produce conclusions in terms of probabilities. A risk analysis can offer the investor or public official a much more powerful decision tool than a single "most likely" figure, or even a set of "high", "medium", and "low" estimates.

The risk analysis of a given hypothetical project might begin with a set of expert judgments on the probability distributions of cost overruns, completion delays, future oil-price trends, product-market conditions, interest rates, and general inflation, and conclude as follows:

"There is a 50-percent probability that the DCF ROE will be 15 percent or higher." (This means, of course, there is an even chance that it will be lower than 15 percent.) "There is, however, a 20-percent risk that the ROE (return-on-equity) will be zero or less, and a 10-percent risk that the project will default on its debt."

Equity investors might consider a 15-percent profit expectation (the weighted average of all probable outcomes)
as adequate, and be willing to accept a one-in-five risk of losing money if this risk is offset by a "fair gamble" of earning much more than 15 percent. The 10-percent risk of default would probably be intolerable to prospective lenders, however. The risk analysis might also say of the proposed investment, that:

"Changing the debt-equity ratio from 75:25 to 50:50 would reduce the chance of default from one-in-ten to one-in-fifty; the probability of just breaking even or losing money would fall from one-in-five to one-in-ten. But reducing the "leverage" (the proportion of debt) in the project's capital structure in this way would also reduce the expected ROE from 15 percent to 11.5 percent."

In this case the risk of default might be low enough, but the expected ROE would be inadequate. Combining risk analysis and sensitivity analysis gives us an even more powerful decision tool. Consider this observation about another fictional project:

"Although the expected rate of return and risk of default are both acceptable, we must point out that this project will never make a profit in the unlikely event that world oil prices stabilize at their current levels or continue to decline. To achieve a 50-percent expectation of a 15-percent ROE, we must assume that oil prices advance at an average annual rate at least two percent faster than general inflation."

The intuition of the investor or policymaker on how "unlikely" it is that world oil prices will stabilize may be just as good as that of the experts who carried out the analysis. In any event, the user of the analysis now has the information with which to make his own policy judgment.

Finally, risk analysis could offer the following kind of observation on a hypothetical royalty-oil sales proposal:
"The proposed project has a better-than-even chance of standing on its own feet. In order to reduce the probability of default to less than 5 percent so that private debt financing can be obtained, however, the State must be prepared to discount its royalty oil by as much as $5.00 per barrel if and when necessary to meet debt-service demands. The likelihood that a subsidy of this magnitude will be necessary is less than 7 percent but there is an almost one-third chance that some discount on feedstocks will ultimately be required."

The contract between the State of Alaska and the Battelle Northwest Laboratories analyzing the proposed Susitna hydroelectric project and its alternatives requires Battelle to provide a full range of sensitivity analyses, to be specific about the probabilities assigned to key assumptions, and to present its results in the form of probability distributions. To our knowledge, this is the first time the State has made such an assignment --- but the Susitna project is one that could involve a direct outlay of billions of dollars of State money.

**Coping with uncertainty and risk.**

The analytical methods described in the previous pages do not reduce or control business risks, but only identify and attach numbers to them. Means do exist, however, by which refiners and petrochemical manufacturers can reduce their exposure to surprises and the damage caused by them. The chief measures are long-term contracts, plant and system flexibility, vertical integration, horizontal concentration, and risk-spreading through diversification.

**Long-term contracts.** Investors in refineries and petrochemical plants can reduce their capital costs and certain kinds of business risks by building a highly specialized facility designed to process a single feedstock into a predetermined product slate for a predetermined customer or group of customers.
This kind of arrangement is much more common in oil and gas transportation and among utility companies than it is in either refining or chemicals manufacturing. A prospective shipper on a proposed pipeline may offer the carrier (the pipeline company) a "throughput and deficiency agreement," under which the shipper promises to pay the carrier a minimum bill proportional to the desired transport capacity, even if the shipper does not use that capacity.

Likewise, a utility that buys coal, natural gas, or electricity may bind itself in a "take-or-pay" contract to pay for a specified volume on a specified schedule, whether or not the utility actually takes the contracted amount. A stricter version of the minimum-bill or take-or-pay contract greatly facilitates debt financing. This is the "all events" or "hell-or-high-water" provision, which requires the shipper or purchaser to pay the minimum bill even if the carrier or seller can not perform (because of project noncompletion or breakdown, for example).

Facilities with long-term "back-to-back" raw-materials purchase and product-sales contracts are generally easy to finance with very high debt-to-equity ratios. One example is the Alberta Gas Ethylene Company's Joffre plant, which has long-term contracts from its parent (Nova, Ltd.) for ethane feedstock, and a long term "cost-of-service" ethylene sales contract with Dow Canada.

Project financing. One advantage of projects with back-to-back purchase and sales contracts is that they can, at least in principle, be "project-financed" with "non-recourse" debt. Project financing establishes a new corporate entity to own and operate the facility and the non-recourse feature means that the facility's owners are not responsible for debt service; their exposure is limited to their equity contribution, which may be comparatively small. (Capital structures for most project-financing proposals tend to contain 75 to 90 percent debt. The original financing plan for the Alpetco plant contemplated no net equity contribution by its sponsors.)
Project financing is not a method, however, of eliminating risk but only of shifting it to other parties through take-or-pay or similar contracts, and its feasibility depends both upon the creditworthiness of those parties and the tightness of their contractual obligations. For this reason, it is mostly regulated public utilities that use this financing technique, and the technique is feasible even for them only where State and Federal regulatory agencies can assure in advance that debt-service charges will be "perfectly tracked" to a captive market of final consumers.

The sponsors of many, if not most, recent large-scale energy-industry ventures have hoped that they could project-finance them with a high ratio of nonrecourse debt --- the Alaska Highway natural gas pipeline, Alpetco, and the Northern Tier oil pipeline are familiar examples. Very few have ever been successful, and we are not aware of any completely nonrecourse financing that has yet been carried out for a major nonutility energy project. Successful financing has always seemed to hinge on a creditworthy third party that agrees to pay off the debt even if the facility is never completed.

The success ratio of attempted project financings over the last few years has been so low that promoters of huge and complex energy projects are increasingly seeking, instead, government loan and purchase guarantees or joint ventures with large equity participants. Nevertheless, two maxims will be useful to Alaskans in evaluating future industrial promotions:

1. Lending institutions are not willing to bear the completion, technical, and marketability risks for large-scale resource-extraction, transportation, or processing ventures in Alaska; and

2. Unless the sponsors have found someone able and willing to provide the project with conventional levels of equity capital (25 percent or more) and to guarantee the project's entire debt (at least until it goes into operation), it is reasonable to assume that the facility will not be built.
In other words, nonrecourse and highly-leveraged project financing is as much a myth for enterprises in Alaska as it has proved to be in the Lower 48. Even the participation of major international companies (like U.S. Steel, Westinghouse, and Getty Oil in the Northern Tier Pipeline, or Exxon, Arco, and Columbia Gas in ANGTS) does not assure financing unless these companies are willing to supply risk capital and guarantee project debt. However, certain features of project financing, like long-term contracts that facilitate plant specialization can provide a real boost to more conventional strategies of capital formation. The rest of this chapter covers some other techniques for reducing business risk.

**Plant and system flexibility.** Although plant specialization tends to reduce technical risks and construction costs, it magnifies feedstock-supply and market risks. Most refineries and petrochemical complexes built in recent years have considerable built-in flexibility. In the case of refineries, technical flexibility provides the ability to run a wide range of crude-oil mixtures and to vary their product slates. Petrochemical complexes have been built, where feasible, to include (or provide room for future addition of) both an ethane cracker and a naphtha cracker.

A large company with several plants of different design, adapted to different feedstocks and different product slates, will have much more flexibility to deal with changes in raw-material supply and market conditions than a smaller, single-plant enterprise, even if the large firm's individual plants are relatively specialized.

**Horizontal concentration.** It is the advantages of system-wide flexibility that encourage horizontal concentration --- the tendency of big firms to get bigger. In the 1980's, for example, Dow and its affiliated ventures and joint ventures will be producing (or buying on long-term contract) ethylene from naphtha and gas oil on the U.S. Gulf, in Europe, and in East Asia, and ethylene from NGL's produced and marketed under a number of different arrangements in the southwestern United States, Alberta, Saudi Arabia, and perhaps Alaska.
Obviously, not all of these ethylene supplies will turn out to be the lowest-cost sources, and some of the ventures may well prove to be money-losers. But with a broad, diversified feedstock base, Dow is unlikely to do worse than the average in its industry, and unless the world market for ethylene derivatives stagnates completely, Dow should do very well in the next decade.

**Vertical integration.** An earlier chapter of this report alluded to the historical tendency of crude-oil producers to integrate downstream into refining and products marketing in order to assure themselves product outlets and thus to retain their market shares in periods of surplus. BP's acquisition of Sohio and part of the Sinclair system is a doubly outstanding example --- first because of the obvious logic of the combination and second because it was only partly successful.

With the discovery of the Prudhoe Bay field in 1968, BP was about to become North America's number one crude-oil producer, but it had no refineries or retail outlets and hence no assured market. Sohio, on the other hand, was the largest "independent" refiner --- independent in the sense of having almost no crude-oil production. To this extent the BP/Sohio marriage was perfect.

The geography of the merger has turned out to be abominable, however, particularly in light of Congressional restrictions on foreign exchanges of North Slope crude oil. Unlike Arco and Exxon, which have refineries and dealer networks on the West Coast, Sohio has none, and thus the BP group still has no properly situated outlets for its crude oil. As a result, Sohio has to absorb two or three dollars per barrel in added transport costs for oil sold or exchanged east of the Rockies --- a burden that Arco and Exxon are spared on most of their Alaska production.

"Upstream" or "backward" integration of refiners or petrochemical companies into crude-oil production not only gives the processor a more secure raw-materials supply, but helps stabilize feedstock costs as well. During the first half of 1981, for example, the most recent round of OPEC price increases together with the deregulation of domestic crude-
oil prices raised the average cost of raw materials to U.S. refiners several dollars per barrel, but market conditions did not allow them to recover these higher costs in petroleum-product prices. This situation put most independent refiners and refiners with low crude-oil self-sufficiency ratios into a no-profit or operating-loss position. To the extent that a refiner is self-sufficient in crude oil, however, the loss of refining profits is at least partially offset by additional crude-oil production profits. (The offset is usually less than total, because of the higher royalty, severance-tax, and Windfall Profits Tax liabilities that result from higher wellhead prices.)

The unreliability of foreign crude-oil supplies in recent years has made upstream vertical integration highly attractive at the same time that it has become increasingly expensive to achieve. The decline in Lower-48 crude-oil production and the major companies' loss of overseas concessions have drastically reduced self-sufficiency ratios. After several Middle-Eastern oil-supply interruptions, almost every large refiner and petrochemical producer, regardless of its existing degree of backward integration, has been trying to get direct control of as much crude oil as its can or, failing that, to work out some kind of marriage or joint venture with a crude-oil producer. With the acquisition of Sohio by BP in the early 1970's, Ashland and Clark are the last large independent refiners.

In 1977-78, for example, Ashland attempted to sell a major share of the company to the National Iranian Oil Company (NIOC) in exchange for a long-term crude-oil guarantee. In 1979 Getty Oil --- despite its surplus of crude-oil production relative to its refinery capacity --- bought Reserve Oil Company, whose subsidiary Western Crude Oil gathers and markets crude oil for hundreds of small producers. Just this year, the Hawaiian Independent Oil Company announced a major investment by Kuwaiti interests, who would presumably be responsible for providing crude oil to the Hawaii refinery.

The Alaska NGL-based petrochemical scenario set out in connection with Figure 10 earlier in this chapter offers a
final illustration of the risk-reducing value of vertical integration. In this scenario, a prospective feedstock seller ("Exxon") and a prospective buyer ("Dow") are both confident that the value of Prudhoe Bay ethane as feedstock for an ethylene cracker at Cook Inlet is about 50 cents per mmbtu more than its value as part of the sales-gas stream in the Alaska Highway natural-gas pipeline.

Neither party really knows what the NGL's extraction plant and pipeline or the petrochemicals plant will cost, or what world market conditions will be for ethylene derivatives five or ten years from now. Accordingly, the anticipated profit per mmbtu of ethane shipped and processed, while assuredly positive, might be considerably less than 50 cents or considerably more than 50 cents. But any feedstock price low enough to insure "Dow" against loss would be considerably less than the "most-likely" value of the material according to "Exxon's" estimate. The obvious resolution of this dilemma would be for Exxon to sell its NGL's not to "Dow" but to an "Exxon" subsidiary (or perhaps to a "Dow-Exxon" joint venture). This way, "Exxon" would receive the whole profit (or nearly the whole profit), whether it turned out to be large or small.

Another incentive favoring vertical integration comes from uncertainty about transportation charges on the NGL's pipeline. It is impossible to know for certain to what extent the Federal Energy Regulatory Commission (FERC) and the Alaska Public Utilities Commission (APUC) will regulate charges on the pipeline or what rules they will use. Federal regulation of oil pipelines has historically used a "fair-value" rate base, which permits charges to increase over time, but a FERC administrative law judge recommended in 1980 that TAPS transportation tariffs be set on the basis of "depreciated original cost," which results in declining charges. The choice between the two rules may vary the first-year transportation charges on an Alaska NGL's line by a factor of two or three. Uncertainty about pipeline charges thus may lend great uncertainty to any assessment of the feasibility of a petrochemicals industry based on NGL's in Alaska.
Once more, resolution of the dilemma may hinge on vertical integration. If the major shipper owns the pipeline, the tariff as such does not much matter (apart from its effect on tax and royalty collections) --- pipeline transportation charges are largely a bookkeeping shift of profits (or losses) from one pocket to another. The most risk-protected system for Alaska petrochemicals, therefore, would include producer participation in both then NGL's ownership and in the petrochemical complex.