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Energy Intensive Industry for Alaska
Volume I: Alaskan Cost Factors Market Factors Survey of Energy Intensive Industries

September 1978

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Alaska Division of Energy and Power Development and the U.S. Department of Energy under Contract 300A 01123

Institute of Social and Economic Research,
University of Alaska

Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
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FINAL REPORT

ENERGY INTENSIVE INDUSTRY FOR ALASKA

VOLUME I
ALASKAN COST FACTORS
MARKET FACTORS
SURVEY OF ENERGY INTENSIVE INDUSTRIES

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THE POTENTIAL FOR ENERGY INTENSIVE INDUSTRIAL DEVELOPMENT IN ALASKA: PHASE II, III: FACTORS EXTERNAL TO ALASKA

Prepared for the

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1.0 INTRODUCTION

This report is addressed to the relationship of the State of Alaska's indigenous energy and other natural resources and the role they may play in the future economic development of the State.

Alaska is popularly and frequently referred to as the "energy warehouse" of the United States. This public awareness derives primarily from the current activity surrounding the development of oil and natural gas resources on the North Slope and the expectation that additional reserves will be found in other locations. The availability of very major coal (largely subbituminous) reserves is less well known but well recognized by natural resource authorities. The hydroelectric power potential, also very large, is in the same category--known to people knowledgeable on Alaska but less well recognized by the public at large.

Alaska is also popularly regarded as a "warehouse" of other mineral resources, principally metallic, which could be exploited. On the other hand, the State is regarded by many as a largely untouched wilderness with regions of great natural beauty that deserve preservation in their own right.

The term "warehouse," though widely used in reference to Alaska, is however largely a misnomer. Very few of the energy or non-energy resources have been developed to the point where they are "available on pallets" in the usual warehouse connotation. The sole notable exceptions are the oil and gas resources of the Cook Inlet Basin and the North Slope and, earlier, the placer and hard rock gold and other metal mining activities now largely dormant. In fact, much of the information available on geologic resources is at best reconnaissance grade being based largely on surface observations and inferences. As a result the resources are poorly understood.

Similarly, the hydroelectric power resources of Alaska have been developed to probably far less than one percent of the ultimate unconstrained potential.

Renewable natural resources such as forest products, also very large, have similarly not been developed primarily due to institutional constraints, higher costs, transportation to the domestic market and the near market availability of lower cost sources in the Lower 48. Although far from "energy intensive," the fisheries resource of Alaska's Continental Shelf is immense and, under newly established international agreements relating to the 200 mile economic zone, may become a very significant factor in Alaska's economic development. This would be over and above the significant contribution the fisheries industry already makes to the State's economy.

Assuming that the State wishes to encourage development of stable noncyclical industry, a natural first question is: Can Alaska's energy resources and other endowments be coupled in ways that bring the desired economic development? Subsidiary questions relate to the benefits (stable employment opportunities, reduction in the cost of living, increased state revenues, etc.) and costs (environmental impacts, increased need for public services, etc.).

The question of industrial development, however oriented and regardless of location, is largely one of economics. Industries will choose to locate in a manner to maximize their long-term return on investment and judge one location vs an alternative on this basis. In all location decisions, comparisons are made to at least the economics of one or more alternative locations.

The use of the term "economics" above is not intended to imply simply accounting of simplistic costs of production (principally raw materials, energy, labor, and financing costs) and costs of marketing. The industry decision-maker will also include in his or her analysis a review of many factors that are less quantifiable. These factors include perceptions of stability and skills of the labor force, unionization, hospitality of the candidate locations toward industry entry, extent of competition in transportation outlets for products, and actions by competitive interests. All of these factors ultimately have their economic content.

For any development to take place it must pass a number of economic tests. In short, an Alaskan development must compete with other locales (an international perspective is important for a number of industries) for attraction of a desired industry.

The major considerations for industrial location in Alaska are as follows:

1) Competitive position of a given product produced in Alaska in its marketplace. Since Alaska's population is relatively low, it does not in itself constitute a major market, particularly for intermediate products. Thus products produced in Alaska from Alaskan materials in most instances must bear the burden of transportation

costs to the domestic or Pacific Rim markets such as Korea, Japan, and Taiwan.

2) Capital costs for industrial plants constructed in Alaska are significantly higher than in the contiguous states ($\sim$1.5 fold) in part due to transportation costs associated with importing materials and in part to the higher costs of field construction in the State. These costs are even higher when compared to similar costs in most Asian countries.

3) Operating costs, both labor and material components, are recognized as being considerably higher.

4) Plant scale is becoming an increasingly important factor in modern industrial development. In most industries, new developments are currently taking place usually with "world scale" plants. Product transportation costs have become a smaller component in the final price and geographically larger markets can accommodate the entry of the larger plants with their attendant economies of scale.

The above four conditions present significant problems to be overcome for successful industrial location in Alaska and are undoubtedly the primary reasons for the current sparceness of nonservice industrial development within the State. Energy intensive or related industries that have developed to date include small scale petroleum refining and the world scale agrichemical ammonia and urea operations at Kenai. The former industry is at a scale necessary to meet instate market needs where its competitive position is favored by the cost of importing petroleum products and the proximity and hence lower cost of feedstocks. The latter industry is the largest ammonia/urea installation on the West Coast. In this instance the Collier Carbon and Chemical Company plant's competitiveness is based principally upon the availability of very low cost (typically $0.17 per MMBTU) natural gas from the Cook Inlet Basin.

This low cost feed stock situation is to some extent unique in that natural gas was discovered in the course of search for crude oil. With the (then) lack of transportation systems to major markets, where it could demand a much higher price, the Cook Inlet natural gas became almost a nuisance product in a buyer's market. The low feed stock costs under long-term contracts allow the Alaskan ammonia/urea industry to compete in the West Coast and international market despite higher product transportation costs.

With the advent of natural gas transportation systems (NLG in this instance), an outlet for the Cook Inlet natural gas is now available into markets where it can command a far higher price. As a consequence of this improved marketability, Cook Inlet gas now sells for $0.50 per MMBTU as feed for a natural gas liquefaction plant and is competitively exported to Japan. Thus a producer long-term contract price approximately threefold above that for the ammonia/urea operation is obtained as the result of access to new markets.

It is expected that this price effect will continue at even stronger levels in the future. New contracts for old gas (regulated) will likely be in the $1.50 per MMBTU range new gas approaching $2.00 per MMBTU and escalating.

The net result is that the competitive situation is altered to the detriment of a new Alaskan ammonia/urea or similar petrochemical venture although not necessarily to the point of totally removing the competitive edge. However, it must be recognized that fuel or feedstock costs from alternative sources, e.g., the continguous states, have also risen and will continue to do so.

Another factor that will have strong bearing on the future of energy intensive or related industries, regardless of location, is national energy policy currently evolving. Current federal government intervention into energy affairs is pervasive to say the least with most signs pointing to increased rather than decreased distortion of normal market functioning. The effects of this intervention are both direct (taxes, price regulation, prohibitions, or certain uses, etc.) and indirect, the latter arising principally from uncertainty. Whereas normally functioning market can be fairly well forecasted as a basis for business decisions, future nonmarket or institutional factors such as price regulation are far less predictable. Uncertainty is the bane of business decision making--the higher the uncertainty, obviously the greater tendency to defer decisions committing financial resources to projects with a high degree of exposure to risk or regulatory intervention.

The current so-called "surplus" of crude oil on the West Coast despite rising foreign imports is perhaps a good example of the consequences of the uncertainty factor and is particularly germane to Alaska. Even knowing that Alaskan North Slope crude oil would become available on the West Coast in mid-1977 and could be used to reduce foreign oil imports (a clear national objective), refiners deferred capital projects necessary for allowing Alaskan crude to displace foreign imports. As a consequence the West Coast "surplus" is more accurately described as a "shortage" of appropriate refinery capacity brought about by regulation, in this case primarily due to imposition of more stringent fuel sulfur standards for environmental reasons.

The more direct effects of national energy policy on industrial development will be immense regardless of location. The national policy is understandably directed toward solution of a set of perceived problems on a lumped-together national basis. The primary real national problem is, of course, the growing dependency upon imported energy with all the national security and balance of payments issues associated therewith. The lumping-together process may however result in regional diseconomies and particularly so in Alaska given its resource base and geographic isolation.

As a potential area for industrial location, Alaska has both advantages and disadvantages. The advantages include:

- Very large energy reserves and resources
- Low cost transportation to Asian markets
- Very large raw material resource base
- Land availability
- A new industrial plant would be the most modern and efficient
- Significant capital availability for new ventures
- Outlook for declining energy costs relative to other domestic locations
- Apparent hospitality toward industry

The disadvantages include:

- Higher plant capital and labor costs
- Limited local market and remoteness from major domestic markets
- Limited intrastate transportation systems
- Uncertain land and related resources status

All things considered, it appears that the major inhibitions to industrial locations in Alaska relate primarily to the relatively higher costs of doing business in the State. Thus any action the State can take to reduce this cost will be beneficial, including the successive attraction of basic industries that on their own will reduce costs of construction and ultimately lower the cost of living and the adverse labor cost differential.

2.0 EXECUTIVE SUMMARY

2.1 ALASKAN LABOR COSTS

- An average Alaskan employee has earned 130% to 140% more than the average employee working in the remainder of the U.S. during the 1965 to 1973 time period. The Alaskan wage differential became even greater during the TAPS pipeline construction era and increased to 175% of the national average.

- Prior to the construction of the pipeline, Alaskan labor costs were increasing at a slower rate than the national average. The result was that the Alaskan wage differential as compared to the nation was diminishing and Alaskan employees were becoming relatively less costly as compared to the national average. The local inflation driven by construction of pipeline has apparently caused a change in the past trend and more recently the Alaskan wage differential increased.

- The State should concentrate on attracting industries which are the more efficient with respect to labor; i.e., a large ratio of output (in dollars) per employee. This will minimize the unit cost of labor per unit of output. Plants locating in Alaska should have access to the latest technology. Most new technology is very efficient in terms of labor requirements. Alaskan labor costs should then be at least partially offset by the latest technology.

- The Alaskan wage differential relative to the national average wage should diminish again as the Alaskan economy readjusts from the pipeline boom economy. The differential should also become less as the Alaskan economy matures and becomes somewhat more self-sufficient.

2.2 ALASKAN ENERGY AND CAPITAL COSTS

- Both residual fuel oil and new natural gas is estimated to cost about $2.50 per MMBTU during the 1985-2000 time period (January 1, 1977 dollars).

- Beluga coal is estimated to cost about $0.85 per MMBTU at the mine mouth and $1.00 per MMBTU at the Coast (January 1, 1977 dollars).

- Healy coal is estimated to cost $0.70 per MMBTU FOB Healy. Railroad transportation would increase the cost to $0.90 per MMBTU delivered to Nenana and $1.10 per MMBTU delivered to Anchorage (January 1, 1977 dollars).

- Prices of fossil fuels can be expected to increase at a rate about 2 to 3% faster than the rate of general inflation over the long term (20-30 years).

- Capital or construction costs for industrial facilities for various locations in Alaska relative to costs in the Pacific Northwest are estimated to be:

Anchorage	1.65 times higher
Beluga	1.80 times higher
Healy/Nenana	2.20 times higher
Fairbanks	2.00 times higher

2.3 ENERGY INTENSIVE INDUSTRIES

- The presence of large energy resources in Alaska will not in itself attract industry to them until such time as the costs of energy in Alaska are lower than in alternative industry locations. This reduction must be enough so as to reduce the disadvantages of higher construction, labor, and marketing costs.

- The above situation appears to be the case vis-a-vis Japan and although the average cost of energy in the contiguous states is lower than in Alaska, the gap is expected to narrow in the future.

This will come about as a result of phased deregulation of new natural gas, the decline in production of regulated gas, and possibly the institution of import fees on imported foreign oil.

- The industries that will tend to locate in Alaska as a result of energy considerations can be characterized by the following attributes:

  1) Product is produced in large volumes in large facilities and readily shipped in bulk.

  2) Energy as a factor of production represents a large fraction of the total cost of production.

  3) Labor cost should be low, i.e., the industry must be capable of a high degree of automation and employ continuous as opposed to batch processes.

  4) The industry should be a primary industry, i.e., not dependent upon having to import intermediate materials and components and should produce a slate of products that can be directly marketed.

  5) A substantial market for the products should exist in foreign countries such as Japan where energy costs are high and where product shipment under foreign flag is possible.

- The energy intensive industries meeting the above criteria are, in order of merit:

  1. Lime
  2. Aluminum
  3. Portland Cement
  4. Methanol
  5. Carbon Black
  6. Ammonia
  7. Chlorine

- Industrialization has historically been a gradual process in frontier areas and generally has followed a course initiated by industries that will have a substantial local market, i.e., construction materials such as lime and Portland cement. Provision of these products in turn reduce the cost of living and doing business and thus increase the attractiveness of the location to other following industries.

- The Japanese markets for energy intensive products appear to be particularly attractive to Alaskan industries vis-a-vis domestic "Lower 48" market. This condition arises from several considerations:

  1) Japan is almost totally dependent upon imported foreign energy, principally oil from Saudi Arabia. The landed price (Yokohoma) is approximately $13.27/bbl or $2.29/MM Btu. Conversely, the U.S. domestic prices for energy are regulated (both natural gas and oil) at considerably below the world price. For example, the average (weighted foreign and domestic) refinery acquisition cost of crude oil has run at about $11.98/bbl or $2.06/mm Btu. An even stronger disparity exists for natural gas where recent interstate sales contracts have ranged in the $1.36 to $1.67/mm Btu. Domestic coal prices have recently (June 1977) ranged from $0.47 to $1.14/mm Btu for the Mountain and South Atlantic states respectively. The corresponding national average coal price in June 1977 was $0.993/mm Btu. Thus based simply on fossil energy costs alone, the "Lower 48" will tend to "shut out" energy intensive Alaskan products.

     It should be noted that the above situation could change rather significantly in future years as a result of federal regulation. Imposition of a crude oil import tariff of say $3.00/bbl ($0.52/mm Btu) would be significant as would the phased deregulation of new natural gas. Thus, the competitive position of Alaska vis-a-vis the Lower 48 can be expected to increase with time.

2) Industrial production in Alaska can be marketed in Japan using foreign flag vessels at about 1/3 the cost of transportation to the outside domestic market. Under the Jones Act, interstate commerce must move in U.S. registry vessels at an approximately fourfold higher unit cost.

3) Due to the imbalance of trade, Japan had a $7.3 billion surplus in 1977. This surplus is creating severe strains in the foreign currency exchange providing inducement to purchase U.S. products.

4) The cost of land in Japan suitable for industrial siting is currently in the range of $million/acre. This factor among others is contributing to development of industries that are labor intensive as opposed to energy intensive as the latter typically also require relative large acreage.

- Cement and Cement Products. One aspect of the cement and cement products industry relates to Japan. Currently, the Japanese cement industry, though highly energy efficient, is in a state of overcapacity as a result of intense competition from the lower labor costs in Korea and Taiwan. Given the very major demands for cement for the potential Upper Susitna hydroelectric projects, the possibility for moving an existing Japanese cement plant to Alaska should be explored further. A 300,000 ton/year cement plant (valued in the Lower 48 at $30 to $40 million) might be moved to Alaska for on the order of $3 to $4 million. The $2 billion Upper Susitna project being studied assumed an import of cement from the lower 48 and considerable savings might accrue from local production. Construction of the Watana dam is expected to require approximately 26,000 tons per year during a 3-year period.

In addition, the contiguous Pacific Northwest states and British Columbia is, and is expected to remain, a cement deficit region. Some export of cement from Alaska to the domestic market might well be possible.

- Petrochemical Industry. A preliminary analysis indicates that the economics of locating a petrochemical/agrichemical complex adjacent to the North Slope natural gas pipeline, in interior Alaska, are not promissing. The high cost of construction in inland Alaska, plus the cost of shipping the products to the domestic market appears to make the operation of such a complex unprofitable in today's market place, irregardless of feedstock costs. For comparative purposes the economics of the chemical complex in Alaska were compared to a similar complex, operating with naphtha feedstock, on the Gulf Coast. The Gulf Coast operation appeared to have an economic advantage for all products.

- Petroleum Refining. Since the introduction of Alaskan North Slope (ANS) crude oil into the market, there has been a large surplus of crude oil available to refiners on the West Coast. Despite this the industry has developed no major plans for expansion of refining capacity on the West Coast as refining capacity already significantly exceeds product demand in the area. Traditionally West Coast refiners have concentrated on optimizing gasoline production and as a result cannot directly replace imports with heavy, sour ANS. Therefore, ANS crude is the surplus crude on the West Coast and a large fraction being shipped to the Gulf Coast and Virgin Islands for refining.

  The outlook for development of a basic grass roots petroleum refinery in Alaska is not good; however, consideration is being given to establishing a petrochemical refinery (ALPETCO) to process ANS royalty oil for product marketing in Japan.

2.4 TIMING

The question of when energy intensive industries will seek development in Alaska is most difficult to forecast. However, there are certain considerations that can contribute to an understanding of the probable timing:

1) Electric power intensive industries, e.g., aluminum reduction and chlor-alkali industries will be attracted only when and if low cost hydroelectric power becomes available in relatively large blocks necessary to support an economically scaled plant. The most likely major hydroelectric development is the proposed Upper Susitna project (1,580 MW total). A two-step construction project has been recommended; the Watana system with a capacity of 686 MW available 6 years from start of construction followed by Devil Canyon to complete the 1,580 MW 10 years after project initiation. The project initiation, presuming favorable findings from the 4-year Plan of Study just initiated, could be by 1982 leading to Watana power availability by 1988 and full Upper Susitna power by 1992. Therefore, a 1990 date for electric power intensive industries appears reasonable.

2) Industries dependent upon coal based energy, e.g., the cement industry, will probably not be attracted until a significant market increment is added (such as the hydroelectric projects mentioned above) or until the lowest cost coal source (Beluga) becomes available. A reasonable date for the latter is in the mid 1980's corresponding to the potential startup of the first coal fired Beluga station.

3) For industries dependent upon oil or natural gas, the situation is somewhat more clouded due to uncertainties in federal regulation and to a lesser extent on the future behavior of the world oil price as set by the Organization of Petroleum Exporting Countries (OPEC). Alaska is in the anomolous position of having its most widely known and highest valued resource subject to considerable uncertainty both as to price and marketing.

Currently, it appears that these resources are more highly valued as readily transportable fuels and are subject to foreign export limitations either directly or as petrochemical products. In addition, pending federal legislation may preclue their industrial use in new plants except in instances where process and product requirements preclude the use of coal.

Also, strong competition exists in the world petrochemical market (Saudi Arabia with feedstock costs approaching zero) and at least a near term over capacity problem in Japan.

On the side encouraging oil and gas based industrial projects in Alaska, is the strong likelihood that basic oil and gas energy costs in the Lower 48 will increase more rapidly than in Alaska. In part, this will occur as the result of phased deregulation of new natural gas, the decline in domestic production of old oil and the possibility of the imposition of a major import tax on foreign oil. Thus the "rolled in" or weighted average cost of oil and gas in the Lower 48 domestic market will increase more rapidly than in Alaska where the dominant production will continue from "old" oil and gas reservoirs at least until the late 1980's.

There is a very slight possibility that the OPEC cartel will break. The history of successful cartels suggests a mean lifetime of about 6 years prior to the institution of a price war. In the unlikely event of a price brake in the world oil market, an Alaskan venture would be severely disadvantaged due to the fact that the higher capital carrying charge nature of an Alaskan plant vis-a-vis a Lower 48 plant will cause this contribution to production costs to become more dominant.

Conversely, in the more probable scenario of OPEC continuance, the expectation is that, as prudent depletable resource managers, they will increase prices at a rate 2 to 3 percent above general inflation. Alaskan energy becomes increasingly attractive as capital, labor, and transportation costs become lesser fractions of the total cost of production. This is particularly true for processes employing the relatively inflation proof hydroelectric power.

3.0 SCOPE

As noted in the Preface, this volume covers the Alaskan and product market factors influencing industry locations in the state and provides a survey of the most energy intensive industries. This volume was prepared by Pacific Northwest Laboratory, operated by Battelle Memorial Institute.

In conducting this work, Battelle analyzed the factors external to Alaska that would influence development and the cost of energy and labor in Alaska. This thus covers the industries likely to be drawn to Alaska because of its energy resources and to analyze these in terms of:

1) the cost of using Alaska energy resources in Alaska as opposed to the Lower 48.
2) skill-adjusted wage and salary differentials between relevant Alaskan areas and the Lower 48, and
3) basic plant and equipment and other operating cost differentials between relevant Alaskan areas and the Lower 48.

This report also develops an understanding of the likely level at which development might take place and its timing.

4.0 ALASKA ENERGY COSTS AND AVAILABILITY

When selecting a location for an industrial site a company must evaluate the costs of constructing and operating facilities in a number of locations. This chapter presents representative energy costs in Alaska. These costs can be compared with the representative energy costs in the Lower 48 which are presented in Chapter 5.

Fossil fuels available in the southcentral and Fairbanks areas of Alaska include distillate and potentially residual fuels from refinery operations either existing (Kenai and North Pole) or a future refinery based on North Slope crude oil, natural gas (Cook Inlet and Fairbanks via the North Slope pipeline), and coal (from Cook Inlet and interior sources). Over the long term, other fuel sources may be developed within the near offshore and not too distant from the Southcentral and Fairbanks areas.

An understanding of future fossil fuel costs is essential to the evaluation of any energy intensive industry. Thus, before attempting to arrive at a "best guess" or a "reasonable range" of expected fossil fuel costs it is worthwhile to review estimates made by prior studies, make adjustments based on new information, and then apply some economic theory.

The future costs of fossil fuels in Alaska will be determined by a number of factors that have different weights depending on the fuel type:

1) The world energy market is largely controlled by the Organization of Petroleum Exporting Companies (OPEC).
2) The marginal cost of production plus the appropriate taxes, royalties, and return on investment.
3) The general rate of inflation.
4) The nature and extent of federal price controls and taxes.
5) Transportation tariffs.
6) Terms and conditions of long-term contracts for natural gas.

7) The market rate of interest.

8) The extent to which Alaskan fuels can participate in the domestic and world markets through transportation systems.

Different fuels (coal, gas and oil) costs can be expected to respond to the above factors in different manners and hence are discussed separately in the first three sections of this chapter.

At the present time and through the year 2000 it appears that electric power in Alaska will be generated by a combination of fossil fuel fired and hydroelectric generating facilities. The cost of power from fossil fuel fired plants will be strongly influenced by the cost of fuel and the capital construction costs. The cost of electric power produced by hydroelectric facilities will of course be rather isolated from inflation but will be strongly influenced by the capital construction costs. Forecasts of the cost of electric power in Alaska are presented and discussed in the fourth section of this chapter.

In each of the following sections both the existing price and availability of the energy sources are estimated. In addition, future price levels and availabilities are forecasted. The "more reasonable" estimates for the cost of the various energy sources are summarized in the last section of this chapter.

4.1 Oil Costs and Availability

4.1.1 Crude Oil

The obvious source of crude oil for Alaskan use is crude oil produced in Alaska. At the present time there is crude oil produced in the Cook Inlet area and on the North Slope. Crude oil production estimates for the period 1976-1985 are shown in Table 4.1.

As shown in Table 4.1 North Slope production is expected to steadily increase during the 1977-1985 time period. Production from the existing Prodhoe Bay fields is expected to decline fairly rapidly beyond 1985, however. Production from the existing southern Alaska fields is expected to decline steadily during the 1976-1985 period and beyond.

TABLE 4.1. Alaskan Crude Oil Production, 1976-1985

Region	Production (1000 Barrels/Day) 1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Prudhoe Bay & Adjacent Fields	--	200	1000	1150	1200	1500	1500	1575	1625	1675
Southern Alaska Older Fields	173	160	150	140	120	108	96	85	73	60
Future Discoveries	--	--	--	15	60	73	86	100	150	200
TOTAL	173	360	1150	1305	1380	1681	1682	1760	1848	1935

SOURCE: Reference 1, pp. 4.19.

Estimating the extent of future discoveries in Alaska is highly speculative. The estimates present in Table 4.1 must be regarded as an educated guess at best. Federal and state leasing policy would be of critical importance here. Also, the extent of the reserves both in Alaska and offshore of Alaska in areas yet to be explored is not known. Production from future discoveries is estimated to be quite low during the early 1980s but increase to about 200,000 b/d by 1985. The forecasted increase during 1983-1985 is primarily due to increased exploration activity brought about by a reduction in the worldwide supply of crude oil during this period. (See for example References 2 and 3.) Based on this reasoning the amount of production from new discoveries can possibly be expected to increase steadily beyond 1985.

The availability of imported crude oil in future years is rather speculative. At the present time there exists a surplus of production capacity on a worldwide basis. This surplus of production capacity is expected to be eliminated during the mid-180s.[2,3] In any event however imported crude oil should be available if the purchaser is willing to pay the posted price.

The price of crude oil in Alaska, as well as the rest of the world, is controlled by the OPEC cartel. The OPEC pricing strategy appears to be based on their perception of the marginal costs of production of the nearest competitor. This policy is intended to maximize their long-term profits.

In the future OPEC's most probable strategy (assuming the cartel can be sustained and no other super-giant oil fields are found or alternative lower cost technologies are developed) will be to escalate its prices paralleling the market rate of interest occurring in its western world market area. The market rate of interest sets the basis from which OPEC can measure its opportunity cost and escalates at approximately 2-3 percentage points higher than the general inflation rate as measured by the GNP deflator. Thus for a general 5% per annum inflating rate, the OPEC oil increase rate would be expected to be about 7-8% per annum.

Since Alaska crude will be competing in domestic marketplaces where the marginal barrel is foreign crude, the market value of crude oil in Alaska will be largely determined by the landed price for imported crude with appropriate quality and locational adjustments. At the present time the estimated price of Alaskan North Slope (ANS) crude (which composes the majority of Alaskan production) should be about $13.21 on the West Coast.[1, p. 8.7] Assuming a transportation cost of 90 cents from Valdez to the West Coast and 30 cents from Valdez to the Cook Inlet area, the cost of crude oil in the Cook Inlet area should be about $12.61.[1, p. 8.5] As pointed out above, this price can be expected to escalate at a rate of about 2-3% higher than the rate of inflation over the long term (20-30) years).

4.1.2 Residual and Distillate Fuel Oil

At the present time there are three crude oil refineries in the southcentral and Fairbanks area. The operating companies, location, and crude capacity of these refineries are shown in Table 4.2.

TABLE 4.2. Alaskan Crude Oil Refineries

	Total Crude Capacity (b/d)
Chevron U.S.A. Inc. - Kenai	22,000
Tesoro Petroleum Corp. - Kenai	38,000
North Pole Refining - North Pole	22,600
TOTAL	82,600

SOURCE: The Oil and Gas Journal, March 28, 1977, p. 99.

These refineries are producing products primarily for the existing Alaskan market. Any large additional requirement for residual or distillate fuel oil would have to be supplied by: 1) imports of fuel oil, 2) expansion of existing refinery capacity, or 3) construction of new refinery capacity.

Figure 4.1 summarizes some past data and several estimates of future industrial fuel oil prices in the Railbelt region. These estimates are presented primarily to illustrate the divergency of opinion that exists. Curves (1) and (3) estimated by the Institute for Social and Economic Research (ISER) for distillate and residual fuels are based on their assumption that fuel costs will track a general inflation rate of 6% per annum after 1980. Forecasts by the Interior Alaska Energy Advisory Team (IAEAT) for 1980 - 1985 appear low based on recent experience and the influences affecting inflation and escalation.

4.2 Natural Gas Cost and Availability

There are many areas of Alaska that have excellent speculative prospects for natural gas. However, the Cook Inlet region is the only current major producer. The estimated remaining reserves in the latter region as of January 1, 1977 are summarized in Table 4.3. Estimates of additional

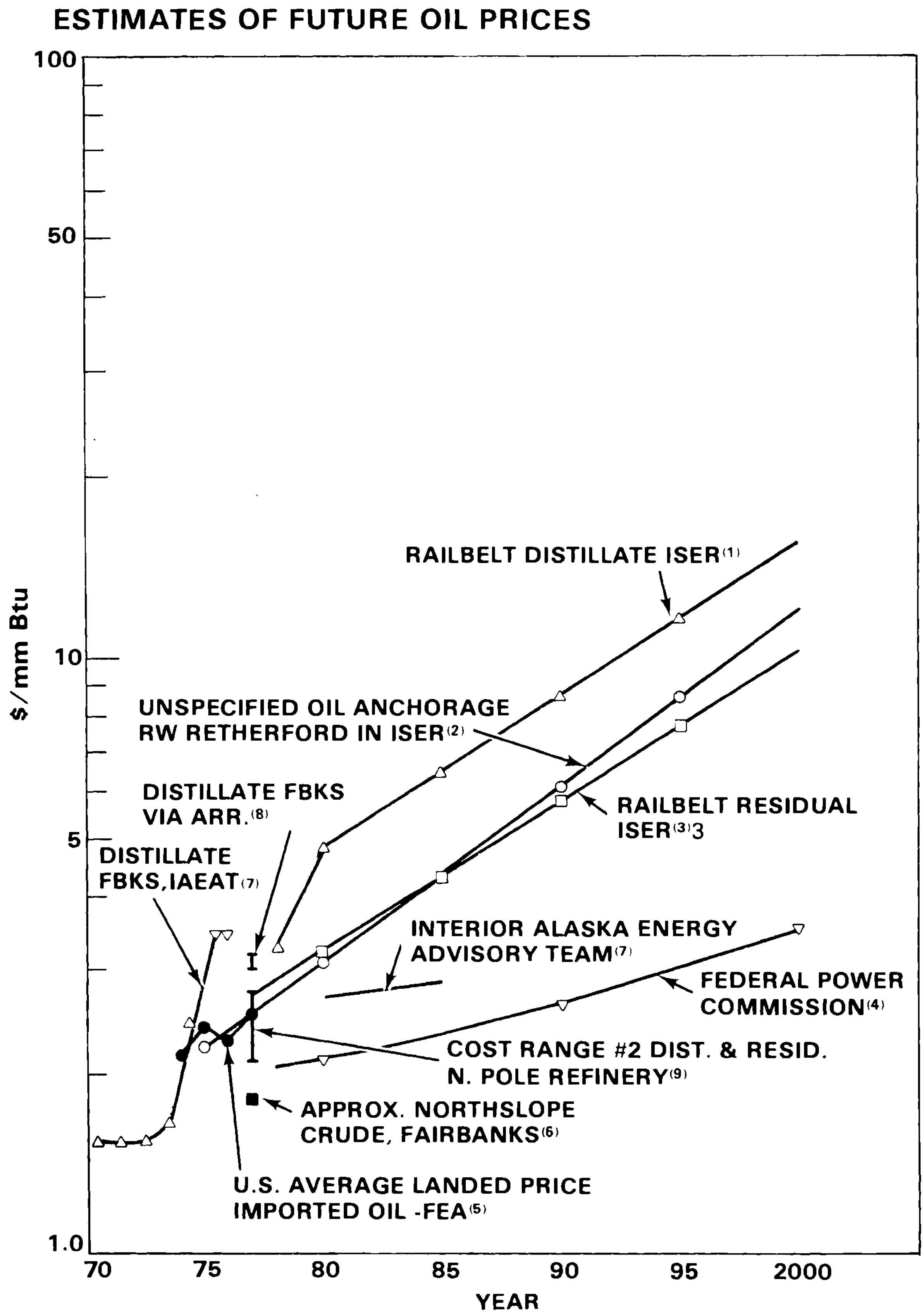


FIGURE 4.1. Estimate of Future Oil Prices

Footnotes for Figure 4.1

Curve No.

1. Railbelt distillate, Institute of Social & Economic Research, "Electric Power in Alaska, 1976-1995," August 1976, Pages 7-24, 25. Six percent per annum inflation and escalation assumed after 1979.

2. Unspecified oil at Anchorage. Estimate by R. W. Retherford reported by ISER, pages 7-11, 25. 7.3% per annum apparent inflation escalation rate.

3. Railbelt Residual, ISER, pages 7-25, 6% per annum inflation and escalation assumed.

4. Railbelt unspecified oil in "1976 Alaska Power Survey," Vol. 1, pages 8-9, Federal Power Administration.

5. U.S. Landed Price, average foreign imported crude, Federal Energy Administration Monthly Energy Review, September 1977.

6. Prudhoe Bay Crude at North Pole, Battelle Estimate, September 1977 based on Oil & Gas Journal, September 5, 1977, page 56, 50% of Pipeline Tariff applicable.

7. Distillate oil Fairbanks, Interior Alaska Energy Advisory Team, June 17, 1977.

8. Distillate, Fairbanks via Alaska Railroad, Date from GVEA, FMUS, October 1977.

9. Range of Cost for #2 Distillage and Residual FOB North Pole Refinery, Data from GVEA, FMUS, October 1977.

TABLE 4.3. Cook Inlet Natural Gas Reserve Estimates

	Total Estimated Remaining Reserves TCF	Uncommitted Reserves TCF
Producing Fields	7.24	2.98
Shut-in Fields	1.08	0.96
TOTAL	8.32	3.94

SOURCE: Reference 4, p. 2.

speculative resources in the region range up to 15.47 TCF of which the majority are expected to be offshore and yet to be discovered.(4, p. 2)

In 1975, the Cook Inlet region consumed about 154 BCF of natural gas, 69 BCF of which were for in-state use not related to export. Forecasts for subsequent years' demands are as follows:

TABLE 4.4. Cook Inlet Natural Gas Annual Demand Estimates

	Billions of Cubic Feet				
	1980	1985	1990	1995	2000
In-State Use	104	139	154	168	185
Export	106	266	278	302	310
TOTAL	210	405	432	470	495

SOURCE: Reference 4, p. 2.

Based on the data presented in Tables 4.3 and 4.4 the currently committed reserves will be exhausted by about 1987, the known reserves in currently producing fields will be exhausted in 1993 and by 1995 the total estimated known reserves will be exhausted. Beyond 1995 dependence will be upon resources to be discovered.

The largest known reserve of natural gas in Alaska is contained in the Prudhoe Bay field. The known reserves in this area are estimated to be 26 trillion cubic feet or over 11% of the total known United States reserves. Production of these reserves will likely be initiated in 1983-1985 at a rate of two billion cubic feet (BCF) per day and possibly as high as 2.5 billion cubic feet per day. Present plans call for this gas to be transported through the Northwest-Alaskan gas pipeline running from Prudhoe Bay to Fairbanks and then into Canada following the Alaska highway.

Compared to fuel oil, natural gas prices represent a completely different and even more complex situation. Figure 4.2 illustrates some estimates of future gas prices under differing long-term contracts for old gas, marketability situations, and potential regulatory conditions. Again, the illustration demonstrates the wide ranges of possible outcomes under varying assumptions.

Due to the necessary investments in transmission and transportation systems, natural gas prices usually involve long-term (20-30 yr) contracts often with clauses covering take-or-pay, escalation, rollover, and adjustments for alternative future takers, etc.

In addition to the above factors, future natural gas prices are subject to considerable regulatory uncertainty. Assuming that new transportation systems will allow Alaskan gas access to the domestic market, a number of possible outcomes can occur under new contracts for <u>old</u> gas or for <u>new</u> gas. Under the current Federal Energy Regulatory Commission (formerly the FPC) ruling 770A, new gas can be priced at the wellhead according to Curve No. 5. However, the present Administration and the House (H.R.-8444) propose that new gas follow a formula pricing based upon the average refinery crude oil acquisition cost which in early 1977 was approximately $1.98/mm Btu.

Assuming inflation plus escalation at a rate of 8% per annum, the <u>new</u> gas could be priced at the wellhead as high as the levels shown by Curve No. 1.

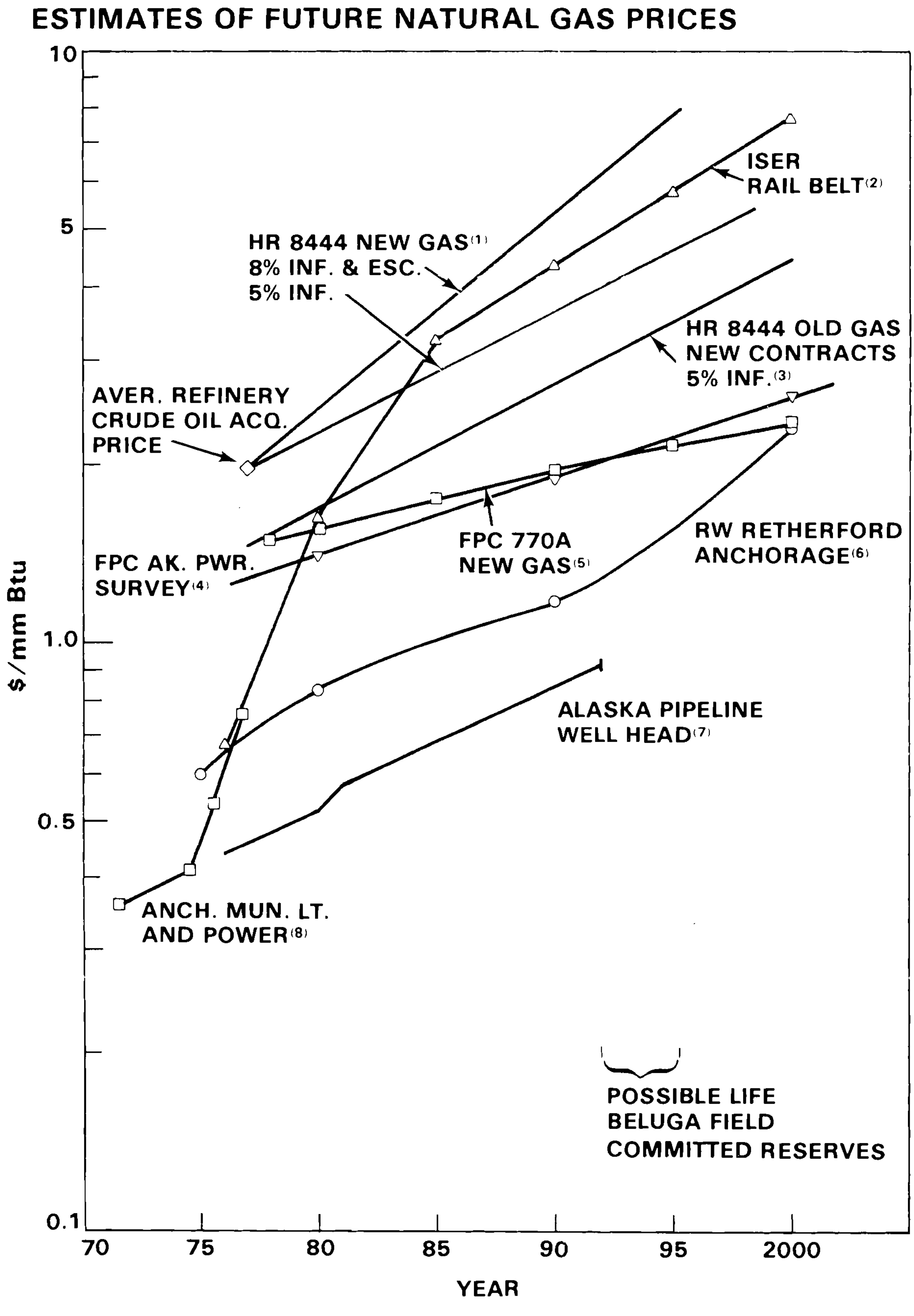


FIGURE 4.2. Estimates of Future Natural Gas Prices

Footnotes for Figure 4.2

Curve No.

1. Proposed National Energy Act H.R. 8444 - New gas at wellhead. Five and 8% inflation plus escalation assumed in refinery average crude oil acquisition cost from January 1977. This price is at the wellhead and does not include federal excise taxes on utility use on transmission cost to the plant.
2. Railbelt gas, Institute for Social and Economic Research.
3. Proposed National Energy Act H.R. 8444 - Old gas at wellhead at 5% inflation rate.
4. "1976 Alaska Power Survey," Federal Power Commission estimate.
5. FPC ruling 770A wellhead price.
6. R. W. Retherford estimate appearing in ISER report, "Electric Power in Alaska, 1976-1995." August 1976, pages 7-25.
7. Contract Provisions. Alaska Pipeline Co. Wellhead cost.
8. Anchorage Municipal Light and Power cost.

For old gas (i.e., presently producing fields) under new contracts or rollover contracts, the wellhead price might be expected to track Curve No. 3 assuming a 5% general inflation rate and no escalation.

4.3 Coal Costs and Availability

Coal prices and availability in Alaska appear much more predictable due to the absence of regulation and the currently limited influence of marketability factors.

Two sources of coal supply for the Southcentral and Fairbanks regions are most pertinent to this analysis:

1) The Nenana Coal Field currently being mined by the Usibelli Coal Co. at about 700,000 tons/yr with plans for expansion to 1.5 million tons/yr. This mine currently supplies the Golden Valley Electric Association (GVEA) plant located at Healy and the Fairbanks Municipal Utility System in Fairbanks.

2) A potential future coal source is the Beluga Field in the Cook Inlet region. The latter field is known to contain very substantial reserves but the new mine development required will be costly due to lack of transportation facilities and mine supporting infrastructure.

Figure 4.3 summarizes various previous forecasts of coal prices in the Southcentral and Fairbanks regions. The Nenana Coal Field is the obvious supplier for future interior generation based on coal. Recent cost of coal delivered by truck to the GVEA Healy Plant is $0.70/MMBTU and by rail at Fairbanks, $1.05/MMBTU. For delivery to the Nenana area, additional costs above mine mouth costs, will be incurred including tipple costs (approximately $0.11 per MMBTU currently) and Alaska Railroad tariffs. The latter may be reduced if unit trains were to be employed.

The Usibelli Coal Mine, Inc. has indicated that they expect their prices to rise at about 7% per annum. This pricing schedule appears reasonable if it is assumed that a 5% per annum general inflation rate continues and a 2 percentage point markup escalation is appropriate for the resource owner. Early 1977 mine mouth coal costs were $0.60/MMBTU.

Therefore, assuming mine mouth and tipple costs increase at 7% per annum and that rail transportation costs have an 80% exposure to general inflation (i.e., 4% per annum) coal costs appropriate for the Fairbanks-North Star Borrough load center should follow the curve shown in Figure 4.3.

The Healy area could also serve the Cook Inlet region via the Alaska Railroad. Tariffs for Healy coal delivered by rail at Anchorage and Portage as provided by the Alaska Railroad are summarized in Table 4.5 as a function of annual tonnage and car ownership.[5]

For the purpose of this analysis we have assumed that the tariff would be about $0.30 per MMBTU resulting in Healy-Anchorage curve as shown in Figure 4.3.

The Beluga/Susitna coal field is an obvious source of supply for coal in the Beluga area. The reserves are very large and capable of supporting a world scale mine for export and mine mouth industrial development. The coal is subbitimunious (Rank C) and of relatively low heating value ($\sim$7100 Btu/lb) at run-of-mine but quite low in sulfur (0.15% typical). Coal preparation including washing and drying could raise the heating value to 9,000 Btu/lb. Some of the coal will be of too low a quality for export but would nevertheless be suitable for mine mouth industrial development.

Placer Amex Inc., holder of the larger leases, has recently conducted considerable exploration to prove out the reserve. They are of the opinion that a 6MMTPY for export mine would be required to support the front end capital investment necessary for such a frontier area operation, in particular for the harbor and loading facilities. Under private

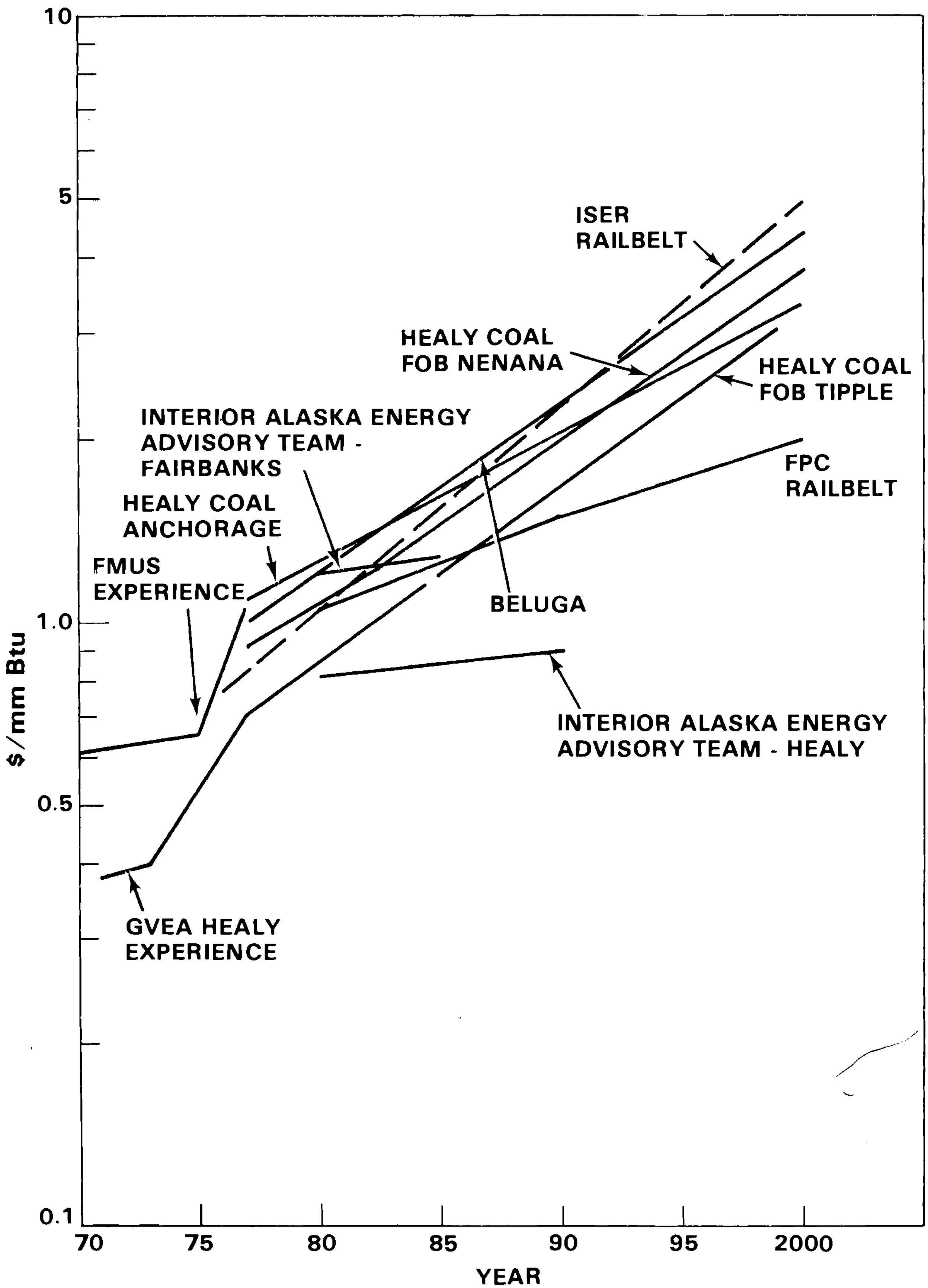


FIGURE 4.3. Estimates of Future Coal Prices

TABLE 4.5. Alaska Railroad Tariffs-Healy Origin[a]

Annual Tonnage	Anchorage				Portage			
	Shipper Owned Cars		Carrier Owned Cars		Shipper Owned Cars		Carrier Owned Cars	
	%/Ton	$MMBTU	$/Ton	$/MMBTU	$/Ton	$/MMBTU	$/Ton	$/MMBTU
200,000 to 500,000	-	-	7.67	0.441	-	-	7.73	0.444
1,000,000	4.21	0.242	5.51	0.317	4.71	0.271	6.01	0.345
1,500,000	4.20	0.241	5.18	0.298	4.70	0.270	5.68	0.326
2,000,000	4.10	0.236	5.00	0.287	4.59	0.264	5.49	0.316

(a) Conversion to $/MMBTU based on 8700 BTU/# coal quality.

financing conditions the estimated coal price FOB mine would be in the range of $0.85 to $1.00/MMBTU ($12 to 14/ton).

A mining operation not involving export facilities, though not having the economies of scale, could produce coal at similar prices for local consumption.

The 6MMTPY economic mining scale would support about 2,000 MW of generating capacity, a scale which suggests that mining for export or for other industrial development in combination with onsite use would be required at least initially. If coal were used to provide all process heat requirements for a 150,000 bbl/day oil refinery, this load alone would require about 2 MMTPY.

Other alternative Railbelt coal supply regions include the Mananuska and Kenai fields. The Matanuska field is 50-70 miles northeast of Anchorage and the valley is served by a branch line of the Alaska Railroad.[a] The beds of the Matanuska Valley vary in thickness and the seams are separated by shale and sandstone layers. Reserves are estimated at only 100 million tons. Coal quality is good however, being bituminous in rank with a heating value in excess of 11,000 Btu/lb and a sulfur content of 0.6% or less.

Because of the limited proven reserves and difficult underground mining situation in the Matanuska Valley, no further consideration is given to this area as a coal source.

The Kenai field (∿300 million tons, 7,700 Btu/lb, 0.1-0.4% sulfur) also suffers from having seams 6 ft or less in thickness. In addition, the beds are lenticular, making continuous mining of a seam impossible over large areas.

4.4 Electric Power

Table 4.6 presents the costs of electric power in several categories for Alaska. These costs can be compared to the costs shown for the Pacific Coast States of California, Oregon, and Washington as well as some

(a) The tracks have been removed past Palmer but the roadbed still exists.

TABLE 4.6. Cost of Power to Ultimate Consumers

($/kWh)

State	Residential	Commercial & Industrial		Street & Highway Lighting	Other Public Authorities	Railroads and Railways	Inter-departmental
		Small Light and Power	Large Light and Power				
California	0.035	0.033	0.024	0.050	0.010	0.017	0.009
Oregon	0.018	0.017	0.008	0.035	0.008	-	0.009
Washington	0.013	0.014	0.005	0.023	0.009	0.011	0.001
Massachusetts	0.050	0.047	0.037	0.084	0.040	0.062	0.040
Pennsylvania	0.041	0.038	0.026	0.078	0.041	0.029	0.028
Tennessee	0.023	0.027	0.017	0.034	0.024	-	0.019
Alaska	0.034	0.032	0.033	0.060	0.047	0.031	0.035

SOURCE: Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1976, New York, 1976, pp. 33-45.

representative eastern U.S. states: Massachusetts, Pennsylvania, and Tennessee. As shown in Table 4.6 the cost of power in Alaska in most consumer categories is typically higher than the cost of power in the Pacific Coast states. California power costs are only slightly higher, however. The lower electric power costs in Oregon and Washington can be attributed to the large percentage of relatively low cost power produced by hydroelectric generating facilities located in the Pacific Northwest.

The power costs in Tennessee are also relatively low due mainly to the TVA hydroelectric program. Of the states listing in Table 4.6 Massachusetts typically has the highest cost of power while Pennsylvania ranks second in most cases.

Future costs of electric power in Alaska and the Lower 48 are difficult to predict. Utilities in the Lower 48 are faced with rising construction costs for both coal and nuclear plants due to increased materials and labor costs as well as environmental considerations. Fuel costs for both coal and nuclear plants are also increasing. Alaskan utilities are faced with the same factors in addition to the historically greater construction and operation costs existing in Alaska. One factor that may tend to retard the increase in power costs in Alaska is the possible construction of additional hydroelectric generating facilities in the state. Based on existing cost data there are several possible hydroelectric projects that could produce power at a lower cost than thermal facilities.[6, p. 8.5] At the present time there are no similar plans for significant increases in hydroelectric power generation in the Lower 48.

Based on this analysis there is no reason to believe that the rate of increase in power costs will differ between the two regions. If this is the case, the relationship among the electricity costs shown in Table 4.6 will continue into the future.

A recent analysis of the bus bar costs of electric power in Alaska suggests that the bus bar cost of electric power from coal steam turbine generating plants will increase at a rate about 2.5% above the rate of general inflation. Hydroelectric power costs including transmission costs are forecasted to increase at a rate about 1.0-1.5% above the rate of general inflation.[5, p. 8.5] Assuming that distribution, customer, and sales expenses increase at a similar rate these estimates could be used as rough estimates of the increases in electricity prices in the future.

The electrical transmission and distribution system in Alaska is not nearly as extensive as the systems existing in the Lower 48. The electrical transmission and distribution systems in Alaska are typically limited to the immediate proximity of a city or town. Several cities and towns are interconnected in the Anchorage/Homer/Kenai region, however. Fairbanks is interconnected with Healy and Nenana and the Tenana Valley. For these reasons the availability of electric power represents a more serious restriction for industrial siting in Alaska than in the Lower 48.

4.5 Summary of Energy Costs in Alaska

From the above discussion, it is obvious that forecasts of future energy costs in Alaska are subject to considerable uncertainty. Nevertheless, given the assumptions regarding the world Btu market and the National Energy Policy (NEP), at least some rational judgments can be made.

As mentioned in Section 4.1.1 the costs of crude oil are expected to increase at about 2 to 3% faster than the rate of general inflation. At this point this assumption appears to also be reasonable for the cost of fuel oil, natural gas and coal. For the purposes of this analysis the fuel prices summarized in Figure 4.4 will be used. Electricity prices will be assumed to increase at about 2% faster the general inflation.

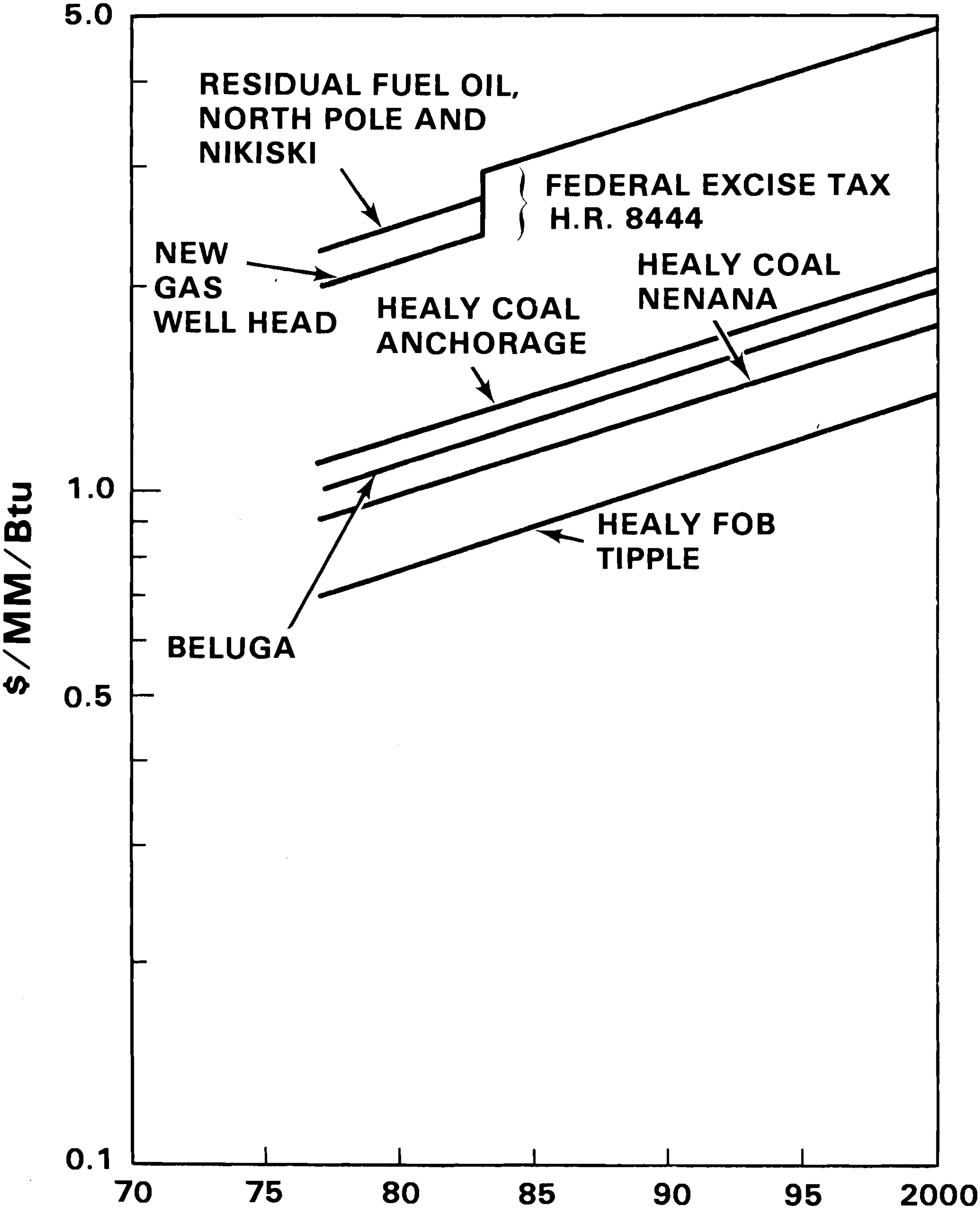


FIGURE 4.4. Summary of Probable Fuel Costs - Zero Inflation Rate

REFERENCES CHAPTER 4.0

1. North Slope Royalty 0.1 Market, Pricing and Revenue Analysis, Division of Research Services, Legislative Affairs Agency, Alaska State Legislature, March 1978.

2. CIA Sees World Oil Shortfall by 1985, The Oil and Gas Journal, April 25, 1977, p. 90.

3. BP Sees Global Oil Shortage in 1990s, The Oil and Gas Journal, October 24, 1977, p. 62.

4. Alaskan North Slope Royalty Natural Gas - An Analysis of Needs and Opportunities for In-State Use, Alaska Department of Commerce and Economic Development, Division of Energy and Power Development, August 1977.

5. Personal Communication, A. Polachek, Alaska Railroad, November 11, 1977.

6. Alaskan Electric Power - An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, Division of Energy and Power Development, Department of Commerce and Economic Development, March 1978.

5.0 CONTIGUOUS STATES ENERGY COSTS AND AVAILABILITY

Much of the discussion and data presented in Chapter 4.0 is directly applicable to the energy costs in the Lower 48. The evaluation presented in this chapter is aimed at presenting historical and current data on oil, natural gas and coal costs. In many cases costs of fuel to electrical utilities is presented as representative of large industrial purchases.

5.1 Oil Costs and Availability

5.1.1 Crude Oil

As explained in Section 4.1.1 the price of imported crude oil is controlled by OPEC. Domestic crude prices are presently controlled by a variety of price controls and entitlements. Foreign and domestic crude oil prices and refiner acquisition costs are presented in Figure 5.1 for the 1974-1978 time period. It was pointed out in Chapter 4 that crude oil and fuel oil prices are expected to increase at a rate about 2 to 3 percent above the general inflation rate in the future. Imported crude oil would have essentially the same landed cost in Alaska as in the Lower 48.

5.1.2 Residual and Distillate Fuel Oil

The prices paid for residual fuel oil by electric utilities in various regions in the Lower 48 are presented in Table 5.1.

5.2 Natural Gas Price and Availability

The costs of natural gas delivered to steam electric utility plants for the 1975-1977 period are presented in Table 5.2.

The prices for natural gas increased relatively rapidly during the 1975-1977 time period. It is unclear what the natura gas pricing provisions of the National Energy Plan (NEP) will be. In any event, the price of natural gas on a per Btu basis can be expected to increase to be roughly equivalent to the price of residual oil over the near future (5 yrs).

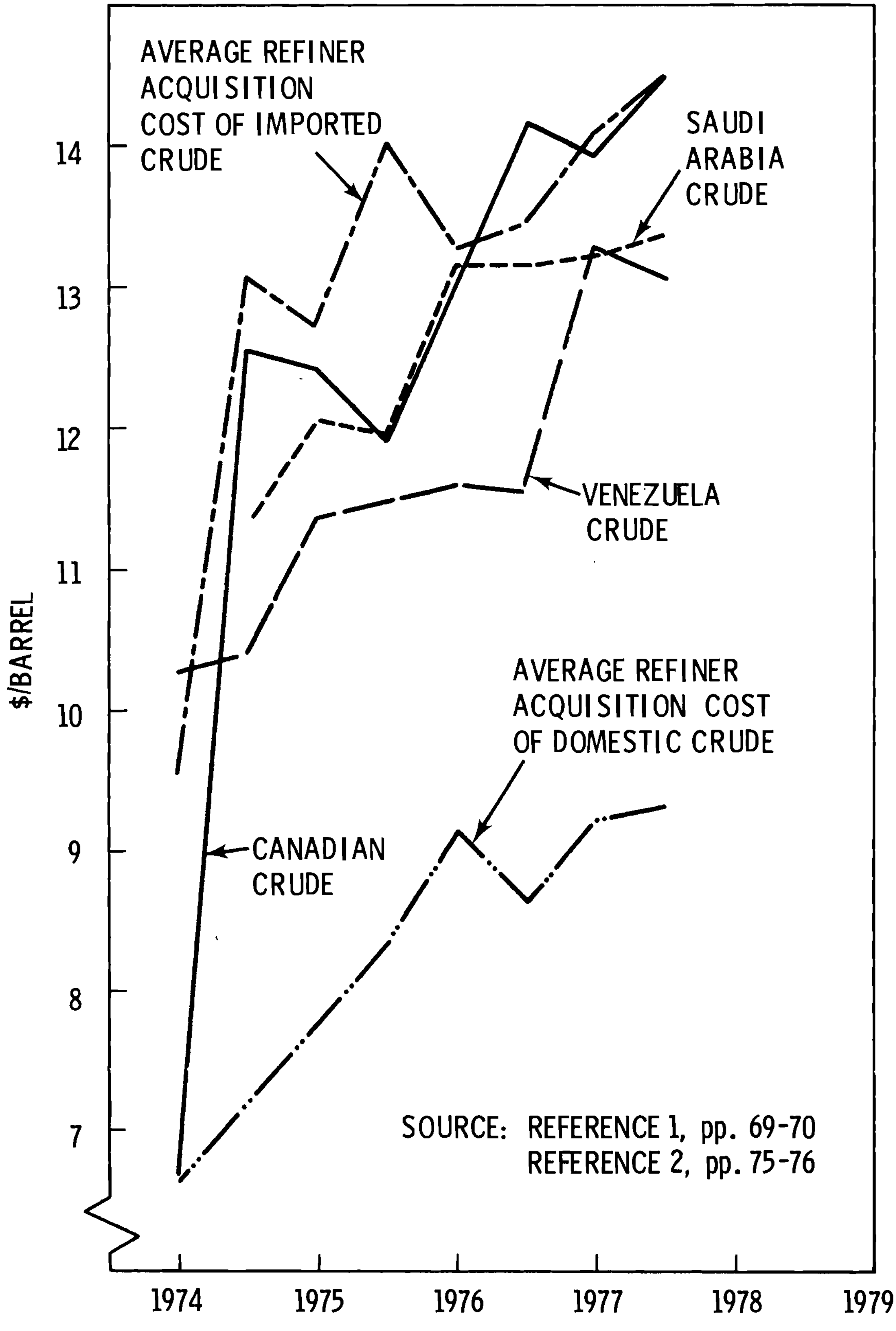


FIGURE 5.1. Foreign Crude Oil Prices and Refiner Acquisition Costs

TABLE 5.1. Electrical Utility Residual Fuel Oil Prices (cents per million Btu)

Region	June 1975	June 1976	June 1977
New England	201.7	177.8	216.2
Middle Atlantic	201.5	187.3	223.1
East North Central	163.3	211.8	248.6
West North Central	165.5	148.8	186.6
South Atlantic	189.3	171.9	210.1
East South Central	165.5	166.9	177.7
West South Central	182.0	176.4	194.3
Mountain	199.0	212.4	215.3
Pacific	245.6	229.1	235.7

SOURCE: Reference 1, p. 75; Reference 2, p. 83.

TABLE 5.2. Electrical Utility Natural Gas Prices (cents per million Btu)

Region	June 1975	June 1976	June 1977
New England	121.7	153.7	193.9
Middle Atlantic	92.7	108.0	144.2
East North Central	111.6	139.8	177.3
West North Central	58.1	78.1	104.8
South Atlantic	72.2	83.1	74.4
East South Central	77.0	123.0	134.3
West South Central	69.2	98.1	122.1
Mountain	69.6	89.5	132.9
Pacific	84.1	147.6	200.5

SOURCE: Reference 1, p. 75, Reference 2, p. 83.

At this point the availability of natural gas must be examined on a regional basis. Since the price of gas in the intrastate market is not regulated new gas contracts should be available in gas producing states at the market price. Gas supplies in the interstate market are much tighter and would have to be evaluated on a case by case basis.

5.3 Coal Price and Availability

The prices paid by utilities for coal during the 1975-1977 time period are presented in Table 5.3.

TABLE 5.3. Electrical Utility Coal Prices (cents per million Btu)

Region	June 1975	June 1976	June 1977
New England	116.5	122.3	130.1
Middle Atlantic	101.6	102.5	107.4
East North Central	82.4	86.6	95.5
West North Central	53.9	64.7	77.0
South Atlantic	98.4	100.7	113.9
East South Central	80.5	84.5	95.0
West South Central	21.0	27.3	63.9
Mountain	31.0	35.9	47.4
Pacific	58.4	75.2	71.2

SOURCE: Reference 1, p. 75; Reference 2, p. 83.

As can be seen from Tables 5.1 through 5.3, the prices paid by utilities for coal is generally lower than the prices paid for natural gas and fuel oil. There are two primary reasons for this: 1) coal generally requires much more emissions control equipment to meet emissions standards, and 2) coal is less convenient to use and to transport than either natural gas or oil.

5.4 Electric Power Costs and Availability

The costs of electric power in several representative states in the Lower 48 were presented in Section 4.4.

1. Federal Energy Administration, Monthly Energy Review, December 1976, National Energy Information Center, Washington, DC.

2. U.S. Department of Energy, Monthly Energy Review, December 1977, National Energy Information Center, Washington, DC.

6.0 ALASKA CONSTRUCTION AND CAPITAL COSTS

Several methods can be used to estimate the construction or capital cost of industrial facilities. Each method has a different level of uncertainty associated with it. As would be expected, the less the uncertainty associated with an estimate, the more time and money required to prepare it. Several factors contribute to the uncertainty of an estimate; rapidly escalating equipment, site materials, and labor costs are perhaps the most important at the present time.

The most accurate estimating procedure is to obtain a firm bid for the installed equipment from a supplier. This procedure can be costly, however, since it usually requires site-specific studies and binding commitments from subcontractors. As a result, this method is typically not used unless there are definite plans to purchase the equipment.

The next most accurate method of estimating the capital cost of a facility is to obtain an estimate (nonfirm) by a supplier. In most cases with large and expensive equipment, suppliers are reluctant to give such estimates because the total costs are highly dependent on site-specific factors which require a working knowledge of local conditions. In most cases, suppliers with recent experience in the area can give relatively accurate short term estimates.

Another relatively accurate estimating procedure is to develop the costs of the proposed facilities based on data from recent purchases of similar equipment of the same size located in a similar location. This technique is not applicable in most cases for Alaska because of limited experience with industrial facilities in the State.

For survey analysis such as this, one method of estimating capital costs is to use a construction cost location adjustment factor. Conditions that influence the construction cost of facilities differ among various regions. The differences may be due to such things as the relative availability of transportation facilities, labor costs, climate, and distance from equipment suppliers. In many cases, these factors combine to influence costs in a consistent manner which allows a location adjustment factor to be used. This number is expressed at the ratio between the construction cost of an item at a proposed location and the construction cost of that item at a base location; i.e.,

$$\text{Location Adjustment Factor} = \frac{\text{Cost at Proposed Location}}{\text{Cost at Base Location}}$$

Such a location adjustment factor may be used to estimate the cost of a facility in Alaska given the cost of a similar facility in the Lower 48.

Because of the large and diverse nature of Alaska, the "Alaska factor" must be defined for a specific location in the state. The base location in the Lower 48 should also be specified although it is not as critical as in Alaska. A number of Alaska factors are listed in Table 6.1.

The Alaska factor can be refined slightly by using different factors to escalate labor and materials. The total cost of the completed project is weighted based on the relative amount of labor and materials used. Labor and material adjustment factors were developed by the Alaska Power Administration (APA), for the Interim Feasibility Study on the Upper Susitna River Hydroelectric Study.[1] The labor adjustment factor was 1.9 and the materials adjustment factor was 1.1. These numbers are based on Oregon and Washington data and a remote job site in Alaska (approximately 100 miles north of Anchorage). These estimates are also presented in Table 6.1.

Assuming that 30% of the total cost is labor (typical estimate for an industrial facility), an overall factor of 1.34 is computed.

$$\text{Overall Factor} = 0.3 \times 1.9 + 0.7 \times 1.1 = 1.34$$

This figure appears to be generally lower than the other factors shown in Table 6.1. A possible reason for this is:

The factor of 1.1 for materials assumes that the cost of transportation including loading and unloading from the Pacific Northwest

TABLE 6.1. Alaskan Construction Cost Location Adjustment Factors

FROM / TO	Pacific Coast	Anchorage	Beluga	Healy	Fairbanks	Barrow	Railbelt
Washington, DC	1.06[a]	1.7[b]	2.75[b]	2.42[b]	-	-	-
Pacific Coast	-	-	-	-	-	-	1.1 - Materials[c] 1.9 - Labor
Lower 48 (General)	-	1.35[d]	-	-	-	-	-
Anchorage	-	-	-	-	1.2[e]	2.8[e]	-
Derived for Pacific Northwest	-	1.65	2.70	2.35	2.0		
Battelle Estimates	-	1.50	1.80	2.20	2.0		

(a) Based on Handy-Whitman Index for North Atlantic Region and Pacific Region. January 1, 1977 price levels - total plant all steam generation.
(b) Letter from Charles A. Debelius, Colonel, Corps of Engineers to M. Frank Thomas, Regional Engineer, Federal Power Commission, May 5, 1975. Based on heavy construction with labor being 50% of the total cost.
(c) Upper Susitna River Basin, Interim Feasibility Report, Appendix 1, Part 2. U.S. Army Corps of Engineers, p. H-57, December 12, 1975. Upper value is for materials, lower value is for labor.
(d) Electric Power in Alaska, 1976-1995. ISER, University of Alaska, p. G.1.1, August 1976. (Letter from Thomas R. Stahr to A. Tussing, May 10, 1976.)
(e) Electric Power in Alaska, 1976-1995. ISER, University of Alaska, p. G.2.1, August 1976.

to the Railbelt is \$2.37/100 lb. A more recent estimate for materials typical of power plant is \$8.00/100 lb.(2) Using this estimate, the materials factor becomes 1.27 (round to 1.25).

Using this modified estimate and again assuming that 30% of the total cost is labor, an overall factor of 1.45 is indicated:

$$\text{Overall Factor} = 0.3 \times 1.9 + 0.7 \times 1.25 = 1.45$$

It appears that an Alaska factor of 1.4 to 1.5 is justified for estimating the cost of a plant in the Anchorage area given the cost of a plant in the Pacific Northwest. Previous work done by Battelle for the State of Alaska indicates that a multiplier of 1.5 would be appropriate for a chemical plant using modular construction to minimize site labor.(3)

Construction costs at Beluga should be higher than costs in the Anchorage area. The estimate prepared by the Corps of Engineers (2.75) appears to be higher than recent estimates of construction costs in the Beluga area would suggest, however. There are some cost trade-offs which support this viewpoint.

Real estate costs might be less in the Beluga area for example. Also, if much of the plant were modularized and prebuilt in Puget Sound even large modules could be barged to the area beaches where off loading could be achieved (using the 25-30 ft tides) without the need of harbor construction. Such large modules could not be handled over normal dock and rail terminal facilities.

Housing for labor would be an added cost item at remote locations. The plant site could be only 50 to 70 air miles from Anchorage and a weeking rotation of crews would be possible. Fuel for equipment and daily supplies could come by landing craft type barges from Anchorage or Nikiski.

Based on this reasoning an Alaska construction cost factor of 1.80 is used for the Beluga area in Cook Inlet.

Plant construction in the interior could not take advantage of the modular construction opportunities available at tide waters. A construction cost factor of 2.2 is used for interior areas on the Railbelt.

Of course, the sites listed in Table 6.1 do not represent all of the possible industrial sites in the State of Alaska. The estimates presented in Table 6.1 can be used to extrapolate cost multipliers for other regions in the State.

1. Upper Susitna River Basin, Interim Feasibility Report, Appendix I, Part 2, U.S. Army Corps of Engineers, p. H-57, December 12, 1975.

2. John Chapman, Chief-Estimating Section, Alaska District, U.S. Army Corps of Engineers, Personal Communication, Anchorage, AK, October 12, 1977.

3. Alaskan North Slope Royalty Natural Gas, An Analysis of Needs and Opportunities for In-State Use, Division of Energy and Power Development, Department of Commerce and Economic Development, State of Alaska, p. VIII-36, September 1977.

7.0 ANALYSIS OF ALASKAN LABOR COSTS AND ESTIMATION OF WAGE DIFFERENTIAL BY INDUSTRY

7.1 INTRODUCTION

Labor costs can be a significant portion of total production costs and vary widely from industry to industry and state to state. For example, in 1970 labor costs were approximately 30 percent of the nation's total production costs. That means that for every $3 of goods and services produced, $1 was spent for employee compensation. The 3 to 1 ratio is a national average for all industries and of course wide fluctuations will be found in the ratio for specific industries. For example, some service industries may have a ratio of 5 to 4 while for some automated manufacturing industries the ratio may be 5 to 1.

The local labor costs must be kept in perspective with total production costs and other elements considered in siting industrial plants. For example, higher than average labor costs might be offset by less costly raw materials, energy costs, or transportation costs. Therefore, industrial managers will desire sites with relatively low labor costs; but they have a stronger incentive to locate in areas which provide a low or competitive total production cost.

Most agree that labor costs are usually greater in Alaska than in the Lower 48 states. The question requiring an answer, however, is how much greater are labor costs in Alaska than the Lower 48? What is the differential in labor costs and how important will these labor costs be with respect to the costs of other factors of production and the total cost of production. For example, products might be identified which require a minimum of labor and then plants designed which are efficient with respect to utilization of labor, close to markets (Japan), and requiring materials which are relatively more available in Alaska than in the Lower 48 states.

One can safely assume that when all things are equal industry will locate at a site which allows them to minimize production costs. This makes them the most competitive and most profitable. In reality plant siting turns out to be a series of compromises and production costs are almost always greater than the theoretical minimum; e.g., the preferred site is not obtainable at a reasonable price. In addition there may be and frequently is one dominating factor of production whose availability almost dictates future plant locations independent of labor costs. Therefore, while labor costs are important, they are not the only cost of production and industries and markets should be identifiable for which an Alaskan location will have significant advantages. These need to be identified as well as the labor costs so that the latter can be put in perspective. For example, if one were to construct a new cement plant, the preferred site would have an adequate supply of low cost energy and labor and a large, adjacent source of limestone. Currently there are no low cost sources of energy, but an assured supply will be attractive. Alaska can provide the latter and in addition limestone sources exist. Given these two positive factors, Alaska might be a preferred site independent of labor costs.

7.2 OBJECTIVE

The following sections of this chapter identify the cost of labor for numerous, potential Alaskan industries. The average weekly labor costs were developed for each of these industries located in several states as well as Alaska. The data were selected to identify and illustrate the range of labor costs for selected industries. For each industry, several states were selected on a basis of:

1) large employment in the given industry,
2) proximity to Alaska,
3) potential for competing with industry located in Alaska, and
4) representing the highest or lowest labor cost among the Lower 48 states.

The results of the analysis include average weekly cost of labor and the percentage of the national average labor cost for 10 industries and selected states.

7.3 IDENTIFICATION OF WAGE DIFFERENCES

7.3.1 Data

Data were collected from U.S. Department of Labor, Bureau of Labor Statistics[a] for the years 1965, 1970, 1973, and 1975. The data collected was for 12 states, the U.S. average, Pacific Region (Washington, Oregon, California, Alaska, and Hawaii) plus the Western Southcentral states (Arkansas, Louisiana, Oklahoma, and Texas). The states were selected because they represented potential competition for an Alaskan industry, the state had a large fraction of the industry's employees, or the state's employees received the greatest or least weekly salary. For example, Texas is included because it has the greatest number of employees in the oil refining and petrochemicals industries.

The industrial classifications selected were:

1) all industries,
2) contract construction,
3) all mining,
4) all manufacturing,
5) petroleum refining and related industries,
6) paper and allied products,
7) chemicals and allied industries,
8) crude petroleum and natural gas,
9) services, and
10) transportation, communication and other public utilities.

The data were analyzed and utilized for estimating weekly "wage rates" per employee for each of the 10 industries.

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages - First Quarter, 1965, 1970, 1973, and 1975.

The wage rates were calculated by 12 states, the total U.S., the Pacific Region and the West Southcentral Region. These data then provided a basis for comparing Alaskan labor costs or wage rates with labor costs in other states for 10 industrial classifications.

Quarterly data were utilized as it was the most appropriate for identifying wage differentials, i.e., the difference between Alaskan and other states' wage rates. The published data for employment is by month and the wage data is by quarters. The quarterly data needed to be converted to a per capita income in order to have a basis for comparison. The quarterly wages were converted to weekly income per employee by dividing by 13 (weeks in a quarter) and the employment for March. The result is an "average weekly wage" per employee based upon the first quarter's earnings.

The published data does not include any correction for hours worked so the weekly "wage rate" would be overstated (on a 40-hr/wk basis) for those employees who worked more than the normal 40-hr week. The first quarter data were selected to minimize this data problem as no data is available for "correcting or adjusting" the published data.

Large, industrial classifications were also used when appropriate. These larger classifications were required to obtain data for Alaska which would be large enough to provide a reliable wage rate. For example, some industries in Alaska which might be expanded currently have very few employees. The data for these industries might be too small to provide a realistic weekly wage unless aggregated with other industries. These industries were aggregated as necessary and appropriate. The data errors were then reduced by averaging.

7.3.2 Data Analysis

Weekly wage rates were calculated for 10 industrial classifications for 12 states, 2 regions and an average for the United States. The rates were calculated for 1965, 1970, 1973, and 1975. The data and wage rates are tabulated in Appendix A.7. A summary of the data for each classification is provided in Tables 7.1 through 7.10 for Alaska, the U.S. average and key states, Figures 7.1 through 7.10 also illustrate the data.

The calculated weekly wage rates are for historical data and are used to illustrate the past trend. The data represent the cost of labor for existing plants. No attempt was made to develop estimates or labor productivity in each of the industries; i.e., production per employee. The labor productivity will also be influenced by the age of the plant; generally the newer the plant the more efficient it will be with respect to labor productivity. Also, any new plant to be constructed in Alaska should have access to the latest technology and in turn be the most efficient in terms of labor.

Weekly wages were calculated for the classification, "All Industries," which represents the average for all industries. This is a general classification which includes all employees covered by state unemployment insurance laws and for federal civilian workers covered by the program of Unemployment Compensation for Federal Employees. Table 7.1 provides a summary of the weekly wage rates for the U.S. (a national average), California, Alaska, and the Pacific Region (Washington, Oregon, California, Alaska, and Hawaii). Table 7.1 also includes values for the percent of national average wage rate. For example, in 1973 the Alaskan average weekly wage rate was 133% of the average national wage rate. In previous years (1970 and 1965) the Alaskan rate was 135 to 140% of the national average. In 1975, however, the average rate increased to 175% of the national average. The data are probably reflecting the inflationary impacts and the long workweeks associated with the Trans Alaskan Pipeline.

TABLE 7.1. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for All Industries(a)

	1975		1973		1970		1965	
	$/Week	%	%Week	%	$/Week	%	$/Week	%
United States	186.30	100	161.2	100	137.4	100	105.8	100
California	198.3	106.4	174.3	108.1	149.5	108.8	119.5	112.9
Alaska	326.1	175	214.8	133.3	193.8	141	143.06	135.2
Pacific	197.4	106	172	106.7	147.6	107.4	116.85	110.4

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

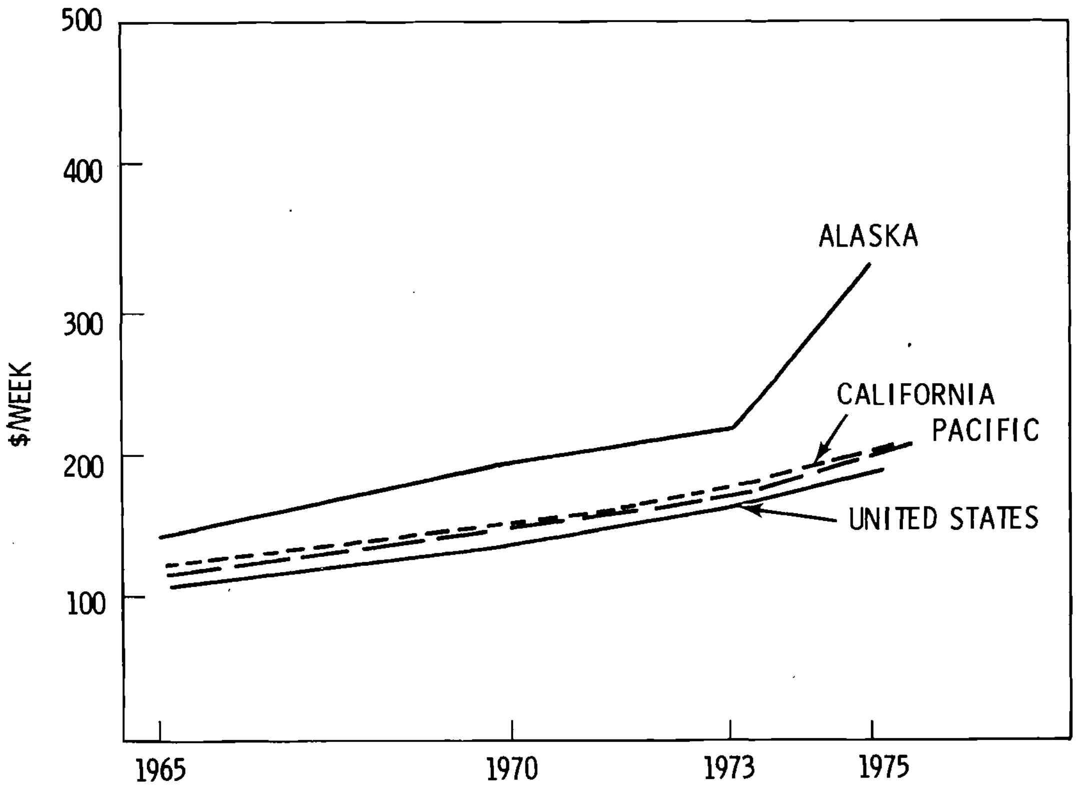


FIGURE 7.1 Average Weekly Wage - All Industry

A similar analysis was completed for "Contract Construction". Alaskan employees in contract construction receive a considerably greater wage than the average U.S. contract construction worker. In 1965 the Alaskan employee received 180% of the national weekly wage. In 1975 the contract construction worker's weekly wage was 260% of the national average. This reflects the inflationary impact of the pipeline and additional hours worked per week. One should not interpret this data as meaning that an Alaskan employee receives 2.6 times the hourly rate of the national average worker. The rate, independent of a major construction project, is probably closer to 1.8 times the national average. The data is summarized in Table 7 2.

TABLE 7.2. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Contract Construction[(a)]

	1975		1973		1970		1965	
	$/Week	%	$Week	%	$Week	%	$/Week	%
United States	229.67	100	189.87	100	164.41	100	116.82	100
Washington	245.67	107	205.72	108.3	178.09	108.3	127.95	109.5
California	273.51	119.1	220.89	116.3	195.06	118.6	147.45	126.2
Alaska	591.01	257.3	316.45	166.7	311.49	189.5	211.05	180.7
Pacific	282.85	123.2	218.64	115.2	192.78	117.3	143.46	122.8

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

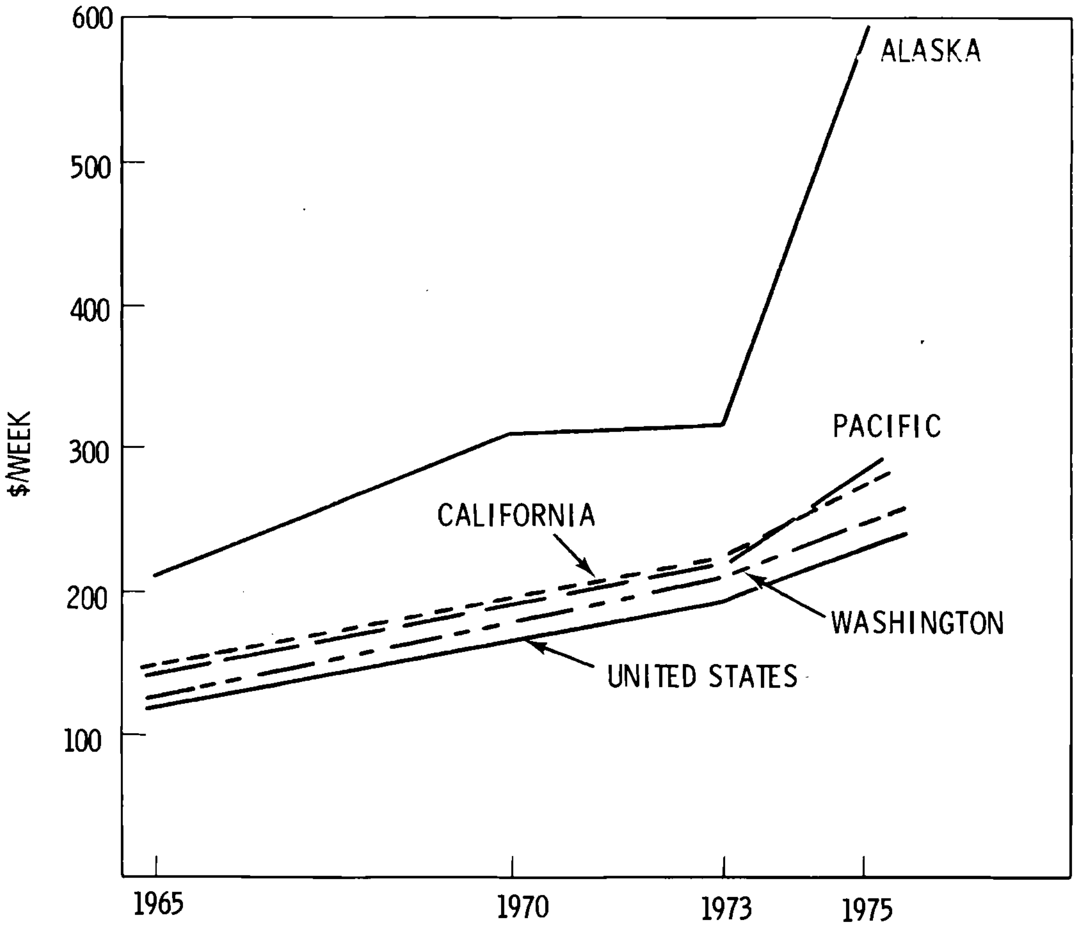


FIGURE 7.2 Average Weekly Wage - Contract Construction

Similar analysis were completed for mining and the seven other industrial categories included in the study. The wage rate for the mining industry is approximately 180% of the national average. The wage rates for all the other industries are also greater than the national average. The general category entitled "manufacturing" has the lowest differential and is 20 to 25% greater than the average U.S. manufacturing workers. Workers in the other six categories receive from 125 to 180% of average national workers. The data for these employees is provided in Tables 7.3 through 7.10 and Figure 7.3 through 7.10.

TABLE 7.3. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Mining[(a)]

	1975		1973		1970		1965	
	$/Week	%	$/Week	%	$/Week	%	$/Week	%
United States	266.13	100	210.39	100	170.99	100	125.58	100
Texas	275.63	103.6	219.49	104.3	180.31	105.5	113.69	90.5
California	294.44	110.6	243.78	115.9	199.79	116.8	149.90	119.4
Alaska	502.68	188.9	355.88	169.2	306.78	179.4	196.58	156.5
Pacific	310.66	116.7	245.40	116.6	206.46	120.7	148.65	118.4

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

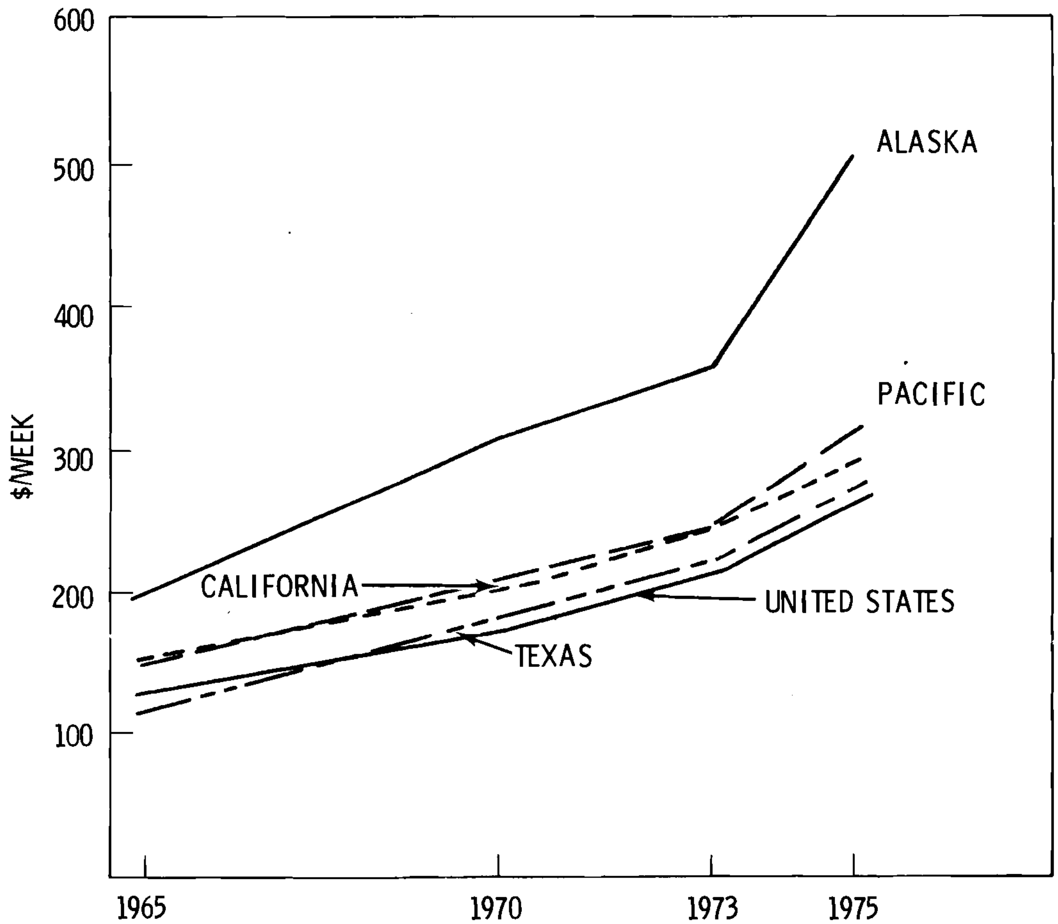


FIGURE 7.3 Average Weekly Wage - All Mining

TABLE 7.4. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Manufacturing[a]

	1975		1973		1970		1965	
	$/Week	%	$/Week	%	$/Week	%	$/Week	%
United States	215.23	100	182.06	100	149.84	100	116.62	100
Washington	244.81	113.7	205.11	112.7	176.35	117.7	130.08	111.5
California	231.37	107.5	196.76	108.1	171.59	114.5	136.06	116.7
Alaska	267.03	124.1	186.03	102.2	173.08	115.5	135.96	116.6
Pacific	230.87	107.3	-	-	-	-	133.13	114.1

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

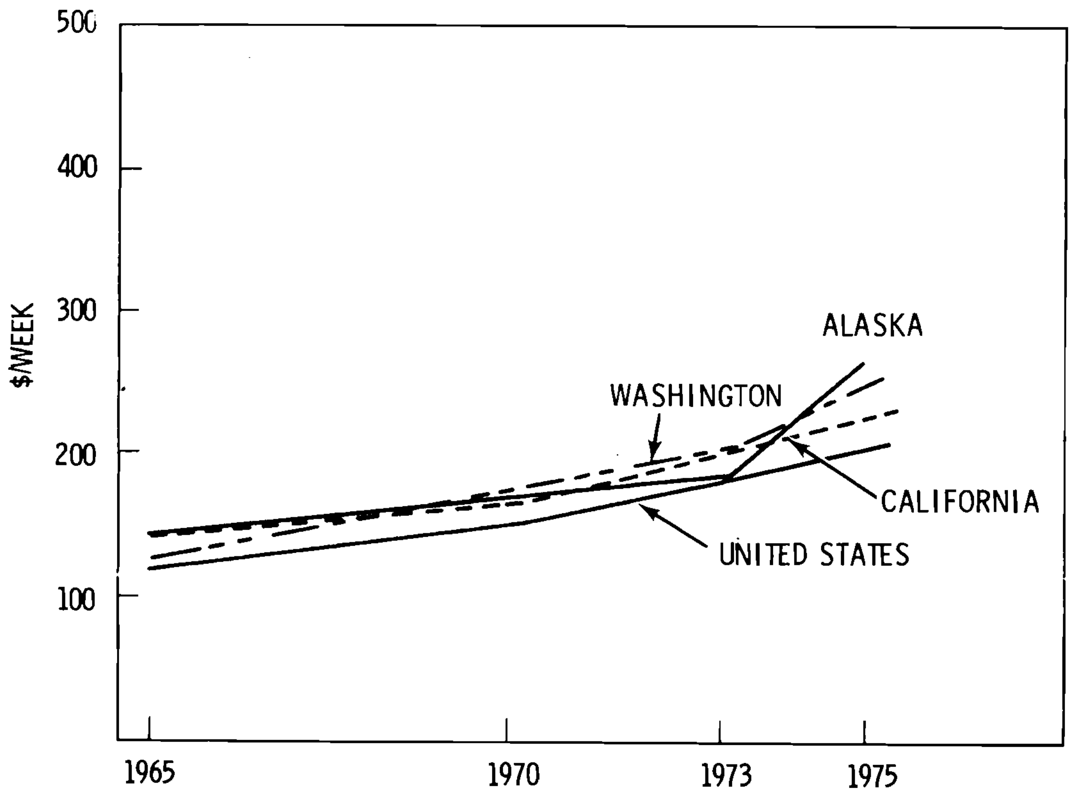


FIGURE 7.4 Average Weekly Wage - All Manufacturing

TABLE 7.5. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Petroleum Refining[a]

	1975		1973		1970		1965	
	$/Week	%	$/Week	%	$/Week	%	$/Week	%
United States	309.33	100	244.86	100	197.4	100		
Texas	308.75	99.8	245.27	100.2	197.9	100.2		
California	355.12	114.8	272.21	111.2	214.3	108.6		
Alaska	384.62	124.3	332.81	135.9	292.3	148.1		
Pacific	349.43	113.0	269.97	110.3	212.3	107.6		

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

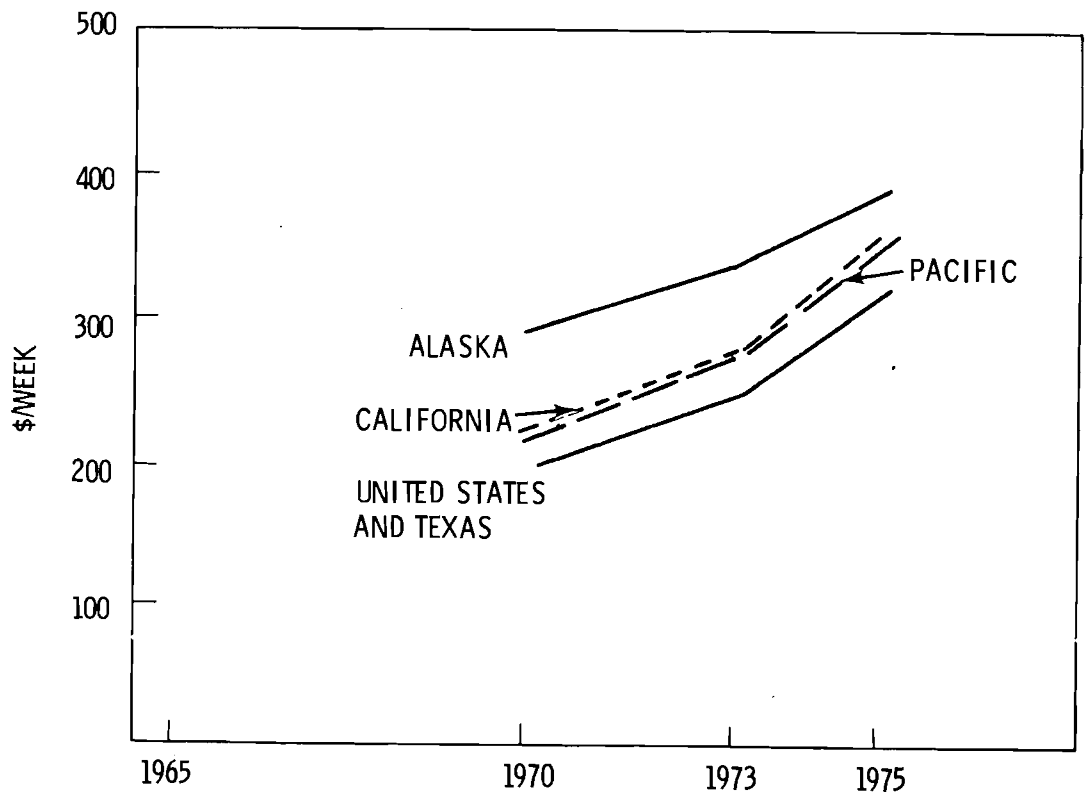


FIGURE 7.5 Average Weekly Wage - Petroleum Refining

TABLE 7.6. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Paper and Allied Products[(a)]

	1975		1973		1970		1965	
	$/Week	%	$/Week	%	$/Week	%	$/Week	%
United States	232.38	100	192.32	100	156.31	100	121.12	100
Washington	267.40	115.1	224.65	116.8	169.63	108.5	132.21	109.2
California	234.12	100.7	201.39	104.7	160.19	102.5	126.14	104.1
Alaska	371.79	160.0	319.75	166.3	269.23	172.2	174.83	144.3
Pacific	249.57	107.4	212.62	110.6	167.11	106.9	130.25	107.5

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

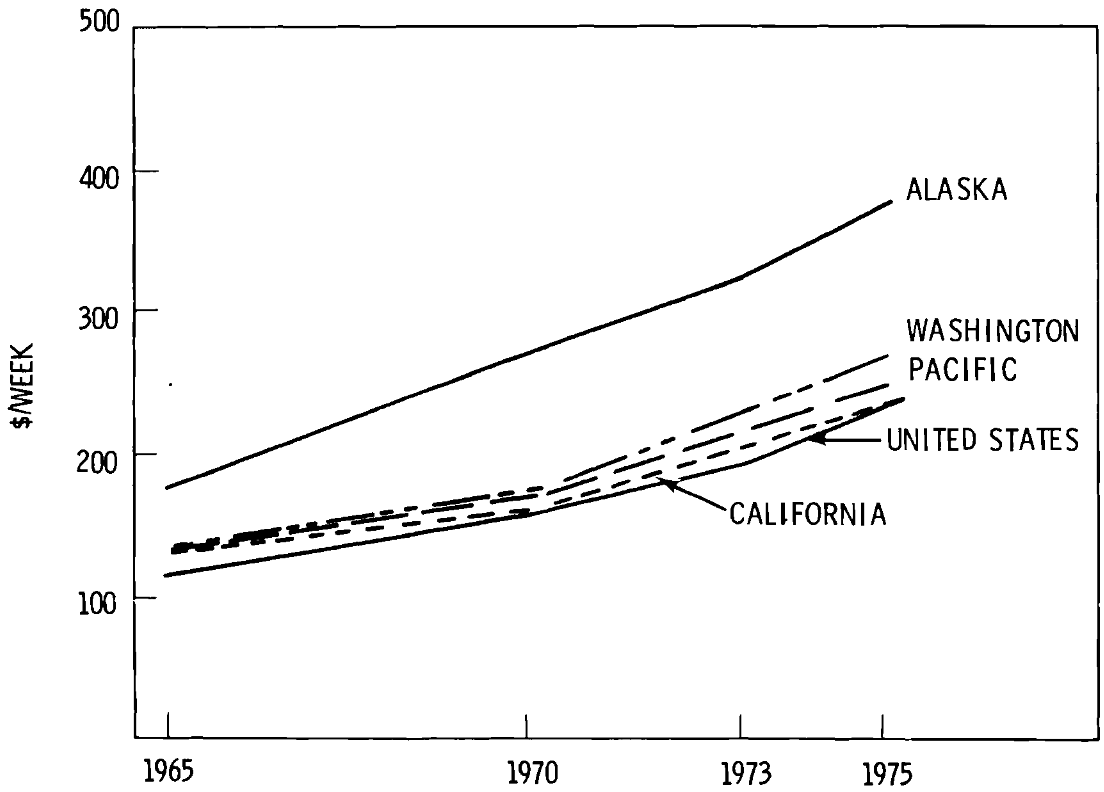


FIGURE 7.6 Average Weekly Wage - Paper and Allied Products

TABLE 7.7. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Chemicals and Allied Products[a]

	1975		1973		1970		1965	
	$/Week	%	$/Week	%	$/Week	%	$/Week	%
United States	269.21	100	223.07	100	181.59	100	142.87	100
New York	287.58	106.8	241.10	108.1	196.80	108.4	151.93	106.3
Washington	264.27	98.2	225.34	101.0	190.42	104.9	156.47	109.5
California	242.38	90.0	209.09	93.7	173.15	95.4	140.31	98.3
Alaska	500.00	185.7	368.47	165.2	312.95	172.3	192.31	134.6
Pacific	245.10	91.0	210.28	94.3	174.55	96.1	142.00	99.4

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

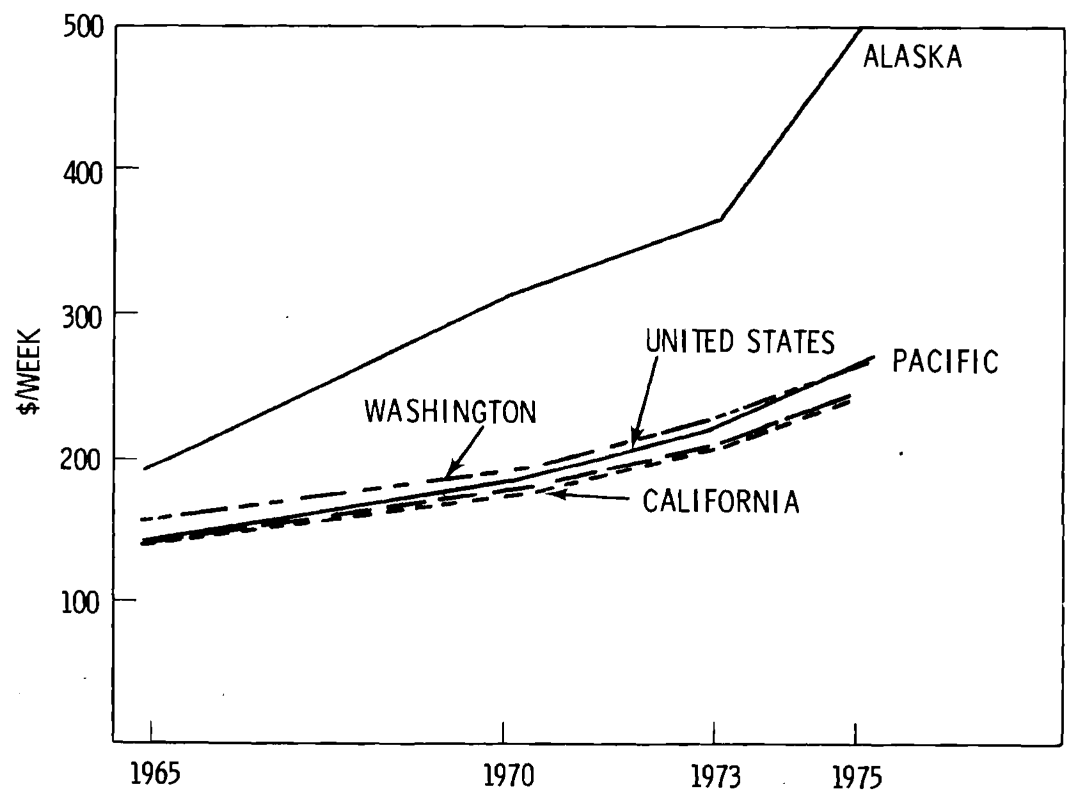


FIGURE 7.7 Average Weekly Wage - Chemicals and Allied Products

TABLE 7.8. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Crude Petroleum and Natural Gas[a]

	1975		1973		1970		1965	
	$/Week	%	$/Week	%	$/Week	%	$/Week	%
United States	232.38	100	214.85	100	181.35	100	132.79	
Texas	222.02	95.5	222.74	103.7	183.02	100.9	77.38	
California	260.73	112.2	250.04	116.4	202.33	111.6	76.92	
Alaska	371.79	160.0	257.82	120.0				
Pacific	249.57	107.4	-		-		77.28	

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

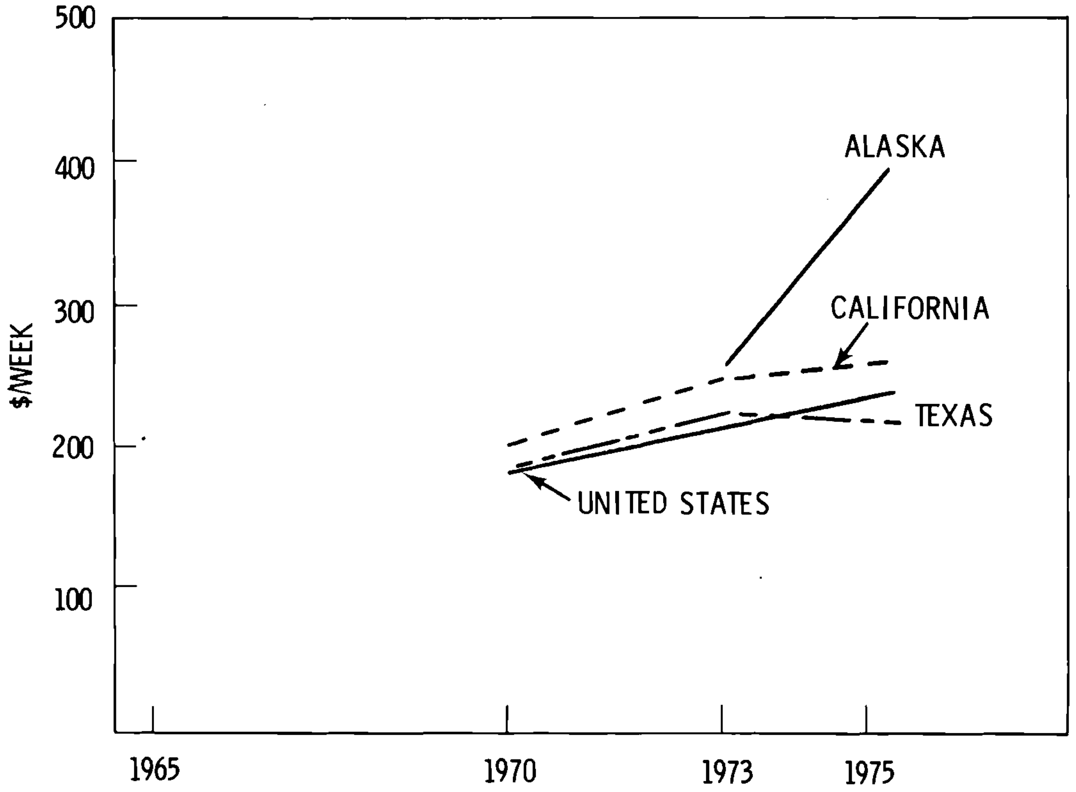


TABLE 7.8 Average Weekly Wage - Crude Petroleum and Natural Gas

TABLE 7.9. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Services[a]

	1975		1973		1970		1965	
	$/Week	%	$/Week	%	$/Week	%	$/Week	%
United States	150.93	100	128.82	100	110.04	100	91.88	100
New York	182.07	120.6	158.73	123.2	132.17	120.1	100.81	109.7
Washington	144.98	96.1	121.64	94.4	101.91	92.6	75.51	82.2
California	167.75	111.1	145.35	112.8	124.05	112.7	99.36	108.1
Alaska	245.63	162.7	166.07	129.4	145.12	131.9	110.08	119.8
Pacific	162.91	107.9	139.66	108.4	118.83	108.0	94.39	102.7

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

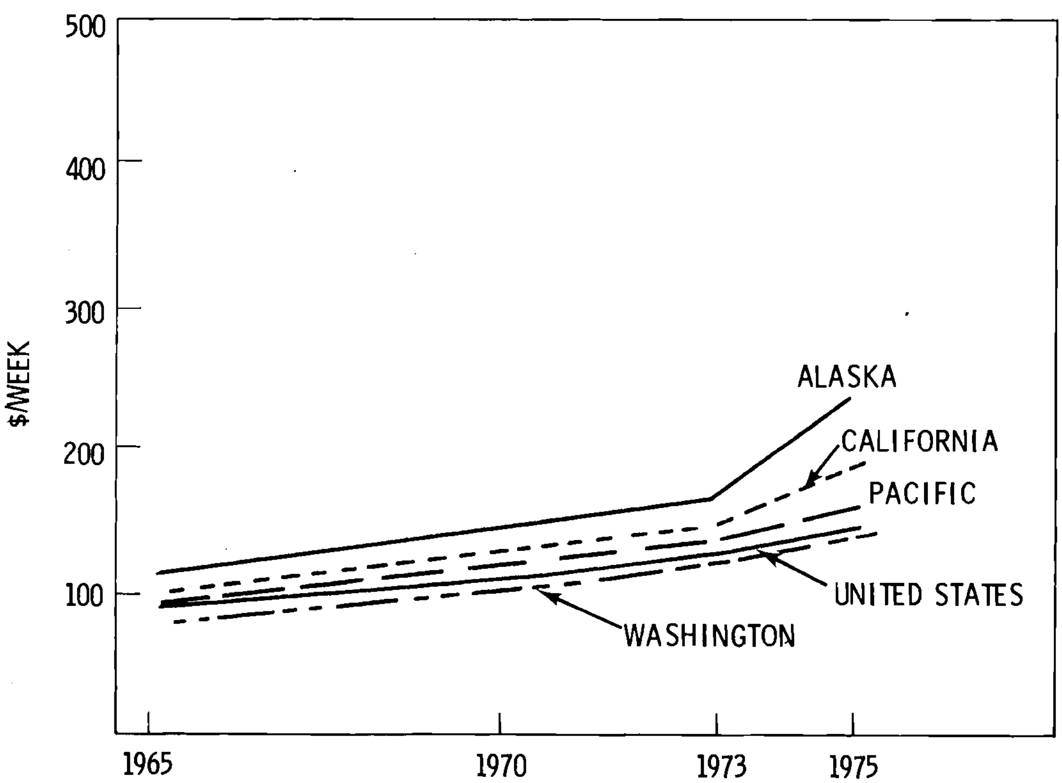


TABLE 7.9 Average Weekly Wage - Services

TABLE 7.10. Weekly Wages by Industry and Region Dollars per Week and Percent of National Average for Transportation, Communications and Public Utilities(a)

	1975		1973		1970		1965	
	$/Week	$	$/Week	%	$/Week	%	$/Week	%
United States	233.55	100	201.86	100	158.54	100	119.15	100
Washington	249.30	106.7	213.93	106	169.23	106.7	131.23	110.1
California	255.36	109.3	221.09	109.5	174.85	110.3	133.14	111.7
Alaska	361.65	154.8	259.17	128.4	223.99	141.3	175.82	147.6
Pacific	254.17	108.8	218.35	108.2	173.4	109.4	132.63	111.1

(a) U.S. Department of Labor, Bureau of Labor Statistics, Employment and Wages First Quarter, 1975, 1973, 1970 and 1965.

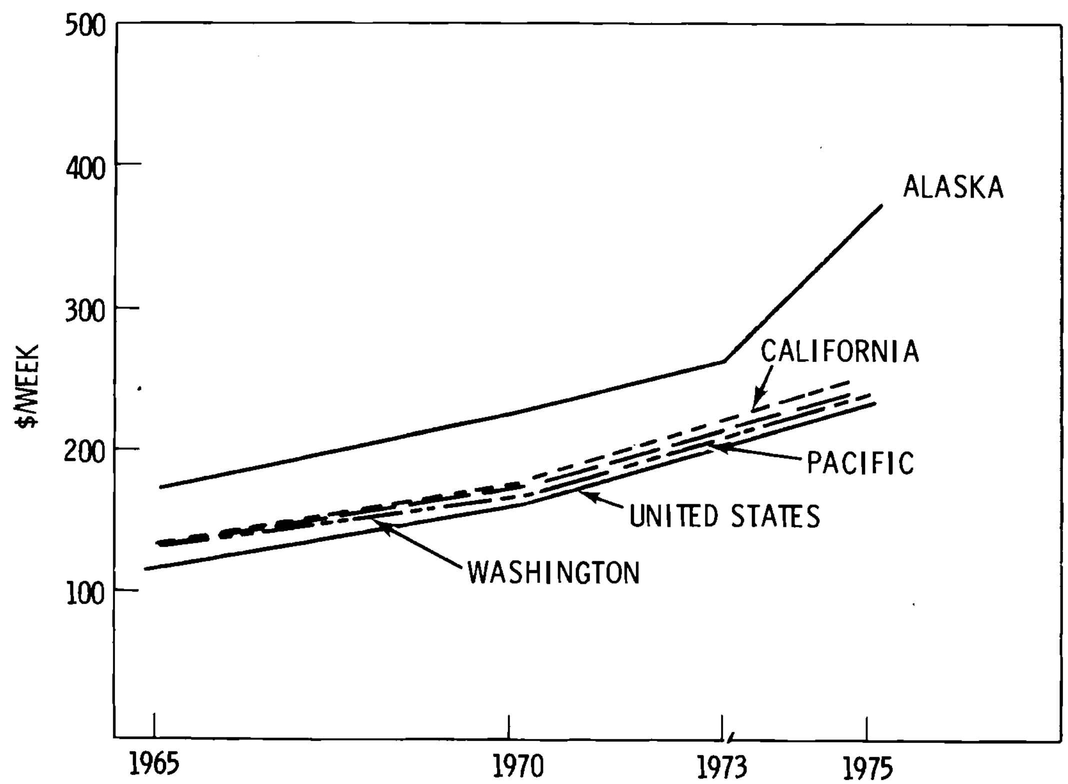


TABLE 7.10 Average Weekly Wage - Transportation Communications and Public Utilities

The percentage values in Tables 1 through 10 reveal an interesting trend for several of the Alaskan industries. For most of the industries such as construction, manufacturing, petroleum refining, paper, transportation, communications and public utilities the Alaskan wage differential was decreasing until 1975. In 1975 the trend was reversed and the Alaskan wage differential began to increase again. (One can only speculate as to what the wage differential will be after the Alaskan economy adjusts back to a more normal status from the recent pipeline era, but it will probably decrease.)

TABLE A.7.1. Calculated Average Weekly Wage Per Employee By State and Region for All Industries

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	5283.5	7981.4	116.20
South Dakota	85.8	96.7	86.70
Mississippi	329.2	325.3	76.01
Texas	2131.1	2657.6	95.93
Idaho	132.4	157.3	91.39
Colorado	410.2	546.4	102.46
Washington	673.4	975.1	111.39
Oregon	470.7	635.7	103.89
California	4609.6	7162.6	119.53
Montana	117.6	142.6	93.28
Hawaii	210.6	269.7	98.51
Alaska	50.0	93.1	143.23
Pacific	6014.4	9136.2	116.85
W. So. Central	3560.4	4344.4	93.86
U.S. Average	46390.0	63808.0	105.81

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.2. Calculated Average Weekly Wage Per Employee By State and Region for Contract Construction

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	223.6	395.4	136.03
South Dakota	5.0	6.6	101.54
Mississippi	23.0	24.4	81.61
Texas	166.3	214.1	99.03
Idaho	9.0	11.9	101.71
Colorado	26.8	42.3	121.41
Washington	41.0	68.2	127.95
Oregon	30.9	49.9	124.22
California	309.1	592.5	147.45
Montana	8.8	11.9	104.02
Hawaii	17.4	28.7	126.88
Alaska	3.9	10.7	211.05
Pacific	402.2	750.1	143.46
W. So. Central	283.4	356.6	96.79
U.S. Average	2655.6	4033.1	116.82

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.3. Calculated Average Weekly Wage per Employee by State and Region for Mining Industry

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	8.4	17.3	158.42
South Dakota	1.6	1.8	86.54
Mississippi	5.7	8.2	110.66
Texas	107.2	189.1	113.69
Idaho	3.3	5.2	121.21
Colorado	11.4	20.2	136.30
Washington	1.8	2.9	123.93
Oregon	31.2	60.8	149.90
Montana	7.0	11.2	123.08
Hawaii	0.05	0.07	107.69
Alaska	0.9	2.3	196.58
Pacific	35.5	68.6	148.65
W. So. Central	200.0	347.3	133.58
U.S. Average	609.3	994.7	125.58

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.4. Calculated Average Weekly Wage Per Employee by State and Region for All Manufacturing

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	1816.7	2926.2	123.90
South Dakota	12.4	17.0	105.46
Mississippi	144.5	136.9	72.88
Texas	555.5	795.5	110.16
Idaho	30.6	40.3	101.31
Colorado	82.4	132.6	123.79
Washington	213.9	361.7	130.08
Oregon	147.9	223.6	116.29
California	1370.8	2424.6	136.06
Montana	20.1	29.8	114.05
Hawaii	22.5	27.4	93.68
Alaska	4.3	7.6	135.96
Pacific	1759.5	3045.1	133.13
W. So. Central	930.4	1270.5	105.04
U.S. Average	17,656.4	26,767.1	116.62

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.5. Calculated Average Weekly Wage Per Employee by State and Region for Petroleum Refining and Related Industries.

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	9.6	24.3	194.71
South Dakota	-	-	-
Mississippi	1.0	1.4	107.69
Texas	36.7	69.4	145.46
Idaho	-	-	-
Colorado	0.6	1.0	128.21
Washington	1.2	2.4	153.85
Oregon	0.3	0.5	128.21
California	29.5	64.2	167.41
Montana	1.1	2.2	153.85
Hawaii	-	-	-
Alaska	-	-	-
Pacific	31.3	67.6	166.13
W. So. Central	56.7	106.1	143.94
U.S. Average	182.4	362.5	152.88

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.6. Calculated Average Weekly Wage per Employee by State and Region for Paper and Allied Products

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	65.8	102.0	119.24
South Dakota	-	-	-
Mississippi	5.3	7.9	114.66
Texas	12.0	18.2	116.67
Idaho	-	-	-
Colorado	1.0	1.5	115.38
Washington	19.2	33.0	132.21
Oregon	7.3	12.7	133.38
California	30.0	49.3	126.14
Montana	-	-	126.14
Hawaii	0.2	0.2	76.92
Alaska	1.1	2.5	174.83
Pacific	57.7	97.7	130.25
W. So. Central	34.3	53.5	119.98
U.S. Average	629.9	991.8	121.12

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.7. Calculated Average Weekly Wage per Employee by State and Region for Chemicals and Allied Products

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	88.2	174.2	151.93
South Dakota	0.05	0.08	123.08
Mississippi	4.8	6.3	100.96
Texas	50.7	140.5	213.17
Idaho	1.2	2.0	121.46
Colorado	1.9	3.0	121.46
Washington	8.8	17.9	156.47
Oregon	1.9	2.0	80.97
California	46.6	85.0	140.31
Montana	0.4	0.7	134.62
Hawaii	0.5	0.7	107.79
Alaska	0.04	0.1	192.31
Pacific	57.8	106.7	142.00
W. So. Central	73.5	140.5	147.04
U.S. Average	896.0	1664.1	142.87

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.8. Calculated Average Weekly Wage per Employee by State and Region for Crude Petroleum and Natural Gas Industries.

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	1.8	1.8	76.92
South Dakota	0.01	0.009	69.23
Mississippi	4.8	4.8	76.92
Texas	100.9	101.5	77.38
Idaho	0.002	0.003	115.38
Colorado	4.4	4.4	76.92
Washington	0.09	0.09	76.92
Oregon	0.01	0.007	53.85
California	21.2	21.2	76.92
Montana	1.7	1.7	76.92
Hawaii	-	-	-
Alaska	0.5	0.6	92.31
Pacific	21.8	21.9	77.28
W. So. Central	185.6	187.1	77.54
U.S. Average	276.5	477.3	132.79

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.9. Calculated Average Weekly Wage per Employee by State and Region for Service Industry.

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	699.4	916.6	100.81
South Dakota	7.3	5.5	57.96
Mississippi	23.8	16.9	54.62
Texas	223.1	190.7	65.67
Idaho	17.6	17.3	75.61
Colorado	67.0	56.2	64.52
Washington	81.4	79.9	75.51
Oregon	53.6	47.6	83.98
California	719.2	929.0	99.36
Montana	13.9	11.0	60.87
Hawaii	35.1	33.6	73.64
Alaska	5.8	8.3	110.08
Pacific	895.1	1098.4	94.39
W. So. Central	364.5	302.8	63.90
U.S. Average	4398.1	5253.4	91.88

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.10. Calculated Average Weekly Wage per Employee by State and Region for Transportation, Communities and Public Utilities.

1965

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	420.0	724.4	132.67
South Dakota	7.6	10.3	104.25
Mississippi	20.4	24.9	93.89
Texas	188.5	248.6	101.45
Idaho	8.7	12.3	108.75
Colorado	327.7	567.2	133.14
Washington	46.6	79.5	131.23
Oregon	34.4	57.2	127.91
California	327.7	567.2	133.14
Montana	9.6	13.5	108.17
Hawaii	15.7	24.5	120.04
Alaska	6.3	14.4	175.82
Pacific	430.8	742.8	132.63
W. So. Central	326.2	432.9	102.08
U.S. Average	3192.6	4945.2	119.15

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1965, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.11. Calculated Average Weekly Wage per Employee by State and Region for All Industries

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	5806.4	11,592.2	153.57
South Dakota	100.06	138.24	106.27
Mississippi	402.05	550.16	105.26
Texas	2730.44	4565.12	128.61
Idaho	155.72	237.69	117.41
Colorado	537.42	930.35	133.16
Washington	839.97	1591.33	145.73
Oregon	550.77	937.45	130.93
California	5568.30	10,822.29	149.50
Montana	127.72	193.28	116.41
Hawaii	288.51	509.80	135.92
Alaska	67.48	170.00	193.79
Pacific	7315.03	14,030.87	147.55
W. So. Central	4425.37	7,243.37	125.89
U.S. Average	55,272.0	98,709.3	137.38

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.12. Calculated Average Weekly Wage per Employee by State and Region for Contract Construction.

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	235.56	583.62	187.32
South Dakota	4.74	7.92	128.53
Mississippi	27.37	39.10	109.89
Texas	201.48	366.93	140.09
Idaho	9.01	18.07	154.27
Colorado	33.50	73.27	168.24
Washington	50.39	116.66	178.09
Oregon	26.38	57.00	166.21
California	294.66	747.19	195.06
Montana	7.23	13.61	144.80
Hawaii	26.19	67.48	198.20
Alaska	5.27	21.34	311.49
Pacific	402.88	1009.66	192.78
W. So Central	323.42	583.15	138.70
U.S. Average	3097.32	6620.08	164.41

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.13. Calculated Average Weekly Wage per Employee by State and Region for Mining Industry.

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	7.5	20.93	214.67
South Dakota	2.39	4.34	139.68
Mississippi	6.61	11.84	137.79
Texas	100.16	234.78	180.31
Idaho	3.32	6.91	160.10
Colorado	13.67	33.72	189.75
Washington	1.57	3.42	167.56
Oregon	1.19	2.34	151.26
California	31.51	81.84	199.79
Montana	6.12	12.77	160.51
Hawaii	-	-	-
Alaska	3.37	13.44	306.78
Pacific	37.68	101.134	206.46
W. So. Central	192.92	449.17	179.94
U.S. Average	603.64	1341.78	170.99

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.14. Calculated Average Weekly Wage per Employee by State and Region for Manufacturing

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	1817.4	3876.2	164.06
South Dakota	14.97	25.02	128.56
Mississippi	179.05	239.82	103.03
Texas	749.63	1395.68	143.22
Idaho	38.39	64.19	128.62
Colorado	114.10	231.86	156.31
Washington	248.71	570.18	176.36
Oregon	166.68	324.94	149.96
California	1598.47	3565.71	171.59
Montana	22.53	39.61	135.24
Hawaii	23.79	40.94	132.38
Alaska	6.04	13.59	173.08
Pacific	-	-	-
W. So. Central	1220.08	2171.32	136.90
U.S. Average	19841.1	38640.00	149.84

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.15. Calculated Average Weekly Wage per Employee by State and Region for Petroleum Refining and Related Industry.

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	10.8	37.0	263.5
South Dakota	N.D.	N.D.	-
Mississippi	1.3	2.5	147.9
Texas	38.1	98.0	197.9
Idaho	-	-	-
Colorado	0.8	1.5	144.2
Washington	1.2	2.8	179.5
Oregon	0.5	0.9	138.5
California	30.4	84.7	214.3
Montana	1.1	2.5	174.8
Hawaii	0.38	1.1	222.7
Alaska	0.05	0.19	292.3
Pacific	32.5	89.7	212.3
W. So. Central	58.8	147.1	192.4
U.S. Average	192.06	492.9	197.4

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.16. Calculated Average Weekly Wage per Employee by State and Region for Paper and Allied Products

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	64.7	127.3	151.35
South Dakota	-	-	-
Mississippi	7.2	14.4	153.85
Texas	17.2	31.9	142.67
Idaho	1.0	2.08	160.8
Colorado	1.3	2.3	136.10
Washington	19.5	43.0	169.63
Oregon	9.2	21.5	179.80
California	36.4	75.8	160.19
Montana	-	-	-
Hawaii	0.2	0.3	115.38
Alaska	1.0	3.5	269.23
Pacific	66.3	144.1	167.11
W. So. Central	44.0	88.2	154.20
U.S. Average	710.9	1444.6	156.31

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.17. Calculated Average Weekly Wage per Employee by State and Region for Chemicals and Allied Products.

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	91.7	234.6	196.8
South Dakota	-	-	-
Mississippi	5.5	9.3	130.07
Texas	65.1	161.7	191.07
Idaho	1.5	3.2	164.10
Colorado	2.3	4.7	157.19
Washongton	6.1	15.1	190.42
Oregon	2.9	4.8	127.32
California	56.2	126.5	173.15
Montana	0.4	0.7	134.62
Hawaii	0.6	1.2	153.85
Alaska	0.205	0.834	312.95
Pacific	65.4	148.4	174.55
W. So. Central	95.4	236.3	190.53
U.S. Average	1064.0	2511.7	181.59

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.18. Calculated Average Weekly Wage per Employee by State and Region for Crude Petroleum and Natural Gas.

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	1.3	4.9	289.94
South Dakota	-	-	-
Mississippi	5.8	10.9	187.93
Texas	93.6	222.7	183.02
Idaho	-	-	-
Colorado	6.2	17.2	213.40
Washington	-	-	-
Oregon	-	-	-
California	21.1	55.5	202.33
Montana	1.7	3.8	171.95
Hawaii	-	-	-
Alaska	-	-	-
Pacific	-	-	-
W. So. Central	177.6	422.1	237.67
U.S. Average	263.5	621.2	181.35

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.19. Calculated Average Weekly Wage per Employee by State and Region for Services.

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	865.3	1486.8	132.17
South Dakota	11.9	11.1	71.75
Mississippi	31.9	34.3	107.52
Texas	335.4	421.8	96.74
Idaho	21.6	26.7	95.09
Colorado	93.5	110.9	91.24
Washington	117.9	156.2	101.91
Oregon	72.7	82.5	87.29
California	975.7	1573.5	124.05
Montana	17.3	16.9	75.14
Hawaii	54.7	70.9	99.70
Alaska	9.7	18.3	145.12
Pacific	1230.8	1901.3	118.83
W. So. Central	526.4	636.4	121.13
U.S. Average	6688.6	9568.2	110.04

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.20. Calculated Average Weekly Wage per Employee by State and Region for Transportation, Communications and Public Utilities.

1970

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	463.6	1095.4	181.8
South Dakota	8.6	14.2	127.0
Mississippi	24.1	39.8	127.0
Texas	219.1	413.8	145.3
Idaho	9.9	17.4	135.2
Colorado	43.4	90.5	160.0
Washington	59.7	131.2	169.1
Oregon	38.8	81.4	161.4
California	410.1	932.1	174.8
Montana	10.3	18.5	138.2
Hawaii	23.4	48.2	158.5
Alaska	8.5	24.8	224.4
Pacific	540.4	1217.8	173.4
W. So. Central	373.9	700.6	144.14
U.S. Average	3797.3	7826.1	158.5

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1970, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.21. Calculated Average Weekly Wage per Employee by State and Region for All Industries.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	6073.0	14,613.00	185.09
South Dakota	146.0	227.0	119.60
Mississippi	548.0	865.0	121.42
Texas	3504.0	6583.0	144.52
Idaho	201.0	356.0	136.24
Colorado	764.0	1552.0	156.26
Washington	961.0	2097.0	167.85
Oregon	674.0	1368.0	156.13
California	6513.0	14,755.0	174.27
Montana	165.0	291.0	135.66
Hawaii	331.1	668.31	155.27
Alaska	79.76	222.75	214.83
Pacific	8558.5	19,131.3	171.95
W. So. Central	5712.0	10,545.0	142.01
U.S. Average	65,742.0	137,786.0	161.22

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.22. Calculated Average Weekly Wage per Employee by State and Region for Contract Construction.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	252.2	781.6	238.39
South Dakota	8.03	15.25	146.09
Mississippi	38.65	60.06	119.53
Texas	260.8	510.8	150.66
Idaho	12.2	27.5	173.39
Colorado	66.1	158.0	183.87
Washington	51.9	138.8	205.72
Oregon	36.3	89.2	189.02
California	302.0	867.2	220.89
Montana	11.1	23.4	162.16
Hawaii	25.6	80.1	240.69
Alaska	5.18	21.31	316.45
Pacific	421.0	1196.6	218.64
W. So. Central	413.57	809.19	150.51
U.S. Average	3705.4	9146.3	189.87

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.23. Calculated Average Weekly Wage per Employee by State and Region for Mining.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	7.7	29.1	290.71
South Dakota	2.2	5.7	199.30
Mississippi	6.4	13.5	162.26
Texas	105.0	299.6	219.49
Idaho	2.65	7.18	208.51
Colorado	13.72	42.18	236.49
Washington	1.73	4.55	202.31
Oregon	1.54	3.92	195.80
California	29.55	93.65	243.78
Montana	6.08	16.13	204.21
Hawaii	-	-	-
Alaska	1.807	8.36	355.88
Pacific	34.65	110.54	245.40
W. So. Central	197.3	547.18	213.33
U.S. Average	622.5	1702.6	210.39

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.24. Calculated Average Weekly Wage per Employee by State and Region for Manufacturing.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	1618.7	4219.8	200.53
South Dakota	18.7	36.0	148.09
Mississippi	216.5	349.6	124.21
Texas	780.6	1690.6	166.6
Idaho	44.7	90.2	156.08
Colorado	137.2	334.7	187.65
Washington	235.0	626.6	205.11
Oregon	185.9	439.8	181.98
California	1592.6	4073.6	196.76
Montana	23.4	51.3	168.64
Hawaii	22.94	46.11	154.62
Alaska	7.60	18.38	186.03
Pacific	-	-	-
W. So. Central	1308.4	2712.4	159.47
U.S. Average	19,907.8	47118.1	182.06

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.25. Calculated Average Weekly Wage per Employee by State and Region for Petroleum Refining and Related Products.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	10.3	47.1	351.76
South Dakota	0.15	0.43	220.51
Mississippi	1.4	3.8	208.79
Texas	36.6	116.7	245.27
Idaho	-	-	-
Colorado	0.54	1.39	198.01
Washington	1.39	5.05	279.47
Oregon	0.65	1.47	173.96
California	24.5	86.7	272.21
Montana	1.1	3.3	230.77
Hawaii	0.43	1.46	260.57
Alaska	0.049	0.212	332.81
Pacific	27.04	94.9	269.97
W. South Central	57.1	174.2	234.68
U.S. Average	190.0	604.8	244.86

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.26. Calculated Average Weekly Wage per Employee by State and Region for Paper and Allied Products.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	54.46	131.4	185.60
South Dakota	-	-	-
Mississippi	46.5	115.1	190.41
Texas	17.5	41.5	182.42
Idaho	1.109	2.611	181.11
Colorado	1.52	3.208	162.35
Washington	17.36	50.7	224.65
Oregon	9.4	27.25	223.00
California	35.4	92.68	201.39
Montana	-	-	-
Hawaii	0.271	0.547	155.27
Alaska	1.008	4.19	319.75
Pacific	63.44	175.35	212.62
W. So. Central	47.4	117.9	191.33
U.S. Average	705.64	1764.2	192.32

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.27. Calculated Average Weekly Wage per Employee by State and Region for Chemicals and Allied Products.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	78.2	245.1	241.10
South Dakota	-	-	-
Mississippi	5.8	12.4	213.80
Texas	62.0	196.5	243.80
Idaho	1.7	4.8	217.20
Colorado	2.2	5.6	195.80
Washington	5.5	16.2	226.57
Oregon	2.1	5.5	201.47
California	53.1	144.4	209.20
Montana	0.4	1.0	192.30
Hawaii	0.665	1.51	174.67
Alaska	0.181	0.867	368.47
Pacific	61.6	168.45	210.30
W. So. Central	93.8	293.6	240.77
U.S. Average	1035.8	3003.7	223.10

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.28. Calculated Average Weekly Wage per Employee by State and Region for Crude Petroleum and Natural Gas.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employment ($)
New York	1.96	11.2	439.56
South Dakota	-	-	-
Mississippi	5.3	11.7	169.81
Texas	98.95	285.94	222.74
Idaho	-	-	-
Colorado	6.7	21.9	251.44
Washington	-	-	-
Oregon	-	-	-
California	20.2	65.66	250.04
Montana	1.4	3.8	208.79
Hawaii	-	-	-
Alaska	21.9	73.4	257.82
Pacific	-	-	-
W. So. Central	183.84	517.17	216.40
U.S. Average	268.27	749.3	214.85

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.29. Calculated Average Weekly Wage per Employee by State and Region for Services.

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employment ($)
New York	1313.91	2711.29	158.73
South Dakota	31.19	33.80	83.36
Mississippi	65.72	82.47	96.53
Texas	579.51	829.10	110.05
Idaho	33.95	50.42	114.24
Colorado	149.28	226.69	116.81
Washington	170.24	269.2	121.64
Oregon	113.73	162.3	109.77
California	1295.00	2446.96	145.35
Montana	33.13	40.21	93.36
Hawaii	68.0	107.10	121.15
Alaska	13.50	29.25	166.67
Pacific	1660.5	3014.8	139.66
W. So. Central	907.73	1277.66	108.27
U.S. Average	11,245.3	18,832.1	128.82

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.30. Calculated Average Weekly Wage per Employee by State and Region for Transportation, Communications and Public Utilities

1973

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employment ($)
New York	443.3	1323.6	229.68
South Dakota	10.48	21.66	158.98
Mississippi	30.64	60.86	152.79
Texas	244.84	571.32	179.50
Idaho	11.62	24.68	163.38
Colorado	50.93	139.5	210.70
Washington	59.02	164.14	213.93
Oregon	42.42	109.60	198.75
California	417.13	1198.92	221.09
Montana	11.6	25.5	169.10
Hawaii	24.84	65.05	201.44
Alaska	9.02	30.39	259.17
Pacific	-	-	-
W. So. Central	409.5	956.17	179.61
U.S. Average	4029.2	10,573.4	201.86

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1973, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.31. Calculated Average Weekly Wage per Employee by State and Region for all Industries.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	5758.0	15,941.0	212.96
South Dakota	159.0	299.0	144.37
Mississippi	535.0	1013.0	145.65
Texas	3758.0	8547.0	174.95
Idaho	218.0	454.0	160.44
Colorado	775.0	1839	182.57
Washington	1024.0	2612.0	196.25
Oregon	761.0	1767.0	178.51
California	6717.0	17,313.0	198.27
Montana	-	-	-
Hawaii	341.0	799.0	180.28
Alaska	120.0	510.0	326.13
Pacific	8963.0	23,000.0	197.39
W. So. Central	6064.0	13,530.0	171.64
U.S. Average	66,588.0	161,288.0	186.30

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.32. Calculated Average Weekly Wage per Employee by State and Region for Contract Construction.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	193.4	662.3	263.42
South Dakota	7.9	19.4	188.90
Mississippi	36.5	74.8	157.64
Texas	278.3	718.9	198.71
Idaho	13.0	36.8	217.75
Colorado	45.2	135.4	230.43
Washington	51.1	163.2	245.67
Oregon	30.3	94.9	240.92
California	268.5	954.7	273.51
Montana	10.1	27.6	210.21
Hawaii	27.5	94.0	262.94
Alsaka	20.2	155.2	591.01
Pacific	397.6	1462.0	282.85
W. So. Central	444.2	1125.5	194.91
U.S. Average	3240.2	9674.4	229.67

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.33. Calculated Average Weekly Wage per Employee by State and Region for Mining.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	7734.0	34.5	343.48
South Dakota	2.4	6.6	211.51
Mississippi	6.6	17.0	199.35
Texas	132.9	476.1	275.63
Idaho	3.56	10.4	224.91
Colorado	18.3	68.104	286.52
Washington	1.8	5.89	251.93
Oregon	1.4	4.05	216.04
California	32.2	123.4	294.44
Montana	6.9	22.98	254.56
Alaska	4.0	26.	502.68
Pacific	39.454	159.338	310.66
W. So. Central	237.87	833.3	269.49
U.S. Average	735.2	2544.0	266.13

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.34. Calculated Average Weekly Wage per Employee by State and Region for Manufacturing

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	1418.8	4425.0	239.91
South Dakota	18.9	43.1	175.42
Mississippi	190.1	374.0	151.32
Texas	792.6	2099.5	203.76
Idaho	44.1	105.0	183.15
Colorado	133.2	394.0	227.54
Washington	239.9	763.5	244.81
Oregon	171.0	469.5	211.20
California	1552.2	4668.7	231.37
Montana	20.7	54.7	203.27
Hawaii	23.1	56.3	187.48
Alaska	7.0	24.3	267.03
Pacific	1993.2	5982.2	230.87
W. So. Central	1286.2	3274.5	195.84
U.S. Average	18102.2	50,649.8	215.23

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.35. Calculated Average Weekly Wage per Employee by State and Region for Petroleum Refining.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	10.0	58.4	449.23
South Dakota	0.2	0.6	230.77
Mississippi	1.5	5.5	282.05
Texas	36.3	145.7	308.75
Idaho	0.001	0.005	384.62
Colorado	0.6	1.9	243.59
Washington	1.9	7.8	315.80
Oregon	0.5	1.4	215.38
California	25.3	116.8	355.12
Montana	0.9	3.6	307.69
Hawaii	0.5	1.9	292.31
Alaska	0.06	0.3	384.62
Pacific	28.2	128.1	349.43
W. So. Central	56.1	217.5	298.23
U.S. Average	188.3	757.2	309.33

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.36. Calculated Average Weekly Wage per Employee by State and Region for Paper and Allied Products.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	46.8	134.7	221.40
South Dakota	0.04	0.2	384.62
Mississippi	6.3	18.6	227.11
Texas	16.7	48.2	222.02
Idaho	1.0	3.5	269.23
Colorado	1.5	4.1	210.26
Washington	16.8	58.4	267.40
Oregon	9.5	32.2	260.73
California	34.4	104.7	234.12
Montana	-	-	-
Hawaii	0.3	0.7	179.49
Alaska	1.2	5.8	371.79
Pacific	62.2	201.8	249.57
W. So. Central	43.8	129.8	227.96
U.S. Average	629.2	1900.8	232.38

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.37. Calculated Average Weekly Wage per Employee by State and Region for Chemicals and Allied Products.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	73.8	275.9	287.58
South Dakota	0.2	0.4	153.85
Mississippi	6.7	17.6	202.07
Texas	67.4	256.1	292.28
Idaho	2.2	7.5	262.24
Colorado	5.2	16.9	250.00
Washington	6.2	21.3	264.27
Oregon	2.1	6.6	241.76
California	56.3	177.4	242.38
Montana	0.5	1.6	246.15
Hawaii	0.7	2.1	230.77
Alaska	0.2	1.3	500.00
Pacific	65.5	208.7	245.10
W. So. Central	102.4	386.1	290.04
U.S. Average	1031.0	3608.2	269.21

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.38. Calculated Average Weekly Wage per Employee by State and Region for Crude Petroleum and Natural Gas.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	2.2	13.6	475.52
South Dakota	0.04	0.1	192.31
Mississippi	5.4	14.8	210.83
Texas	126.2	458.2	279.29
Idaho	0.02	0.04	153.85
Colorado	8.6	34.6	309.48
Washington	0.06	0.2	256.41
Oregon	0.007	0.02	219.78
California	23.4	92.3	303.42
Montana	2.0	6.2	238.46
Hawaii	-	-	-
Alaska	3.8	25.0	506.07
Pacific	N.D.	N.D.	
W. So. Central	223.5	794.1	273.31
U.S. Average	326.8	1154.6	271.77

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.39. Calculated Average Weekly Wage per Employee by State and Region for Service.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	1356.7	3211.1	182.07
South Dakota	34.2	44.6	100.31
Mississippi	72.0	107.9	115.28
Texas	655.4	1153.3	135.36
Idaho	38.7	69.2	137.55
Colorado	165.0	306.2	142.75
Washington	193.5	364.7	144.98
Oregon	123.0	214.3	134.02
California	1403.2	3060.1	167.75
Montana	37.9	53.9	109.40
Hawaii	67.1	121.2	138.94
Alaska	21.9	70.5	247.63
Pacific	1808.8	3830.8	162.91
W. So. Central	1019.6	1745.4	131.68
U.S. Average	12,146.7	23,833.6	150.93

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

TABLE A.7.40. Calculated Average Weekly Wage per Employee by State and Region for Transportation, Communications and Public Utility.

1975

Region	March Employment (1000)	1st Quarter Wages ($ Million)	Weekly Wage/Employee ($)
New York	409.8	1453.2	272.78
South Dakota	10.9	26.3	185.60
Mississippi	30.4	72.4	183.20
Texas	260.8	715.3	210.98
Idaho	12.5	31.2	192.00
Colorado	52.7	163.4	238.51
Washington	60.2	195.1	249.30
Oregon	41.3	123.1	229.28
California	419.1	1391.3	255.36
Montana	12.4	31.9	197.89
Hawaii	25.7	75.9	227.18
Alaska	14.4	67.7	361.65
Pacific	560.8	1853.0	254.17
W. So. Central	435.5	1188.7	209.96
U.S. Average	3973.9	12,065.3	233.55

SOURCE: Tables C-5 and C-6, Employment and Wages, First Quarter 1975, U.S. Dept. of Labor, Bureau of Labor Statistics.

8.0 ECONOMIC FACTORS OF PRODUCTION AND MARKETS FOR ALASKA'S ENERGY INTENSIVE INDUSTRIES

8.1 ECONOMIC FACTORS OF PRODUCTION

The usual factors of production are raw materials (including energy), land, labor, and capital. In the U.S. these factors of production must be combined in a manner which results in production of products which can be sold in competitive markets. The market price must also be sufficient to include a profit which is required to offset potential risks and provide investors with appropriate incentives. Existing markets will usually determine what the market price is and in turn, firms that can sell their products at that price usually obtain a share of the market. The process is dynamic however, and as a new firm enters the market, the market price has a tendency to fall as more products are offered; i.e., as supply increases, the price declines in order to clear the market of available supply.

New firms or industries desiring to locate or expand existing firms in Alaska will face these same economic facts. They will have to find the appropriate combination of production factors (raw materials, land, labor, energy, and capital) which will allow them to produce their products at a competitive price. The existance of profitable firms in Alaska obviously verifies the fact that this is possible for some industries; e.g., pulp, fish processing, forest products, and fertilizer production. The challenge before Alaska, assuming it desires new and expanded industries, is to identify the appropriate combination of production factors given potential markets for Alaskan products. In addition, each geographic region usually has some unique, economic advantage over other areas; e.g., Alaska has a latent supply of raw materials, energy, and is close to Asian markets. The challenge is to identify these unique economic advantages and then capitalize on them.

Industrial managers have an ability to identify these unique advantages which are not always apparent to the lay person. They will then capitalize on the advantages assuming appropriate incentives are foreseeable. For Alaska, this may require some deviations from past operating practices and some untried combinations of production factors may also be required. This may be necessary if Alaskan industries are to be competitive; e.g., more capital might be required as a substitute for relatively costly

Alaskan labor. In addition, Alaska may find that its primary markets are in the Pacific Rim, Japan for example, and not the lower 48 states. A cursory evaluation of logical candidates is necessary to identify the probable industries and most attractive markets. A detailed analysis of the probable industries should then be completed to identify the more feasible opportunities.

The fact is that industries locating in Alaska must be able to compete in either the intrastate market, the "export markets" (the other 49 states and foreign countries) or both if they are to survive. In order to compete, Alaskan industry must find a cost advantage as was stated earlier. The market clearing price or market price will be essentially the same for each product independent of where they are produced. The cost of each item or factor of production may vary, however, dependent upon the site. The major cost items for any producer will be: 1) labor, 2) energy, 3) raw materials, and 4) capital (investment). A competitive Alaskan producer must combine these items in a manner such that he is competitive; i.e., his total production costs are less than or equal to his competitors within and outside of the State. (The non-Alaskan producer will also have the cost of transporting his products to Alaska.) Therefore, if the Alaskan producer can produce a product at the same cost as a non-Alaskan producer, the Alaskan producer can become the price setter as he has an advantage over the foreign or non-Alaskan producer; i.e., the cost of transporting products to Alaska.

Similarly, for the Alaskan export market Alaskan producers must be competitive if they wish to compete in foreign markets. This time, however, the Alaskan producer will have the additional transportation cost as compared to the overseas domestic producer. This should be possible for some Alaskan products and markets. A likely product might be aluminum produced in Alaska and sold in Japan.

For some cases such as mining, the location of a plant is almost dictated by the presence of the ore independent of other factors of production. For example, ore processing plants (concentrators) are usually at the mine independent of the cost of labor, land, etc., at the mine site. The concentrator is located at the mine because the cost of transporting the ore to another site would be overwhelming. The most economical arrangement is to move workers to the mine site, concentrate the ore, and ship the concentrates to a smelter while leaving the tailings at the mine. This is a simplistic example, but others exist for most regions including Alaska. Identifying other examples with appropriate markets should be achievable.

Two other factors apparently or potentially available in Alaska may also influence the location of new industries in Alaska. The first is an apparent hospitality for new industry and the second is a large, potential supply of energy, both fossil and potential hydro; e.g., the Upper Susitna River. For example, these two factors might be sufficient to attract an aluminum reduction plant to Alaska.

8.2 THE ALUMINUM INDUSTRY AND JAPANESE MARKETS(1)

The aluminum industry has been attempting since 1966 to locate a new plant in the Pacific Northwest and has not been totally successful to date. For example, Alumax Pacific Corporation proposed to build a new aluminum reduction plant in the Pacific Northwest. They attempted to locate the plant in Warrenton, Oregon, but failed to gain the necessary permits. More recently, Alumas proposed to relocate the plant to McNary, Oregon. The necessary permits have been delayed and construction is still pending.

In addition, the Bonneville Power Authority has notified the existing aluminum industry that when their current contracts expire, they will not be renewed. Any new contracts, if granted, will certainly be at a greater cost, as the existing hydro generating capacity in the Pacific Northwest is essentially fully utilized.

A power contract is especially important to an aluminum reduction plant. These plants consume large quantities of electric energy (5 to 8 kWh/lb of product depending upon the process utilized). The cost of a relatively uninterrupted supply of this power is also important. For example, using 25 mil power, the electrical costs will be $0.12 to $0.20/lb and for 60 mil power the electrical energy costs will be $0.30 to $0.48/lb. At a U.S. market price of $0.45/lb, one can see that the cost of power accounts for at least 25% of the production costs in the U.S. (using 25 mil power) but greater than two-thirds of the production cost using 60 mil power.

(1) A more detailed evaluation of this aluminum industry is provided in Volume II of this report series.

The availability and cost of power have been the primary factor in siting an aluminum reduction plant, assuming a permit can be obtained. These recent problems with plant siting and inadequate future power supply tend to make Alaskan sites more attractive.

An Alaskan site could be competitive assuming electric power is available at a competitive price offsetting higher construction and operating costs. Given a low cost power supply, a primary aluminum smelter may be one of those industries which could be sited in Alaska independent of the costs of other factors; e.g., labor rates. An Alaskan plant would have to compete with aluminum reduction plants in the lower 48 states and other countries. Domestic siting competition appears to be diminishing however, as new plants are not moving forward, and the cost of electrical energy in other regions will probably escalate more rapidly than in Alaska due to Alaska's abundance of oil, coal, and gas resources.

An Alaskan plant should also find a market in Japan and have an advantage over Japanese plants. Currently, Japan imports approximately 550,000 tons of aluminum ingot annually. Their total consumption is nearly 2 million tons per year and grew at 8%/yr during the early 1970's. The growth rate slowed during the recent recession but has begun to recover and could approach 6 to 8% again.

Most areas such as Alaska should have less costly energy than Japan as their industrial energy costs are reported to be approaching 60 mills/kWh. Thus, if an Alaskan reduction plant could obtain power at even 25 mills/kWh, they should be more than competitive with Japanese aluminum industry. Because of energy costs, Japan should prefer to import more aluminum and produce less with their relatively expensive energy. The transportation costs to Japan should not cause a problem as they are estimated to be approximately $0.01/lb against a current domestic (U.S.) selling price of $0.56/lb. Thus, the transportation costs of shipping aluminum to Japan in foreign vessels will be almost insignificant.

More detailed analysis is admittedly necessary to quantify the apparent competitiveness of an Alaskan aluminum reduction plant designed to supply the Japanese markets. Additional analysis is also needed to identify other industries where Alaska has a unique advantage due to its availability of energy and natural resources. Alaska's proximity to Japan and the Pacific Rim is an advantage for Alaska's industry and trade with this region should continue to expand. Recently, trade relations with Japan have continued to improve and Japan now has a stronger desire to import U.S. products. Some of the reasons why Japan has and will continue to increase her imports from the U.S. and Alaska are:

- In 1977, Japan had a $7.3 billion surplus of trade with the U.S. Japan is now being pressured to reduce this surplus and increase her imports of U.S. goods. As a result, the Japanese Government has relaxed import controls and is now encouraging increased imports and more foreign investments.
- Japan is almost totally dependent upon imports for natural resources such as energy and minerals. They prefer to have several sources for each commodity as opposed to a few. Alaska could become a more important supplier and currently supplies natural gas, logs, pulp, urea, and fishery products to Japan in significant quantities.
- Japan is desperately short of land for industrial parks. Thus, they are investing in new plants in foreign countries and may wish to invest more in Alaska. To date, they have made major investments in the Kenai ammonia/urea and gas liquefaction plants and the pulp mill.
- Japan's labor forces, though currently experiencing high unemployment, may recover in the near future and Japan's industry may increase abroad to gain access to the necessary labor.

9.0 ENERGY INTENSIVE INDUSTRY SCREENING AND EVALUATION

9.1 INTRODUCTION

The definition of "energy intensive industries" is to some extent subjective but is usually thought to imply a high ratio of energy (Btus) input per unit of production. The energy input can be construed as including both raw material energy content (e.g., oil, natural gas, coke, oxygen, etc.) where the feed stock itself has an intrinsic energy energy content) or as applied process energy. Aluminum is an example of the latter case where electric power is used in the electrochemical reduction process and results in the most energy intensive material product on a weight basis. Table 9.1 summarizes the 17 most energy intensive products currently produced by U.S. industries.

The basic characteristics of energy intensive industries that would tend to locate in Alaska as opposed to other locations are:

1) The product is produced in large volumes by world scale facilities and can readily be shipped in bulk form. This has a tendency to overcome the cost of transportation disadvantage associated with Alaska's remoteness from major markets.

2) Energy as a factor in production should be a large fraction of the total production cost, hence decreasing the significance of the other factors such as labor and capital charges.

3) The labor cost contribution to the total cost should be low to help offset the higher cost of labor in the State. This suggests that the industries that may be attracted are those that can be highly automated and generally use continuous as opposed to batch processes.

4) The industry should be a primary industry, i.e., its products should not be dependent upon the availability of intermediates that might have to be imported into the State in order to produce the finished product. In addition, the process should

TABLE 9.1. Energy Intensive Industrial Products

Product	Energy Consumption in BTU/Pound	Value $/Pound	Energy Consumption in BTU/$ Product	Total Annual Production in 10^9 Pounds
Aluminum[a]	122,000	0.447	272,930	9.06
Phosphorus[a]	86,000	0.66	130,303	1.05
Copper[a]	56,000	0.70	80,000	3.74
Carbon Black[b]	21,430	0.12	178,580	3.50
Ethylene[b]	31,250	0.13	240,384	22.4
Ammonia	19,500	0.12	162,500	64.0
Paper	16,130	--	--	124.0
Methanol[c]	16,100	0.076	211,842	6.8
Caustic Soda	14,950	0.25	59,800	23.1
Ethylbenzene[c]	14,460	--	--	6.5
Styrene[c]	13,000	0.21	61,904	6.0
Steel[a]	12,000	0.15	80,000	256.0
Chlorine	10,350	0.073	141,780	20.6
Glass[a]	8,800	--	--	25.0
Lime[a]	4,250	0.0145	293,100	42.2
Portland Cement[a]	3,800	0.0160	237,500	171.0
Petroleum Refining[c]	2,074	0.053	39,130	1,350.0

(a) Includes all energy from ore mining through smelting and refining of products.
(b) Includes energy in feed material, plus process energy requirements.
(c) Process energy requirements only, feed material not included.

be such that few if any by-products are produced, particularly those that cannot be marketed directly but require additional upgrading or combination with other materials not readily available.

The criteria of energy intensiveness listed as Number 2 above is particularly important to this analysis. Although the energy intensiveness measurement of Btu/lb of product is significant, a more appropriate measure appears to be the ratio of Btu/$ value. Given comparable production cost contributions for other factors of production and transportation of products, this ratio appears to capture most of the attractive aspects of a lower cost energy region better than the Btu/lb ratio. Thus column 4 in Table 9.1 presents the ratio of Btu's of input energy to the current domestic value of product.

Aside from meeting intrastate demands for energy products, the industrial utilization of energy can be thought of as a means of converting the energy into an alternative product form, e.g., conversion of energy equivalents into pounds of product. Thus Alaska as an energy resource-rich state can export Btu's as might be represented by barrels of oil, or it can export the equivalent amount in terms of a product such as aluminum ingots or slabs.

With the exception of ethylene, all of the products listed in Table 9.1 are produced in large scale and suitable for bulk shipment and at comparable rates per ton. Thus those industries whose products contain the highest ratios of Btu per dollar of product value will be the most likely attracted to regions with low delivered energy costs assuming other costs are not significantly different from those in alternative locations.

Thus, from Table 9.1 the industries most likely to be attracted to the energy resource area are, in order of merit:

1. Lime	6. Ammonia
2. Aluminum	7. Chlorine
3. Portland Cement	8. Phosphorus
4. Methanol	9. Steel
5. Carbon Black	10. Copper

Steel, copper, and phosphorus can be eliminated from the above list as there are currently no sources of nonenergy raw materials in the State that can compete with other lower cost domestic sources, i.e., the cost of importing raw materials into Alaska coupled with the cost of exporting the finished product will preclude development until such time as raw material sources within the State are opened up. Due to a variety of market and institutional factors such as the D-2 lands debate, such is not expected within the next 10 to 15 years. In addition, the market for these products within the State is not sufficient to support the scale of industrial development necessary for competitive plants and essentially all products would have to be exported.

Although importing alumina would be necessary for support of an aluminum reduction plant, over 80% of the U.S. domestic supply is already based upon foreign imports from Australia, Jamaica, Surinam, and the Dominican Republic; and Alaska should not be seriously disadvantaged although the intrastate market for aluminum will not support a competitively scaled plant. Aluminum reduction is so strongly dependent upon low cost hydroelectric power, costs of product export are not a major inhibitor.

Carbon black, primarily used in the manufacture of motor vehicle tires, does not appear attractive as the product is bulky and the major market is in the interior U.S. and would entail the additional rail freight cost.

Lime and Portland cement are two products which have a significant intrastate market in support of construction projects. Successful development of these industries could result in reduced costs of construction in Alaska and, in turn, reduce the currently high cost of capital facilities that inhibit other industries which might otherwise be located in the State. These two products are literally and figuratively the foundation for other industrial developments. Construction of the Upper Susitna hydroelectric products alone could require a major Portland cement plant.

Ammonia and its natural coproduct urea production have already attracted to the State the world scale plants based on very low cost natural gas then available from the Cook Inlet region.

Elemental phosphorus is not a primary industry in that it must be preceded by a phosphorus acid process based on phosphate rock for which Lower 48 domestic supplies are plentiful and closer to the agricultural markets.

The petrochemicals industry is of great current interest in Alaska due to the possible availability of natural gas and liquids from future North Slope natural gas production and a proposal for processing the 12-1/2% royalty fraction of the North Slope oil production through a major petrochemical facility to be located in the State with products to be marketed largely in Japan.

The above industries are discussed and evaluated in the following pages.

9.2 THE ALUMINUM METAL INDUSTRY

Aluminum is the most prevalent metallic element in the earth's crust. Furthermore, it ranks as the third most prevalent among all of the elements of the earth's crust being exceeded only by the elements oxygen and silicon. However, it never exists naturally as the free metallic material, it being always in compound form mainly as oxide and silicates. Although there are many important large-scale uses for processed aluminum compounds in the form of pulp and paper chemicals, refractories, abrasives and water treatment chemicals as well as unprocessed compounds in the form of Portland cement and clay ceramics, the demands for the pure and alloyed metal exceeds that of all of the processed compounds. The remainder of this summary is concerned with a discussion of aluminum in metallic form. In the following, therefore, whenever aluminum is mentioned it is considered to be in the pure metallic form or in the form of alloys of high aluminum metal content.

The Metal

Aluminum is a light, silvery colored metal of very low density being nearly one-third the density of iron. In aboveground situations it has excellent resistance to corrosion. It is an outstanding electrical conductor. Similarly it is an outstanding heat conductor. It also has excellent corrosion resistance to most food liquids such as fruits and juices. In addition it has unique corrosion resistance to strong oxidizing acids such as nitric. As polished surfaces it has durable and high reflectivity for light. Mechanically it is easily worked and formed. Although in some form, particularly in the purest state, it is quite soft, many of its simplest alloys are of very high strength. It can easily be produced in cast form; it can be welded; it can easily be extruded in a variety of complex shapes; it can be rolled and embossed sheet form or in the form of very thin foils.

These many attractive properties have encouraged its use in a number of important applications. Because of these features in terms of volume and value it exceeds all metals except iron. However, among all major products, it requires much more energy to produce than any other--a total of 122,000 Btu per pound compared with 56,000 for copper and 12,000 for steel. Aluminum is produced exclusively by the electrolysis of pure aluminum oxide which has been dissolved in molten cryolite which is mainly the xynthetic mineral of sodium aluminum fluoride, Na_3AlF_6. The temperature of this process is about 950°C. The 31 plants which conduct this process in the United States have a combined annual capacity of nearly 4,500,000 metric tons.

Uses

The many unique properties of aluminum has encouraged its use in a wide variety of major applications; principal among these are:

Transportation Equipment (because of high strength, corrosion resistance and light weight)--air and space craft, trucks, railroad equipment, automobiles, travel trailers and mobile homes.

Power (because of high strength, low density, high light reflectivity, and high electrical conductivity)--high voltage, electrical transmission lines and solar energy applications.

Construction (because of attractive finish, corrosion resistance, strength, light weight, ease of fabrication)--exterior surfaces, framing for doors and windows and decorative fittings.

Containers (because of attractive finish, corrosion resistance, ease of fabrication, light weight)--fruit, vegetable, juice, beer, soft drink and food containers.

Machinery (because of light weight, high strength, corrosion resistance and ease of fabrication including welding, casting and forming)--heat exchange equipment, cast parts, frames, wheels, housings, and mountings.

Appliances and Equipment (because of light weight, strength, corrosion resistance, and heat conduction)--heating and air conditioning, furniture, tools, cooking and garden equipment.

Surface Finishing (because of high and durable light reflectivity, light weight and ease in forming into foil and powdered forms, corrosion resistance and decorative features including capability of compounding with colors)--embossed, etched, colored and other decorative thinsheet forms, paint formulation and heat reflective insulation.

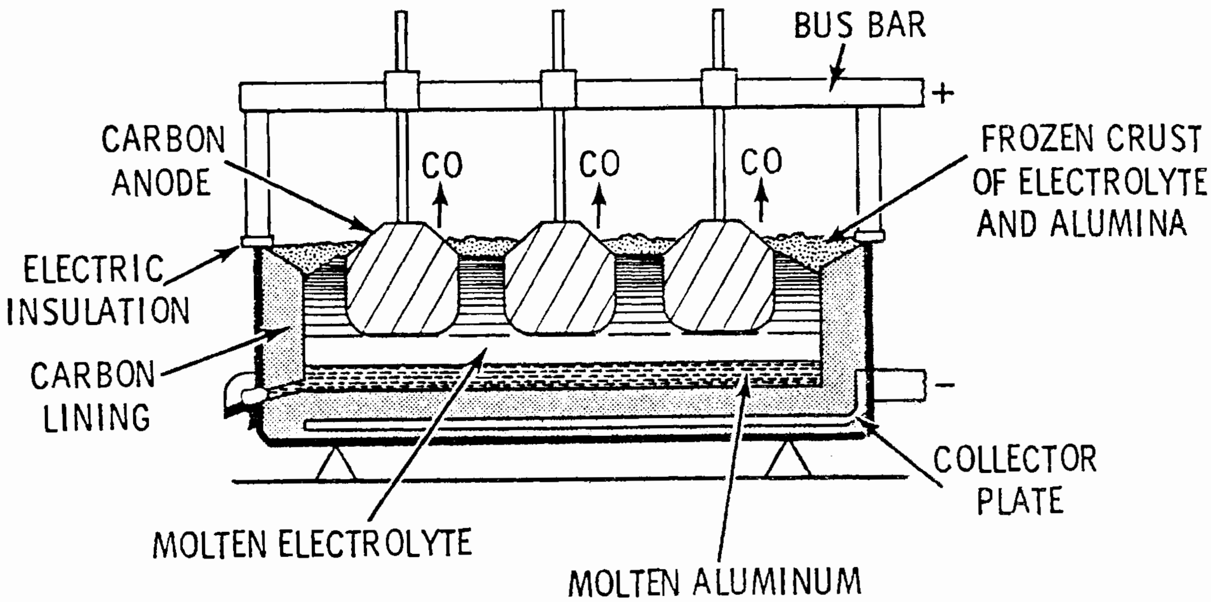
The Process

Aluminum is produced by the electrolysis of molten cryolite (Na_3AlF_6) in which relatively pure aluminum oxide is dissolved. Some additives are also used to improve the physical and electrical properties of the melt; these include minor amounts of aluminum fluoride, calcium fluoride (fluorspar) and lithium fluoride. The aluminum oxide concentration in the molten solution ranges from about 2 to 6 percent. The essential chemical reaction is about as follows:

$$\underset{\text{aluminum oxide feed material}}{Al_2O_3} + \underset{\text{carbon}}{C} \xrightarrow[\text{cryolite, solvent}]{Na_3AlF_6} 2\ Al + \underset{\text{The ratio of these waste gases is variable}}{CO_2 + CO}$$

Although the above equation is representative, there are other factors which significantly influence the efficiency and raw material requirements. Principal among these are the design and operation of the individual electrolysic cells and the design and processing of the electrode (anode) carbon. A typical electrolysis cell for aluminum production is shown in the following sketch.

In this process the feed material (aluminum oxide) is added intermittently through the top crust. Also the molten aluminum is drawn off intermittently. The carbon anodes which are continuously consumed in the process are formed and introduced almost continuously. Although the cell structures are rugged and durable, they eventually fail and must be totally rebuilt. The life of a cell is usually a few years. An array of cells which may number in the hundreds is called a pot line. A number of pot lines comprise a whole reduction plant. A representative reduction plant



Cross-Section of an Aluminum Production Cell

may have an annual capacity of 100,000 short tons of pure metal. The largest plant in the U.S. is the Rockdale, Texas, plant of the Aluminum Company of America with 285,000 tons. The smallest in the United States is the plant of Conalco at Lake Charles, Louisiana, with 36,000 tons per year (1973).[1]

The raw materials, energy and labor requirements for the two major process (anode) types are reported as follows:

(1) See U.S. Bureau of Mines Bulletin 667, "Mineral Facts and Problems, Bicentennial Edition," 1975.

Estimated ranges of alumina, energy,[1] labor, and raw materials to make 1 short ton of primary aluminum metal.

	Type of anode	
	Prebaked	Soderberg
Alumina .... short tons..	1.9–1.95	1.9–1.95
Makeup cryolite (Na_3AlF_6) .... pounds..	10–70	10–70
Makeup aluminum fluoride (AlF_3) .... do....	25–60	25–60
Calcium fluoride (CaF_2) .... do..	4–8	4–8
Energy, million Btu: [2]		
Alumina reduction (electricity)	45–56	55–60
Electrode carbon		
Petroleum coke, calcined (700–950 pounds)	9–12	9–10
Pitch (280–330 pounds)	3–4	3–4
Anthracite coal (40–80 pounds)	.5–.7	.7–1
Anode and cathode baking (oil, gas, electricity)	2.3–5.5	.1–.2
Holding furnace, ingot casting, and melting operations (gas, oil, electricity)	5.2–7.8	5.2–7.8
Total labor and supervision .... man-hours..	8–15	10–20

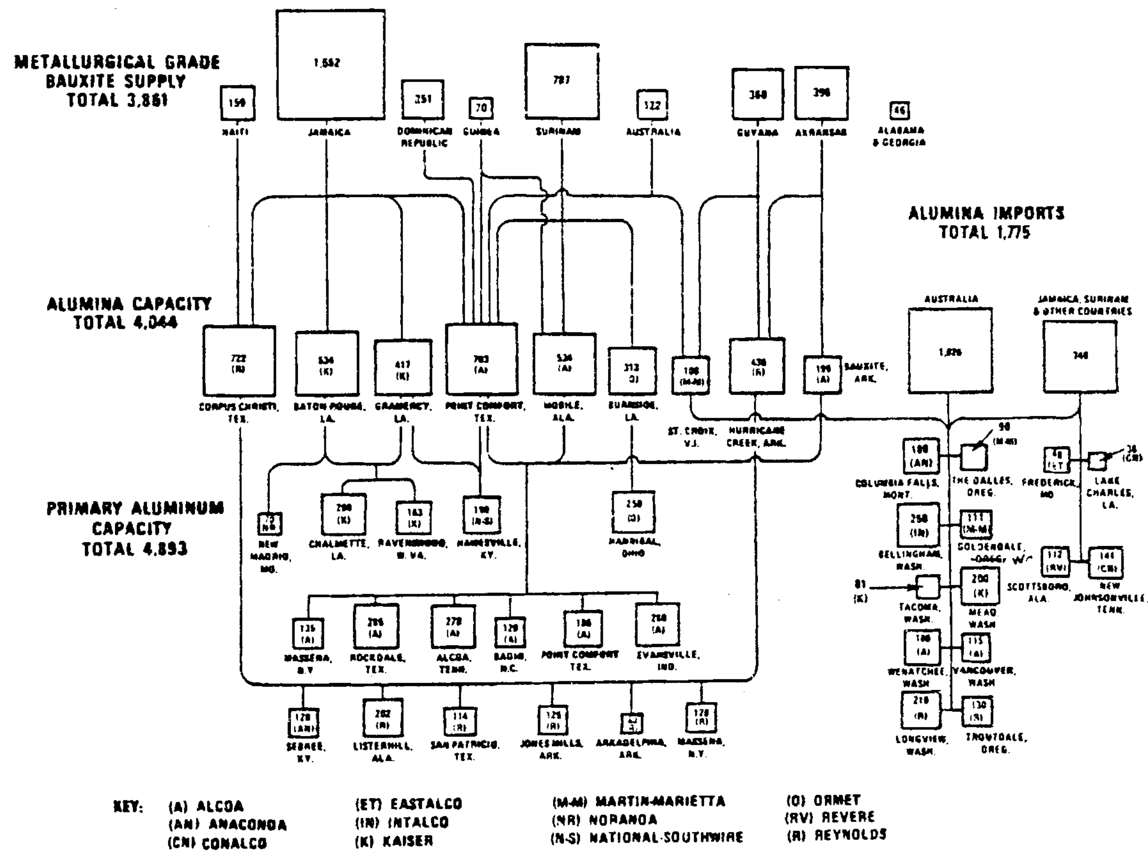
[1] Assumed energy equivalent of oil is 150,000 Btu per gallon; natural gas, 1,000 Btu per cubic foot; coal and pitch, 24 million Btu per short ton; petroleum coke, 26 million Btu per short ton; electricity, 3,413 Btu per kilowatt-hour.

[2] Excludes energy required to produce fluorine compounds, estimated at 2–7 million Btu per ton of primary aluminum, and to calcine petroleum coke, equivalent to about 1–2 million Btu per ton of primary aluminum.

The principal raw material, alumina (refined aluminum oxide), is largely imported, mainly from Jamaica, and other Carribean countries, Australia, and Africa which have large resources of the desired mineral, buaxite. This mineral in these producing countries is in some cases processed for economic as well as political reasons to alumina. However, the largest portions of the imported bauxite mineral are still processed in the United States. Depending on geography and beneficial contracts a significant portion of U.S. reduction plants continue to depend on imported, refined alumina. Furthermore, it is expected that unless significant or unreasonable price increases develop over the years, the U.S. will continue to be dependent upon such imported bauxite and increasingly on refined alumina as well. However, if there are major indigenous deposits of suitable bauxite (or other aluminum minerals such as alunite, anorthosite, ferruginous bauxite and kaolin) alumina production may also be considered as a local and integrated part of an overall aluminum industry. Reference (1) diagrams the flow of bauxite and alumina to the U.S. aluminum industry as follows:

DISTRIBUTION OF U.S. BAUXITE AND ALUMINA SUPPLY AND ALUMINUM PLANT CAPACITIES 1973

(THOUSAND SHORT TONS OF ALUMINUM CONTENT)



Except for carbon for anode production the other raw materials are rather minor; however, most of the fluoride, mineral raw material is also imported.

Carbon for anode production is in the form of so-called pitch and petroleum coke; both are by-products of the petroleum refining industry and are generally available locally in the U.S. Some anthracite coal is also used in electrode fabrication. Since about 0.6 lb of such carbon is consumed for each pound of aluminum produced, carbon is a major raw material.

With regard to capital requirements for the aluminum industry, reference (1) also states as follows: "A new bauxite mine in an undeveloped area might cost as much as $80 per ton of annual capacity. The cost of new alumina production facilities in 1974 was believed to be $300 to $500 per ton of annual capacity. Estimated cost of primary aluminum plants built in 1974 ranged from $1200 to $1800 per annual ton capacity." Assuming then that it takes about 4.5 tons of bauxite to provide a ton of metal and also about 2 tons of alumina, the total capital cost per ton of metal starting from the mine would be about $2500 per ton of annual capacity. In addition the cost of new electric powder generating facilities "would add another $600 to $1200 per ton of annual metal capacity." (This estimate was based on the use of about 8.5 kWh per pound of metal.) The same reference indicated operating costs (exclusive of profit) to be about as follows:

Bauxite	$ 22 to 110 per ton of metal
Alumina	90 to 160 per ton of metal
Primary Aluminum	300 to 600 per ton of metal
Total	$ 412 to 870 per ton of metal (or $0.206 to $0.435/lb)

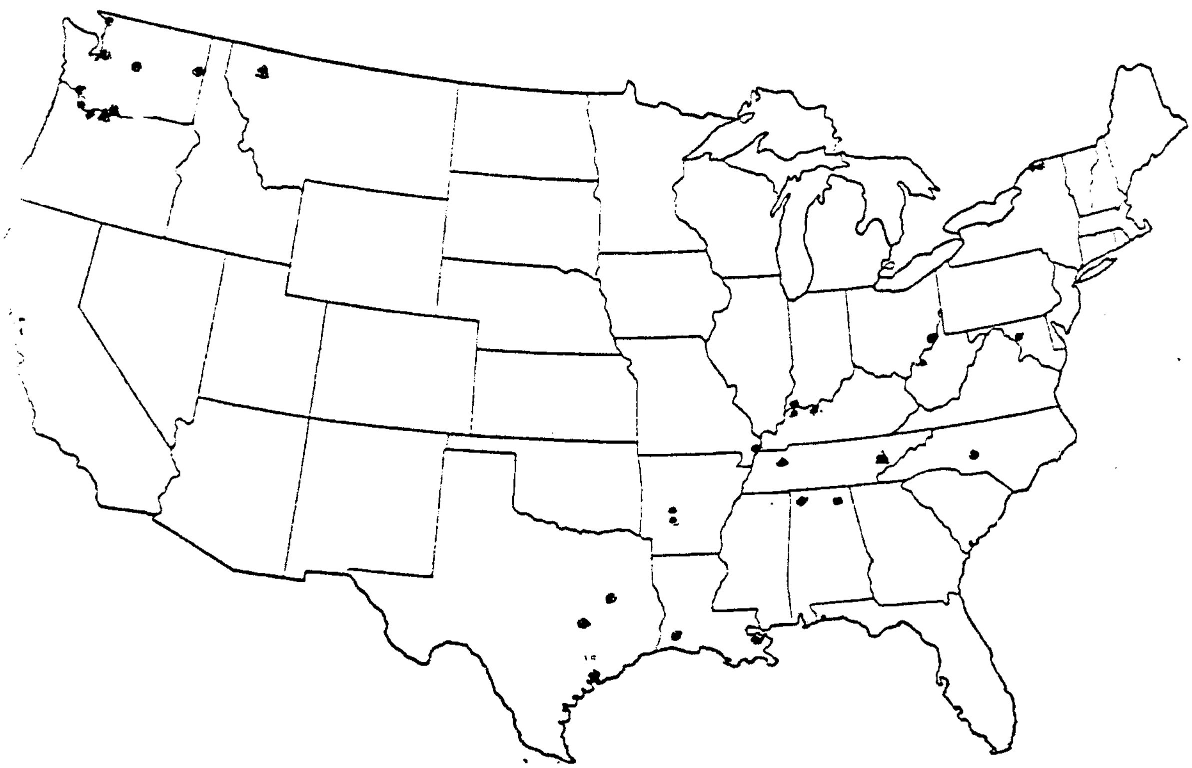
In addition to these costs there is the cost for delivery of the ingot aluminum to the consumer.

Thus the three major costs in aluminum manufacture relate to the cost of power, the cost of alumina and the cost of delivery of ingot to the consumer.

Although the chart shown on an earlier page shows that a dozen companies are producing metal in the U.S., three of these produce two-thirds of the total U.S. production. About half of all these companies own foreign ore and alumina processing plants. In 1975 the total metal produced in the U.S. as ingot and mill products had a value of about $7 billion.

Present Status of the Industry

Although aluminum reduction plants are widely distributed across the U.S. there is centralization around areas of former and recent low cost electric power. For earlier plants this was almost exclusively hydroelectric power--in the Pacific Northwest, the Tennessee Valley, the Ohio Valley, the St. Lawrence Valley and North Carolina.



Geographical Distribution of Aluminum Production[2]

(2) C. A. Rohrmann, et al, Battelle-Northwest Report BNWL-2137 for U.S. DOE, November 1977, "Chemical Production from Waste Carbon Monoxide - Its Potential for Energy Conservation."

Factors other than power costs have been involved in some of these plant locations--such as sea coast sites which are available to imported alumina, proximity to users (and fabriactors) of the product, and availability of other low-cost energy sources such as natural gas in Texas (when it was much cheaper than it is today).

These plants have a very wide range of capacities--285,000 down to 36,000 tons per year. The growth rate has been impressive with a domestic demand growth averaging 7.4% per year. Foreign demand growth has been at the rate of 9.5%.. Although such figures are impressions in themselves, if any significant increase in the standard of living of both the developing and underdeveloped populations is achieved the demand for the metal because of its favorable properties could significantly exceed these existing growth rates. These possible developing needs and the associated power demands would be prodigious indeed and suggest a continuing bright future for the expansion of this industry. Furthermore, if the price of copper improves (as it is likely to do) to the level it was before the recent recession aluminum metal is certain to displace more of this metal in the electrical field.

Future Prospects

Although bauxite of foreign origin is likely to continue to be the principal raw material for metal production, there are strong political and security reasons for shifting toward the use of more domestic minerals for a significant fraction of the industry. This would result in new industries for alumina production based on kaolin, ferruginous bauxite, alunite and anorthosite. These minerals are continuing to be investigated at the process development level but a clearly favorable economic justification has yet to be apparent.

There will certainly be a continuing need to make even small gains in more efficient use of energy by improvements in cell design, electrolyte and electrode materials. Some concepts suggest that improvements to the cell designs to assure collection of higher strength carbon monoxide waste gas may contribute significantly to energy conservation (see Reference 2 mentioned previously). Similarly the waste carbon resulting from reconstruction of wornout cells may be productively converted to raw or intermediate Btu gas with attendant recovery of valuable fluoride chemicals for recycle. Such a development could achieve even greater economic as well as favorable material conservation results. Radical changes in processes are not anticipated; however, the effort of Alcoa to develop a process based on chlorides rather than fluorides should be noted. It is claimed that this process would reduce cell power requirements by about 30%. Furthermore it would contribute to the solution of some nagging air pollution problems associated with the present fluoride based processes.

Conclusions

Aluminum represents a particularly interesting prospect for Alaska, particularly in relationship to the Japanese or other Asian markets. Japan, for example, faces very high costs of electric power (40-60 mills/kWh industrial rate) due to their heavy dependence on costly imported oil. As a consequence, the Japanese metals industry is moving overseas--an example being the 50% Japanese participation in the proposed Alumax plant on the Columbia River in Oregon to utilize alumina imported from Australia. The cost of transporting aluminum ingot or slab from South Central Alaska to Japan should, if anything, be somewhat less than transporting (approximately ∿3500 k-miles) the same commodity from Portland, Oregon (approximately $20/ton at 4100 k-miles). Compared to the high intrinsic value of aluminum (approximately $1120/ton) the product transportation cost is near negligible. Cost of importing alumina from Australia to Alaska will similarly be slightly less than to the Pacific Northwest.

The Japanese market for aluminum is also attractive from the standpoint of the balance of trade standpoint.

Alaska may be in the position of being able to provide lower cost hydroelectric power surplus to utility needs. This situation could come about only if the Upper Susitna or other major hydroelectric project is constructed. The Alaskan utility loads are strongly winter peaking whereas the availability of hydropower tends to scale during the spring and summer months. Thus an aluminum industry could operate on interruptible power during the off-peak months and absorb hydroenergy that might otherwise be "spilled." This is the current situation in the Pacific Northwest states where more than 30 percent of the U.S. aluminum production capacity is located. By purchasing off-peak power a significant reduction in the total cost of power to the consumer can be achieved through careful integration of an interruptible load into the power system.

A full evaluation of the potential for an aluminum reduction industry location in Alaska will require integration with a thorough analysis of future loads and generating resources, power marketing studies and hydrologic evaluation of the hydroelectric system to be selected. Nevertheless, at this stage an aluminum industry development has a number of factors working towards its success and it must be considered a leading contender. It also has the added positive attribute of being dependent upon a renewable source of energy (hydropower).

9.3 CEMENT INDUSTRY

A. GENERAL CHARACTERISTICS

1. Location of Major Production Regions

Delaware, Massachusetts, Minnesota, New Hampshire, New Jersey, North Dakota, Rhode Island, and Vermont.[2] All but three of these states are in the Northeastern Region of the U.S.

2. Markets

For the most part cement companies market their product locally, where they may be competing with as many as 15 to 20 other companies.[1] Cement has a high weight-to-value ratio; therefore, it is generally transported on land by rail or truck over a radius of 200-300 miles surrounding the cement plant,[1] where access to water transportation is extended considerably beyond a 300-mile radius.[1]

3. Industrial Structure

In 1974, 51 companies operating 175 integrated plants and grinding only plants produced over 80 million short tons of cement in the U.S. The 10 largest U.S. cement companies provided over 50% of the U.S. market for cement.[3]

4. Process Description

There are two main processes for producing cement--the wet process and the dry process. Cement production by the wet process has been decreasing, and cement production by the dry process has been increasing in the past several years. One reason for this is that the dry process uses less energy than the wet process. Therefore, the dry process was chosen as the cement industry representative for this study. Since more than 90% of the cement produced in the U.S. is Portland cement, the process description is based on the production Portland cement.

The manufacture of Portland cement by the dry process involves four steps:

- Acquiring raw materials,
- Preparing raw materials,
- Producing clinker, and
- Grinding and mixing product cement.

The acquisition of raw materials involves mining of calcareous (lime-bearing) materials, mining of argillaceous (clayey) materials, and acquiring other raw materials such as blast furnace slag, sand, sandstone, iron materials, and coal-ash. These raw materials are transported to the cement plant. The raw materials are prepared for clinkering or "burning" by first being crushed and, if necessary, dried. Next, the raw materials are dry ground to reduce the size of particles. Roller mills are increasingly being used for this grinding step in the dry process. Following grinding the materials are thoroughly mixed and blended. The production of clinker is accomplished by "burning" the ground raw materials in various types of kilns. Two types of kilns are long rotary kilns and short rotary kilns with preheaters and possibly flash calciners. For this study a short rotary kilm with a suspension preheater was chosen. In the kiln the materials chemically react at elevated temperatures and exit from the kiln as hard granular masses called clinker. The final grinding and mixing step consists of grinding the clinker to powder with about 5% by weight of gypsum added during grinding. The gypsum is added to control the time required for the cement to set once water is mixed with it.

The wet process differs from the dry process only in the raw material preparation step. In the wet process, the raw materials are crushed and then wet ground in tube or ball mills. The slurry is then mixed, filtered, and fed into the kiln. The remainder of the wet process is the same as the dry process.

5. Trends in Process Development

The general trend in the cement industry seems to be a shift from wet process plants to dry process plants. Preheaters and flash calciners are being used in dry process plant to decrease the size of kiln necessary for a given output and to utilize fuel more economically. There is also a trend to converting to coal fired kilns rather than oil or gas fired kilns. A possible future process may be a fluidized bed calciner but at present this has problems associated with its heat recovery system.

6. Economic Plant Scale

According to 1974 information[3] the average production size of a dry process cement plant is about 500,000 short tons/year. In talks with a couple of representatives of cement plant construction companies, the figure of 1,000,000 short tons/year seems to be the economic plant scale of the near future. A plant production size of 445,500 short tons/year was chosen for this study due to the necessary information available for evaluation and also due to the limited markets served economically by an Alaska plant.

7. Capital Cost

The capital cost is a major factor in the development of a new cement plant. The capital cost for the hypothetical cement plant using the dry process chosen for this study is $80,858,000. This includes a 1.65 scale-up factor from costs in the Lower 48 states to costs in Alaska, no costs for land on which the plant is built, and fixed capital and working capital. This capital investment represents about $180/ton of cement produced per year.

8. Labor Requirements

The total number of employees estimated to be needed to run the hypothetical cement plant is about 100 employees. This represents about 1 employee/13.5 tons of cement produced per day.

9. Cost Data Sheet

10. References

(1) Environmental Considerations of Selected Energy Conserving Manufacturing Process Options: Volume X. Cement Industry Report, Report for Industrial Environmental Research Lab, Cincinnati, OH, by Arthur D. Little, Inc., Cambridge, MA, PB-264-276 (EPA-600/7-76-034j), December 1976.

(2) The American Cement Directory 1977, Bradley Pulverizer Co., 123 S. 3rd St., Allentown, PA, 18105, March 15, 1977.

(3) Industrial International Data Base - The Cement Industry, Rational Use of Energy Program Pilot Study, Report for Committee on the Challenges of Modern Society, North Atlantic Treaty Organization, by Gordian Associates, Inc., New York, 1976, NATO/CCMS-46.

1. Process - Portland Cement, Dry Process, Rotary Kiln with Suspension Preheater
2. Capacity - 445,500 TONS/YR, 1350 TONS/DAY, 330 DAYS/YEAR[1]
3. Capital Investment - $80,858,250[2]
4. Feedstock Requirements[3] - Limestone 610,000 TONS/YR, CLAY/SHALE 64,000 TONS/YR, Sand and Miscellaneous 25,000 TONS/YR, GYPSUM 21,000 TONS/YR
5. Total Product Cost:

I. Manufacturing Costs -	
A. Direct Production Costs	
1) Feedstock Costs	$ 2,856,000 [4]
2) Chemicals	-0-
3) Direct Operating Labor	3,626,000 [5]
4) Direct Supervision @ 10% Direct Operating Labor	363,000
5) Utilities	
Fuel (as coal) @ $1.00/$10^6$BTU	1,559,000 [6]
Electrical Power @ $0.04/KWH	2,406,000 [7]
Process Water	-0-
Cooling Water Makeup @ $1.20/1000GAL	241,000 [8]
Cooling Water Circulation @ $0.07/1000 GAL	14,000 [9]
6) Maintenance (Includes Labor, Supervision, and Supplies) @ 2% Fixed-Capital	1,470,000 [10]
7) Operating Supplies	147,000 [11]
A. TOTAL	$12,682,000
B. Fixed Charges	
1) Depreciation, 10% S.L.	7,351,000 [12]
2) Taxes and Insurance @ 2% of Fixed Capital	1,470,000
B. TOTAL	$ 8,821,000
C. Plant Overhead @ 50% of I.A. 3, I.A. 4, and I.A. 6	$ 2,730,000
II. General Expenses	
Administrative Costs @ 15% of I.A.3, I.A.4, and I.A.6	819,000
6. Total Annual Product Cost	$25,052,000
7. By-Product Credits:	
8. Net Product Cost	$25,052,000
9. ROI, 25% Before Taxes on Fixed-Capital Plus 10%	-0-
on Working Capital	$19,112,000
10. Net Costs and ROI	$44,164,000

11.	Net Transfer Price/TON Cement	\$ 99.13
12.	Shipping Costs/TON Cement (Tanker to Portland/Japan)	\$ 19.60 (13)
13.	Current Price/TON Cement	
	At Seattle	\$ 49.00 (14)
	At Ankorage	\$ 78.40 (14)
	At Fairbanks	\$102.00 (14)

FOOTNOTES

(1) Based on the capacity of the reference plant dealt with in Reference 1, page 29.

(2) Based on information from 6 private firms a value of $100/TON/year was chosen as reasonable for construction in the lower 48 states. It is assumed that this figure is just fixed-capital and that it includes air pollution control. A scale-up factor of 1.65 is used to adjust the cost to Alaska.

Therefore;

$445{,}500 \ \frac{\text{TONS}}{\text{YR}} \times \frac{\$100}{\text{TON/YR}} \times 1.65 = \$73{,}507{,}500$ is fixed-capital investment and

$73,507,500 X 0.10 = $7,350,750 is working capital.

∴ $73,507,500 + $7,350,750 = $80,858,250 for total capital investment.

(3) Based on information from Reference 2 page 26 & 27 that gave values as follows:

limestone	1.370 tons/ton cement
clay/shale	0.144 tons/ton cement
sand & misc.	0.057 tons/ton cement
gypsum	0.048 tons/ton cement

Therefore;

$1.370 \ \frac{\text{tons limestone}}{\text{ton cement}} \times 445{,}500 \ \frac{\text{tons cement}}{\text{YR}} = 610{,}335 \ \frac{\text{tons limestone}}{\text{YR}}$

$0.144 \ \frac{\text{tons clay/shale}}{\text{ton cement}} \times 445{,}500 \ \frac{\text{tons cement}}{\text{YR}} = 64{,}152 \ \frac{\text{tons clay/shale}}{\text{YR}}$

$0.057 \ \frac{\text{tons sand \& misc.}}{\text{ton cement}} \times 445{,}500 \ \frac{\text{tons cement}}{\text{YR}} = 25{,}394 \ \frac{\text{tons sand \& misc.}}{\text{YR}}$

$0.048 \ \frac{\text{tons gypsum}}{\text{ton cement}} \times 445{,}500 \ \frac{\text{tons cement}}{\text{YR}} = 21{,}384 \ \frac{\text{tons gypsum}}{\text{YR}}$

(4) Based on approximate figures given in a phone conversation with Wayne Williams of Lone Star in Seattle

limestone $3/TON

clay/shale $10/ton

gypsum $16/ton

The cost for sand & misc. was obtained from Reference 3, page 146 as ~$2/ton

Therefore;

610,000 tons limestone/yr X $3/ton	=	$1,830,000
64,000 tons clay/shale/yr X $10/ton	=	640,000
25,000 tons sand & misc/yr X $2/ton	=	50,000
21,000 tons gypsum/yr X $16/ton	=	336,000
		$2,856,000

(5) Based on 0.17 man-hr/376 lbs cement for direct labor from Reference 4, page 171 assuming \$9.00 man-hr for direct labor

Therefore;

$$0.17\ \frac{\text{man-hr}}{376\text{lbs cement}} \times \frac{2000\text{lbs}}{\text{TON}} \times 445{,}500\ \frac{\text{tons cement}}{\text{YR}} \times \frac{\$9.00}{\text{man-hr}} = \$3{,}625{,}612/\text{yr}$$

This value is assumed to include the direct labor for pollution control also.

(6) Based on a range of values given in literature it was assumed that $3.5X10^6$BTU/ton cement was the fuel requirement and it was assumed that coal cost \$1.00/10^6BTU

Therefore;

$$3.5 \times 10^6\ \frac{\text{BTU}}{\text{TON cement}} \times \frac{\$1.00}{10^6\text{BTU}} \times 445{,}500\ \frac{\text{tons cement}}{\text{YR}} = \$1{,}559{,}250/\text{yr}$$

(7) Based on a range of values given in the literature it was assumed that 135 KWH/ton cement was the electricity requirement and it was assumed that electricity cost \$0.04/KWH. The electricity for pollution control is assumed to be included.

Therefore;

$$135\ \frac{\text{KWH}}{\text{TON}}\text{ cement} \times \frac{\$0.04}{\text{KWH}} \times 445{,}500\ \frac{\text{tons cement}}{\text{YR}} = \$2{,}405{,}\frac{700}{\text{YR}}$$

(8) Based on 450 GAL/TON cement from Reference 1, page 28 and assuming cost is \$1.20/1000 GAL

Therefore

$$450\text{ GAL/TON cement} \times \$1.20/1000\text{ GAL} \times 445{,}500\text{ TONS } \frac{\text{cement}}{\text{YR}} = \$240{,}570/\text{YR}$$

(9) Based on 450 GAL/ton cement from Reference 1, page 28 and assuming cost is \$0.07/1000 GAL

Therefore

$$450\ \frac{\text{GAL}}{\text{TON}}\text{ cement} \times \frac{\$0.07}{1000\text{ GAL}} \times 445{,}500\text{ TONS cement} = \frac{\$14{,}033}{\text{YR}}$$

(10) Assuming the maintenance to be 2% of fixed-capital and to include pollution control

Therefore

$$\$73{,}507{,}500 \times \frac{0.02}{\text{YR}} = \$1{,}470{,}150/\text{YR}$$

(11) Assuming operating supplies are 10% of maintenance costs

Therefore

\$1,470,150/YR X 0.10 = \$147,015/YR

(12) Assuming that depreciation is 10% of fixed-capital

$$\$73{,}507{,}500 \times \frac{0.10}{\text{YR}} = \$7{,}350{,}750/\text{YR}$$

(13) Based on Reference 5, Appendix A, methanol process, the transport charges are \$0.0098/LB

Therefore

$$\$0.0098/\text{lb} \times \frac{2000\ \text{lbs}}{\text{TON cement}} = \frac{\$19.60}{\text{TON cement}}$$

(14) Based on prices for 1977 obtained from Bill Jacobson for Kaiser Cement in Seattle.

REFERENCES

1. Environmental Considerations of Selected Energy Conserving Manufacturing Process Options: Volume X. Cement Industry Report, Authur D. Little, PB-264-276, December 1976.

2. Energy Use Patterns in Metallurgical and Nonmetallic Mineral Processing (Phase 4-Energy Data and Flowsheets, High Priority Commodities)Battelle Columbus Labs, PB-245-759, June 1975.

3. Commodity Data Summaries, Bureau of Mines, 1977.

4. R. Norris Shreve, Chemical Process Industries, Third Edition, 1967.

5. Alaskan North Slope Royalty Natural Gas, Battelle Northwest, August 1977.

9.4 CHLOR-ALKALI INDUSTRY

I. INTRODUCTION

Process Overview[1]

Chlorine and caustic soda are produced almost entirely by electrolytic methods from aqueous solutions of sodium chloride or fused chloride. In the electrolysis of brine, chlorine is produced at the anode, and hydrogen, together with sodium hydroxide, at the cathode. Since the anode and cathode products must be kept separate, many ingenious cell designs have been invented and commercialized. However, all these designs have been either variations on a type of diaphragm or on a mercury intermediate electrode.

Diaphragm cells contain an asbestos diaphragm to separate the anode from the cathode. This allows ions to pass through by electrical migration but reduces the diffusion of products. Diaphragms permit the construction of compact cells of lowered resistance, because the electrodes can be placed close together. The diaphragms become clogged with use, as indicated by higher voltage and higher hydrostatic pressure on the brine feed. They must be replaced regularly. The diaphragm permits a flow of brine from anode to cathode and thus greatly lessens or prevents side reactions (e.g., sodium hypochorite formation). Newer cells with metal cathodes (titanium coated with rare earth oxides, platinum or noble metals, or oxides) rarely develop clogged diaphagms and operate for 12 to 24 months without requiring diaphragm replacement. It is expected that Du Pont's Nafion (a perfluorosulfonic acid polymer), and similar materials used as membranes to replace asbestos, will increase service life. Presently under development are permionic membranes which pass NaOH while retaining NaCl increasing the purity of diaphragm cell caustic and eliminating a purification step to remove chlorine.[2]

Mercury cells produce purer NaOH, but a small loss of mercury to the environment presents extreme problems. Originally, it was believed that this loss was unimportant, but marine life concentrates the mercury biologically, resulting in fish containing lethal amounts of methyl mercury. Ingestion of contaminated fish led to development of the so-called Miniamata disease, resulting in deaths and affliction. In 1973, Japan outlawed mercury cell use after 1978, and the construction of mercury cells in the United States came to an abrupt halt. Careful process control,[3] combined with treatment of water and air effluent, may make it possible for mercury cell plants to meet environmental standards and survive, but most companies are hesitant to erect new units. Greatly improved diaphragm cell technology, particularly the replacement of graphite anodes with dimensionally stable titanium anodes with a catalytic coating, has swung interest to large (200 kA) diaphragm cells. The use of plastic has simplified cell construction, minimized and simplified maintenance, and allowed outdoor cell rooms in some cases, thus reducing costs.

Technological Trends

At the beginning of this century, in the early days of the electrolytic chlorine industry, a great techno-commercial argument took place about the relative merits of diaphragm and mercury cells; no definite answer was ever produced to the question. In some places, in particular the USA where energy was less expensive, the diaphragm cell fluorished and became the main chlorine producing cell; whereas, in Europe the mercury cell became dominant. This rivalry between the two types of cells was brought to a sudden end by the ecological concern about the effect of mercury in the environment. Much research has gone into mercury cell modification, mostly dealing with process effluent cleanup. Due to Japan's legal limit on the use of mercury cells after March 1978, most mercury process cleanup engineering was developed there.[4] Now recent news releases[5,6] imply that the outright ban on mercury cells in Japan may be scrapped or at least delayed because of success attained with the new cleanup technology. This technology is now finding its way into the European and American markets as well.[7]

While mercury cell operators are presently concentrating on cleaning up their operations, new development in the diaphragm cell technology are also receiving attention. The progress made in the last 10 years can be partly attributed to Dimensionally Stable Anodes (DSA®). Through the use of such novel metallic anodes in place of the older graphite anodes, lower cell voltages and higher current efficiencies are possible with the higher product purity and lower maintenance costs.[8] Extensive work on new membranes to replace the asbestos diaphragm is being undertaken by many manufacturers. The membranes developed by several American companies,[10] including Diamond Shamrock Corporation and Hooker Chemical, are based on Du Pont's Nafion which is a copolymer of tetrafluoroethylene and another monomer to which a sulfonic acid group is bonded. The membranes are permselective which minimizes the amount of salt which can pass through the diaphragm into the caustic solution. Since 1974[9] this technology has been utilized on a commercial scale. The latest efforts by the developers has been in exporting the technology.[11,12,13] The newest development in diaphragm technology comes from Asahi Chemical Industry Company of Japan[14] whose perfluorocarboxylic acid membrane yields a higher current efficiency at higher concentration of caustic from the electrolyzer. This technology will be further developed in cooperation with PPG Industries Inc.[15]

Structure of the Industry

There are over thirty different corporations operating plants in the chlor-alkali industry in the U.S. today. Four of these companies--Dow, Hooker (Occidental), PPG and Diamond Shamrock--control about half of the U.S. production of chlorine and caustic soda. These four, minus Diamond Shamrock, along with FMC and Pennwalt, control plants in Canada and Mexico as well. The tables[16] give the specifics of these production patterns. Of the total North American production capacity, less than 10 percent is in the Pacific Northwest and British Columbia.

TABLE 1. Chlorine Plants in the United States
(Not including plants building)

State & City	Producer	Year Built[a]	Cells	Capacity T/C	Containers Filled	Notes
[illegible]	[illegible]	[illegible]	[illegible]			
Niagara Falls	Olin Corporation	1897	Olin E11F (merc.) ('60)	210	- - S -	1
Syracuse	Allied Chemical Corp.	1927	Solvay S60 (merc.) ('53)	960	- - S -	1
			Hooker HC4B (diaph.) ('68, '77)			
North Carolina						
Acme	Allied Chemical Corp.	1963	Solvay V-200 (merc.)	165	- - S -	1
Canton	Champion International Corp.	1916	Hooker S1 (diaph.)	50	- - - -	1,7
Ohio						
Ashtabula	IMC Chemical Group, Inc.	1963	Olin E11F (merc.)	110	- - S -	2
Ashtabula	RMI Company	1949	Downs (fused salt)	190	- - S -	4
Barberton	PPG Industries, Inc.	1936	Columbia (diaph.)	300	- - S -	1
Tennessee						
Charleston	Olin Corporation	1962	Olin E11F, E812 (merc.)	630	- - S B	1
Memphis	E.I. duPont du Nemours & Co., Inc.	1958	Downs (fused salt)	150	- - S -	4
Memphis	Velsicol Chemical Corp.	1943	Hooker HC-4B (diaph.) ('69)	70	- - S -	1

(a) Refers to year chlorine production started at location.
(b) Dow Freeport includes both Texas and Oyster Creek divisions.
(c) Expansion in progress - see Table 3.
(d) See Table 4.

Table 1. (Cont'd)

State & City	Producer	Year Built(a)	Cells	Capacity T/D	Containers Filled	Notes
Saskatchewan						
Saskatoon	Prince Albert Pulp Co. Ltd.	1963	Krebs (merc.) Kureha HD-4 (merc.) ('69)	(c)	C T S -	1
<u>CUBA</u>						
Los Villas	Electro Quimica del Caribe SA (government operated)	1935	Vorce (diaph.)		C T - -	1
<u>MEXICO</u>						
Guanajuato						
Salamanca	Guanos y Fertilizantes de Mex., SA (form. Montrose) (Guanomex)	1959	Krebs (Paris) (M) (expansion 1971)		- - - -	1
Jalisco						
Guadalajara	Pennwalt del Pacifico, SA	1976	Diamond DS45 (D)		CT T S -	1
Mexico						
Chalco	Fabrica de Celulosa el Pilar SA	1953	Pomilio (D)		- - - -	1
San Cristobal (Ecatepec)	Guanos y Fertilizantes de Mex., SA (Guanomex) (form. Ind. Nac. Quim. Farmaceutical)	1954	Krebskosmo (M) (expansion 1959)		C T S -	1
Santa Clara	Pennwalt, SA de CV	1958	De Nora 14TGL (M) De Nora 14 x 3 F (M) ('66) Mathieson E11 (M) ('67)		C T S -	1
Michoacan						
Zacapu	Industrias Quimicas de Mix., SA	1975	Diamond MDC20 (D)		- - S -	1
Nuevo Leon						
Monterrey	Celulosa y Derivados, SA Plantas Quimicas (form. Sosa de Mixico)	1958	Mathieson E8 (M) (expansion 1972)		C T S -	1
Veracruz						
Pajaritos	Industria Quimica del Istmo, SA	1967	De Nora 18 x 4 (M) De Nora 18 H 4 (M) ('72)	(c)	- - S -	1
<u>PUERTO RICO</u>						
Guayanilla	PPG Industries (Caribe)	1971	De Nora 27M2 (merc.)	500	C T - -	1
Texas						
Baytown	Mobay Chemical Corp.	1972	Uhde (HCl)	100	- - - -	5
Corpus Christi	E.I. du Pont de Nemours & Co., Inc.	1974	Kelchlor, Diamond MDC55 (diaph.)	1000	- - - -	1,10
Corpus Christi	PPG Industries, Inc.	1938	Columbia N 1, N 3 (diaph.)	(c)	- - S -	3
Deer Park	Diamond Shamrock Corp.	1938	Diamond MDC22 (diaph.) De Nora 18 SGL (merc.)	1050	- - S B	1
Deer Park	Shell Chemical Co.	1966	Hooker HC-4BT (diaph.)	370	- - - -	1
Denver City	Vulcan Materials Co.	1947	Hooker S 1 (diaph.)	50	- - - -	1
Freeport(b)	Dow Chemical USA	1940	Dow (diaph.), Dow (magnesium	7330(c)	- - S -	1,9
Houston	Ethyl Corporation	1952	Downs (fused salt)	110	- - S -	4
Houston	Champion International Corp.	1936	Hooker S 1 (diaph.)	40	- - - -	1,7
LaPorte	Diamond Shamrock Corp.	1974	Diamond MDC 29 (diaph.)	1200(c)	- - S -	1
Point Comfort	Aluminum Co. of America	1966	De Nora 24 x 5, 24H5 (merc.)	460	- - S B	1
Port Neches	Jefferson Chemical Co., Inc.	1959	Hooker S3B (diaph.)	150	- - - -	1
Snyder	American Magnesium Co.	1969	VAMI (magnesium)	70	- - - -	9
Utah						
Rowley	NL Industries, Inc.	1977	Modified IG Farben (magnesium)	125	- - S -	9
Virginia						
Hopewell	Hercules, Inc.	1939	Hooker HC3 (diaph.)	85	- - S -	1
Washington						
Bellingham	Georgia-Pacific Corp.	1965	De Nora 18 x 4 (merc.)	250	- - S B	1,7
Longview	Weyerhaeuser Company	1957	Diamond MDC29 (diaph.) ('75)	380	- - S -	1,7
Tacoma	Hooker Chemicals & Plastics Corp.	1929	Hooker S1, S3 (diaph.)	400(c)	- - S B	1
Tacoma	Pennwalt Corp.	1929	Glanor 1144 (diaph.)	470	C T S -	1
West Virginia						
Moundsville	Allied Chemical Corp.	1953	Solvay S60 (merc.)	260	- - S B	1
New Martinsville	PPG Industries, Inc.	1943	Columbia N 1, N 3, N 6 (diaph.) Uhde 20 sq. m. (merc.) ('58)	690	- - S B	1
So. Charleston	FMC Corporation	1916	Hooker HC3B (diaph.) ('73) Hooker H1 (diaph.) ('73)	800	- - S B	1
Wisconsin						
Green Bay	Fort Howard Paper Co.	1968	Hooker HC3C (diaph.)	--	- - - -	1,7
Port Edwards	BASF Wyandotte Corp.	1967	De Nora 24H5 (merc.)	14	- - S -	1

(a) Refers to year chlorine production started at location.
(b) Dow Freeport includes both Texas and Oyster Creek divisions.
(c) Expansion progress - see Table 3.
(d) See Table 4.

(c) Expansion progress - see Table 3.
(d) See Table 4.

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TABLE 2. Chlorine Plants in Canada, Cuba and Mexico (Not including plants building)

Province & City	Producer	Year Built[(a)]		Capacity T/D	Containers Filled	Notes
CANADA						
Alberta						
Fort Saskatchewan	Dow Chemical of Canada, Ltd.	1968	Dow (diaph.)	(c)	- - S -	1
British Columbia						
Nanaimo	Canadian Occidental Petroleum Ltd.	1964	Hooker S4, HC4BT (diaph.)		- - S -	1
North Vancouver	Canadian Occidental Petroleum Ltd.	1957	Hooker S3B, HC-60, HIA (diaph.)		- - S B	1
Squamish	FMC of Canada Ltd.	1965	De Nora 24 x 5 (merc.)		- - S B	1
Manitoba						
Brandon	Hooker Chemicals Canada, Ltd.	1968	Dryco (diaph.)		- - S -	1
New Brushwick						
Dalhousie	Canadian Industries, Ltd.	1963	I.C.I. (merc.)		- - S -	1
Nova Scotia						
Abercrombie Point	Canso Chemicals Ltd.	197-	I.C.I. (merc.)		- - S -	1
Ontario						
Cornwall	Canadian Industries, Ltd.	1935	I.C.I. (merc.)	(c)	C T S -	3
Dryden	Reed Ltd.	1962	Hooker Mx (membrane) ('75)		- - S -	1,7
Sarnia	Dow Chemical of Canada, Ltd.	1948	Dow (diaph.)		- - S -	1
Quebec						
Beauharnois	Stanchem	1948	Uhde (merc.) ('71)		- - S -	1
Becancour	Canadian Industries, Ltd.	1975	Hooker H2A (diaph.)	285[(c)]	- - S -	1
Lebel-sur-Quevillon	Domtar Pulp Ltd.	1967	Olin E11F (merc.)		- - - -	1
Shawinigan	Canadian Industries, Ltd.	1938	I.C.I. (merc.)		- - S -	1
Saskatchewan						
Saskatoon	Prince Albert Pulp Co. Ltd.	1963	Krebs (merc.), Kureha HD-4 (merc.) ('69)	(c)	C T S -	1
CUBA						
Los Villas	Electro Quimica del Caribe SA	1935	Vorce (diaph.)		C T - -	1
Sagua La Grande	(government operated)					
MEXICO						
Guanajuato						
Salamanca	Guanos y Fertilizantes de Mex., SA (form. Montrose) (Guanomex)	1959	Krebs (Paris) (M) (expansion 1971)		- - - -	1
Jalisco						
Guadalajara	Pennwalt del Pacifico, SA	1976	Diamond DS45 (D)		C T S -	1
Mexico						
Chalco	Febrica de Celulosa el Pilar SA	1953	Pomilio (D)		- - - -	1
San Cristobal (Ecatepec)	Guanos y Fertilizantes de Mex., SA (Guanomex) (form. Ind. Nac. Quim. Farmaceutica)	1954	Krebskosmo (M) (expansion 1959)		C T S -	1
Santa Clara	Pennwalt, SA de CV	1958	De Nora 14TGL (M), De Nora 14 x 3 F (M) ('66), Mathieson E11 (m) ('67)		C T S -	1
Michoacan						
Zacapu	Industrias Quimicas de Mex., SA	1975	Diamond MDC20 (D)		- - S -	1
Nuevo Leon						
Monterrey	Celulosa y Derivados, SA Plantas Quimicas (form. Sosa de Mexico)	1958	Mathieson E8 (M) (expansion 1972)		C T S -	1
Veracruz						
Pajaritos (Coatzacoalcos)	Industria Quimica del Istmo, SA	1967	De Nora 18 x 4 (M), De Nora 18H4 (M) ('72)	(c)	- - S -	1

(a) Refers to year chlorine production started at location.
(b) Expansion in process - see Table 3.

TABLE 3. New Plants Expansions and Modernizations

Location	Producer	Project	Status	Projected Completion	Notes
UNITED STATES					
Alabama					
Mc Intosh	Olin Corp.	Phase 2, 500 T/D Hooker H4	Engrg.	2 Q '78	1
Louisiana					
Geismar	BASF Wyandotte Corp.	Modest Expansion Diaphragm Cells	Underway	2 Q '77	1
Lake Charles	PPG Industries, Inc.	Phase 2, 750 T/D (Bipolar)	Engrg.	1980	1
Plaquemine	Georgia Pacific Corp.	Expansion 900 to 1200 T/D Hooker H4, $30 million	Engrg.	Early '79	1
New York					
Niagara Falls	Hooker Chems. & Plastics Corp.	450 T/D Hooker H4 (diaph.)	Engrg.	1 Q '78	1
Oregon					
Portland	Pennwalt Corporation	Expansion 310 to 410 T/D Expansion 410 to 570 T/D (diaph.)	Bldg. Engrg.	Mid '79 1981	1
Texas					
Baytown	Goodrich/Bechtel	800 T/D Diamond MDC 55	Engrg.	Early '80	1
Freeport	Dow Chemical USA	Expansion, Dow (diaph.) 1000 T/D	Underway	1978	1
La Porte	Diamond Shamrock Corp.	"Incremental Expansion"	Bldg.	Early '78	1
Washington					
Tacoma	Hooker Chems. & Plastics Corp.	Expansion 400 to 675 T/D	Engrg.	Mid '79	1
CANADA					
Alberta					
Fort Saskatchewan	Dow Chemical of Canada	Expansion 900 T/D Dow (diaph.)	Bldg.	Late '79	1
Ne Brunswick					
Nackawic	St. Anne - Nackawic Pulp & Paper Co.	small plant Asahi membrane cell	Engrg.	Mid '79	1
Ontario					
Cornwall	Canadian Industries Ltd.	Conversion to metal anodes	Underway	1 Q '78	1
Quebec					
Becancour	Canadian Industries Ltd.	Expansion 385 to 770 T/D $100 million	Bldg.	4 Q '79	1
Saskatchewan					
Saskatoon	Prince Albert Pulp Co.	replacement cell room Asahi membrane cell	Engrg.	Fall '78	1
MEXICO					
Veracruz					
Pajaritos	Cloro de Tehuantepec SA	500 T/D Glanor 1144 (Bipolar)	Underway	Early '79	1

TABLE 4. Operations Shut-Down

Location	Producer	Extent	Scheduled	Notes
Texas				
Corpus Christi	PPG Industries Inc.	Complete shutdown	1 Q '78	1

All capacities shown are published capacities.

II. ENERGY REQUIREMENTS

The major production route for the chlor-alkali industry today is by way of electrolysis of brine or molten salt. Due to this circumstance, there is no chance for energy source substitution. Or to look at the problem another way, one could say there is perfect substitutability among any of the competitive means of generating electrical power. A variable energy cost for evaporation to concentrate the caustic solution is also required for diaphragm cells. As the technology of the permselective membranes developes this cost will continue to decrease.

Basing an energy cost calculation on a published cost accounting for chlor-alkali production[14] and adjusting energy costs to 24 mills per kWh, \$4.40 per metric ton of steam and a capital cost multipler for Southern Alaska of 1.5; the percent energy cost of the total production cost is about 60 percent for the standard asbestos-diaphragm or mercury cells but may drop substantially to about 55 percent for the Asahi permselective membrane cell. Actual kWh requirements for the electrolysis portion of the process range from 3524 kWh/mton Cl_2[14] to 3750 kWh/mton Cl_2[17] for the mercury cell, down to 3040,[17] 3137[18] and 2929[14] kWh/mton Cl_2 for the asbestos diaphragm cell. The additional energy requirement of caustic concentration from the cell product of 15 percent up to the commercial product of 50 percent when using diaphragm cells is from 2416[18] to 2668[14] kWh/mton of NaOH (measured as 100% NaOH). The new permselective membrane technology may drop this cost to as low as 297 kWh/mton NaOH while increasing the electrolysis cost to only 3054 kWh/mton Cl_2.[14] With the current market price of \$135 per ton of chlorine or caustic soda 50% solution, the energy intensiveness calculates to 84,000 Btu/\$ of product in the mercury cell and 128,000 Btu/\$ of product in the asbestos diaphragm cell. The newer membrane technology could require as little as 77,000 Btu/\$ of product.

III. ECONOMIC CONSIDERATIONS

Market Conditions[19]

A major market for chlorine is ethylene dichloride, which eventually becomes polyvinyl chloride (PVC). In this derivative chain, comfortable downstream capacity is reinforcing the effects of large polyvinyl chloride inventories. This capacity situation is a mild but not unpleasant surprise in view of the severe environmental problems in this area in the past several years. Earlier acute problems of toxic vinyl chloride emission in production, subsequent polymerization, and PVC fabrication plants now seem well in hand. Some vinyl chloride capacity and possibly some PVC capacity have been lost, but the total likely was smaller than once thought. Debottlenecking efforts probably have overcome all of this capacity loss. The result then is ample PVC capacity even with good growth in consumption. Unfortunately for producers, PVC's capacity situation merely helps translate chlorine's weak profitability downstream.

Industry sources still cite PVC production as the really buoyant market force for chlorine this past year. PVC, in effect, has offset declines in other chlorinated organics, particularly fluorocarbons used as propellants. The propellant market may have accounted for 3 percent or so of chlorine demand, some 300,000 tons a year at most. This market soon will be gone for practical purposes. However, chlorine consumption in making other fluorocarbons such as refrigerants is still rising, although regulatory curbs may be on the way. Prospects for other products containing chlorine vary over the range of 7 percent annual growth down possibly to zero in pulp and paper. Prospects are even poorer in cases such as environmentally curbed trichloroethylene.

Although still a major user of chlorine, the pulp and paper industry is shifting to other bleaching materials. The result is little growth for this area.

Major derivatives of chlorine are ethylenedichloride 20%, other chlorinated hydrocarbons 15%, propylene oxide 10% and various inorganics

10%. Major uses of chlorine are for diverse chemicals 35%, plastics (mostly PVC) 20%, solvents 15%, pulp and paper 15% and water treating 5%.

Demand growth for caustic during 1978 will be in the usual big use areas such as the manufacture of a diverse lot of other chemicals. Used largely in neutralization processes, caustic counts on this area for half of all domestic sales. Because chemical manufacturing continues to grow fairly well, this use of caustic will grow, too, perhaps 7 percent per year or well above the overall caustic growth rate of 4 to 5 percent annually.

One general use of caustic, neutralizing effluent streams, has had particularly strong growth in recent years. However, the big growth in pollution control is over and caustic's growth rate for this use likely will fall back to about the overall growth rate in chemicals manufacture.

Pulp and paper holds second spot among easily identifiable use areas for caustic. This use continues to have an above-average growth rate because of steady growth in demand for pulp and paper products and a trend toward more use of caustic per unit of production at the expense of chlorine.

Aluminum's use of caustic--converting bauxite ore to alumina for subsequent reduction to the metal--has been threatened by two factors. First, domestic U.S. alumina production has not been keeping up because of increased alumina imports. Second, concerted efforts to recycle aluminum metal are beginning to slow the growth in alumina demand.

Major uses of caustic soda are for diverse chemicals 50%, pulp and paper 15%, aluminum production 5%, textiles 5%, and petroleum refining 5%. There are no derivatives of sodium hydroxide produced on a commercial scale.

Additional sources peg chlorine growth at 5 percent for 1978 and caustic soda growth at 5 percent through 1980[20,27] or perhaps slightly lower at 4.2 percent.[21] These rates follow on prerecession growth rates of 6 to 7 percent in 1963 to 1973.[22] Capacity use at plants which coproduce chlorine and caustic soda will hover around 80 percent through 1978 for the second year in a row. This operating rate contrasts with historical and desired optimum rates of 96 percent or more in these highly efficient plants.[19] This below capacity production has resulted in a marginally tight supply for caustic soda. The cause of the present supply situation is a weak demand for chlorine. At one time, chlor-alkali plants were run mostly for chlorine output. Coproduct caustic, if not sold, was literally thrown away, even by dumping in the ocean. The situation is a lot different now. Production costs related to selling prices are such that neither product can be discarded or sold at bargain-basement prices. The result is that chlor-alkali units can be run economically only if reasonably good prices are obtained for both chlorine and caustic.

As basic chemicals, sodium hydroxide and chlorine, face stiff competition. Sodium carbonate is the main substitute for caustic soda[17] in such diverse chemical production processes as aluminum, glycerine, glycols, phosphates, silicates and sodium fluoride, the carbonate also replaces hydroxide in the NSSC pulp mills while sodium sulfate can replace sodium hydroxide in kraft pulp mills.[22] Sodium chlorate and ozone compete with chlorine in bleaching,[21] and peroxides and ozone are also replacing chlorine in water treatment processes;[17] but in the specialty chemical and plastics industry, chlorine has only limited competition from HCl.[17]

Geographic Considerations

Location of the salt fields is one of the factors which has to be taken into account in the siting of plants for the manufacture of chlorine and caustic. In the USA where more than one-third of the world's chlorine is made, about 75 percent of the output is from electrolysis of brine made in local salt fields. A significant portion of the other 25 percent is produced in the Pacific Northwest which receives its salt as a solid barged from Baja California. There the salt is produced by solar evaporation of sea water. In the case of Japan, which makes over 10 percent of the world's output of chlorine, all the salt needed has to be imported, almost entirely as salt from solar evaporation of sea water. Most European producers are near salt fields except in West Germany, the main European chlorine producer, where the development of the nineteenth century dye stuffs industry resulted in many chemical manufacturing sites remote from the salt fields. Today rock salt is mined and shipped to these electrolytic plants.(23) Salt requirements are about 1.8 tons/ton of Cl_2 produced. The delivered cost of the salt from Baja California to the Kenai coast is approximately $19/ton.

A second factor to consider in situating a chlor-alkali plant is the electric power cost and availability. The energy intensiveness of the industry may make this the overriding consideration.

Thirdly, transportation must be considered in the siting process. The technology of transporting the hazardous products of the process is well developed. Yet serious accidents do occur as shown by two recent fatality-causing releases in the southeast U.S. that have been in the newspaper headlines. The ICC controls transportation costs by setting freight tariffs and designating official territories. Railroads must file rate schedules as common carriers and barge traffic also provides competition. Marine transportation is certified by the U.S. Coast Guard and Pacific Northwest and British Columbia producers are known to barge chlorine and caustic along the Pacific Coast from Alaska to California for the paper industry.

However, chlorine and caustic soda are not generally shipped long distances because the products have a low value in proportion to weight which limits their competitiveness with locally produced products. Freight costs as a percent of sales price escalate rapidly the more distant the market. Each plant has a natural geographic marketing area that cannot easily be invaded by competing plants in distant localities.

The chlorine and caustic soda industry, therefore, is a market oriented industry.[24] Although caustic can be shipped economically if a water port is available, no ocean-going shipments of chlorine are known on a commerical scale.

IV. DEVELOPMENT AND OPERATING COSTS

Capital

Current capital costs for new plants or expansion range from \$100K/ton/day on the Gulf Coast[16,25] to \$133 K/ton/day and \$216K/ton/day in Sweden[12] and Brazil,[13] respectively, to \$260K/ton/day in Quebec, Canada.[26] However, due to the low capacity utilization profitability is less than needed. Depending on how the accounting is done, the level of return will range between insufficient for replacement of plants to sufficient for plant replacement but not high enough to outbid alternative investments. Producers' quarterly financial statements may very well continue to complain that one reason for poor overall profits is chlor-alkali operations doldrums.[19]

General capital cost calculations for chlor-alkali plants usually put plant pay back life at 15 years with a discounted cash flow at 20 percent. New plants are sized from 500 to 1,000 tons/day Cl_2. Capacity is continuing to expand though some projects have been scrapped due to the capacity glut.[21]

Labor

The labor requirement for a new 1,000 ton/day plant would be nearly 150 people not including marketing and shipping personnel or process engineers. The key to successful operation lies with supervision with only a small amount of training required for the shift workers. Therefore, an influx of skilled workers would not be required to run the plant. Construction of the facility would, of course, require skilled craftsmen during the construction period.

Development Time

There are no significant regulatory requirements for placing a new chlor-alkali plant other than normal environmental impact statements. EPA concern is significantly less than with those industries dealing in organic chemicals. Trouble spots are pH maintenance in the plant waste water effluent and the suspended solids which may appear in the neutralizing process. Chlorine emissions are of concern, but their control is well within today's technology limits. Construction time for a 1,000 ton/day plant is about 1-1/2 years. Though life spans for capital recovery purposes are 15 years, plant life expectancy may be as great as 40 years as evidenced by pre-World War II diaphragm cells now being replaced by new technology.[16]

Environmental Residuals

The major effluent stream will be an aqueous discharge stream containing dilute caustic and salt which will require neutralization. Neutralization often produces a suspended solids problem which also must be rectified. Purification of the aqueous salt cell feedstock often produces inorganic salt streams which require disposal, although this is used to precipitate calcium, magnesium and iron are precipitated with sodium hydroxide and sulfate is reduced by precipitation with barium chloride. The precipitates are allowed to settle, then are filtered from the cell feed.[23] Old cell membranes, if diaphragm cells are utilized, will also require disposal. A major environmental problem may result from the use of mercury cells. Specific constraints and technology for mercury control would have to be reviewed as they become available.

V. EXOGENOUS INFLUENCES

Visibility

Though chlorine gas has definite negative conotations, chlor-alkali plants apparently suffer little more public abuse than any other industrial chemical production site. The plants provide employment and are relatively clean. But two recent railroad accidents resulted in releases of chlorine gas which caused the deaths of several people in each case. This type of problem does not reflect on the production plant or even on the industry per se, but it does point out the difficulties of transportation safety of this hazardous chemical. Current information distributed by the popular press indicates that the Congress may even investigate the transportation of such hazardous chemicals, which could result in stricter regulations, which in turn translates to higher transportation costs. Of course, the chance of such hazardous spills and the transportation costs increase proportionately with the transportation distance. One might also expect that the amount of public outcry against shipping of such hazardous chemicals would also increase directly in proportion with the number of people subject to possible exponsure to the chemicals, which would, in most cases, be proportional to the distance transported.

International Trade

Foreign trade in chlorine is listed as negligible in all sources. The small amount of trade which does occur is mainly by barges in the Pacific Northwest and by railroad car between the U.S. and its North American neighbors. Exports of caustic soda are expected to drop from 10 percent of production in 1977 to about 5 percent in 1978. The reasons behind the shrinking exports are strong domestic selling prices and increased production from foreign plants.(19)

VI. CONCLUSIONS

Although mercury cells have several advantages including easier shutdown operation, less maintenance and repair, less steam requirement and lower capital cost for evaporating equipment, there remain several drawbacks. Electrical power cost is greater for the electrolysis, floor area requirements are greater and the mercury inventory cost is substantial. The initial inventory of mercury for a 1,000 ton/day plant could cost up to $7.5 million. Research and development in the area of mercury containment will probably continue, but the main thrust for new plants appears to be in the use of permselective membrane systems. The main advantage of such systems is their lower total power requirement when considering both the electrolysis and the product concentrating step.

The chlor-alkali industry is market oriented and, as such, plants have been built all across the country wherever needed. The products are so basic that the need exists (and therefore a plant exists) in almost every major industrial area of the country. The market allows for only a small distribution area. In Alaska, for example, there are two paper/pulp plants which are likely customers; and although there are nearly 40 other paper/pulp plants in Washington, Oregon, Idaho and Northern California accessible by water with nearly 20 percent of the nation's capacity for paper,[28] there are also six chlor-alkali plants in the same region. Alaskan chlorine and caustic soda would have to compete with Pacicif Northwest products which are produced with cheap hydropower. Raw material cost is 30 percent higher in Alaska for Baja Californian salt, and some consideration would have to be given to developing a salt deposit known to exist at the southern end of the Alaskan panhandle.[20] Penetration into the Japanese market remains only a remote possibility for an Alaskan plant; ocean-going chlorine is almost unheard of. A Japanese subsidiary of Dow Chemical only recently was allowed to build a new chlor-alkali plant in Japan after months of haggling with that country's economic controllers. The new 1,100 ton/day plant will be built on Japan's northernmost island and was strongly opposed by Japan's domestic chlor-alkali industrialists.[29] Attempts to market Alaskan caustic soda or chlorine in Japan would most likely be met by stiff resistance.

Transportation remains the major point of contention. Unless questionable local sources of salt can be developed, an Alaskan chlor-alkali plant will be at a distinct disadvantage due to higher raw material costs. Transportation of the products is a risky business, and, unless further industrial development is made locally to provide new markets, long transportation distances will be required. Long transportation distances not only add cost to the product, but also increase chances of public exposure to the chemicals and the possible resultant regulatory consequences.

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9.5 LIME INDUSTRY

A. GENERAL CHARACTERISTICS

1. Locations of Major Producing Regions

Lime is commercially produced in 30 of the continguous 48 states as well as in Hawaii and Puerto Rico. In 1972, the States of Ohio, Pennsylvania, Missouri, Texas, Michigan, and Illinois produced 61% of the total U.S. lime output.(1) The greatest concentration of commercial lime plants appears to be in the Great Lakes region.

2. Markets

There appears to be very few markets for lime in Alaska. According to the U.S. Army Corps of Engineers in 1976, only 826 tons of lime was shipped by water into Alaska for the whole year.(2) A 1967 Census of Transportation by the U.S. Department of Commerce showed that over 80% of lime shipped in 1967 was transported less than 300 miles.(1) This indicates that the lime industry markets tend to be of a localized nature.

3. Industrial Structure

In 1972 the U.S. Bureau of Mines reported the total number of active lime plants, both commercial and captive, as being 186 plants.(1) Of these about 100 were commercial plants. In 1972, 10 companies operating 30 plants accounted for 45% of the total lime production.(1)

4. Process Description

Fundamentally there are no differences in the types of processes used in the production of lime. Basically the only differences are in the calcination steps involved in different plants. There are four possible types of calcining kilns--rotary kilns, vertical kilns, rotary hearth kilns, and fluidized solids kilns. Of these four types of kilns, the rotary kilns and the vertical kilns are most widely used. Therefore, in this study, the lime industry was evaluated according to processes involving either rotary kilns or vertical kilns.

The manufacture of lime involves five basic steps:

- acquisition of raw materials,
- processing of raw materials,
- calcining,
- processing of quicklime, and
- hydration of quicklime.

Limestone is the raw material for producing lime and is acquired by quarrying/mining. The limestone is then transported to the lime plant. The raw materials are processed by crushing and screening the limestone to 6 ft-8ft sized chunks. These chunks can be fed to a vertical kiln at the point or they can be crushed, screened, and classified in order to be fed to a rotary kiln. The calcination step involves heating the limestone in the kiln in order to drive off carbon dioxide. The quicklime is processed by crushing pulverization. At this point the quicklime could be sold but if it is not used relatively soon after production it will absorb moisture and carbon dioxide from the air. Therefore, for better storage most of the quicklime is hydrated by adding water to the quicklime. This hydrated lime (or slaked lime) is more readily stored for future use.

5. Trends in Process Development

The basic trend in the lime industry is toward larger plant sizes with the smaller, less economical plants becoming inactive.

6. Economic Plant Scale

As already mentioned the economical plant scale trend is toward the larger plants. In 1972, according to the U.S. Bureau of Mines, 36% of the lime plants had capacities greater than 200,000 short tons/year whereas these same plants produced 65% of the total lime output.

For this study, only 3,045,000 short ton/year plants were evaluated because of the limited demand for lime in Alaska and the high rates of transportation for the low value of lime on the economic market.

7. Capital Costs

The capital cost per the hypothetical 30,000 short ton/year vertical kiln plant was calculated to be $4,149,000. This assumes that a vertical kiln producing 100 tons/day costs $1,600,000 and that this cost is only 70% of the fixed capital cost. A 1.65 scale-up factor to adjust costs from the Lower 48 states to the costs in Alaska is also assumed. This total capital cost consists of fixed-capital and working capital but it does not include the cost of the land on which the plant is built. This capital investment represents about $138/ton of lime produced per year.

The capital cost for the hypothetical 45,000 short ton/year rotary kiln plant was calculated to be $1,815,000. This includes a 1.65 scale-up factor from costs in the Lower 48 states to costs in Alaska and fixed capital and working capital. This cost does not include the cost of the land on which the plant is built. This capital investment represents about $40/ton of lime produced per year.

8. Labor Requirements

The total number of employees estimated to be needed to run the vertical kiln lime plant is 25 employees. This represents about 1 employee/4 tons of lime produced per day. The total number of employees estimated to be needed to run the rotary kiln plant is also about 25 employees. This represents about 1 employee/6 tons of lime produced per day.

9. Data Cost Sheets

10. References

(1) Industrial Energy Study of the Concrete, Gypsum, and Plaster Products Industries, PB-237-833 by Stanford Research Institute for Federal Energy Administration and U.S. Bureau of Mines, August 1974.

(2) Waterborne Commerce of the United States, Calendar Year 1976, Part 4 Waterways and Harbors, Pacific Coast, Alaska, Hawaii, by the Department of the Army Corps of Engineers.

1.	Process - Lime Production, Rotary Kiln	
2.	Capacity - 45,000 TONS/YR, 150 TONS/DAY, 300 DAYS/YR[1]	
3.	Capital Investment - $1,815,000[2]	
4.	Feedstock Requirements - 130,000 TONS/YR[3]	
5.	Total Product Costs	
	I. Manufacturing Costs -	
	A. Direct Production Costs	
	1) Feedstock Costs	$390,000[4]
	2) Chemicals	-0-
	3) Direct Operating Labor	$259,000[5]
	4) Direct Supervision @ 10% of Direct Operating Labor	$ 26,000
	5) Utilities	
	Fuel (as coal) @$1.00/$10^6$BTU	315,000[6]
	Electrical Power @ $0.04/KWH	86,000[7]
	Process Water @ $1.00/1000 GAL	36,000[8]
	6) Maintenance @ 2% fixed capital	33,000
	7) Operating supplies @ 10% of Maintenance	3,000
	A. TOTAL	$1,148,000
	B. Fixed Charges	
	1) Depreciation, 10% S.L.	$ 165,000
	2) Taxes and Insurance @ 2% of Fixed Capital	33,000
	B. TOTAL	$ 198,000
	C. Plant Overhead @ 50% of I.A.3, I.A.4, and I.A.6	159,000
	II. General Expenses @ 15% of I.A.3, I.A.4, and I.A.6	48,000
6.	Total Annual Product Cost	1,553,000
7.	By-Product Credits:	-0-
8.	Net Product Cost	1,553,000
9.	ROI, 25% before Taxes on Fixed-Capital Plus 10% on Working Capital	429,000
10.	Net Costs and ROI	1,982,000
11.	Net Transfer Price/TON LIME	44.04
12.	Shipping Costs/Ton Lime	$40 - $125[9]
13.	Current Price/Ton Lime	$50[10] F.O.B. Portland

FOOTNOTES

(1) Based on communication with Mr. Schaeffer of Fuller Co. in which he stated that the smallest rotary kiln Fuller makes is 150 T/D kiln.

(2) Based on the low figure of $1,000,000 fixed capital for a 150 T/D rotary kiln lime plant in the lower 48 states from Fuller Co., 1.65 factor to Alaska, and 10% of fixed capital being working capital.

(3) Based on BCL estimate that 2.88 tons of limestone is needed per ton of lime produced.

(4) Based on a figure of $3/ton for limestone (same value as used in the cement section)

(5) Based on 4 men per shift, 8 hr. shifts, 7 days/week, 300 days/year, $9/hr, 3 shifts per day.

(6) Based on an estimate of $7X10^6$BTU/ton lime for an average rotary kiln from PB-237-833 (Stanford Research Institute)

(7) Based on an estimate of 48 KWH/ton lime (based on numbers for crushing & calcining in the BCL report)

(8) Based on a value of 0.4 GAL/LB lime (assumed the same as for a cement plant from Plant Design and Economics for Chemical Engineers, M.S. Peters and K.D. Timmerhaus, McGraw-Hill Book Company, Second Edition, 1968, page 133).

(9) $40 value is based on the difference of price/ton of cement in Seattle and Ankorage, and the $125 value is a very rough guess from an Ash Grove Cement Company representative for shipping lime from Portland to Alaska.

(10) Based on current prices F.O.B. Portland given in phone call to Ash Grove Cement Company.

1. Process - Lime Production, Vertical Kiln
2. Capacity - 30,000 TONS/YR, 100 TONS/DAY, 300 DAYS/YR[1]
3. Capital Investment - $4,149,000[2]
4. Feedstock Requirements - 86,400 TONS/YR[3] Limestone
5. Total Product Costs

I. Manufacturing Costs -		
A. Direct Production Costs		
1) Feedstock Costs	$ 259,000	(4)
2) Chemicals	-0-	
3) Direct Operating Labor	160,000	(5)
4) Direct Supervision @ 10% of Direct Operating Labor	16,000	
5) Utilities		
Fuel (as oil)[6] @ $\$2.00/10^6$BTU	324,000	(7)
Electrical Power @ $0.04/KWH	12,000	(8)
Process Water @ $1.00/1000 GAL	24,000	(9)
6) Maintenance @ 2% Fixed Capital	75,000	
7) Operating Supplies @ 10% of maintenance	8,000	
A. TOTAL	$ 878,000	
B. Fixed Charges		
1) Depreciation, 10% S.L.	$ 377,000	
2) Taxes and Insurance @ 2% of Fixed Capital	75,000	
B. TOTAL	$ 452,000	
C. Plant Overhead @ 50% of I.A.3, I.A.4, and I.A.6	$ 126,000	
II. General Expenses @ 15% of I.A.3, I.A.4, and I.A.6	$ 38,000	
6. Total Annual Product Cost	$1,494,000	
7. By-Product Credits:	-0-	
8. Net Product Cost	$1,494,000	
9. ROI, 25% Before Taxes on Fixed-Capital Plus 10% on Working Capital	$ 981,000	
10. Net Costs and ROI	$2,475,000	
11. Net Transfer Price/TON LIME	82.50	
12. Shipping Costs/TON LIME	$40-$125	(10)
13. Current Price/TON LIME F.O.B. Portland	50.00	(11)

FOOTNOTES

(1) Based on communication with Mr. Gory of Kennedy Van Saun. 100 TON/DAY was the smallest size of vertical kiln that was still economical (smallest Van Soun makes is 60-75 T/D)

(2) Based on an equipment cost figure for a 100 TON/DAY vertical kiln at $1,600,000 and assuming that the equipment cost is 70% of the fixed capital, 1.65 factor to Alaska, and 10% of fixed capital being working capital.

(3) Based on BCL estimate that 2.88 TONS of limestone is needed per ton of lime produced.

(4) Based on a figure of $3/ton for limestone (same value used as in cement section).

(5) Based on 2 men, 8 hr shift, 5 days/week; 6 men, 8 hr shift, 7 days/week; 300 days/year; $9/hr.

(6) Oil is used because of the vertical kiln specification.

(7) Based on estimate of 5.4 X 10^6BTU/ton lime from PB-237-833 (Stanford Research Institute).

(8) Based on an estimate of 10KWH/ton lime (based on numbers for crushing and mining in BCL report)

(9) Based on a value of 0.4 GAL/LB lime (assumed the same as for a cement plant from Plant Design and Economics for Chemical Engineers, M.S. Peters and K.D. Timmerhaus, McGraw-Hill Book Company, Second Edition, 1968).

(10) $40 value is based on difference of price/ton of cement in Seattle and Ankorage, and the $125 value is a very rough guess from Ash Grove Cement Company representative for shipping lime from Portland to Alaska.

(11) Based on current prices F.O.B. Portland given in phone call to Ash Grove Cement Company.

9.6 METHANOL FROM COAL

Process Description

Nearly all the methanol produced in the United States uses natural gas as feedstock, while the rest of the world depends heavily on naphtha and other hydrocarbons. When natural gas and naphtha are used as feedstocks, they are steam reformed to produce a synthesis gas. When heavier hydrocarbons are used as feedstock, they are gasified by partial oxidation with steam and oxygen in a gasifier to form synthesis gas. The synthesis gas from the reformer or gasifier is then pressurized and subsequently converted into methanol in a catalytic packed converter. Two major types of converters are used. The older ones operate at 200-300 atm and 300°C with zinc/chromium oxide catalysts. Newer units use copper catalysts and operate at 50-100 atm and 250-270°C. The methanol produced from the converter is ready to be used as methyl-fuel. Commercial grade methanol is obtained by the distillation of crude methanol.

As mentioned early, the feedstock for the methanol synthesis in the U.S. is exclusively natural gas. However, as natural gas reserves are depleted, coal will be the logical choice to replace it as the feed material for the methanol synthesis. The development of the advanced coal gasification processes, which effectively convert coal to gas, makes the methanol synthesis gas from coal similar with that from natural gas. With 200 billion tons of proven minable coal and lignite reserves in the U.S. there should be no problem in supplying the raw material required for the future methanol and methyl-fuel synthesis for this country.

A schematic process flow sheet for methanol synthesis via coal gasification processes can be constructed as shown in Figure 9.1. Coal from storage is crushed to proper size and charged into coal feed lock hoppers. If the process is operated at atmospheric pressure, coal can be fed directly into the gasifier. Coal, in the gasifier, is converted to a gas stream containing mainly CO and H_2 by steam, oxygen (or air), and other gasifying media. The gasifier effluent is then passed through

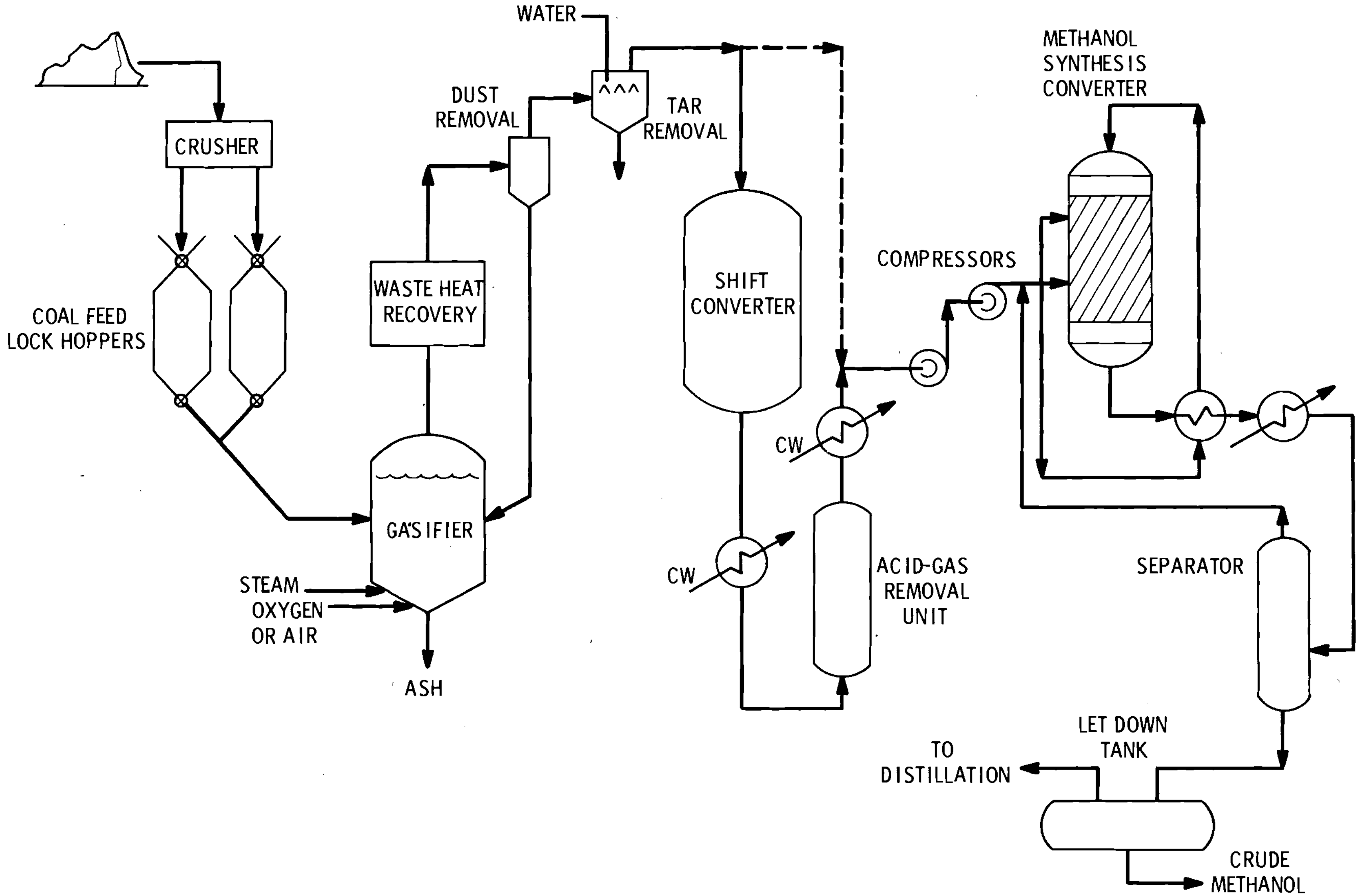

FIGURE 9.1. Methanol Synthesis via Coal Gasification Processes

a dust collector and scrubber to remove particulates and tar from the gas stream. Depending upon the type of process and operating conditions the composition of the gasifier effluent varies substantially. If the proportions of CO, CO_2 and H_2 in the gas is correct and the sulfur content is low enough for the methanol synthesis, the gas is pressurized and directly introduced to the methanol converter. However, in most cases, the gases generated from gasifiers require some adjustments in gas composition and purification to remove undesired impurities before they are used for the methanol synthesis. CO/H_2 and CO_2/H_2 ratios can be adjusted by passing the gas through a shift converter and/or a CO_2 removal unit. Sulfur compounds (mainly in the form of H_2S) can be removed from gas stream by monoethanol amine, hot potash, rectisol processes, and others. The cleaned synthesis gas is then pressurized and fed into various methanol synthesis loops. The crude methanol produced from the converter, after pressure letdown is ready to be used as methyl-fuel. If pure methanol is desired, distillation of the crude methanol is required.

Process Economics

Producing methanol from coal cannot compete with steam methane reforming at current natural gas prices on the Gulf Coast (∿\$2.00/million Btu) as can be seen in the following process work sheet. Improvements in gasification technology which allow pressurization of the gasifier (which traditionally has been run at atmospheric pressure) would trim both capital and operating costs for production of methanol from coal.(3) A 10-15% reduction in capital and operating costs would reduce methanol costs by 3¢/4¢/gal.

Assuming these improvements in gasification technology are made and natural gas rises to \$2.25/million Btu, coal at approximately \$0.50/million Btu (∿\$10/ton) is required to compete with natural gas. (In Alaska methanol from coal still could not compete due to significantly higher capital and operating costs.)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Methanol Production from Beluga Coal
2. Capacity 5000 ton/day fuel gate methanol 3. Capital Investment $573 mm
4. Feedstock Requirements 1,194,000 lb/hr Beluga Coal ($100 Btu/lb, 25% moisture)
5. Operating Costs:

A. Feedstock Costs @ $1.00/10^6 Btu	$76.3 x 10^6/yr	
B. Catalysts and Chemicals	$ 1.5 x 10^6/yr	
Total		$ 77.8 x 10^6/yr
C. Utility Requirements		
Fuel @ $1/10^6 Btu (coal)	$11.0 x 10^6/yr (172,000 lb/hr Beluga Coal)	
Electrical Power @ $0.025/kWh	$11.2 x 10^6/yr	
Cooling Water Makeup @ $1.20/Mgal	$ 2.0 x 10^6/yr	
Boiler Feed Water @ $2/Mgal	$ 2.6 x 10^6/yr	
Waste Water Treatment @ $1.90/Mgal	$ 0.9 x 10^6/yr	
Cooling Water Circulation @ $0.03/Mgal	$ 0.4 x 10^6/yr	
Total		$ 28.1 x 10^6/yr
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 80 @ $30,000/yr. (includes benefits)	$ 2.4 x 10^6/yr	
Supervision, @ 20% of Operating Labor	$ 0.5 x 10^6/yr	
Maintenance, @ 4% of Capital Plant	$20.9 x 10^6/yr	
General Administrative and Overhead @ 100% of Labor	$ 2.4 x 10^6/yr	
Taxes and Insurance, @ 2% of Capital Plant	$10.5 x 10^6/yr	
Depreciation, 10% S.L.	$52.3 x 10^6/yr	
Total		$ 89.0 x 10^6/yr
6. Total Annual Manufacturing Costs		$194.9 x 10^6/yr
7. Co-product/By-product Credits:		-
Total		
8. Net Manufacturing Cost		$194.9 x 10^6/yr
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$135.8 x 10^6/yr
10. Net Costs and ROI		$330.7 x 10^6/yr
11. Net Transfer Price $/gal		$ 0.67
12. Shipping Costs (Ship or barge to West Coast) $/gal		$ 0.03
13. Total Costs $/gal West Coast FOB		$ 0.70
14. Current Price $/gal West Coast FOB		$ 0.47

(a) Includes development of transportation from mine mouth to north shore at Cook Inlet. Also includes development of terminal facilities on the north shore. (∿$80 mm)

Economic Plant Scale

The approximate minimum reference size for a coal to methanol plant has been estimated to be 5,000 to 15,000 bbl/day (700-2100 tons/day). The most economic size would appear to be 20,000 to 35,000 bbl/day (3000 to 5000 tons/day).[(1)]

Capital Costs

Table 1 gives estimated capital costs for coal to methanol plants.

TABLE 1. Coal to Methanol - Capital Costs

Reference	Size Tons/D MeOH	Coal Type	Gasification Process	Capital Investment $M At Time of Study	Capital Investment $M Estimated 1978
(2)	5000	Easkin Bit.	Koppers-Totzek	253 (1974)	345
(2)	5000	West. Subbit.	Winkler	241 (1974)	330
(3)	5000	-	Winkler	273 (1975)	330

A similar plant built in the Cook Inlet area would cost approximately $495 million in 1978 dollars based on 50% increase in capital costs for this area. Additional capital investment would be required to develop a transportation system to move the coal from the Beluga fields to the north shore of the Cook Inlet (14-24 miles) and a shipping terminal would have to be built on the north shore. This additional capital investment is estimated at $80 million[(4)] bringing the total capital investment to $575 million.

Markets

Methanol is produced at 11 plants in the U.S. with a total capacity of 1312 million gallons annually. All 11 plants are located in the Gulf Coast area. (See Table 2.) Demand for methanol was 1015 million gallons in 1977 and has grown at 6.2 percent per year over the past 10 years. Future growth is predicted to be 6-8 percent per year through 1981. Current price for methanol is $0.44/gal FOB Gulf Coast.

Table 3 shows the uses of methanol. Forty-three percent of the methanol produced goes to synthesis of formaldehyde. A significant portion ($\sim$15%) of formaldehyde production is in the Pacific Northwest. (This would seem to be the logical market for methanol produced in Alaska.) Formaldehyde is expected to grow at 7-8 percent per year through the next 5 years. Acetic acid is the fastest growing end-use for methanol and is likely to take a larger share as this technology becomes more widely used.

The possibilities for methanol in the future are myriad--transportation fuel, protein synthesis, steel manufacture, sewage treatment, and peak power generation represent only a partial list. The leap from theory to commercial use will depend on a number of factors, including coal gasification technology, international politics, and allocation of capital for pilot plants. One major expansion is now set for the late 70s and one is a good possibility. Other expansions will most likely come in the form of incremental revamping and process improvement.

TABLE 2. U.S. Methanol Production[5]

Producer	Capacity[a]
Air Products, Pace, FL	50
Borden, Geismar, LA	160
Celanese, Bishop, TX	150
Celanese, Clear Lake, TX	230
DuPont, Beaumont, TX	200
DuPont, Orange, TX	100
Georgia-Pacific, Plaquemine, LA	120
Hercules, Plaquemine, LA	100
Monsanto, Texas City, TX	100
Rohm & Haas, Deer Park, TX	22
Tenneco, Houston, TX	80
Total	1312

(a) Capacity in millions of gallons annually.

TABLE 3. Uses of Methanol[6]

Formaldehyde synthesis	45
Methyl halides	4
Methylamines	4
Methyl methacrylate	4
Dimethyl terephthalate	7
Solvent uses	10
Other	26
Total	100

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9.7 PETROLEUM REFINING

Petroleum refining is the separation and processing of crude oil fractions into various salable products. The products produced and the processing schemes used are different for every refinery depending on the crude oil type and the product slate desired. Closely related to petroleum refining is the production of petrochemicals from refined products. Figure 1 shows a block flow diagram of a multipurpose refinery and petrochemical complex.

Crude oil distillation is the major initial operation in nearly all refineries. The oil is separated into six major fractions according to their respective boiling points. From lowest to highest boiling points these are light ends (C_4 and lighter), straight run gasoline, naphtha, kerosene, gas oil, and reduced crude.

The light ends cut is treated to remove sulfur (usually H_2S) and then is either sold (LPG), used as refinery fuel, or used as in-plant process feed (alkylation, hydrogen production, or olefin production). Straight run gasoline goes directly to the gasoline blending pool or is subjected to isomerization for octane improvement and then goes to the gasoline blending pool.

The naphtha cut is hydrotreated to remove sulfur and then is catalytically reformed. Catalytic reforming produces a high octane stream containing high quantities of aromatics. Reformed light naphtha typically is used as feed to an Aromatics Complex for production and/or recovery of BTX (benzene, toluene, and xylene) and other aromatics (cumene, ethylbenzene, etc.). Reformate from heavy naphtha goes to the gasoline pool. Naphtha is also the most common feedstock for olefins production.

The kerosene cut is treated to remove sulfur and goes to the distillate blender. The main products of the distillate blender are jet fuel, diesel fuel, and No. 2 fuel oil.

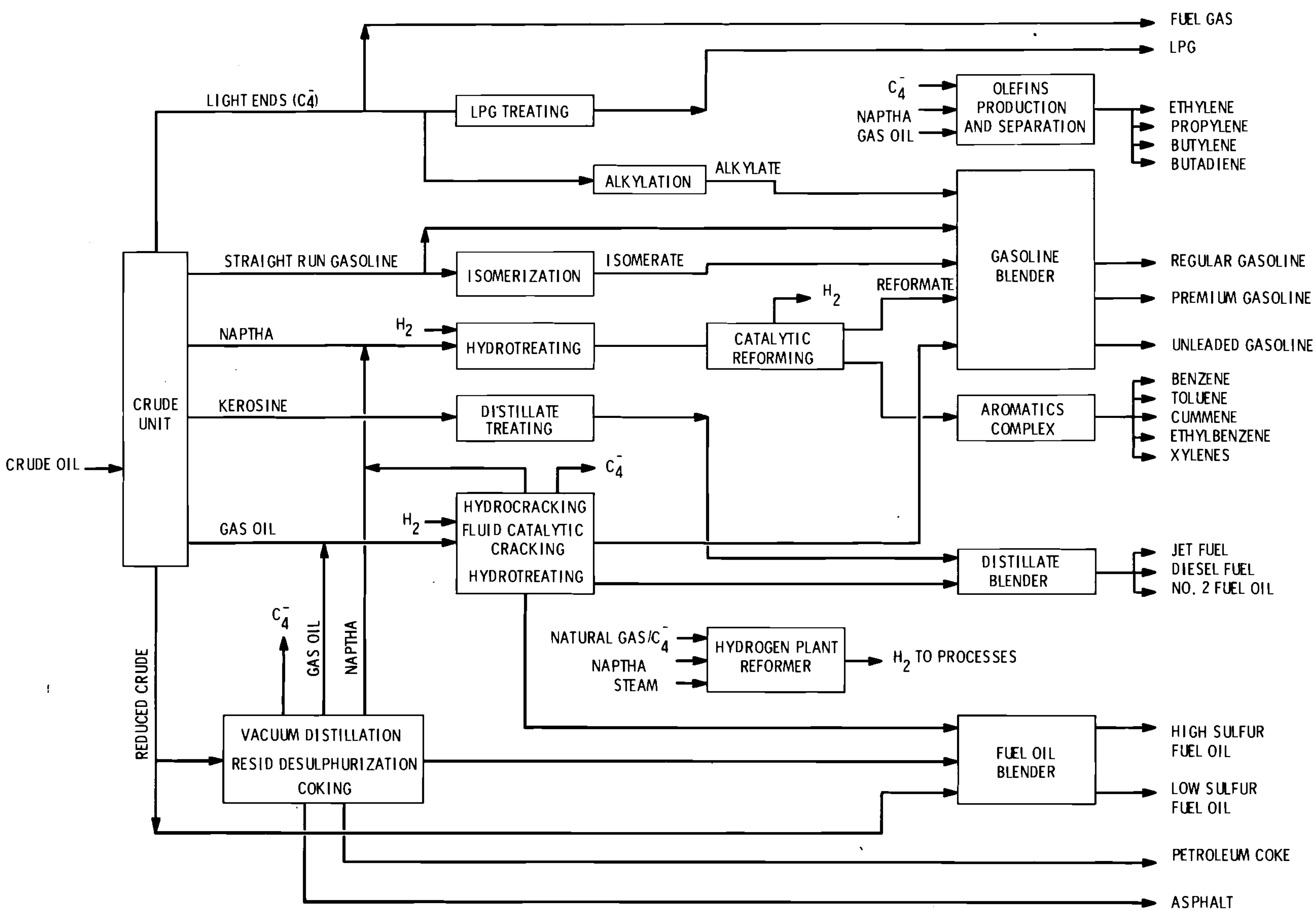

FIGURE 1. Multipurpose Refinery and Petrochemical Complex Block Flow Diagram

There are several processing options for the gas oil cut depending on crude oil type and desired product slate. If the refinery is gasoline oriented, the light gas oil can be hydrocracked to gasoline and other distillates. Heavy gas oil goes to the fluid catalytic cracker which produces additional gasoline and distillates as well as a heavy fuel oil. If the refinery is oriented toward residual fuel oil production, the gas oil is hydrotreated to remove sulfur and then goes to the fuel oil blender. Depending on the sulfur content of the gas oil and the desired sulfur content of the fuel oil, gas oil may go directly to the fuel oil blender.

As with gas oil there are several options for reduced crude processing. In a residual fuels oriented refinery the reduced crude is either hydrotreated in a residium desulfurizer to produce a low sulfur fuel oil or goes directly to the fuel oil blender depending on the fuel oil sulfur content desired. To produce additional gasoline and distillate the reduced crude can be vacuum distilled into additional gas oils and a vacuum residium. Depending on crude type the vacuum residium can be used directly as asphalt or as fuel oil. It also can be fed to a residium desulfurizer to produce low sulfur fuel oil, or it can be fed to a coker to produce additional gas oils and distillates and petroleum coke.

The gasoline blender combines all the gasoline streams in the refinery and various additives to produce regular, premium, and unleaded gasoline. The distillate blender combines various distillate streams to produce jet fuel, diesel fuel, and No. 2 fuel oil. The fuel oil blender combines various residual fuel oil streams to produce residual fuel oils of various sulfur contents.

Production of basic petrochemicals from refinery feedstocks is often considered part of the refining process. The most common applications are production of olefins (ethylene, propylene, butylene and butadiene) by cracking naphtha, and recovery and separation of benzene toluene, and xylenes from catalytic reformate by extraction and distillation.

Synthesis of cumene, ethylbenzene and other more complex aromatics is also commonly part of the refining process.

Trends in Process Development

Table 1 shows the production of U.S. refineries in 1955 and 1975. The past 20 years have resulted in only small changes in the product slate (increasing jet fuel production, and decreasing residual fuel production); however, it appears that during the next 20 years significant changes will take place due to depletion of the world's petroleum reserves. It is generally agreed upon that in the long term (2001) petroleum refineries will be used only for production of transportation fuels (gasoline, diesel, and jet fuel) and for petrochemicals. These are the areas where it will be most difficult to replace petroleum with alternate energy sources.

Coal and nuclear will gradually take over in the field of producing electricity. Natural gas, electricity, and solar energy will dominate home heating and coal will be dominant in industrial heating applications including petroleum refineries. This leaves transportation fuels and petrochemicals for petroleum.

With regard to transportation, only methanol used with gasoline or by itself appears likely to have an impact between now and the end of the century. Syncrudes from shale oil and coal are not expected to make significant contributions in this century.

Coal and natural gas based petrochemical production is viable; however, coal is better suited to power generation and the demand for natural gas for home heating is not likely to leave significant quantities available for petrochemical production.

In the short term (1980s), however, refiners may be forced to shift toward increased production of residual and distillate fuels. Development of nonpetroleum energy sources (principally coal and nuclear) has been slowed tremendously. Imported petroleum and increased production of

TABLE 1. Yield and Throughput U.S.[1] Refinery Industry

Product	% Volume 1955	% Volume 1975
Gasoline	46.4	49.6
Jet fuel	2.0	6.6
Kerosene and distillate fuel oil	25.1	21.2
Residual fuel oil	14.7	9.3
Lubes, wax, coke, and asphalt	6.0	7.0
Other	5.8	6.3
TOTAL	100.0	100.0
Total throughput, 1,000 b/d	7,857	13,224

residual fuels appears to be the only means of making up for recent delays in development of nuclear and coal energy.

Economic Plant Scale

It appears that feed rates of processing units are approaching their maximum economic size. New crude units will not be substantially larger than 200,000 B/D, cracking units larger than 80,000-100,000 B/D, nor catalytic reformers larger than 30,000-50,000 B/D. Small refineries, capacity under 50,000 B/D, are economically viable under certain special conditions.

Energy and Utility Requirements

Table 2 shows typical energy and utility requirements for a petroleum refinery. Overall, refineries consume the energy equivalent of approximately 10% of the crude they process. New refineries, by making greater use of heat exchangers, improving furnace efficiencies, and providing closer process integration, may reduce the energy required by about 25%.

TABLE 2. Refinery Energy and Utility Requirements[2]

Steam	10-50 lb/bbl
Recirculating Cooling Water	200-800 gal/bbl
Power	1-5 kWh/bbl
Water Consumption	1 bbl/bbl
Fuel	300×10^3-600×10^3 Btu/bbl

Capital Cost

The capital cost of a petroleum refinery varies significantly depending on the crude type to be processed and the desired product slate. Table 3 shows the effect of crude type on capital cost for grass roots refineries of various sizes. The capital costs are for a refinery of average complexity, located on the Gulf Coast, producing mainly transportation fuels (gasoline, diesel, and jet) and heating fuels (home heating oil and residual fuel).

TABLE 3. Capital Costs of Petroleum Refineries[3]

Refinery Type		Capital cost, $MM	
Mbpsd	Feedstock	1970	1977
250	Lt. Arab.	383	515
250	Low sulfur	229	307
150	Lt. Arab.	259	349
15	Lt. Arab.	40	54
15	Low sulfur	22	29

A similar refinery located on the Kenai Peninsula, processing 150,000 b/d of Alaskan North Slope crude cans, would have a capital cost of approximately $525 million. Basic capital costs for North Slope and Arabian Lite would be similar. North Slope is lower in sulfur (1.04% to 1.8%)[4] so less desulfurization would be required; however, North Slope is also heavier (28° API to 33° API)[4] so additional cracking would be required. The major difference is the relocation to the Kenai Peninsula from the Gulf Coast which results in approximately a 50% increase in capital costs.

A somewhat more complex refinery producing significant quantities of olefins and aromatics in addition to transportation fuels and residual fuels would have capital costs approximately 50% higher ($525 million - Gulf Coast, $765 million - Kenai Peninsula). For a refinery producing only transportation fuels and petrochemicals (olefins and aromatics) capital costs would be 100-150% higher ($875 million - Gulf Coast, $1315 - Kenai Peninsula).

Labor Requirements

It has been estimated that a world scale refinery in Alaska would provide permanent employment for over 400 people at the refinery and indirectly would result in permanent employment for over 600 more people most of whom would be Alaskans. During construction the labor force would average approximately 2600.[5]

Lead Time

The lead time required to bring new petroleum refining facilities on stream varies from 3 to 6 years, depending on the size and complexity of the refinery.

Marketing

The Petroleum Administration for Defense District (PADD) V consisting of the States of Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington is the closest market for refined products from an Alaskan refinery and as a result it is the most attractive market since transportation charges are the lowest of any market area. Forecasts for the demand for refined products in PADDV are presented in Table 4.[6]

To meet the demand for these products PADDV refineries currently are processing a crude mix of heavy, high sulfur, California crude; light, low sulfur, Indonesia crude; light, high sulfur, Arabian crude and some Alaskan North Slope crude. The number and capacity of refineries

TABLE 4. Product Demand - PADDV (1976-1985)[6]
(1000 barrels/day)

	1976		1977		1978		1979		1980		1981	1982	1983	1984	1985
	b/d	%	b/d	%	b/d	%	b/d	%	b/d	%					
Gasoline[a]	1030	43.8	1080	41.1	1120	41.5	1150	41.9	1180	42.2					
Jet Fuel	290	12.3	290	11.1	300	11.1	315	11.5	330	11.8					
Mid-Distillate	285	12.1	340	12.9	365	13.5	390	14.2	420	15.0					
Residual	445	18.9	575	21.9	550	20.4	520	18.9	485	17.3					
Other	300	12.8	340	12.9	360	13.4	370	13.5	380	13.6					
Total	2350	100	2625	100	2695	100	2745	100	2795	100					
Total[b]					2625		2725		2810		2865	2920	2975	3005	3035
TOTAL	2350		2625		2695		2725		2810		2865	2920	2975	3005	3035

SOURCE: (a) The Near-Term Outlook for Petroleum Demand in District V, W. J. Levy Consultants Corp., New York, December 1977.
(b) Based on conversations with oil companies operating on the West Coast.

TABLE 5. Number and Capacity of Petroleum Refineries in PADDV (6)
(January 1, 1977)

Refining District, PADD District and State	Petroleum Refineries (Number)			Crude Oil Distillation — Crude Oil Throughput Capacity (Barrels per Calendar Day					
					Operable		Inoperable		
	Total	Operating	Shutdown	Total	Operating	Shutdown	Shutdown	Total	Building
PADDV									
Alaska	2	2	-	60,000	60,000	-	-	60,000	25,000
Arizona	1	1	-	5,000	5,000	-	-	5,000	-
California	40	40	-	2,326,320	2,081,942	244,378	6,000	2,332,320	1,500
Hawaii	1	1	-	40,000	40,000	-	-	40,000	-
Nevada	1	-	1	-	-	-	500	500	2,500
Oregon	1	-	1	14,000	-	14,000	-	14,000	-
Washington	8	7	1	367,900	363,400	4,500	-	367,900	1,500
Total	54	51	3	2,813,220	2,550,342	262,878	6,500	2,819,720	30,500

SOURCE: U.S. Department of the Inrerior, Bureau of Mines, Petroleum Refineries in the United States and Puerto Rico, January 1, 1977.

in PADDV is given in Table 5. Comparing the total refinery capacity in PADD (Table 5) with the total product demand in PADDV (Table 4) indicates there is significant overcapacity in the region (2.8×10^6 B/D capacity - 2.35×10^6 B/D demand). Very little capacity was being added as of January 1977. No major expansion in refining capacity is planned in the region, and it is doubtful that an expansion will take place until the present uncertainty over a national energy policy is resolved.

This lack of planned expansion comes despite the large surplus of crude oil available on the West Coast as a result of introduction of Alaskan North Slope crude oil into the market. Alaskan North Slope cannot directly replace imported crude oil on the West Coast. Alaskan North Slope is significantly heavier than Indonesian and Arabian imports and existing PADDV refineries cannot totally replace imported crude with ANS and meet the product demand slate for the region. The current surplus on the West Coast is 400,000 B/D which is being shipped to the Gulf Coast and Virgin Islands via the Panama Canal. It has been estimated that the surplus crude available on the West Coast may reach 725,000 B/D by 1985.[7]

Due to its lower quality and the required product slate on the West Coast, ANS is currently and will likely remain the surplus crude.

Assessment of Market Conditions

Since the 1973 oil embargo the petroleum industry has operated in a rather uncertain manner. Few long term capital and contractual commitments have been made. More recently, the industry is trying to anticipate the impact of the proposed National Energy Policy. Based on this cautious investment philosophy and the current over capacity on the West Coast it is unlikely that any expansion on the refinery capacity on the West Coast will be planned in the next few years. Should any expansion occur it would most likely be an addition or modification to an existing facility.

A grass roots refinery specifically designed for Alaskan North Slope crude and planned to come on stream after 1985 (by which time demand may finally exceed refining capacity in PADDV) is a possibility. If this were to come about California would be the favored location over Alaska due to the higher capital costs in Alaska; however, environmental concerns in California might make it impossible to build such a facility.

A company or group of companies with a demand for refinery products (residual fuel for power plants, feedstock for petrochemicals, etc.) that would like to secure their own source of crude oil might be willing to build a refining complex in Alaska to obtain Alaska's royalty oil. This would appear to be the only way a petroleum refinery is likely to be located in the State of Alaska.

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6. "North Slope Royalty Oil Market, Pricing and Revenue Analysis," Battelle Pacific Northwest Laboratories, Richland, WA. Prepared for Division of Research Services, Legislative Affairs Agency, Alaska State Legislature Under Contract No. 2311203378, March 1978.

7. "Where Will North Slope Oil Go?", Chemical Engineering, March 14, 1977.

PROCESS WORKSHEET - ALASKAN COASTAL LOCATION

1. Process Petroleum Refining
2. Capacity 150,000 b/d   3. Capital Investment $525
4. Feedstock Requirements Alaskan North Slope Crude - 49.5 x 10^6 bbl/yr
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 3.3 x 10^6/yr	
Total		$ 3.3 x 10^6/yr
C. Utility Requirements		
Fuel @ $2/$10^6$ Btu	$ 4.45 x 10^6/yr	
Electrical Power @ $0.024/kWh	$ 2.38 x 10^6/yr	
Cooling Water Makeup @ $1.20/Mgal	$ 1.25 x 10^6/yr	
Boiler Feed Water @ $2/Mgal	$ 2.08 x 10^6/yr	
Waste Water Treatment @ $1.90/Mgal	$ 0.65 x 10^6/yr	
Cooling Water Circulation @ $0.03/Mgal	$ 0.74 x 10^6/yr	
Total		$11.6 x 10^6/yr
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 180 @ $30,000/yr (includes benefits)	$ 5.40 x 10^6/yr	
Supervision, @ 20% of Operating Labor	$ 1.08 x 10^6/yr	
Maintenance, @ 4% of Capital Plant	$18.00 x 10^6/yr	
General Administrative and Overhead @ 100% of Labor	$ 5.40 x 10^6/yr	
Taxes and Insurance, @ 2% of Capital Plant	$ 9.00 x 10^6/yr	
Depreciation, 10% S.L.	$45.00 x 10^6/yr	
Total		$83.9 x 10^6/yr
6. Total Annual Manufacturing Costs		$98.7 x 10^6/yr
7. Co-product/By-product Credits:		-
Total		-
8. Net Manufacturing Cost		$98.7 x 10^6/yr
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$120.0 x 10^6/yr
10. Net Costs and ROI		$218.7 x 10^6/yr
11. Net Transfer Price/Pound		$ 4.42/bbl
12. Shipping Costs (Ship or barge to West Coast) $/bbl		$ 0.70/bbl
13. Total Costs $/bbl		$ 5.12/bbl
14. Current Price $/bbl on West Coast		$ 15.60/bbl
15. Net Surplus Applied to Domestic Feedstocks $/bbl		$ 10.48/bbl
16. Crude Oil Shipping Costs (Valdez to Kenai) $/bbl		$ (0.30/bbl)
17. Average Entitlements for North Slope Crude $/bbl		$ 2.50/bbl
18. Allowable Cost of Crude Oil (FOB Valdez)		$ 12.68/bbl

9.8 PETROCHEMICALS AND AGRICHEMICALS FROM NORTH SLOPE NATURAL GAS

The natural gas from Alaska's North Slope represents a potential feedstock for the production of petrochemicals and agrichemicals. Development of these industries could provide benefits to the State of Alaska in the form of development and alternate markets for the State's royalty natural gas.

This analysis was undertaken to determine the economic viability of a chemical production complex utilizing North Slope natural gas. A brief profile of the various chemical commodities evaluated in this analysis follows.

Ethylene and Propylene

The tremendous growth in ethylene consumption as a chemical intermediate is one of the real success stories of the petrochemical industry. Prior to World War II its growth rate paralleled and reflected continued increased demands for ethylene glycol and synthetic ethyl alcohol. With the advent of a commercial styrene industry in 1944, greater demands for ethyl chloride beginning in the late 1940s, and the rapid use of polyethylene as a major plastic beginning in 1950, the rise in ethylene demands can best be described as spectacular. These new demands, coupled with additional requirements for ethylene oxide and synthetic ethyl acohol, have brought ethylene to the number-two spot, second only to ammonia, in the petrochemical industry.

Four new large end uses for ethylene opened up in the late 1960s and 1970s, namely, ethylene-propylene elastomers, α-olefins, linear alcohols, and vinyl acetate. Prolyethylene is the largest outlet for ethylene, accounting for about 40% of production. The three important plastics, polystyrene, polyethylene, and polyvinyl chloride, represent very significant markets for ethylene. Ethylene derivatives, ethylene dichloride, ethanol, etc., consume another 40% of ethylene production.

Ethylene, both in number of kilograms produced for chemical use and in dollar value, is the world's most important petrochemical building block. Ethylene is unique in that it must be used close to the point of production, since it is not easily transportable. Furthermore, production costs are favored by very large manufacturing facilities. More than anything else, these two facts have been responsible for the petrochemical empire along the Gulf Coast of Texas and Louisiana. Most ethylene/propylene production is located on the Gulf Coast, although plants are also located on the East Coast, in the Midwest and on the West Coast.

Propylene, after ethylene and benzene, is the third most important olefin used as a petrochemical building block. It is fast emerging from its position as a low-value ethylene by-product to a rival of ethylene for the position of major chemical and plastic feedstock. Propylene is actually produced in much larger quantities than ethylene; however, all production capacity is not available to the chemical industry. The bulk of propylene production is consumed in the manufacture of gasoline-alkylate and polymer gas.

The demand for polypropylene makes it the largest outlet for propylene, accounting for 23% of production. Propylene oxide and acrylonitrile vie for the second-place market for propylene. Oxide consumption is growing fast as a result of the growth of urethane and polyester resins. Other major outlets include isopropyl alcohol, cumene, and oxo chemicals.

At the present time there is worldwide overcapacity in the ethylene industry. This situation is expected to continue through 1981, when U.S. capacity is expected to reach 43.4 billion pounds due to expansions and new plants. Demand is expected to grow at a modest 5-6% per year to about 30 billion pounds in 1981. Propylene demand is expected to grow a faster 8-9% per year rate.

Economies of scale have led to large ethylene/propylene plants with production capacities on the order of 250 million to one billion pounds per year. The capital cost for such a plant located on the Gulf Coast is in excess of 200 million dollars.

Process Description

In general, ethylene and propylene plants are of two types: refinery-connected, where ethylene and propylene are isolated from off-gases or other refinery products; for example, ethane, propane, are used for at least part of their feedstock; and plants that obtain these products by intentional cracking of hydrocarbons.

Almost any naphthenic or paraffinic hydrocarbon heavier than methane can be steam-cracked to yield ethylene and propylene. Feedstocks currently used throughout the world are ethane, propane, butane, naphthas, gas oils, and even crude oils. Lower-molecular-weight feedstocks normally produce higher yields of ethylene; higher-molecular-weight feedstocks result in a higher propylene/ethylene ratio.

In the U.S. about 75% of the ethylene produced by steam-cracking hydrocarbons was derived from ethane and propane. The remainder was derived from naphtha or gas oil. A shift to heavier feedstocks can be expected due to rising prices and shorter supplies of ethane and propane. Currently, about 75% of propylene is derived from petroleum refineries and 25% from intentional cracking of hydrocarbons.

In the steam-cracking process the hydrocarbon feedstock, diluted with steam, is passed through a pyrolysis furnace, where cracking occurs. Temperatures in the furnace are between 815 and 870°C. Steam is used as a diluent in the conversion step to inhibit coking in the furnace tubes. Contact time of the feedstock in the furnace is 1 sec or less. The yield of ethylene and propylene, as well as other cracking products, is set by this pyrolysis step. After the appropriate feedstock and conversion have been selected, the reaction kinetics (temperature patterns, contact time, and pressure) determine the final product distribution.

Ethane is the preferred feedstock if only ethylene is desired; propane if only propylene is desired.

The hot effluent gases are cooled rapidly to quench the pyrolysis reaction, usually in a quench tower. A four-stage, two-case centrifugal compressor then pressurizes the cooled pyrolysis gases to over 500 psig. Acid gases are absorbed in a system employing monoethanolamine, caustic, and water.

After flashing off the hydrogen, the dried gas is cooled and sent to the demethanizer, where methane is recovered overhead for fuel and the C_2 bottoms flow, under pressure, to the deethanizer. In this column the C_3 and heavier materials are removed as a bottoms stream and fed to the depropanizer. Acetylene is removed from the ethylene by catalytic hydrogenation of the deethanizer overhead. The stream from the acetylene hydrogenator is then fractionated to separate ethane gas for recycle to the pryolysis furnace and the product ethylene.

The depropanizer feed is fractionated, producing C_4 bottoms for transfer to the debutanizer and overhead, which, after hydrogenation to remove propadiene and methyl acetylene, goes to a C_3 stripper. Here propane is recovered for recycle to the furnace, and chemical-grade propylene is produced.

In the debutanizer C_4 fractions and pryolysis gasoline are separated for subsequent sale.

Ethylene Glycol

The chief uses of ethylene glycol are as a permanent "antifreeze" for motor vehicles and the manufacture of ethylene glycol-terephthalate polyester fibers, films and resins. Diethylene glycol, which is co-produced with ethylene glycol, is used in the manufacture of polyurethane and polyester resins. These end uses are expected to grow moderately.

The capital cost of a plant capable of producing 300 million pounds per year of ethylene glycol is estimated at about $50 M.

Process Description

The catalytic oxidation of ethylene with air yields ethylene oxide and carbon dioxide. Ethylene oxide may then be hydrated to yield ethylene glycol.

Ethylene and air are mixed in a volume ratio of about 1:10 and passed over a catalyst composed of silver oxide. Generally, an anticatalyst such as ethylene dichloride (about 1 ppm) is added to the ethylene feed to suppress the formation of carbon dioxide. At essentially atmospheric pressure and temperatures of 270 to 290°C, 60 to 70% of the ethylene is converted to ethylene oxide.

The reaction products are fed to a scrubber, where ethylene oxide is absorbed. This residual gas is compressed and recycled. Ethylene oxide is stripped from solution, and then distilled to remove light ends. The raw ethylene oxide may then be converted to ethylene glycol by acid or pressure hydration in a tower reactor. The acid hydration process makes use of a 0.5 to 1.0% sulfuric acid solution. Contact time is 30 min at 50 to 70°C. In the pressure-hydration process, a residence time of 1 hr at 195°C and 185 psi is required. The weight ratio of water to ethylene oxide is 6:1. In both cases diethylene and triethylene glycol are formed as by-products. They may be separated from the ethylene glycol by vacuum distillation.

Propylene Glycol

Polyester resins account for over 45% of propylene glycol consumption. Other markets include cellophane manufacture, brake fluids, pet foods, tobacco humectant and food and pharmaceutical uses. Growth in demand will be tied to the market for unsaturated polyester resins.

Current capacity of 855 million pounds is located on the Gulf Coast, with the exception of one plant in West Virginia, and is more than adequate to meet present demand of about 575 million pounds.

The current Gulf Coast capital cost of a plant capable of producing 130 million pounds per year is estimated to be about $30 M.

Process Description

Propylene oxide may then be converted to propylene glycol by acid or pressure hydration in a tower reactor. The hydration of ethylene oxide in 0.5 to 1.0% sulfuric acid medium takes place at 50 to 70°C with a contact time of 30 min. The pressure hydration of propylene oxide takes place at 195°C and 185 psi with a residence time of 1 hr. After dehydration and vacuum distillation, the propylene glycol is recovered as overhead from the distillation column.

Dipropylene glycol is obtained as a by-product of propylene glycol manufacture, or intentionally by the addition of propylene oxide to propylene glycol.

Styrene and Polystyrene

Polystyrene plastics currently use about half of all U.S. styrene production. Styrene production was about 6,620 million pounds in 1977 with capacity rated at 9,180 million pounds. Other uses for styrene include styrene butadiene rubber, acrylonitrile-butadiene-styrene (ABS) resins and unsaturated polyester resins. A 5-6% growth rate for styrene is expected over the next 10 years. Present overcapacity may lead to some older plants being retired.

Polystyrene producers have been operating at about 70% of capacity and several less efficient plants have been retired. Future growth in demand for polystyrene is expected to be about 6-7%.

Over 95% of all current U.S. styrene production capacity is located in Texas and Louisiana. Capital costs for a new Gulf Coast styrene plant with a capacity of 400 million pounds per year are estimated to be about $60 M. A styrene to polystyrene plant, rated at 200 million pounds per year, is estimated to cost about $30 M.

Process Description

Benzene is alkylated with ethylene in the presence of an aluminum chloride or boron trifluoride catalyst. The resulting ethylbenzene is catalytically dehydrogenated in the presence of steam or benzene to yield styrene.

Dry benzene (99%) and ethylene (95%) are continuously fed into an alkylating tower operating at essentially atmospheric pressure. A small amount of ethyl chloride is added to the ethylene feed as a source of hydrogen chloride (as well as ethylene) which acts as a catalyst promoter. Granular aluminum chloride (97.5%) is fed to the top of the alkylator at a constant rate. The reactant ratio is about 0.6 mole ethylene/mole benzene. No ethylene is recycled, and the losses to the vents are negligible. From 65 to 100 kg of ethylbenzene may be obtained per kilogram of aluminum chloride catalyst.

The exothermic alkylation reaction is maintained at approximately 95°C by cooling water. The aluminum chloride combines with the hydrocarbon (benzene and ethylbenzene) to form a hydrocarbon-in-soluble complex (reddish-brown oil). The reaction products are fed to coolers, where the temperature is reduced to about 40°C. Here the aluminum chloride complex is separated from the crude mixture in settling tanks and is pumped back to the alkylator or to a high-temperature dealkylator. The latter, operating at 200°C, breaks down a charge of complex polyethylbenzenes to benzene and ethylbenzene (which are returned to the system) and a tarry aluminum chloride residue. Approximately 80% of the aluminum chloride may be recovered.

The crude ethylbenzene from the settling tanks is sent to a caustic scrubbing system for neutralization. After being washed with a 50% caustic solution, the "sweetened" material is charged to a fractionating system for purification of ethylbenzene.

The purified ethylbenzene is heated to 520°C. Superheated steam (710°C) and the ethylbenzene vapors are continuously mixed and fed into a reactor in a ratio of 2.6 kg steam/kg ethylbenzene. The reactor contains a selective fixed dehydrogenation catalyst such as zinc, chromium, iron, or magnesium oxide, on activated charcoals, aluminas, or bauxites.

At a catalyst temperature of about 630°C conversions of 35 to 40% per pass may be realized.

The reaction product leaves the top of the reactor at about 565°C and is cooled to condense out tars. A final condenser liquefies the steam, styrene, toluene, and benzene. The condensed materials pass to a settling tank, where the hydrocarbons are decanted and the water is discharged to a disposal system.

The crude styrene of average composition (37% styrene, 61% ethylbenzene, 1% toluene, 0.7% benzene, and 0.3% tar) is passed through a pot containing sulfur. This stream (containing enough dissolved sulfur to act as a polymerization inhibitor) is preheated and then fed to vacuum columns. At 157 torr pressure, benzene and toluence distill at a head temperature of 57°C.

The column bottoms (90°C) containing styrene, ethylbenzene, and tar are passed successively to primary and secondary vacuum columns where ethylbenzene is separated from the styrene and recycled to the reactor. Styrene is distilled in the second column to remove tar and sulfur. A polymerization inhibitor is added to the top of the column. The tarry residue discharged from the bottom is burned. The distilled styrene passes to receivers, where more inhibitor is added. The finished material is refrigerated below 20°C and loaded to insulated tank cars.

The polymerization of styrene monomer to polystyrene can be accomplished by the addition of polymerization catalysts and heat to a suspension of the monomer in water. The hard beads which form are separated from the water and dried.

Low Density Polyethylene

Low density polyethylene (LDPE) finds its main use in sheet and films. Other uses include injection molding, wire and cable coatings and other extrusion coatings. The market for low density polyethylene is expected to grow at the rate of 8.5% per year. Current production, about 6 billion pounds, is about 85% of rated capacity. Production is centered on the Gulf Coast with other plants located in Iowa, Illinois and California.

A new plant located on the Gulf Coast, with a capacity of 400 million pounds per year, is estimated to cost about $100 M.

Process Description

Ethylene is mixed with recycled material and compressed to about 300 psi. A chain transfer agent (catalyst) is added and the mixture is further compressed to about 15,000 to 25,000 psi. The mixture then enters a reactor or autoclave where initiator is added and polymerization takes place. Molten polymer is separated from the remaining gaseous material which is recycled. The molten polymer is fed into a pelletizing extruder and the pellets are cooled and dried.

High Density Polyethylene

About 40% of U.S. high density polyethylene (HDPE) production is used in blow molding. Another 20% is consumed in injection molding with the remainder utilized in various end uses such as pipe and conduit and film and sheet products.

Consumption of HDPE is expected to grow at about 10-12% per year through 1985, but present production capacity (in excess of 4 billion pounds annually) is operating at about 71-74% of maximum ratings.

Over 90% of HDPE capacity is located in Texas and Louisiana and a new 150 million pounds per year plant located on the Gulf Coast is estimated to cost nearly $40 M.

Process Description

There are several HDPE production processes. In the Union Carbide process gaseous ethylene, comonomer and dry catalyst are fed to a reaction system consisting of a fluid bed reactor, recycle compressor and recycle cooler. The reaction occurs at pressures less than 300 psi and temperatures of 85-105°C. Circulating gas fluidizes a bed of growing polymer using supported chromium catalysts. Circulation of the ethylene gas provides monomer for the polymerization reaction and acts as a medium for heat removal. The polymer is granular and flows intermittently into product discharge tanks.

Polypropylene

Injection and blow molding products account for about 36% of polypropylene use. Fiber and filament uses, especially as a replacement for jute carpet backing, account for another 30%. Remaining uses include extruded products and film. Current polypropylene production capacity is about 3 billion pounds per year, but is currently operating at only 65-70% of capacity. Use is projected to grow at the rate of 10-12% per year through 1985.

Most polypropylene plants are located in Texas and Louisiana. The remaining plants are located in New Jersey, Delaware and West Virginia. A new plant capable of producing a 100 million pounds per year is estimated to cost in excess of $50 M for a U.S. Gulf Coast location.

Process Description

Propylene, a hydrocarbon diluent, and a titanium tetrachloride-aluminum alkyl catalyst are continuously fed to a polymerization reactor operating at 50-100°C and 100-400 psi. The crystalline polymer formed in the reactor is insoluble and precipitates. The polymer granules are separated from the other components, dried and extruded as pellets. Molecular weight control is achieved by the addition of hydrogen gas, a chain-transfer agent.

Vinyl Chloride and Polyvinyl Chloride (PVC)

Nearly all vinyl chloride monomer produced is used in making polyvinyl chloride homopolymer and copolymer resins. Polyvinyl chloride resins are used extensively in making pipe (40%) and electrical insulation (22%). Other uses include packaging, apparel and recreation plastic products. Cosmetic and toiletry makers have been abandoning PVC bottles because of monomer migration problems, but this use is not a large market for PVC.

Vinyl chloride monomer production capacity is about 7 billion pounds per year in the U.S. Present capacity exceeds demand and growth will be tied to the construction industry.

Nearly all vinyl chloride monomer production is located on the U.S. Gulf Coast. A new 200 million pound per year vinyl chloride monomer plant is estimated to cost in excess of $20 M on the Gulf Coast. A PVC plant of the same capacity is estimated to cost about $40 M.

Process Description

Most vinyl chloride processes utilize the pyrolysis of ethylene dichloride to produce the monomer.

Ethylene dichloride is produced by the vapor or liquid-phase reaction of ethylene and chlorine in the presence of a catalyst.

Chlorine gas is bubbled through a tank of ethylene dibromide, and the mixed vapors are passed into a chlorinating tower maintained at 40 to 50°C. The chlorine meets a stream of ethylene gas, and the resulting reaction products are passed from the top of the tower through a partial condenser (above 85°C) into a separator. The ethylene dibromide liquefies and is returned to the process. Gaseous ethylene dichloride is fed into a fractionating column to yield a refined product. The yield is about 96 to 98%.

Vaporized ethylene dichloride is then dried and passed over a contact catalyst (e.g., pumice or charcoal). The catalyst is usually packed in atainless-steel tubes directly heated in a cracking furnace. At 50 psig, with the effluent gases at 480 to 510°C, a 50% conversion and a 95 to 96% yield is attained.

The hot effluent gases from the furnace are quenched by direct contact with a stream of ethylene dichloride. Uncondensed gases are sent to an indirect (surface) condenser to recover the remainder of the condensable vapors; the noncondensables are scrubbed with water to recover hydrogen chloride.

The combined liquid streams from the quencher and condenser are fed to a fractionation tower operated under sufficient pressure to yield vinyl chloride by condensing the overhead vapors in a water condenser. The vinyl chloride is sent to storage.

In most plants the vinyl chloride facilities are built adjacent to the ethylene dichloride plant so that the binyl chloride raw materials are essentially ethylene and chlorine.

Polyvinyl chloride is polymerized in an autoclave or reactor in the presence of a catalyst similar to the other plastic resins. A PVC compound can be tailor-made to achieve end properties by the addition plasticizers, fillers and other additives.

Acrylonitrile

About 50% of acrylonitrile production is used in the production of acrylic and modacrylic fibers. Acrylonitrile-butadiene-styrene (ABS) and styrene-acrylonitrile (SAN) resins, which are used to produce tough all-around plastics, account for another 20%. Other uses include adiponitrile production and nitrile rubber production.

Capacity for the production of acrylonitrile is over 2 billion pounds and is expected to grow to about 2.5 billion by 1980. Current production facilities are operating at about 84% of capacity and this trend is expected to continue. Plants are located in Texas, Louisiana, Ohio and Tennessee. A new 100 million pound per year plant located on the Gulf Coast is estimated to cost over $40 M.

Process Description

Acrylonitrile is produced by reacting a mixture of propylene, ammonia, and air in the presence of a catalyst.

Refinery propylene (40 to 90% pure) or chemical-grade propylene (90+ %), fertilizer-grade ammonia, and air in volume proportions of 1 part propylene, 1 part ammonia, and 2 parts oxygen are mixed and fed to a fluidized bed catalytic reactor. The catalyst is a supported molybdenum-based catalyst, such as 50 to 60% bismuth phosphomolybdate on silica. At reaction conditions of 400 to 450°C, 0.5 to 2 atm and 10 to 20 sec contact time, the propylene is converted to acrylonitrile with a yield in excess of 70% of that theoretically obtainable.

The reactor effluent is fed to an absorption column, where it is scrubbed with water to separate fixed gases and unreacted propylene, which are sent overhead. The water solution of acrylonitrile from the bottom of the scrubber goes to a separator, where wet acrylonitrile is taken overhead. This product is then dried and purified by distillation. Acetonitrile bottoms from the product separator are purified by conventional distillation methods.

Principal by-products are acetonitrile and hydrogen cyanide. One kilogram of propylene yields 0.84 kg acrylonitrile, 0.03 kg acetonitrile, and 0.13 kg hydrogen cyanide.

Methanol (Methyl alcohol)

Over 45% of the methanol produced in the U.S. is used in the production of formaldehyde. Other uses include general process solvent, methyl acrylate production, methyl halide production and the direct synthesis of acetic acid. The latter is a relatively new process and can be expected to grow in the future. A pending development which would have a major impact on the production of methanol is its use as a motor fuel and a fuel for peaking power generation.

Current production capacity is in excess of 1.4 billion pounds per year and the industry is operating at about 78% of capacity. Production facilities are centered in Texas and Louisiana. A new 1000 ton per day plant, based on natural gas feedstock and located on the Gulf Coast, is estimated to cost in excess of $35 M.

Process Description

Methanol is synthesized by the reaction of hydrogen and carbon monoxide under high pressures. The reactants, hydrogen and carbon monoxide, are obtained in a variety of ways from different raw materials.

A common source in the United States is reformed natural gas. In this case natural gas that has been desulfurized by passage over activated carbon is preheated and mixed with carbon dioxide and steam at 30 psig. The mixture is passed into heated alloy-steel tubes in a furnace. The tubes are normally packed with a promoted nickel catalyst. The reaction, which takes place at 800°C, is essentially:

$$3CH_4 + CO_2 + 2H_2O \rightarrow 4CO + 8H_2$$

The resulting synthesis gas is cooled by passage through waste-heat boilers, various heat exchangers, and water coolers.

A gas suitable for methanol synthesis can also be produced by partial oxidation of methane or other light hydrocarbons.

Other sources of raw material gas that have been used are naphtha, heavy oils and coal.

Regardless of the source of the carbon monoxide-hydrogen mixture, the ratio is adjusted so that approximately the theoretical ratio is obtained (2 volumes of hydrogen to 1 volume of carbon monoxide). The mixed gases are compressed in multistage compressors to pressures of 3000 to 5000 psi and heated in heat exchangers by the reaction gases. The heated gases pass through a copper-lined steel converter containing a mixed catalyst of the oxides of zinc, chromium, manganese, or aluminum. The temperature of the reaction is maintained at approximately 300°C by proper heat removal. The converter must be heated to initiate the reaction but, once started, it is self-supporting. The temperature is kept constant by proper space velocity and heat interchange.

The methanol-containing gases leaving the reactor are cooled by the reactants in heat exchangers and condensed under full operating pressures. The pressure is released, and the cool (0 to 20°C) liquid methanol is run off. It may be further purified by distillation. The residential gases are returned to the system for reprocessing. Accumulation of inert gases is guarded against by purging part of the recycle gases.

The most recent advance is toward high-volume plants utilizing large steam-driven compressors operating at lower pressures. In this low-pressure process a copper-based catalyst is used with pressures of 50 to 100 atm. The high activity of the catalyst allows the reaction to take place at temperatures between 250 and 270°C. The process is more efficient because of lower by-product formation, lower energy costs, and lower investment and maintenance requirements.

Formaldehyde

Current U.S. formaldehyde production capacity is about 9 billion pounds per year, but demand is depressed to about 6 billion pounds per year. About 25% of formaldehyde production is used to produce urea-formaldehyde resins used in making plywood and particle board. Another 25% is consumed in making phenolic resins. The remainder is scattered through a variety of end uses. Growth of formaldehyde consumption is dependent primarily on housing starts.

Formaldehyde production sites are scattered throughout the middle and southeastern states and along the West Coast states of Washington and Oregon.

A new 400 million pound per year formaldehyde plant, located on the Gulf Coast, is estimated to cost about $6 M.

Process Description

Formaldehyde is made either by catalytic vapor-phase oxidation of methanol or by a combination oxidation-dehydrogenation process. Formaldehyde and the unreacted methanol in the product gases are absorbed in water and separated by distillation in either process.

Generally, air and methanol are mixed mechanically or by maintaining the methanol at a constant level and temperature in the vaporizer, through which air is drawn. The alcohol-air mixture contains 30 to 50% methanol. Residual alcohol spray is vaporized in a preheater.

The reactor contains a silver or copper gauze catalyst. The reaction over these catalysts is a combination of dehydrogenation and oxidation, the former being responsible for high yields, whereas the latter supplies heat and aids in keeping the catalyst active. The best metal oxide catalyst is a mixture of molybdenum, iron, or vanadium oxides. The reaction over this type of catalyst is mainly one of oxidation and requires a large excess of air, at a catalyst temperature of 450 to 600°C and a contact time of about 0.01 sec.

Separation of methanol and formaldehyde is accomplished by alternate scrubbing and cooling; the gases then pass to a final scrubber fed with cold water and are vented to the atmosphere. These exit gases contain 19 to 22% hydrogen and 74 to 75% nitrogen. The gases also contain between 4 and 5% carbon dioxide, together with traces of CO, oxygen, and methane.

The combined condensate and scrubber liquor from the main column (containing formaldehyde, water, and approximately 15% unreacted methanol) are fed into a fractionating column, where 37% formaldehyde plus the desired amount of methanol stabilizer is removed from the bottom and excess methanol is removed from the top and returned to the vaporizer. Overall yields are 85 to 90% by weight based on the methanol charged.

Essentially all formaldehyde is produced from methanol. Of the two processes starting with methanol, the one using the oxide catalyst gives higher yields but is also more expensive to operate. The process is particularly suitable for large plants.

Ammonia

Over 75% of the anhydrous ammonia produced in the United States is used as fertilizer, either directly or as urea, ammonium nitrate or other ammonium compounds. Plastics, fibers and resins account for another 10%. U.S. ammonia production capacity is in excess of 22 million tons per year, but production is about 17 million tons, or about 77% of capacity. Demand is heavily tied to agriculture and prospects for a large increase in the near future are dim. Thus, the industry is caught in a cost-price squeeze with demand falling and natural gas prices rising.

Ammonia production facilities are widespread throughout the United States in order to be close to agricultural markets. A new, natural gas based, 1000 ton per day ammonia plant is estimated to cost about $60 M.

Process Description

Nitrogen and hydrogen in a 1:3 ratio react catalytically at high temperatures and pressures to produce ammonia. The nitrogen is derived from the air by means of liquefaction, or by burning out the oxygen in air with hydrogen. Hydrogen is obtained from many sources, including water gas, coke-oven gas, natural gas, fuel oil, catalytic reformer gases, and the electrolysis of water or brine. Since World War II, natural gas has become the most important hydrogen source in the U.S.

The natural gas is preheated, passed over a bauxite catalyst to remove the sulfur, and then treated with steam in a reforming furnace. By use of a nickel catalyst in the reformer, a 70% conversion of methane to carbon monoxide and hydrogen is attained. The partially reformed gas is then led to a combustion furnace, where sufficient air is added to give nitrogen and hydrogen concentrations that will eventually result in the 1:3 molar ratio required for best yields in the ammonia synthesis reaction. The combustion chamber also contains a nickel catalyst, so the reforming reaction is also completed in the unit. Temperature of the reaction gases reached 925°C.

In the initial gas-reforming processes pressure of about 30 to 50 psi and temperatures up to 925°C were used. Modern plants use higher pressures, up to 500 psi.

The gases are cooled to 425°C by a water quench and then fed to a shift converter where, in the presence of an iron oxide catalyst, carbon monoxide is reduced to less than 1%, by means of the water shift gas reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

The gas is cooled, compressed to 200 psi, and sent to the gas-purification system. Carbon dioxide is removed by absorption; many absorbents are used, including monoethlanolamine solution, potassium carbonate solution, Sulfinol (sulfolane, $C_4 H_8 SO_2$), propylene carbonate, and others.

Final cleanup of carbon monoxide and carbon dioxide (to less than 10 ppm) is accomplished by methanation. Here the gases are passed over a nickel catalyst where any remaining oxides are hydrogenated to methane.

Other popular processes for preparation and purification of ammonia synthesis gas are the hydrocarbon partial oxidation process and the liquid nitrogen-catalytic reformer off-gas process.

In the partial oxidation process air is liquefied and then separated into oxygen of 95% purity and nitrogen of 99.99% purity.

The reforming and combustion chamber steps of the process described previously are replaced by a partial oxidation unit using 95% oxygen and a large excess of natural gas. A sufficiently high temperature results from the partial combustion to allow reaction between the excess methane and the water vapor formed by the combustion process. The effluent gases, chiefly carbon monoxide and hydrogen, are quenched and processed as previously described, that is, through a shift converter and a monoethanolamine unit. The last traces of carbon monoxide and any residual hydrocarbon are removed by washing with liquid nitrogen in a low-temperature wash tower.

When catalytic reformer off gas is used as the source of hydrogen, purification may be effected by a light caustic scrub and a liquid nitrogen wash. Nitrogen for both the wash tower and the feed stream is supplied by an air liquefaction unit.

In any case the purified 3:1 hydrogen-nitrogen mixture is ready for compression to reaction pressure and feed to the ammonia synthesis unit. A typical pressure is about 300 atm although the range is wide: from

130 to 650 atm. The compressed gas is filtered to remove oil. At the inlet to the reactor, the fresh feed is joined by a recycle stream of unconverted nitrogen and hydrogen. By means of internal heat exchangers, the temperature of the feed gases is raised to 400 to 600°C, with an average of about 475°C.

The reactor contains an iron oxide catalyst promoted by addition of small amounts of aluminum, potassium, calcium, or magnesium oxides.

The gases leaving the reactor are cooled (-10 to -20°C), and some of the ammonia liquefies. Part of the gas is purged to prevent accumulation of diluents such as argon, and the purge gas is used for fuel. The remaining gas is recompressed and recycled. The conversion per pass is approximately 20 to 22% and the overall yield with recirculation approaches 85 to 90%.

Urea

Current U.S. urea production capacity is in excess of 6.5 million tons per year. However, production is only about 4.5 million tons per year. The market for urea is very similar to that for ammonia with 65-75% of production going to fertilizer use. Other uses are urea-formaldehyde and melamine resins (15%) and animal feeds (10%). Prospects for growth in the near future are similar to those of ammonia--very poor.

Urea production is scattered throughout the U.S. A modern 1500 ton/day plant is estimated to cost about $30 M on the Gulf Coast.

Process Description

Urea is produced by the indirect dehydration of the intermediate, ammonium carbamate, formed by the high-pressure reaction of excess ammonia and carbon dioxide. A description of one complete process follows.

Ammonia and carbon dioxide, in a weight ratio of about 2.3:1 (3:1 mole ratio), are compressed to liquids and charged separately into a steam-heated, silver-lined autoclave (reactor). The reactants require about 2 hours to pass through the autoclave which is maintained at a temperature of approximately 190°C and a pressure of 1500 to 3000 psi. During this time the ammonia and carbon dioxide react to form ammonium carbamate which is largely converted to urea.

The reaction mixture, consisting of about 35% urea, 8% ammonium carbamate, 10.5% water, and 46.5% unreacted ammonia, is discharged from the autoclave and cooled to approximately 150°C. The melt is passed to an ammonia still, operating at 60°C, where 60 to 65% of the unconverted ammonia and any unreacted carbon dioxide are distilled and collected in an ammonia-absorption system. The absorbed materials may be reused in the reactor or converted to liquid fertilizer.

The residue in the ammonia still, consisting largely of urea and water, is discharged to a crystallizer, where it is cooled to about 15°C. About 70% of the remaining free ammonia is removed by vacuum and sent to the recovery system. The resulting slurry is passed to a continuous centrifuge, separating the crystalline urea. The mother liquor, containing about 21% ammonium carbamate, 38% urea, 14% ammonia, and 27% water, is sent to the ammonia-recovery system, where it is utilized in the manufacture of the liquid fertilizer.

The yield of urea in the crude melt based on the carbon dioxide charged is 80 to 85%. If the ammonia recovered by absorption is taken into account, this yield is essentially the same based on the ammonia charged. However, about 60% of this crude urea is recovered as crystalline product, the remainder going to make up liquid fertilizer (urea-ammonia liquor).

Ammonium Nitrate

Ammonium nitrate, like ammonia and urea, is heavily tied to agricultural uses. About 80% of ammonium nitrate production is consumed as fertilizer. Nearly all the remainder is used in making explosives. U.S. ammonium nitrate production capacity is over 7 million tons/yr. Its current status is similar to those of ammonia and urea. Most ammonium nitrate is produced in conjunction with ammonia and nitric acid facilities.

A new 800 ton/day nitric acid-ammonium nitrate production facility is estimated to cost about $13 M on the Gulf Coast.

Process Description

Ammonia and nitric acid are reacted to yield ammonium nitrate either in solution or in a molten form. It is then further processed to crystal or granular form. Concentration of the nitric acid is typically 57 to 60% but may range from 40 to 65%.

The chief differences between various processes are the concentration of the reactants and the method used to remove the solid phase from solution.

In a typical prilling process, ammonia vapor and nitric acid are reacted in a stainless-steel neutralizing vessel under agitation. As the materials come into contact, the heat of reaction causes the solution to boil, thus concentrating it to an 85% solution. The nearly neutral solution is then pumped to a vacuum evaporator and concentrated to about 95%. The hot (125 to 140°C) solution of nitrate is then pumped to the top of a spray tower, or prilling tower, about 60 miles high, whence it is discharged through a spray head. As it falls countercurrent to a stream of conditioned air, the material solidifies into small spherical pellets (called prills) about the size of buckshot. The particles are screened, dried further, and then dusted with clay or fine diatomaceous earth to minimize caking tendencies. Over- and undersized particles are separated in a final screening, redissolved, and returned to the reactor.

In the Stengel process, ammonia vapor (143°C) and 60% nitric acid (165°C) are fed to a packed stainless-steel reactor. The concentration of the reactants is such that the heat of reaction vaporizes the water present. The mixture of nitrate and water (205°C) is led to a cyclone-type separator from which steam leaves the top and molten ammonium nitrate the bottom. Air is blown through the molten nitrate to reduce the moisture content to 0.2%. The molten mass is solidified by cooling on a continuous, water-cooled, stainless-steel belt. The resulting solid sheet of ammonium nitrate is carried to the end of the belt, removed, and ground to granular form. The granules are conditioned with clay in a coating drum and bagged for shipment.

A third process for making solid ammonium nitrate is continuous vacuum crystallization. The ammonium nitrate solution (about 60%) formed in the reactor is concentrated by evaporation (65°C) to between 75 and 80% dry substance. It is then charged into a special polished stainless-steel vacuum crystallizer, somewhat similar to the Oslo-Krystal classifying type used for ammonium sulfate, but modified to give a rotating rather than a classified suspension and to provide adequate growth of seed crystals to intermediate sizes. By operation at a temperature of about 36°C an absolute pressure of 25 MM Hg, and a concentration of 75 to 79% ammonium nitrate, crystals of size, shape, and strength favorable for fertilizer use are produced continuously at a relatively high rate.

The product is removed from the bottom of the crystallizer in a slurry containing about 40% by weight of crystals and run to a centrifuge. The mother liquor is returned to the system, while the crystals, containing about 1% water, are fed to a counterflow rotary dryer, where at 82°C the moisture content is reduced to about 0.1%. The crystals are usually conditioned by dusting (3 to 4% kiselguhr, for example) and then packaged in bags.

Economic Evaluation

An inland location adjacent to the proposed Alaska Northwest natural gas pipeline was chosen as the site for this study. Other assumptions made in this evaluation are listed below:

- Costs for both construction and production are on an early 1978 basis. This avoids the necessity for escalation factors and market projections.
- It was assumed that North Slope natural gas was available from a pipeline adjoining the complex; for example, the Alcan pipeline route.

- It was assumed that labor, a townsite, shipping facilities, and other infrastructure were in place at the site.
- It was assumed that equipment for the plants would be shipped to Alaska for final assembly and emplacement.
- A regional index factor of 2.0 times U.S. Gulf Coast plant costs was used for Inland Alaska coastal construction.

The regional index factor of two times Gulf Coast costs represents a substantial barrier to competitive production. A similar situation exists in the Mid-East. The construction cost index for Saudi Arabia is estimated to be 1.66 times the index for the U.S. Gulf Coast.

Large, "world scale" plant sizes were used in the study in order to take advantage of economies of scale. Assuming pipeline flow of 2.5 BCF/day with 78% extraction of ethane and 99% extraction of propane, the royalty portion of the liquid petroleum gases (LPG) is about sufficient to feed an olefins plant of half the size used in this study. However, the ammonia and methanol plants, which use natural gas feedstock, would utilize less than 30% of the royalty natural gas available. It must be mentioned that the limited scope of this study required the adaptation of published cost information for the various chemical processes without a thorough point-by-point engineering evaluation. This point is particularly important in regard to the initial capital expenditures which play a dominant role in determining product unit costs and on which local conditions in Alaska could have a dramatic effect.

The chemical commodities evaluated are by no means the only ones which can be produced from natural gas and LPG, but are large volume commodities for which cost information is readily available. Many of the materials are feedstocks for other chemical products which can be further processed before fabrication into end products.

Appendix A contains a worksheet for each commodity evaluated. The top of each page lists the commodity produced, the size of the plant, and the capital investment consisting of plant investment plus an allowance for working capital for each process. The capital investment estimates used in this study assume a grass roots facility wherein both the inside battery limits (ISBL), the main process elements of the plant, and outside battery limits (OSBL) facilities such as steam generation, water treatment, cooling towers, etc., are provided. For the purposes of this evaluation the OSBL facilities were estimated by adding on 35-40% of the ISBL investment for each plant. Major items such as air separation plants were included in the ISBL estimates.

The LPG extraction plant costs used in this study assume that the LPG plant is a conventional expander type plant with recompression.

Item No. 4 on the process worksheets indicates the feedstock requirements to be obtained from other plants in the complex or from the LPG or natural gas streams.

Item 5.A indicates the annual cost for feedstocks other than natural gas and LPG which must be imported to the complex. Item 5.B indicates the cost estimates for catalyst replacement and small amounts of incidental chemicals used in each plant. Items 5.C and 5.D indicate the estimated utility requirements and labor, maintenance overhead, taxes, insurance and depreciation estimates, respectively. Item 6 is a summation of all the costs shown to this point. Item 7 indicates a credit at current market prices for any by-products produced in the process and exported. Item 8 indicates the net manufacturing cost after taking any by-product credit. Item 9 indicates a return on investment before taxes calculated at 25% of the fixed plant investment plus 10% on the estimate of working capital invested in feedstock and product inventories, work in process, accounts receivable and operating cash. Item 10 indicates total net cost plus allowance for return on investment. Item 11 indicates the net manufacturing cost per pound of product exclusive of feedstock costs for Item 4. Item 12 indicates estimated shipping costs per pound. Item 13 gives the total delivered cost. Item 14 indicates the current (March 13, 1978) market prices taken from Table 1. Item 15 is the net surplus per pound of

TABLE 1. Current Chemical Prices

Commodity	Price
Chlorine	$135/ton, FOB
Ethylene Glycol	$0.245/lb, Delivered Eastern U.S.
Propylene Glycol	$0.25/lb, Delivered
Vinyl Chloride Monomer	$0.143/lb, FOB
Polyvinyl Chloride	$0.39/lb, Freight Allowed
Ammonium Nitrate, Bulk	$110/ton, Delivered
Acrylonitrile	$0.275/lb, FOB
Formaldehyde, 37%	$0.0525/lb, Delivered
Urea	$130/ton, Delivered Western U.S.
Methanol	$0.50/gal, Los Angeles, FOB Gulf Coast $0.44/gal
Polystyrene	$0.28/lb, Delivered
Styrene Monomer	$0.21/lb, FOB
H.D. Polyethylene	$0.318/lb, Freight Allowed
L.D. Polyethylene	$0.315/lb, Freight Allowed
Polypropylene	$0.30/lb, Delivered
Ammonia	$130/ton, Delivered
Ethylene	$0.13/lb, FOB-Contracts
Propylene	$0.095/lb, FOB
Naphtha	$15.50/bbl.

Source: Chemical Marketing Reporter,
March 13, 1978

product which can be applied to the feedstocks in Item 4. Item 15 times the capacity in Item 2 equals the sum available to purchase the feedstocks in Item 4. Item 15 times the capacity in Item 2 equals the sum available to purchase the feedstocks in Item 4.

Decreasing supplies of natural gas in the Lower 48 states and increasing gas costs are expected to cause a shift to heavier feedstocks by chemical producers in the future. For this reason, we elected compared Alaskan chemical production costs from natural gas to production costs on the U.S. Golf Coast using naphtha feedstock. Process worksheets for these plants are shown in Appendix B.

Many of the plants produce chemicals which are used as feedstocks in another plant. By using the above method we can start at the surplus over manufacturing cost for a final product and go backward through an entire chain of plants to determine what price can be paid for LPG or natural gas and still have the entire process chain economically feasible. In several instances the surplus from a final product is not sufficient to cover the manufacturing cost of its feedstock. In this instance, manufacturing the product in Alaska is not economically viable. For example, the surplus from the manufacture of polystyrene in Alaska is $0.068/lb. The polystyrene plant produces 200 million pounds per year. Therefore, $13,600,000 ($0.068 x 200 million) is available to defray the cost of the 206 million pounds of styrene monomer feedstock required for the polystyrene plant. This amounts to $0.066 per pound ($13,600,000 ÷ 206 million pounds) maximum that can be paid for styrene monomer. However, the bare manufacturing cost (exclusive of local feedstock) for styrene monomer is $0.254 per pound, so the manufacture of polystyrene is not economically feasible even at a zero LPG price. This data is summarized in Table 2 for each process, utilizing Alaskan natural gas feedstock. Where a plant utilized two local (domestic) feedstocks, the surplus applied to each was ratioed on the basis of their current market prices.

TABLE 2. Chemical Product Economic Summary (Basis: Alaska Inland Location)

Product	Manufacturing Cost @ Zero Hydrocarbon Cost ($/lb)	Product Shipping Cost ($/lb)	Delivered Cost ($/lb)	Current Market Price ($/lb)	Breakeven Point ($/lb)	Allowable Hydrocarbon Feedstock Costs $	Allowable Hydrocarbon Feedstock Costs $/lb6 Btu[(a)]
Ethylene	0.184	N.A.	-	0.130	-	-	-
Propylene	0.129	N.A.	-	0.095	-	-	-
Propylene	0.208	0.031	0.239	0.250	Propylene @ 0.061	N.C.	-
Ethylene Glycol	0.171	0.031	0.202	0.245	Ethylene @ 0.061	N.C.	-
Styrene Monomer]	0.254	0.031	0.285	0.210	Ethylene @ (0.240)	N.C.	-
Polystyrene	0.158	0.054	0.212	0.280	Styrene Monomer @ 0.066	N.C.	-
L.D. Polyethylene	0.252	0.054	0.306	0.315	Ethylene @ 0.009	N.C.	-
H.D. Polyethylene	0.235	0.054	0.289	0.318	Ethylene @ 0.028	N.C.	-
Polypropylene	0.464	0.054	0.518	[illegible].300	Propylene @ (0.190)	N.C.	-
Vinyl Chloride	0.182	0.031	0.213	0.143	Ethylene @ (0.147)	N.C.	-
Polyvinyl Chloride	0.207	0.054	0.261	0.390	Vinyl Chloride @ 0.128	N.C.	-
Acrylonitrile	0.355	0.031	0.386	0.275	Propylene @ (0.077) Ammonia @ (0.042)	N.C.	-
Methanol	0.058	0.018	0.076	0.050	Natural Gas @ (0.002)/SCF	N.C.	-
Formaldehyde	0.018	0.017	0.035	0.053	Methanol @ 0.042	N.C.	-
Ammonia	0.068	0.015	0.083	0.065	Natural Gas @ (0.001)/SCF	N.C.	-
Urea	0.035	0.022	0.057	0.065	Ammonia @ 0.014	N.C.	-
Ammonium Nitrate	0.037	0.041	0.078	0.055	Ammonia @ (0.050)	N.C.	-

(a) Naphtha @ 20.300 Btu/lb.
(b) N.A. indicates not applicable; shipping cost prohibitive.
(c) N.C. indicates not competitive.
(d) ( ) indicates negative value.

Similar data are shown in Table 3 for the Gulf Coast evaluation utilizing naphtha feedstock.

Table 2 indicates that none of the chemical commodities evaluated can be produced competitively at an inland Alaskan location; not even if LPG and natural gas are available at zero cost.

Looking at Table 3 (Gulf Coast chemical production from naphtha), the breakeven point for the manufacture of ethylene glycol is ethylene feedstock at a price of $0.206 per pound. After taking into account feedstock-to-product ratios and the bare manufacturing cost for ethylene, we find that the manufacture of ethylene glycol is economically viable at a naphtha price of $0.084 per pound or less. This corresponds to a price of approximately $4.11 per million Btu (assuming naphtha at 20,300 Btu/lb).

Examination of Tables 2 and 3 indicates that an inland Alaska petrochemical/agrichemical complex based on natural gas is not competitive with a Gulf Coast complex based on naphtha. The reasons for this is the much higher construction cost index for inland Alaska.

TABLE 3. Chemical Product Economic Summary (Basis: U.S. Gulf Coast Location - Naphtha Feedstock)

Product	Manufacturing Cost @ Zero Hydrocarbon Cost ($/lb)	Product Shipping Cost ($/lb)	Delivered Cost ($/lb)	Current Market Price ($/lb)	Breakeven Point ($/lb)	Allowable Hydrocarbon Feedstock Costs $	$/10⁶ Btu(a)
Ethylene	0.022	FOB	-	0.120	Naphthe @ 0.014	Naphtha @ 3.53/bbl	0.69
Propylene	0.015	FOB	-	0.095	Naphtha @ 0.014	Naphtha @ 3.53/bbl	0.69
Propylene Clycol	0.115	0.006	0.121	0.250	Propylene @ 0.177	Naphtha @ 0.074/lb	3.62
Ethylene Glycol	0.095	0.006	0.101	0.245	Ethylene @ 0.206	Naphtha @ 0.084/lb	4.11
Styrene Monomer	0.145	0.007	0.152	0.210	Ethylene @ 0.186	Naphtha @ 0.074/lb	3.67
Polystyrene	0.092	0.033	0.125	0.280	Ethylene @ 0.018	N.C.	
L.D. Polyethylene	0.144	0.033	0.177	0.315	Ethylene @ 0.133	Naphtha @ 0.050/lb	2.48
H.D. Polyethylene	0.126	0.033	0.159	0.318	Ethylene @ 0.151	Naphtha @ 0.059/lb	2.89
Polypropylene	0.255	0.033	0.288	0.300	Propylene @ 0.010	N.C.	
Vinyl Chloride	0.117	0.007	0.124	0.143	Ethylene @ 0.040	Naphtha @ 0.008/lb	0.40
Polyvinyl Chloride	0.117	0.033	0.150	0.390	Ethylene @ 0.253	Naphtha @ 0.105/lb	5.17
Acrylonitrile	0.158	0.007	0.165	0.275	Naphtha @ 0.037	Naphtha @ 0.037/lb	1.83
Methanol	0.075	FOB	-	0.067	N.C.		
Formaldehyde	0.011	0.006	0.017	0.053	Methanol @ 0.084	Naphtha @ 0.018/lb	0.90
Ammonia	0.047	0.007	0.054	0.065	Naphtha @ 0.014/lb	Naphtha @ 0.014/lb	0.67
Urea	0.022	0.006	0.028	0.065	Ammonia @ 0.064	Naphtha @ 0.021/lb	1.04
Ammonium Nitrate	0.025	0.006	0.031	0.055	Ammonia @ 0.053	Naphtha @ 0.007/lb	0.37

(a) Naphtha @ 20.300 Btu/lb.
(b) N.A. indicates not applicable; shipping cost prohibitive.
(c) N.C. indicates not competitive.
(d) ( ) indicates negative value.

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9.9 PULP INDUSTRY

A. GENERAL CHARACTERISTICS

1. Location of Major Producing Regions

In 1974 65 percent of the total U.S. output of all types of wood pulp was produced in Georgia, Alabama, Washington, Louisiana, Florida, Oregon, Maine, Mississippi, South Carolina, and Virginia.[1] Eight out of 10 of these states are located in either the southeastern, the south-central, or the northwestern states. Based on 1977 figures[1] the regions of the U.S. having the greatest number of kraft pulp mills per number states in the region are the southeastern, the southcentral and the north-western regions. Based on the number of kraft pulp mills in Canada in 1977[1], British Columbia, Ontario, and Quebec appear to be the greatest kraft pulp producers in Canada with British Columbia being the dominant one.

2. Markets

There are no known markets in Alaska for kraft pulp.

3. Industrial Structure

According to information from Reference 2, it appears that the production of bleached kraft market pulp is concentrated within about four North American companies.

4. Process Description

The process for producing bleached kraft pulp involves three mainline steps--wood preparation, pulping, and bleaching--and several auxiliary steps such as chemical recovery, lime reburning, and power production. A flow diagram of the bleached kraft process is illustrated in Figure 1. The wood preparation step involves removing the bark from the logs to be pulped and cutting the logs into wood chips. The pulping step involves the digestion or cooking of the wood chips at elevated temperature and pressure in a solution of sodium hydroxide and sodium sulfide called white liquor. During the digestion process the major portion of the

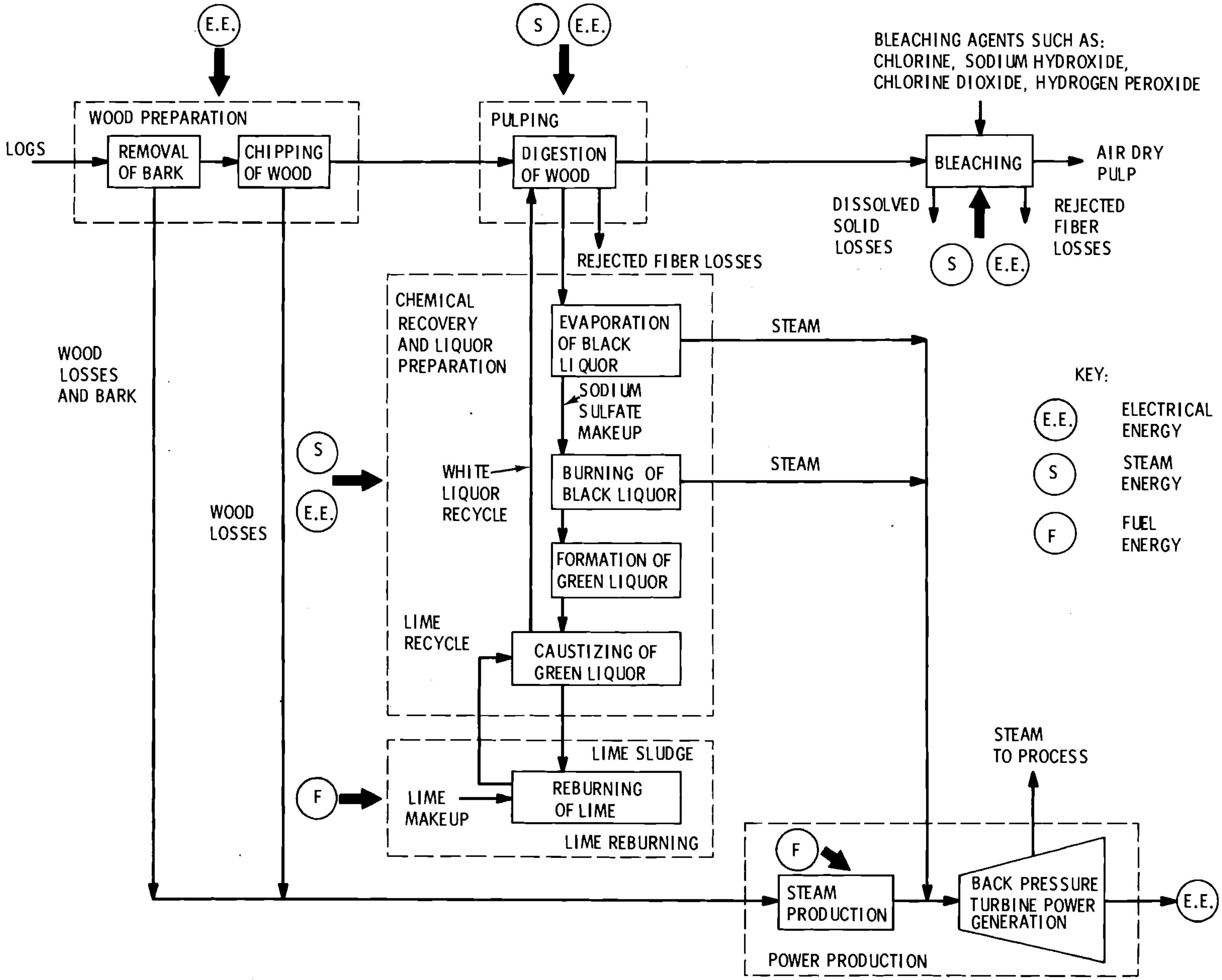

FIGURE 1. Flow Diagram of Bleached Kraft Process

lignin in the wood and some of the carbohydrate materials are dissolved in the digestion solution. After completion of the digestion process the contents of the digester vessel are discharged to atmospheric pressure, and the crude pulp is separated in countercurrent washers from the solution called black liquor. The black liquor consists of lignin, carbohydrate materials, and inorganic cooking chemicals. The crude pulp is next transferred to the bleaching step. The unbleached, washed pulp is bleached in multistage equipment. The bleaching step removes the residual lignin and colored impurities in the pulp while maintaining as much as possible of the pulp yield and pulp strength. The bleaching sequence involves various chemicals such as chlorine, sodium hydroxide, chlorine dioxide, and hydrogen peroxide.

The black liquor from the pulping step is processed in the auxiliary chemical recovery step. First, the black liquor is evaporated to 60-65 percent solids and then burned in a smelter-type furnace for recovery of heat and cooking chemicals. Sodium sulfate may be added to the black liquor prior to the furnace to make up for sodium losses in the pulp. The molten mixture of inorganic sodium carbonate and sodium sulfide from the bottom of the furnace is dissolved in water to make the so-called green liquor. The green liquor is treated with lime (calcium oxide) to convert the carbonate to hydroxide. The clarified solution from the lime treatment is called white liquor and is recycled to the digester vessel. The lime sludge (calcium carbonate) from the lime treatment step is processed in the auxiliary lime reburning step. The sludge is burned in a kiln to convert it to lime for reuse. Steam for use in the power production step is produced by black liquor evaporation, black liquor burning, and bark burning. The steam is discharged through a back pressure turbine to produce electrical power and process steam.

5. Trends in Process Development

In the pulp industry there are three basic pulping processes--chemical pulping, mechanical pulping, and a combination of the previous two called chemi-mechanical or semichemical. There are two main types of chemical pulping-sulfite and kraft. Sulfite pulping uses steam pressure and an acid chemical (calcium, magnesium, sodium, or ammonium bisulfite plus sulfurous acid) to reduce wood chips to pulp. Kraft pulping uses steam pressure and alkaline chemicals (sodium hydroxide and sodium-sulfide) to reduce wood chips to pulp. Mechanical pulping is accomplished by either pressing logs against a revolving grindstone or mechanically fiberizing wood chips. The dominant semichemical process is called the neutral sulfite semichemical (NSSC) process. This process consists of reducing wood chips, which have been partially softened under steam pressure with chemicals, to pulp by mechanical action. Of all these pulping processes the kraft process was responsible for 69 percent of the total wood pulp production in the U.S. during 1975.[1]

The kraft process has changed very little since the commercial development of bleached kraft pulp in the early 1930s. Mechanical pulping involving stone grinding has changed little in the past hundred years. With the advent of the mechanical refiner, wood chips, sawdust, and shavings can be utilized to make refiner mechanical pulp (RMP). There are three potential new technologies that are being considered in the pulping industry. One is the alkaline-oxygen pulping process. This process involves an alkaline treatment to soften the wood chips, mechanical disintegration, treatment with oxygen under alkaline conditions to remove most of the remaining lignin and finally a multistage bleach sequence--chlorine dioxide, caustic extraction, and chlorine dioxide. This alkaline-oxygen process would eliminate the air pollution from malodorous sulfur compounds and greatly alleviate the bleach plant effluent problem. Another process that is already under development is the Rapson effluent-free kraft process. This process consists of a number of changes to the conventional kraft pulping process to eliminate effluents. Some of these changes are as follows:

1) replacement of about 70% of the chlorine normally used in the first-stage chlorination step by chlorine dioxide,

2) countercurrent washing in the bleach plant,
3) reuse of all bleach-plant effluent in the pulping step, and
4) use of the R-3[a] process for chlorine dioxide generation.

A third process already in use is the thermomechanical pulping (TMP) process. This process involves preheating wood chips and then fiberizing the chips in a pressurized disc refiner which consists of two circular metal plates generally rotating in opposite directions. The TMP process compares with the refined mechanical pulping process (RMP) in that the RMP process reduces wood chips to fibers at atmospheric conditions. The TMP process improves fiber properties and allows the use of chips and residual wood which is an improvement over stone grinding for both reasons and an improvement over the RMP process for the first reason.

The trends in pulp industry are toward conservation of energy, updating old equipment rather than building new plants due to the high capital cost, and recovery of as much energy as possible from wood residues.

6. Economic Plant Scale

Since the kraft process produces the majority of the wood pulp, a bleached kraft pulp mill was chosen as a representative of pulp industry. According to Reference 2 the minimum size for a bleached kraft pulp mill is 600 tons of pulp/day. This was the size plant chosen for this study.

7. Capital Cost

The capital costs are a major factor in the development of the pulp industry.(3) The capital costs for many firms considering building new pulp mills is prohibitive and many of these firms are spending their money to upgrade old equipment rather than build new plants. The capital costs for the hypothetical bleached kraft pulp mill for this study are \$245,000,000. This involves a 1.65 scale-up factor from costs in the Lower 48 states to costs in Alaska, no costs for land on which the plant

(a) A proprietary process for chlorine dioxide generation.

is built, and fixed capital and working capital. This capital investment represents about \$1170 capital/air dry ton of pulp produced per year.

8. Labor Requirements

The pulp industry is a mechanized industry and the labor requirements reflect this fact. The total number of employees estimated to be needed to run the hypothetical bleached kraft pulp mill is 150-200 employees. This represents from 1 employee/4 air dry tons of pulp per day to 1 employee/2.5 air dry tons of pulp per day.

9. Cost Data Sheet

10. References

(1) Lockwood's Directory of the Paper and Allied Trades, Harry Dyer, Editor-in-Chief, Vance Publishing Corp., New York, NY, 1977.

(2) Environmental Considerations of Selected Energy Conserving Manufacturing Process Options: Volume V. Pulp and Paper Industry Report, Report for Industrial Research Lab., Cincinnati, Ohio by Arthur D. Little, Inc., Cambridge, MA, PB-264-271 (EPA-600/7-76-034e), December 1976.

(3) Textile and Paper Chemistry and Technology, J. C. Arthur, Jr., Editor, A symposium sponsored by the Cellulose, Paper, and Textile Division at the 171st Meeting of the American Chemical Society, New York, NY, April 5-9, 1976, ACS Symposium Series 49, 1977.

1. Process - Bleached (5-stage) Kraft Pulp
2. Capacity - 210,000 ADT/YR, 600 ADT/Day, 350 DAYS/YR[1]
3. Capital Investment - $245,000,000[2]
4. Feedstock Requirements - 500,000 TONS/YR (Bone Dry Wood & Bark)[3]
5. Total Product Cost:

I. Manufacturing Costs -		
A. Direct Production Costs		
1) Feedstock Costs		$64,286,000 [4]
2) Chemicals		6,300,000 [5]
3) Direct Operating Labor		1,098,000 [6]
4) Direct Supervision		300,000 [7]
5) Utilities		
Fuel (as oil) @ $\$2/10^6$BTU		3,167,000 [8]
Electrical Power		-0-
Process Water @ $2/1000 GAL		4,620,000[10]
Cooling Water Makeup @ $1.20/1000 GAL		5,040,000[11]
Cooling Water Circulation @ $0.07/1000 GAL		294,000[12]
6) Maintenance (Includes labor, supervision and supplies)		2,310,000[13]
7) Operating Supplies		210,000[14]
8) Pollution Control (operating & Maintenance)		3,150,000[15]
	A. TOTAL	$90,775,000
B. Fixed Charges		
1) Depreciation, 10% S.L		$22,275,000[16]
2) Taxes & Insurance @ 2% of Fixed-capital		4,455,000
	B. TOTAL	$26,730,000
C. Plant Overhead @ 50%[17] of I.A.3, I.A.4, and I.A.6 and		1,854,000
II. General Expenses		
Administrative Costs @ 32% [18] of I.A.3, I.A.4, and I.A.6 above		$ 1,187,000

6. Total Annual Product Cost	$120,546,000

7. By-Product Credits:

Electricity	$ 735,000[19]
Tall Oil	1,354,000[20]
Turpentine	196,000[21]
TOTAL	$2,285,000

8.	Net Product Cost	$118,261,000
9.	ROI, 25% before taxes on fixed-capital plus 10% on Working Capital	57,915,000
10.	Net costs and ROI	176,176,000
11.	Net Transfer Price/ADT Pulp	$838.93
12.	Shipping Costs/ADT Pulp (Tanker to Japan)	19.60 [(22]
13.	Total Costs/ADT Pulp	$858.53
14.	Current Price/ADT Pulp	$365.00 [(23]

FOOTNOTES

(1) Based on the assumption that this pulp mill would be about the same capacity as the two existing pulp mills in Alaska. (See Reference 1, p.37).

(2) Based on the lowest estimate of 4 private firms ($225,000/ADT/DAY) and assuming that this estimate is just fixed-capital for the lower 48 states. It is also assumed that this value includes pollution control. A scale-up factor of 1.65 is used to adjust the cost to Alaska.

Therefore;

$225,000/ADT/DAY X 600 ADT/DAY X 1.65 =$222,750,000 is fixed-capital investment and

$222,750,000 X 0.10 = $22,275,000 is working capital

∴ $222,750,000 + $22,275,000 = $245,025,000 for total capital investment

(3) Based on a material balance given in Reference 2 for the kraft process and normalized to a 1 ADT of pulp output. About 2.38 tons of wood & bark is needed to form 1 ADT of pulp.

Therefore;

210,000 ADT/DAY X 2.38 TONS Wood & Bark/ADT Pulp = 499,800 TONS Wood & Bark/DAY

(4) Based on the value of $150/1000 boardfeet given by Ron Galdebene-Alaskan Forest Service for the price of timber to the pulp mills. Also assuming the density of the bone dry timber is 28 lbs/ft^3.

Therefore;

$$500{,}000 \text{ Tons (wood \& bark) /YR} \times \frac{2000 \text{ LBS}}{\text{TON}} \times \frac{\text{FT}^3}{28\text{LBS}} \times \frac{12 \text{ boardfeet}}{\text{FT}^3} \times$$

$150/1000 boardfeet = $64,285,714/YR

(5) Number used from Reference 3, page 93 for chemicals as $30/ADT pulp

$30/ADT pulp X 210,000 ADT/YR = $6,300,000/YR

(6) Based on 0.7 man-hr/ADT from Reference 3, page 93 and assuming only 83% of that number is for direct labor. Also assuming $9.00/man-hr as based on information in Reference 4, page 2.

Therefore

$$\frac{0.7 \text{ man-hr}}{\text{ADT}} \times \frac{\$9.00}{\text{man-hr}} \times \frac{210{,}000 \text{ ADT}}{\text{YR}} \times \underline{0.83} = \$1{,}098{,}090/\text{YR}$$

(7) Based on 0.7 man-hr/ADT from Reference 3, page 93 and assuming only 17% of that number is for direct supervision. Also assuming $12.00/man-hr for supervisors wages.

Therefore;

$$0.7 \frac{\text{man-hr}}{\text{ADT}} \times \frac{\$12.00}{\text{man-hr}} \times \frac{210{,}000 \text{ ADT}}{\text{YR}} \times 0.17 = \$299{,}880/\text{YR}$$

(8) Calculated from information in Reference 3, page 59 and ending up with 7.54 X $10^6 \frac{\text{BTU}}{\text{ADT}}$ to be purchased as fuel.

$$7.54 \frac{\times 10^6 \text{BTU}}{\text{ADT}} \times \frac{\$2.00}{10^6 \text{BTU}} \times 210{,}000 \frac{\text{ADT}}{\text{YR}} = \$3{,}166{,}800/\text{YR}$$

(9) Assumed that the plant can generate all its electrical power needs from recovery processes.

(10) From Reference 3, page 93 there is 11,000 GALS/ADT.

Therefore;

$$11{,}000 \frac{\text{GALS}}{\text{ADT}} \times \frac{\$2.00}{1000\text{GAL}} \times 210{,}000 \frac{\text{ADT}}{\text{YR}} = \$4{,}620{,}000/\text{YR}$$

(11) From Reference 3, page 93 there is 20,000 $\frac{\text{GALS}}{\text{ADT}}$

Therefore;

$$20{,}000 \frac{\text{GALS}}{\text{ADT}} \times \frac{\$1.20}{1000\text{GAL}} \times 210{,}000 \frac{\text{ADT}}{\text{YR}} = \$5{,}040{,}000/\text{YR}$$

(12) From Reference 3, page 93 there is 20,000 $\frac{\text{GALS}}{\text{ADT}}$

Therefore;

$$20{,}000 \frac{\text{GALS}}{\text{ADT}} \times \frac{\$0.07}{1000\text{GAL}} \times 210{,}000 \frac{\text{ADT}}{\text{YR}} = \$294{,}000/\text{YR}$$

(13) Based on 0.6 man-hrs/ADT from Reference 3, page 93 and assuming $10.00/man-hr. Also from Reference 3, page 93 is $5/ADT for materials and supplies.

Therefore;

$$\left[\left(0.6 \frac{\text{man-hr}}{\text{ADT}} \times \frac{\$10.00}{\text{man-hr}}\right) + \frac{\$5 \text{ supplies}}{\text{ADT}}\right] \times 210{,}000 \frac{\text{ADT}}{\text{YR}} = \$2{,}310{,}000/\text{YR}$$

(14) Based on $1.00/ADT for supplies from Reference 3, page 93

Therefore;

$$\frac{\$1.00}{\text{ADT}} \times 210{,}000 \frac{\text{ADT}}{\text{YR}} = \$210{,}000/\text{YR}$$

(15) Based on $15.00/ADT from Reference 3, page 94.

Therefore;

$$\frac{\$15.00}{\text{ADT}} \times 210{,}000 \frac{\text{ADT}}{\text{YR}} = \$3{,}150{,}000/\text{YR}$$

(16) Assumed to be 10% of the fixed capital

$$\$222{,}750{,}000 \times \frac{0.10}{\text{YR}} = \$22{,}275{,}000/\text{YR}$$

(17) From value for Plant Overhead in Reference 3, page 93.

(18) From value for Labor Overhead in Reference 3, page 93.

(19) Based on excess production of electricity of $140 \frac{KWH}{ADT}$ as given in Reference 3, page 93 and assuming power sells for \$0.025/KWH

Therefore;

$$140 \frac{KWH}{ADT} \times 0.025/KWH \times 210{,}000 \frac{ADT}{YR} = \$735{,}000$$

(20) Based on a material balance given in Reference 2 for the kraft process and normalized to a 1 ADT of pulp output. Tall oil is produced at a rate of 86 lbs /ADT. The price for tall oil from Chemical Marketing Reproter October 31,1977 is \$150/TON

Therefore;

$$\frac{86LBS\ TALL\ OIL}{ADT} \times 210{,}000 \frac{ADT}{YR} \times \frac{\$150}{TON} \times \frac{TON}{2000LBS} = \$1{,}354{,}500/YR$$

(21) Based on a material balance given in Reference 2 for the kraft process and normalized to a1ADT of pulp output. Turpentine is produced at a rate of 15LBS /ADT. The price for turpentine from Chemical Marketing Reporter October 31,1977 is \$.45/GAL

Therefore

$$15 \frac{LBS\ Turpentine}{ADT} \times 210{,}000 \frac{ADT}{YR} \times \frac{GAL}{7.22LBS} \times \frac{\$.45}{GAL} = \$196{,}329.$$

(22) Based on Reference 5, Appendix A, methanol process the transport charges are $\frac{\$0.0098}{LB}$

There $\frac{\$0.0098}{LB} \times \frac{2000\ LBS}{ADT\ PULP} = \frac{\$19.60}{ADT\ PULP}$

(23) Based on chart in Reference 6, page 140.

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1. Lockwoods Directory of Paper and Allied Trades, 1976.

2. Evaluation of the Theoretical Potential for Energy Conservation in Seven Basic Industries, Battelle Columbus Labs. PB-244-772, July, 1975.

3. Environmental Considerations of Selected Energy Conserving Manufacturing Process Options: Volume V. Pulp and Paper Industry Report, Arthur D. Little, PB-264-271, December, 1976.

4. Alaska's Forest Products Industry, State Forester, State of Alaska, Jan 1976.

5. Alaskan North Slope Royalty Natural Gas, Battelle Northwest, August 1977.

6. North America - Profile 1977, Pulp and Paper.

APPENDIX A

PETROCHEMICAL PROCESS WORKSHEETS - ALASKAN INLAND LOCATION

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process LPG (liquid petroleum gas) Extraction-Expander Type
2. Capacity 21,323 bbl/day ethane ~~13,891 bbl/day propane~~ 3. Capital Investment $121 x 10^6
4. Feedstock Requirements ~590 mm SCFD North Slope Gas
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals		
Total		
C. Utility Requirements		
Fuel @ $2/$10^6$ Btu	$ 8,237,000	
Electrical Power @ $0.025/kWh	$ 103,000	
Cooling Water Makeup @ $1.20/Mgal	$ 106,000	
Boiler Feed Water @ $2/Mgal	$ 16,000	
Waste Water Treatment @ $1.90/Mgal	$ 40,000	
Cooling Water Circulation @ $0.07/Mgal	$ 234,000	
Total		$ 8,736,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 12 @ $28,000/yr. (includes benefits)	$ 336,000	
Supervision, @ 20% of Operating Labor	$ 67,000	
Maintenance, @ 4% of Capital Plant	$ 406,000	
General Administrative and Overhead @ 100% of Labor	$ 336,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 203,000	
Depreciation, 10% S.L.	$10,150,000	
Total		$11,498,000
6. Total Annual Manufacturing Costs		$20,234,000
7. Co-product/By-product Credits:		
Total		
8. Net Manufacturing Cost		$20,234,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$27,325,000
10. Net Costs and ROI		$47,559,000
11. Net Transfer Price/Pound		
12. Shipping Costs/Pound		
13. Total Costs/Pound		
14. Current Price/Pound		
15. Net Surplus Applied to Domestic Feedstocks/Pound		

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Olefin Plant
2. Capacity 1000 mm lb/yr ethylene ~~243.6 mm lb/yr propylene~~ 3. Capital Investment $437 mm
4. Feedstock Requirements 1245 mm lb/yr ethane; 902.2 mm lb/yr propane
5. Operating Costs:

A. Feedstock Costs	$47,559,000	
B. Catalysts and Chemicals	$ 425,000	
Total		$47,984,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$ 7,000,000	
Electrical Power @ $0.025/kWh	$ 317,000	
Cooling Water Makeup @ $1.20/Mgal	$ 960,000	
Boiler Feed Water @ $2/Mgal	$ 200,000	
Waste Water Treatment @ $1.90/Mgal	$ 342,000	
Cooling Water Circulation @ $0.07/Mgal	$ 1,610,000	
Total		$10,429,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 65 @ $28,000/yr. (includes benefits)	$ 1,820,000	
Supervision, @ 20% of Operating Labor	$ 364,000	
Maintenance, @ 4% of Capital Plant	$15,652,000	
General Administrative and Overhead @ 100% of Labor	$ 1,820,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 7,826,000	
Depreciation, 10% S.L.	$39,130,000	
Total		$ 66,612,000
6. Total Annual Manufacturing Costs		$125,025,000
7. Co-product/By-product Credits:		
C_4 Mixture @ $0.10/lb	$ 6,000,000	
Aromatic Mixture @ $0.13/lb	$ 6,032,000	
Total		($12,032,000)
8. Net Manufacturing Cost		$112,993,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$102,395,000
10. Net Costs and ROI		$215,388,000
11. Net Transfer Price/Pound	Ethylene--85.4% of Mfg. Cost[(a)] Propylene--14.6% of Mfg. Cost[(a)]	$0.184/lb ~~$0.129/lb~~
12. Shipping Costs/Pound		
13. Total Costs/Pound		
14. Current Price/Pound		
15. Net Surplus Applied to Domestic Feedstocks/Pound		

(a) Assumes product pricing ratio $\frac{\text{ethylene}}{\text{propylene}} = \frac{1.0}{0.7}$

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Low Density Polyethylene
2. Capacity 400 mm lb/yr 3. Capital Investment $230 mm
4. Feedstock Requirements 416 mm lb/yr ethylene
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 244,000	
Total		$ 244,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	$ 2,120,000	
Electrical Power @ $0.025/kWh	$ 7,000,000	
Cooling Water Makeup @ $1.20/Mgal	$ 456,000	
Boiler Feed Water @ $2/Mgal	$ 184,000	
Waste Water Treatment @ $1.90/Mgal	$ 91,000	
Cooling Water Circulation @ $0.07/Mgal	$ 756,000	
Total		$ 10,607,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 85 @ $28,000/yr. (includes benefits)	$ 2,380,000	
Supervision, @ 20% of Operating Labor	$ 476,000	
Maintenance, @ 4% of Capital Plant	$ 7,960,000	
General Administrative and Overhead @ 100% of Labor	$ 2,380,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 3,980,000	
Depreciation, 10% S.L.	$19,900,000	
Total		$ 37,076,000
6. Total Annual Manufacturing Costs		$ 47,927,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$ 47,927,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$ 52,850,000
10. Net Costs and ROI		$100,777,000
11. Net Transfer Price/Pound		$0.252
12. Shipping Costs/Pound (Rail to coast, hydrotrain to Seattle, rail to Chicago)		$0.054
13. Total Costs/Pound		$0.306
14. Current Price/Pound		$0.315
15. Net Surplus Applied to Domestic Feedstocks/Pound		$0.009

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process High Density Polyethylene
2. Capacity 150 mm lb/yr   3. Capital Investment $88 mm
4. Feedstock Requirements 157.5 mm lb/yr ethylene
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 662,000	
Total		$ 662,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	--	
Electrical Power @ $0.025/kWh	$ 443,000	
Cooling Water Makeup @ $1.20/Mgal	--	
Boiler Feed Water @ $2/Mgal	--	
Waste Water Treatment @ $1.90/Mgal	--	
Cooling Water Circulation @ $0.07/Mgal	--	
Total		$ 443,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 30 @ $28,000/yr. (includes benefits)	$ 840,000	
Supervision, @ 20% of Operating Labor	$ 168,000	
Maintenance, @ 4% of Capital Plant	$ 3,040,000	
General Administrative and Overhead @ 100% of Labor	$ 840,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 1,520,000	
Depreciation, 10% S.L.	$ 7,600,000	
Total		$14,008,000
6. Total Annual Manufacturing Costs		$15,113,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$15,113,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$20,200,000
10. Net Costs and ROI		$35,313,000
11. Net Transfer Price/Pound		$0.235
12. Shipping Costs/Pound (Rail to coast, hydrotrain to Seattle, rail to Chicago)		$0.054
13. Total Costs/Pound		$0.289
14. Current Price/Pound		$0.318
15. Net Surplus Applied to Domestic Feedstocks/Pound		$0.029

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Polypropylene
2. Capacity 110 mm lb/yr 3. Capital Investment $118 mm
4. Feedstock Requirements 126 mm lb/yr propylene
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 106,000	
Total		$ 106,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	$ 1,012,000	
Electrical Power @ $0.025/kWh	$ 523,000	
Cooling Water Makeup @ $1.20/Mgal	$ 153,000	
Boiler Feed Water @ $2/Mgal	$ 88,000	
Waste Water Treatment @ $1.90/Mgal	$ 21,000	
Cooling Water Circulation @ $0.07/Mgal	$ 254,000	
Total		$ 2,051,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 64 @ $28,000/yr. (includes benefits)	$ 1,792,000	
Supervision, @ 20% of Operating Labor	$ 358,000	
Maintenance, @ 4% of Capital Plant	$ 4,280,000	
General Administrative and Overhead @ 100% of Labor	$ 1,792,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 2,140,000	
Depreciation, 10% S.L.	$10,700,000	
Total		$21,062,000
6. Total Annual Manufacturing Costs		$23,219,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$23,219,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$27,850,000
10. Net Costs and ROI		$51,069,000
11. Net Transfer Price/Pound		$0.464
12. Shipping Costs/Pound (Rail to Coast, hydrotrain to Seattle, rail to Chicago)		$0.054
13. Total Costs/Pound		$0.518
14. Current Price/Pound		$0.300
15. Net Surplus Applied to Domestic Feedstocks/Pound		($0.218)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Vinyl Chloride Monomer
2. Capacity 192 mm lb/yr 3. Capital Investment $48 mm
4. Feedstock Requirements 91.6 mm lb/yr ethylene, 119.2 mm lb/yr chlorine
5. Operating Costs:

A. Feedstock Costs chlorine @ $200/ton dlud.	$11,920,000	
B. Catalysts and Chemicals		
Total		$11,920,000
C. Utility Requirements		
Fuel @ $2/10^{6} Btu	$ 1,200,000	
Electrical Power @ $0.025/kWh	$ 535,000	
Cooling Water Makeup @ $1.20/Mgal	$ 298,000	
Boiler Feed Water @ $2/Mgal	$ 75,000	
Waste Water Treatment @ $1.90/Mgal	$ 60,000	
Cooling Water Circulation @ $0.07/Mgal	$ 434,000	
Total		$ 2,602,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 32 @ $28,000/yr. (includes benefits)	$ 896,000	
Supervision, @ 20% of Operating Labor	$ 179,000	
Maintenance, @ 4% of Capital Plant	$ 1,760,000	
General Administrative and Overhead @ 100% of Labor	$ 896,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 880,000	
Depreciation, 10% S.L.	$ 4,400,000	
Total		$ 9,011,000
6. Total Annual Manufacturing Costs		$23,533,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$23,533,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$11,400,000
10. Net Costs and ROI		$34,933,000
11. Net Transfer Price/Pound		$0.182
12. Shipping Costs/Pound (Rail to coastal terminal, tanker to Gulf Coast, barge to Chicago/Omaha terminal)		$0.031
13. Total Costs/Pound		$0.213
14. Current Price/Pound		$0.143
15. Net Surplus Applied to Domestic Feedstocks/Pound		($0.070)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Polyvinyl Chloride
2. Capacity 190 mm lb/yr 3. Capital Investment $94 mm
4. Feedstock Requirements 192 mm lb/yr Vinyl Chloride Monomer
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 828,000	
Total		$ 828,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$ 293,000	
Electrical Power @ $0.025/kWh	$ 333,000	
Cooling Water Makeup @ $1.20/Mgal	$ 66,000	
Boiler Feed Water @ $2/Mgal	$ 18,000	
Waste Water Treatment @ $1.90/Mgal	$ 22,000	
Cooling Water Circulation @ $0.07/Mgal	$ 96,000	
Total		$ 828,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 78 @ $28,000/yr. (includes benefits)	$2,184,000	
Supervision, @ 20% of Operating Labor	$ 437,000	
Maintenance, @ 4% of Capital Plant	$3,040,000	
General Administrative and Overhead @ 100% of Labor	$2,184,000	
Taxes and Insurance, @ 2% of Capital Plant	$1,520,000	
Depreciation, 10% S.L.	$7,600,000	
Total		$16,965,000

6. Total Annual Manufacturing Costs		$18,621,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$18,621,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$20,800,000
10. Net Costs and ROI		$39,421,000
11. Net Transfer Price/Pound		$0.207
12. Shipping Costs/Pound (Rail to Coast, hydrotrain to Seattle, rail to Chicago)		$0.054
13. Total Costs/Pound		$0.261
14. Current Price/Pound		$0.390
15. Net Surplus Applied to Domestic Feedstocks/Pound		$0.129

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Styrene Monomer
2. Capacity 400 mm lb/yr 3. Capital Investment $149 mm
4. Feedstock Requirements 125 mm lb/yr ethylene, 326 mm lb/yr benzene
5. Operating Costs:

A. Feedstock Costs -- Benzene @ $0.14/lb dlud.	$45,640,000	
B. Catalysts and Chemicals	$ 800,000	
Total		$46,440,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	$ 3,800,000	
Electrical Power @ $0.025/kWh	$ 300,000	
Cooling Water Makeup @ $1.20/Mgal	$ 144,000	
Boiler Feed Water @ $2/Mgal	$ 152,000	
Waste Water Treatment @ $1.90/Mgal	$ 76,000	
Cooling Water Circulation @ $0.07/Mgal	$ 218,000	
Total		$ 4,690,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 24 @ $28,000/yr. (includes benefits)	$ 672,000	
Supervision, @ 20% of Operating Labor	$ 134,000	
Maintenance, @ 4% of Capital Plant	$ 4,640,000	
General Administrative and Overhead @ 100% of Labor	$ 672,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 2,320,000	
Depreciation, 10% S.L.	$11,600,000	
Total		$20,038,000
6. Total Annual Manufacturing Costs		$71,168,000
7. Co-product/By-product Credits:		
Al Chloride (25 wt%), 3.6 mm lb/yr @ $0.03/lb	$ 108,000	
Toluene (97 wt%), 20.8 mm lb/yr @ $0.63/gal	$ 1,812,000	
Total		($ 1,920,000)
8. Net Manufacturing Cost		$69,248,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$32,300,000
10. Net Costs and ROI		$101,548,000
11. Net Transfer Price/Pound		$0.254
12. Shipping Costs/Pound (Rail to coastal terminal, tanker to Gulf Coast, barge to Chicago/Omaha terminal)		$0.031
13. Total Costs/Pound		$0.285
14. Current Price/Pound		$0.210
15. Net Surplus Applied to Domestic Feedstocks/Pound		($0.075)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Polystyrene

2. Capacity 200 mm lb/yr   3. Capital Investment $70 mm

4. Feedstock Requirements 206 mm lb/yr styrene monomer

5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 64,000	
Total		$ 64,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$ 191,000	
Electrical Power @ $0.025/kWh	$ 500,000	
Cooling Water Makeup @ $1.20/Mgal	$ 19,000	
Boiler Feed Water @ $2/Mgal	$ 4,000	
Waste Water Treatment @ $1.90/Mgal	$ 8,000	
Cooling Water Circulation @ $0.07/Mgal	$ 1,000	
Total		$ 723,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 100 @ $28,000/yr. (includes benefits)	$2,800,000	
Supervision, @ 20% of Operating Labor	$ 560,000	
Maintenance, @ 4% of Capital Plant	$2,280,000	
General Administrative and Overhead @ 100% of Labor	$2,800,000	
Taxes and Insurance, @ 2% of Capital Plant	$1,140,000	
Depreciation, 10% S.L.	$5,700,000	
Total		$15,280,000

6.	Total Annual Manufacturing Costs	$16,067,000
7.	Co-product/By-product Credits:	
	Total	0
8.	Net Manufacturing Cost	$16,067,000
9.	ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital	$15,550,000
10.	Net Costs and ROI	$31,617,000
11.	Net Transfer Price/Pound	$0.158
12.	Shipping Costs/Pound (Rail to Coast, hydrotrain to Sea Seattle, rail to Chicago)	$0.054
13.	Total Costs/Pound	$0.212
14.	Current Price/Pound	$0.280
15.	Net Surplus Applied to Domestic Feedstocks/Pound	$0.068

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Ethylene Glycol
2. Capacity 300 mm lb/yr 3. Capital Investment $122 mm
4. Feedstock Requirements 210 mm lb/yr ethylene, 277 mm lb/yr oxygen
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 239,000	
Total		$ 239,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$ 1,242,000	
Electrical Power @ $0.025/kWh	$ 75,000	
Cooling Water Makeup @ $1.20/Mgal	$ 144,000	
Boiler Feed Water @ $2/Mgal	$ 30,000	
Waste Water Treatment @ $1.90/Mgal	$ 57,000	
Cooling Water Circulation @ $0.07/Mgal	$ 567,000	
Total		$ 2,115,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 72 @ $28,000/yr. (includes benefits)	$ 2,016,000	
Supervision, @ 20% of Operating Labor	$ 403,000	
Maintenance, @ 4% of Capital Plant	$ 4,160,000	
General Administrative and Overhead @ 100% of Labor	$ 2,016,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 2,080,000	
Depreciation, 10% S.L.	$10,400,000	
Total		$21,075,000

6. Total Annual Manufacturing Costs		$23,429,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$23,429,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$27,800,000
10. Net Costs and ROI		$51,229,000
11. Net Transfer Price/Pound		$0.171
12. Shipping Costs/Pound (Rail to Coast, tanker to Gulf Coast, barge to Chicago/Omaha)		$0.031
13. Total Costs/Pound		$0.202
14. Current Price/Pound		$0.245
15. Net Surplus Applied to Domestic Feedstocks/Pound		$0.043

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Propylene Glycol
2. Capacity 130 mm lb/yr   3. Capital Investment $62 mm (Inc. O_2 plant)
4. Feedstock Requirements 95 mm lb/yr propylene
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 94,000	
Total		$ 94,000
C. Utility Requirements		
Fuel @ $2/$10^6$ Btu	$ 538,000	
Electrical Power @ $0.025/kWh	$ 32,000	
Cooling Water Makeup @ $1.20/Mgal	$ 62,000	
Boiler Feed Water @ $2/Mgal	$ 13,000	
Waste Water Treatment @ $1.90/Mgal	$ 25,000	
Cooling Water Circulation @ $0.07/Mgal	$ 91,000	
Total		$ 761,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 48 @ $28,000/yr. (includes benefits)	$ 1,344,000	
Supervision, @ 20% of Operating Labor	$ 269,000	
Maintenance, @ 4% of Capital Plant	$ 2,200,000	
General Administrative and Overhead @ 100% of Labor	$ 1,344,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 1,100,000	
Depreciation, 10% S.L.	$ 5,500,000	
Total		$11,757,000
6. Total Annual Manufacturing Costs		$12,612,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$12,612,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$14,450,000
10. Net Costs and ROI		$27,062,000
11. Net Transfer Price/Pound		$0.208
12. Shipping Costs/Pound (Rail to coast, tanker to Gulf Coast, barge to Chicago/Omaha)		$0.031
13. Total Costs/Pound		$0.239
14. Current Price/Pound		$0.250
15. Net Surplus Applied to Domestic Feedstocks/Pound		$0.011

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Acrylonitrile
2. Capacity 100 mm lb/yr   3. Capital Investment $97 mm
4. Feedstock Requirements 117.5 mm lb/yr propylene, 47.5 mm lb/yr ammonia
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 319,000	
Total		$ 319,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$ 450,000	
Electrical Power @ $0.025/kWh	$ 454,000	
Cooling Water Makeup @ $1.20/Mgal	$ 288,000	
Boiler Feed Water @ $2/Mgal	$ 27,000	
Waste Water Treatment @ $1.90/Mgal	$ 60,000	
Cooling Water Circulation @ $0.07/Mgal	$ 420,000	
Total		$ 1,699,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 36 @ $28,000/yr. (includes benefits)	$1,008,000	
Supervision, @ 20% of Operating Labor	$ 202,000	
Maintenance, @ 4% of Capital Plant	$3,240,000	
General Administrative and Overhead @ 100% of Labor	$1,008,000	
Taxes and Insurance, @ 2% of Capital Plant	$1,620,000	
Depreciation, 10% S.L.	$8,100,000	
Total		$15,178,000
6. Total Annual Manufacturing Costs		$17,196,000
7. Co-product/By-product Credits:		
Hydrogen Cyanide, 13 mm lb/yr @ $0.20/lb	$2,600,000	
Acetonitrile, 3 mm lb/yr @ $0.30/lb	$ 900,000	
Total		($ 3,500,000)
8. Net Manufacturing Cost		$13,696,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$21,850,000
10. Net Costs and ROI		$35,546,000
11. Net Transfer Price/Pound		$0.355
12. Shipping Costs/Pound (Rail to coast, tanker to Gulf Coast, barge to Chicago or rail to Southeast)		$0.031
13. Total Costs/Pound		$0.386
14. Current Price/Pound		$0.275
15. Net Surplus Applied to Domestic Feedstocks/Pound		($0.111)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Ammonia
2. Capacity 876 mm lb/yr 3. Capital Investment $139 mm
4. Feedstock Requirements 14,279 mm SCF/yr natural gas (feedstock and fuel)
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 419,000	
Total		$ 419,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	Inc. in feedstock	
Electrical Power @ $0.025/kWh	$ 164,000	
Cooling Water Makeup @ $1.20/Mgal	$ 158,000	
Boiler Feed Water @ $2/Mgal	$ 420,000	
Waste Water Treatment @ $1.90/Mgal	$ 133,000	
Cooling Water Circulation @ $0.07/Mgal	$2,208,000	
Total		$ 3,083,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 60 @ $28,000/yr. (includes benefits)	$1,680,000	
Supervision, @ 20% of Operating Labor	$ 336,000	
Maintenance, @ 4% of Capital Plant	$4,960,000	
General Administrative and Overhead @ 100% of Labor	$1,680,000	
Taxes and Insurance, @ 2% of Capital Plant	$2,480,000	
Depreciation, 10% S.L.	$12,400,000	
Total		$23,536,000

6. Total Annual Manufacturing Costs	$27,038,000
7. Co-product/By-product Credits:	
Total	0
8. Net Manufacturing Cost	$27,038,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital	$32,500,000
10. Net Costs and ROI	$59,538,000
11. Net Transfer Price/Pound	$0.068
12. Shipping Costs/Pound (Rail to coast, barge to West Coast)	$0.015
13. Total Costs/Pound	$0.083
14. Current Price/Pound	$0.065
15. Net Surplus Applied to Domestic Feedstocks/Pound	($0.018)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Urea
2. Capacity 1095 mm lb/yr 3. Capital Investment $77 mm
4. Feedstock Requirements 635 mm lb/yr ammonia, 832 mm lb/yr carbon dioxide
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 159,000	
Total		$ 159,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$4,812,000	
Electrical Power @ $0.025/kWh	$1,738,000	
Cooling Water Makeup @ $1.20/Mgal	$ 578,000	
Boiler Feed Water @ $2/Mgal	$ 22,000	
Waste Water Treatment @ $1.90/Mgal	$ 188,000	
Cooling Water Circulation @ $0.07/Mgal	$ 958,000	
Total		$ 8,296,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 48 @ $28,000/yr. (includes benefits)	$1,344,000	
Supervision, @ 20% of Operating Labor	$ 269,000	
Maintenance, @ 4% of Capital Plant	$2,440,000	
General Administrative and Overhead @ 100% of Labor	$1,344,000	
Taxes and Insurance, @ 2% of Capital Plant	$1,220,000	
Depreciation, 10% S.L.	$6,100,000	
Total		$12,717,000
6. Total Annual Manufacturing Costs		$21,172,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$21,172,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$16,850,000
10. Net Costs and ROI		$38,022,000
11. Net Transfer Price/Pound		$0.035
12. Shipping Costs/Pound (Rail to Coast, ship to Gulf Coast, barge to Chicago/Omaha)		$0.022
13. Total Costs/Pound		$0.057
14. Current Price/Pound		$0.065
15. Net Surplus Applied to Domestic Feedstocks/Pound		$0.008

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Ammonium Nitrate (Including Nitric Acid Plant)
2. Capacity 527.8 mm lb/yr 3. Capital Investment $36 mm
4. Feedstock Requirements 241 mm lb/yr ammonia
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 398,000	
Total		$ 398,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$1,344,000	
Electrical Power @ $0.025/kWh	$3,887,000	
Cooling Water Makeup @ $1.20/Mgal	$ 239,000	
Boiler Feed Water @ $2/Mgal	$ 349,000	
Waste Water Treatment @ $1.90/Mgal	$ 17,000	
Cooling Water Circulation @ $0.07/Mgal	$ 400,000	
Total		$ 6,236,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 12 @ $28,000/yr. (includes benefits)	$ 336,000	
Supervision, @ 20% of Operating Labor	$ 67,000	
Maintenance, @ 4% of Capital Plant	$1,120,000	
General Administrative and Overhead @ 100% of Labor	$ 336,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 560,000	
Depreciation, 10% S.L.	$2,800,000	
Total		$ 5,219,000
6. Total Annual Manufacturing Costs		$11,853,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$11,853,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$ 7,800,000
10. Net Costs and ROI		$19,653,000
11. Net Transfer Price/Pound		$0.037
12. Shipping Costs/Pound (Rail to Coast, hydrotrain to Seattle, rail to Omaha)		$0.041
13. Total Costs/Pound		$0.078
14. Current Price/Pound		$0.055
15. Net Surplus Applied to Domestic Feedstocks/Pound		($0.023)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Methanol
2. Capacity 730 mm lb/yr 3. Capital Investment $93 mm
4. Feedstock Requirements 9866 mm SCF/yr Natural Gas
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 310,000	
Total		$ 310,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	$3,752,000	
Electrical Power @ $0.025/kWh	$ 44,000	
Cooling Water Makeup @ $1.20/Mgal	$ 771,000	
Boiler Feed Water @ $2/Mgal	$ 217,000	
Waste Water Treatment @ $1.90/Mgal	$ 374,000	
Cooling Water Circulation @ $0.07/Mgal	$1,124,000	
Total		$ 6,282,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 40 @ $28,000/yr. (includes benefits)	$1,120,000	
Supervision, @ 20% of Operating Labor	$ 224,000	
Maintenance, @ 4% of Capital Plant	$3,120,000	
General Administrative and Overhead @ 100% of Labor	$1,120,000	
Taxes and Insurance, @ 2% of Capital Plant	$1,560,000	
Depreciation, 10% S.L.	$7,800,000	
Total		$14,944,000

6. Total Annual Manufacturing Costs	$21,536,000
7. Co-product/By-product Credits:	
Total	0
8. Net Manufacturing Cost	$21,536,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital	$21,000,000
10. Net Costs and ROI	$42,536,000
11. Net Transfer Price/Pound	$0.058
12. Shipping Costs/Pound (Rail to coast, tanker to West Coast)	$0.018
13. Total Costs/Pound	$0.076
14. Current Price/Pound	$0.050
15. Net Surplus Applied to Domestic Feedstocks/Pound	($0.026)

PROCESS WORKSHEET - ALASKAN INLAND LOCATION

1. Process Formaldehyde, 37 wt% Solution
2. Capacity 400 mm lb/yr 3. Capital Investment $16 mm
4. Feedstock Requirements 172.4 mm lb/yr Methanol
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	$ 204,000	
Total		$ 204,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	$ 460,000	
Electrical Power @ $0.025/kWh	$ 70,000	
Cooling Water Makeup @ $1.20/Mgal	$ 110,000	
Boiler Feed Water @ $2/Mgal	$ 86,000	
Waste Water Treatment @ $1.90/Mgal	$ 68,000	
Cooling Water Circulation @ $0.07/Mgal	$ 182,000	
Total		$ 976,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 16 @ $28,000/yr. (includes benefits)	$ 448,000	
Supervision, @ 20% of Operating Labor	$ 90,000	
Maintenance, @ 4% of Capital Plant	$ 440,000	
General Administrative and Overhead @ 100% of Labor	$ 448,000	
Taxes and Insurance, @ 2% of Capital Plant	$ 220,000	
Depreciation, 10% S.L.	$1,100,000	
Total		$2,746,000
6. Total Annual Manufacturing Costs		$3,926,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		$3,926,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		$3,250,000
10. Net Costs and ROI		$7,176,000
11. Net Transfer Price/Pound		$0.018
12. Shipping Costs/Pound (Rail to Coast, Tanker to Seattle/Portland)		$0.017
13. Total Costs/Pound		$0.035
14. Current Price/Pound		$0.053
15. Net Surplus Applied to Domestic Feedstocks/Pound		$0.018

APPENDIX B

PROCESS WORKSHEETS - U.S. GULF COAST

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Olefin Plant - Based on Kawait Naphtha - high cracking severity
2. Capacity 1000 mm lb/yr ethylene ~~420 mm lb/yr propylene~~ 3. Capital Investment $298 mm
4. Feedstock Requirements 12,346,000 bbl/yr Kawait Naptha
5. Operating Costs:

A. Feedstock Costs Naphtha		
B. Catalysts and Chemicals	600,000	
Total		600,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	3,466,000	($11,267 \times 10^9$ Btu provided by cracking residue gases)
Electrical Power @ $0.025/kWh	350,000	
Cooling Water Makeup @ $1.20/Mgal	1,704,000	
Boiler Feed Water @ $2/Mgal	100,000	
Waste Water Treatment @ $1.90/Mgal	600,000	
Cooling Water Circulation @ $0.07/Mgal	2,450,000	
Total		8,670,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 80 @ $24,000/yr. (includes benefits)	1,920,000	
Supervision, @ 20% of Operating Labor	384,000	
Maintenance, @ 4% of Capital Plant	10,640,000	
General Administrative and Overhead @ 100% of Labor	1,920,000	
Taxes and Insurance, @ 2% of Capital Plant	5,320,000	
Depreciation, 10% S.L.	26,600,000	
Total		46,784,000

6. Total Annual Manufacturing Costs		56,054,000
7. Co-product/By-product Credits:		
Batadiene, 141,700,000 lb/yr @ $0.18/lb	25,506,000	
C4 mixture, 106,700,000 lb/yr @ $0.10/lb	~~10,670,000~~	
Pyrolysis gasoline, 740,900,000 lb/yr @ $18/bbl	54,325,000	
Hydrogen, 5,100,000 lb/yr @ $\$2.00/10^6$ Btu	~~600,000~~	
Aromatic fuel oil, 195,400,000 lb/yr @ $\$1.90/10^6$ Btu	6,349,000	Total ~~(97,450,000)~~
8. Net Manufacturing Cost		(41,396,000)
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		69,700,000
10. Net Costs and ROI		28,304,000
11. Net Transfer Price/Pound [Ethylene @ 77% of manuf. cost / Propylene @ 23% of manuf. cost[a]]		~~$ 0.022~~ $ 0.015
12. Shipping Costs/Pound FOB Plant		

13. Total Costs/Pound	Ethylene	0.022
	Propylene	0.015
14. Current Price/Pound	Ethylene	0.120
	Propylene	~~0.095~~
15. Net Surplus Applied to Domestic Feedstocks/Pound	Ethylene	0.010
	Propylene	0.080

(a) Assumes product pricing ratio: $\frac{\text{Ethylene}}{\text{Propylene}} = \frac{1}{0.7}$

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Low Density Polyethylene
2. Capacity 400 mm lb/yr 3. Capital Investment $115 mm
4. Feedstock Requirements 416 mm lb/yr ethylene
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	230,000	
Total		230,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	2,120,000	
Electrical Power @ $0.025/kWh	7,000,000	
Cooling Water Makeup @ $1.20/Mgal	456,000	
Boiler Feed Water @ $2/Mgal	184,000	
Waste Water Treatment @ $1.90/Mgal	91,000	
Cooling Water Circulation @ $0.07/Mgal	756,000	
Total		10,607,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 85 @ $24,000/yr. (includes benefits)	2,040,000	
Supervision, @ 20% of Operating Labor	408,000	
Maintenance, @ 4% of Capital Plant	3,980,000	
General Administrative and Overhead @ 100% of Labor	2,040,000	
Taxes and Insurance, @ 2% of Capital Plant	1,990,000	
Depreciation, 10% S.L.	9,950,000	
Total		20,408,000
6. Total Annual Manufacturing Costs		31,245,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		31,245,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		26,425,000
10. Net Costs and ROI		57,670,000
11. Net Transfer Price/Pound		$ 0.144
12. Shipping Costs/Pound (Rail to Chicago)		$ 0.033
13. Total Costs/Pound		$ 0.177
14. Current Price/Pound		0.315
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.138

PROCESS WORKSHEET - U.S. GULF COAST

1. Process High Density Polyethylene
2. Capacity 150 mm lb/yr   3. Capital Investment $44 mm
4. Feedstock Requirements 157.5 mm lb/yr ethylene
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	623,000	
Total		623,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	--	
Electrical Power @ $0.025/kWh	443,000	
Cooling Water Makeup @ $1.20/Mgal	--	
Boiler Feed Water @ $2/Mgal	--	
Waste Water Treatment @ $1.90/Mgal	--	
Cooling Water Circulation @ $0.07/Mgal	--	
Total		443,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 30 @ $24,000/yr. (includes benefits)	720,000	
Supervision, @ 20% of Operating Labor	144,000	
Maintenance, @ 4% of Capital Plant	1,520,000	
General Administrative and Overhead @ 100% of Labor	720,000	
Taxes and Insurance, @ 2% of Capital Plant	760,000	
Depreciation, 10% S.L.	3,800,000	
Total		7,664,000
6. Total Annual Manufacturing Costs		8,730,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		8,730,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		10,100,000
10. Net Costs and ROI		18,830,000
11. Net Transfer Price/Pound		$ 0.126
12. Shipping Costs/Pound (Rail to Chicago)		0.033
13. Total Costs/Pound		$ 0.159
14. Current Price/Pound		$ 0.318
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.159

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Polypropylene
2. Capacity 110 mm lb/yr 3. Capital Investment $59 mm
4. Feedstock Requirements 126 mm lb/yr propylene
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	100,000	
Total		100,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	1,012,000	
Electrical Power @ $0.025/kWh	523,000	
Cooling Water Makeup @ $1.20/Mgal	153,000	
Boiler Feed Water @ $2/Mgal	88,000	
Waste Water Treatment @ $1.90/Mgal	21,000	
Cooling Water Circulation @ $0.07/Mgal	254,000	
Total		2,051,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 64 @ $24,000/yr. (includes benefits)	1,536,000	
Supervision, @ 20% of Operating Labor	307,000	
Maintenance, @ 4% of Capital Plant	2,140,000	
General Administrative and Overhead @ 100% of Labor	1,536,000	
Taxes and Insurance, @ 2% of Capital Plant	1,070,000	
Depreciation, 10% S.L.	5,350,000	
Total		11,939,000
6. Total Annual Manufacturing Costs		14,090,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		14,090,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		13,925,000
10. Net Costs and ROI		28,015,000
11. Net Transfer Price/Pound		$ 0.255
12. Shipping Costs/Pound (Rail to Chicago)		$ 0.033
13. Total Costs/Pound		$ 0.288
14. Current Price/Pound		0.300
15. Net Surplus Applied to Domestic Feedstocks/Pound		• 0.012

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Vinyl Chloride Monomer
2. Capacity 192 mm lb/yr   3. Capital Investment $24 mm
4. Feedstock Requirements 91.6 mm lb/yr ethylene, 119.2 mm lb/yr chlorine
5. Operating Costs:

A. Feedstock Costs Chlorine @ $150/ton	8,940,000	
B. Catalysts and Chemicals		
Total		8,940,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	1,200,000	
Electrical Power @ $0.025/kWh	535,000	
Cooling Water Makeup @ $1.20/Mgal	298,000	
Boiler Feed Water @ $2/Mgal	75,000	
Waste Water Treatment @ $1.90/Mgal	60,000	
Cooling Water Circulation @ $0.07/Mgal	434,000	
Total		2,602,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 32 @ $24,000/yr. (includes benefits)	768,000	
Supervision, @ 20% of Operating Labor	154,000	
Maintenance, @ 4% of Capital Plant	880,000	
General Administrative and Overhead @ 100% of Labor	768,000	
Taxes and Insurance, @ 2% of Capital Plant	440,000	
Depreciation, 10% S.L.	2,200,000	
Total		5,210,000
6. Total Annual Manufacturing Costs		16,752,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		16,752,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		5,700,000
10. Net Costs and ROI		22,452,000
11. Net Transfer Price/Pound		$ 0.117
12. Shipping Costs/Pound (Barge to Chicago/Omaha Terminal)		$ 0.007
13. Total Costs/Pound		$ 0.124
14. Current Price/Pound		0.143
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.019

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Poly Vinyl Chloride
2. Capacity 190 mm lb/yr 3. Capital Investment $47 mm
4. Feedstock Requirements 192 mm lb/yr vinyl chloride monomer
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	779,000	
Total		779,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	293,000	
Electrical Power @ $0.025/kWh	333,000	
Cooling Water Makeup @ $1.20/Mgal	66,000	
Boiler Feed Water @ $2/Mgal	18,000	
Waste Water Treatment @ $1.90/Mgal	22,000	
Cooling Water Circulation @ $0.07/Mgal	96,000	
Total		828,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 78 @ $24,000/yr. (includes benefits)	1,872,000	
Supervision, @ 20% of Operating Labor	374,000	
Maintenance, @ 4% of Capital Plant	1,520,000	
General Administrative and Overhead @ 100% of Labor	1,872,000	
Taxes and Insurance, @ 2% of Capital Plant	760,000	
Depreciation, 10% S.L.	3,800,000	
Total		10,198,000
6. Total Annual Manufacturing Costs		11,805,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		11,805,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		10,400,000
10. Net Costs and ROI		22,205,000
11. Net Transfer Price/Pound		$ 0.117
12. Shipping Costs/Pound (Rail to Chicago)		$ 0.033
13. Total Costs/Pound		$ 0.150
14. Current Price/Pound		0.390
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.240

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Styrene Monomer

2. Capacity 400 mm lb/yr 3. Capital Investment $74 mm

4. Feedstock Requirements 125 mm lb/yr ethylene, 326 mm lb/yr benzene

5. Operating Costs:

A. Feedstock Costs Benzene @ $0.086/lb	28,036,000	
B. Catalysts and Chemicals	700,000	
Total		28,736,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	3,800,000	
Electrical Power @ $0.025/kWh	300,000	
Cooling Water Makeup @ $1.20/Mgal	144,000	
Boiler Feed Water @ $2/Mgal	152,000	
Waste Water Treatment @ $1.90/Mgal	76,000	
Cooling Water Circulation @ $0.07/Mgal	218,000	
Total		4,690,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 24 @ $24,000/yr. (includes benefits)	576,000	
Supervision, @ 20% of Operating Labor	115,000	
Maintenance, @ 4% of Capital Plant	2,320,000	
General Administrative and Overhead @ 100% of Labor	576,000	
Taxes and Insurance, @ 2% of Capital Plant	1,160,000	
Depreciation, 10% S.L.	5,800,000	
Total		10,547,000
6. Total Annual Manufacturing Costs		43,973,000
7. Co-product/By-product Credits: Al Chloride (25 wt%), 3.6 mm lb/yr @ $0.04/lb	144,000	
Toluene (97 wt%), 20.8 mm lb/yr @ $0.63/gal	1,812,000	
Total		(1,956,000)
8. Net Manufacturing Cost		42,017,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		16,100,000
10. Net Costs and ROI		58,117,000
11. Net Transfer Price/Pound		$ 0.145
12. Shipping Costs/Pound (Barge to Chicago/Omaha Terminal)		$ 0.007
13. Total Costs/Pound		$ 0.152
14. Current Price/Pound		0.210
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.058

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Polystyrene
2. Capacity 200 mm lb/yr   3. Capital Investment $35 mm
4. Feedstock Requirements 206 mm lb/yr styrene monomer
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	60,000	
Total		60,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	191,000	
Electrical Power @ $0.025/kWh	500,000	
Cooling Water Makeup @ $1.20/Mgal	19,000	
Boiler Feed Water @ $2/Mgal	4,000	
Waste Water Treatment @ $1.90/Mgal	8,000	
Cooling Water Circulation @ $0.07/Mgal	1,000	
Total		723,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 100 @ $24,000/yr. (includes benefits)	2,400,000	
Supervision, @ 20% of Operating Labor	480,000	
Maintenance, @ 4% of Capital Plant	1,140,000	
General Administrative and Overhead @ 100% of Labor	2,400,000	
Taxes and Insurance, @ 2% of Capital Plant	570,000	
Depreciation, 10% S.L.	2,850,000	
Total		9,840,000
6. Total Annual Manufacturing Costs		10,623,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		10,623,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		7,775,000
10. Net Costs and ROI		18,398,000
11. Net Transfer Price/Pound		$ 0.092
12. Shipping Costs/Pound (Rail to Chicago)		$ 0.033
13. Total Costs/Pound		$ 0.125
14. Current Price/Pound		0.280
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.155

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Ethylene Glycol
2. Capacity 300 mm lb/yr 3. Capital Investment $61 mm
4. Feedstock Requirements 210 mm lb/yr ethylene, 277 mm lb/yr oxygen
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	225,000	
Total		225,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	1,242,000	
Electrical Power @ $0.025/kWh	75,000	
Cooling Water Makeup @ $1.20/Mgal	144,000	
Boiler Feed Water @ $2/Mgal	30,000	
Waste Water Treatment @ $1.90/Mgal	57,000	
Cooling Water Circulation @ $0.07/Mgal	567,000	
Total		2,115,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 72 @ $24,000/yr. (includes benefits)	1,728,000	
Supervision, @ 20% of Operating Labor	346,000	
Maintenance, @ 4% of Capital Plant	2,090,000	
General Administrative and Overhead @ 100% of Labor	1,728,000	
Taxes and Insurance, @ 2% of Capital Plant	1,040,000	
Depreciation, 10% S.L.	5,200,000	
Total		12,122,000
6. Total Annual Manufacturing Costs		14,462,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		14,462,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		13,900,000
10. Net Costs and ROI		28,362,000
11. Net Transfer Price/Pound		$ 0.095
12. Shipping Costs/Pound (Barbe to Chicago/Omaha Terminal)		0.006
13. Total Costs/Pound		$ 0.101
14. Current Price/Pound		0.245
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.144

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Propylene Glycol
2. Capacity 130 mm lb/yr 3. Capital Investment #31 mm
4. Feedstock Requirements 95 mm lb/yr propylene
5. Operating Costs:

A.	Feedstock Costs		
B.	Catalysts and Chemicals	88,000	
	Total		88,000
C.	Utility Requirements		
	Fuel @ $2/10^6 Btu	538,000	
	Electrical Power @ $0.025/kWh	32,000	
	Cooling Water Makeup @ $1.20/Mgal	62,000	
	Boiler Feed Water @ $2/Mgal	13,000	
	Waste Water Treatment @ $1.90/Mgal	25,000	
	Cooling Water Circulation @ $0.07/Mgal	91,000	
	Total		761,000
D.	Labor, Maintenance, Overhead, etc.:		
	Operating Labor, 48 @ $24,000/yr. (includes benefits)	1,152,000	
	Supervision, @ 20% of Operating Labor	230,000	
	Maintenance, @ 4% of Capital Plant	1,100,000	
	General Administrative and Overhead @ 100% of Labor	1,152,000	
	Taxes and Insurance, @ 2% of Capital Plant	550,000	
	Depreciation, 10% S.L.	2,750,000	
	Total		6,934,000
6.	Total Annual Manufacturing Costs		7,783,000
7.	Co-product/By-product Credits:		
	Total		0
8.	Net Manufacturing Cost		7,783,000
9.	ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		7,225,000
10.	Net Costs and ROI		15,008,000
11.	Net Transfer Price/Pound		$ 0.115
12.	Shipping Costs/Pound (Barge to Chicago/Omaha Terminal)		$ 0.006
13.	Total Costs/Pound		$ 0.121
14.	Current Price/Pound		0.250
15.	Net Surplus Applied to Domestic Feedstocks/Pound		0.129

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Acrylonitrile
2. Capacity 100 mm lb/yr   3. Capital Investment $48.5 mm
4. Feedstock Requirements 117.5 mm lb/yr propylene, 47.5 mm lb/yr ammonia
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	300,000	
Total		300,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	450,000	
Electrical Power @ $0.025/kWh	454,000	
Cooling Water Makeup @ $1.20/Mgal	288,000	
Boiler Feed Water @ $2/Mgal	27,000	
Waste Water Treatment @ $1.90/Mgal	60,000	
Cooling Water Circulation @ $0.07/Mgal	420,000	
Total		1,699,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 36 @ $24,000/yr. (includes benefits)	864,000	
Supervision, @ 20% of Operating Labor	173,000	
Maintenance, @ 4% of Capital Plant	1,620,000	
General Administrative and Overhead @ 100% of Labor	864,000	
Taxes and Insurance, @ 2% of Capital Plant	810,000	
Depreciation, 10% S.L.	4,050,000	
Total		8,381,000
6. Total Annual Manufacturing Costs		10,380,000
7. Co-product/By-product Credits:		
Hydrogen Cyanide, 13 mm lb/yr @ $0.33/lb	4,290,000	
Acetonitrile, 3 mm lb/yr @ $0.40/lb	1,200,000	
Total		(5,490,000)
8. Net Manufacturing Cost		4,890,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		10,925,000
10. Net Costs and ROI		15,815,000
11. Net Transfer Price/Pound		$ 0.158
12. Shipping Costs/Pound (Barge to Chicago or Southeast Terminal)		0.007
13. Total Costs/Pound		$ 0.165
14. Current Price/Pound		0.275
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.110

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Ammonia (Naphtha Feedstock)
2. Capacity 876 mm lb/yr 3. Capital Investment $92 mm
4. Feedstock Requirements 2,786,519 bbl/yr Naphtha Feed & Fuel 705,546,610 lb
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	606,000	
Total		606,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	Included in feedstock	
Electrical Power @ $0.025/kWh	291,000	
Cooling Water Makeup @ $1.20/Mgal	631,000	
Boiler Feed Water @ $2/Mgal	1,577,000	
Waste Water Treatment @ $1.90/Mgal	266,000	
Cooling Water Circulation @ $0.07/Mgal	3,312,000	
Total		6,077,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 45 @ $24,000/yr. (includes benefits)	1,080,000	
Supervision, @ 20% of Operating Labor	216,000	
Maintenance, @ 4% of Capital Plant	2,960,000	
General Administrative and Overhead @ 100% of Labor	1,080,000	
Taxes and Insurance, @ 2% of Capital Plant	1,480,000	
Depreciation, 10% S.L.	7,400,000	
Total		14,216,000

6. Total Annual Manufacturing Costs		20,899,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		20,899,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		20,300,000
10. Net Costs and ROI		41,199,000
11. Net Transfer Price/Pound		$ 0.047
12. Shipping Costs/Pound (Barge to Chicago/Omaha Terminal)		$ 0.007
13. Total Costs/Pound		0.054
14. Current Price/Pound		0.065
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.011

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Urea
2. Capacity 1095 mm lb/yr 3. Capital Investment $38.5 mm
4. Feedstock Requirements 635 mm lb/yr Ammonia, 832 mm lb/yr Carbon Dioxide
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	150,000	
Total		150,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	4,812,000	
Electrical Power @ $0.025/kWh	1,738,000	
Cooling Water Makeup @ $1.20/Mgal	578,000	
Boiler Feed Water @ $2/Mgal	22,000	
Waste Water Treatment @ $1.90/Mgal	188,000	
Cooling Water Circulation @ $0.07/Mgal	958,000	
Total		8,296,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 48 @ $24,000/yr. (includes benefits)	1,152,000	
Supervision, @ 20% of Operating Labor	230,000	
Maintenance, @ 4% of Capital Plant	1,220,000	
General Administrative and Overhead @ 100% of Labor	1,152,000	
Taxes and Insurance, @ 2% of Capital Plant	610,000	
Depreciation, 10% S.L.	3,050,000	
Total		7,414,000
6. Total Annual Manufacturing Costs		15,860,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		15,860,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		8,425,000
10. Net Costs and ROI		24,285,000
11. Net Transfer Price/Pound		$ 0.022
12. Shipping Costs/Pound (Barge to Chicago/Omaha Terminal)		0.006
13. Total Costs/Pound		$ 0.028
14. Current Price/Pound		0.065
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.037

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Ammoniam Nitrate (including nitric acid plant)
2. Capacity 527.8 mm lb/yr 3. Capital Investment $18 mm
4. Feedstock Requirements 241 mm lb/yr Ammonia
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	375,000	
Total		375,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	1,344,000	
Electrical Power @ $0.025/kWh	3,887,000	
Cooling Water Makeup @ $1.20/Mgal	239,000	
Boiler Feed Water @ $2/Mgal	349,000	
Waste Water Treatment @ $1.90/Mgal	17,000	
Cooling Water Circulation @ $0.07/Mgal	400,000	
Total		6,236,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 12 @ $24,000/yr. (includes benefits)	288,000	
Supervision, @ 20% of Operating Labor	58,000	
Maintenance, @ 4% of Capital Plant	560,000	
General Administrative and Overhead @ 100% of Labor	288,000	
Taxes and Insurance, @ 2% of Capital Plant	280,000	
Depreciation, 10% S.L.	1,400,000	
Total		2,874,000
6. Total Annual Manufacturing Costs		9,485,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		9,485,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		3,900,000
10. Net Costs and ROI		13,385,000
11. Net Transfer Price/Pound		$ 0.025
12. Shipping Costs/Pound (Barge to Chicago/Omaha Terminal)		0.006
13. Total Costs/Pound		$ 0.031
14. Current Price/Pound		0.055
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.024

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Methanol
2. Capacity 730 mm lb/yr   3. Capital Investment $112 mm
4. Feedstock Requirements 1,425,603 bbl/yr Naphtha 360,962,680 lb
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	560,000	
Total		560,000
C. Utility Requirements		
Fuel @ $\$2/10^6$ Btu	9,188,000	
Electrical Power @ $0.025/kWh	75,000	
Cooling Water Makeup @ $1.20/Mgal	771,000	
Boiler Feed Water @ $2/Mgal	271,000	
Waste Water Treatment @ $1.90/Mgal	374,000	
Cooling Water Circulation @ $0.07/Mgal	1,124,000	
Total		11,749,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 45 @ $24,000/yr. (includes benefits)	1,080,000	
Supervision, @ 20% of Operating Labor	216,000	
Maintenance, @ 4% of Capital Plant	3,760,000	
General Administrative and Overhead @ 100% of Labor	1,080,000	
Taxes and Insurance, @ 2% of Capital Plant	1,880,000	
Depreciation, 10% S.L.	9,400,000	
Total		17,416,000
6. Total Annual Manufacturing Costs		29,725,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		29,725,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		25,300,000
10. Net Costs and ROI		55,025,000
11. Net Transfer Price/Pound		$ 0.075
12. Shipping Costs/Pound (Tanker to West Coast Terminal)		FOB Gulf Coast
13. Total Costs/Pound		$ 0.075
14. Current Price/Pound FOB Gulf Coast		0.067
15. Net Surplus Applied to Domestic Feedstocks/Pound		(0.008)

PROCESS WORKSHEET - U.S. GULF COAST

1. Process Formaldehyde 37 wt% Solution
2. Capacity 400 mm lb/yr 3. Capital Investment $8 mm
4. Feedstock Requirements 172.4 mm lb/yr Methanol
5. Operating Costs:

A. Feedstock Costs		
B. Catalysts and Chemicals	192,000	
Total		192,000
C. Utility Requirements		
Fuel @ $2/10^6 Btu	460,000	
Electrical Power @ $0.025/kWh	70,000	
Cooling Water Makeup @ $1.20/Mgal	110,000	
Boiler Feed Water @ $2/Mgal	86,000	
Waste Water Treatment @ $1.90/Mgal	68,000	
Cooling Water Circulation @ $0.07/Mgal	182,000	
Total		976,000
D. Labor, Maintenance, Overhead, etc.:		
Operating Labor, 16 @ $24,000/yr. (includes benefits)	384,000	
Supervision, @ 20% of Operating Labor	77,000	
Maintenance, @ 4% of Capital Plant	220,000	
General Administrative and Overhead @ 100% of Labor	384,000	
Taxes and Insurance, @ 2% of Capital Plant	110,000	
Depreciation, 10% S.L.	550,000	
Total		1,725,000
6. Total Annual Manufacturing Costs		2,893,000
7. Co-product/By-product Credits:		
Total		0
8. Net Manufacturing Cost		2,893,000
9. ROI. 25% Before Taxes on Fixed Investment plus 10% on Working Capital		1,625,000
10. Net Costs and ROI		4,518,000
11. Net Transfer Price/Pound		$ 0.011
12. Shipping Costs/Pound (Tanker to West Coast Terminal)		$ 0.006
13. Total Costs/Pound		$ 0.017
14. Current Price/Pound		0.053
15. Net Surplus Applied to Domestic Feedstocks/Pound		0.036