COLLECTED WORK NO. 26

INDUSTRIAL ENERGY USAGE PATTERNS

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INDUSTRIAL ENERGY USAGE PATTERNS

INTRODUCTION

Many controversial areas and differences of opinion are involved in energy supply/demand/cost factors. However, on one point there is agreement: our professional and personal lives have been irreversibly altered by changes in the energy sector. These changes will continue in the future!

In the past, our affluent economy and the industries that supply our needs were fueled by plentiful, low-cost energy sources largely available within our borders. This is no longer true. We are in a transitional period in which the future is not predictable because we have never before faced the energy problems that we now see before us.

To illustrate the problem, our recent prime energy sources have been oil and natural gas. However, our domestic production of these fuels peaked in 1970 and 1973, respectively, while long-term energy demand trends continue upward. Energy costs have escalated significantly since the 1973 oil embargo, and all evidence indicates that the long-term energy price trend will continue to be up. We cannot again expect to see energy prices that existed before the early 1973 preembargo days.

Despite the obstacles that we face, there is a strong incentive to keep our industrial plants operating at high capacity. This incentive is illustrated by Slide 1, which shows a worldwide trend; namely, that increased commercial energy usage tends to result in higher per capita gross national product,[1] which in turn determines the way we live and the strength of our national security.

Of particular interest to this discussion is the industrial sector that provides the goods we need. Industry has historically consumed about one-third of our energy. We know that we face legislative, regulatory, economic, and supply changes in energy, which will affect the industrial sector. One example is that of new regulation to prohibit use of natural gas in new utility and large industrial boilers. We therefore must locate and select alternative fuels for this and other purposes, which presents a challenge to industry and to your organization.

A number of approaches will obviously be used to meet this future energy supply challenge. One will be to use our energy more efficiently by application of conservation techniques. Another will be to adopt alternative energy sources and advanced technology. Part of this second approach includes significant incentives to find ways to increase the use of our vast coal resources and nuclear energy potential.

Anticipating that energy questions will dominate future world economics and security for the remainder of the twentieth century, The Ralph M. Parsons Company strengthened its programs several years ago to meet these challenges. Examples include:

- Acceptance of assignments in 1972 to assist the Office of Coal Research, now a part of the Energy Research and Development Administration (ERDA), to develop viable coal conversion processes to produce ecologically clean liquid, solid, and gaseous fuels from coal. Specific responsibilities include:

- Provision of <u>Preliminary Design</u> services in which Parsons develops preliminary conceptual designs and economic evaluations for commercial coal conversion plants.
- Provision of <u>Technical Evaluation</u> services to assist ERDA in monitoring certain coal liquefaction development programs.

- Creation of an Energy Department in preembargo 1973 to provide services in the field of the emerging energy technologies.
- Development of new technology to meet future needs. Examples are:
  - A bulk methanation process, an integral step in the production of substitute natural gas (SNG).
  - A tail gas treating process that removes sulfur contaminants from gaseous plant effluents to meet environmental standards.

These Parsons programs are contributing already by helping to meet future energy supply needs.

With this background, this paper will present a summary of industrial energy supply requirements and suggest methods to meet them. In addition to background information on the total U.S. scene, it will present information on the western United States and depict energy characteristics of the paper industry, which are of interest here in the Pacific Northwest. The paper's specific objectives are:

- Description of industrial energy demands.
- Suggestion of methods of meeting future demands with emphasis on application of alternative sources and technology.

INDUSTRIAL ENERGY CONSUMPTION

The distribution of U.S. energy consumption by sector is illustrated in Slide 2. Here we see that the industrial sector is the largest consumer of energy, using about one-third of the total, followed by transportation and residential-plus-commercial.[2]

The source of this energy is shown in Slide 3. Here we see that somewhat more than 80% of our energy requirements are of U.S. origin and the remainder, largely in the form of liquid petroleum products, are imported. The total amounts to 36.6 million barrels per day of oil equivalent.[3]

Distribution of U.S. consumption by type is illustrated in Slide 4. Here we see that oil and natural gas supplied more than three-quarters of our energy in 1974, while coal, which represents more than 80% of our indigenous fossil reserves, supplied less than 20% of our energy.

Let's pause here and note that the preceding results indicate several objectives for future energy programs. We should:

1. Define ways to produce a larger share of our energy needs from indigenous sources. This includes expanded domestic production of oil and gas, plus increased use of coal and nuclear energy.
2. Use energy more efficiently.

A look at the energy usage pattern for the western section of the U.S., as compared to the country as a whole, is shown in Slide 5. This shows that District V of the Petroleum Administration for Defense (PAD), consisting of California, Arizona, Nevada, Oregon, and Washington, depends more on oil and less on coal than the average in the U.S.[4] It is also a larger percentage user of electricity than the other districts. The electricity used in District V is largely produced from residual fuel, gas, and hydroelectric facilities. Another characteristic of District V is that environmental restraints tend to be more stringent in the high-consuming urban areas.

Let's now consider those industries that are large energy users and therefore most sensitive to energy supply and cost factors. The nine industries listed in Slide 6 consume approximately 40% of the energy consumed by U.S. industry; this amounts to about one-eighth of the total U.S. energy consumption.[4,5]

Since we are meeting in the Pacific Northwest, the paper industry is of interest. The production of basic paper products and conversion to consumer products used approximately 0.40 x 10^{15} Btu (quads) of energy in 1972.[5] This represented approximately 2.0% of the industrial energy usage. The energy sources used by the paper industry were approximately as shown below:

Energy Source	%	
Oil	24.6	
Natural Gas	18.4	
Coal	9.1	
Electricity and Steam	5.4	
Internal	42.5	(Internally generated waste-wood products, black liquor, electric)
	100.0	

To illustrate the magnitude of the consumption, the industry used about a billion ft^3/day of natural gas in 1972, and about half of that was supplied on an interruptible basis.[7]

These results indicate that the industry should consider the possibility that it may have to look to greater future dependence on coal and nuclear-based energy sources - unless it can obtain assurance of continued access to adequate oil and natural gas supplies at competitive prices. Current and projected future energy supply patterns indicate that these conversions should be carefully considered to ensure that Pacific Northwest industries will continue to operate at desired levels of production.

POTENTIAL FUTURE CHANGES IN ENERGY SUPPLY/DEMAND/COST PATTERNS

The accurate prediction of future energy supply/demand/cost patterns is difficult. However, it is important to consider them in order to minimize the impact of future events that will affect these patterns. Slide 7 indicates one possible projection of future energy supply for the U.S. using an intermediate scenario - considered neither highly optimistic nor highly pessimistic.

This slide indicates relatively constant supplies of liquid petroleum products and natural gas, increasing dependence on coal and nuclear energy, and decreasing dependence on imports. The inference is that industries now dependent on oil and natural gas should be looking not only toward conservation techniques, but also toward means of substituting other energy sources to fuel their expansion plans, if necessary.

Turning to industrial energy demands, one 1980 scenario, based on "business as usual" coupled with conservation efforts, indicates fossil fuel requirements to be:[8]

Energy Source	Quantity in 10^{15} Btu/Yr (Quads)	%
Natural Gas	9.5	43
Petroleum	7.4	33
Coal	5.4	24
Total	22.3	100.0

This represents a predicted future shift in source energy distribution with the relative use of natural gas by industry declining, petroleum increasing, and coal essentially maintaining its share but providing a greater absolute quantity of energy.

Energy cost projections are most difficult, but the consensus is that the long-term trend is up, with the rate of increase leveling off in the post-1985 period.[9, 10] For the near term, the real costs of energy may stabilize as the world adjusts to higher prices by reducing its energy consumption growth rate.

The net result is to reaffirm the opinion that incentive exists to design and operate our plants to use energy efficiently, not only to ensure that there is adequate energy available to keep them onstream, but also because of the large potential dollar savings. A second objective is to define alternative energy sources that are reliable and economically competitive. Let's now look at these two approaches.

POTENTIALS FOR ENERGY CONSERVATION

National goals have been set for energy conservation by the Federal Energy Administration. For instance, the petroleum industry has been assigned the goal of improving its energy efficiency by 15% by 1980 and has actually achieved an 8.7% improvement within the past 3 years.[11] For comparison, the paper industry has been given the goal of a 10% improvement over base year 1972.[11] To date, it can claim a 2.1% gain[6], worth approximately $20,000,000 per year using an arbitrary $2 per million Btu energy value.

Energy conservation represents an important application of engineering, scientific and economic disciplines. It amounts to using a systematic plan of analysis and measurement to define optimum energy usage. It applies advanced design and operating technology to such items as optimizing burner design, heat exchanger design, control of product evaporation losses, plant location and logistics, methods of meeting environmental standards, optimization of plant prime mover systems including extraction turbines to provide process steam, and increased heat recovery.

An example of potential improvement in heat recovery is the reduction of stack gas temperatures. Traditionally, boilers have operated with stack gas temperatures in the range of 400 - 450°F. This temperature was set by the dewpoint of sulfur oxides in the gas. Where low-sulfur fuels are available, cost/benefit analysis of the value of additional recovered energy vis-a-vis the incremental cost of heat recovery could provide the incentive to reduce the temperature by 100 - 200°F for large industrial boiler applications.

The need for industrial energy conservation studies has brought forth a number of firms to supply such services to the industry. These contractors offer the potential advantages of objectivity, a broad range of disciplines to handle the required diverse technical and economic analyses, the ability to quickly provide cost/benefit analyses based on current construction and revamp costs, and the ability to complete studies without diluting the efforts of plant personnel whose prime responsibility is to maintain production.

ALTERNATIVE AND ADVANCED TECHNOLOGY OPTIONS

We hope that the abundant new reserves of "low-cost" crude oil and natural gas will be discovered in the U.S. and that our energy supply/cost problems will disappear. However, we have no assurance that this will happen and that the present suppliers will be able to meet future market demands. We therefore should make plans for alternative means of energy for industrial use as required and economically justified. Some available alternatives include coal, solar energy, and advanced methods of electricity generation. Let's look at these candidates in turn.

Coal

For direct combustion: where low-sulfur coal is available at a competitive delivered price, it can be used directly as a boiler fuel and deserves consideration for increased use by industry. Where coal has a high-sulfur content, it can be used in conjunction with stack gas scrubbing facilities as they prove reliable and economical.

The in-plant production of low or intermediate Btu gaseous plant fuel by gasification of coal deserves consideration. The use of air to gasify the coal will produce a fuel with a heating value in the range of 150 to 250 Btu per standard cubic foot; the use of oxygen will increase this to the range of 400 to 500 Btu per standard cubic foot. High-sulfur coal can be gasified and its sulfur content removed by proven techniques to produce a clean fuel.

As precedence for this approach, there were numerous industrial gasifiers used in the U.S. prior to the introduction of widespread distribution of natural gas in the late 1940s and '50s. There are many in operation outside of the U.S. today; we know they work. The return of in-plant coal gasification as a source of fuel, as well as a chemical plant raw material, is a probable future event. The next generation of gasifiers is expected to be more reliable and efficient than earlier versions.

The construction of many large complexes to produce substitute natural gas (SNG) from coal is predicted. These facilities are expected to be constructed and operated by the utility and pipeline companies. SNG will be distributed through existing natural gas pipelines or new lines constructed for that purpose. These SNG units will be larger and necessarily more complex than the facilities for in-plant low/intermediate Btu gas supply. A cost/benefit analysis can provide guidance for the preferred choice between the two for a given industrial plant and location.

Coal liquefaction in large industrial complexes can supply a variety of low-sulfur fuels including solids and liquids; all liquefaction plants can co-produce some gas for local fuel use. Importantly, they also produce petrochemical and chemical feedstocks that can become increasingly important.

Solar Energy

Solar energy is currently used on a limited scale for residential applications. Its use, while small, is growing rapidly. Looking into the future, a number of industrial applications of solar energy are expected. These applications include heating and cooling of buildings as well as supply of low temperature energy for use in industrial purposes. Basic technology for these applications exists and is being researched for improvement. Parts of the western U.S. offer greatest opportunity for its application. Still further in the future, probably in the year 2000 era, is the potential for production of electricity by solar means. Significant improvements to reduce costs must first be developed.

Electricity

Further development in large scale production of electricity near the fuel source and improved methods and efficiencies in transmission can be expected. This scheme offers the potential advantage of centralization of environmental control responsibility and facilities. These are potential intermediate-range (10-15-year) developments. Successful development would provide incentive to use electrical energy more widely in industrial plant operations.

SUMMARY: IMPACT ON INDUSTRY

The potential impact of energy cost and changing supply patterns is expected to be significant. It will increasingly affect both our professional and personal lives. In plant operations, we must use existing energy more efficiently than we did in the past. We must also maintain flexibility to use the best/most economical form of energy at a given time, and this can be expected to be a fluid picture. These objectives will add a new dimension to our responsibilities.

Before 1973 we accepted the availability of adequate quantities of low-cost energy as a part of our heritage. Now we realize that we must work harder, use more innovative approaches, and look more carefully at the economics involved to meet our industrial plant design and operating objectives.

ACKNOWLEDGMENT

We gratefully acknowledge the guidance and support of the Energy Research and Development Administration-Fossil Energy for our work in support of their program to develop viable coal conversion technology for use by U.S. industry and other users.

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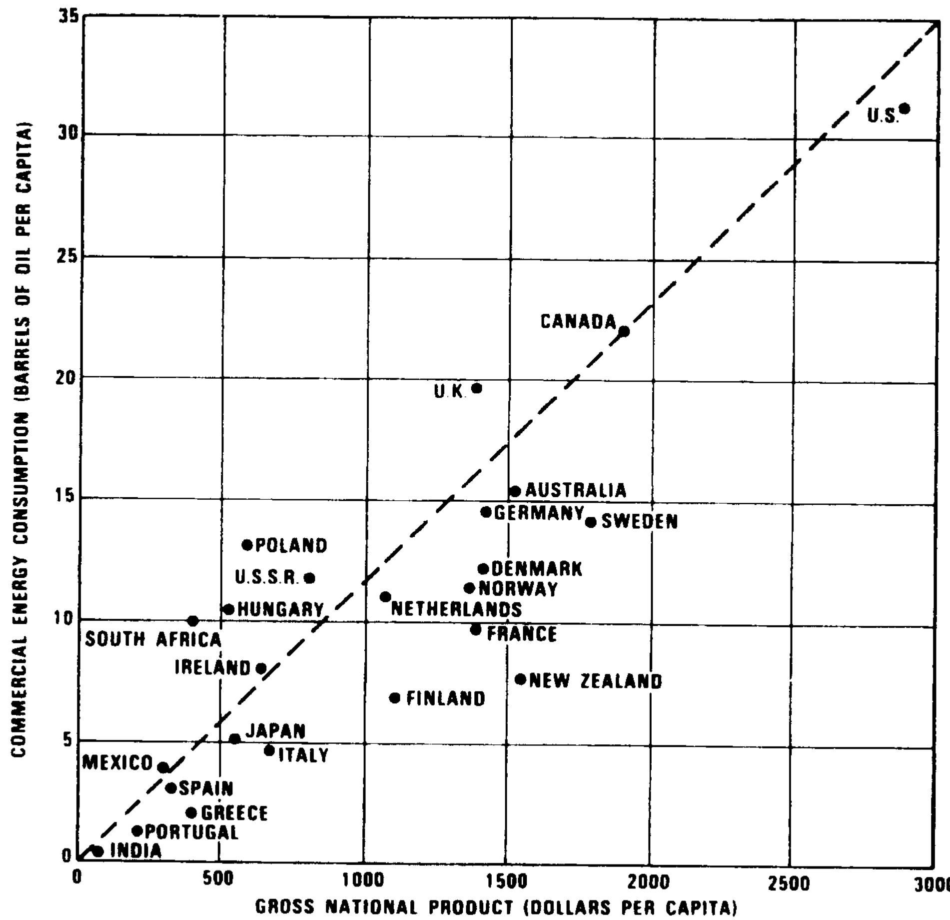
INDUSTRIAL ENERGY USAGE PATTERNS

PER CAPITA GNP DEPENDENCY ON COMMERCIAL ENERGY CONSUMPTION



AFTER COOK, 1971

SLIDE 1

INDUSTRIAL ENERGY USAGE PATTERNS
ENERGY CONSUMPTION BY SECTOR

SECTOR	10^{15} BTU			PERCENT		
	1970	1975	1980	1970	1975	1980
INDUSTRIAL	23.1	24.9	27.4	35	34	33
TRANSPORTATION	17.9	18.3	19.9	28	25	24
RESIDENTIAL/ COMMERICAL	17.5	23.4	28.2	27	32	34
OTHER	6.8	6.6	7.5	10	9	9
TOTAL	65.3	73.2	83.0	100	100	100

1970 ACTUAL

1975 ESTIMATED

1980 FORECAST

INDUSTRIAL ENERGY USAGE PATTERNS

1974 ENERGY CONSUMPTION BY MAJOR SOURCES

ENERGY SOURCE	UNITS	UNITS/DAY	MMB/D (OIL EQUIV.)	QUADS (10^{15} BTU)	% (BTUS)
U.S. ORIGIN					
OIL	BBLS	10.9 MMB/D	10.9	21.8	29.8
NAT. GAS	MCF	61 X 10^5 MCF	10.6	21.3	28.9
COAL	TONS	1.64 MMT/D	6.5	13.0	17.8
HYDRO/GEO.	KWH	2.55 MWh	1.5	2.9	4.1
NUCLEAR	KWH	1.02MWh	0.6	1.2	1.6
TOTAL			30.1	60.2	82.2
IMPORTS					
OIL	BBL	6.0 MMB	6.0	12.0	16.4
NAT GAS	Mcf	2.7 X 10^5 Mcf	0.5	1.0	1.4
TOTAL			6.5	13.0	17.8
GRAND TOTAL			36.6	73.2	100.0

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SLIDE 3

INDUSTRIAL ENERGY USAGE PATTERNS

ENERGY CONSUMPTION BY TYPE*

TYPE	MM B/D (OIL EQUIVALENT)	PERCENT
OIL	16.9	46.2
NATURAL GAS	11.1	30.3
COAL	6.5	17.8
HYDRO/GEOTHERMAL	1.5	4.1
NUCLEAR	0.6	1.6
TOTAL	36.6	100.0

*1974

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SLIDE 4

INDUSTRIAL ENERGY USAGE PATTERNS

GEOGRAPHICAL ENERGY USAGE DISTRIBUTION

COMPARISON OF WESTERN UNITED STATES WITH NATIONAL AVERAGE

CLASS	PAD V PERCENT	U.S. PERCENT
PETROLEUM (OIL)	25.2	16.3
NATURAL GAS	53.0	50.5
COAL	4.1	21.5
ELECTRICITY	17.7	11.7
TOTAL	100.0	100.0

SLIDE 5

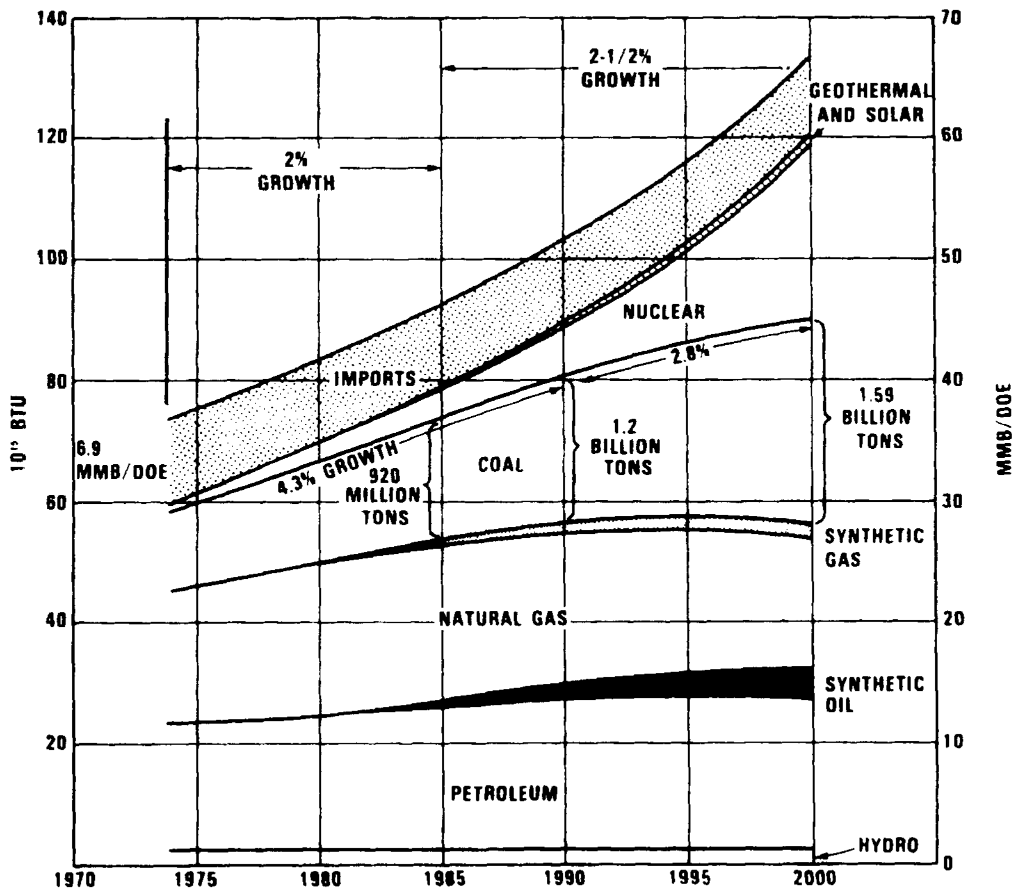
INDUSTRIAL ENERGY USAGE PATTERNS

ENERGY CONSUMPTION BY INDUSTRY

INDUSTRY	10^{15} BTU/YR	MM B/D OIL EQUIVALENT	PERCENT OF INDUSTRIAL USE
PLASTICS	0.604	0.302	3.0
PETROLEUM REFINING	1.745	0.873	8.6
CEMENT	0.602	0.201	2.9
ALUMINUM	0.690	0.345	3.3
STEEL	2.528	1.264	12.4
GLASS	0.205	0.103	1.0
PAPER	0.479	0.239	2.3
RUBBER	0.199	0.099	1.0
FOOD PROCESSING	1.031	0.515	5.1
TOTAL	8.083	3.941	39.6

SLIDE 6

INDUSTRIAL ENERGY USAGE PATTERNS
PROJECTED FUTURE ENERGY SUPPLY
1975 TO 2000



SLIDE 7

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POTENTIAL MARKETS FOR EMERGING ENERGY TECHNOLOGIES

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ABSTRACT

Nations bordering the Pacific Ocean represent one of the world's major trade areas, with a population of 375 million. Economic viability of this area after the mid-80s will depend upon its ability to obtain major supplies of energy at affordable prices. This paper concludes that energy-producing reserves and current and projected oil and gas supply/demand ratios could result in a shortfall in excess of 12 million barrels per day (MM BPD) equivalent by 1990 in this area. The dim prospects for locating large new oil and gas provinces are reviewed. The cost of finding and delivering oil and gas from new wells and the current cost of imported oil are also reviewed and found to be high. These costs are then compared with projected costs for LNG, synfuels from coal, and synfuels from shale delivered to a Southern West Coast U.S.A. location. Results indicate that six emerging technologies are possible competitive sources of environmentally acceptable fuels that could produce the required major energy supplies at affordable prices. The six deserve prompt attention to evaluate development of capability to build and operate industrial production facilities using these technologies.

INTRODUCTION

Nations bordering the Pacific Ocean area face an increasing near-term (1990) deficit in oil/gas supply. Hard decisions should be made soon regarding ways to increase the energy supply for these nations in order to maintain and expand the area's economic viability. This paper discusses ways to achieve that objective.

The area is a current net importer of oil - 5.2 MM BPD of Middle East oil were imported in 1975. The shortfall in oil and natural gas is projected to increase to about 12.3 MM equivalent BPD by 1990. The fondest hope is that large new low-cost oil/gas provinces will be found, either in the Pacific area or in other parts of the world for supply to the area. However, the history of the past 30 years provides little hope that this will happen - during that time, only five major Free World oil provinces were discovered, which had total recoverable reserves equivalent to about 4 years' current Free World demand. In addition, the cost of discovering, producing, and transporting for future discoveries will be high - as illustrated by the Alaskan fields (Ref. 1 states that the cost of transporting Alaskan oil to the West Coast will be in the range of \$5 to \$8/barrel, and with a \$11.64/barrel new oil wellhead price the delivered price to the West Coast could be \$17/barrel or higher).

Fortunately, the Pacific area has large reserves of coal and oil shale and the logistical capability to distribute energy as illustrated by large LNG projects. Conversion of the area's more than 275 billion tons of currently economically minable coal to synfuels could provide about 700 equivalent billion barrels of environmentally acceptable oil and gas. This represents about 65 years' supply to the area based on projected 1990 demand.

Proven reserves of oil shale currently considered economically minable could add another 7 years, making the total potential for synfuels production from coal and shale more than 70 years' supply. Increasing the allowable cost of recovery of coal and shale would increase the synfuels availability many times.

While all coal and shale will not be converted to synfuels, the potentials listed above clearly illustrate that options exist for the production of oil and gas requirements. A key question is that of economics. Current projections (to be discussed here) show that under favorable economic conditions, selected future generation synfuels processes could compete with imported oil and gas. Synfuels production facilities will be large and capital-intensive.

If the synfuels are to make significant contributions to the marketplace by 1990, hard decisions must be made to proceed with the demonstration of the technologies and supporting development - particularly in the area of equipment for these large plants.

This paper projects the Pacific area future energy demands and describes projected technologies and costs of meeting that demand. The information presented herein incorporates some results based on work by The Ralph M. Parsons Company for the Energy Research and Development Administration - Fossil Energy, Major Facilities Division. During the past 4 years, Parsons has developed four conceptual designs for production of synfuels from coal (Refs. 2, 3, 4, 5).

The future supply of energy to the Pacific area will undoubtedly require large innovative projects with management, technical, and logistical challenges similar to the North Slope Project, in which crude oil from the Prudhoe Bay area in Alaska is gathered and prepared for transport to

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the lower 48 states. Parsons has been Managing Contractor for this work, which is a part of the largest private undertaking in history, and of which Increments I and II will be completed within budget and ahead of schedule.

THE TECHNOLOGIES

Emerging energy technologies here include procedures for supplying liquid and gaseous fuels to high population/industrialization areas by techniques yet to be widely used on a commercial scale: liquefied natural gas (LNG) and liquids/gases from coal or shale. Tar sands were considered but are not included because of the limited number of large reserve locations and low potential for export movements. Enhanced oil recovery and stack gas scrubbing were excluded because of time/space limitations for this presentation.

LOGIC PATTERN

To look at the potential contributions of new oil and gas productions plus the market potentials for the emerging energy technologies, we have selected an arbitrary logic pattern. This logic pattern projects that each of the energy options will be a potential supply to a defined high-population industrialized area with stated environmental regulations; we have arbitrarily selected a Southern West Coast location in the U.S.A. as this area. The environmental fuel user restrictions for this area are illustrated in Table I. The logic is that comparison at this location will provide a basis for subsequent comparisons at other locations.

All economics are based on fourth-quarter 1976 U.S. dollars. Required product selling prices are based on a 12% discounted cash flow rate of return (DCF), 65% debt financing, 9% interest rate, 4-year construction schedule, and 25-year operating life, unless otherwise stated.

THE AREA

As used here, the Pacific area ("area") consists of representative industrial Free World countries that border the Pacific Ocean. In countries with large geographical areas, it includes those sections that might reasonably be expected to supply competitive transportation for export supply from the area. The latter restriction would apply to Canada, Australia and the United States. Countries, and states within countries, included in this discussion are listed in Table II. They are also shown in Figure 1, where the considerable shipping distances are illustrated.

The population of the countries and states under study is approximately 375 million (Ref. 6) - about 14% of the current Free World population. The shipping distances can be great; for instance, shipment of low-sulfur Indonesian oil to the West Coast of the United States requires a movement of approximately 8,300 nm. Similarly, shipments between Alaska and Japan or between the lower United States and Peru cover approximately 3,700 nm. Efficient transportation procedures are therefore a major factor in the Pacific area energy strategies.

Table I. Fuel User Restrictions in Southern California

Parameter	Maximum Emissions Allowed by Standards
Visible emissions	Ringelmann 1 (approximately 20% opacity)
Particulates	Volume: 0.01 grain/dry standard cubic foot
	Weight: 11 lb/hr
Nitrogen oxides (as NO_2)	
Electric power generation	Gaseous fuel, 80 ppm; liquid fuel, 160 ppm; solid fuel, 225 ppm
Other fuel-burning	Gaseous fuel, 125 ppm; liquid or solid fuel, 225 ppm
Carbon monoxide	2000 ppm
Sulfur dioxide	[Proposed: 500 ppm]
	Fuel Composition Regulations
Sulfur content	Gaseous fuel, 800 ppm calculated as H_2S
	Liquid or solid fuel, 0.5% by weight[a]

[a]This requirement is met by Indonesian stocks (average sulfur content: crude, 0.1%; residual oil, 0.3%), not by Alaskan stocks (average sulfur content: crude, 1.0%; residual oil, 1.7%).

Table II. Geographical Scope

Alaska
Western Canada[a]
Western United States[b]
Central America[c]
Western South America[d]
Australia and New Zealand
Brunei and Malaysia
Indonesia
Japan

[a]Western Canada - British Columbia, Alberta Northwest territory, Yukon, and Arctic Islands.
[b]Western United States - P.A.D. IV & V, California, Oregon, Washington, Nevada, Arizona, Idaho, Montana, Wyoming, Utah, and Colorado.
[c]Central America - Guatemala, El Salvador, Honduras, Nicaragua, Costa Rica, and Panama.
[d]Western South America - Columbia, Ecuador, Peru, Bolivia, and Chile.

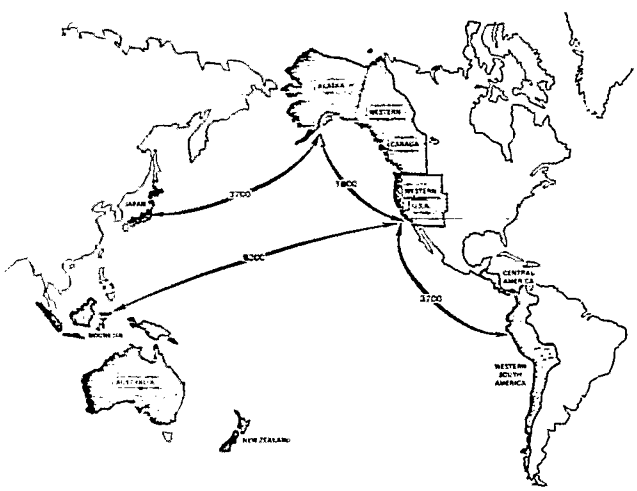

Figure 1. Shipping Distances (nautical miles)

ENERGY SUPPLY/DEMAND

A summary of 1975 oil and gas supply/demand status and projections to the year 1990, are shown in Figure 2 (Refs. 7, 8, 9, 10, 11, 12, 13, 14). Table III shows the projected 1990 shortfall in oil and natural gas supplies to be about 12.3 MM equivalent BPD. This projected shortfall is based on a forecasted supply of Alaskan crude at 2 MM BPD and that all of this will be supplied to the western United States.

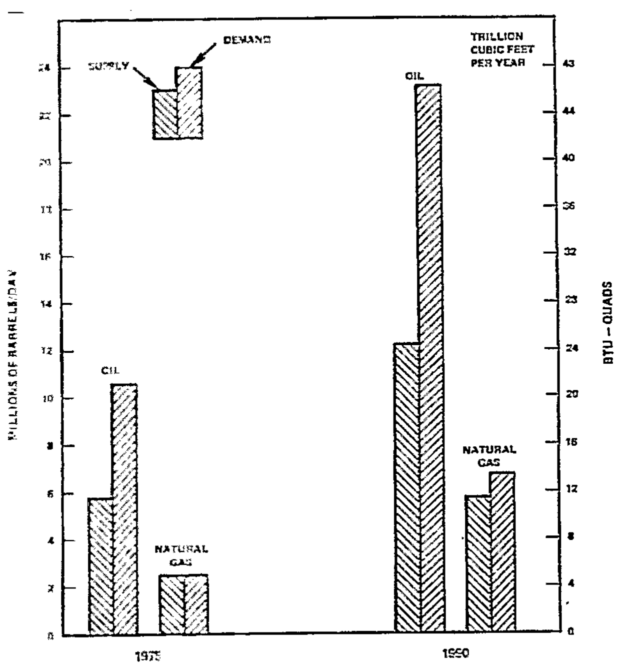

Figure 2. Summary of Oil and Natural Gas Supply and Demand - Pacific Area Countries

In 1975, and also 1990, the projected results indicate that some areas will have an adequate supply to sustain their needs; others must depend on imports or alternately face a serious deterioration in their economic growth rate. To illustrate, 5.2 MM BPD of Middle East oil were imported to the area in 1975 with prime importers being Japan and the U.S.A.

Table III. Projected 1990 Shortfall of Oil and Natural Gas by Country/Area

	Projected Shortfall (Excess)		
Country (Area)	Oil (MMBPD)	Natural Gas (TCF/yr)	Total in Equivalent 6 MM Btu Barrel
Alaska	(2.0)	(1.2)	(2.6)
Western Canada	1.3	(1.1)	0.8
Western U.S.	2.9	3.1	4.4
Central America	--	--	--
Western South America	1.1	--	1.1
Australia and New Zealand	1.1	(0.4)	0.9
Brunei and Malaysia	(0.7)	(0.6)	(1.0)
Indonesia	(2.7)	(0.9)	(3.1)
Japan	10.5	2.8	11.8
Total	11.5	1.7	12.3

Problems are also on the horizon worldwide. Projections show that by 1990 world crude oil demand will be 70 to 75 MM BPD and crude oil production may be about 65 MM BPD - a sizable potential deficit (Refs. 7, 10).

The current economically recoverable reserves for coal, crude oil, natural gas and shale in the Pacific areas are shown in Figure 3 (Refs. 7, 15, 16, 17).

The reserves would be adequate to supply projected area demands for many years if natural gas were liquefied and transported as LNG and the coal and shale reserves were converted to synfuels.

CRUDE OIL

Proven reserves are shown in Figure 3; production during 1975 is illustrated in Figure 4.

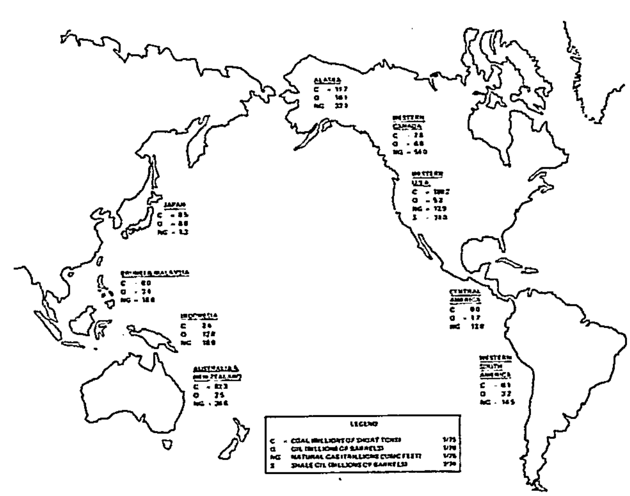

Figure 3. Proven Reserves

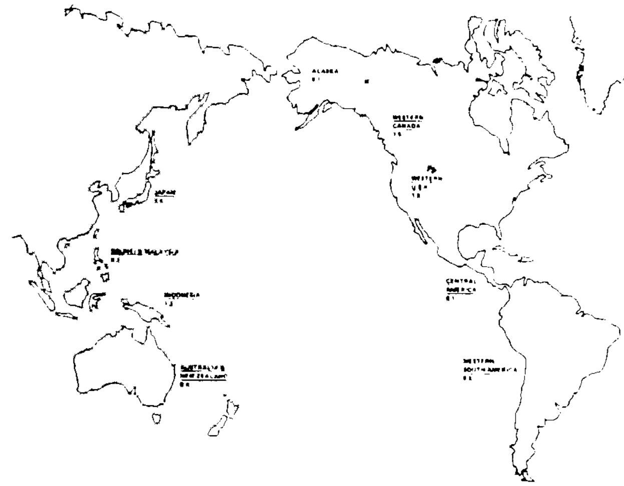

Figure 4. Current Crude Oil Production (millions of barrels per day)

The trend of proven reserves is down. In the U.S.A., no major onshore discoveries were made in 1974 or 1975 (Ref. 18). Attention has therefore shifted to offshore exploration, and deeper wells. It has been reported that the petroleum industry held exploratory rights to more than a billion acres in offshore areas deeper than 650 feet at the end of 1974 (Ref. 19). A well has been drilled in 3,460 feet of water off the coast of Thailand (Ref. 20), and capability to drill in 6,000+-foot depths has been reported (Ref. 21).

Sufficient exploration of the continental shelves has been accomplished to safely predict that the probability of discovering another find comparable to the Middle East is negligible (Ref. 22). The North Sea has been the only major offshore oil and gas area discovered during the past 10 years. Further, only five new oil provinces have been discovered offshore or onshore in the Free World during the past 30 years. These are listed in Table IV (Ref. 22). Total recoverable reserves from these areas is about 78 billion barrels, equivalent to about 4 years of Free World demand.

Table IV. Major New Oil Provinces Discovered During Last 30 Years - ex U.S.S.R.

Area	Recoverable Reserves Discovered (billion barrels)
Alaska	11
Algeria	10
Libya	21
Nigeria	12
North Sea	24
Total	78

Prediction of potential new reserves is extremely risky. However, one qualified prediction is summarized in Table V, which shows a total potential of 22 to 51 billion barrels of new reserves for the area (Ref. 22). This represents about 1 to 2.5 years' supply of the 1990 projected demand. Further, authorities predict an additional 50 to 100 billion barrels will be found in the world. However, it is improbable that any of the potential new reserves will make a significant contribution to production for the next 15 years (Ref. 23). While these predictions are necessarily highly speculative, they define the implications of dependence on crude oil for future energy supplies.

Table V. Potential New Pacific Area Offshore Oil and Natural Gas Reserves

Area	Potential New Reserves	
	Oil (billion barrels)	Gas (TCF)
South America	3 - 5	5 - 15
U.S.A., Lower 48	2 - 6	4 - 5
Alaska	5 - 15	50 - 75
Canadian Arctic	2 - 5	10 - 30
Burma, West Thailand, and West Malaysia	3 - 6	10 - 20
Indonesia, ex China Sea	5 - 8	20 - 30
Australia, New Zealand, and West Pacific	2 - 6	30 - 70
Total	22 - 51	129 - 245

Prediction of capital and operating costs for future offshore oil (and gas) wells, as well as required selling price at a given return, is also risky. Let's look at some data and opinions in order to define the order of magnitude of the economics: It is a fact that drilling costs have escalated significantly since 1973; this is illustrated in Figure 5 (Ref. 7).

To illustrate: A particular well drilled in Gulf Coast U.S.A. waters has been predicted to cost about $1.45 million in 1976 (Ref. 18). Oil production from offshore Louisiana in 1975 averaged just slightly over 1 MM BPD and the number of producing wells was about 3,280 (Ref. 24), indicating an average production rate of about 305 BPD per well. Based on the cost of $1.45 million to create the well, the indicated capital cost is approximately $5,000/BPD capacity. The addition of an offshore loading system, transfer pipelines and high complexity refining capacity would add about $4,000/BPD, bringing the total to the order of $9,000/BPD. Allowance for unsuccessful wells would make the BPD investment higher.

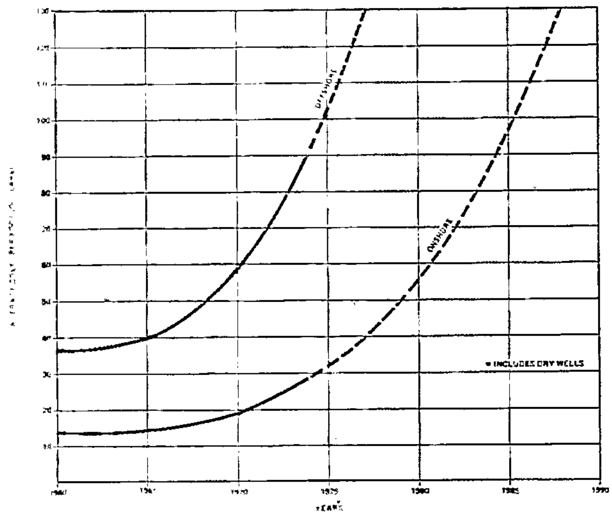

Figure 5. Cost of Drilling and Equiping Oil and Gas Wells (current dollars)*

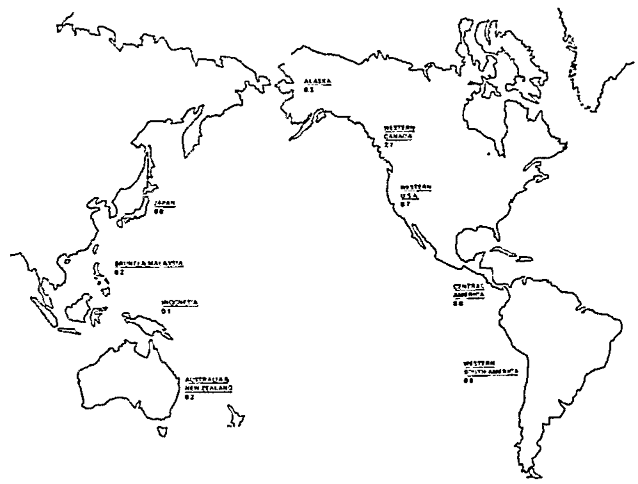

Figure 6. Current Natural Gas Production (trillion cubic feet per year)

An alternative has been described (Ref. 22). In this, water depths of 325 to 500 feet are projected. United Kingdom license and tax items are used. Capital costs amount to approximately $600 million for a platform, 20 completed wells, and an offshore loading system to produce 50,000 BPD after 3 years. This results in capital costs of about $12,000/BPD. Required addition of piping and refining brings total capital to about $16,000/BPD.

Operating cost factors, and therefore required product selling prices, can vary widely. Nevertheless, estimates of what may be called "representative" economics were made. These indicate that operating costs for crude oil production, transport to the refinery and refining may range from $4.50 to $7.30/bbl (Ref. 25), resulting in required "plant gate" product selling prices, at 12% DCF, of $10.60 to $19.00/bbl.

NATURAL GAS PRODUCTION

Current natural gas production in the area is illustrated in Figure 6. Estimates shown in Table 5 indicate that new reserves totaling 130 to 245 trillion cubic feet (TCF) might be located, mainly in offshore locations (Ref. 21). This represents 10 to 18 years' supply at the projected 1990 demand rate.

Information indicates that the costs for gas wells will be in the same range as for oil wells (Ref. 26). Therefore, for purposes of this paper, we can say that costs for development and production of large new gas sources will be similar to those described above for crude oil, and proceed to a summary of the potential market for emerging technologies.

LIQUEFIED NATURAL GAS

Some Pacific area locations possess excess natural gas in low industrialization areas. Other highly industrialized locations are deficient in natural gas resources relative to long-term demands. Figure 3 shows natural gas reserves and production potential by area. Japan and the Western U.S.A. are the largest potential markets for LNG. Projections indicate that 1990 LNG shipments to Japan will be 2.8 TCF (Ref. 10) and to West Coast U.S.A. will be 0.4 TCF (Ref. 27).

LNG plants being designed and built today are generally based on a modified multicomponent refrigerant cycle (MCR); see Ref. 28. The liquefaction plant shown in Figure 7 utilizes a multicomponent refrigerant process modified with propane precoolers similar to the efficient system installed at Arzew (Ref. 29). The process involves makeup refrigerant recovery from feed gas, and yields LNG with a heating value of 1150 Btu/scf. The process indicated is for an LNG plant receiving relatively dry gas containing some carbon dioxide. Primary products are LNG and a pentanes-plus stream.

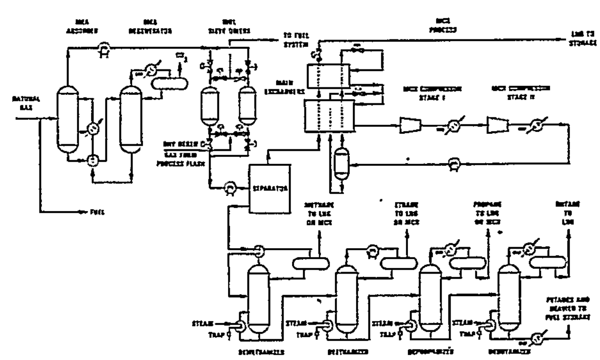

Figure 7. LNG: Typical Flow Schematic for Modified MCR Liquefaction Plant

Larger LNG plants are expected in the future. This can be done by increasing the capacity of the individual trains. Currently, the largest trains under construction are two 250 MM scfd units for Pertamina's Badak, Indonesia facility. Improvements in the technology of LNG production and shipment are expected in coming years. However, a limiting factor can be the environmental restraints placed upon receipt, storage and revaporization of the LNG in or near high population areas such as Southern West Coast U.S.A. where a number of U.S. Coast Guard and local harbor regulations cover the transportation and handling of LNG. National institutional and association codes and standards also specify parameters to be adhered to on construction and operation of LNG facilities.

Current estimated cost for 1981 delivery of LNG from Indonesia to Southern West Coast U.S.A. customers is approximately \$3.10/MM Btu (Ref. 27). This equates to about \$2.60/MM Btu in fourth-quarter 1976 dollars. These costs are summarized in Table VI, which shows the contribution of the separate LNG project activities to the projected delivered gas cost. The cost and market value trends indicate that by 1990 a probable delivered cost will be in the range of \$4.50/MM Btu in the West Coast U.S.A. area.

Table VI. LNG Cost Summary - Indonesia to Southern California

Activity	Total Capital Investment (\$/MCF day)	Cost (\$/MM Btu)[a]
Gas gathering, liquefaction, and loading	915	1.15
Transportation	2,020	1.14
Receiving, storage, regasification, and transmission	408	0.28
Total	3,343	2.57

[a]Based on 1150 Btu/CF natural gas.

The estimated fixed capital investment for the LNG project is about \$1.7 billion, equivalent to about \$17,400 per daily barrel equivalent (DBE) The plant gate costs in Indonesia correspond to approximately \$3,800/DBE, and the required plant gate selling price is estimated at about \$6.90/DB; the transportation, receipt, storage, regasification and distribution costs are therefore the major contributors to this type of project costs.

COAL-BASED SYNFUELS

Coal reserves are enormous - potential reserves in the U.S.A. alone are projected to be in excess of 3 trillion tons, with slightly less than half in western U.S.A. Reserves recoverable in the western area of the lower 48 states under current economic conditions are about 180 billion tons, which represents more than 300 years' supply at current use rate (Ref. 17). Australia/New Zealand, Canada and Alaska also have significant reserves, making coal a major potential source of synfuels in the area.

Production techniques and projected economics for coal-based syncrudes are based on conceptual designs for second- and third-generation plants to best illustrate potential for these emerging technologies. They incorporate processes and equipment, still under development, considered to have good chances of success and in some cases, a limited data base.

Because of space limitations, brief descriptions of each are presented; we suggest that the reader review more detailed descriptions of the designs for perspective in drawing conclusions regarding their potential in the late 1980s and 1990s.

All coal conversion plants discussed here, except the low-Btu case, are conceived to be located in Wyoming and to use 8,850-Btu/lb coal containing 20+% moisture. Low-Btu gasification is conceived to be located in the consuming area.

FISCHER-TROPSCH

A simplified block flow diagram for a conceptual design of a large Fischer-Tropsch (F-T) plant, intended to be responsive to future U.S.A. requirements, is shown in Figure 8 (Ref. 4).

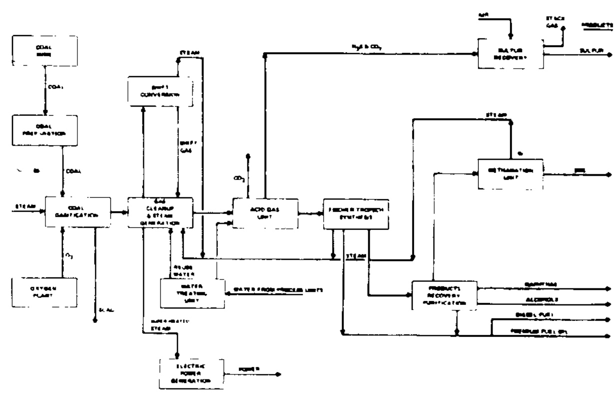

Figure 8. Fischer-Tropsch Block Flow Diagram

This complex includes a captive coal mine which produces approximately 55,000 tons per day (TPD) of run-of-mine (ROM) coal and dries/sizes it to produce about 44,000 TPD of feed coal to the process plant. The energy content of the products is about 525 billion Btu/day, consisting of substitute natural gas (SNG) and liquids; the liquids are LNG, light and heavy naphthas, diesel oil and fuel oil. The liquid products are premium products ecologically; they contain nil sulfur, nitrogen and particulates. The ratio of SNG to liquids, on a Btu basis, is about one.

This is essentially a two-train plant. The feed coal is gasified in two 2-stage entrained slagging steam-oxygen gasifiers with characteristics similar to the Bi-Gas unit being piloted under ERDA sponsorship at Homer City, Pa. The syngas produced in the gasifier, primarily a mixture of hydrogen and carbon monoxide, is exhaustively purified and then converted to liquids in the F-T reactor; this is a unique design using flame-sprayed iron catalyst on extended heat exchanger surface. The heat of reaction is recovered as 1,250 psi steam. The methane produced in the F-T reactor and gasifier is recovered cryogenically for SNG production. The liquids are recovered and refined.

The shift and methanation reactor designs are similar to the F-T reactor previously described. Efficient heat recovery leads to a projected overall thermal efficiency of about 68% using the high-moisture coal.

The projected product characteristics and marketability are shown in Table VII. The projected plant gate economics indicate that the fixed capital investment is approximately $19,000/DBE, the operating cost is $7.65/BE including a royalty payment of $1.50/ton of feed coal produced, and the required product selling price is $17.60/BE for a 12% DCF.

Table VII. Projected Fischer-Tropsch Product Characteristics and Marketability

Product	Projected Key Characteristics	Projected Prime Markets
SNG	1,035 Btu/scf Pipeline delivery pressure = 1000 psig	Pipeline gas
Butanes	82% butane, 16% butylene, traces of propane propylene and pentanes Nil sulfur and nitrogen	LPG
Light naphtha	Straight-chain mono-unsaturated and straight-chain saturated hydrocarbons ASTM distillation range, 96 - 185°F 85.5°API gravity; nil sulfur content	Petrochemical feedstock
Heavy naphtha	Straight-chain mono-unsaturated and straight-chain saturated hydrocarbons ASTM distillation range, 186 - 300°F 71.5°API gravity; nil sulfur content	Petrochemical feedstock
Diesel fuel	Straight-chain hydrocarbons; nil sulfur and nitrogen Meets diesel specifications ASTM distillation range, 301 - 640°F Cetane number, 60-plus	Diesel fuel
Fuel oil	Waxy, high pour point, sulfur-free ASTM distillation 570 - 883°F HHV, 19,855 Btu/lb; 41°API gravity	Turbine fuel or utility/industrial fuel

The projected costs for the F-T and the alternative liquid-from-coal synfuels plants included here show higher costs using the high-moisture, low-heating-value Wyoming coal than projected for Illinois No. 6 seam coal (Refs. 4, 5).

OIL/GAS

The O/G conceptual multiproduct design is depicted in the block flow diagram shown in Figure 9 (Ref. 5). Coal conversion steps in this design consist of a solvent-refined coal (SRC) II hydroliquefaction process and 2-stage entrainment slagging-type steam-oxygen gasification to produce the hydrogen necessary for hydroliquefaction of the coal and hydrotreating the liquid. The SRC II mode of operation recycles unfiltered coal dissolver effluent to the dissolver feed to result in higher hydrogen uptake and production of liquid products.

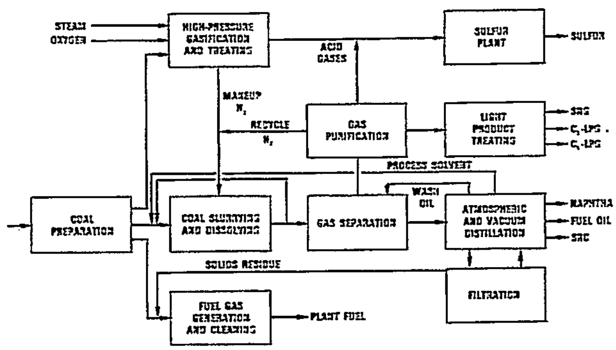

Figure 9. Oil/Gas Plant Block Flow Diagram

The complex has a captive mine to produce approximately 70,000 TPD of ROM coal, which is dried/sized to produce about 54,000 tons of feed coal to the process plant. 31,000 tons per stream day is fed to the dissolver where the coal is liquefied, the products fractionated and the ash plus undissolved coal removed by filtration. The naphtha is hydrotreated. Products consist of SNG, LPG, naphtha, and a heavy fuel oil; the ratio of liquid products to SNG, on a Btu basis, is about 1.5.

Projected product characteristics and marketability are shown in Table VIII; the products would meet existing ecological requirements. Economic estimate results indicate that the fixed capital investment is of the order of $14,700/DBE and the required plant gate product selling price is about $14.25/BE — again higher than for a midwestern U.S.A. location.

HYDROTREATED OIL/GAS FUEL OIL

Another option is to further hydrotreat the heavy fuel oil components produced in the O/G design just described. The fuel oil product will then have lower sulfur and nitrogen contents to make it ecologically more attractive. Additional light products, i.e., naphtha, LPG and SNG, will be produced by the hydrotreating step.

A preliminary evaluation of the effects and costs for hydrotreating the O/G fuel oil components was made. To do this, available data and experience on the subject of hydrotreating coal-derived liquids were reviewed and predicted performance data selected. Results indicate that the ROM feed coal requirements increase by about 20% to 85,000 TPD. Product quantities and key characteristics are compared for the O/G and hydrotreated oil/gas (H-O/G) cases in Table IX.

Preliminary economic results indicate that the fixed capital investment increases to $17,800/DBE, and the required plant gate product selling price becomes $16.80/BE.

Table VIII. Projected Oil/Gas Product Characteristics and Marketability

Product	Projected Key Characteristics	Projected Prime Markets
SNG	1050 Btu/ SCF HHV	Pipeline gas
LPG	Mixed C_3 and C_4	LPG
Naphtha	54.0°API, High naphthene 155 - 380°F boiling range	Gasoline precursor
Fuel oil	0.4% sulfur, -8.2° API	Utility/ industrial fuel

Table IX. Comparison: Oil/Gas and Hydrotreated Oil/Gas Products

	Oil/Gas		Hydrotreated Oil/Gas	
Item	Quantity	Key Characteristic	Quantity	Key Characteristic
Feed coal	70,000 TPD ROM	Wyoming Coal	85,000 TPD ROM	Wyoming coal
SNG	260 MM SCFD	1050 Btu/ SCF	300 MM SCFD	1050 Btu/ SCF
LPG	15,900 BPD	Mixed C_3 and C_4	17,400 BPD	Mixed C_3 and C_4
Naphtha	14,300 BPD	High naphthene	22,600 BPD	High naphthene
Fuel oil	36,400 BPD	0.4% S -8.2° API 925°F at 50%	18,100 BPD	0.1% S 25°API 700°F at 90%

SUBSTITUTE NATURAL GAS

A simplified block flow diagram is shown in Figure 10. The complex includes a captive coal mine and coal preparation plant.

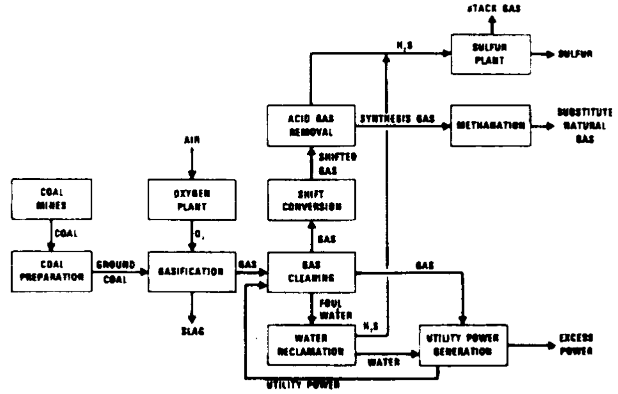

Figure 10. SNG Block Flow Diagram

This concept of a second- or third-generation SNG plant uses much of the gasification, gas purification and methanation capability earlier described for the conceptual F-T complex (Ref. 4). It includes two 2-stage entrained gasifiers operating at moderate pressure (470 psig). The syngas produced in the gasifier is cleaned, shifted in a sour shift reactor to adjust the hydrogen to carbon monoxide ratio, the acid gases removed, the purified gases methanated, moisture removed and the gas pressurized to 1,000 psig for delivery to the pipeline.

Coal feed is 57,000 TPD of ROM to produce 44,000 TPD of dried, sized coal. The product is about 550 million scfd of SNG with a heating value of 950 Btu/scf.

Projected economics indicate that the fixed capital investment is of the order of $19,000/DBE, and the required plant gate product selling price is $3.05/MM Btu ($18.25/BE).

LOW BTU GAS

Another alternative is the use of low Btu gas for close-coupled clean energy supply to turbines or boilers. A block flow diagram depicting this type of facility is shown in Figure 11.

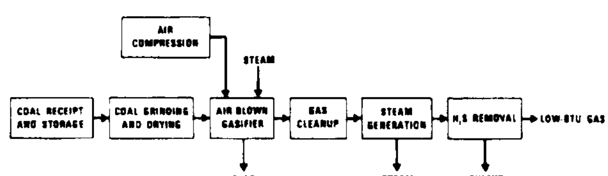

Figure 11. Low Btu Gas Block Flow Diagram

The plant location is conceived to be the consuming area; e.g., a power plant or other large consumer of energy. The low heating value of the feed coal and product (150 to 160 Btu/scf), however, makes the cost of transportation over long distances highly significant.

The concept is that the coal would be mined in Wyoming and shipped by unit train to the low Btu plant site in the Southern West Coast U.S.A. The process plant area includes coal storage and grinding as feed to the gasification unit.

The gasifier would be a low-pressure (40 psig) 2-stage entrained-type vessel with a slagging bottom. Its design would be similar to that of a blast furnace. Particulate solids are removed from the gasifier effluent prior to sulfur removal. Sulfur-free gas would be pipelined to nearby consumers. Utilities, offsite and waste treatment facilities required for plant operation are included.

Approximately 2,500 TPD of coal are fed to the plant to produce about 200 MM scfd of 160 Btu/SCF gas delivered at 25 psig.

Preliminary economics indicate fixed capital investment, including an allowance for the coal mine, is equal to about $10,800/DBE. The projected required product selling price is approximately $2.50/MM Btu or $15.10/BE. Note that the estimated required product selling price for a Wyoming mine mouth gasification plant would be about $1.70/MM scf or $10.30/BE.

SHALE OIL

The largest Pacific area oil shale reserves are in the western U.S.A. Estimates indicate potential reserves could produce 1.8 trillion barrels of oil. Of this total the rich Green River deposits in Colorado and Utah, which are 30 or more feet thick and contain a minimum of 30 gallons of oil per ton, could yield 74 billion barrels (Ref. 30, 35). Oil shale therefore represents a significant potential for future syncrude production.

At least three procedures have been proposed for production of shale oil: surface retorting, in-situ retorting and combination (in-situ production combined with surface retorting of shale removed in the mine development to create void volume for the in-situ retorts).

This paper will include the surface retorting and combination procedures.

SURFACE RETORTING

The process is illustrated in the simplified block flow diagram (Figure 12; Ref. 31). This discussion is based on use of Colony plant design (Refs. 32, 33) TOSCO II retorts. Other processes are available or under development.

The process involves mining the shale, crushing the rock and retorting at about 900°F and near atmospheric pressure to recover crude shale oil. The gas produced is treated to recover LPG and byproduct sulfur. Heavy fractions of the crude oil are coked; liquids are processed to produce approximately 50,000 BPD of crude shale oil. Projected characteristics of the crude shale oil from a Colorado rock are illustrated in Table X (Ref. 33). To meet the consuming area environmental regulations, this shale oil would be hydrotreated for this study to about 0.4% sulfur. Our estimates of the cost of the hydrotreating step were added to the estimated costs to produce the hydrostabilized oil (Ref. 34). Projected economics are that the fixed capital investment would be about $17,500/DBE and the required plant gate product selling price $15.15/BE.

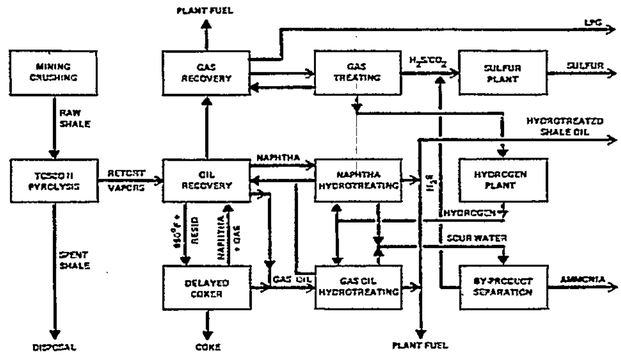

Figure 12. Oil Shale Surface Retorting Block Flow Diagram

Table X. Crude Shale Oil Characteristics

Component Boiling Range	Crude Shale Oil			
	Volume (%)	Degrees API	Sulfur (wt %)	Nitrogen (wt %)
C_5 - 400°F	17	51.0	0.7	0.4
400 - 950°F	60	20.0	0.8	2.0
950+ °F	23	6.5	0.7	2.9
Total	100	21	0.7	1.9

COMBINATION PROCESS

The combination process is depicted in Figure 13 (Ref. 34). In this case, all shale removed in the mine development to create a 25% void volume in the in-situ retorts was processed in surface facilities which included three TOSCO II retorts.

The in-situ shale oil is produced as a water emulsion which is broken to yield oil and water phases. The oil phase is combined with the crude oil produced in the retorts and processed, including hydrostabilization, to produce pipelineable shale oil, coke and some electrical power for export.

The projected economics indicate a fixed capital investment of approximately $12,250/DBE and a required product selling price of about $11.25/BE.

Other in-situ processes are under development. Occidental Research Corporation is actively pursuing commercialization of its technology.

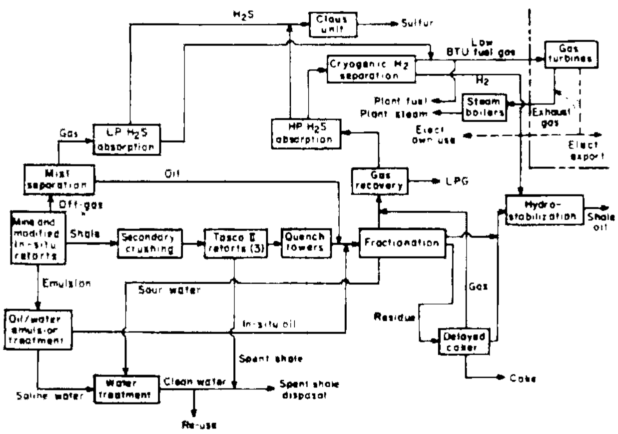

Figure 13. Oil Shale Combination Process Block Flow Diagram

ECONOMIC COMPARISON

Table XI is a plant gate economic comparison of the energy supply options. Preparation of this comparison required a number of interpretations and judgments to rationalize technical and economic inputs from multiple facilities not yet built and operated. The results therefore represent judgmental projections of what might occur, rather than "return cost" results. An attempt was made in each case to consider all available information to provide assurance that the projections are consistent, based on the technologies described. Only the future will tell if they properly predicted the relative technical performances and economics.

Table XI indicates that the relative plant gate-required product selling prices for the emerging technologies array themselves in the following order of increasing costs: (1) LNG (2) oil shale - combination, (3) O/G coal conversion and oil shale - surface retorting, (4) hydrotreated O/G and F-T and (5) SNG.

Table XI. Projected Cost Comparison of Energy Options, Fourth-Quarter 1976 Dollars (Plant Gate Costs)

Option	Fixed Capital Investment ($/DBE[a])	Total Capital Investment ($/DBE[a])	Operating Cost ($/BE[b])	Required Product Selling Price ($/BE at 12% DCF)
Refined products from crude oil	9,000 - 16,000	11,000 - 19,000	4.30 - 7.30	10.60 - 19.00
Emerging Energy Technologies				
LNG	3,800	4,700	3.72	6.90
Shale oil-combination	12,250	17,200	4.12	11.25
Coal conversion: O/G	14,700	18,500	6.60	11.25
Low Btu gas ex coal	10,800	13,350	10.11	15.10
Shale oil-surface retort	17,500	21,700	3.50	13.15
Coal conversion hydrotreated O/G liquid	17,900	22,100	7.50	16.80
Coal conversion: F-T	19,000	23,550	7.65	17.60
SNG ex coal	18,900	25,600	8.20	18.25

[a]DBE - daily barrel equivalent; 6 MM Btu barrel.

[b]BE - barrel equivalent, 6 MM Btu barrel.

Table XII presents similar economic projections for a delivered cost to a Southern West Coast U.S.A. location. Transportation costs are, significant in most cases. Also, the differences in fuel characteristics can be important.

Table XII. Projected Cost Comparison of Energy Options, Fourth Quarter 1976 Dollars (Delivered, Southern West Coast)

Option	Required Product Selling Price ($/BE[a] at 12% DCF)
Refined products from crude oil	11.70 - 20.10
Emerging Energy Technologies	
Shale oil-combination	12.22
Low Btu ex coal	15.11
LNG	15.42
Coal conversion: O/G	16.10
Shale oil-surface retort	16.10
Coal conversion: hydrotreated O/G liquids	18.63
Coal conversion: F-T	19.78
SNG ex coal	21.23

[a]BE = barrel equivalent; 6 MM Btu barrel.

The emerging energy technology options array themselves in this case in the following order of increasing cost groupings: (1) shale oil - combination process, (2) low Btu gas, LNG, O/G coal conversion and shale oil surface retorting, (3) hydrotreated O/G and F-T coal conversion and (4) SNG ex coal.

Again, the coal conversion costs appear to be biased in the direction of higher costs due to the nature of the coal selected for this study; also, higher transportation costs to the consuming area than for shale oil.

By comparison, current costs of Indonesian oil imported to the use area are understood to be in the range of $15 to $16 per barrel. Also, FEA has estimated that Middle East oil imported to West Coast U.S.A. currently costs $13.74/bbl (Ref. 1). This indicates that combination shale oil, low Btu gas, LNG, O/G coal conversion and shale oil-surface retorting all deserve serious consideration for further development, based on indicated potential for being competitive with imported oil. Also, F-T could be attractive, based on potential premium prices for product petrochemical feedstocks and nil sulfur/nitrogen fuels.

SUMMARY AND CONCLUSIONS

The Pacific area faces an increasing near-term shortfall in supply of environmentally acceptable liquid and gaseous fuels. While we hope to locate "cheap" sources of oil and gas, available information says that this is not probable. However, the area is fortunate in having significant reserves of coal and shale which have the potential to supply oil and gas equivalent to about 70 years' 1990 projected demand for the area. Therefore, an incentive exists to develop the emerging technologies to produce oil and and gas at a cost competitive with alternative sources such as imported oil or oil produced from new wells.

This paper has surveyed procedures and projected costs for producing oil and gas from wells and emerging energy technologies. The results indicate that the costs of oil and gas from new wells could be in the same range as those projected for LNG and those from plants using second- and third-generation emerging energy technologies. Projected costs for oil from new wells range from $11.70 to $20.10 at a Southwest Coast U.S.A. location in late 1976 dollars. Recent published information indicates that refined products from the Alaska fields could approach the upper-range figure. First-quarter 1977 costs of imported low sulfur Indonesian oil to this area are understood to be in the range of $15- to $16/bbl. At these values, the prompt development of combination shale oil, low Btu gas, LNG, oil/gas coal conversion and surface-retorted shale oil all deserve serious consideration. Fischer-Tropsch also deserves consideration because of the premium fuels and petrochemical feedstocks it can produce. Hard decisions must be made soon to have an impact by 1990.

ACKNOWLEDGMENT

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SECTION 5
ENVIRONMENTAL ASSESSMENT