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OCEAN THERMAL ENERGY CONVERSION MISSION ANALYSIS STUDY, PHASE II

March 1978

Work Performed Under Contract No. EX-76-C-01-2421

General Electric Company—Tempo
Center for Advanced Studies
Washington, D. C.

U.S. Department of Energy

Solar Energy

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MISSION ANALYSIS STUDY
PHASE II

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PREPARED FOR:

U.S. DEPARTMENT OF ENERGY
DIVISION OF SOLAR ENERGY

UNDER CONTRACT:

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PREPARED BY:

GENERAL ELECTRIC COMPANY-TEMPO
CENTER FOR ADVANCED STUDIES
777 - 14th STREET, N.W.
WASHINGTON, D.C. 20005

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In addition to Dr. Cohen; Mr. S. Gronich; Mr. J. Madewell and several other members of the staff of the Department of Energy provided invaluable assistance, advice, and guidance throughout the program.

The technical team who performed the analysis and wrote portions of this report included: Mr. W. Hausz, Ms. J. Anderson, Mr. C. Meyer, Mr. E. Rosendahl, Mr. J. Keating, Dr. D. McCormick, Dr. B. Berkowitz, and Mr. E. Tschupp. In addition, Ms. M. Jagen was responsible for graphics and production of the report.

We express our appreciation for the contributions of all of these people in assisting us in the completion of the study.

ABSTRACT

The market potential for OTEC has been identified as being electricity, and electrical energy-intensive products (such as ammonia and aluminum). Market penetration scenarios are derived for electrical utilities and energy-intensive industries in Southern and Southeastern United States, Puerto Rico/Virgin Islands and Hawaii. In addition, the production of hydrogen for aircraft fuel and the potential of an "electrochemical bridge" to provide peak power at locations remote from OTEC sites are considered, along with the feasibility of open-ocean mariculture as an adjunct to OTEC power production. The economic impact on overall energy costs from sales of by-product shellfish protein is analyzed.

A technological experience curve is derived for OTEC and applied to an OTEC systems model, to examine the optimization of market penetration scenarios. The legal, institutional and political ramifications of OTEC market penetration are evaluated, along with the facilities, materials, energy and other resource requirements for OTEC development. The likely benefits of OTEC as a domestic energy source are estimated, and an initial appraisal is made of the OTEC product potential for national markets. Possible Federal incentive programs for the stimulation of OTEC commercialization are examined.

EXECUTIVE SUMMARY

OBJECTIVES AND PRIMARY ASSUMPTIONS

The overall objective of this investigation of "missions" for Ocean Thermal Energy Conversion (OTEC) Systems was to evaluate the following three factors relative to a number of potential applications that have been suggested for OTEC systems:

- The size of the total energy market for each application;
- The ability of OTEC to compete with alternative energy sources for the application; and
- The penetration of OTEC systems into the market.

Three OTEC/application configurations were examined:

a) The moored offshore plant, delivering power and/or energy-intensive products to national and regional markets via cable, pipeline or ship;

b) The grazing,* tropical-ocean, plant-ship producing energy-intensive products for shipment to national markets; and

c) The "Island Energy-Intensive Industry (IEII)" option, a hybrid between (a) and (b): OTEC plants stationed near a tropical island to deliver power to the island, most of which may be used onshore in energy-intensive industries whose products would be shipped to the continental states.

The relationship between configurations (a) and (b) and the application options is shown in Fig. ES-1. It was assumed that OTEC systems would be

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* The plant-ship "grazes" to seek out the highest temperature difference within a given ocean area throughout the year, thereby to maximize production output and minimize capital cost per kWh

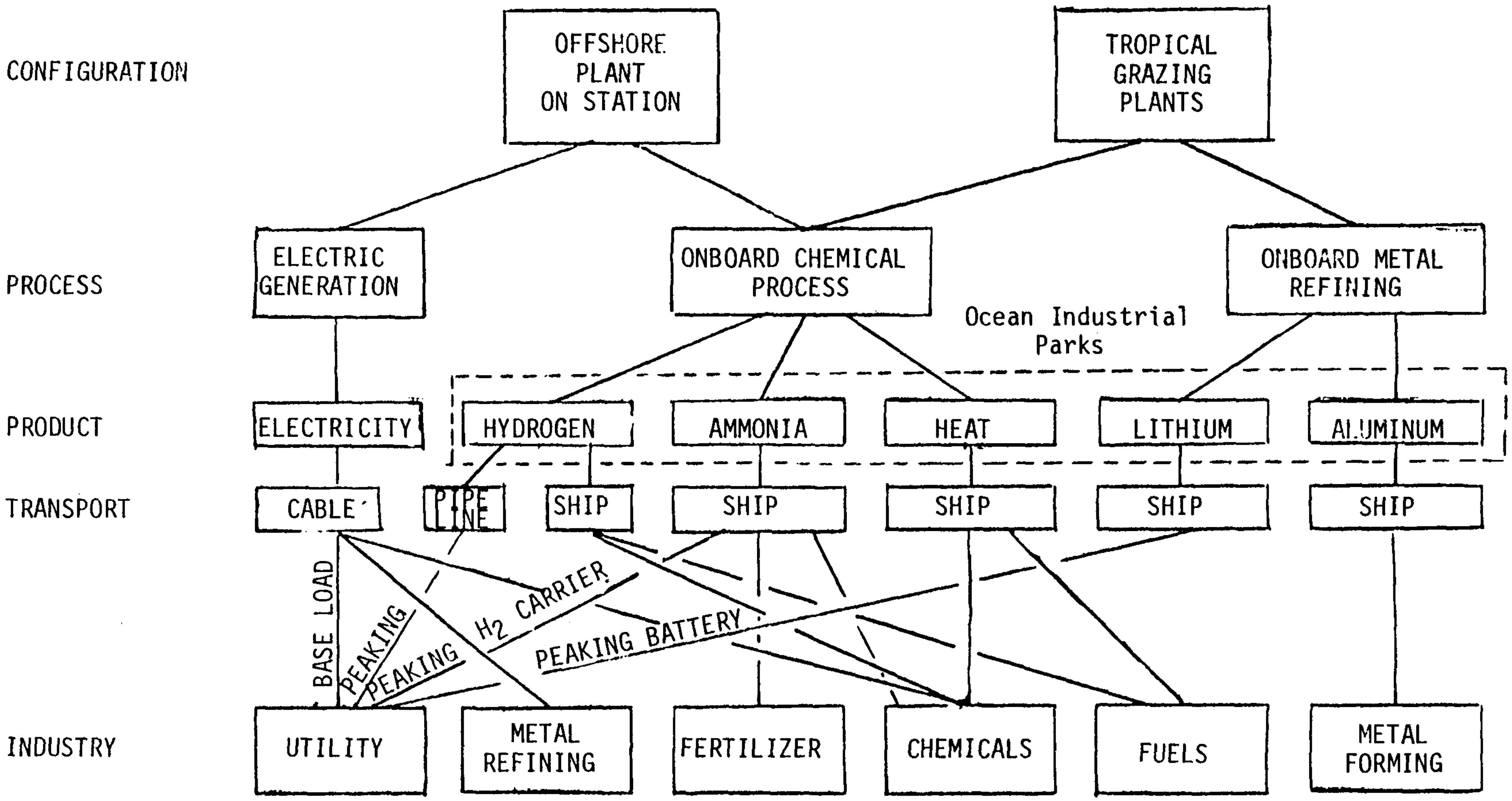

FIGURE ES-1 - OTEC COMMERCIALIZATION PATHS implemented by an accelerated technology transfer program led by the Department of Energy (DOE) in cooperation with several industries to introduce and develop two primary configurations in parallel, as well as the IEII option. This approach would assure that the best applications would be identified as early as possible and would maximize the fossil energy savings and other benefits of OTEC systems. Accordingly, it was assumed that the DOE OTEC program would:

- Develop the technology through component development programs;
- Demonstrate the technology and develop operating performance and cost data by means of 10- to 20-MWe pilot/demonstration plants;
- Participate in the construction and operation of the initial commercial units for each industry application to encourage the acceptance by the industries of the new technology and to encourage the development of the supporting economic and industrial infrastructure; and
- Encourage the establishment of incentives to accelerate the acceptance of OTEC systems by appropriate energy-intensive industries.

With this framework the potential for OTEC market penetration and requirements for commercial viability were examined for four applications:

a) Delivery of baseload power via submarine cable;

b) Production of chemical, thermal, or electrochemical energy carriers that could be used in the production of peaking power by electric utilities;

c) Production of ammonia for fertilizers and chemicals and as a hydrogen carrier for (a) or (b), and

d) Refining of alumina to aluminum, an electrolytic process.

As an adjunct to (b), production of liquid hydrogen for use as an aircraft fuel was considered. A brief evaluation of the potential for mariculture systems in association with OTEC plants also was made.

BASELOAD POWER TO UTILITY GRIDS

In considering OTEC baseload power going to a utility grid three factors were examined: (1) the match between OTEC power output at specific sites and specific loan centers that could be served by those sites, (2) the costs of power delivered to load centers and the projected busbar electricity costs (BBECs) near the load centers for power generated by conventional systems, and (3) the size of the baseload requirements in the potential service area for OTEC systems.

The compatibility of the OTEC power output with the load is demonstrated in Fig. ES-2, which shows as solid curves the monthly variations in demands served in 1976 by Florida Power and Light, a large utility serving the Miami area, and ES-3 for Louisiana Power and Light. The dashed curves show the predicted power output variations for OTEC plants stationed off Miami and New Orleans, respectively. The OTEC outputs were determined from a performance algorithm attributed to Lavi (1) and were normalized to 100% at the value of the peak monthly generation of the utility in 1976. Since the maximum and minimum OTEC outputs occur at about the same times as those for the load, OTEC systems will be well matched to load. The impacts of the winter minima are not as severe as suggested by this figure, because these utilities, which experience summer peaking loads due to air-conditioning, schedule their required long-outage maintenance during the winter when they have excess baseload capacity. Addition of OTEC plants as baseload plants would reduce the under-utilization of their fossil-fueled and nuclear equipment in the winter.

The primary potential service area was assumed to comprise the three electrical reliability councils in the southeastern United States adjacent to the Gulf - the Southeast Reliability Council (SERC), the Southwest Power Poor (SWPP) and the Electric Reliability Council of Texas (ERCOT). However, the results indicated that a larger area could be served by the Gulf plants by energy transfers to adjacent reliability councils and/or use of direct, long-distance, overland transmission systems. The shaded area in Fig. ES-4 shows the range from the coast to which OTEC power could be delivered at an estimated cost of 35 mills/kWh in the year 2000 using a 3000-kVA transmission system. This power level could be produced, e.g., by eight 250-MWe OTEC plants. The width of the shaded area reflects the uncertainty in overland transmission cost. The numbers in parentheses indicate DOE estimates (2) of regional BBECs for baseload power generated by nuclear or coal-fired plants. As can be seen, OTEC power delivered at 35 mills/kWH would be competitive with conventional sources.

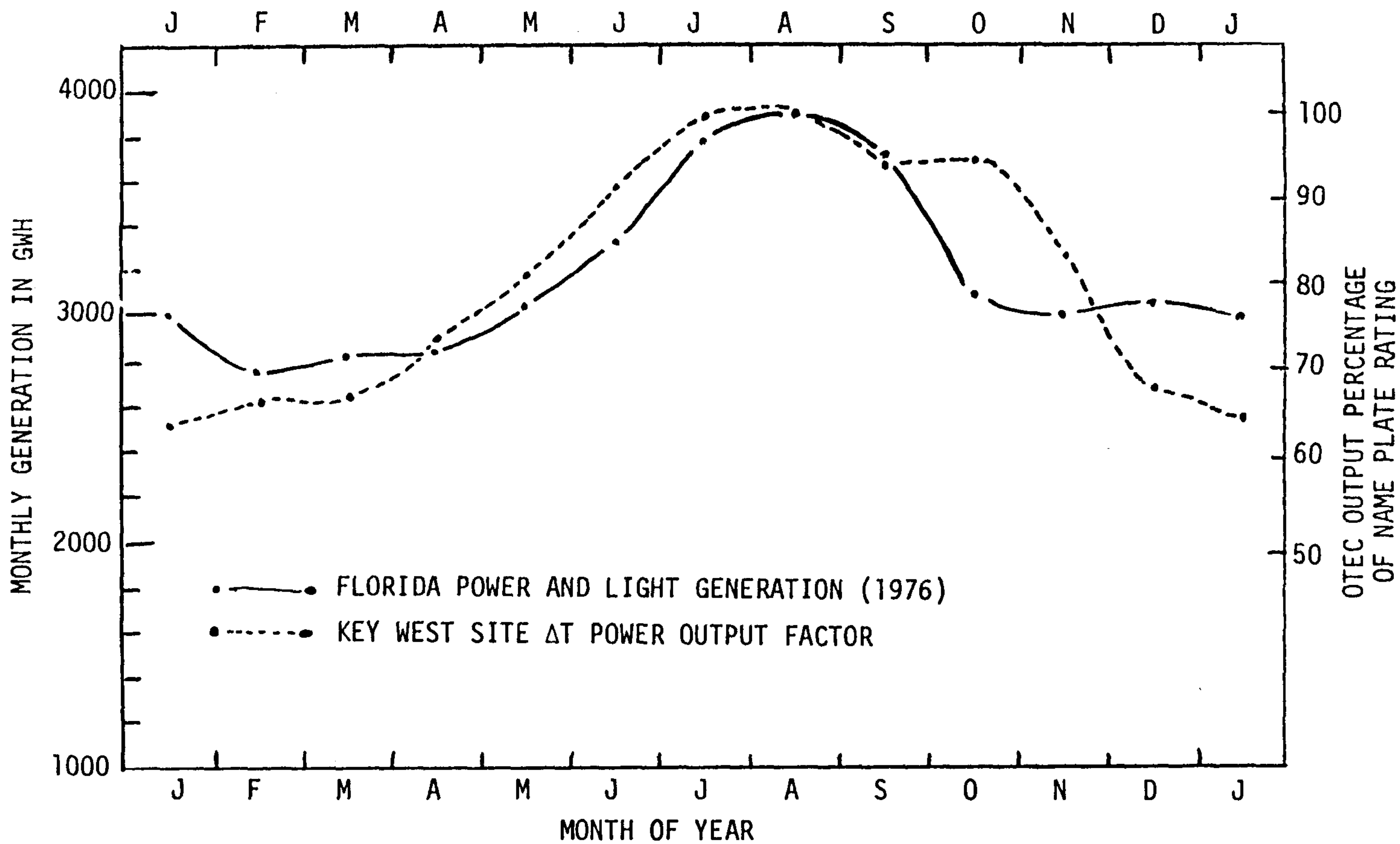

FIGURE ES-2 - COMPARISON BETWEEN SEASONAL VARIATIONS IN FLORIDA POWER AND LIGHT GENERATION AND OTEC OUTPUT

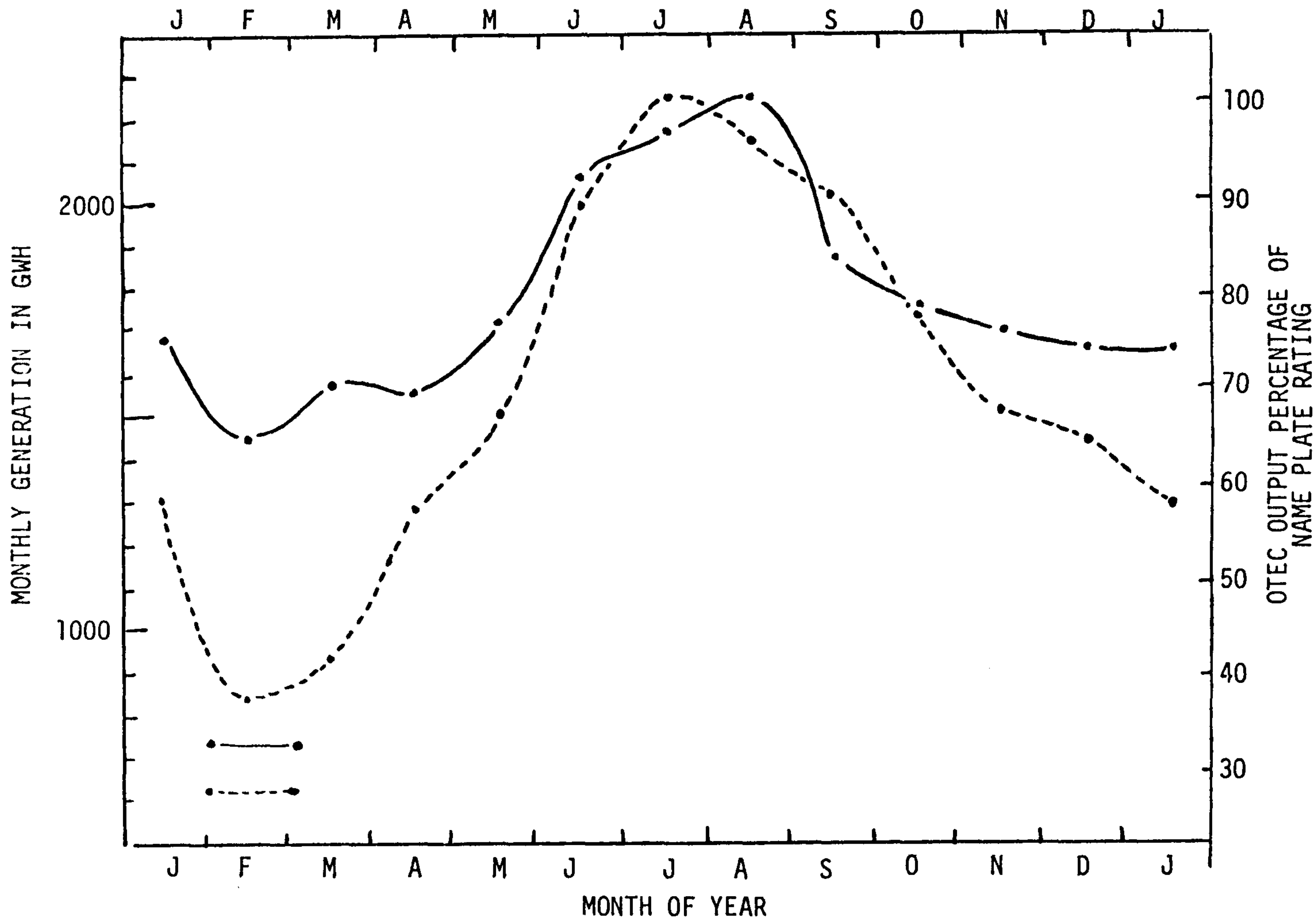

FIGURE ES-3 - COMPARISON BETWEEN SEASONAL VARIATIONS IN LOUISIANA POWER AND LIGHT GENERATION AND OTEC OUTPUT

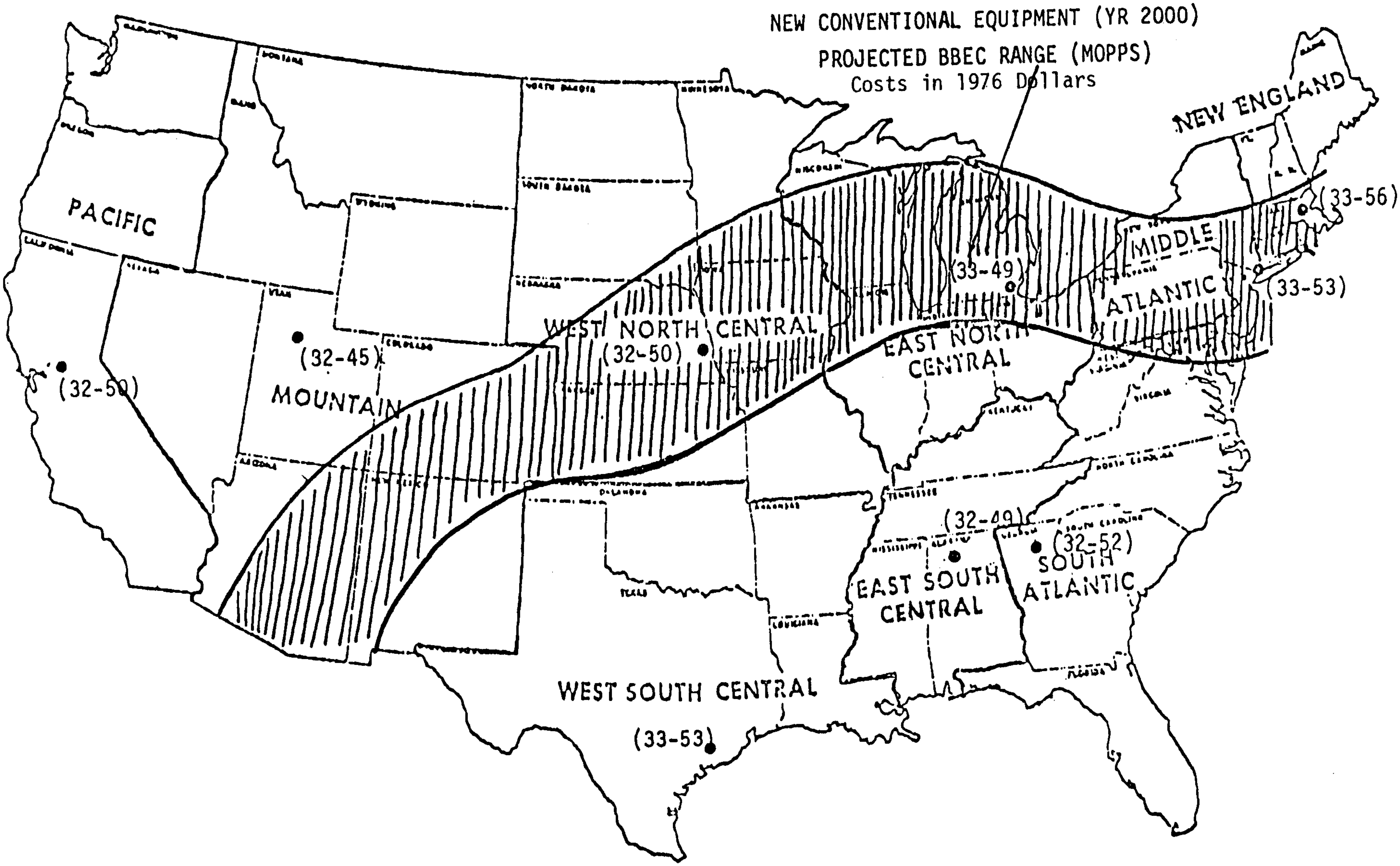

FIGURE ES-4 - OTEC POWER SERVICE REGION WITH 3000 MEGAWATT TRANSMISSION LINKS

Assuming that OTEC power will be deliverable at this price, market penetrations for baseload additions and replacements were projected as shown in Fig. ES-5. High values were based on TEMPO projections; low values on the national energy projections suggested by Whittle, Weinberg, et al. (3). A penetration between 6 and 35 GWe is predicted for the year 2000.

PEAKING POWER

The aforementioned approach of producing high-energy products for reconversion to electricity could extend the application of OTEC power into the high-cost (80-105-mill/kWh) (2) peaking power field. On the assumption that one or more OTEC product systems could meet this cost range, the potential market was estimated based on national peaking unit projected acquisitions starting with the initial year of 1990. The peaking acquisitions were based on (a) the two national power scenarios (the top curves in Fig. ES-5), (b) the assumption that 20% of total acquisitions are peaking capacity (4), (c) the assumption that OTEC would eventually capture only 50% of the total annual acquisition market, and (d) that peaking equipment is used only 1000 to 1200 hr/yr. Fig. ES-6 shows the estimated range of U.S. peaking capacity in the two top curves, the range of peaking acquisitions under the two capacity estimates as the middle pair of lines, and the range of OTEC capacity required given in the bottom pair of lines. The market penetration is assumed to proceed from 1990 to its saturation value of 50% of annual acquisitions with a 10 year takeover time. For these assumptions, the required OTEC capacity would fall between 4 and 8 GW_e by the year 2000 which was large enough to warrant further analysis.

Several options for stored, shipped OTEC power to serve this peaking power field were examined. The lithium-water-air battery, which is currently in an early stage of development appeared to be competitive. Figure ES-7 compares the cost of the electricity delivered to shore. However, in peaking operation the discharge plant only operates 1140 hours per year and the resulting idle time adds a capital recovery factor premium to the delivery costs of between 60 and 90 Mills/KWH which makes the Lithium batterys more costly than the projected costs (2).

The other options considered included gaseous and liquid hydrogen and ammonia (to be converted to obtain hydrogen) for use in gas-turbine peaking units, and molten salts to provide thermal energy for steam turbines. These

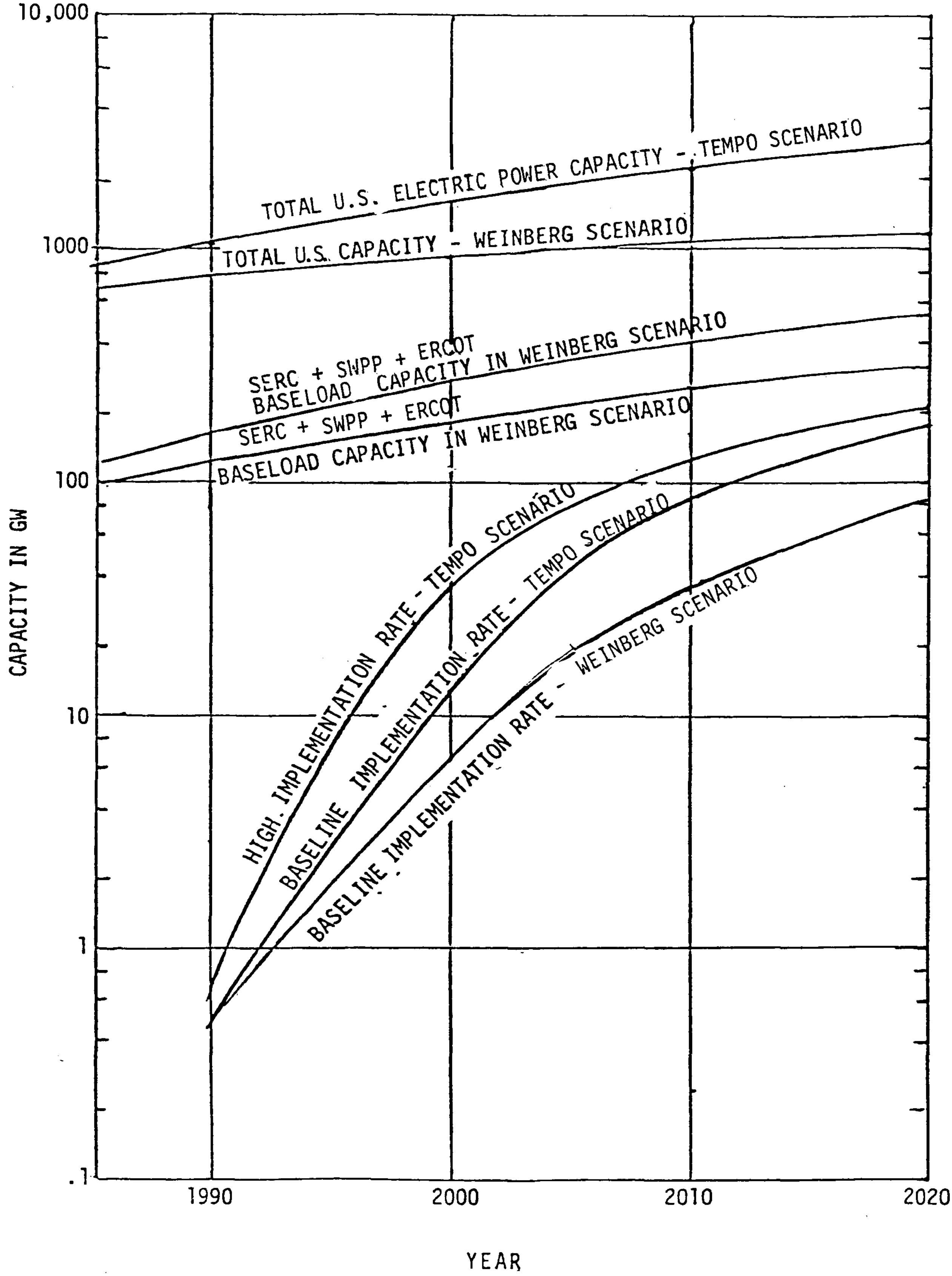

FIGURE ES-5 - SCENARIOS OF TOTAL U.S. POWER REQUIREMENT, SOUTHEASTERN U.S. BASELOAD REQUIREMENT, AND BASELOAD MARKET PENETRATION FOR OTEC.

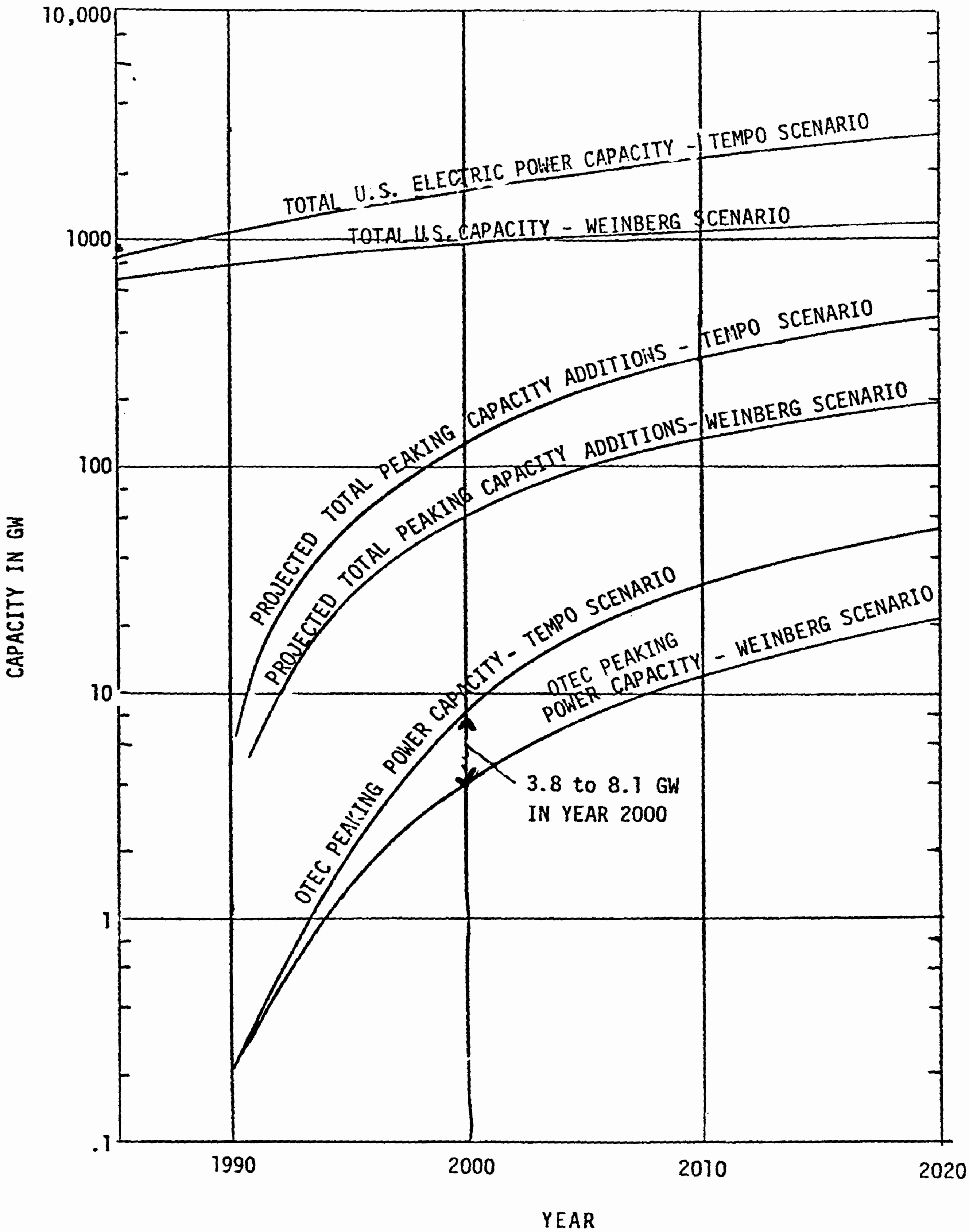

FIGURE ES-6 - SCENARIOS OF U.S. TOTAL POWER REQUIREMENTS, SOUTHEASTERN U.S. ADDITIONS, AND OTEC MARKET PENETRATION FOR PEAKING POWER.

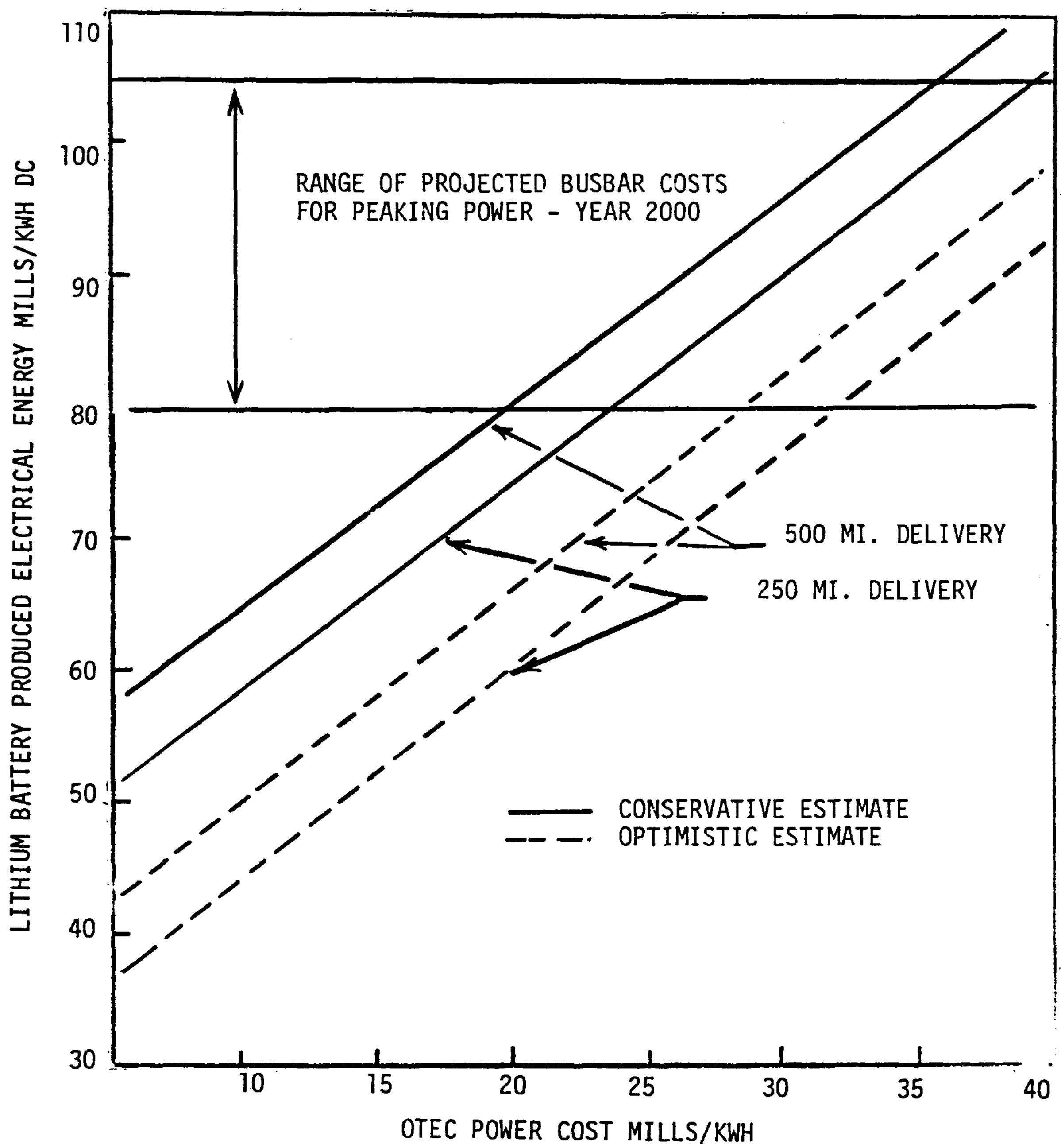

FIGURE ES-7 - COST OF LITHIUM BATTERY (LONG RANGE IMPROVED TECHNOLOGY) POWER PRODUCED ON SHORE AS A FUNCTION OF OTEC SHAFT POWER COST ALL COSTS IN 1976 DOLLARS alternatives show less promise, especially if shipping distances are large for liquid hydrogen or molten salts. Capital costs for hydrogen-fueled gas turbines would be similar to those for oil-fueled units. Hydrogen-fired units would require slightly different fuel injectors, pumps, tubing and valves, but these changes would not significantly affect costs. Since hydrogen is a clean fuel, equipment maintenance requirements would be reduced slightly.

THE HYBRID ISLAND INDUSTRY OPTION

Representatives of chemical and metal-refining companies have expressed concern about (a) possible technical problems of putting their processes aboard ship, such as process sensitivity to motion, and (b) institutional problems, such as establishment of insurance rates for what would be considered a higher risk environment at sea. These concerns might be alleviated by establishing some initial OTEC installations near U.S. islands in semi-tropical waters where the annual average temperature difference would be relatively high, namely, Hawaii and Puerto Rico, to produce ammonia and aluminum. Furthermore, the projected growths of the grid electricity demand on these islands are large enough in themselves to justify some OTEC installations, and the islands have no coal available and few good sites for nuclear plants, so that they presently generate power with oil. With the projected oil prices increases, OTEC systems would be cost-competitive in the year 1990 or sooner as shown in the top part of Fig. ES-8. Therefore, it was assumed that the OTEC market in the islands should include the ammonia and aluminum industries plus the local baseload power. Using these assumptions, Fig. ES-9 shows an installation scenario for OTEC units at Hawaii and Puerto Rico.

The low delivered cost of OTEC power for Puerto Rico results because a public utility there is financed using low-interest bonds, pays no taxes, and makes no profit. Thus, OTEC power costs are 30% lower for Puerto Rico than for Hawaii or other sites where privately-owned utilities have higher costs for money, pay taxes, and seek a profit. Some reduction is also realized for the Puerto Rico financing case in connection with fossil-fueled plants, but since fuel cost is a large portion of the delivered power cost in that case, advantages of public-utility financing are less dramatic than in the OTEC case.

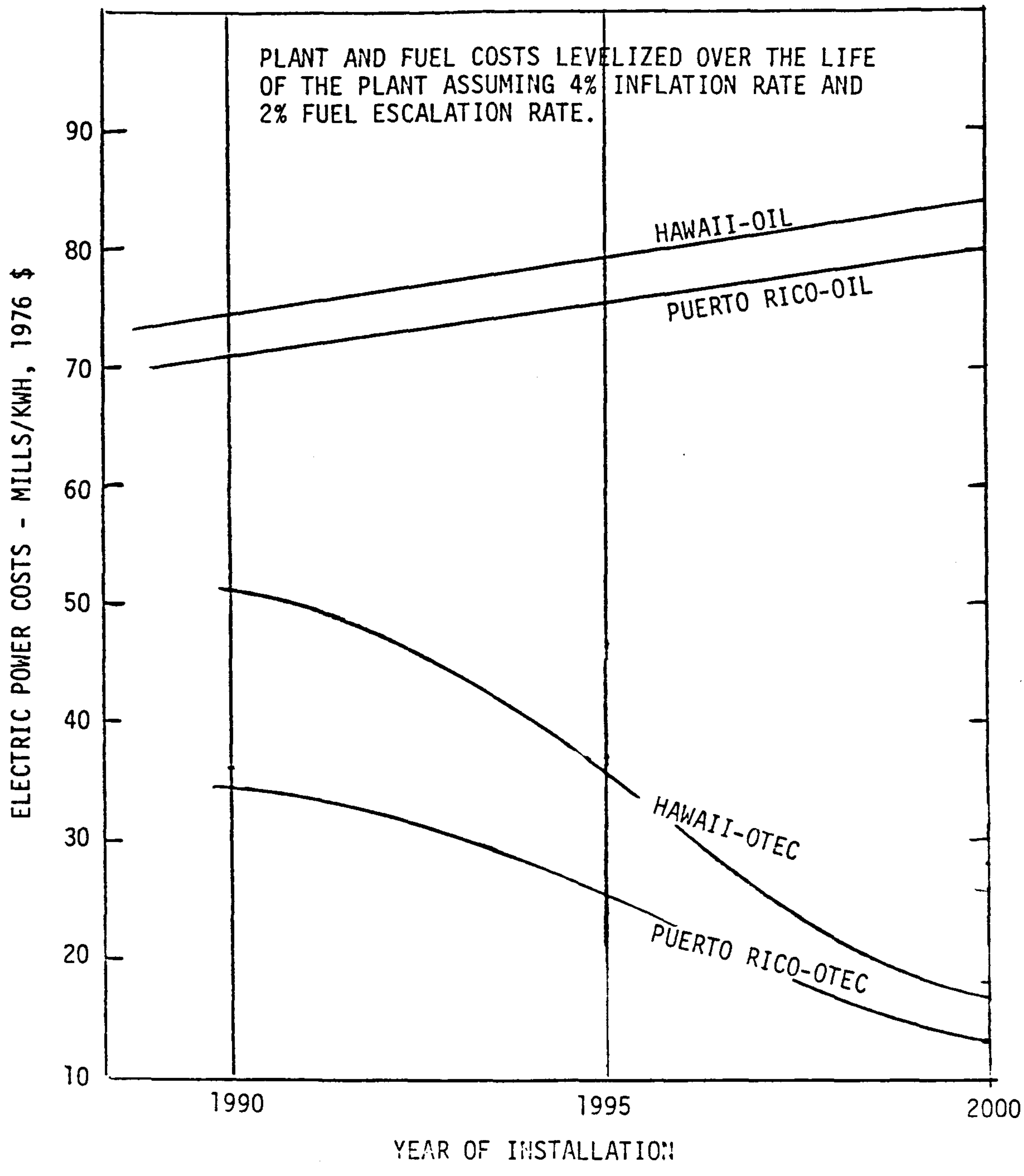

FIGURE ES-8 - COMPARISON OF BUSBAR POWER COSTS FOR NEW POWER INSTALLATIONS IN HAWAII AND PUERTO RICO

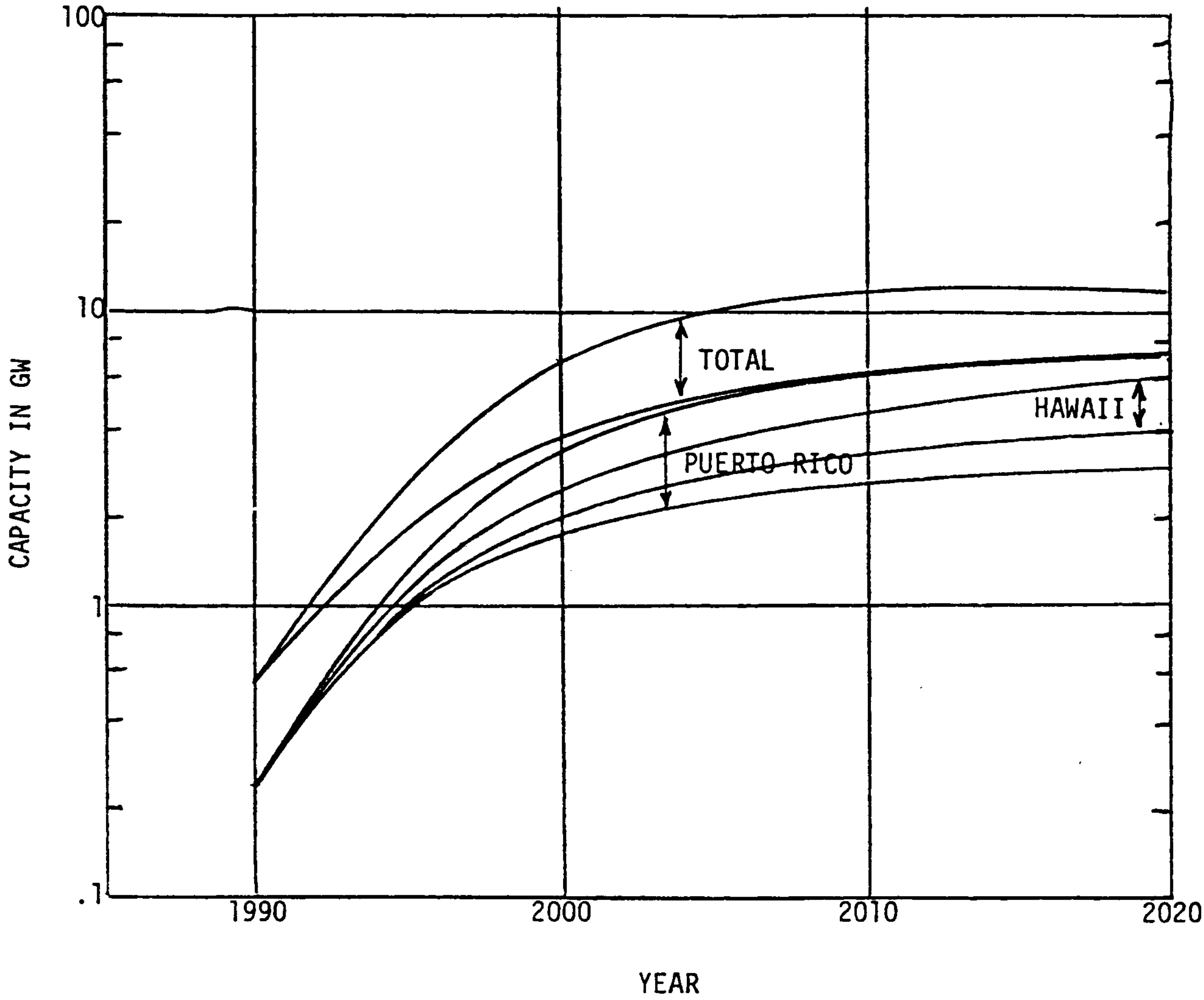

FIGURE ES-9 - OTEC INSTALLATION SECENARIO FOR
PUERTO RICO AND HAWAII

AMMONIA AND ALUMINUM

Ammonia production costs for new plants beginning operation in the mid-1980s to late 1990s were estimated for three processes--conventional natural-gal-reforming, coal-gasification, and the OTEC process which produces hydrogen by electrolysis of water. For all plants the capital investment and fuel costs were levelized over the plant lifetime of 20 years. Fig. ES-10 shows the projected cost ranges and the market penetration scenario to the year 2010 for offshore plants. The ammonia produced by offshore plants will be competitive before the year 2000. In the market penetration scenario, Fig. ES-11, the top two curves are the high (5%/yr.)and low (2.8%/yr.) projections of ammonia demand in the United States. The three lower curves show the high, baseline, and low projections of market penetration by OTEC/ammonia plants, assuming that an incentive program is used to introduce OTEC into the ammonia industry at an accelerated rate. The conclusion is that between 4 and 12 GW_e of OTEC power will be needed in the year 2000 as indicated by the right-hand scale.

The aluminum industry was evaluated in much the same way. Fig. ES-12 shows that tropical-ocean-OTEC-produced aluminum costs would be competitive with aluminum produced by coal-fired or nuclear power plants before 2000. The total capacity additions required by the year 2000 would be 15-30 GW_e, of which the potential OTEC penetration is 1.7-4.5 GW_e.

IMPLICATIONS OF FINDINGS

Several potential industrial applications for OTEC systems could make significant contributions to the nation's energy needs. Projected costs for OTEC power include the anticipated beneficial effects of technological improvements or innovations in second-generation plants in the mid-1990s and experience-related improvements. Achievement of these "learning curve" benefits is based on deployment of at least 6 to 8 GW_e of OTEC power, which in turn is based on initiation of production of commercial units by 1985 to have 0.5-1.0 GW_e in operation by 1990. An industrial incentive structure must be established before 1985, so that the using industries can design and build their first shipboard processing plants by the time the first OTEC units are deployed. Thus, the policy decisions must be made now to select the industrial options and recommend to the Administration and Congress appropriate incentives.

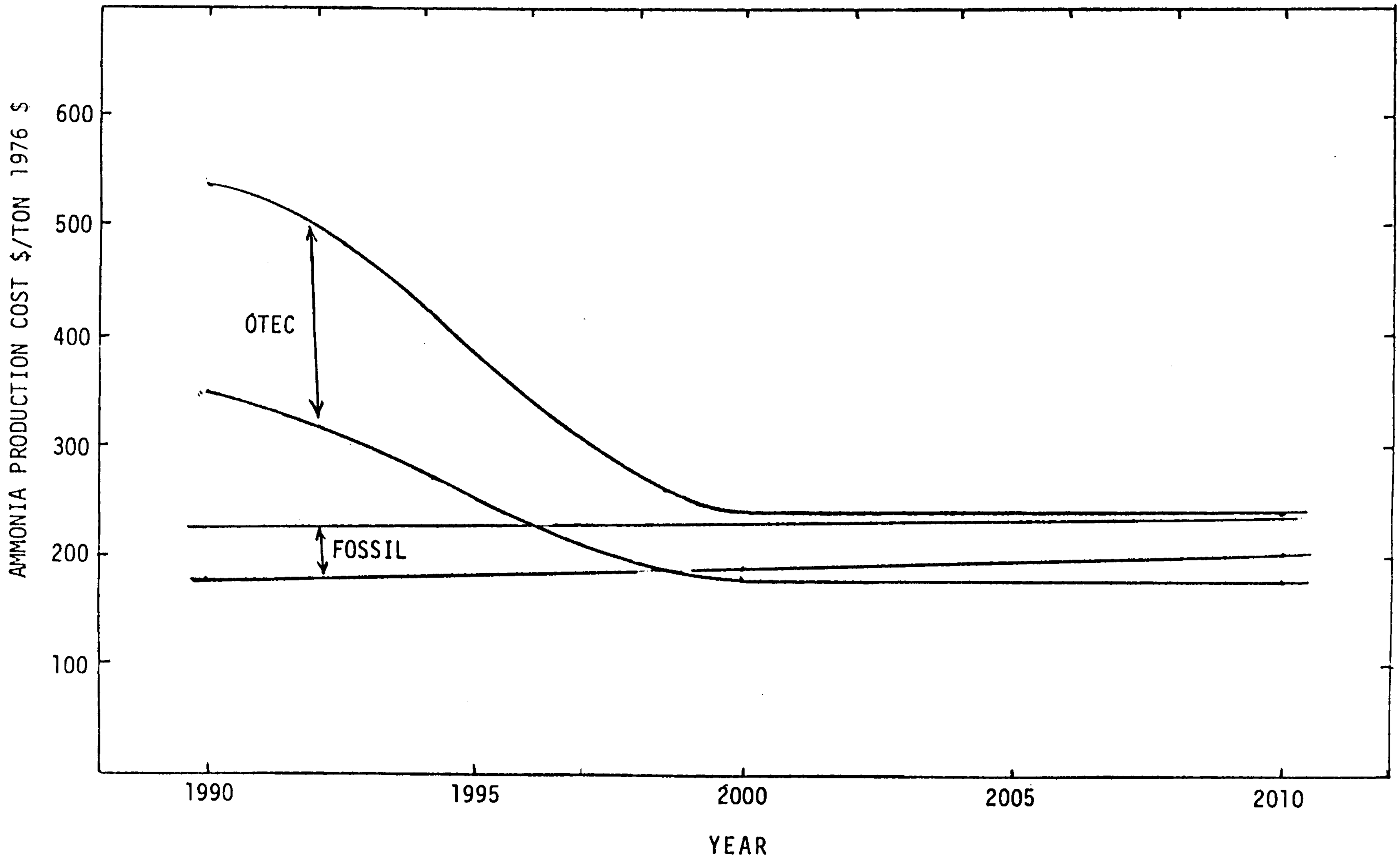

FIGURE ES-10 - COMPARISON OF AMMONIA PRODUCTION COSTS BY OTEC & FOSSIL FUELS

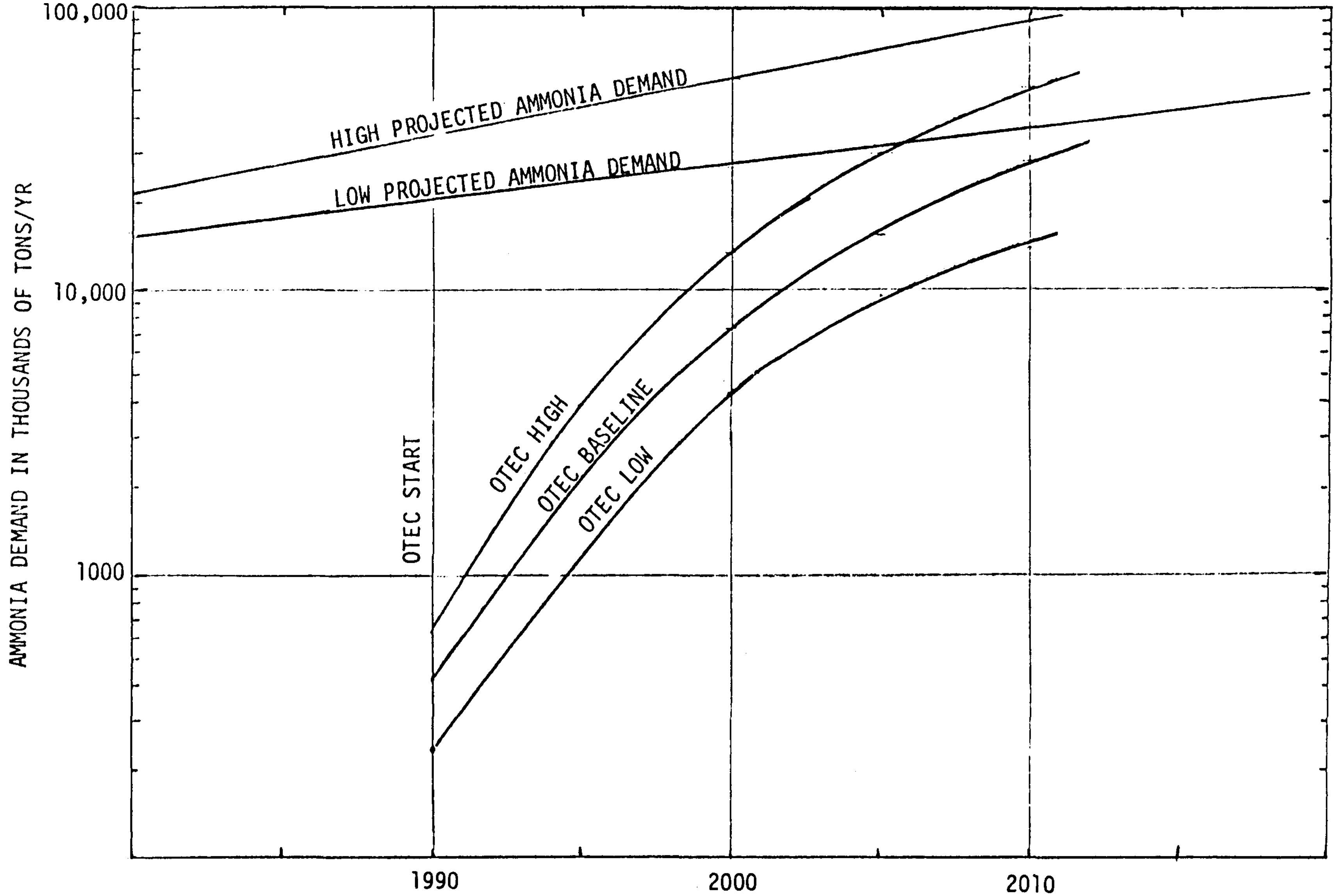

FIGURE ES-11 - PENETRATION OF OTEC IN TO THE AMMONIA MARKET

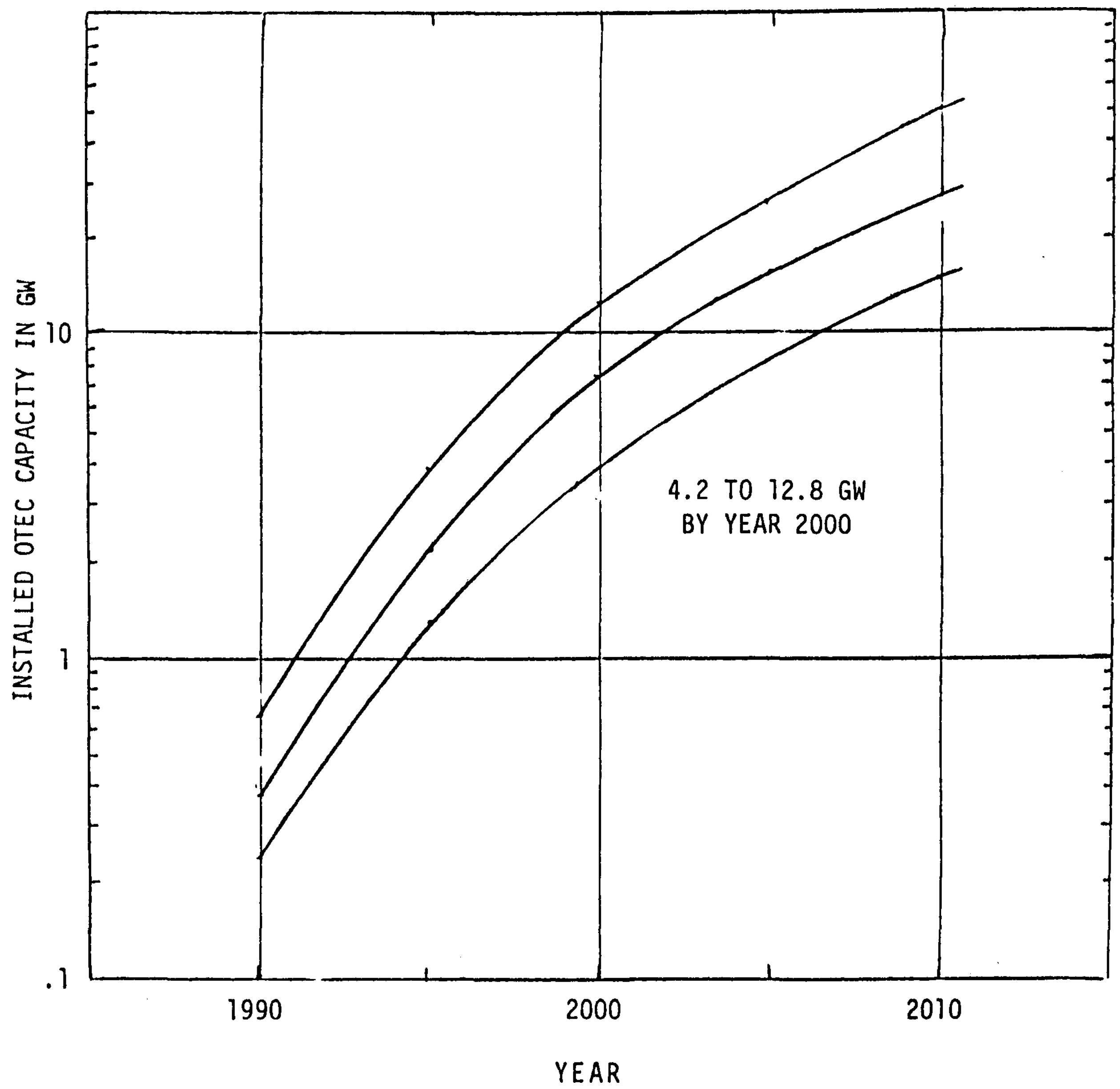

FIGURE ES-12 - OTEC GENERATING CAPACITY
REQUIRED BY PENETRATION IN TO THE AMMONIA MARKET

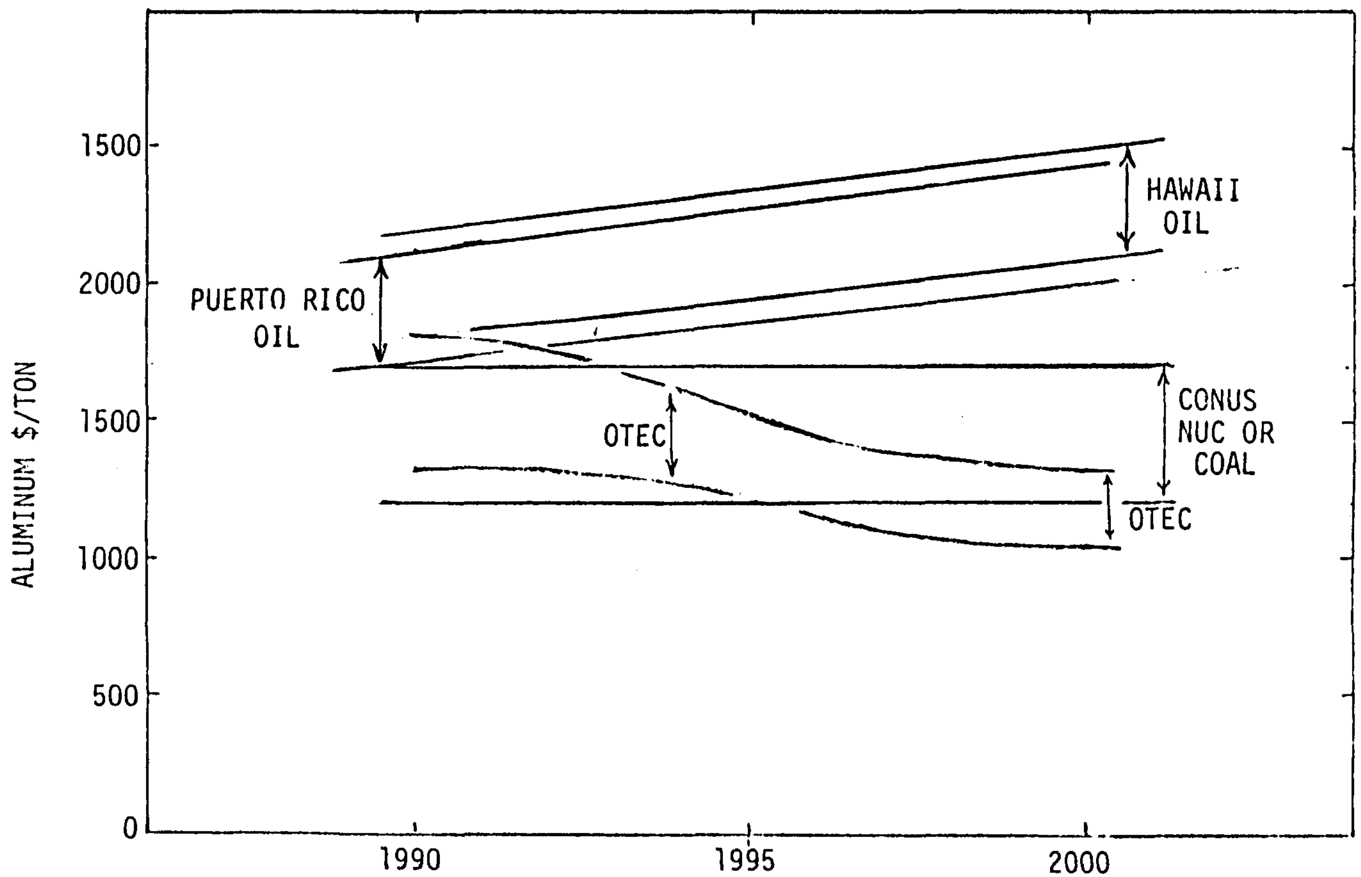

FIGURE ES-13 - ALUMINUM PRODUCTION COST COMPARISON - OTEC VERSUS FUELS

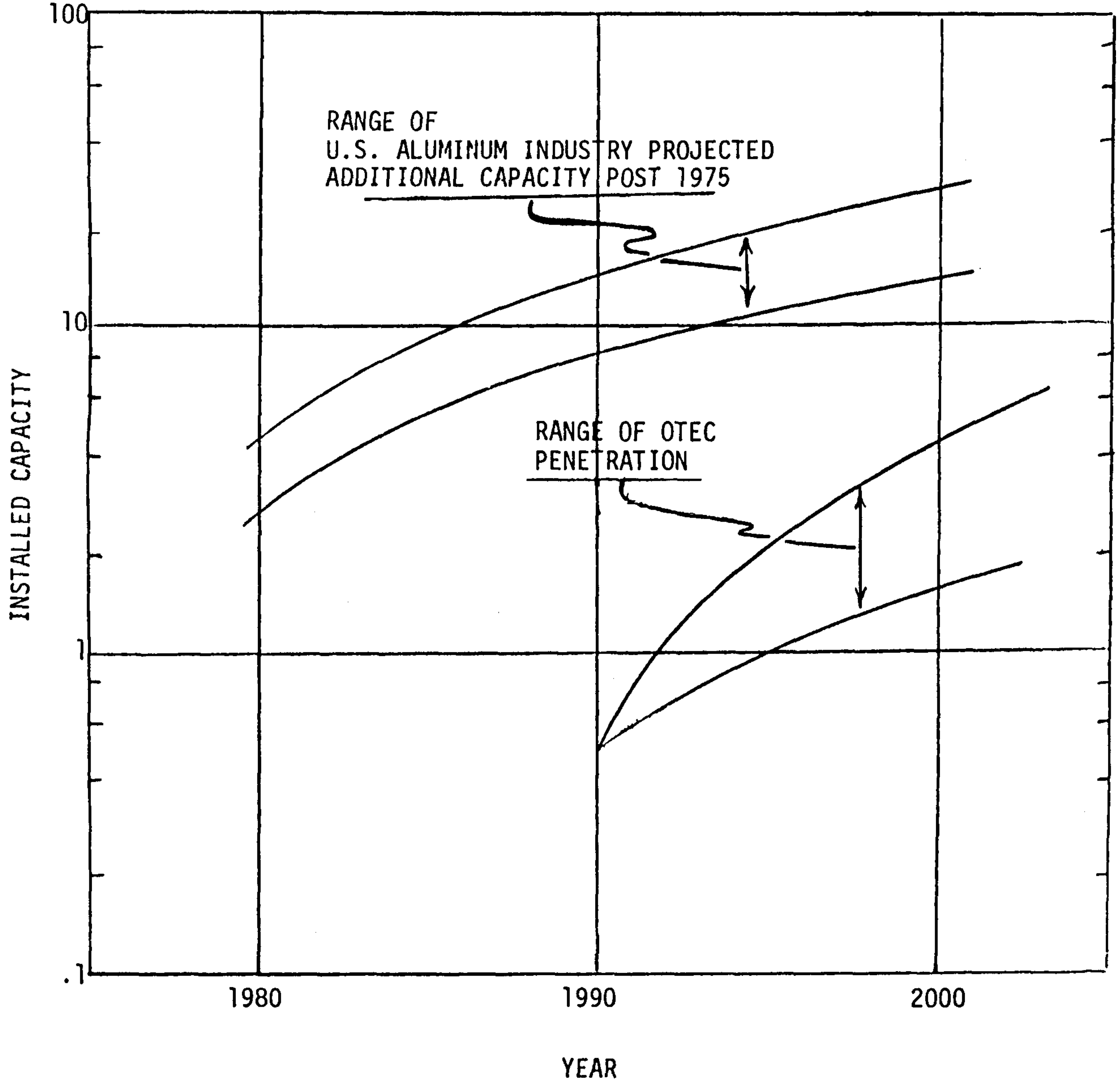

FIGURE ES-14 - POTENTIAL OTEC PENETRATION INTO THE ALUMINUM MARKET

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SECTION I

INTRODUCTION AND BACKGROUND

The basic purpose of the Mission Analysis Study is to examine the potential applications for Ocean Thermal Energy within the framework of national needs for energy and the desire of the Department of Energy that all of its energy conversion systems ultimately be capable of being accepted as commercially viable sources of energy by business and industry.

To provide a framework for the analysis some assumptions have been made in this study that should be stated to provide the context in which the analysis was done.

First - It was assumed that the ultimate uses of OTEC energy would include offshore and at sea installations for producing energy or energy intensive products useful in the national economy. The offshore plants could deliver power or products to shore via cable or pipeline. The tropical open ocean plants would deliver power or products to shore by ship. A third hybrid intermediate configuration was also examined which we have called the "Energy Island" configuration which considers the combination of an offshore OTEC power unit combined with an onshore factory unit in tropical waters. This configuration was considered primarily as an early installation mechanism for introducing industries to OTEC power systems. It was assumed that, in industries such as aluminum smelting where power reliability and platform stability are major concerns, using an island set in tropical waters would be a first step toward the all at sea tropical grazing plant.

Second - as mandated by Congress a program is underway to develop the required technologies for both types of systems in parallel and to stimulate the potential user industries to accept and incorporate the new technology.

For this purpose a development program was assumed as described in figure I-1. This chart indicates the major components of the development program which is under way. On the assumption that the development program will proceed in an

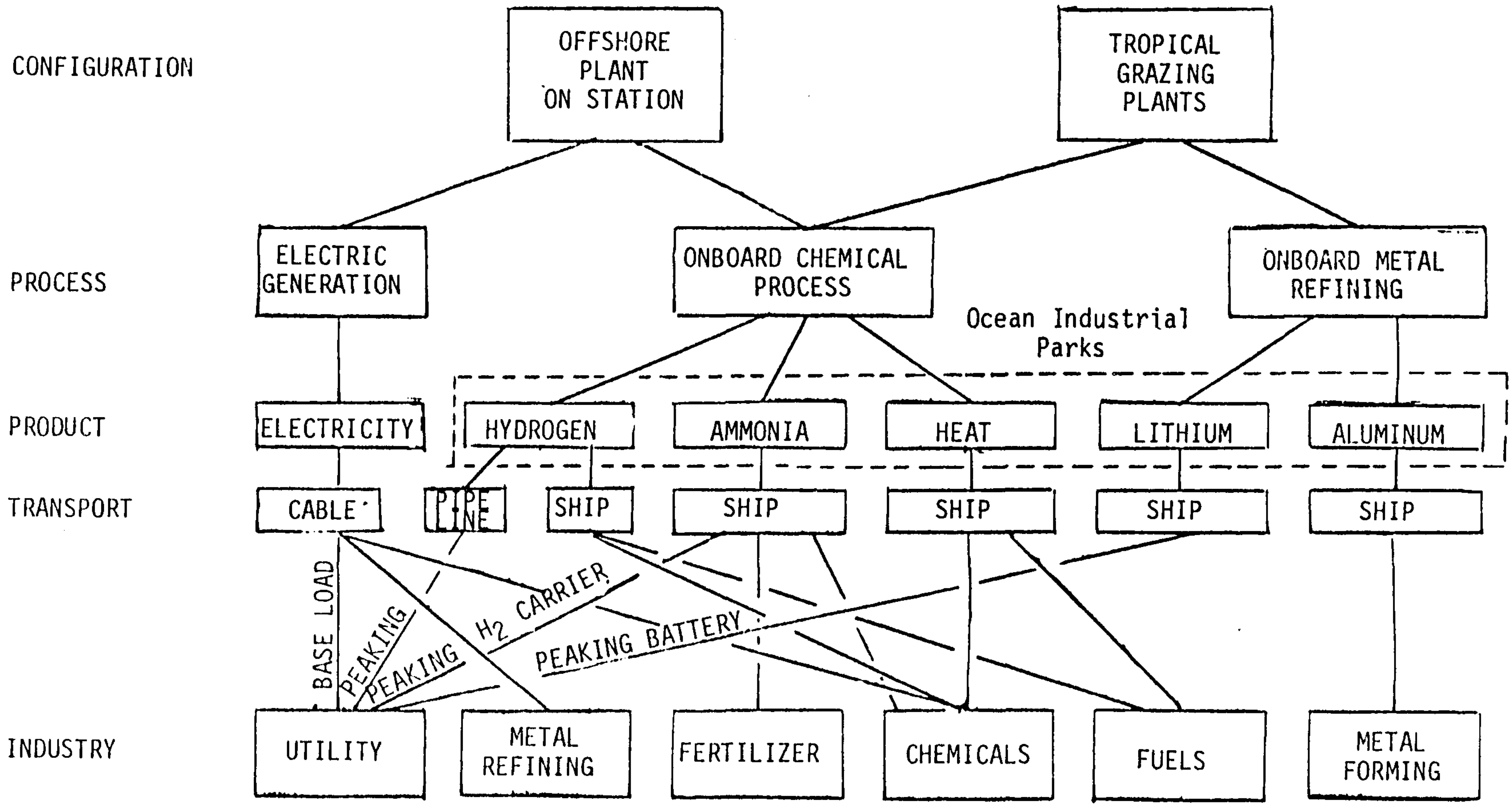

FIGURE I-1 - OTEC COMMERCIALIZATION PATHS orderly fashion and that the first prototype OTEC units will be launched in 1985 a projection of the implementation steps that must take place to develop the potential of the ocean thermal resource. Fig. I-2 shows the implementation steps that were assumed in a time frame of an accelerated commercialization program resulting from initial federal participation, establishment of financial and other incentives and the stimulus of diminishing fossil fuel supplies around the world.

The implementation program shown in Fig. 1-2 assumes that the OTEC program will not only include the development of 1, 5 and 25 megawatt prototypes, a 100 megawatt pilot commercial plant plus at least three initial commercial units, but because the OTEC systems will produce products as well as power, it will be necessary to develop the production process for the OTEC products to gain operating experience with OTEC power systems. As a result process breadboard development and testing was assumed and the commercial plant design and construction was assumed to include the process plant as well as the OTEC power systems for the product options.

Process breadboards will be required for the two products considered (ammonia and aluminum) for two reasons:

First, the development of process equipment and machinery suitable for use aboard floating platforms will require testing to assure satisfactory performance in the presence of vessel motion. This could be a serious problem with aluminum smelting and in probably not a problem in ammonia production.

Second, the development of a different than currently conventional process for the production of ammonia synthesis gas will require testing, to assure that the data on performance and costs are available to permit the design of the commercial sized units is optimized.

To accomplish this accelerated implementation multiple prototype units were assurred to be built and operated in each size range: 1, 5 and 25 megawatts. The construction of multiple prototype units by two or more manufacturers will spread the technological experience over a broad base and will spread the rate at which OTEC costs decline when the fabrication of commercial sized units are initiated. In addition, the production of multiple prototype units not only will permit operational experience to be obtained in a number of sites both offshore and in the tropical grazing mode but also permit the initiation of industrial operating experience with the process plant bread boards that will also have to be started as part of the program.

The steps indicated in Figure I-2 are optimistically scheduled on the assumption that each step will be initiated as soon as technologically possible with no external delays.

As can be seen, based on the DOE schedule of 100 MW Pilot Plant Launch in 1983 the initiation of construction of several commercial production facilities immediately thereafter would permit initial deployment of several commercial units by 1990 and a significant contribution to the nations energy sources could be realized by the year 2000 by which time commercial viability would have been established and the industrial infrastructure and institutions for producing and using Ocean Thermal Energy Conversion Systems established.

Third, the purpose of the research performed in phase II of the Ocean Thermal Energy Conversion Mission Analysis was to examine in detail selected missions for the OTEC systems to determine whether or not specific applications could be identified that employ early commercial feasibility.

The missions that were examined included:

- Power to shore for input into the grid as baseload.
- Grazing plant ships and island industries in tropical waters to determine whether significant benefits can be realized in early implementation of industrial applications.
- Hydrogen production.
- Power to shore via storable energy for use in peaking.

In each of these missions the analysis examined the market potential to be expected over a range of operating conditions in the market and competing conventional technologies.

To permit the indication of the sensitivity and the potential variations in the results the data is presented wherever possible by giving a range of the expected results.

Fourth, financial constraints and cost accounting methods were assumed that are representative of industrial practices in the industries that OTEC

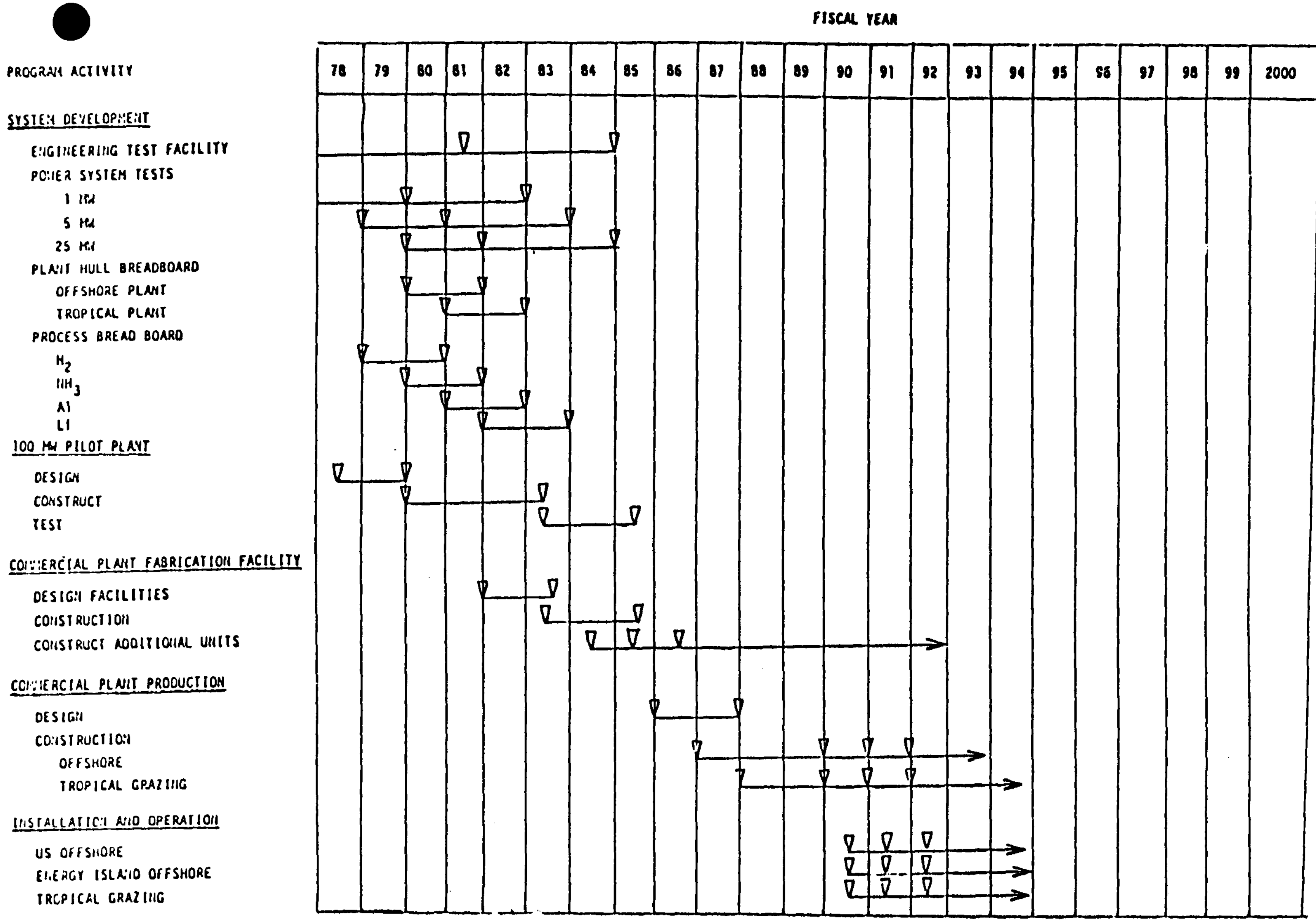

FIGURE I-2 - PROJECTED COMMERCIAL IMPLEMENTATION SCHEDULE systems would be serving. This means that:

- In the power delivery to shore operation it was assumed that the OTEC units would be owned and operated by a regulated corporation, and regulated by either state or federal regulatory commissions. The estimates of power production costs were made using conventional utility practices.
- In the product missions whether the product was produced on the grazing plants, or the island industry plants the estimates of product production costs were made using conventional practices appropriate to that industry.

It should be noted that these financial practices are not as liberal as is possible with ship building and operation in the United States because of incentive programs available to these industries. However, there is still question as to the legal status of the OTEC plants; whether they will be accorded ship status, whether they will be regulated, etc. This aspect of the problem remains to be resolved and should be investigated further.

SECTION II

ELECTRIC POWER OPTIONS

To provide a realistic estimate of the compatability of the Ocean Thermal Energy conversion systems with the Southeastern US power systems three areas were selected for examination as representative load centers. They were Miami, New Orleans, and Houston. As potential OTEC sites for serving these areas several specific locations where thermal resource data was available were examined. The Sites examined were:

For Miami - Approximately 40 miles south of Key West
- Approximately 30 miles east of Miami
- Approximately 160 miles off the west coast of florida

For New Orleans - Approximately 50 miles southeast of the mouth of the Mississippi river.

For Houston - Approximately 150 miles east of Brownsville.

To provide estimates for the tropical ocean plants - both tropical grazing and island industry three additional sites were examined:

- Approximately 600 miles east of Recife, Brazil
- Southeast of Puerto Rico
- West of the island of Hawaii

Figures II-1A and II-1B show the sites.

BASELOAD POWER TO UTILITIES IN THE SOUTHEASTERN U.S.

In considering OTEC compatability with the using utilities the impact of the temperature difference available at the location and the variation of the temperature difference through the year was a major concern. There appeared to be a potentially good match because the utilities along the gulf are known to be summer peaking utilities but there was some concern that in the winter the temperature minimum would prevent OTEC operation. The parameters affecting the OTEC performance were determined from other studies being performed and the projected OTEC output compared with the Utility load pattern.

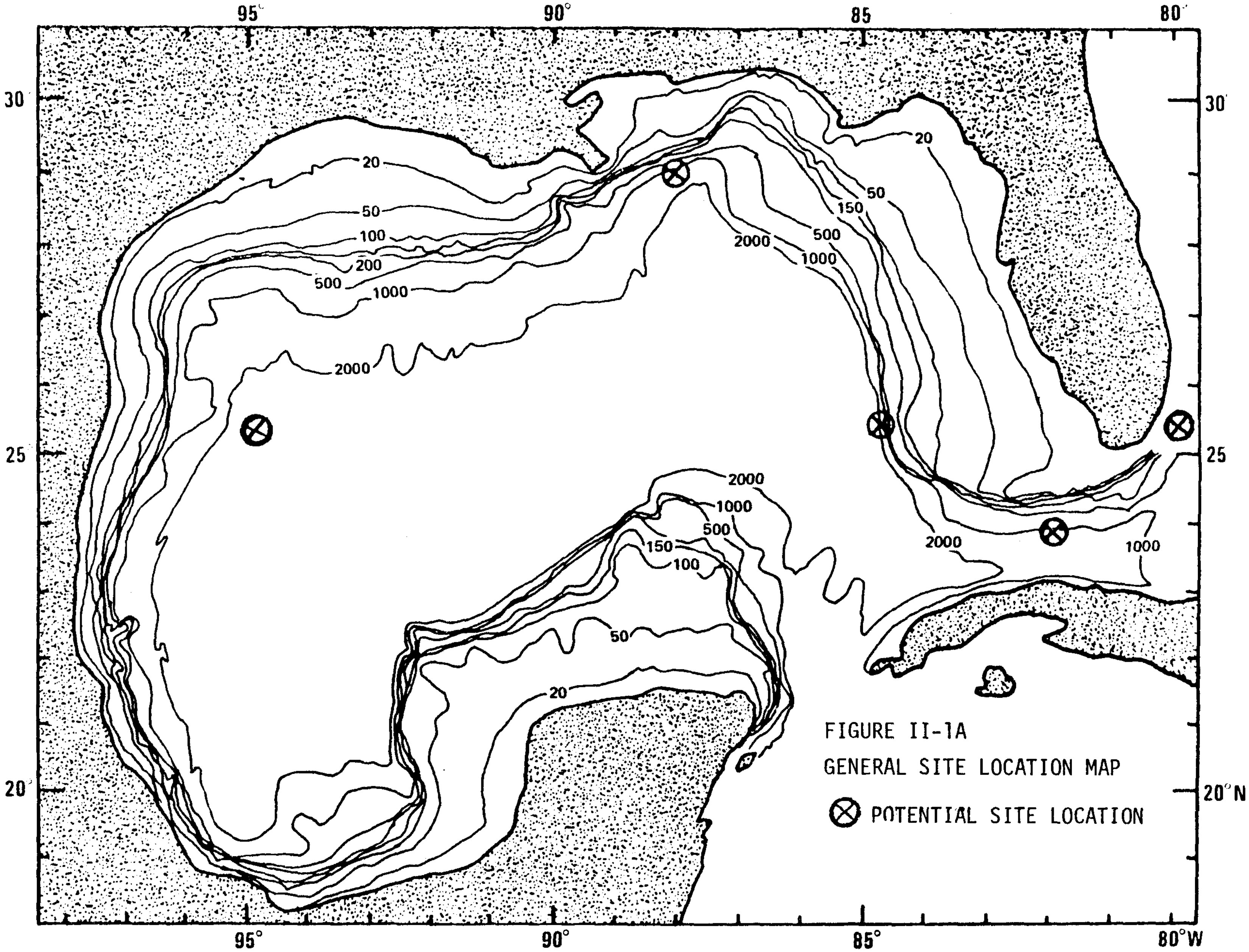

FIGURE II-1A
GENERAL SITE LOCATION MAP

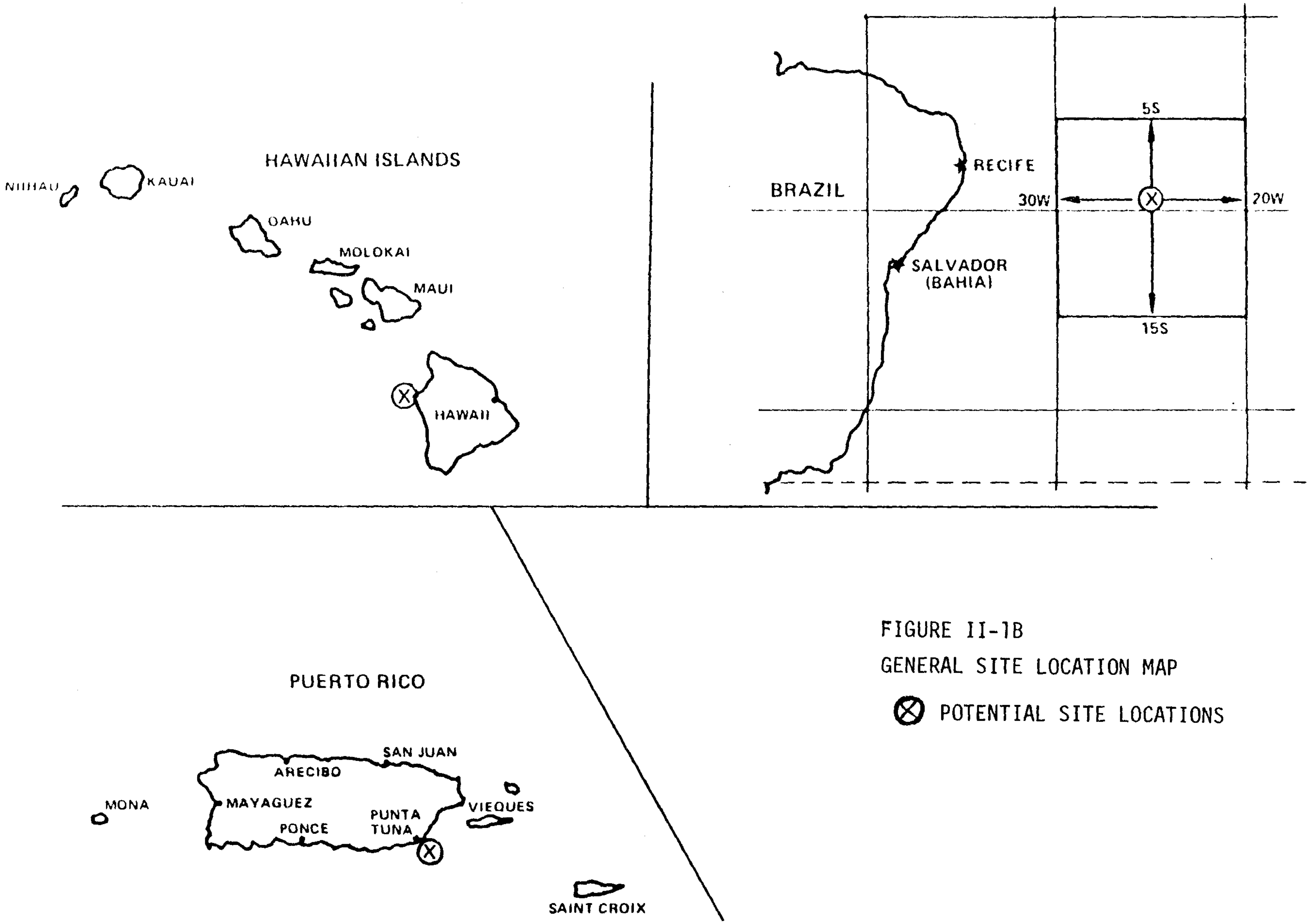

FIGURE II-1B
GENERAL SITE LOCATION MAP

⊗ POTENTIAL SITE LOCATIONS

OTEC SEASONAL POWER VARIATION

Based on oceanographic data available for the different sites monthly temperature difference data was made available by ODSI*. For the purpose of this study it was assumed that the OTEC unit at the site would be designed to take advantage of the maximum temperature difference available in the best month of the year and then the performance degradation to be expected was determined for each month of the year to determine three things:

- Was the worst month of the year (the month with the minimum temperature difference) so bad that the OTEC unit installed there would not be able to generate some power to deliver to the utility.
- Was the overall generation pattern sufficiently well matched to the utility load pattern so that the maximum utilization of OTEC power would be realized.
- Would the cost of power delivered to the user vary significantly as a function of location and would the cost variation effect the competitiveness of OTEC power.

The method of determining these factors is based on the anticipated performance of the heat exchangers.

The results of the analysis of the evaluation of the temperature difference variations are summarized in Table II-2 which indicates the temperature differences to be expected for each site as a function of the month of the year.

With respect to the concern that the minimum temperature differences would be so low that the OTEC would not be able to deliver power it was found that the minimum monthly power output ratio for the worst month (February, New Orleans) was 37% which is still well above the 24% parasitic pump power requirement required by the improved Lockheed design (1977 design).

UTILITY LOAD CHARACTERISTICS

To determine the load characteristics for representative utilities in the OTEC region data was obtained on the generation of Florida Power and Light,

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* OTEC Thermal Resource Report Series, by Ocean Data Systems, Inc. Monterey California, 1977

TABLE II-2 - ΔT VERSUS MONTHS FOR SELECTED SITES

SITE	BRAZIL	HAWAII	PUERTO RICO	NEW ORLEANS	W. COAST FLORIDA	KEY WEST	MIAMI	BROWNSVILLE
JAN	22.9	20.6	21.2	18.3	19.1	19.3	19.0	17.0
FEB	23.5	20.1	20.9	15.2	19.2	19.7	19.5	16.0
MAR	24.3	20.0	20.9	15.7	18.5	19.7	19.5	17.0
APR	25.0	20.6	21.2	18.0	20.6	20.5	19.5	18.5
MAY	24.3	21.3	22.2	19.7	21.4	21.6	20.3	19.5
JUN	24.2	21.4	22.6	22.9	23.3	23.1	21.3	23.0
JUL	22.9	22.4	22.9	24.8	24.5	24.1	22.0	23.7
AUG	22.6	22.7	23.1	24.2	24.3	23.9	22.0	25.0
SEP	21.9	22.7	23.4	23.4	23.4	23.4	22.0	24.5
OCT	21.8	22.5	23.9	21.1	22.7	23.6	22.0	22.5
NOV	22.2	21.5	23.3	19.8	20.7	22.2	22.0	20.2
DEC	23.0	20.8	22.3	19.5	20.5	20.0	19.5	17.7
AVERAGE	23.2	21.4	22.3	20.2	21.5	21.8	20.6	20.4

NOTES
- ΔT between Surface and 1000 meters except Brazil to 900 meters, Miami to 700 meters
- Data for Brazil is for a grazing concept not a fixed site

Louisiana Power and Light and Houston Light and Power for two years 1976 and 1972. The use of the two years was made to determine whether there would be significant differences in the load pattern from year to year. Initially it was planned to use the average load pattern to match the average ocean temperature difference data however, consideration of the fact that the energy crisis started in 1973 and strong measures were used to conserve energy and reduce electricity consumption in 1974 suggested that it would be better to compare the latest available data (1976) with the last "normal" year before the energy crisis started (1972). The generation history for the three utilities for these two years are shown with the predicted OTEC generation pattern for each site superimposed on Figures II-2, II-3, II-4.

As can be seen, the pattern of the utility loads have been similar for both 1972 and 1976 the only notable difference is the increase in load between the two years, the peaks and minimums occur at essentially the same point and the ratio of peak to minimum is similar.

The ratio of the power output for each month to the peak month was also plotted. This was calculated using the TRW algorithm (1) and normalized to the peak of the 1976 generation to permit the two curves to be compared directly. Three sites are plotted on the chart with the Florida Power and Light generation and one site only is plotted against the Louisiana Power and Light generation and the Houston Light and Power generation.

Comparison of the curves indicates that the OTEC output patterns match the generation curves reasonably well. Peak OTEC outputs fall close to generation maximums and minimum OTEC outputs fall close to the generation minimum. The reason for this is the fact that all three Gulf Coast utilities are typical summer peaking utilities in which the peak demand is the result of air conditioning loads in the summer and fall. The same insolation that causes the air conditioning demand also increases the ocean surface temperature and the ΔT hence the similarity in maximum and minimum timing.

The best match between the OTEC output and utility load is in the Florida Power and Light chart. On this chart the site off Miami maintains the highest average output with its minimum value only slightly below the generation minimum. The Key West site and the Florida West Coast site do fall 10% to 15% below the generation curve at their minimum. The OTEC minimums for Louisiana Power and Light and Houston Light and Power were 20%

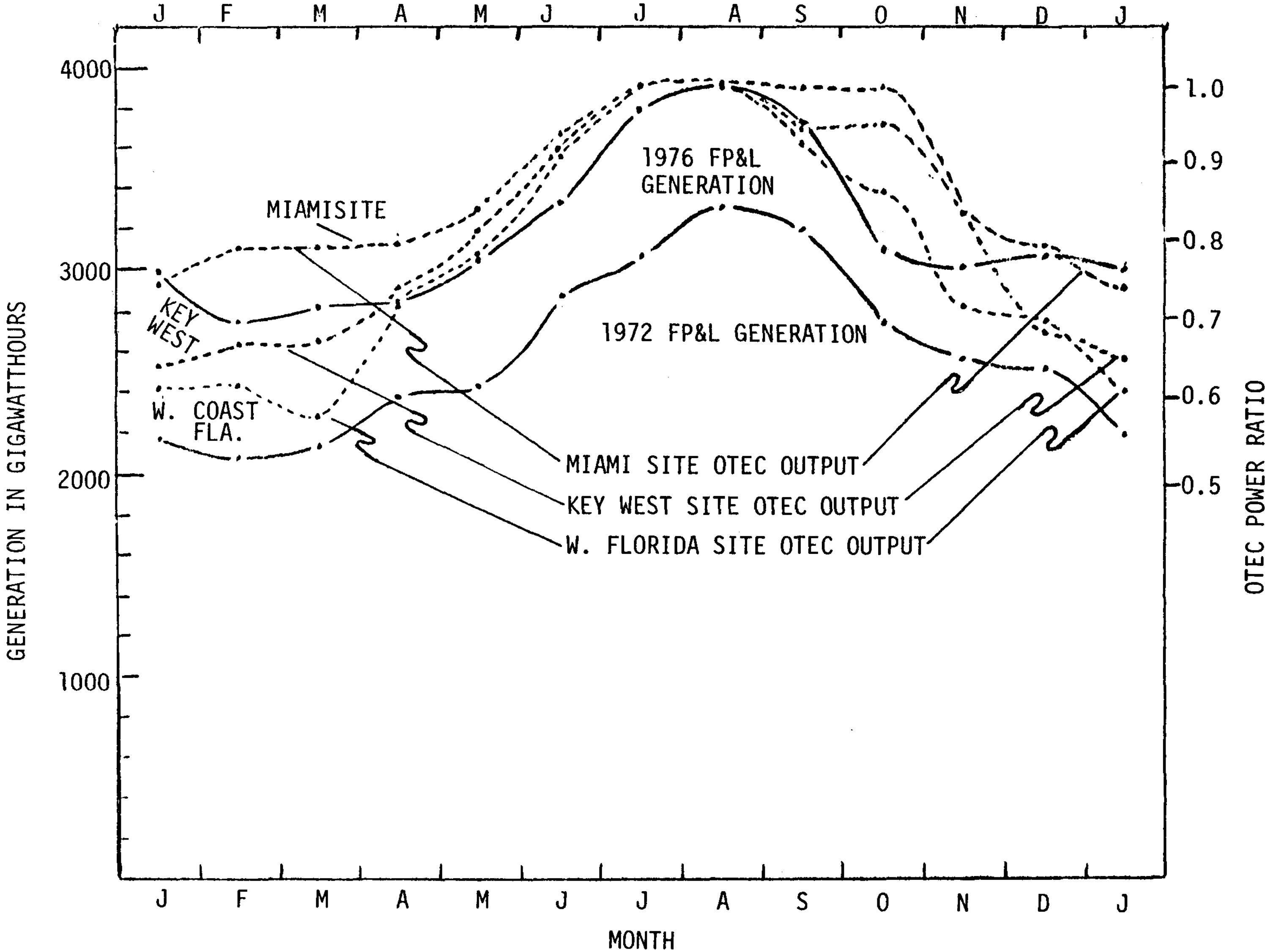


FIGURE II-2 - MIAMI POWER AND LIGHT GENERATION AND OTEC OUTPUT FOR 3 SITES

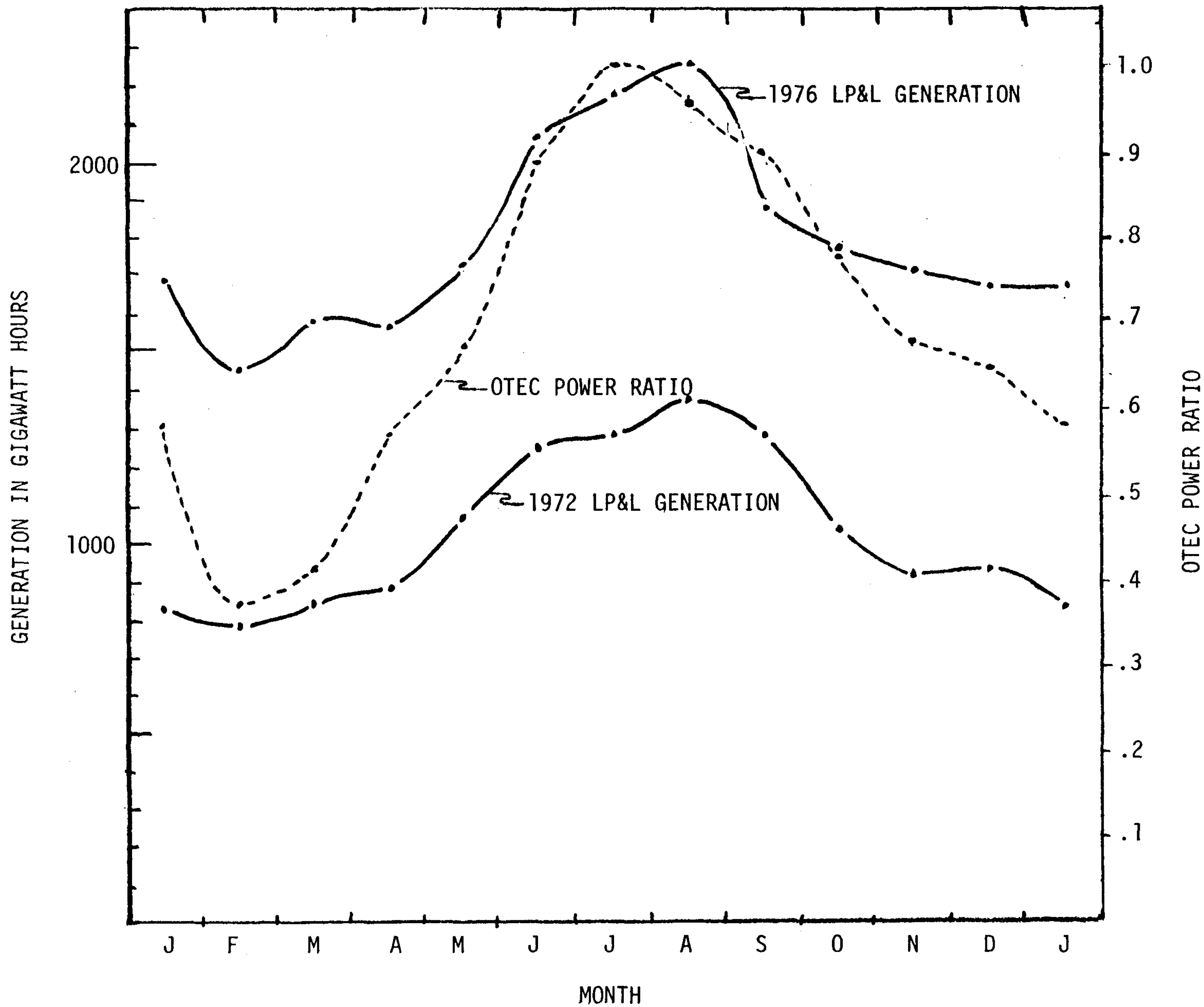


FIGURE II-3 - LOUISIANA POWER AND LIGHT GENERATION AND OTEC POWER OUTPUT

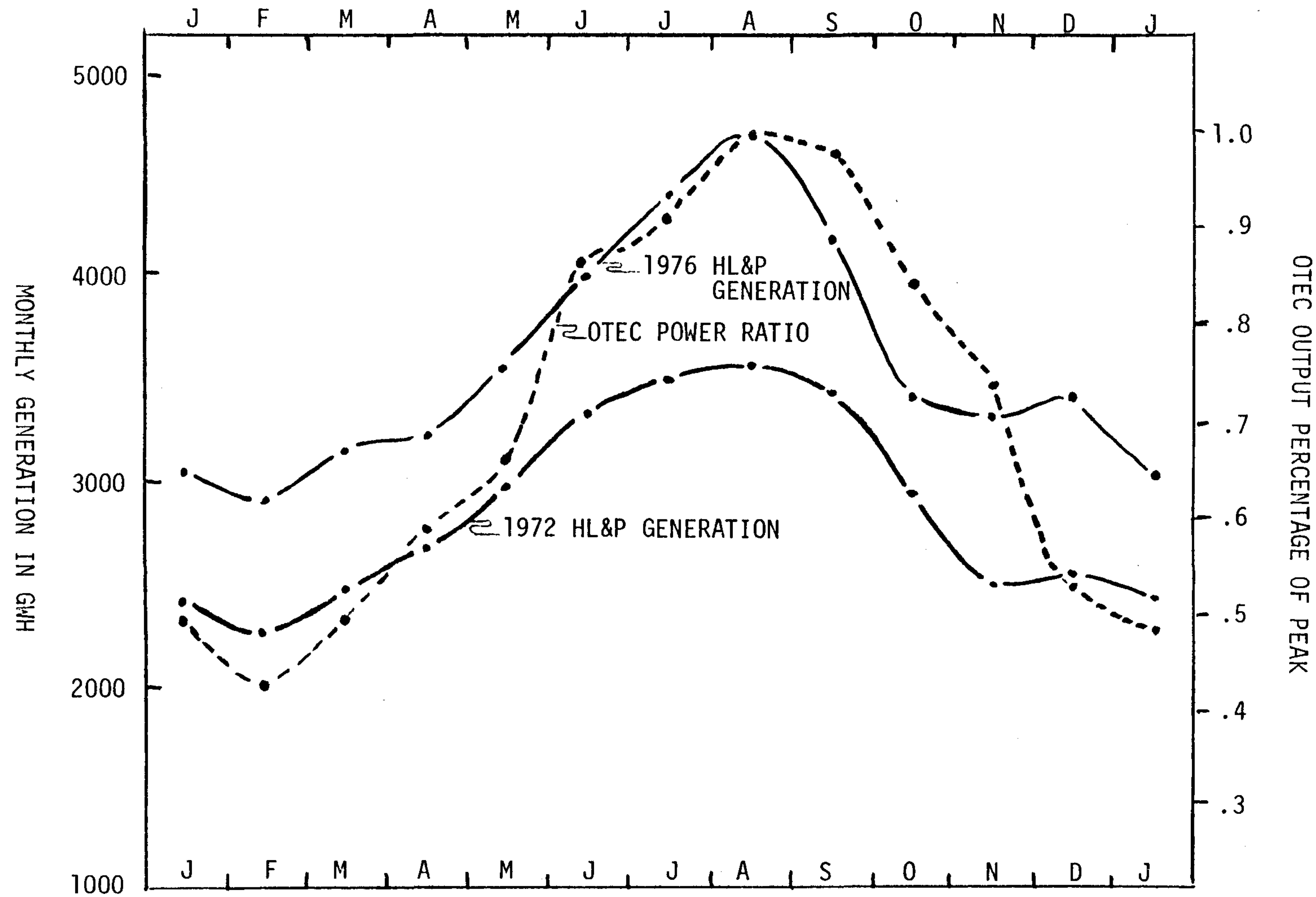


FIGURE II-4 - HOUSTON LIGHT AND POWER GENERATION AND OTEC POWER RATIO and 27% below their corresponding generation minimums. However, these utilities normally would have other baseload systems available to satisfy the need.

Concern might be expressed over the prospect of having a baseload plant whose potential capacity can vary from month to month but this characteristic is exactly the same as encountered with a run of the river hydroplant. As long as the plant has a predictable seasonal variation in flow rate and hence generation utilities can plan their usage and maintainance to minimize costs of operation.

The implications of this is that the utilities will probably treat the OTEC system as they do run of the river power plants which are also seasonal in output and have no fuel costs. Normal utility operation for these plants will be to dispatch them first before all fuelled plants. Then maintainance will be scheduled during the period of the year in which the plant is normally at its minimum output to minimize the loss of revenue from a no fuel cost plant. In the case of fuelled base load plants they are normally scheduled for annual maintenance during the load minimum to reduce the effect on the system loss of load probability of having a baseload plant down and unavailable for an extended period. OTEC systems fortunately combine both features in that their minimum output period occurs at the same time as the system minimum load so that routine maintenance on OTEC units will both minimize revenue losses and minimize increases in the loss of load probability.

To a great extent the fact that the OTEC system increases its power output during the maximum period will enable the utility to use less base load capacity. At the present time with fuelled systems summer peaking utilities normally have surplus base load capacity during the winter as well as surplus peaking capacity resulting in significant under-utilization of equipment.

OTEC POWER COSTS AND THE MARKET POTENTIAL

A great deal of discussion has centered around the commercial competitiveness of OTEC power as a function of the busbar energy costs (BBEC) at which the OTEC plant can generate power and in general this is used as a measure of acceptability to the utilities. It should be realized that there are many factors that will affect the busbar cost acceptability to a utility. Some of these include type of use others include other considerations such as effects on loss of load probability, fuel availability and fuel price variability, capital intensiveness, and many others. In addition, the OTEC plant siting requirements include the need to transmit the power to shore and from the shore to a load center which represent additional costs above the busbar cost. A third area of consideration is the alternative costs of new capacity to the utilities that are considering the use of OTEC.

To provide a frame work for considering OTEC as a baseload option the map of figure II-5 is presented. (2) This chart shows the range of levelized busbar costs in different regions expected in the year 2000 for power produced by the two conventional types of plant most likely to be implemented in that time frame. These plants are conventional coal plants and light water nuclear reactors. As can be seen, the costs range from low values of thirty two mills/kwh to high values of fifty three mills/kwh. In general, the low prices are those associated with the nuclear plants - 32 to 38 mills/kwh and the high prices are those associated with coal plants 37 - 53 mills/kwh.

To get a feeling of how utilities would use OTEC in this environment consider that, OTEC busbar costs ranging between 20 mills/kwh to 40 mills/kwh by the year 2000 have been considered feasable. To evaluate the gross nature of the market for OTEC systems as base load power we assumed that the busbar costs are 20, 30, and 40 mills/kwh. In addition to that assume additional costs of the order of 10 mills/kwh can be expected to cover transmission to the beach and then, if the utility is any distance from the point at which the power comes ashore overland transmission must be added.

In the frame work of the costs shown on Figure II-5 the acceptability of OTEC power would be as follows:

- At 40 mills/kwh BBEC OTEC power onshore would cost approximately 50 mills/kwh and be competitive with coal plants for utilities within less than 100 miles of the OTEC beach terminal. Because utilities try to diversify their base load inventory and because OTEC plants will be exempt from fuel price escalation problems a local utility would probably incorporate OTEC 10 to 20 percent of its baseload generation primarily subtracting this from the percentage that it would otherwise put in coal plants.

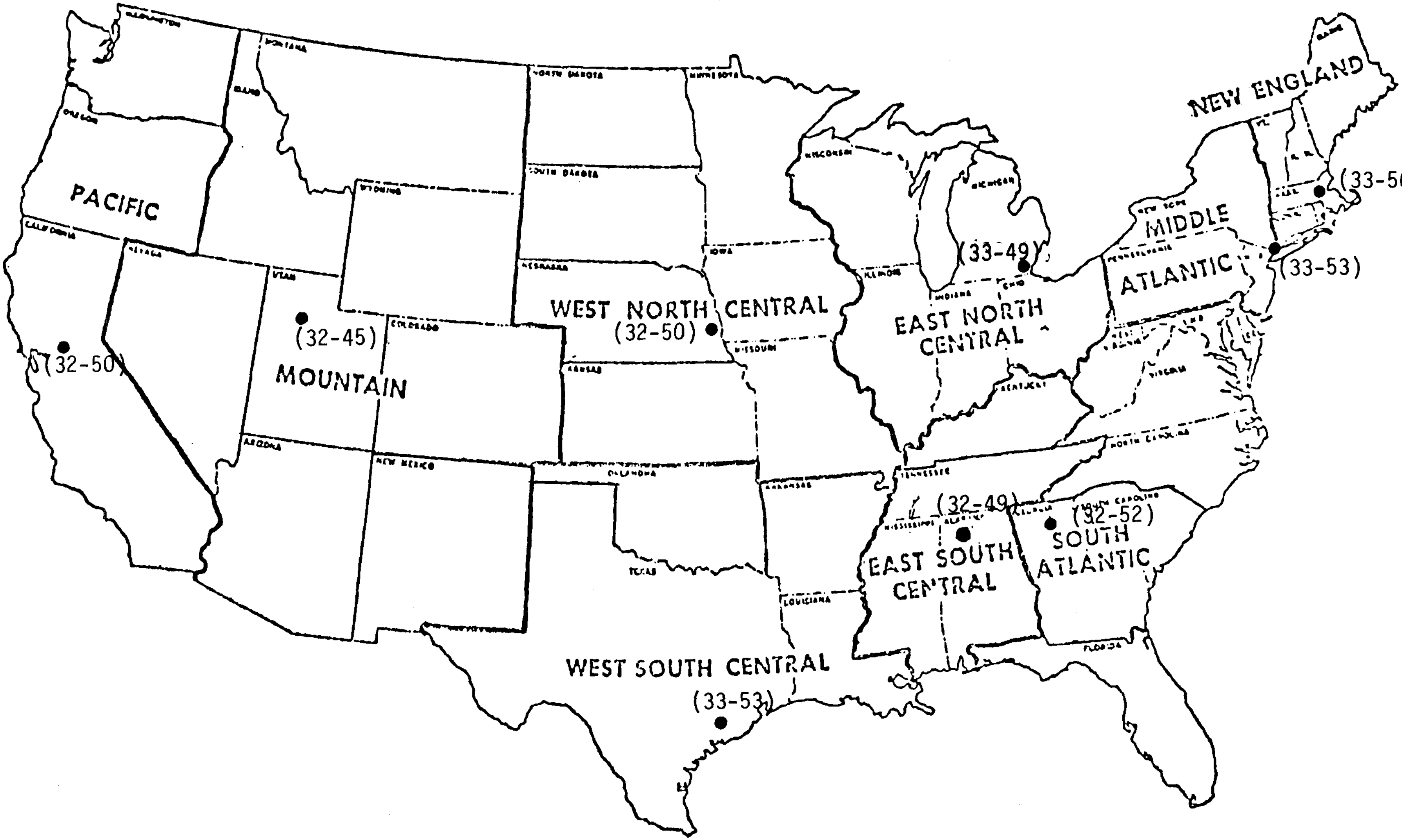


FIGURE II-5 - RANGE OF LEVELIZED BUSBAR COSTS OF BASELOAD POWER FOR THE YEAR 2000 IN MILLS/KWH

- At 30 mills/kwh BBEC OTEC power would cost approximately 40 mills/kwh on the beach. At this cost it would be competitive with both nuclear plants and coal plants for local utilities. Because overland transmission costs are expected to be approximately 3 mills/kwh/100mi for the power output levels of single OTEC plants (250 to 500 MW) the OTEC power would be competitive with coal generated power at distances up to about 300 miles and suggests that at this price the OTEC power could serve a number of utilities or a power pool at least in competition with coal plant generated power.
- At 20 mills/kwh BBEC OTEC power would cost approximately 30 mills/kwh on the beach and be lower in cost than either coal or nuclear. At this price all pool utilities would probably incorporate OTEC for at least 40% of their total base load generation. In addition, because regional costs as shown in figure II-5 are as high or higher than those surrounding the Gulf of Mexico it would be reasonable to expect that OTEC power could be exported out of the parent reliability council if high power transmission is used. At power transmission levels of 3000 megawatts it is estimated that transmission costs can be as low as 1 mill/kwh/100mi. which will permit transmission distances of 700 to 1000 miles and still be competitive with coal fired plants.

As can be seen from the discussion above the market penetration that is possible by OTEC would require that busbar costs of 30 mills/kwh or less must be achieved if OTEC is to make a significant contribution to the base load power requirements of the country.

To permit the estimation of the percentage penetration of both the power and product markets and to obtain an expected range of OTEC power costs a more detailed site specific analysis of costs was done integrating the monthly data on OTEC output and incorporating additional cost factors such as high current mooring differential and transmission costs.

The results of this analysis are summarized in figure II-6 which shows the projected deliverd cost and components of cost for the eight sites shown in figure II-1. The factors considered included:

- Amortization of capital investment
- Mooring differential for high current locations
- Underwater cable costs as a function of offshore distance
- Operations and maintainance costs

The method of estimating costs employed was that developed jointly by ERDA and EPRI (11) and is similar to the method used by most utilities.

The costs for the Brazil site do not include cabling or mooring differential because this site was associated with a tropical grazing plant where the power is to be delivered to an on-board factory. The costs for the Miami and Key West sites were the only ones that included a mooring differential because they were the only sites at which the current excluded the performance of the standard mooring system for which costs had been incorporated into the capital estimates. The costs for the Puerto Rican and Hawaiian sites were based on the assumption that the cable runs were short enough so that AC could be delivered from the OTEC unit and DC to AC interface equipment would not be needed. In addition the Puerto Rican costs were based on public utility financing because the Puerto Rican utility is a public utility.

It should be noted that the low costs of OTEC power projected for the Puerto Rican site is primarily the result of public utility financing. The fact that public utilities pay no taxes, can finance their capital with very low interest bonds and have a number of financial advantages permits them to use a fixed charge rate of 10%. This has a greater impact on power costs than operation in tropical waters with high ΔT conditions or short cable runs to shore. It indicates that to minimize the cost of the first commercial utility installations it will be wise to have the units installed in public utilities.

More detail on these costs is shown in Table II-2. As indicated by this table the integrated power output of the OTEC unit at the site was determined in two ways to see if a significant difference could be expected between differen design philoscphies.

In one design philosophy it was assumed that the OTEC system would be designed to produce name plate output as the peak site ΔT and then, at all months when the ΔT fell below the peak the output would be determined by the

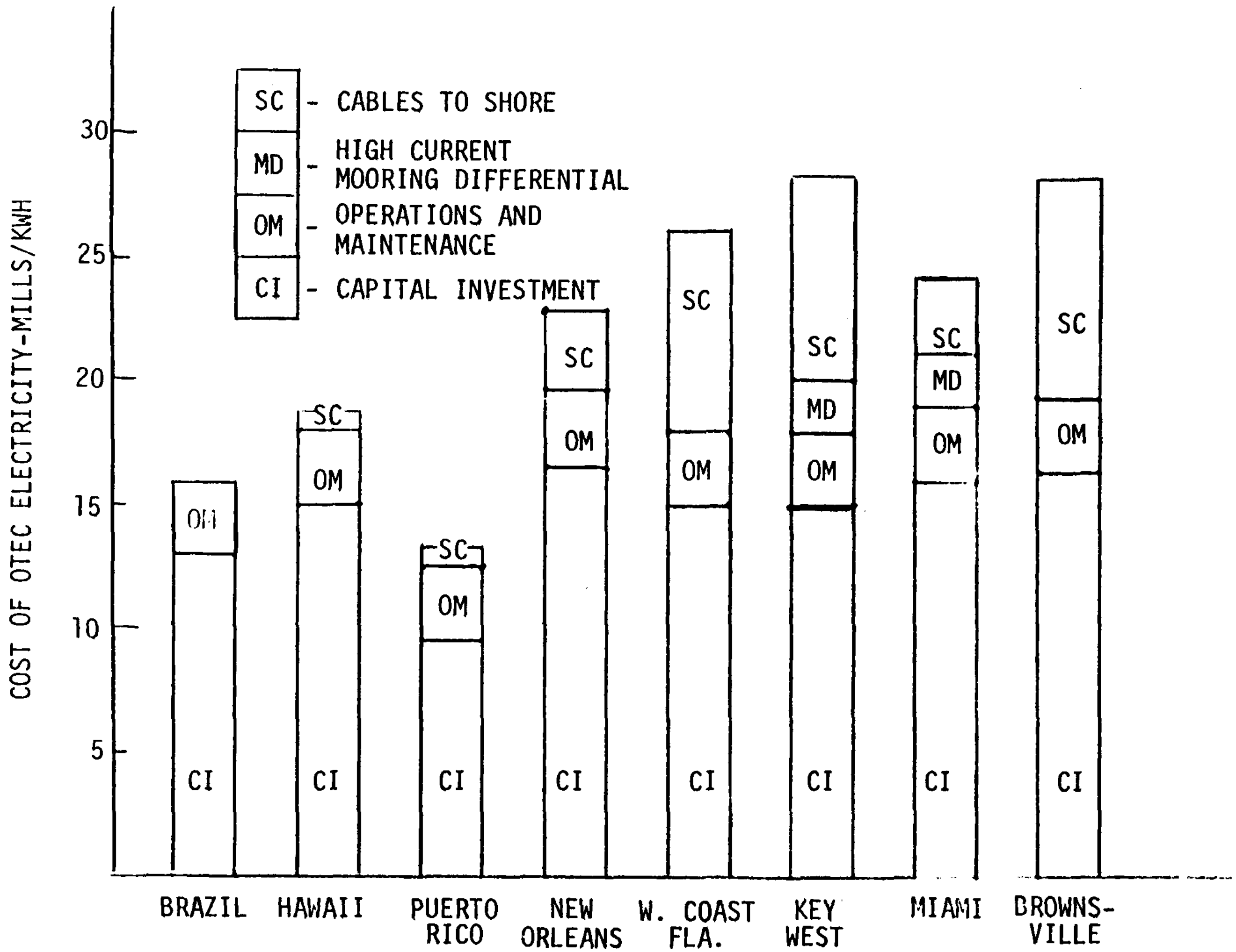


FIGURE II-6 -SITE COMPARISON OF OTEC COST COMPONENTS

TABLE II-2 - COST ESTIMATES[1] FOR SPECIFIC OTEC SITES
IN MILLS/KWH

	CAPITAL[2] INVESTMENT		O&M	HIGH CURRENT MOORING DIFFERENTIAL	CABLE TO SHORE	COST AT BEACH
	PEAK DESIGN POINT	21.1°C DESIGN POINT				
BRAZIL	13.1	11.8	3.0	0	N/A	N/A
HAWAII	14.9	14.4	3.0	0	.5[5]	17.9 -18.4
PUERTO RICO	9.6[3]	8.6[3]	3.0	0	.5[5]	12.1 -13.1
NEW ORLEANS	16.7	16.4	3.0	0	3.7[6]	23.1 -23.4
W. COAST FLA.	15.0	14.2	3.0	0	8.3[7]	25.5 -26.3
KEY WEST	14.8	13.8	3.0	2.25[4]	8.0[7]	27.0 -28.0
MIAMI	16.0	15.9	3.0	2.25[4]	3.3[6]	24.45-24.46
BROWNSVILLE	16.4	16.0	3.0	0	9.4[7]	28.4 -28.8

(1) ALL COSTS LEVELIZED OVER 30 YEAR LIFE USING ERDA/EXPRI FIXED CHARGE METHOD (ERDA/JPL 1012-76/2)

(2) COMPARATIVE COSTS BASED ON INTEGRATED SEASONAL OUTPUT FOR 2 DIFFERENT DESIGNS
PEAK DESIGN POINT - ASSUMES PLANT IS DESIGNED FOR OPERATION AT PEAK MONTH ΔT AND OUTPUT IS DEGRADED IN COOLER MONTHS (TRW ALGORITHM)
21.1°C DESIGN POINT - ASSUMES LOCKHEED PLANT AT $800/KW WITH OVER DESIGNED TURBINE-GENERATOR TO PERMIT GREATER OUTPUT IN MONTHS WHERE ΔT EXCEEDS DESIGN POINT (LAVI ALGORITHM)

(3) PUERTO RICO ASSUMES PUBLIC UTILITY FINANCING 10% FCR ALL OTHERS ASSUMED PRIVATE UTILITY FINANCING 15% FCR

(4) ASSUMED $35 MILLION FOR LOW CURRENT, $100 MILLION HIGH CURRENT FOR A 250 MW PLANT

(5) 2 MI RUN AC CABLE ASSUMED AT 20 TO 25$/KW INSTALLED FOR 250MW PLANT

(6) 40 MI RUN DC CABLE ASSUMED AT 155$/KW INSTALLED FOR 250MW PLANT

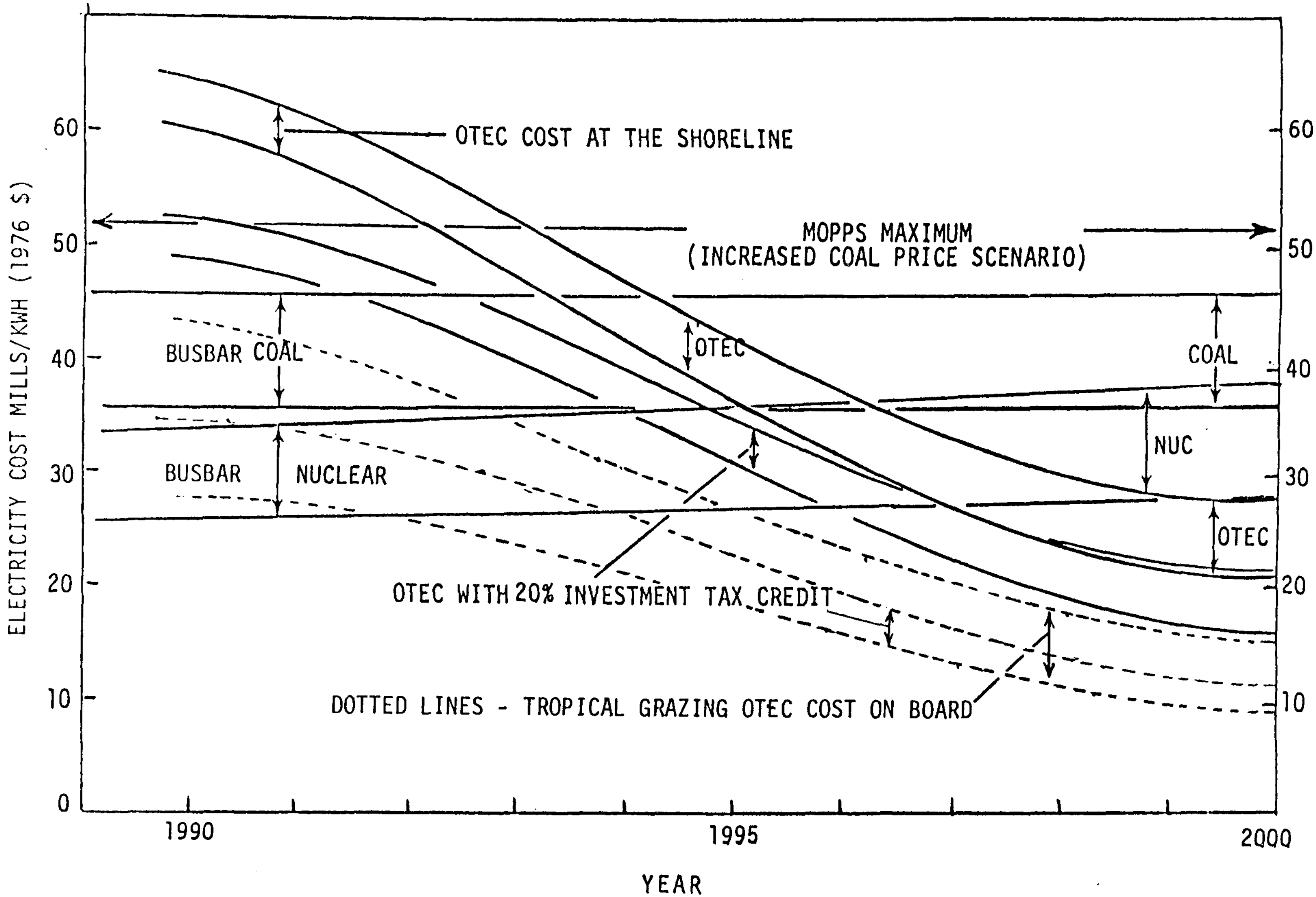
(7) 180 MI RUN DC CABLE ASSUMED AT 350$/KW INSTALLED FOR 3000MW OTEC PARK (REF-R. Cohen)

TRW algorithm (1). In the other design philosophy it was assumed that a temperature intermediate in the seasonal range (21.1°C) was used as the design point for heat exchangers and that an overrated turbine generator unit would be used to deliver the extra power at higher temperatures. The power output of this configuration was determined using the Lavi algorithm (25) and integrated. It was found that the difference in cost per kilowatt hour between the two sets of calculations were small and well within the uncertainties of the assumptions. Thus the expected costs of power delivered to shore are shown in figure II-6 for both design philosophies.

To compare OTEC costs with costs of power produced by competing systems during the 10 year time frame from first installation in 1990 to the year 2000 when large scale production experience (a minimum production of 6 to 8 GW of capacity would be required) will have reduced OTEC system costs to the levels projected figure II-7 is presented. Figure II-7 shows the range of costs of delivered OTEC power during the 10 year period and the busbar costs of coal and nuclear generated baseload power. As can be seen, OTEC costs at the shoreline will decline rapidly from their initial costs in 1990 to the point where they are competitive with coal and nuclear by the latter half of the 1990-2000 decade. The chart also shows the impact of a 20% investment tax credit which has been discussed for all solar options. The tax credit improves the competitive performance by reducing the time to reach competitive costs by approximately 1.5 years.

The chart also shows the change of power costs on the tropical grazing plant which are essentially busbar costs on board. These costs were estimated assuming a 15% fixed charge rate to permit direct comparison with the other plants however it should be noted that industrial equivalents of the fixed charge rate usually run 20% or greater, on the other hand ship financing is heavily subsidized. This aspect requires more detailed analysis of options. The increased efficiency of operating in tropical waters and not requiring power transmission to shore make the busbar costs comparable to coal and nuclear at the beginning of the period and significantly less at the end of the period. However, these costs are on board the plant and are only a part of the overall costs of production of energy intensive products on the factory ships which will be discussed in another section of this report.

Using the OTEC cost figures and the projected busbar cost figures for conventional power shown in Figure II-5 it is possible to crudely estimate an area of competitive costs and project a net potential market for OTEC power in the Southeastern United States.



NOTE - ALL COSTS ARE LEVELIZED COSTS FOR A NEW PLAN IN THE YEAR OF INSTALLATION - IN THE YEAR 2000 OFFSHORE PLANT COSTS RANGE FROM $800 TO $600 PER KILOWATT AND TROPICAL GRAZING PLANT COST $600 PER KILOWATT - A FIXED CHARGE RATE OF .15 WAS ASSUMED

FIGURE II-7 - PROJECTED OTEC, NUCLEAR AND COAL COSTS 1990 TO 2000

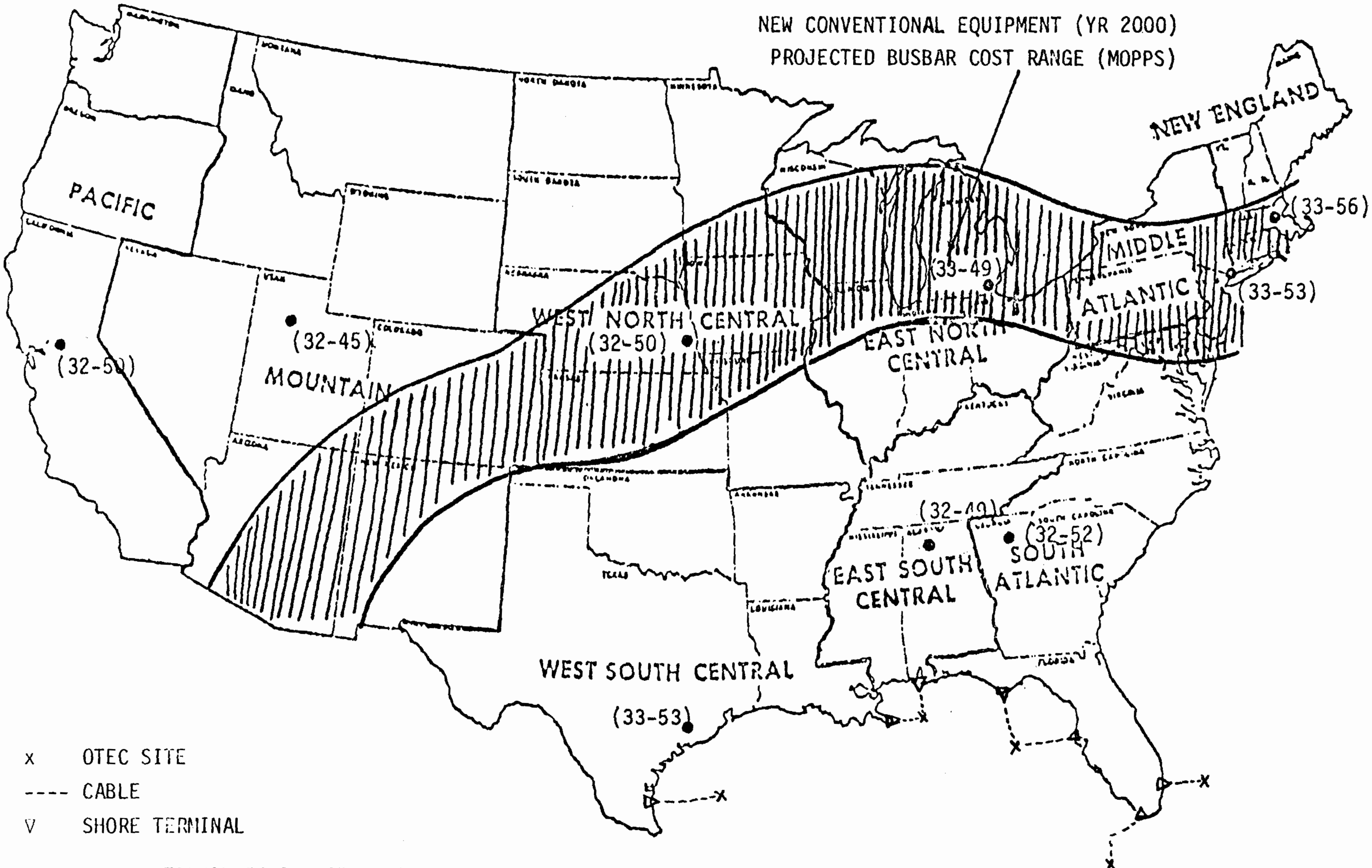


FIGURE II-9 - OTEC POWER SERVICE REGION USING 3000 MEGAWATT TRANSMISSION LINKS ON LAND

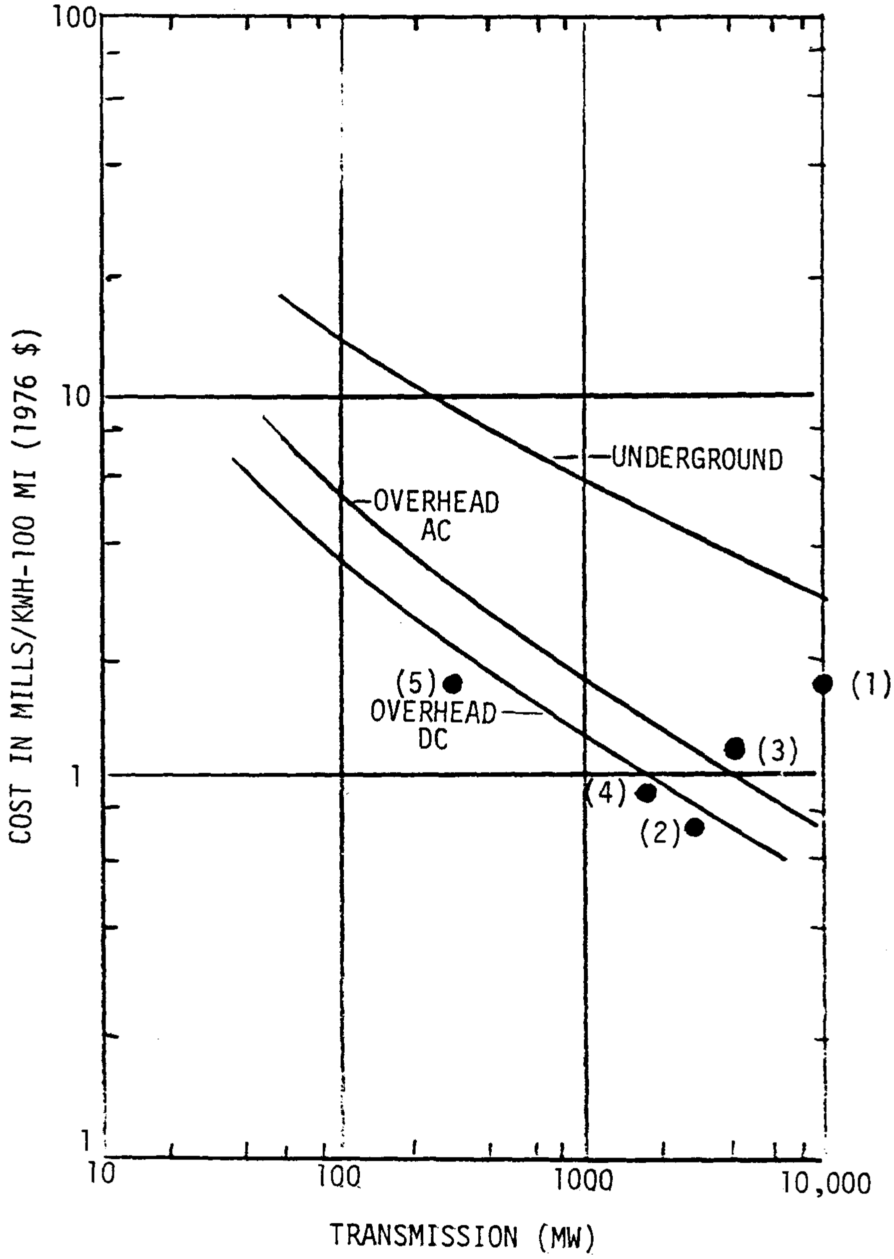
(FURTHEST PENETRATION ASSUMES .8 MILLS/KWH/100MI OVERHEAD TRANSMISSION COST)
(LEAST PENETRATION ASSUMES 1.2 MILLS/KWH/100MI OVERHEAD TRANSMISSION COST)

The area of competitve costs for the year 2000 was determined by using the OTEC power costs on shore and assuming that power could be delivered from a large number of units to a common shore point for long distance overland transmission if desired. To estimate the distance that OTEC power could be competitively transmitted from the shore terminal it was assumed that the power would be transmitted over 3000 megawatt lines for a distance sufficient to increase the cost of the delivered power to 35 mills per kwh when allowances are made for high power transmission costs and power conditioning equipment at the terminal. Transmission costs used in estimating ranged from .8 mills/kwh to 1.2 mills/kwh which appeared reasonable based on the data available in Figure II-8 which indicates several estimates of large range, high power transmission costs. As indicated above these are only crude estimates. The actual cost of transmission will depend on the specific installation considered.

Using the costs indicated the distance from the on shore terminals that OTEC power can be delivered at a cost of 35 mills/kwh is shown on Figure II-9. The southernmost boundary of the hatched area is the minimum range and the northernmost boundary is the maximum range when all uncertainties in costs are considered. This chart implies a sizeable service area for OTEC power.

To determine just how big the OTEC market could be projection the demand for power and the portion of it that OTEC systems could supply in the southeastern United States were made. It was assumed that the three power pools in the southeastern U.S. would be the service area. These power pools are shown in Figure II-10 and are the Southeast Reliability Council, the Southwest Power Pool and the Electric Reliability Council of Texas. As can be seen these power pools cover essentially the same area as that south of the hatched area on Figure II-9 indicating that OTEC would be competitive in the region.

The projected additions to base load capacity in these three power pools was estimated under two assumptions to obtain a range of market estimates TEMPO has projected a most probable scenario of additons based on a number of sources and then, to provide a low estimate TEMPO used the very low national energy consumption projections proposed by Dr. Weinberg of the Oak Ridge Associated Universities and estimated from it the potential demand for electricity in these power pools.



(1) AC - W. SMITH
(2) AC - EPRI
(3) DC - MOPPS
(4) AC - MOPPS
(5) AC - MOPPS

FIGURE II-8 - COSTS OF POWER TRANSMISSION

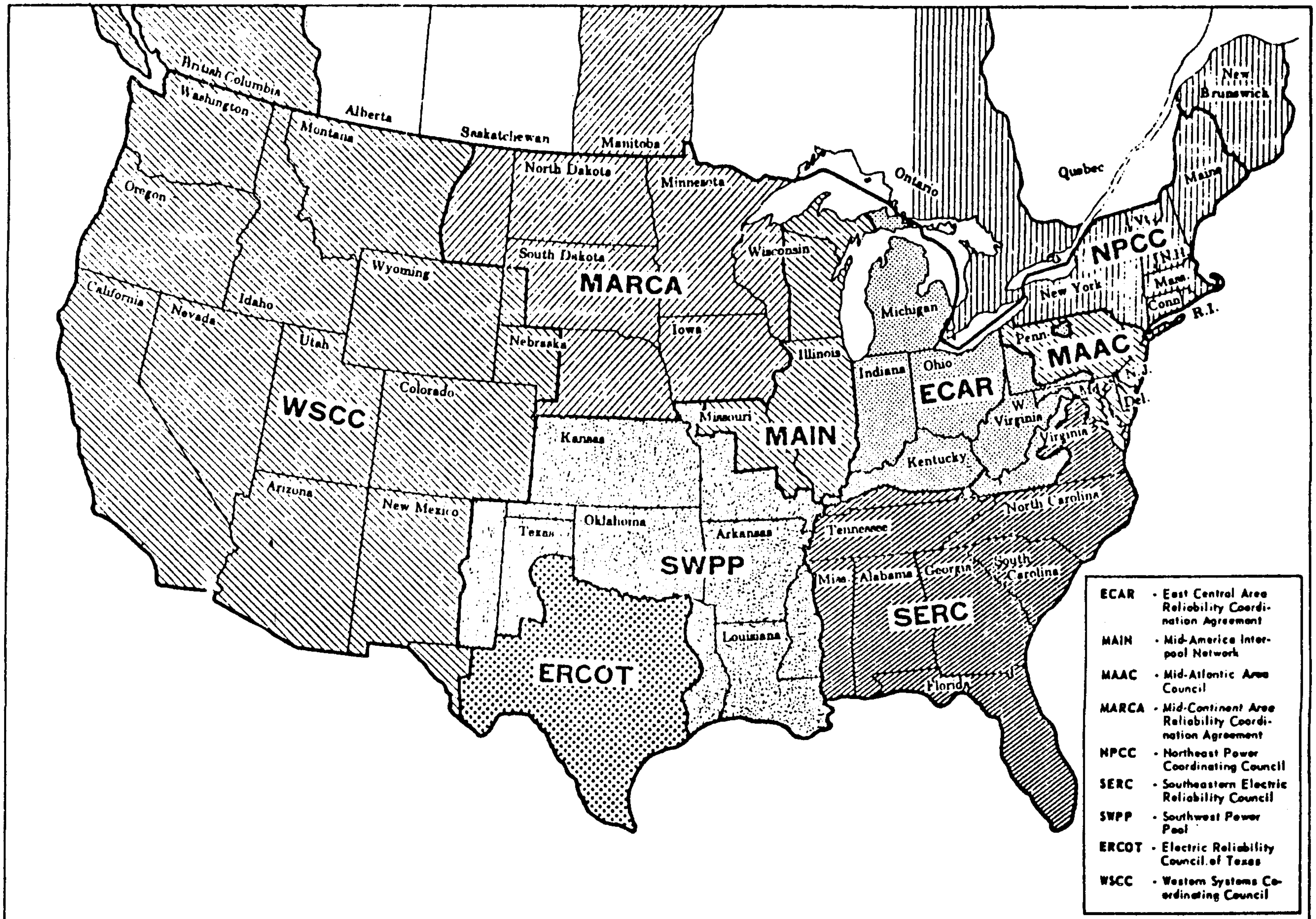


FIGURE II-10 - REGIONAL ELECTRIC RELIABILITY COUNCILS

April 1, 1974

Using these baseload addition projections from 1990 to 2000 OTEC penetration into the additons market was projected using a model that assumed that the ultimate market capture by OTEC would be limited to 40% of the total baseload additions because of the utilities need to maintain diverse sources. In additon, two implementation rates were assumed for the TEMPO projection. In the baseline projection it was assumed that it would take 15 years for the market capture to go from 4% to 36% of the annual additions and in the high implementation rate it was assumed that this would be accomplished in 10 years.

These implementation rates are high with comparison to most industrial technological innovations which normally have takeover times of between fourty and fifty years but, they appear to be possible for an innovation which is developed and produced as the result of a planned and coordinated federal program to accelerate industrial acceptance.

The net installed OTEC capacity under these penetration projections is shown in Figure II-11 from the year 1990 to the year 2020. As can be seen under these assumptions OTEC could supply between 100 and 200 GW of power by the year 2020. More important is the fact that by the year 2000 in this application alone it will be possible to have installed between 6.0 GW of capacity for the most pessimistic estimate to as much as 35 GW for the most optimistic estimate. This application alone can provide the OTEC production demand required to achieve the cost reductions needed to make OTEC competitive with conventional base load power systems.

Shipment of Peaking Electricity by Stored Energy (Electrochemical Bridge)

In the study work was done by the Institute of Gas Technology on the use of electrochemical bridges as a means of providing electrical power and/or energy intensive products. The details of their analysis and results are compiled as an IGT report which is attached as Appendix A to this report. This section of the report will summarize and interpret their results with respect to the competitiveness of the different chemicals analyzed.

In the area of power delivery by electrochemical bridge it was expected that energy intensive products could be used in the production of electricity if desired. However, because of expected efficiency losses in the conversion of electricity to product and back to electricity it was not expected

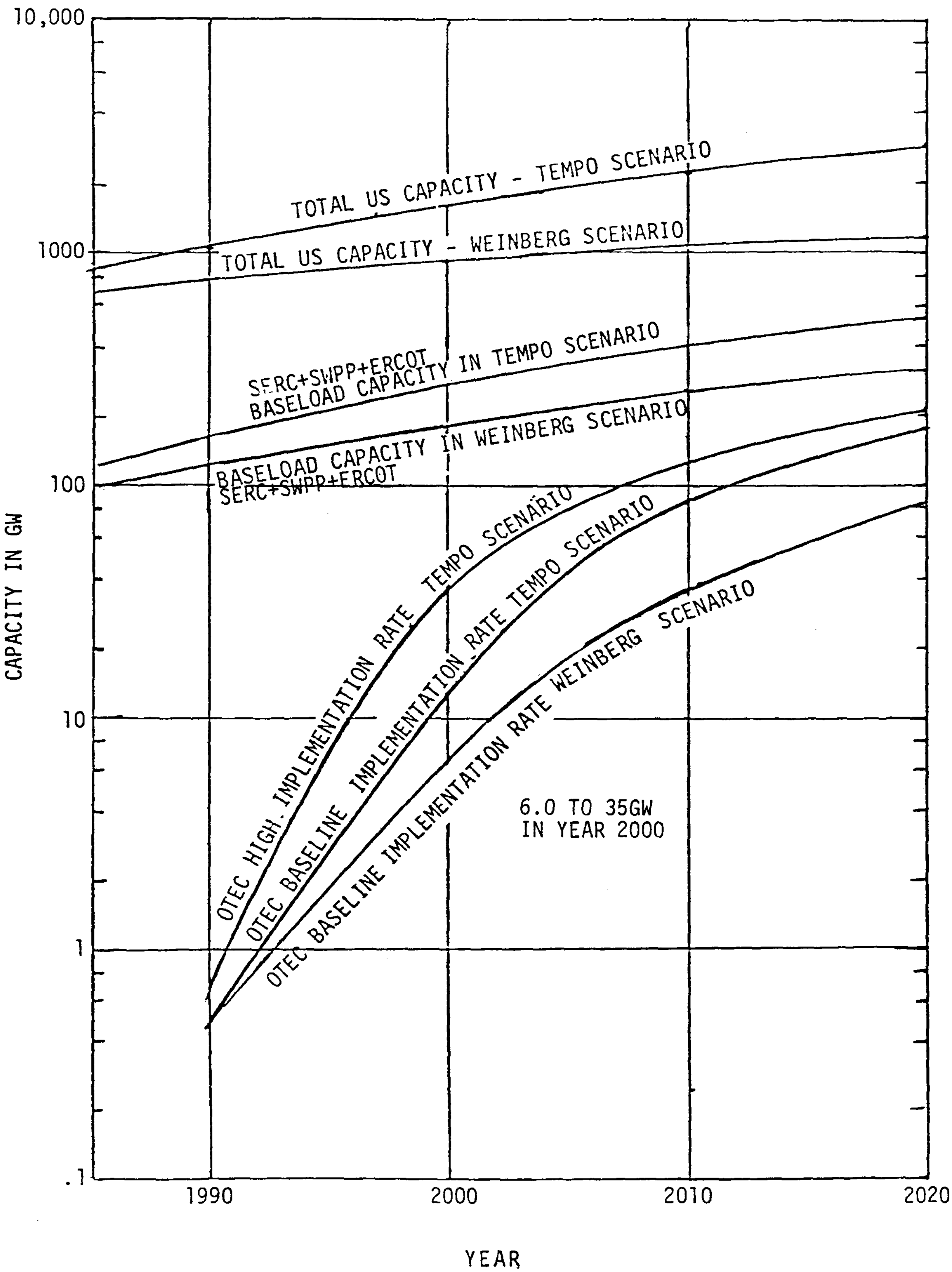


FIGURE II-11 - OTEC SCENARIO OF INSTALLED BASELOAD CAPACITY that OTEC electrochemical bridge electricity would be competitive with base load power generated by conventional systems but that it might be competitive with the much more expensive power produced by peaking units. To evaluate these costs of electricity produced by using four possible chemicals (lithium, ammonia, hydrogen and molten salts) produced at the eight sites previously identified and delivered to five different locations in the continental United States (New York, Miami, New Orleans, Houston and Los Angeles). Destinations appropriate to the location of the site were selected to reduce the number of calculations and costs were estimated for electricity to product conversion, transportation and product to electricity conversion. In addition the cost calculations were parameterized by permitting the cost of OTEC power to be assumed to be 10, 20, 30, and 40 mills per kilowatt hour.

Of primary concern in this area is whether or not the costs of peaking power generated by using OTEC storable high energy products will be competitive with peaking power produced by conventional sources. Estimates of the costs of peaking power have been made in the MOPPS study (2) which estimated that the range of levelized busbar costs of power generated by such units would be between 80 and 105 mills per kilowatt hour in the year 2000. This range was for newly installed units operating from 1000 to 1200 hours per year as is usual for such equipments.

The results for hydrogen, ammonia and molten salts were clearly not competitive. Ammonia was most nearly competitive with costs as low as 113 to 147 mils/kwh for OTEC power at 10 mills/kwh and delivery distances from essentially 3000 to 4000 miles. The minimum cost for liquid hydrogen peaking power produced by 10 mil OTEC power exceeded 130 mills/kwh.

Molten salts could be competitive at short ranges (less than 100 mi) but because of heat loss in transit it would not be competitive at greater distances.

Lithium batterys on the other hand appeared to be competitive at ranges up to 500 miles or more because their costs were in the range of 50 to 60 mills per kilowatt hour when OTEC power costs were in the 10 mill per kilowatt hour range. However, in peaking operation when the battery discharge plant would only be operating approximately 1140 hours per year the capital recovery factor for the discharge plant adds approximately 60 to 90 mills per kilowatt hour to the delivered power cost. For the most optimistic case of 10 mill/Kwh 10 miles off Miami and delivered and used in Maimi the total cost to the utility would be 106 to 145 mills per kilowatt hour which is not in the competitive range projected by reference (2).

SECTION III

ISLAND INDUSTRY OPTION

The Island Industry OTEC option was initially proposed as a potential first step for introducing OTEC power to the energy intensive industries that appear to be good candidates for at sea production such as ammonia or aluminum.

It was felt that by permitting the industry to get experience with an OTEC powerplant supplying an onshore factory in tropical waters where OTEC power would be cheapest they would be more willing to take the next step of going to a factory ship configuration.

However, to be an effective first step demonstration the island industry installation should be commercially competitive. This section of the report addresses the commercial competitiveness.

It should be noted that the Island Industry configuration is not suggested as a long term OTEC system. There would not be enough suitable islands for a large enough number of OTEC installations. To achieve large scale OTEC production of energy intensive products factory ships would be required.

INDUSTRIAL SITE SUITABILITY

To examine the suitability of the Island Industry concept three coastal areas have been identified as potential OTEC sites. These sites are Hawaii, Puerto Rico and the Gulf Coast for comparison. This subsection examines the suitability of these sites in economic, demographic, geographic and political terms. For the most part data is arrayed comparatively so that the reader may gain some insight into the relative merits of the sites.

Hawaii and Puerto Rico were selected because they are in tropical waters where the OTEC system performance will be much better than for systems along the coast of the continental United States. In addition they have good OTEC sites close inshore to good land sites suitable for factories.

Louisiana was chosen as a representative of the Gulf Coast for comparison. This choice was made because New Orleans would be a logical port of entry for products into the Continental U.S. for Island products.

Demographic Factors

The various demographic factors which describe the selected sites are summarized in Table III-1. While the geographical area of Hawaii is almost double that of Puerto Rico, the State of Hawaii consists of several islands. Also over 80 percent of the Hawaiian population, is concentrated on the island of Oahu (area: 600 square miles.) This concentration raises population density for this segment of the Hawaiian population to 1,200 persons per square mile, a figure which exceeds that of highly dense Puerto Rico (930 persons per square mile). The entire island of Oahu is the Honolulu metropolitan area, a factor which accounts for Hawaii's high degree of urbanization compared to other areas (60%). Population density for the island of Hawaii (area: 4,037 square miles) the prime industrial site, is only 19 persons per square mile.

Louisiana, whose population density is similar to that for the U.S. as a whole, exceeds PUerto Rico in land area by a sizable margin, however, they are comparable in population. These disproportionate factors consequently result in the population density of Louisiana being only one-tenth the density of Puerto Rico. This imbalance will be exacerbated as Puerto Rico's high population growth rate leads to an increasingly disproportionate density. Louisiana's density is representative of the other states on the Gulf Coast with only Florida (154 persons per sqaure mile) being significantly different. Similarly, Louisiana's 1% population growth rate is representative of the Gulf coast area except Florida's rate which is over 3 percent and Texas's rate which is almost 2 percent.

Analysis of the labor force of each area shows varying results. The unemployment picture ranges from Louisiana with a very favorable unemployment picture (6.8 percent versus U.S. rate of 7.7 percent) to Hawaii (9.8 percent) to Puerto Rico with a most unfavorable rate of over 19 percent.

TABLE III-1 - DEMOGRAPHIC FACTORS (1976)

FACTOR	HAWAII	PUERTO RICO	LOUISIANA	U.S.
Area (sq. mi.)	6,450	3,435	48,523	3.6×10^6
Population (1000's)	887	3,190	3,818	215,000
Population Density[a] (per sq.mi.)	137	930	85	60
Population Growth (annual rate)	2%	3%	1%	1%
Urbanization	81%	60%	63%	73%
Employment (1,000's)	361	715	1,384	89,700
Percent of Population Employed	41%	22%	36%	42%
Unemployment Rate	9.8%	19%	6.8%	7.7%

[a] Based on land area.

Source: Most of the statistics have been taken directly or derived from the <u>Statistical Abstract of the U.S.</u>

The Puerto Rico situation is considered even worse than that shown by the 19 percent unemployment rate, since inclusion of work force dropouts would probably push the rate to over 40 percent. The high Puerto Rican unemployment rate also accounts for the low employment as a percentage of population.

The employment picture on the Gulf Coast is quite favorable with all but the Florida rate (9.0 percent) under the U.S. average (7.7 percent). Louisiana's unemployment rate (6.8 percent) is representative of its immediate Gulf Coast neighbors with the rate ranging from 5.7 percent in Texas to 9.0 percent in Florida. Employment as a percentage of population ranges from 36 percent in Louisiana to 43 percent in Texas.

While an awareness of current conditions provides some insight into the potential of each site to absorb OTEC power, projections for the period during which OTEC units will be installed are much more relevant to the analysis. Both Hawaii and the Gulf Coast have the land area to absorb the current growth rates of population and associated industry, there are obviously some major adjustments required in Puerto Rico.

Electricity Generation

Growth in electricity generating capacity for the islands is summarized in Table III-2. Projections are based on growth rate projections obtained from the area utilities. The upper limits are those rates provided by the utilities. The lower limits were adjusted downward in recognition of the recent trend in downward revisions of capacity expansion plans.

Almost all of the currently installed generating capacity in Hawaii and Puerto Rico are oil and diesel units. Because of the distance from usable coal deposits the fuel costs for coal units make them noncompetitive. Water resources are small and do not provide a large percentage of electric power. Nuclear power plants in Hawaii are not considered feasible because of seismic activity and only two sites on Puerto Rico are considered feasible for the same reason. Some of the feasible sites have been eliminated for environmental concern.

Because of the small markets served by the utilities in these areas, only smaller sized units can be installed. Units larger than 600 megawatt capacity must be avoided because of the impact of failure of a single large unit on the loss of load probability of the system.

TABLE III-2 - ISLAND ELECTRICITY DEMAND PROJECTIONS
ACCUMULATED CAPACITY ADDITIONS FROM 1985

GIGAWATTS

HAWAII	1990	1995	2000	2010	2020
DEMAND (4-5%)	.5-.7	1-1.5	1.5-2.5	4-6	7-11
PUERTO RICO					
DEMAND (3-4%)	.6-1	1.4-2	2-3.5	3-7	5-13

SOURCE: DEMAND BASED ON STATEMENT BY ISLAND UTILITY COMPANIES.

Both Hawaii and Puerto Rico are pursuing unconventional energy sources. Hawaii has developed a geothermal heat well (500 MW_e) on the island of Hawaii and is attempting to obtain federal assistance for construction of the power plant to tap the well. Puerto Rico is currently constructing a wind energy site on the east end of the island as a federal demonstration project.

Both Hawaii and Puerto Rico are using intermediate and peaking units to meet baseload demands. It is anticipated that these island utilities will readily shift these units to meet intermediate and peak load demands once OTEC units become available. Consequently, during the first few years (1985-2000) it is assumed that all additions will be to baseload and will be captured by OTEC. The OTEC capture rate will then decline to 40 percent of additions.

The Gulf Coast employs a variety of technologies and plant sizes. These factors were discussed in section II. Table III-3 contains projections of Gulf Coast additions and that fraction which is baseload.

Industrial Activity

Industrial activity in the three OTEC regions varies significantly Table III-4 shows these variations. The low level of manufacturing activity in Hawaii (77%) reflects the states "island paradise" status and its emphasis on tourism. The large government sector (24%) results from the large federal defense installations located there. The active trade and services sectors result from both the tourism and the defense activity, as does the construction sector (24 and 21% respectively), which includes hotel construction.

The significant and growing financial section in Hawaii (7%) represents the important role that Hawaii plays in Asian-U.S. trade and the location of the corporate offices of a number of insurance companies. The public utilities sector (7%) is slightly more labor intensive than in the overall U.S. (5%). This difference probably reflects the absence of railroads and other capital intensive equipment found in the more industrialized areas of the U.S., as well as the large number of transients (tourists) that pass through Hawaii each year.

The low amount of agricultural activity (2%) reflects the lack of tillable land that has resulted in high levels of food imports and the

TABLE III-3 - GULF COAST ELECTRICITY DEMAND PROJECTIONS
ACCUMULATED CAPACITY ADDITONS FROM 1985
GIGAWATTS

	1990	1995	2000	2010	2020
DEMAND	112	255	436	786	1106
BASELOAD (40%)	45	102	174	314	442

TABLE III-4 - ECONOMIC ACTIVITY BY SECTOR

(% OF EMPLOYMENT)

SECTOR	HAWAII	PUERTO RICO	LOUISIANA	U.S.
MANUFACTURING	7%	21%	14% +	25%
TRADE	24	13	20	21
SERVICES	21+	11	15+	18+
UTILITIES *	7+	9	7	5
FINANCIAL**	7+	11	5+	5+
CONSTRUCTION	8	8	7	4
MINING	0	0	4	1
AGRICULTURE	2	6	9	5
GOVERNMENT	24	21	19+	18+
TOTAL EMPLOYED	361,000	715,000	1,384,000	89,700,000

*INCLUDES TRANSPORTATION AND COMMUNICATIONS

**INCLUDES INSURANCE AND REAL ESTATE

+INCREASE IN SHARE EXPECTED BY 1990

SOURCE: STATISTICAL ABSTRACT OF THE U.S., 1976 high degree of mechanization that is used in the production of sugar and pineapples, the main agricultural crops. We will see later that while conversion of Hawaiian land to production of locally consumed food may appear desirable, almost 50 percent of the manufacturing sector is involved in food processing.

Puerto Rico has developed a significant manufacturing sector (21%) through special industrialization efforts over the last thirty years. This industrialization program, identified as "Operation Bootstrap," has been successful until the recent increase in imported oil prices. Since then it has encountered serious problems and has fallen short in several key respects. The most serious problem of the program is found in the high unemployment rates discussed previously. The program was originally designed to attract key industries to build plants which would then serve as nuclei to attract satellite manufacturing and service industries. Because of the high fuel prices since 1973, the program has not succeeded in generating the desired secondary effects.

The absence of growth of secondary industries is reflected in the low level of trade and services (13 and 11% respectively) compared to the U.S. (21 and 18% respectively). The trade activity that Hawaii enjoys because of its unique crossroads position are not part of the Puerto Rican economy. Normal business and marketing services including ship repair, can be obtained readily from the mainland U.S. Much of the industry is located next to the port with goods and supplies are loaded and unloaded right at the plant and not actually passing through the island. The absence of defense installations also detracts from the trade and service sectors. Tourism has been neglected until recently and the hotels and recreational trade have not developed to the extend found in Hawaii.

The large Puerto Rican government sector (21%) reflects the large bureaucracy required to administer the social welfare programs for the large unemployment segment. The degree of automation that has taken place in federal and state government probably has not yet been realized by the Puerto Rican government since inexpensive labor is readily available. The size of the government sector is especially notable in view of the absence of any defense installations on the island.

The Puerto Rican financial sector is especially large (11%) compared to the U.S. (5%). This difference in size is represented mostly in the banking sector which may result from a surplus of accumulated profits. These profits, now accumulating at the rate of $2.5 billion per year are a product of "Operation Bootstrap" in which significant tax breaks were offered with the stipulation that profits would not be withdrawn from Puerto Rico for a number of years. With the post oil crisis slow down in the economy, reinvestment has declined and corporations are leaving their surpluses in the form of bank deposits. Banks are not restricted in their activities and have actively sought foreign investment opportunities.

The Puerto Rican utilities sector reflects a high labor intensity for many of the same reasons as Hawaii. Most transportation is by motor vehicle with capital intensive equipment such as railroads non-existent. Tourism, while not as important in Puerto Rico, is a factor. The Puerto Rican population is also more dispersed and less self-sufficient in necessities, food and clothing, than Hawaii, and therefore, must devote more effort to distributions. With labor less expensive a more labor intensive approach would also be expected. The electricity generating equipment is of a less efficient size, and therefore, can be expected to lead to a more labor intensive activity.

Construction activity in Puerto Rico (8%) is higher than the U.S. (4%) but comparable to Hawaii and Louisiana. Generally all three areas are growing and need new housing and associate business establishments. As in the other potential sites, labor is less expensive and larger capital intensive public projects, such as bridges and dams are not undertaken in the island areas.

The manufacturing base, especially primary metal and chemical petroleum processing, is of special interest in analyzing the suitability of installing OTEC driven aluminum and ammonia plants in the selected areas. From this part of the manufacturing base will come the nucleus of skilled labor and supporting service that are needed to assure an efficient plant operation until local unskilled workers can be trained. As can be seen from Table III-5 the three areas of interest are somewhat specialized with over 70% of the manufacturing employment located in just five industries. In fact over 70% of Hawaii's manufacturing employment is concentrated in just three industries.

Hawaii's manufacturing activity, which is very low (7% of total employment), is concentrated in two basic industries - food processing (47% of manufacturing employment) and apparel manufacturing (13%). The food processing activity is primarily sugar refining from sugar cane and pineapple canning for export. The

TABLE III-5 - DISTRIBUTION OF MANUFACTURING ACTIVITY
FIVE LARGEST INDUSTRIES BY MANUFACTURING EMPLOYMENT

RANK	HAWAII	PUERTO RICO	LOUISIANA	U.S. (1,000's)
FIRST*	FOOD PROC 11,900 (47%)	TEXTILE/APPAREL 54,054 (36%)	CHEM/PETROL 34,000 (19%)	TEXTILE/APPAREL 2,377 (12%)
SECOND	APPAREL 3,300 (13%)	FOOD PROC 27,739 (18%)	WOOD/PAPER 30,200 (17%)	NON-ELEC MACH 1,930 (10%)
THIRD	PRINT/PUBL 2,500 (10%)	ELEC EQUIP 14,700 (10%)	FOOD PROC 28,000 (16%)	TRANSP EQUIP 1,815 (9%)
FOURTH	STONE & CLAY 1,100 (4%)	CHEM/PETROL 11,160 (7%)	TRANSP EQUIP (12%)	ELEC EQUIP 1,800 (9%)
FIFTH	WOOD 900 (4%)	STONE & CLAY 6,250 (4%)	FAB METAL PROD 12,500 (7%)	FAB METAL PROD 1,534 (8%)
FIVE LARGEST	79%	75%	71%	48%
MANUFACTURING EMPLOYMENT**	25,000 (7%)	149,748 (21%)	179,600 (14%)	19,027 (23%)

* PERCENT OF TOTAL MANUFACTURING EMPLOYMENT
** PERCENT OF TOTAL EMPLOYMENT

balance is engaged in preparation of food for local consumption in which Hawaii has also succeeded in developing local agriculture to the extend that 65% of its food come from local farms. The apparel industry is primarily engaged in manufacture of Hawaiian style sportswear and other types of clothing.

The Hawaiian state government has indicated a lack of interest in heavy industry on the island for environmental reasons. The government also points out that the small market makes such industries impractical. Most of the manufacturing, other than food processing, is located on Oahu where goods are processed for local consumption.

The only primary metal processing is a steel mill that produces reinforcing rods primarily from local scrap, see Table III-6. The small metal working industry primarily services the island ship repair activities. The chemical industry, Table III-7, consists of several small plants that produce soaps and other cleansers. There are two petroleum refineries, located in the foreign trade zones and Oahu. These refineries produce gasoline, jet fuel, heating fuel and synthetic natural gas for the island.

Puerto Rico's manufacturing activity (21% of total employment) represents a significant part of the island economy. However value added by the island is very low. The manufacturing sector is very export oriented with the majority of output of three of the five largest industries being produced for export. Except for the food processing and stone and clay industries, raw materials are imported.

The textile and apparel industry (35% of manufacturing employment) in Puerto Rico includes women's and children's undergarments, nightwear and footwear. The textile segment produces primarily carpeting, knitted fabrics and elastic thread. This industry has declined over the last decades as labor costs, primarily for female labor have risen. The food processing industry (18%) is involved primarily in preparation of foods, with some effort devoted to processing of sugar cane. The Puerto Rican Electrical/Electronic Equipment (10%) industry is involved primarily in small parts manufacture and assembly. Again primarily women are employed; however, this industry has been growing.

The chemical and petroleum industry (7%) produces numerous products including fertilizers, industrial chemicals and pharmaceuticals. This industry grew rapidly in Puerto Rico until the OPEC oil crisis in 1972. Preceding the oil

TABLE III-6 - PRIMARY METALS INDUSTRY ANALYSIS (1972)

FACTOR		HAWAII	PUERTO RICO	LOUISIANA	U. S.
VALUE OF SHIPMENTS (MILLIONS)		$ 10 - 15	$ 35	$ 330	$58,400
VALUE ADDED (MILLIONS)		$ 4 - 6	$ 15	$ 145	$23,250
EMPLOYMENT		150 - 250	1,000	7,300	1.1×10^6
ESTABLISHMENTS (20+ EMPLOYEES)		3	16	20	3,900
EXPECTED GROWTH	2000	105%		100%	95%
	2020	240%		220%	205%

SOURCE: <u>CENSUS OF MANUFACTURERS, 1972</u>
<u>OBERS PROJECTIONS, 1972</u>

TABLE III-7 - CHEMICAL/PETROLEUM INDUSTRY ANALYSIS (1972)

FACTOR		HAWAII	PUERTO RICO	LOUISIANA	U. S.
VALUE OF SHIPMENTS (MILLIONS)		$110-240	$ 1,240	$ 5,500	$86,000
VALUE ADDED (MILLIONS)		$ 35- 75	$ 400	$ 1,800	$38,200
EMPLOYMENT		700-1,500	11,160	34,000	976,000
ESTABLISHMENTS (20+ EMPLOYEES)		7	55	130	5,150
EXPECTED	2000	225%		480%	250%
GROWTH	2020	580%		800%	750%

SOURCE: <u>CENSUS OF MANUFACTURERS, 1972</u>
<u>OBERS PROJECTIONS, 1972</u>

crisis, Puerto Rico enjoyed an oil price advantage over U.S. mainland plants. After the crisis, the price advantage was reversed as the price of imported oil exceeded that of oil in the U.S. because of price controls. Some companies are now trying to sell plants in Puerto Rico. The skills in this sector are especially applicable to ammonia and chemical process plants. The skills are also available because of a surplus of labor resulting from industry decline.

Primary metals processing, Table III-6, in Puerto Rico, as in Hawaii, is not significant. Puerto Rico's only steel mill manufactures reinforcing rods from scrap. The small metal fabricating operations service ship repair and other mechanical repair activities.

SHIPPING ACTIVITY AND PORT CAPACITY

Both Hawaii and Puerto Rico are located along major shipping routes, including routes carrying sizable quantities of alumina, the raw material from aluminum is smelted.

Hawaii and Puerto Rico both have extensive general port facilities in their respective primary cities (Honolulu and San Juan). The volume of goods flowing through these ports is shown in Table III-8. As shown the volume of inbound goods substantially exceeds the volume of outbound goods. This imbalance, however, is somewhat exaggerated by the fact that the main ports are located in the primary cities of each island and most of the inbound goods are consumption goods or are materials and components to support local manufacturing which is mostly located in or around the primary cities. Table III-8 fails to show that most of the export goods leave through other ports in the area. Several of the Hawaiian islands have their own ports through which sugar, and sugar products, leave while few imports flow into these ports. On Puerto Rico, at least ten ports besides San Juan are responsible for sizable amounts of goods. The facilities at these secondary ports are often privately owned for exporting chemicals and petroleum products and importing of raw materials. Much of the agricultural exports, expecially sugar, is exported through these secondary ports.

While the island of Oahu has well developed port facilities in Honolulu, the primary proposed industrial sites are on the island of Hawaii. The

TABLE III-8 - PORT ACTIVITY (1974)

(MILLIONS OF SHORT TONS)

FACTOR	HAWAII	PUERTO RICO	LOUISIANA	U.S.
PORTS	+3 HONOLULU	+10 SAN JUAN	NEW ORLEANS, ET AL	ALL
INBOUND	5.5	8.7	32.8	707.3
OUTBOUND	2.1	2.1	68.8	472.0

possibility of developing a deep water port on the Hawaii has been discussed by state officials but an active project to undertake the planning and development of a port has not been approved.

Location of plants in Hawaii or Puerto Rico most likely would not seriously affect current flows of goods. New dedicated facilities may be required at both locations or additional land based transportation facilities expanded to transfer goods to existing industrial ports.

ISLAND INDUSTRY

Local Markets

Local market potential of the island appears to be limited for both aluminum and ammonia. The primary market for ammonia is fertilizer. Table III-9 shows the current ammonia fertilizer usage and a potential maximum if the application rate were raised to that used for one of the most intensively fertilizer crops, corn. As shown, the market potential for Hawaii (37,000 ST/yr) and Puerto Rico (104,000 ST/yr) is well below the typical plant's annual output of 330,000 ST/yr. Consequently, introduction of ammonia plants into either area would require an export market.

The primary market for aluminum ingot, the output of an aluminum smelter, would be metal working shops and machinery manufacturers. As shown in Table III-10 the metalworking industries are quite small with the value of shipments (which include mostly steel products) in both Hawaii ($170M) and Puerto Rico ($250M) practically equal to the value of annual output of a single plant aluminum ($243M).

Growth of an aluminum market to Puerto Rico is somewhat in doubt in view of recent finds of copper deposits. To the extent that the island undertakes construction of refining facilities and has the resources (water and energy) copper could easily erode aluminum penetration.

In summary, the potential for development of local markets is quite limited. The small land areas of both Hawaii and Puerto Rico limit agricultural growth and associated growth of the local fertilizer market. The aluminum ingot market, on the other hand, is not faced with similar physical limitations. The growth of an aluminum ingot supply could theoretically spawn subsidiary industries consisting of metal working and metal products plants. The Puerto Rican

TABLE III-9 - ISLAND INDUSTRY LOCAL MARKET ANALYSIS (AMMONIA)

	HAWAII	PUERTO RICO
CROP ACREAGE (ACRES)	300,000	600,000
AMMONIA USAGE USAGE		
CURRENT (ST/YR)	37,000	18,300
POTENTIAL* (ST/YR)	52,000	104,000
SUPPLY	IMPORTED	LOCAL PLANT

TYPICAL PLANT OUTPUT: 330,000 ST/YR

* BASED ON AVERAGE AMMONIA FERTILIZER APPLICATION RATE FOR CORN. CORN HAS THE HIGHEST APPLICATION RATE FOR MAJOR FIELD CROPS.

SOURCE: <u>1977 FETILIZER SITUATION</u>, USDA (ERS); <u>STATISTICAL ABSTRACT OF THE U.S., 1976</u>

TABLE III-10 - ISLAND INDUSTRY LOCAL MARKET ANALYSIS (ALUMINUM)

HAWAII

- METAL PRODUCTS AND MACHINERY (SHIPMENTS: $170M)
- METAL PROCESSING SUPPORTS CONSTRUCTION AND SHIP REPAIR
- STEEL MILL PRODUCES REINFORCING RODS
- NO SIGNIFICANT ALUMINUM MARKET

PUERTO RICO

- METAL PRODUCTS AND MACHINERY (SHIPMENTS: $250)
- METAL PRODUCTS AND MACHINERY IS MOST IMPORTANT HEAVY INDUSTRY
- HEAVY FOUNDRY, MACHINE SHIPS, AND STAMPING
- STEEL MILL PRODUCES REINFORCING RODS FROM LOCAL SCRAP
- CANS, DOORS AND SHEET METAL PRODUCTS
- COPPER DEPOSITS (COMPETITION)
- SOME POTENTIAL FOR ALUMINUM MARKET

TYPICAL PLANT OUTPUT: 243M/YEAR

experience and experience in the continental U.S. midwest and northwest, suggests that the growth of these subsidiary industries is market based rather than supply based, and therefore, not likely to grow at isolated island sites away from their markets.

ISLAND IMPLEMENTATION

The islands of Hawaii and Puerto Rico are choice sites for location of OTEC units. The ocean temperature differentials, found in the vicinity of these islands provide an important advantage over coastal U.S. sites. Furthermore, the bathymetry off the island shores is such that many ideal sites are quite close to the shore (five miles or less).

These physical characteristics ultimately give rise to several economic advantages. First, the stability of the ΔT results in a high power output throughout the year and avoids the severe power output reduction during cooler winter months that the New Orleans location experiences. The second economic advantage stems from the nearness to shore of deep water with adequate temperature differentials. This nearness reduces the length of cable required to connect the power cable to a shore based manufacturing plant, permits the delivery of AC current to shore and slightly reduce operating costs for shore supported floating plants.

Another factor which makes the island sites prime candidates for early implementation of OTEC units are current and projected electricity costs on the islands. Both Hawaii and Puerto Rico are highly dependent upon high priced imported oil for power generation. The high transportation costs of imported coal reduce the feasibility of conversion to that alternative fuel. OTEC systems, on the other hand, offer some early cost advantages.

Three OTEC applications have been identified for the islands: production of ammonia and aluminum and generation of electricity for input into the island grid.

Whether or not OTEC power can be applied to these applications will depend on whether it will be competitive with the other sources of power available. Figure III-1 shows the projected levelized costs of power produced by baseload plants using imported oil in Hawaii and Puerto Rico and using OTEC Systems. To simplify the analysis it was assumed that the OTEC plant would be owned and operated by

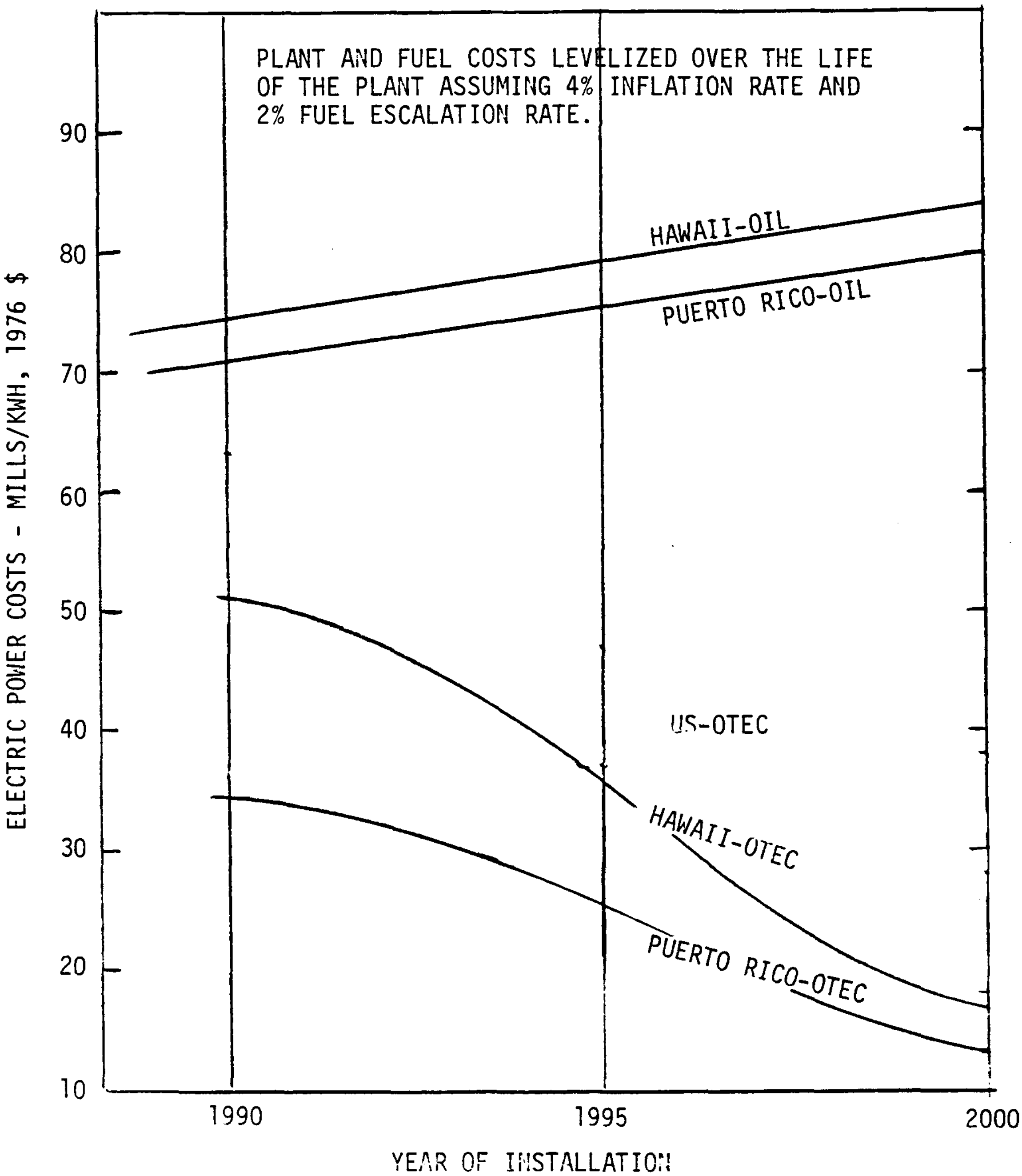


FIGURE III-1 - COMPARISON OF BUSBAR POWER COSTS FOR
NEW POWER INSTALLATIONS IN HAWAII
AND PUERTO RICO

the local utility and that the utility would dedicate OTEC units to the factory but also provide a connection to the grid as a backup in the event of dedicated unit outage. This approach would effectively give the using company the advantage of utility financing on a large capital investment item which is frequently done in the aluminum and other electrically intensive industries. The oil produced power is expected to exceed 70 mills/kwh in the islands and earliest OTEC costs will only be 50 mills at 1990 start up.

Product Options - Aluminum and Ammonia

Use of OTEC power to produce aluminum and ammonia in shore based plants appears feasible for all 3 sites. While both Hawaii and Puerto Rico enjoy significant cost advantages the industrial infrastructure and the capacity of the islands to absorb large industrial activity is limited.

The logistics problems of locating plants away from major markets undermines the cost advantages of island sites. The Gulf Region on the other hand, while slightly less efficient is strategically located near markets.

Because of the limited capacity of the island sites to absorb industrial activity the projections for the island sites reflect only demonstration plants to show feasibility. It is anticipated that additonal OTEC plants will be in the form of plant ships that will not operate in these regions.

Electricity Generation Option

Connection to a power grid provides the largest market at the island sites primarily because of continued population growth and cost considerations, current and projected. The dependence of both Hawaii and Puerto Rico on imported oil for generation of electricity places them among the highest cost areas in the nation. On the other hand the favorable OTEC conditions in these areas makes OTEC competitive by 1990. The cost comparisons are illustrated in Figure III-1. The cost differentials between Hawaii and Puerto Rico reflect the tax advantage of a 10% fixed charge rate enjoyed by the state owned Puerto Rican utility.

The OTEC competitiveness in the Gulf Coast regions are not as immediate since coal is a potential alternative. However, once the bottom of the experience curve is reached, the OTEC's in the Gulf Coast region will be competitive with coal fired plants.

Potential Installation

Because the OTEC power costs are competitive in both island sites it was assumed that the initial industrial installations would be 500 megawatts for ammonia and aluminum plants. Because the islands would have a limited capacity to accept industrial sites it was not attempted to project the number of installations that would be feasable on these islands. Instead, in Sections IV and V estimates of market penetration in the ammonia and aluminum industry are made on a national basis. Some of these would be in the islands.

However, as indicated earlier the power demand on the islands is increasing and by 1990 additional capacity will be required. Because OTEC power will be competitive from the first year of installation and because the islands need for capacity additions would be modest compared to projected OTEC production a highly accelerated OTEC implementation scenario was used. It was assumed that initially all capacity additions would be OTEC units unitl approximately 40% of total capacity would be OTEC units and then the OTEC share of capacity additions would drop to 40% to maintain the desired percentage. The accumulated capacity as a function of time is shown in Table III-13. This indicates that a total of from 3.5 to 5 GW of capacity could be installed by the year 2000 in both sites and between 8 and 13 GW by the year 2020.

TABLE III-11 - ISLAND ELECTRICITY DEMAND PROJECTIONS
ACCUMULATED CAPACITY ADDITIONS FROM 1985

GIGAWATTS

HAWAII	1990	1995	2000	2010	2020
DEMAND (4-5%)	.5-.7	1-1.5	1.5-2.5	4-6	7-11
OTEC	.25	1	1.5-2	2.5-4	4-6
PUERTO RICO					
DEMAND (3-4%)	.6-1	1.4-2	2-3.5	3-7	5-13
OTEC	.25	1-1.5	1.5-3	2.5-5	4-7

SOURCE: DEMAND BASED ON STATEMENT BY ISLAND UTILITY COMPANIES. OTEC PENETRATIONS BASED ON PERCENTAGE PENETRATION OF NEW CAPACITY ADDITIONS INDICATED ON LAST LINE.

SECTION IV

AMMONIA OPTION

AMMONIA MARKET - HISTORY AND BACKGROUND

"Fixed" nitrogen, nitrogen in combination with some other element, is an essential constituent of fertilizers. Although molecular nitrogen is abundant, comprising 80 percent of the atmosphere, the stability of the nitrogen molecule precludes its ready interaction in the low energy processes characteristic of plant growth. Hence, the conversion of atmospheric nitrogen to a biochemically available form, eg. as ammonia, is an important technological accomplishment because of its impact on world food production.

Discovery of such a conversion process by Fritz Haber and Carl Bosch during the first decade of this century freed society from almost complete dependence on natural depostis of sodium nitrate in Chile as its primary source of fixed nitrogen.

The Haber-Bosch discovery involved the type of catalyst and the pressure and temperature conditions under which a mixture of hydrogen and nitrogen would combine to form ammonia. While numerous technological increases have been made in the efficiency and size of the process units, the original concept remains the basis for fixing nitrogen and preparing the industrially important family of nitrogen compounds (ammonia, ammonium salts, nitric acid, nitrates, urea, and others) used not only in agriculture but also in the manufacture of plastics, resins, fibers, explosives, chemicals, pulp and paper, and various metallurgical applications.

The major use of ammonia is its role in agriculture; about 75 percent of U.S. production goes to fertilizer manufacture. Increased utilization of fertilizer has enabled reduction of other major agricultural inputs (cropland, labor, machinery, etc.) while increasing yield. High-yield plant strains and heavy fertilization have been most responsible for growth in productivity, and ultimate yields obtainable by further increases in fertilizer use appear not to have been reached even in the most advanced intensive farming areas (18).

Domestic production of ammonia is a large industry. Ammonia is the third-ranked industrial chemical by tonnage and its manufacture is very energy intensive because the commonest process in use consumes natural gas as both feedstock and fuel for the large amount of heat required. This dependence on a valuable fossil fuel input makes the alternate OTEC process, which consumes only air, water, and solar energy, particularly attractive.

Process Technology

There are many different ways to prepare the hydrogen-nitrogen mixture which is the input to the Haber-Bosch process. On a world wide basis, ammonia is commercially manufactured from natural gas, naphta (a light petroleum distillate), fuel and residual oil, raw petroleum, coke-oven gas, refinery gases, coke and coal, water (as both feedstock and source of hydroelectricity), wood and other forms of biomass, and by-product hydrogen generated by the chlorine-caustic or petroleum refining industries. In addition to these sources of hydrogen, the nitrogen needed is obtained from air with the oxygen removed either by chemical reaction in the course of obtaining the hydrogen or by physical separation. A comparison of ammonia production methods actually reduces to a comparison of "front-end" processes for preparing the proper mixture of hydrogen and nitrogen, known as synthesis gas or syngas.

Three processes warrant particular attention. The first is steam reforming of natural gas which is the dominant, current process but may become uneconomic because of the limited supply and great demand for natural gas. The second obtains ammonia syngas by coal gasification, a process thought to become economically competitive with natural gas reforming because of the size of U.S. coal reserves and the R&D activity in coal gasification presently underway. The third is the process relevant to OTEC, the electrolytic decomposition of water to obtain hydrogen which is mixed with nitrogen obtained by air separation.

All the other product applications investigated in the OTEC context replace conventionally generated electricity with OTEC electricity to satisfy whatever intrinsic electrical demand the process requires, but do not significantly alter it. Unlike these, the concept for OTEC ammonia production replaces the conventional thermochemical preparation of synthesis gas with an electrically intensive process. The difference lies in the nature of the front-end process for syngas preparation; the actual ammonia production sequence is essentially the same in all processes with minor differences resulting from the nature and amount of impurities in the syngas.

The ammonia synthesis loop embodies a straightforward process for catalytically combining hydrogen and nitrogen present in a 3:1 ratio in the input synthesis gas to form ammonia. The reaction is aided by high pressure, and would proceed to a more favorable equilibrium at low temperature except that the rate of reaction would then be too slow for sufficient product to form. Consequently, the operating conditions chosen are a compromise: pressure is set as high as economically feasible (2,000-4,500 psi) and temperature only high enough to achieve about 10-20 percent conversion per pass (750-1000°F). The reaction is exothermic, evolving about 1,350 Btu/lb of ammonia formed. Modern, energy efficient plants recover part of this heat for use at other points, eg. to raise steam for the main centrifugal turbocompressor. The small degree of conversion is compensated for by the ease of separating the product from the syngas by condensing it. The syngas is recirculated, pressurized makeup gas is added, and the stream is readmitted to the catalytic converter.

When synthesis gas is prepared from fossil fuelstocks, two classes of impurities are encountered. One class consists of synthesis catalysts poisons such as carbon monoxide and hydrogen sulfide which must be removed in specific purification steps before the synthesis loop. The other class consists of gases which are inert under ammonia synthesis conditions, typically methane and argon, and which therefore continually build up in concentration. To avoid the adverse effect of these diluents, a fraction of the loop gas is purged and used as fuel. In this respect, synthesis gas prepared by water electrolysis and air separation, each having purification steps intrinsic to those processes, is superior to that prepared by reforming or partial oxidation; little or no purging is required with consequent improvement in overall synthesis efficiency.

To prepare ammonia syngas from natural gas by steam reforming, five separate steps are employed: primary and secondary reforming, shift conversion, carbon dioxide removal, and methanation. In primary reforming, steam and catalytically desulfurized natural gas react at high temperature under the influence of a nickel catalyst and a large heat input to form hydrogen and carbon monoxide in about 70 percent yield. A metered amount of air is added in the secondary reformer where combustion of oxygen from the air with the hydrogen present generates sufficient additional heat to complete the reforming reaction on a nickel catalyst bed, leaving the proper amount of nitrogen (from the air) for the amount of hydrogen that will ultimately be formed. The reformers operate at pressures up to 500 psi and temperatures to 1500°F. The third step, shift conversion, is carried out over an iron oxide catalyst in two stages at progressively lowered temperatures. Under these conditions, the water-carbon monoxide equilibrium shifts to produce more hydrgen and convert the carbon monoxide to dioxide. In the fourth step, virtually all the carbon dioxide can be removed by absorption leaving a gas mixture which, after drying, consists primarily of hydrogen and nitrogen in the proper 3:1 ratio and small proportions of carbon monoxide and argon. The final step, methanation, converts the catalyst poisoning carbon monoxide to the inert component methane by reversing the original reforming reaction; a little of the hydrogen is consumed. The output from this stage is ammonia syngas, ready for compression to the 2,000-4,500 psi operating pressure of the ammonia synthesis loop. (Kellogg, 1975; Faith, Keyes and Clark, 1975.)

To use coal as an ammonia feedstock, a gasification process is employed in which the coal is reacted with air, oxygen, and steam to form a combustible gas mixture containing hydrogen and the carbon oxides. The reactions involved are very complex, consisting of both partial oxidation and reforming steps. Adjustment of temperature, pressure, and input component ratios permits wide variations in the resultant gas composition.

More than 50 modern, coal-based, ammonia plants relying on the Koppers-Totzek (K-T) coal gasification process are in operation around the world. In the K-T process, dried pulverized coal is fed to the gasifier along with steam and oxygen. At about 3000°F, a product gas typically containing 35 percent hydrogen, 55 percent carbon monoxide, and 10 percent carbon dioxide is formed. This gas is further processed by low temperature shift conversion to increase the hydrogen content, carbon dioxide removal by absorption, and methanation. (16). Nitrogen from an air separation unit is added to form ammonia syngas which is then fed to the synthesis loop. Since the concentration of inerts (primarily methane) is higher than is the case with steam-reformed natural gas, a larger fraction of the stream must be purged.

Because coal-based ammonia plants are both more expensive and less efficient in energy use (50-67 percent overall) than natural gas-fed plants, they are competitive with the latter only where natural gas is very expensive (or otherwise unavailable). Current developments in coal gasification are likely to lead to improved systems, but their operating characteristics must be considered conjectural in comparison with K-T plants or steam reforming of natural gas.

Electrolysis of water as the source of hydrogen for ammonia synthesis gas has been employed in Canada, India, Peru, and Norway where cheap hydroelectric power can be generated.

The minimum electrical energy required to decompose water is 14.88 kWh/lb hydrogen. Under these conditions, additional thermal energy input of 10,350 Btu/lb is required to provide the necessary reaction enthalpy, making the total energy equivalent to 17.91 kWh/lb at 77°F. The energy demand decreases with increasing cell temperature.

Because production electrolysis cells necessarily operate irreversibly and must overcome electrode overvoltages, cell resistance, and bubble effects resulting from gas formation, practical energy requirements are larger. High current density and increased operating pressure are desirable to achieve a large production rate for a given cell size and weight, and these factors also increase the energy requirement. Operation at elevated temperatures and use of porous electrodes and electrode surface catalysts are employed to minimize the actual power required.

A variety of practical electrolysis cells, of both acid and alkaline type, have been designed or developed. Significant improvements in electrolysis technology are anticipated over the next 10-15 years, although the rate of improvement will become slower. Taking these trends into account, a figure of 19 kWh/lb for hydrogen high production rate (2,000 amp/sq ft, 1,000 psi, 200°F) cells is adopted for use in subsequent calculations (21).

For OTEC ammonia production, electrolytic hydrogen is combined with nitrogen obtained by air separation. Since both processes produce high-purity materials, there is no necessity to purge the synthesis loop as is the case in conventional ammonia plants employing hydrogen from methane reforming. Virtually 100 percent yield of ammonia can be obtained by continuously recycling the unreacted synthesis gas and adding makeup gas that reacted; 0.18 lb H_2 and 0.82 lb N_2 are required per pound of NH_3.

The raw material, energy, and labor inputs characteristic of the three processes discussed for ammonia production are shown in Table IV-1. In addition to the references already cited in this section, data in the table is drawn from Strelzoff (23), Vancini (24), Perry and Chilton (22), and Franzen and Goeke (15). Some points illustrated by the tabulated data are worthy of comment.

In natural gas reforming, the wide ranges for gas used as fuel and for electricity reflect the opportunities for energy conservation in integrated plants, albeit at an increase in capital investment for heat exchangers and regenerative steam systems. In coal gasification, the type of coal used (lignite, hard coal), the oxygen requirement (from air separation), whether pumps and compressors are electrically or steam turbine driven, and whether heat recovery techniques are extensively employed control the coal, steam and power requirements.

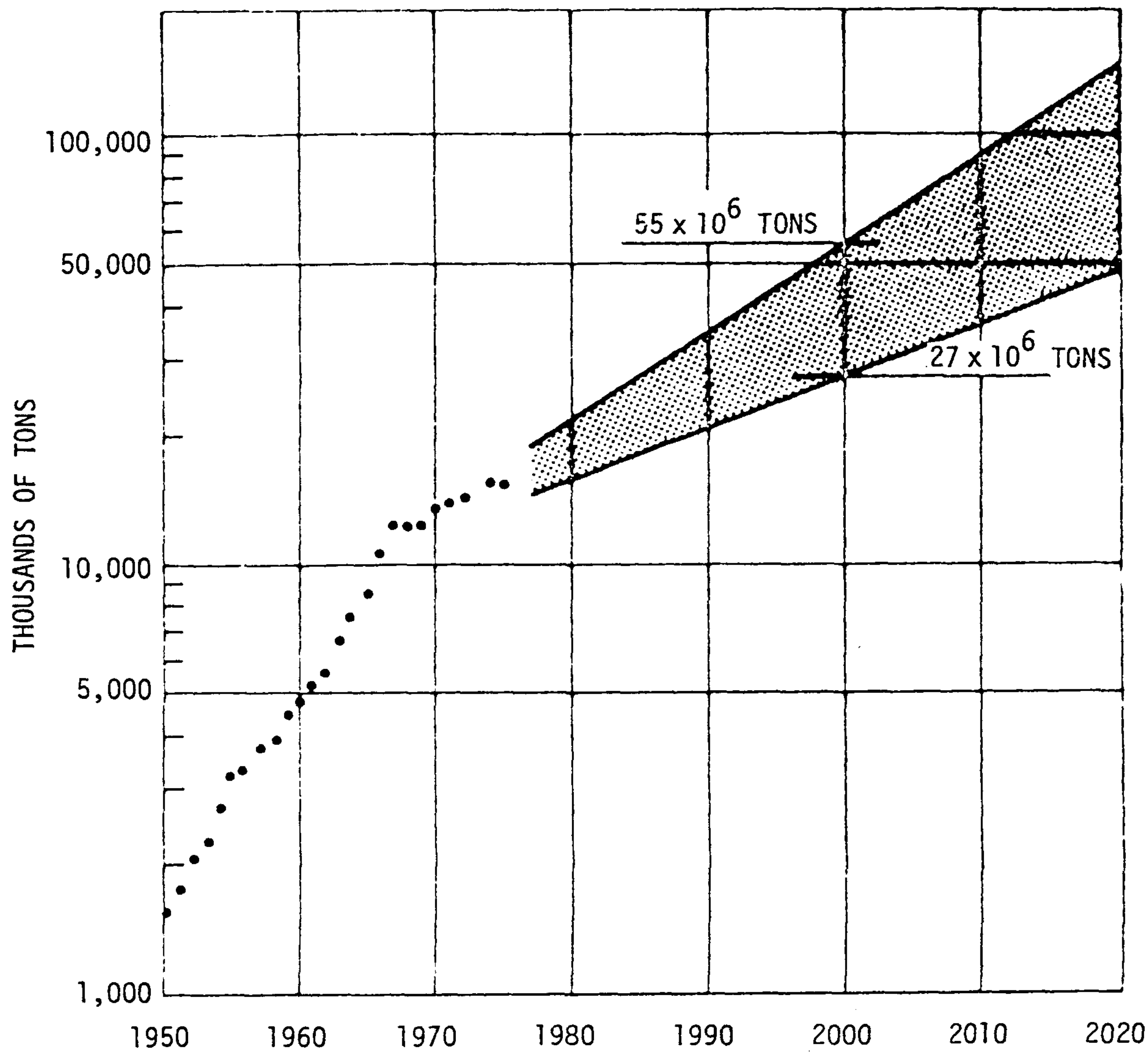
Tabulated values for the electrolytic process represent future technology for large scale water electrolysis and best current state of the art for air separation and ammonia synthesis. Calculations based on essentially complete conversion by this process for a total electrical energy expenditure of 8,000-8,500 kWh/ton of ammonia produced must be looked upon as technologically optimistic.

TABLE IV-I - AMMONIA PRODUCTION OPERATING FACTORS
(PER SHORT TON OF ANHYDROUS AMMONIA)

NATURAL GAS REFORMING		
Natural Gas (methane) as feedstock	21 - 22	Mscf
as fuel	8 - 14	
Total	29 - 36	Mscf
Electricity	28 - 40	kWh
Process Water	2.5 - 3.2	tons
Cooling or Boiler Feed Water	6.5 - 7.2	Mgal
Labor	0.14 - 0.21	man-hr
COAL GASIFICATION		
Coal	2.0 - 2.2	tons
Electricity (includes air separation for O_2 and N_2)	200 - 500	kWh
Process Water (as steam)	4 - 6	tons
Cooling or Boiler Feed Water	3.5 - 4.5	Mgal
Labor	0.31 - 0.36	man-hr
WATER ELECTROLYSIS		
Electricity: electrolysis (19 kWh/lb H_2)	7,600	kWh
air separation (0.1 kWh/lb N_2)	180	
syngas compression	400	
refrigeration and pumping	140	
Total	8,320	kWh
Process Water	1.79	tons
Cooling Water	15	Mgal
Labor (estimated)	0.15 - 0.20	man-hr

Ammonia Demand

The potential market for OTEC in ammonia production will be determined by the growth in demand for the product and the economic competitiveness of the alternative processes. Although annual production, agricultural demand, and the price paid by farmers for fixed nitrogen in any form have fluctuated erratically during the past 10-15 years, examination of the historical trend shows a picture of long term consistent growth. The statistical data and demand projections are shown in Figure IV-1, adapted from Mitre Report 7347. The data indicate a 12.5 percent annual growth rate between 1950 and 1966, followed by a distinct decrease in rate to 3.75 percent per year for the 1967-1976 period. The variance in this latter period is used to characterize the



(Source: Mitre Report 7347.)

FIGURE IV-1 - PROJECTED AMMONIA DEMAND

uncertainty in projecting continued annual growth at the 3.75 percent rate, indicated by the shaded area in the figure. We believe that this is a reasonable and conservative basis for projecting demand from which three growth scenarios can be obtained by using the uncertainty limits to characterize the low and high growth cases. The relevant data are shown in Table IV-2.

TABLE IV-2 - AMMONIA DEMAND GROWTH SCENARIOS, 1975-2000

Scenario	Growth Rate (percent per year)	Year 2000 Demand (million tons)
Low	2.8	27
Probable	3.75	37
High	5.0	55

Cost Projections

Because the study addressed the tropical island industry configuration as a first step to the industrial factory ship operating in tropical waters ammonia production costs were estimated for the two configurations and compared with the costs of ammonia as produced by competitive systems using fossil fuels.

TEMPO estimated the costs of production at the tropical island industry plants and IGT in their subcontract estimated the costs of production on the factory ships. These estimates were made in somewhat different methods but essentially both estimated the costs of ammonia as produced by other sources and as produced by OTEC powered systems emphasizing the year 2000 time frame.

The IGT projections are described in detail in Appendix A which is their report on this subcontract. The results will be summarized briefly here in the text and will be followed by the description of the TEMPO analysis. Both analysis indicate that, for OTEC power prices projected for the year 2000, ammonia produced by OTEC systems and shipped to the continental United States will be competitive with ammonia produced from fossil fuels in the continental United States.

Factory Ship Costs

The IGT analysis projected the cost of ammonia production in the year 2000 for different feed stocks for use in comparing with OTEC costs their results are summarized in Figure IV-2. To estimate the OTEC System ammonia production costs they used a parameterized power cost of 10, 20, 30 and 40 mills/kwh from a 100 megawatt OTEC unit whose net power output was corrected for seasonal ΔT fluctuations and whose net ammonia output was delivered by dedicated ships or barges to various ports. The potential production sites considered were: Key West, the West Coast of Florida, Miami, New Orleans, Brownsville, Puerto Rico, Hawaii and Brazil. The potential destination sites were New York, Miami, New Orleans, Houston and Los Angeles. (Los Angeles was only considered with the Hawaii site).

The detailed costs for combinations of sites and destinations were determined for the four costs of power to determine the range of costs which varied from as low as $173 per ton delivered for 10 mill/kwh power and preferred locations to as high as $494 per ton for 40 mill/kwh power and the most remote locations. As would be expected with the large number of sites, destinations and power cost parameters there are a large number of results which are presented in the appendix. To give a feeling for a respresentative situation it was assumed that by the year 2000 ammonia production at sea would still be an infant industry and that the plants would be comparatively few in relatively isolated operation and shipping their product to New Orleans via a dedicated ammonia ship or barge that would return to the site empty. New Orleans was selected because it is centrally located in the current ammonia production area and has direct access to the agricultural heartland where the majority of currently produced ammonia is used.

During the twenty years following the year 2000 it is anticipated that a 10 year successful at sea operation would encourage industries to expand the number of factory ships drastically but initial emphasis in this study was on the competitiveness by the year 2000.

To illustrate this scenario Figure IV-3 shows the costs projected by I of OTEC factory ship produced ammonia delivered at the port of New Orleans n the sites off New Orleans, Western Florida, Key West, Puerto Rico, and Brazil. As can be seen from the chart, for any power price, two factors: the

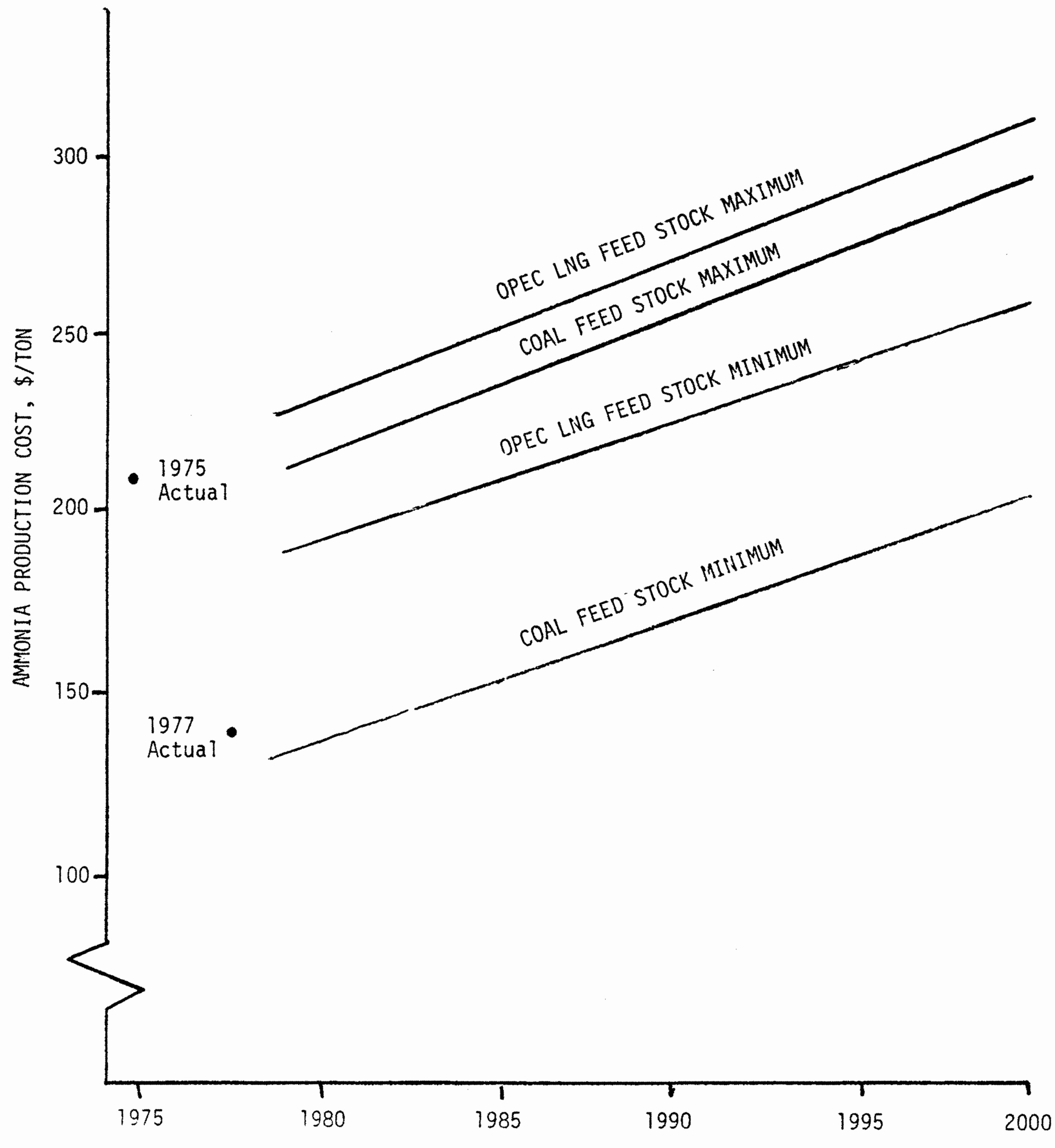


FIGURE IV-2 - AMMONIA PRODUCTION COST FORECAST

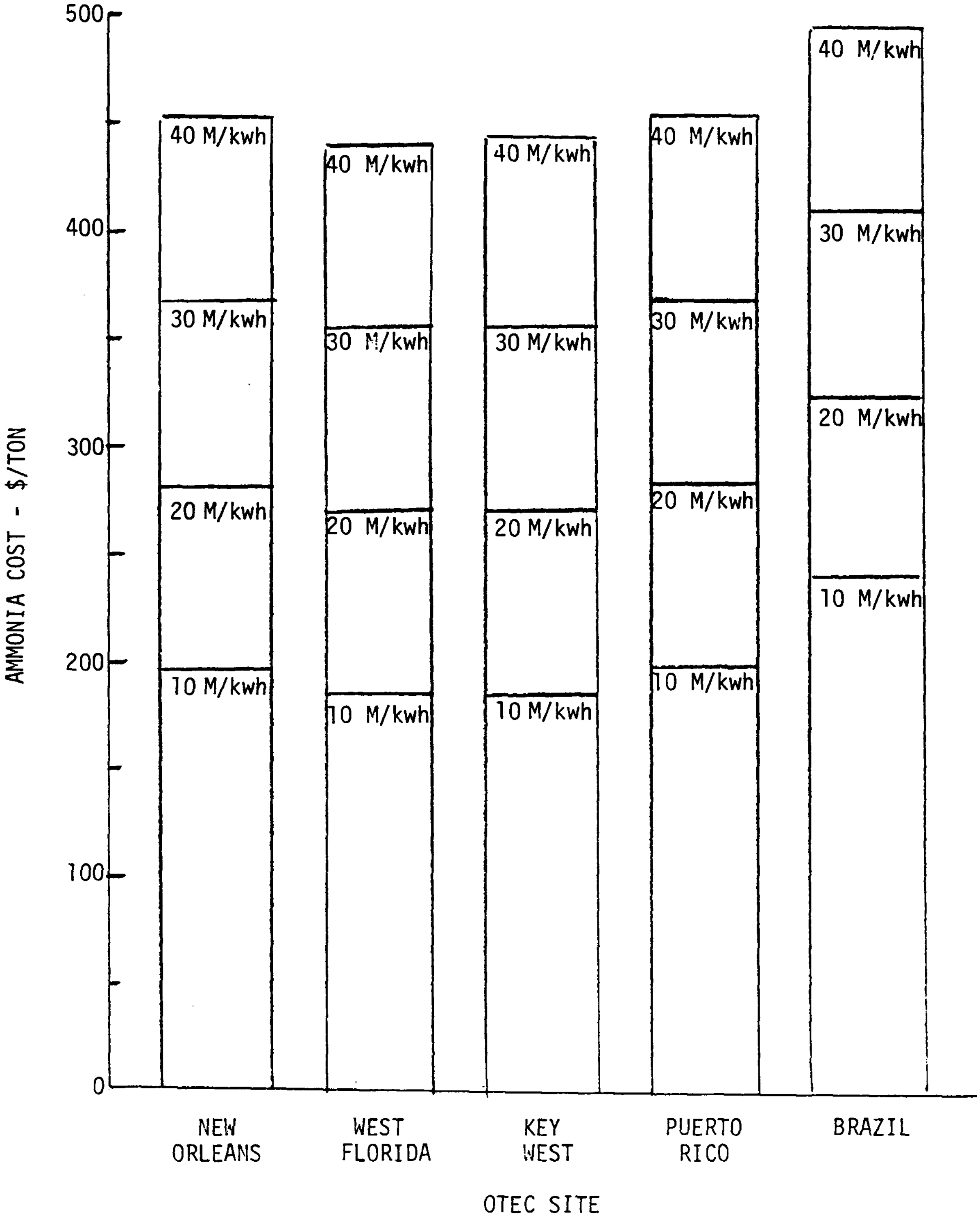


FIGURE IV-3 - AMMONIA COSTS DELIVERED AT NEW ORLEANS FROM VARIOUS SITES seasonal performance degradation and transportation distance effect the costs. The cost of ammonia produced off New Orleans is comparable to the cost of ammonia produced off Puerto Rico because the seasonal performance degradation is much worse than the tropical site and compensates for the cost of 1700 miles of shipping.

As a result of this analysis it is clear that with OTEC power costs on board a factory ship being projected at between 10 and 15 mills/kwh in the year 2000, the ammonia would be competitive. And it is also apparent that because their study shows that costs go through a minimum as a result of the ΔT and shipping cost factors, an optimization study is required that will examine the routes, and markets to permit the selection of best sites for earliest competitiveness.

Island Industry Cost Scenarios

Five production scenarios are investigated as the basis for the economic comparison of alternative ammonia production methods. Since about 95 percent of current domestic production is by natural gas reforming and more than 50 percent of current capacity is along the Gulf Coast from Mississippi to Texas, this process, projected into the 1990-2010 time frame, must be taken as the baseline for comparison. The cost of natural gas is, of course, expected to rise more rapidly than that of other fuels because of its high residential and commercial sector demand, decreasing reserves, and the spread between its current price and estimated prices for imported LNG or coal-derived SNG. The importance of ammonia to agriculture and the utility of natural gas as a feedstock, however, suggest that this application may deserve a high priority. Conservation of natural gas can be accomplished by limiting its use to feedstock only, as in coal-fired gas reformer, and by further improving the overall energy efficiency of new plants. For the present analysis, the natural gas process will be considered as unchanged from its present form with the future cost of natural gas reflecting the large demand on this resource.

As indicated earlier, the chemical engineering literature reflects the belief that preparing ammonia syngas by coal gasification is the most likely competition to natural gas reforming. The size of U.S. coal reserves and the research effort being devoted to gasification processes make this an alternative that must be investigated. For this comparative cost analysis, it is assumed that the ammonia plant is located between the coal region and the agricultural area so that the distribution cost is comparable to that of ammonia from Gulf Coast natural gas plants. It is reasonable to assume that new ammonia capacity will be sited to minimize transport costs of inputs and product, and there is no significant difference in this regard between gas- and coal-fed plants.

For comparison with the two fossil-feed processes, the OTEC process will be considered at three locations: Gulf Coast, Hawaii, and Puerto Rico. The OTEC electricity costs at these locations are analyzed elsewhere in this report and are used consistently throughout. As to distribution costs, all OTECs are assumed to be cable connected to their shore-based ammonia plants, so the Gulf Coast sites are equivalent to the gas-fed plants and no shipping differential is involved. The island sites, however, incur a specific ocean shipping charge for OTEC-produced ammonia to be delivered to continental U.S. farm areas. (Neither island comprises a sufficiently large ammonia market by itself to justify development of this process for that purpose alone.) Representative bulk shipping rates of three mills per ton-mile plus $2.00 per ton for loading, unloading, and port costs will add about $6.50 per ton from Puerto Rico and about $20.00 per ton from Hawaii to the cost of ammonia delivered to New Orleans. This Gulf Coast center is used as the basing point since distribution costs from that point are not detailed for any of the scenarios. In 1976, the 11 Pacific and Mountain states consumed only 14 percent of the agricultural fixed nitrogen used in the U.S., which suggests that a large West Coast demand does not exist for OTEC ammonia produced in Hawaii. In contrast, the East Coast and Appalachian states accounted for over 17 percent of demand, a market which could be served from Puerto Rico over a smaller shipping distance than via New Orleans.

Production Costs

Production cost elements for the three ammonia processes in their respective locations are presented in Table IV-3. In discussing the process technologies, reference was made to tradeoffs between energy efficiency and capital investment; the investment ranges shown reflect this factor as well as the larger variability of the less mature technologies.

TABLE IV-3 - AMMONIA PRODUCTION COST ELEMENTS (1976 DOLLARS)

CAPITAL INVESTMENT				
Integrated 1000 tpd ammonia plant making syngas by: natural gas reforming			150 - 175	$/an. ton
coal gasification			200 - 425	
water electrolysis and air separation			150 - 210	
Construction cost location factors (US = 1.00)				
Hawaii 1.17				
Puerto Rico 1.07				
LABOR COST				
US, Hawaii			7.50	$/man-hr
Puerto Rico			3.35	
RAW MATERIALS AND UTILITIES				
	1990	2000	2010	
Natural Gas	2.39	2.52	2.75	$/Mscf
Coal	29.15	30.48	31.80	$/ton
Electricity (conv)	43.5	43.5	43.5	mills/kWh
OTEC Electricity:				
Gulf Coast	58	22.8	22.8	mills/kWh
Hawaii	51	19.4	19.4	mills/kWh
Puerto Rico	34.5	14.0	14.0	mills/kWh
Process Water	0.11	0.11	0.11	$/ton
Steam	1.45	1.52	1.58	$/ton
Cooling Water	0.05	0.05	0.05	$/Mgal

Fossil fuel and conventional electricity costs for the three dates shown are based on data provided by ERDA. OTEC-generated electricity costs are developed in the power utility mission analysis of this report. Water and steam costs are appropriate for large scale chemical process plants located on the Gulf Coast; steam costs escalate in proportion to coal costs. The figures shown are median values; uncertainties of about ±30 percent are appropriate in most cases.

Results of combining average values of the operating factors of Table IV-1 and the cost figures of Table IV-3 are presented in the exemplar cost calculation of Table IV-4 for 1990. Because the use of levelized or discounted cash flow techniques in the chemical process industries is normally reserved for more detailed cost estimating than is used here, the ammonia cost calculation is done on two bases: first-year costs which are straightforward extensions of the input data, and levelized variable costs over the 15-year assumed plant economic life. As in the utility electricity and aluminum analyses, the levelizing factors are based on 6 percent per year general inflation compounded with whatever escalation rate (in excess of general inflation) is appropriate for a given item as described in the following text. This cost stream over the plant life is then discounted back to the date of initial operation at the industry's internal rate of return (cost of capital) as the discount rate.

TABLE IV-4 - PRODUCTION COST OF ANHYDROUS AMMONIA IN 1990
(1976 DOLLARS PER TON)

Item	First-year Cost ($/ton)	Levelized Cost ($/ton)
NATURAL GAS REFORMING		
Annual Fixed Cost	44.96	44.96
Variable Costs		
Natural Gas	77.68	116.04
Electricity	1.48	2.13
Process and Cooling Water	0.65	0.94
Labor	1.31	1.89
G&A, Sales	8.11	12.10
Total	134.19	178.06
COAL GASIFICATION		
Annual Fixed Cost	83.88	83.88
Variable Costs		
Coal	61.22	90.93
Steam	7.25	10.77
Electricity	15.22	21.94
Cooling Water	0.20	0.29
Labor	2.51	3.62
G&A, Sales	8.64	12.76
Total	178.92	224.19
WATER ELECTROLYSIS — GULF COAST OTEC		
Annual Fixed Cost	48.32	48.32
Variable Costs		
Electricity	482.56	482.56
Process and Cooling Water	0.95	1.36
Labor	1.31	1.89
Total	533.14	534.13

Representative fiscal parameters for the chemical process industry appropriate for ammonia manufacture are a 15-year plant life, 15 percent long-term debt financing at 8 percent interest, 85 percent equity funding anticipating an after-tax return of 15 percent per year, a 50 percent Federal and local income tax rate, and an annual cost of 2 percent of invested capital for insurance and other taxes. This results in an internal rate of return of 13.35 percent and a fixed charge rate of 26.84 percent. These values are used consistently for the three types of ammonia plants shown in Table IV-5, in particular, they apply to the electrolysis, air separation, and ammonia loop components of the OTEC process. The primary input in this case OTEC electricity, is assumed to be purchased from a power utility, and its cost is based on utility financing.

All the elements of the cost computation which experience only general inflation at 6 percent per year are converted from first-year cost to levelized annual cost by the factor 1.441. The natural gas prices of Table IV-3 imply an annual escalation rate of 0.53 percent over inflation between 1990 and 2000, leading to a levelizing factor of 1.494. Similarly, coal (and steam) escalate at 0.45 percent per year for a 1.485 levelizing factor. General and administrative cost and cost of sales (producer level) is taken as 10 percent of all the other variable costs whether on a first-year or levelized basis. This accounts for all the costing methodology elements applied to the reforming and coal gasification processes.

For the OTEC process, first-year and levelized electricity costs are identical because 94 percent of the cost is a fixed charge item. (See discussion of OTEC electricity costs elsewhere.) No G&A or sales costs are included in the product price. Three other factors are considered for the island OTEC locations, none of which apply to the Gulf Coast location shown in the table. They are use of the location multiplier as a factor on the annual fixed cost, use of the appropriate labor wage rate, and inclusion of shipping costs ($6.50 and $20.00 per ton from Puerto Rico and Hawaii, respectively) as previously discussed.

The identical procedure is followed for the year 2000 and 2010 cost estimates using the appropriate time-dependent inputs from Table IV-3 and assuming continuation of the 6 percent inflation rate over the economic life of ammonia plants beginning operations in those years. As before, appropriate levelizing factors are computed whenever the price data of Table IV-3 indicates escalation faster than general inflation. Levelized ammonia prices under the five cost scenarios for each of the three exemplar dates are presented in Table IV-5. Figure IV-4 show this graphically.

TABLE IV-5 - LEVELIZED AMMONIA PRODUCTION COST
(1976 DOLLARS PER TON)

Scenario	1990	2000	2010
Natural Gas, Gulf Coast	178	188	201
Coal, Central States	224	229	234
OTEC, Gulf Coast	534	241	241
OTEC, Hawaii	504	241	241
OTEC, Puerto Rico	347	177	177

Examination of these results indicates that the most generally used process at present loses its dominance of the best OTEC alternative during the last decade of this century. Of the three OTEC sites considered, Puerto Rico appears most likely to become an economically feasible ammonia production center at the earliest date. This is due to its preferred OTEC operating conditions and favorable financial and tax policies which more than offset the cost of product shipping. Shortly after the turn of the century, OTEC powered plants at the other locations will become competitive with coal gasification. Although this latter process is usually considered to be the substitute for natural gas reforming, the OTEC option can be expected to share new additions to capacity early in the next century and move to a dominant position shortly thereafter as fossil fuel prices continue to escalate.

OTEC Requirements for Ammonia Production

Because both the OTEC at sea configuration and the island industry configuration indicate that by the year 2000 costs will be in the competitive range with ammonia produced from fossil fuels in the continental United States. There will be no site limitation on OTEC produced ammonia and an aggressive implementation program would result in the capture of a large portion of the market.

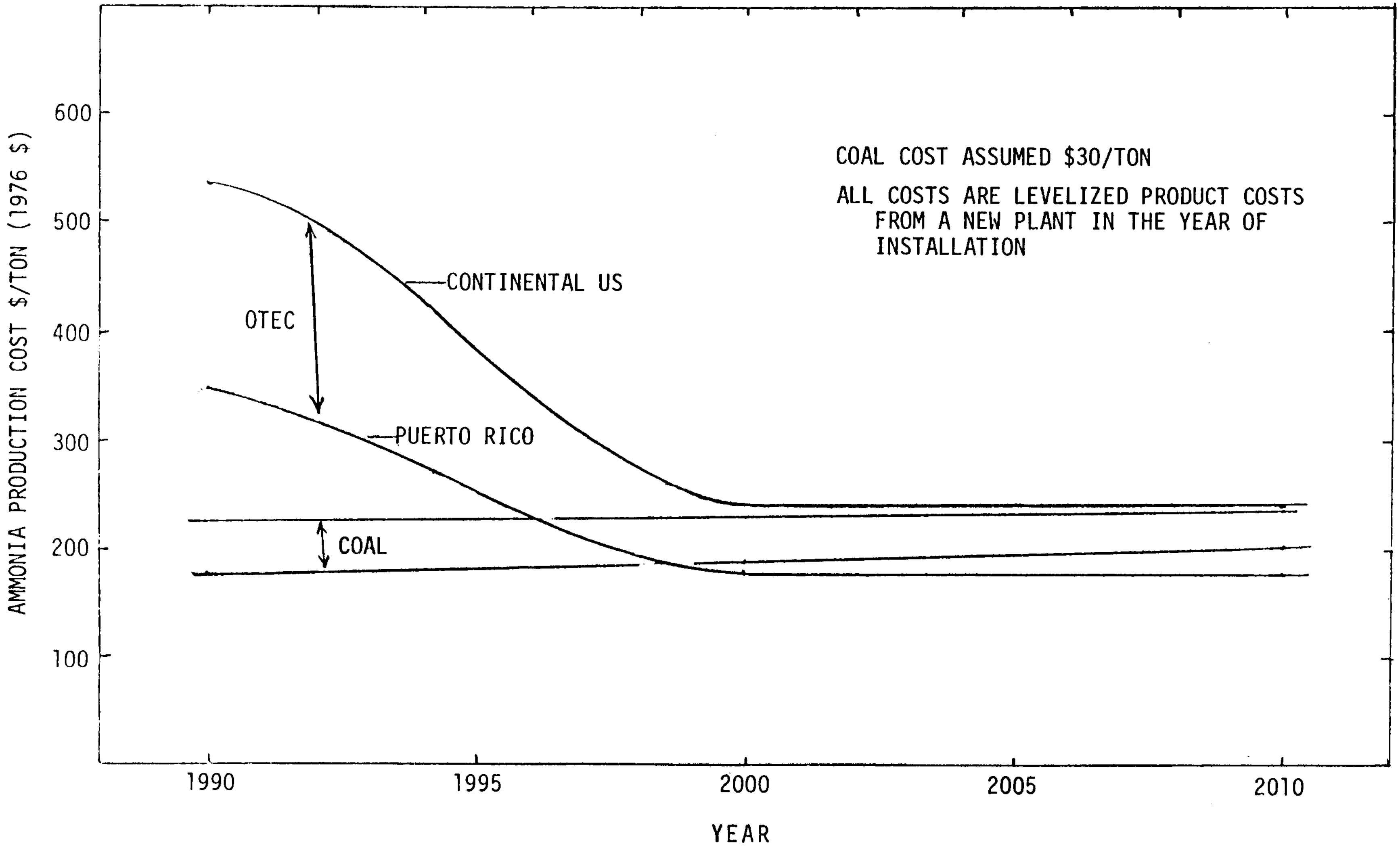


FIGURE IV-4 - COMPARISON OF AMMONIA DELIVERED COSTS BY OTEC & FOSSIL FUELS

The growth rates of Table IV-2 and the 8,320 kWh/ton electrical energy requirement for ammonia can be combined to project the post-1985 market for OTECs in this application. The 1985 date is chosen because no large ammonia-producing OTECs can resonably be operational before that time. Demand growth prior to OTEC availability would be met by fossil fuel processes and would not impose a large load on electrical generating capacity.

The OTEC scenarios are based on the assumption that the economic competitiveness of the electrolytic process is sufficient, either intrinsically or as a result of subsidy, that rapid penetration takes place. Specifically, we assume that in 1990, the OTEC installations will be 10 percent of the annual addition rate to ammonia capacity, approximately 1 or 2 commercial size units. The installation capture rate will grow to 90 percent in a 20-year takeover period, according to the Fisher-Pry formulation. To display the effect of these assumptions, the scenarios are carried out to the year 2010 even though demand projections extrapolated that far are of doubtful validity. The results shown in Table IV-6 are cumulative OTEC capacities added starting in 1990 expressed in thousands of tons ammonia per year (Mtpy) and in gigawatts of electrical generating capacity (GW). The production and generating capacities shown are related by the constant ratio 0.950 kW per tpy, but each scenario reflects the appropriate ammonia demand growth rate (Table IV-2) and the time-dependent capture rate.

TABLE IV-6 - CUMULATIVE, POST-1985 OTEC-AMMONIA PRODUCING CAPACITY (MTPY) AND REQUIRED ELECTRICAL GENERATING CAPACITY (GW)

Growth Scenario:	Low		Probable		High	
Year	Mtpy	GW	Mtpy	GW	Mtpy	GW
1990	260	0.24	420	0.39	690	0.66
1995	1,380	1.3	2,290	2.2	3,940	3.8
2000	4,440	4.2	7,580	7.2	13,520	12.8
2005	9,570	9.1	16,780	15.9	31,030	29.5
2010	15,490	14.7	27,950	26.5	53,680	51.0

Figure IV-5 shows the penetration of the OTEC production in comparison with the projected U.S. demand and Figure IV-6 gives the OTEC capacity required for that penetration.

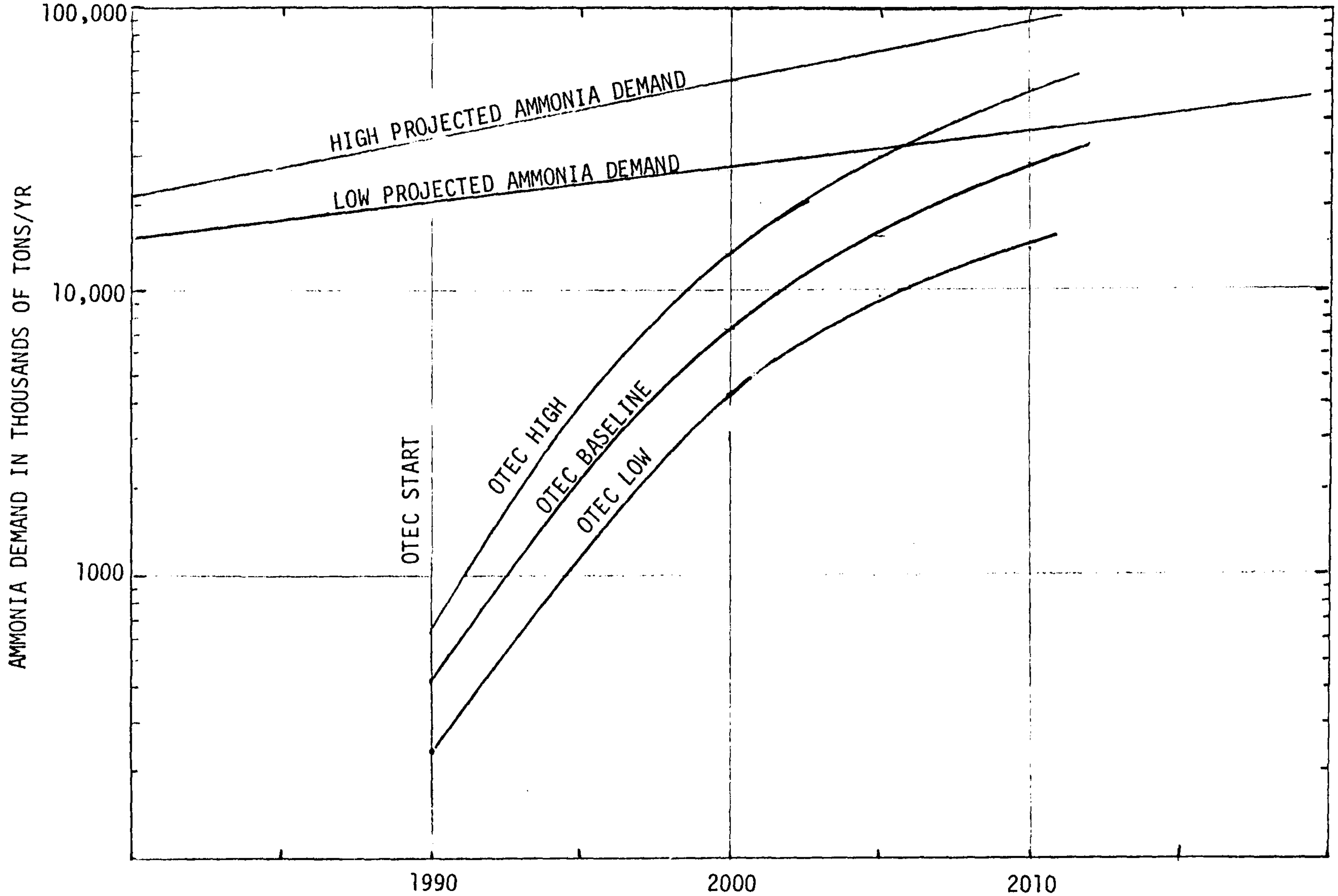


FIGURE IV-5 - PENETRATION OF OTEC INTO THE AMMONIA MARKET

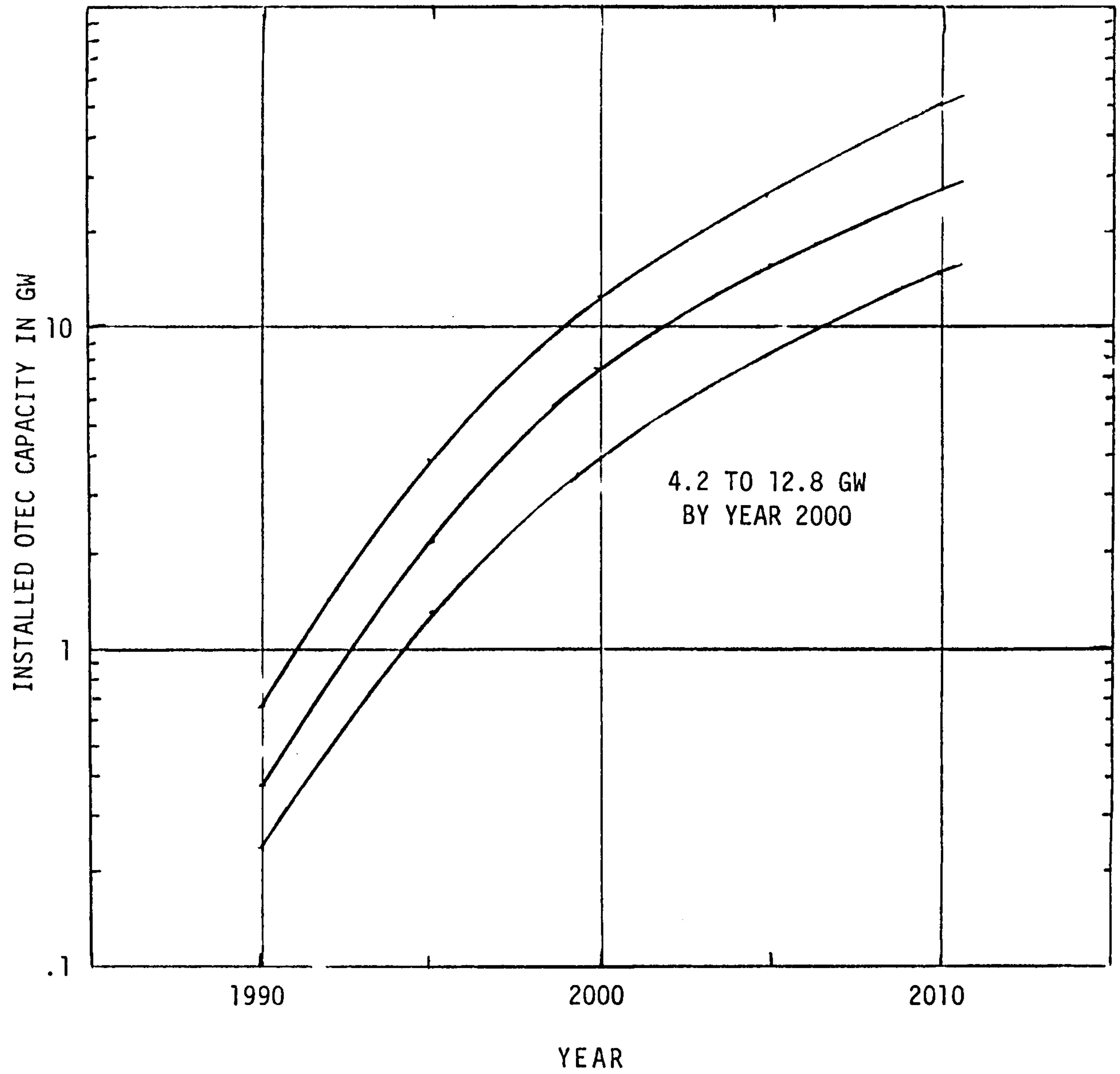


FIGURE IV-6 - OTEC GENERATING CAPACITY
REQUIRED BY PENETRATION INTO THE AMMONIA MARKET

SECTION V

ALUMINUM OPTION

ALUMINUM MARKET - HISTORY AND BACKGROUND

Although first isolated in the form of a free metal in 1829, it was not until 1886 that a commercially feasible process for smelting aluminum was discovered. In that year, Hall in the United States and Heroult in France independently found that the metal could be obtained by electrolytically reducing alumina dissolved in molten cryolite. While that process has been made more efficient in the intervening 90 years, it is the one still in use today.

Since the early years of this century, the growth of aluminum use has been extremely rapid, four doublings in production and demand having occured since about 1945. In 1975, demand stood at 5.6 million tons per year as a result of aluminum's successful penetration of the construction, electrical, transportation, and packaging industries primarily.

In 1888, the Pittsburgh Reduction Company, which later became the Aluminum Company of America (Alcoa), was organized to exploit the Hall process. Initially, patent rights, the high capital investment required, and the non-existence of a market for the new metal contributed to the fact that no other U.S. companies entered the aluminum producing field for over 50 years. During this time, Alcoa had become a vertically integrated large producer with control based on large economies of scale extending to overseas bauxite mines, transport, alumina refining, power generation, smelting, and fabrication.

The demand for aluminum for military purposes during World War II provided the opportunity for the first new entries into the field: Reynolds Metals Company in 1940-1941 and Permanente (later Kaiser) Metals Company in 1946 (19).

Today, twelve companies are involved in primary aluminum production in the United States, but concentration in the industry is such that two-thirds of production is still accomplished by the first three, as shown in Table V-1 (5).

TABLE V-1 - CONCENTRATION IN U.S. ALUMINUM INDUSTRY (THOUSAND SHORT TONS OF ANNUAL PRIMARY SMELTING CAPACITY, 1974)

Rank	Company	Capacity	Percent	Cum. Pct.
1	ALCOA	1,575	32	32
2	REYNOLDS	975	20	52
3	KAISER	724	15	67
4	CONALCO	342	7	74
5	ANACONDA	300	6	80
6	HOWMET	218	4	84
7	MARTIN-MARIETTA	205	4	88
8	REVERE	197	4	92
9	AMAX	130	3	95
10	NATIONAL ALUMINUM	90	2	97
11	SOUTHWIRE	90	2	99
12	NORANDA	70	1	100

In recent years, aluminum smelting has accounted for about 4 percent of all domestically generated electricity. A snapshot summary of the industry as it existed in 1973 is presented in Table V-2 derived from Bureau of Mines data (1975). Bauxite, alumina, and aluminum totals do not correspond exactly because small entries for net trade and stockpile adjustments are not shown. For that year, Bayer refinery capacity factors averaged over 95 percent and smelter capacity factors over 92 percent. Eighty two percent of available alumina went to primary smelting; the balance was used in preparing refractory bricks and linings, abrasives, and other products. New primary metal provided just over 78 percent of supply in that year, and was supplemented by sizeable withdrawals from stockpile and inventory. The fractional demand of the major consuming industries is also shown and is discussed later in connection with demand projections.

The electricity required for Hall process smelting comprises about two-thirds of the total energy consumed in aluminum production and fabrication of intermediate forms by rolling, drawing, and extrusion processes (9).

TABLE V-2 - DEPLOYMENT OF U.S. ALUMINUM INDUSTRY: 1973
(THOUSAND SHORT-TONS OF ALUMINUM CONTENT)

BAUXITE:	Domestic Production	442
	Imported (Jamaica, Surinam, ...)	3,419
ALUMINA:	Nine Bayer Process Refineries	
	Annual Capacity 4,044	
	Domestic Production	3,825
	Imported (Australia, Jamaica, ...)	1,712
	To Primary Reduction Plants	4,529
	To Non-Metal Uses	1,098
ALUMINUM:	31 Hall Process Smelters	
	Annual Capacity 4,893	
	10 Northwest 32%	
	6 Ohio River Valley 22%	
	5 Gulf Coast 18%	
	4 TVA (Tenn., Ala.) 15%	
	6 Other States 13%	

Supply		Demand	
Domestic Smelters	4,529	Construction	1,543
Imports	53	Transportation	1,206
Secondary Metal	265	Electrical	798
From Inventory	219	Containers	884
From Government Stockpile	717	Cons. Durables	575
TOTAL	5,783	Machinery	406
		Other	371
		TOTAL	5,783

Production Technology

A diagrammatic representation of the industrial process presently used for producing aluminum metal is shown in Figure V-1 (10). The following description is intended to provide additional detail with special reference to the electrolytic reduction step.

Bauxite is a heterogeneous material composed primarily of either of two aluminous minerals, gibbsite (alumina trihydrate) or boehmite (alumina monohydrate), combined with iron oxides, aluminum silicates, quartz, and titanium oxides. It is formed by the weathering of aluminum-containing rocks under tropical climatic conditions, and usually appears in extensive near-surface deposits amenable to open-pit or strip mining. Simple beneficiation operations such as crushing and washing may be waranted, and the material may be dried if it is to be transported appreciable distances. Commercial bauxites contain 17-25 weight percent of aluminum.

The Bayer process was patented in 1888 and is still used to refine bauxite to alumina. The process involves caustic leaching at elevated temperature and pressure which brings the aluminum into solution as sodium aluminate. This is separated from the insoluble wastes ("red mud") by filtration, and then decomposed to precipitate hydrated aluminum oxide by cooling. The oxide is separated by filtration, washed, and calcinated to obtain alumina.

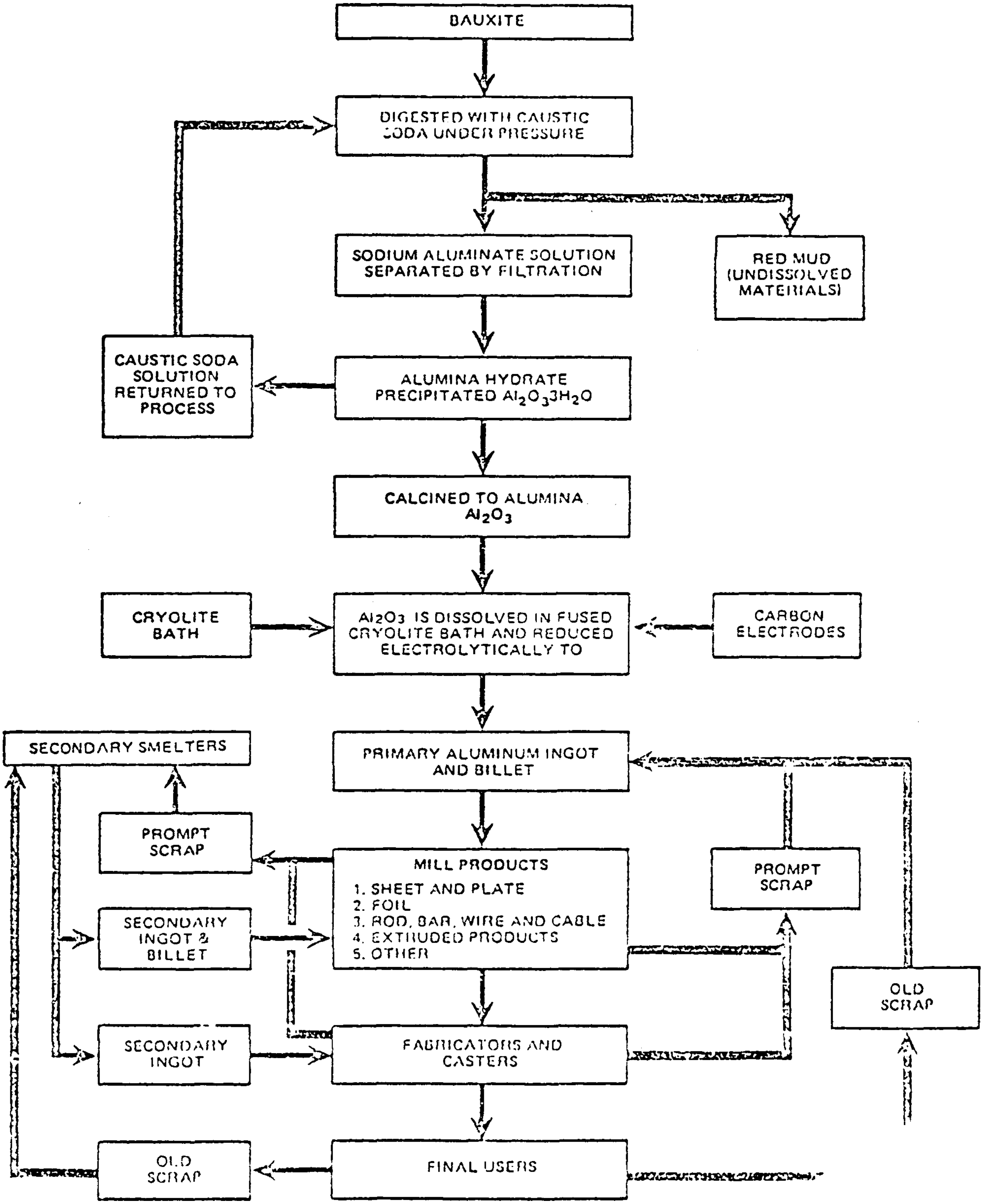
Different bauxite ores require sufficiently different Bayer process conditions (pressure, temperature, concentration, holding times) that particular plants, designed to process specific ores, generally cannot treat other types of ores.

Since calcined alumina has an aluminum content of 52 percent by weight, an advantage in shipping economics is gained by converting bauxite to alumina near the mine. While a Bayer plant is not inexpensive (100-200 million dollars for a typical half-million ton per year capacity), its benefits, assuming an adequate supply of soda ash, lime, and fuel are sufficiently great to account for the worldwide trend toward such installations in bauxite producing countries.

In the Hall process, alumina is electrolyzed between carbon electrodes in a bath of molten cryolite (sodium aluminum fluoride) held at about 950°C by the internal resistance to the 80,000-100,000 ampere current typical of modern cells. The cathode, which comprises the lining of the sides and bottom of the cell, serves to contain the molten aluminum; the anode, which penetrates into the bath from the top, is consumed in the process as it is oxidized to a mixture of carbon monoxide and dioxide carrying off the oxygen initially present in the alumina. Periodically, the molten aluminum product is siphoned from the cell and cast as ingot.

There are two types of Hall cells distinguished by the nature of the anode. In one, the anode is "prebaked", ie. molded from a mixture of petroleum coke, pitch, and pulverized coal, and baked to a solid block for insertion in the cell. The other, the Soderberg cell, depends on continuous feed of the carbonaceous mixture as a paste which solidifies at the operating temperature of the cell. Including preparation, the prebaked anode cell requires less energy than the Soderberg cell.

Aluminum Production Process



Source: Council on Wage and Price Stability, 1976.

FIGURE V-1 - ALUMINUM PRODUCTION PROCESS

In the 90 years since its discovery, the Hall cell has been improved in many ways, the most striking of which has been the continuous reduction in the electrical energy required per pound of aluminum. Since 1947, this figure declined from more than 9 kWh/lb to about 6.5 kWh/lb for the most modern cells and further reductions are being achieved. As older potlines were rebuilt and new cell designs incorporated, the average energy consumption over all smelters has declined as shown by the upper curve of Figure V-2. The indicated data points for 1947, 1963, and 1971 are based on analyses of data drawn from samples of the industry; that for 1980 is projected on the basis of known plans for expansion and rebuilding as of 1974 (9). The extrapolation of the upper curve beyond 1980 is conjectural and intended to represent a continuing decrease in Hall cell energy consumption averaged over all smelters as new and replacement capacity is added at values approaching 6.2 kWh/lb.

An alternative electrolytic process in which aluminum chloride is reduced is presently in pilot plant evaluation by Alcoa. In the chloride process, alumina, carbon, and chlorine are first combined in a thermochemical reactor; volatile aluminum chloride and a mixture of carbon monoxide and dioxide are formed. The aluminum salt is then fed to the electrolytic cell where metallic aluminum and free chlorine are obtained. The chlorine is returned to the thermochemical stage, and the aluminum is cast to ingot. Because the free energy of aluminum chloride reduction is less than that for aluminum oxide, the electrical energy requirement of this process is less than that of the Hall cell; values of 4.5 kWh/lb are cited at present, with the expectation that this can be reduced as the process proves out. The lowest curve in Figure V-2 represents the time-dependence of the energy demand in new chloride process cells.

The potential effect of penetration of the primary smelting industry by the chloride process is respresented by the broken intermediate curve of Figure V-2 starting at 1980. The form of this phenomenon is based on a technological substitution of new technology for old is proportional to the amount of the old remaining at any time (Fisher and Pry, 1971). The parameters of the model are the "takeover time", the period during which the new method increases from 10 to 90 percent takeover, and the midpoint date, the date of 50 percent takeover. The curve shown in Figure V-2 assumes a 20-year takeover period about a 1995 midpoint. Energy demand scenarios for aluminum production reflecting both the Hall process and this rate of penetration by the chloride process are presented in a later section.

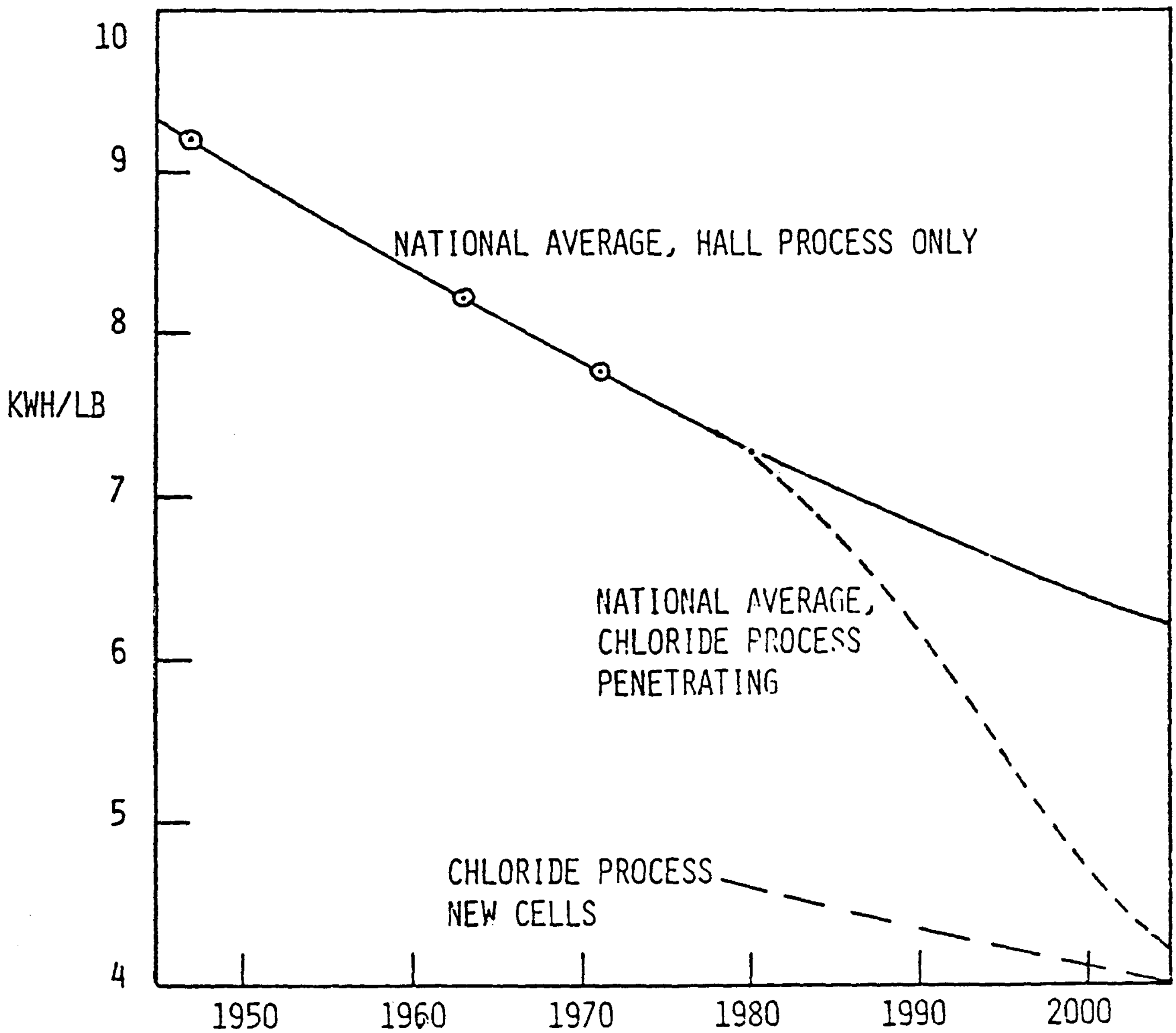


FIGURE V-2 - ALUMINUM SMELTING: SPECIFIC ENERGY

The raw material, energy, and labor inputs characteristic of primary aluminum production at present are summarized in Table V-3 for bauxite mining, alumina refining by the Bayer process, and aluminum smelting by the Hall process (8).

The only technical information released by Alcoa on the chloride smelting process indicates that electricity for reduction is approximately 4.5 kWh/lb or 9 MWh/ton. The stochiometric requirement for carbon in the initial thermochemical step is 900-1000 lb per ton of aluminum produced, and an unknown quantity of fuel would be required to maintain the reaction temperature. While cryolite and other fluorides for makeup of bath losses are not required, some

TABLE V-3 - ALUMINUM PRODUCTION OPERATING FACTORS
(PER SHORT TON OF PRIMARY ALUMINUM METAL)

BAUXITE MINING			
Energy (Mining, Drying, Shipping)		1-5	MMBtu
Labor		3-9	Man-Hours
ALUMINA PRODUCTION			
Bauxite		4-5	Short Tons
Caustic (or Soda Ash and Lime)		200-280	Pounds
Lime		60-200	Pounds
Energy — For Steam		20-30	MMBtu
— For Calcining		7-10	MMBtu
— Miscellaneous		2-5	MMBTU
Labor		3-5	Man-Hours
SMELTING			
Alumina		1.90-1.95	Short Tons
Cryolite and Other Fluorides		40-140	Pounds
Petroleum Coke		700-950	Pounds
Pitch		280-330	Pounds
Anthracite Coal		40-80	Pounds
Electricity for Reduction:	Prebaked	13.2-16.4	MWh
	Soderberg	16.1-17.6	MWh
Heat for Electrode Baking:	Prebaked	2.3-5.5	MMBtu
	Soderberg	0.1-0.2	MMBtu
Heat for Holding, Casting, Melting		5.2-7.8	MMBtu
Labor: Prebaked		8-15	Man-Hours
Soderberg		10-20	Man-Hours

makeup of chlorine would be expected. Thus, the primary difference between the processes is the reduced electricity requirement.

Aluminum Demand

The potential impacts on OTEC generated by the aluminum industry will depend on two factors: the rate of addition of smelting capacity required to satisfy future demand for the metal and the economic feasibility of locating smelters in the vicinity of good OTEC operating sites. The growth of aluminum demand is investigated first.

Development of a commodity demand forecast is normally based on three complementary approaches: statistical projections of historical data, adjustment of the straightforward projections taking account of economic and technological trends, and finally, by using detailed models of the producing industry embedded in an appropriate economic scenario. Each approach requires significantly more information and analysis than its predecessor, but the historical data is the necessary point of departure.

The growth of primary aluminum demand in the United States since 1930 is shown by the points plotted in Figure V-3. After the anomolously rapid increase and subsequent fall-back during World War II, demand has grown at an average rate of 7.6 percent per year since 1948. The projections shown in the Figure for the period 1975-2000 are those developed by the Bureau of Mines based on general trend projections and detailed corrections appropriate to the six major aluminum consuming industries. These projections lead to a median domestic demand of 9.8 million tons per year in 1985 and 18.8 million in 2000, the latter figure falling within an estimated range of 13.8-24.1 million tons per year (Bureau of Mines, 1975). Annual growth rates of the three scenarios for the two time periods are shown in Table V-4.

TABLE V-4 - PRIMARY ALUMINUM DEMAND GROWTH RATES
(PERCENT PER YEAR)

Scenario	Period	
	1975-1985	1985-2000
Low	4.3	3.3
Probable	5.6	4.4
High	7.2	5.1

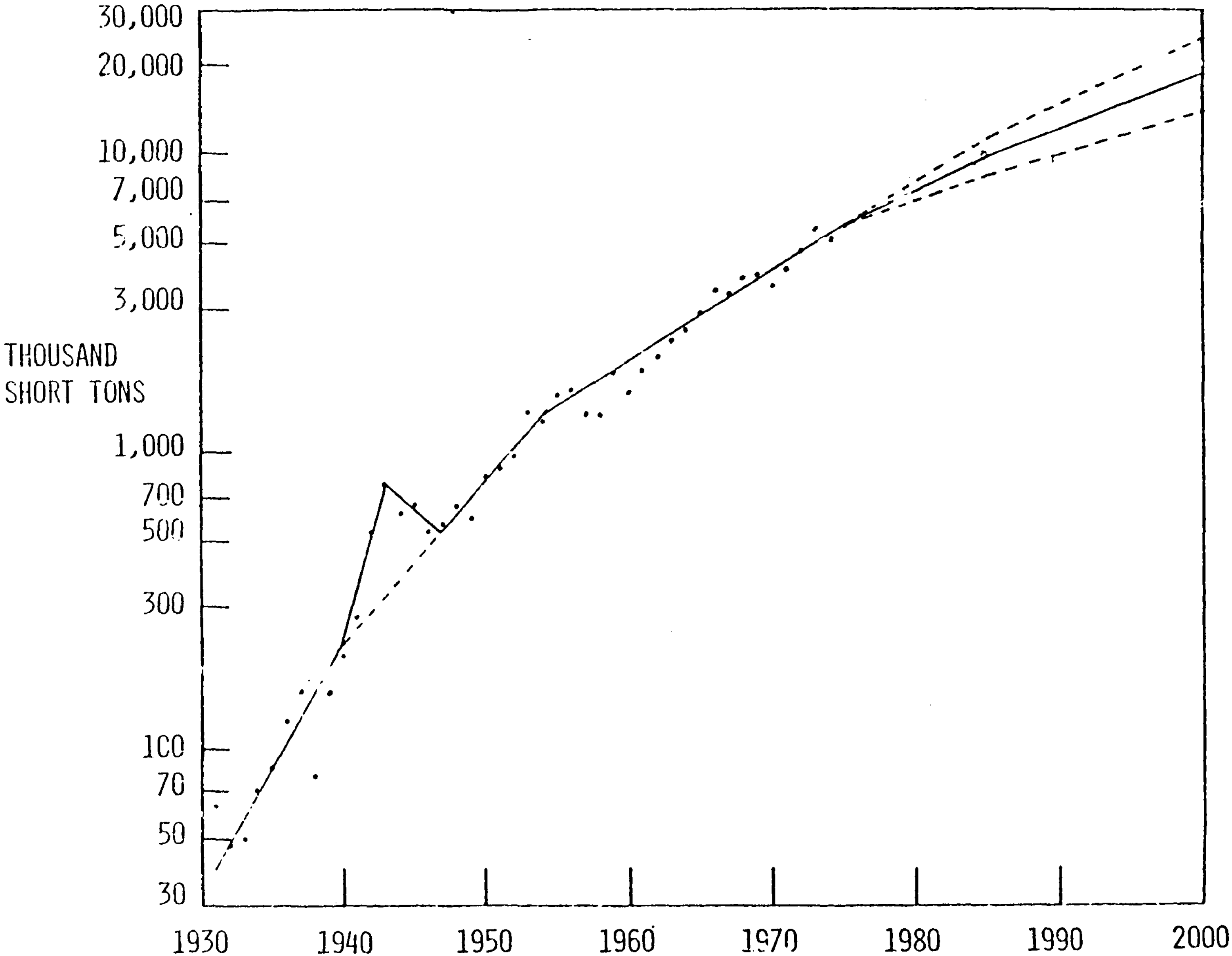


FIGURE V-3 - U.S. PRIMARY ALUMINUM DEMAND

Among the factors which might alter these projected growth rates are availability of bauxite reserves, structural changes in the market for aluminum, and the use of substitute materials.

As of 1975, world bauxite reserves stood at more than 3.8 billion short tons of recoverable aluminum content, distributed as shown in Table V-5 (8). If world demand for primary aluminum continued to grow at its 1964-1974 rate of 8.7 percent per year to the end of the century, cumulative production of 1.48 billion tons would be required, amounting to only 39 percent of 1975 proven reserves. At the same growth rate, those reserves would last past the year 2010. Considering the even larger, presently subeconomic resources or the possibilities of commercializing the use of other aluminous ores than bauxite, depletion of raw material seems not to offer a deterrent to growing use of the metal.

TABLE V-5 - WORLD BAUXITE RESERVES AND RESOURCES
(MILLION SHORT TONS RECOVERABLE ALUMINUM)

Region	Primary Country	Reserves	Resources
North America	Jamaica	280	430
South America	Brazil	780	1,460
Europe	Greece	300	450
Africa	Guinea	1,270	1,810
Asia	Indonesia	200	820
Oceania	Australia	1,010	1,340
TOTAL		3,840	6,310

The second factor for consideration is a structural change in aluminum markets. The six aluminum consuming industries, their demand shares over the 1964-1975 period, and their projected shares in the year 2000 are shown in Table V-6. Except for the doubling of its share by the container and packaging sector over the 1964-1975 period, the variations from one year to the next show no apparent trends (Bureau of Mines, 1975).

Since these consuming industries are large, diversified, and expected to grow in line with general economic growth, and since aluminum is not

TABLE V-6 - ALUMINUM MARKETS

Consuming Industry	Percentage Share 1964-1975	2000
Construction	21-30	21
Transportation	17-24	22
Electrical	13-15	15
Container and Packaging	9-18	17
Appliances and Equipment	9-12	9
Machinery	7-8	8
Other	6-12	8

confined to a single application in any of them (with the possible exception of its role as a conductor in the electrical industry), it follows that there are no significant changes foreseeable to account for diminution of demand. On the contrary, the growth rate of aluminum demand exceeds that of its using industries, indicating continuing penetration of aluminum as it is selected for new uses in those industries.

This raises the question of competition from other materials. Since aluminum is relatively new, its rapid growth reflects the fact that it has displaced traditional materials such as copper, steel, and wood in some applications, and is competitive with new materials such as plastics and composites in others. Should an increase in aluminum price substantially alter its competitive position relative to these materials, long-term adjustments would occur. The increasing pressure on all kinds of resources, however, is reflected by escalation in price of many materials relative to general inflation. Thus, there is little reason not to expect aluminum demand to continue to grow at a rate compatible with its past history but moderated by the general economic patterns expected in the near future.

Power Requirements For Smelting

The amount of new generating capacity that will be required to satisfy aluminum demand can be estimated by combining the growth rate scenarios of Table V-2. Two technology scenarios are evaluated. The first, identified as "Hall", assumes continuing improvement of the Hall process. The second, indentified as "Combined", assumes the first plus its substitution by the chloride process with a 20-year takeover period. Results are presented in Table V-7.

TABLE V-7 - CUMULATIVE, POST-1975 ADDITIONS TO GENERATING CAPACITY FOR PRIMARY SMELTING (GW)

Growth Scenario:	Low		Probable		High	
Technology Scenario:	Hall	Combined	Hall	Combined	Hall	Combined
Year						
1980	2.7	2.7	3.6	3.6	4.8	4.7
1985	6.0	5.9	8.3	8.1	11.3	11.0
1990	8.9	8.6	12.7	12.2	17.3	16.6
1995	12.2	11.4	18.1	16.8	24.7	22.9
2000	16.0	14.2	24.6	21.6	34.0	29.8

These figures indicate a very sizeable demand for new generating capacity during the next 25 years solely for aluminum production. On whatever schedule OTEC capacity becomes available, a significant market will exist in this application. The difference between the two technological options does not become significant until about the year 2000 when the chloride process, having displaced 75 percent of the Hall process, leads to a Combined scenario requiring about 12 percent less energy than the Hall scenario. This is much less significant than the 35 percent differences between the probable growth scenario and either the Low or High cases. In short, if new aluminum is to be produced by an electrolytic process in response to demand growing at even half the rate observed over the past 25 years, the new generating capacity needed for this purpose alone will provide an ample market for OTEC application.

Cost Scenarios

OTEC's role in providing electric power for primary smelting of aluminum is evaluated by comparing the production cost of a ton of aluminum as ingot under the following scenarios.

1. The smelter is located within the continental United States and derives its power from a conventional coal-fired, steam turbo-generator plant (12). As shown elsewhere, this is the lowest cost conventional system available to provide electricity

for new smelting capacity in the period 1985-2020; representative electric costs fall in the 33-48 mills/kWh range in year 2000 (expressed in 1976 dollars).

The alumina is imported as such; Bayer process refining of bauxite (or preparation of alumina from a different ore) is assumed to take place in the vicinity of the mine, and is not an electrically intensive process at any rate. Product aluminum is moved to fabrication plants located near their markets. It is characteristic of the industry that the smelter is sited to minimize the sum of power and shipping costs (19) these being the only inputs which are significantly dependent on location.

This conventionally powered, domestic smelter provides the baseline scenario with which other options are to be compared.

2. In option 2, the smelter is located along the Gulf Coast and derives its power from OTEC generators. The costs of OTEC electricity at a near coast location as a function of date vary as discussed elsewhere in this report.

   Whether a new smelter beginning operation around the year 2000 employs improved Hall cells requiring 6 kWh/lb, its nominal output of about 220,000 tons/yr at a 95 percent capacity factor is compatible with the net power output of a 210-320 MW OTEC. While this might call for a dedicated OTEC of appropriate size, the avoidance of unscheduled power interruption is a critical matter for an aluminum potline and requires the presence of an emergency backup system. In the case of a Gulf Coast location, the utility power grid, which would itself be partially OTEC-fed, should be capable of providing the backup needed to prevent the cells from freezing.

3. The next smelter option takes advantage of island locations having superior OTEC operating areas and located along normal alumina transport routes. Hawaii and Puerto Rico both satisfy these criteria. Both offer near-shore OTEC locations which would minimize cable lengths. Hawaii sits astride the presently

active shipping route for Australian alumina bound for Pacific northwest smelters. Puerto Rico is reasonably close to the present route from Surinam and Guyana and the future routes from Venezuela and Brazil, both of which are expected to increase their alumina production and export. For smelting in Puerto Rico, Jamaican alumina would be shipped some 600 miles eastward.

The effect of shipping cost differentials on the economics of Hawaiian or Puerto Rican smelters is not great as the following analysis demonstrates. Average shipping costs in cents per ton-mile show large variances depending on cargo type, route, demand, port, costs, backhaul cargo, and similar factors. Nonetheless, when average rates for bulk cargo (such as alumina) and liner cargo in large quantity (such as palletized aluminum ingot) are compared, the latter is found to be about twice the former (7, 19). Since approximately two weight units of alumina yield one unit of aluminum, the shipping cost over a given distance (eg. Australia - U.S. West Coast) is approximately the same regardless of where along the route the smelter is located.

Returning now to the island smelter options, observe that while alumina/aluminum shipping costs are not determinative, three other factors may be. The first of these is the possibility of special financing or tax incentives at particular locations. This is the case for Puerto Rico, as described in another section of this report. Such financing arrangements compensate to some extent for generally higher costs associated with engineering projects at island locations arising from increased shipping costs for parts and materials and a frequently inadequate industrial infrastructure.

The other two factors are the requirement for importing carbonaceous material (for electrodes in the Hall process or as a reductant in the chloride process) amounting to about 0.6 ton per ton of aluminum produced and the need for backup electric power in the event of an unscheduled interruption in OTEC output. The latter requirement may be difficult or expensive to provide at the island locations if the utility grid is unable to absorb the large additional load of the smelter on an emergency basis.

Although patently not an economically viable option because of the rapid escalation anticipated for fuel oil costs, the cost of smelting using conventional power sources (oil-fired steam turbogenerator) on the islands is computed for comparison with the OTEC values.

Production Costs

Production cost elements for aluminum smelting except for electric power are summarized in Table V-8; power costs for the various dates, locations, and alternative methods of generation are presented elsewhere. The smelter capital investment figure is based on 14 independent cost citations dated 1967 or later adjusted to their 1976 equivalent by the Marshall and Swift equipment cost index.

TABLE V-8 - ALUMINUM PRODUCTION COST ELEMENTS (1976 DOLLARS)

CAPITAL INVESTMENT		
Hall Smelter (200 MTPY)	1,520 $/An.Ton ± 9% (N = 14)	
Construction Cost Location Factors (US = 1.00)		
Hawaii	1.17	
Puerto Rico	1.07	
LABOR COST		
US, Hawaii		7.50 $/Man-Hour
Puerto Rico		3.35
RAW MATERIALS		
Alumina		65 - 90 $/Ton
Cryolite		350 - 500
Petroleum Coke, Pitch		70 - 100
Anthracite		15 - 25

The operating factors of Table V-3 are combined with the cost elements and electricity prices to estimate the production costs of aluminum ingot as shown in Table V-9 for the year 2000. The cost calculation procedure is briefly described. The fixed charge rate of 21.6 percent is based on financial factors characteristic of the aluminum industry at present: 20-year smelter economic life, 45 percent longterm debt at 8 percent interest, 55 percent income tax rate on earnings. The fixed charge amounts to about 50 percent of the ingot cost.

Variable charges over the smelter life are treated in the same manner as the variable cost items involved in electricity generation employing current costing methods (11, 12). It is assumed that all elements experience general inflation at an average rate of 6 percent per year over the smelter life, and that fuel materials and energy inputs escalate at the somewhat faster rates shown in the table. These rates are derived from projected

TABLE V-9 - PRODUCTION COST OF ALUMINUM (YEAR 2000)
(1976 DOLLAR PER TON INGOT)

Hall Smelter Investment		1,380 - 1,660 $/an. ton	
Industrial Fixed Charge Rate		21.6%	
Item	**Escalation Rate (%)**	**$/Ton**	**Percent**
Annual Fixed Cost	n.a.	298 - 357	22
Variable Costs			
Alumina	6	204 - 282	17
Cryolite	6	26 - 37	2
Petroleum Coke	7.3	53 - 76	4
Pitch	7.3	20 - 28	2
Anthracite	6.8	1 - 1	--
Electricity	*	429 - 624	36
Labor	6	98 - 183	10
Sales, G&A	6	83 - 123	7
	TOTAL	1,212 - 1,711	100

*33-48 mills/kWh; domestic coal-fired utility power;
13 MWh/ton aluminum required by year 2000 Hall smelter.

fuel price scenarios provided by ERDA for use in this analysis. The variable element cost streams are levelized over the plant life to obtain an average annual cost compensated for anticipated escalation and are then discounted back to the first year of commercial operation of the facility for comparison with other cash flows. This procedure is applied to all variable cost items. The cost range shown for electricity is calcualted by the same method using factors appropriate for utility power generation described elsewhere in this report. Results of the cost computation indicate that aluminum ingot from a new smelter beginning operations in 2000 is expected to cost $1,200-1,700 per ton in 1976 dollars, or from 20 to 70 percent more than at the present in real terms.

Having established the price of aluminum ingot under the baseline scenario (continental U.S., coal-fired utility power), the effects of the other locations (Puerto Rico, Hawaii) and electricity sources (OTEC, conventional coal- or oil-fired) can be examined. For simplicity, the mid-value of the cost range is tabulated; the uncertainty ranges under the assumption stated are comparable to that for the baseline case (approximately ±20 percent).

Results of the cost scenarios for 1990 and 2000 are summarized in Table V-10 and shown graphically in Figure V-4. It is apparent that by 1990, the favorable financial environment in Puerto Rico will permit aluminum smelting using OTEC electricity at essentially the same cost as in the U.S. using coal-fueled utility power. At the same date, the Hawaii/OTEC scenario is approximately equivalent to the Gulf Coast/OTEC case, the better efficiency of the OTEC in Hawaiian waters being offset by the higher investment cost of the smelter at that island location.

TABLE V-10 - ALUMINUM COST SCENARIOS MIDRANGE VALUES
(1976 DOLLARS PER TON INGOT)

		1990	2000
Continental US	– Coal	1,410	1,460
Gulf Coast	– OTEC	1,700	1,230
Hawaii	– Oil	2,040	2,340
	– OTEC	1,650	1,240
Puerto Rico	– Oil	1,960	2,260
	– OTEC	1,410	1,140

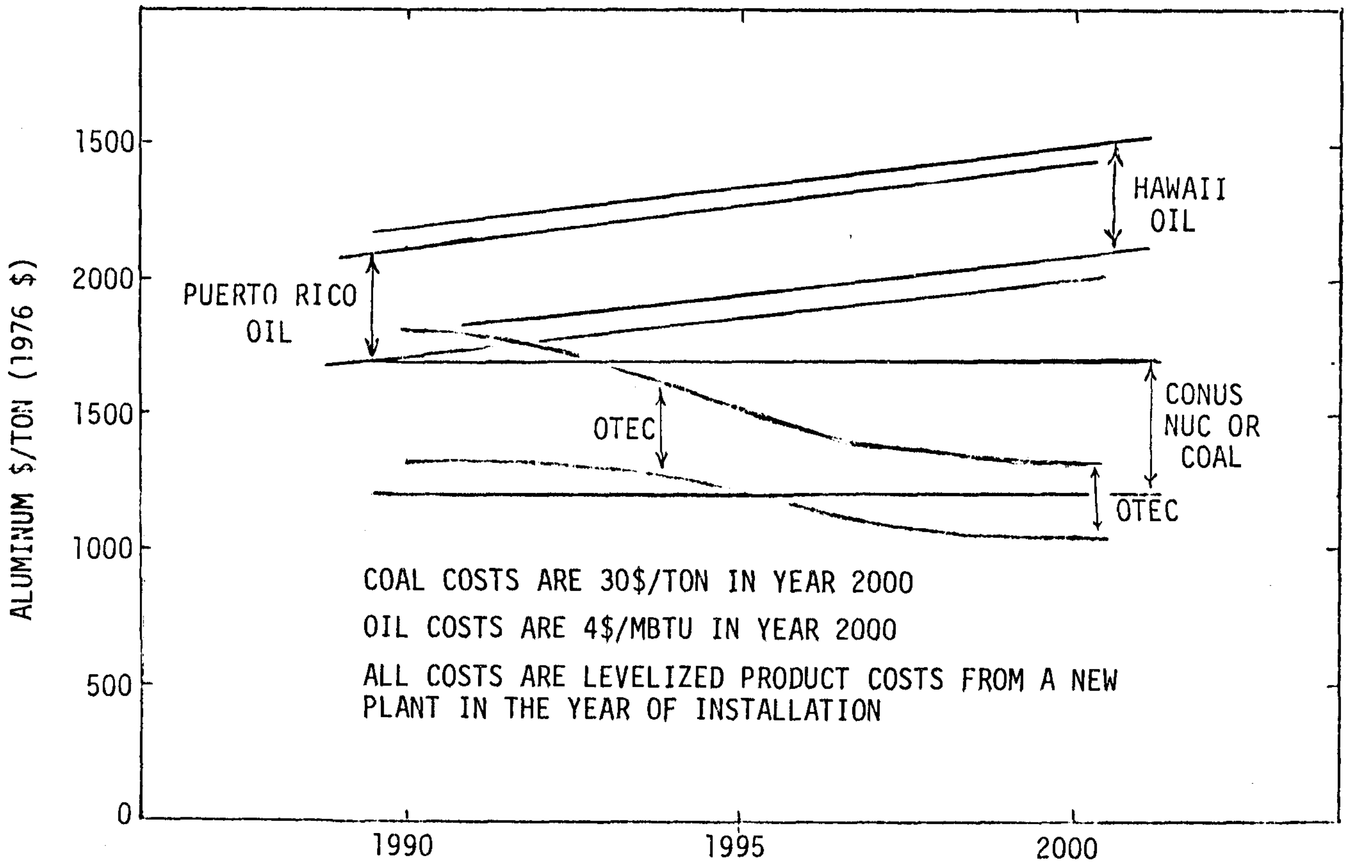


FIGURE V-4 - ALUMINUM PRODUCTION COST COMPARISON - OTEC VERSUS FUELS

By the year 2000, all three OTEC scenarios dominate fossil-fueled power at their respective locations, with Puerto Rico still being preferred but to a lesser extent than in the 1990 comparison. Projection of these trends to later dates would only amplify these effects as fossil-fueled power continues to rise in cost relative to OTEC power. Thus, both island and Gulf Coast locations would be preferred for new smelter construction.

Potential OTEC Penetration

Based on the projected demand for additions to generating capacity shown in Table V-7 a projection of the potential OTEC contribution to aluminum production was made on the assumption that; since OTEC costs will be in the competitive range with coal or nuclear powered aluminum plants from 1990, at least for the tropical sites, an eventual market capture of 50% of new additions would be possible. With that and an aggressive 15 year takeover time penetration projections were made which are shown in Figure V-5. As can be seen, by the year 2000 between 1.7 and 4.5 GW of OTEC capacity could be installed for supplying aluminum smelting power. This capacity represents between 3 and 9 OTEC powered aluminum smelters which presumably could be operated at sea, or on tropical Islands such as Puerto Rico or Hawaii. Beyond the year 2000 significant additions would be required.

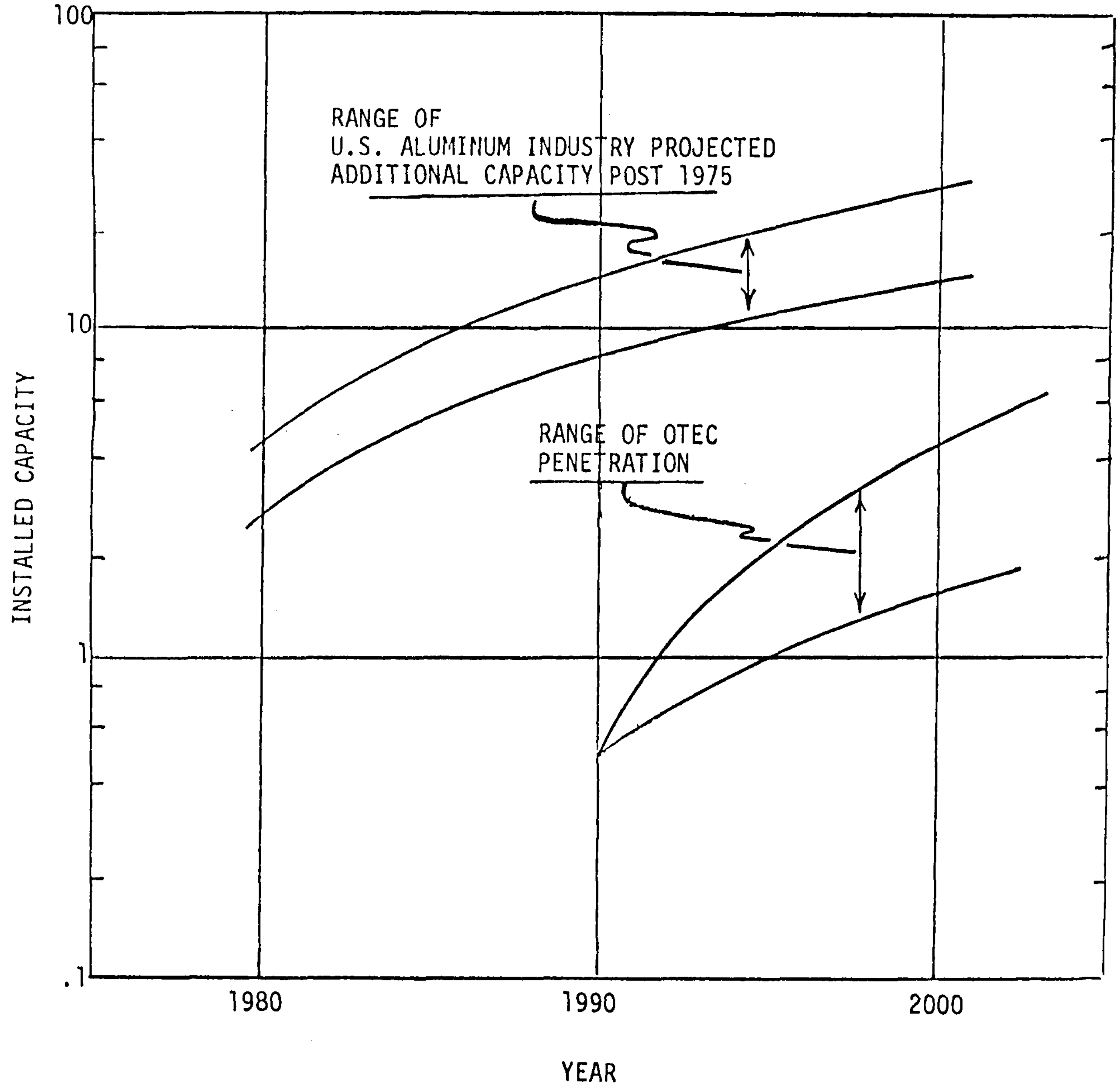


FIGURE V-5 - POTENTIAL OTEC PENETRATION INTO THE ALUMINUM MARKET

SECTION VI

ANCILLIARY PRODUCT OPTIONS

As part of the study it was required that two product options be examined to explore their potential. These product options were hydrogen used as an aircraft fuel and mariculture. This exploration of potential was to be a preliminary evaluation to determine whether they should be explored further.

As part of the study it was considered that one possible application of OTEC plants would be to produce hydrogen with off peak power, to serve as a specialty market. One of the needs of the future is a good fuel to replace fossil fuels as they become less available and, it is necessary to develop technology for the substitute fuels. A primary future fuel is hydrogen which has been considered for use in many applications. The OTEC system could produce hydrogen as a fuel and its use be explored by operating commercial aircraft on it to develop the technology. For the purpose of this investigation it was determined to explore the question of the marginal increase in cost of the airline ticket over the use of fossil fuels to the typical airline operating over long distances on a specific route. For this type of operation it was assumed that the operation would not have to be competitive because the air carrier rates are regulated and the airlines operating the hydrogen fueled route would be permitted to charge higher rates.

Mariculture was to be examined to determine whether a mariculture operation in conjunction with a moored OTEC plant and using OTEC cool water effluent would be capable of producing an income that could be used in reducing the cost of electricity produced by the plant.

These two applications were examined, and it was found that the hydrogen produced cost increases per passenger do not appear to be excessive and, that mariculture operated in conjunction with an OTEC plant will produce an income greater than the additional cost of the mariculture plant and reduce the net cost of OTEC power.

The following discussion describes in more detail the results of the analysis of these two product options.

HYDROGEN AS AN AIRCRAFT FUEL

To evaluate this product option the research that has already been done under NASA sponsorship was depended upon heavily (26, 28, 29, 31) as well as the work done by IGT in their subcontract (Appendix A).

For this analysis it was assumed that hydrogen would only be used on large airbus type of aircraft on long haul routes comparable to transocean or transcontinental routes.

A list of the potential airports at which hydrogen could be used is given below. (27)

TABLE VI-1

Candidate Airports for Hydrogen Fuel

Los Angeles (LAX)
San Francisco (SFO)
Honolulu (HNL)
Washington-Dulles (IAD)
Miami (MIA)
New York-Kennedy (JFK)
Dallas/Fort Worth (DFW)
Atlanta (ATL)
Chicago (ORD)

As can be seen many of these airports are coastal cities, some of them are inland and only two, Miami and Honolulu are in the tropical or subtropical latitudes where OTEC operations are considered feasable.

As a result of this situation the potential alternative means of transporting OTEC produced hydrogen were examined and the cost factors associated with the production, delivery and use of liquid hydrogen as an aircraft fuel as a means of selecting a representative route for use.

Figure VI-1 indicates three candidate liquid hydrogen production and delivery options that would be appropriate for the different airport locations. The top option would be suitable for an airport in the tropical regions near an OTEC site. OTEC power could be delivered to shore to plant producing hydrogen and liquefying it to be delivered to the nearby airport by pipeline. The important factor in this configuration is that the entire process can be OTEC powered from the same site.

The center option represents that which would appear most suitable for an inland airport remote from the OTEC site in this case the hydrogen would best be produced on board the OTEC plant ship and delivered as a gas via pipeline to the using airport where it would be liquified, and stored for use. The transmission of the hydrogen as a gas would minimize high transmission losses associated with pipeline transmission of liquid hydrogen. The remote location of the inland airport may require that non OTEC power be used for the liquification at the airport.

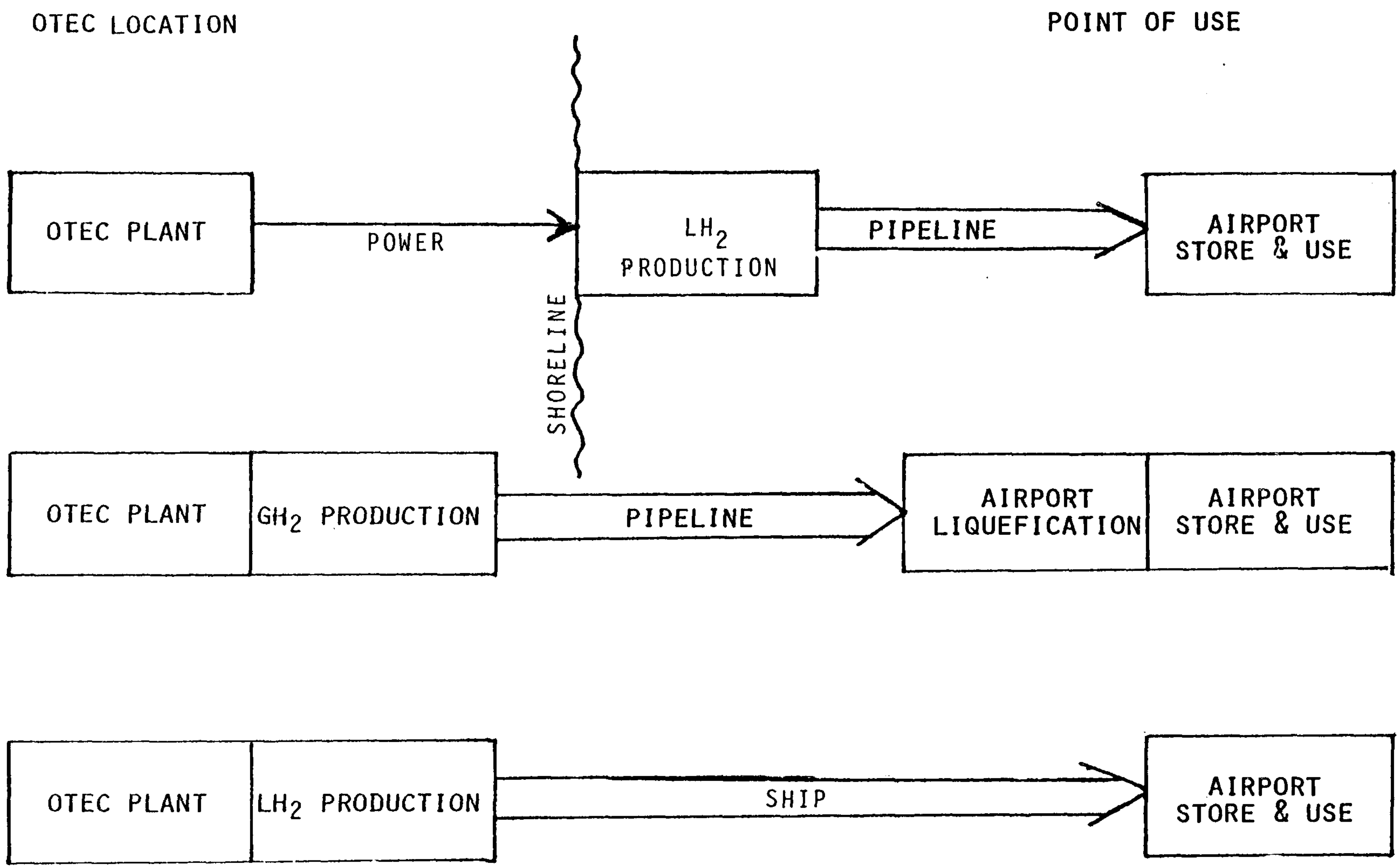
The bottom option would be appropriate for liquid hydrogen delivered to a coastal non tropical airport from an OTEC site. Liquid hydrogen would be manufactured on board an OTEC factory ship and delivered by ship to the coastal airport. Again, like the first option this operation could be essentially completely OTEC powered from the same site. Only the power for pumping the liquid hydrogen from airport storage into the aircraft would have to be locally provided.

As a result of considering these options and the OTEC sites that we have examined the following scenario was used for estimating the increase in direct operating costs as compared with conventional Jetfuel.

It was assumed that some OTEC plants operating offshore from Oahu, Hawaii would produce power to be delivered to shore by cable primarily for use in the grid. During off peak hours, a hydrogen production and liquification plant at the Honolulu airport would use OTEC power and in addition, an on board hydrogen and liquification plant would produce liquid hydrogen to be delivered by ship to the Los Angeles airport.

To determine demand for hydrogen on this route and see if such operation would be compatable with the suggested scenario data was taken from a NASA

FIGURE VI-1 - LIQUID HYDROGEN PRODUCTION AND DELIVERY OPTIONS



study (27) and compared with expected hydrogen production from an OTEC plant. This reference did not have information on the Los Angeles/ Honolulu route but it did have information on the San Francisco to Honolulu route which we have assumed is close enough to give the right order of magnitude.

They project 2953 flights per year from San Francisco to Honolulu with the requirement for annual fuel loading of 33,959 tons per year and an estimated 5% loss associated with the operations resulting in a net requirement for 35,656 tons per year. A similar quantity would be required at the Honolulu airport. IGT estimates for 100 Megawatt OTEC hydrogen factory plants in Hawaiian waters indicates that they would be expected to produce only 12,310 tons of liquid hydrogen annually and presumably the new Lockheed configuration (280 megawatts) would produce slightly more than 30,000 tons. As can be seen, the demand would far exceed the production of a single OTEC unit and it might be desirable to assume dedicated OTEC plants rather than several plants producing hydrogen with off peak power. The load factor on the hydrogen plants would be better and costs would improve.

To estimate the increase in direct operating costs to the airline of using OTEC produced hydrogen the costs of liquid hydrogen produced on shore with OTEC power parameterized at 20, 30, and 40 mills per kilowatt hour were determined and the costs of liquid hydrogen delivered in Los Angeles was taken from the IGT study (Appendix A). These values were averaged to get an average cost of liquid hydrogen. This data is shown in Table VI-2 below.

TABLE VI-2

Costs of Liquid Hydrogen Delivered to Airport
in Dollars per Million BTU as a Function of Power Cost

POWER COST	LOCATION		
	HONOLULU	LOS ANGELES	AVERAGE
20 m/kwh	\$10.80-\$11.80	\$26.93-\$30.68	\$18.86-21.24
30 m/kwh	\$15.30-\$16.30	\$31.66-\$35.40	\$23.48-25.85
40 m/kwh	\$19.90-\$20.70	\$36.38-\$40.43	\$28.14-30.565

To convert this to increases in operating costs for the airlines the comparative aircraft operating cost characteristics developed by Lockheed were used. (26) Figure VI-2 and VI-3 respectively show the additional cost per passenger for a one way trip from Honolulu to Los Angeles and for a round trip where the Los Angeles to Honolulu leg is fueled by OTEC produced hydrogen. The marked increase in costs of the round trip is primarily the result of the high cost of shipment of liquid hydrogen.

If such flights are to be run it might be cheaper to produce the hydrogen for the return flight in Los Angeles. IGT in their evaluation of competitive sources of hydrogen (see Appendix A) estimated that liquid hydrogen produced from coal in the year 2000 would cost from $7.85 to $8.55 per million BTU which is comparable to the costs of OTEC produced hydrogen in Hawaii.

Since this work was completed, analysis by the Applied Physics Laboratory, Johns Hopkins University of a site off the coast of Mexico indicates very low costs for hydrogen produced on a factory ship and delivered to Los Angeles.* This more recent information indicates that this mission should be reassessed. As with the aluminum and ammonia missions, the early competitiveness of OTEC produced hydrogen will be dependent on the relationship between production areas and distance to points of use.

* Private communication - Dr. G. Dugger, APL, Johns Hopkins University.

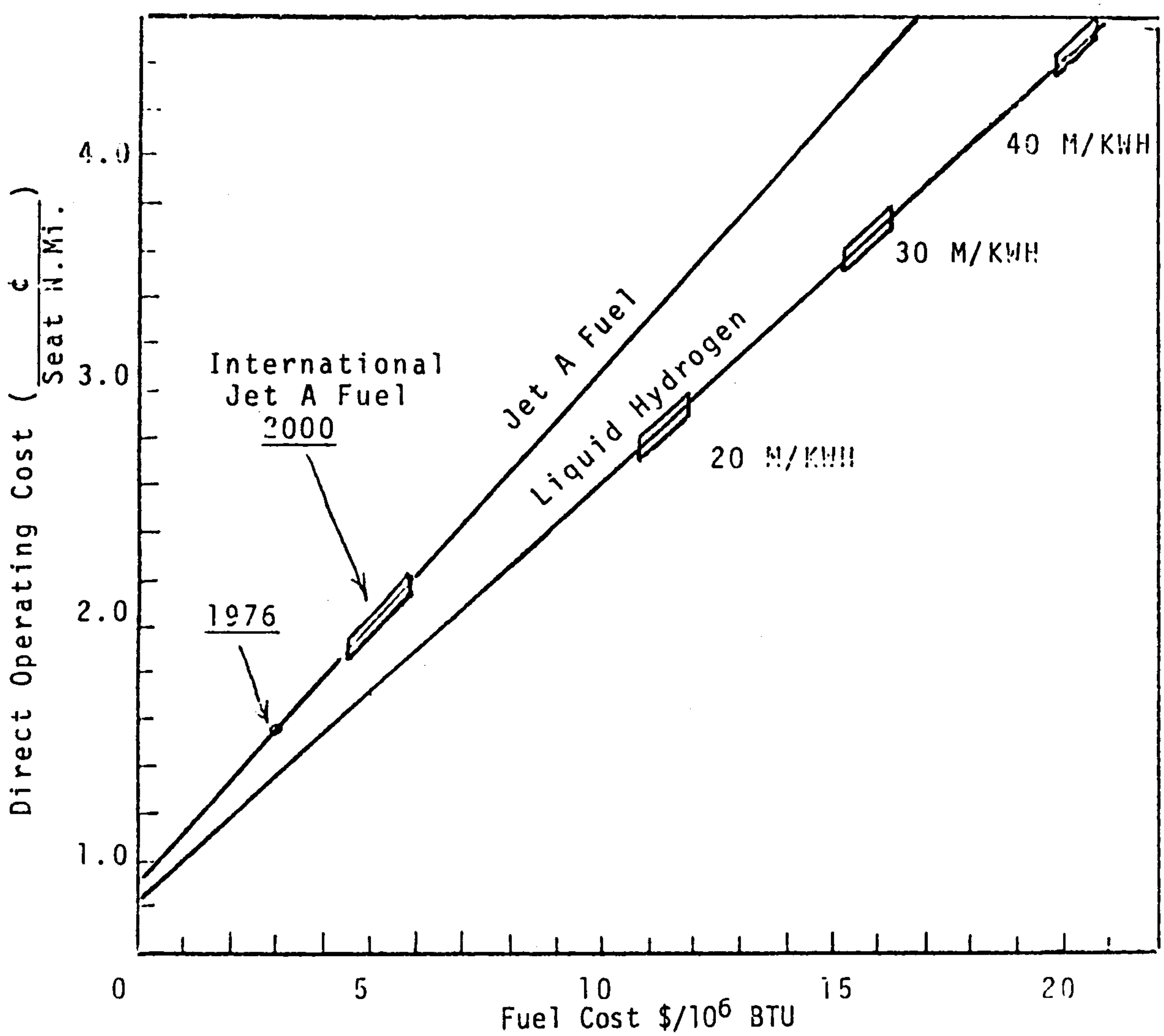


FIGURE VI-2 - INCREASE IN DIRECT OPERATING COSTS OVER JET A FUEL - HONOLULU TO LOS ANGELES

OTEC POWER COST	¢/SEAT MILE	$/2,500 MILE
20 M/KWH	.60 - 1.05	$ 15.00-$ 26.28
30 M/KWH	1.35 - 1.85	33.75- 46.25
40 M/KWH	2.20 - 2.70	55.00 67.50

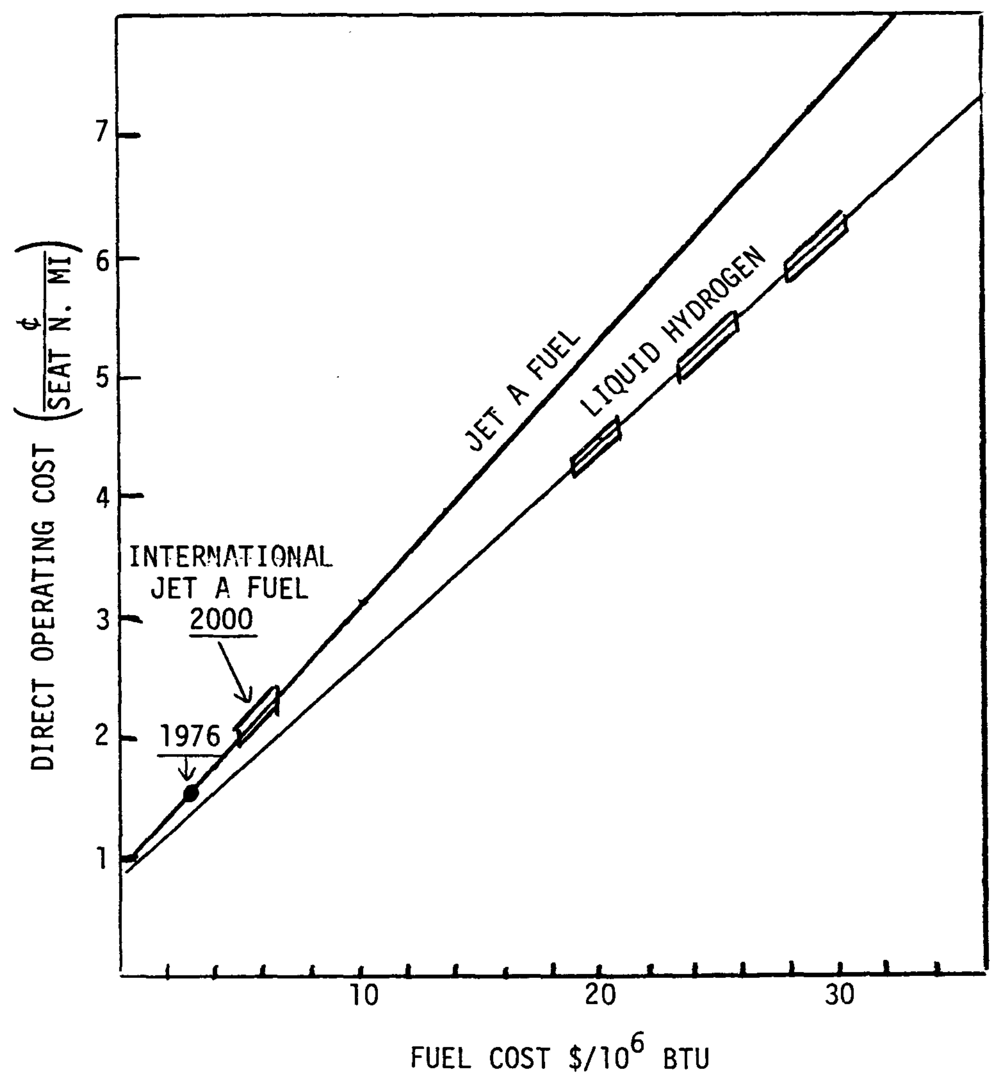


FIGURE VI-3 - INCREASE IN DIRECT OPERATING COSTS OVER JET A FUEL - ROUNDTRIP HONOLULU TO LOS ANGELES

OTEC POWER COST	¢/SEAT MILE	$/5000 MILE
20m/kwh	2.0-2.6	100.00-130.00
30m/kwh	2.9-3.5	145.00-175.00
40m/kwh	3.7-4.3	185.00-215.00

MARICULTURE AS AN ADJUNCT TO OTEC SYSTEMS

Because the cold deep water used in the OTEC condensers is the same nutrient rich water that has been used in mariculture experiments, it appeared possible that a mariculture plant using some of the OTEC discharge could produce high value shellfish which can be used to reduce the total cost of power produced by an OTEC unit.

Initial evaluation (32) of the mariculture potential of using all of the cold water discharge of a single OTEC plant (100 megawatt) indicated that the production potential could exceed the normal annual consumption of clams and oysters in the United States by a factor seven. This suggests that it would not be desirable to use the full discharge because the market could not accept the production.

In addition, initial studies of the effect of cool water recirculation into the warm water intakes indicates that even a small recirculation of cool water would produce significant reductions in the power output of an OTEC plant.

As a result of these two concerns it was decided to consider three alternatives:

1. Examine the feasibility of locating mariculture plants onshore in U.S. teritory to be powered by some of the small prototype oceanthermal units which will be developed in the OTEC R and D program to develop the technology. In this case the prototype units would serve as dedicated power plants for the mariculture plant pumping the nutrient rich deep water and producing power for the rest of the needs of growing and processing shellfish.

2. Examine the marginal cost and possible revenue resulting from the use of a small percentage (approximately 1%) of the cool water discharge in an adjacent shelfish mariculture plant.

3. Examine the feasability of using an OTEC plant in conjunction with a kelp mariculture plant because the kelp mariculture requires larger quantities of cold deep water and considerably more power than a shelfish mariculture operation. In addition the kelp farm structure would tend to contain the deep water and reduce the possibility of recirculation.

OTEC POWERED ONSHORE SHELLFISH MARICULTURE PLANTS

To determine whether it was feasable to have a small prototype OTEC powered shellfish plant on shore it was assumed that the cold water requirement could be met by a 1 to 5 megawatt prototype plant and that the Ocean Thermal conversion plant the plankton ponds and the shellfish ponds would be constructed and operated adjacent to the coast. To permit the operation without excessive pumping losses it was assumed that access to deep water (2000 feet or more) would have to be within five miles of the beach.

It was also assumed that at least the initial markets would be in the continental United States and that the production facilities should be in the continental United States or on possessions or territories of the United States.

It was found that only one area in the continental United States was marginally acceptable and that was off the coast of Florida. However, there were several suitable areas on U. S. states, territories or possessions in the Carribean and the Pacific. Table VI-3 indicates the names, locations and the depth and temperature characteristics of these locations.

The distance of such locations from large markets suggests that the shellfish produced would have to be shipped by air but with such high value products as oysters and clams it should be possible for reasonable distances. In addition, the wide dispersion of the suitable sites in the Pacific suggests that other markets than the continental U.S. could be served. Markets in Japan, the Phillippines, and Australia, where shellfish are more heavily consumed than in the United States, could develop into an export market.

In view of the locations shown it would be presumed that the Carribean locations could serve the Eastern U.S. markets, the Hawaiian location could serve the western U.S. markets and the remainder of the Pacific island locations could serve markets in the orient. To determine the ultimate feasiblity a detailed design analysis and market analysis would be required. However, based on this preliminary site survey a large number of sites would appear to be suitable.

TABLE VI-3

POTENTIAL MARICULTURE LOCATIONS

SITE	LAT./LONG. (APPROX.)	TEMPERATURE OCEAN SURFACE FEB./AUG. °F	DEPTH FEET*
CARIBBEAN AREA			
SE Florida	25°45' N/80°00' W	70-75/82.5+	750
Puerto Rico	18°00' N/67°00' W	77.5-80/80+	greater than 6000
Virgin Islands	18°00' N/64°45' W	77.5-80/80+	3000-9000
PACIFIC REGION			
Okinawa (Kume-shima)	26°20' N/126°45' E	65-70/82.5	greater than 6000
Enewetok	11°30' N/162°15' E	80-82.5/82.5+	"
Saipan/Tinian	15°00' N/145°35' E	"	"
Bikini	11°30' N/165°30' E	"	"
Jaluit	6°00' N/169°30' E	"	"
Palau Islands	7°20' N/134°35' E	"	"
Kwajalein	9°00' N/167°00' E	"	"
Truk Islands	7°15' N/151°45' E	"	"
Yap	9°30' N/138°10' E	"	"
Senyavin	6°50' N/158°15' E	"	"
Majuro/Arno	7°07' N/171°30' E	"	"
Guam	13°25' N/144°40' E	"	"
Canton Islands	2°50' S/171°40' W	82.5/82.5+	"
Enderbury Is.	3°08' S/171°05' W	"	"
Manau Islands (Tau/Ofu/Olosega)	14°10' S/169°30' W	82.5/80-82.5	"
Tutuila Islands (Am. Samoa)	14°20' S/170°40' W	"	"
Sand/Rose Is. (Samoa)	14°33' S/168°10' W	"	"
Hawaiian Is.	20°00' N/158°00' W	70-75/75-80	"

* Approximate depth five miles offshore

OFFSHORE MARICULTURE AS AN ADJUNCT TO OTEC

The feasability of combining mariculture with OTEC as a means of reducing the overall cost of electricity from OTEC by producing shellfish as a byproduct and offsetting the costs of power generation with byproduct sales.

To accomplish this the return from the sales of shellfish would have to be greater than the additional cost of structures and operating and maintainance costs of the mariculture systems.

Several factors had to be considered in estimating the size and cost of a mariculture unit.

First: The cold water discharge that would be used in the mariculture plant would have to be contained in some way for two reasons; the cool water if simply discharged into the ocean in the shellfish culture structures would descend below the depths at which phytoplankton grow before a sufficient population of phytoplankton would have developed for suitable shellfish growth and, because recirculation of the cool deep water into the OTEC warm water intakes has an extremely deleterious effect on the power output of the plant, any cool water discharged at the surface should be discharged as far away and in as small a quantity as possible.

Second: The production potential of the full cold water discharge from a single plant was estimated at 4×10^8 kgm of clam meat per year which is several times greater than the annual U.S. consumption. As suggested by Roels it makes more sense to use a portion of the discharge to satisfy a reasonable fraction of the demand.

To estimate the costs of an offshore mariculture plant it was assumed that an installation using about 1% of cold water assumed by Roels (32) would minimize the potential recirculation problems and still provide large enough production to realize economics of scale. The mariculture plant was assumed to be a roughly circular structure using anchored spar bouys as structural members with the plastic curtain and containment structures based on techniques developed for use in oil spill containment etc. Position and shape were assumed to be maintained by multiple point mooring and the shellfish ponds were located in the center of the structure with the shellfish growing in baskets by the techniques developed by Roels.

The nutrient cold water was assumed to be transported to the phytoplankton tanks via a large plastic pipe of the same material as the containment ponds. Pumping power was assumed to be provided by OTEC as part of the cold water pumping requirement.

The physical location of the mariculture plant was assumed to be a sizeable distance from the OTEC plant, of the order of one half mile, to reduce the chance of recirculation to a negligable value.

The assumptions imply that both the OTEC plant and the mariculture plant are fixed in position and orientation relative to each other. This means that neither unit can be moored on a single point mooring and that directional stabilization is necessary to prevent the nutrient delivery pipe from being fouled.

To give a feeling for the type of structure that this concept would produce figures VI-4 and VI-5 are sketches of the structure. Appendix C presents a description of the engineering data and analysis which was used to estimate the marginal costs of the mariculture plant.

The conceptual configuration described above was used to estimate materials requirements and components and to make a rough order of magnitude cost estimate.

Table VI-4 indicates the component costs in 1976 dollars estimated for the mariculture plant. These estimates were assumed to be only for use in determining whether the marginal return would exceed the marginal cost.

To estimate the marginal return it was assumed that the sale price of shellfish in 1975 would be representative of the sale price to be received for shellfish at the time that the mariculture plants could be deployed. This assumes that the price of shellfish increases at the same rate as inflation.

The approximate yield of the mariculture plant described above would be 8.5 million pound wet meat weight per year which is of the order of oyster imports per year. The 1975 sale price of shellfish average approximately $1 per pound of meat exvessel. If the mariculture plant is amortized at the same .15 fixed charge rate as the OTEC plant the annual marginal cost of the mariculture plant would be $3.75 million with an annual return of $4.75 million.

FIGURE VI-4 - CONCEPT - OTEC MARICULTURE FARM

DISCHARGE UTILIZATION, 1%   VIEW FROM ABOVE

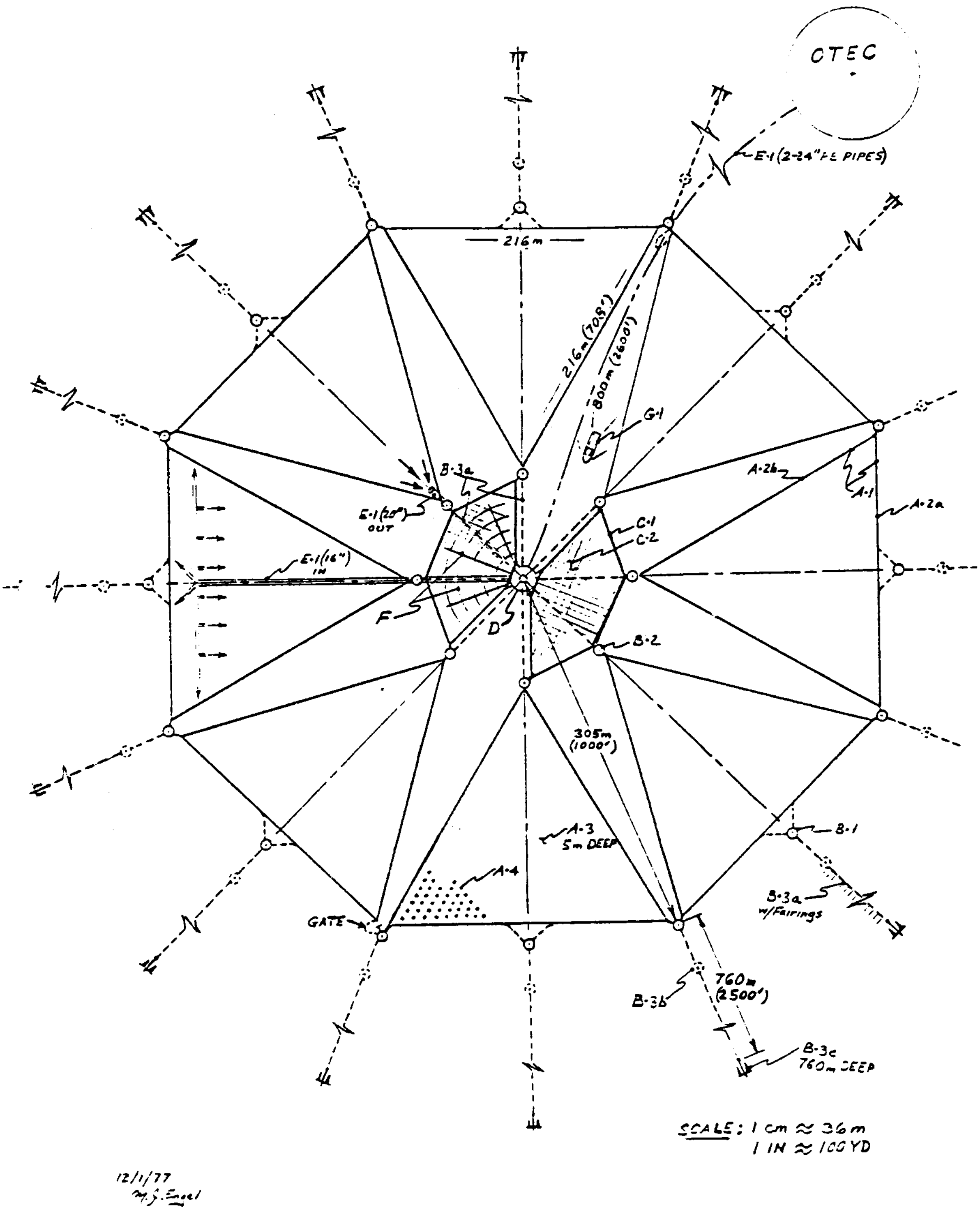


FIGURE VI-5 - CONCEPT - OTEC MARICULTURE FARM

CROSS-SECTION VIEW
W/FLOW SCHEMATIC

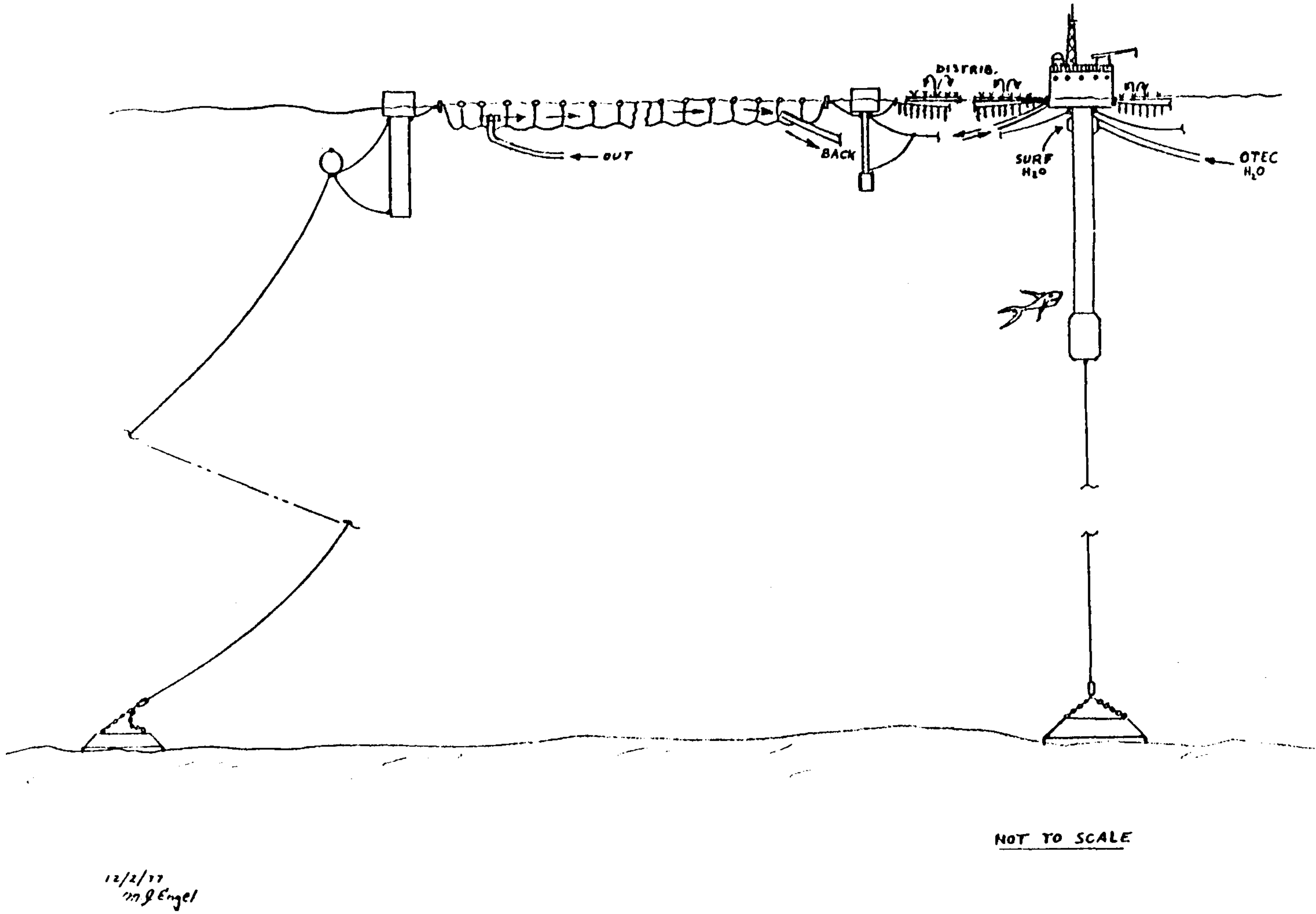


TABLE VI-4

MARICULTURE PLANT COSTS

Materials	$ 1.70 million
Support Structure Buoys Tension members Mooring	7.70 million
Shellfish Growth Grid	.37 million
Central Structural and Central Bowy	1.00 million
Water feed system	.45 million
Phytoplankton pond nutrient distribution system	.80 million
Support Equipment Tenders Communications Maintenance Equipment	1.20 million
Construction Engineering and Management	5.60 million
Contingencies	4.70 million
Capitalized O&M	1.50 million
Total	25.00 million

This return could then be applied to reducing the cost of electricity produced. The magnitude of the cost reduction will depend on the size and performance characteristics of the OTEC plant assumed but for a 250 megawatt plant with a capacity factor of approximately .9 and a seasonal degradation factor of approximately .9. (Which are representative of tropical operation) The $4.75 million, if plowed back into the operation of the power generation plant would permit a reduction of costs of 2.7 mills per kilowatt hour which at such locations would be close to a 15% reduction in cost.

At this rate it would seem worth exploring further to get a better conceptual design, a more accurate estimate of costs and if possible a better estimate of both national and export markets.

OTEC OPERATION IN CONJUCTION WITH KELP MARICULTURE

The third mariculture alternative considered was the possible use of OTEC plants to provide power and the nutrient deep ocean water needed to operate a Kelp Biomass Energy farm.

Again a survey was made to determine the requirements for nutrient water and power in a Kelp-Biomass energy farm.

The 100,000 acre Kelp farm was assumed to be representative of the OTEC load. This farm normally requires power for two purposes; (1) pumping power to raise the deep nutrient rich water to the surface and distribute it to the kelp and (2) propulsion power to maintain the tension required to maintain spacing of structured elements and to counteract the effect of current drift in high winds or high current locations.

Use of OTEC Electricity for Ocean Farming and Mariculture

OTEC-produced electricity might be used to supply some of the energy needs of an ocean farm (with or without mariculture), either to reduce the cost of the farm's output of fuel or to make more fuel available to be marketed. The Sciences Corporation (33) are for the harvesting vessel, for positioning the cultivation substrates, and for forcing upwelling of cold water. Only the latter two are candidates for using OTEC electricity.

In the detailed analysis, OTEC-supplied cold water was found to be inadequate, by a factor of five, to supply the needs of a 100,000-acre (40,500 ha) kelp farm. Could OTEC electricity power pumps proposed to produce enough upwelling for 100,000 acres? The answer is not clear, because ocean-farm energy estimates are in a preliminary stage. The estimates which are available produce substantially different implications with regard to OTEC electrical load, as can be seen in Table VI-5.

TABLE VI-5

Forced Upwelling: Ocean-Farm Power and Energy Requirements for 500,000 Acre-Feet (6.2×10^8 m^3) Per Day of Cold Water.

Basis	Horsepower	MW	GWH/year
One-foot lift, no losses	29,300	22	192
Lockheed OTEC Study (LMSC, 1975)	75,000	56	491
Integrated Sciences Corp. (Budhraja, et al, 1976)	79,000	59	516
One hp/AF/day (Wilcox & Leese, 1976, p 87)	500,000	373	3,260

A lower bound on the amount of electricity required to force upwelling is formulated on the basis of a statement by Wilcox (34): the total gravity head against which water from a depth of 500 or 1000 feet (150 to 300 m) must be lifted is less than one foot (0.3 m). The same reference states that the pumping power requirement is probably less than five horsepower per acre (0.4 ha) of farm. In another paper (35) Wilcox states that pumping power per acre-foot (1 234 m^3) will probably be less than one horsepower per day. Wilcox and Leese (36) assume the cold-water requirement to be five acre-feet per acre (2 500 m^3/ha) per day, and postulate a 1-foot lift for the distribution head and a friction factor which adds 0.36 feet of head.

From the above, the lower bound of pumping power per acre is that required to lift a weight-equivalent of five acre-feet (6 170 m^3) of water at a rate of one foot (0.3 m) per day. For a 100,000 acre farm, the required power is 29,300 hp (22 MW), shown on the first line of Table VI-5.

Lockheed's OTEC study of cold-water pumping (37) indicates 0.15 hp/acre foot/day is the power needed; 500,000 acre foot/day x 0.15 hp/AF/day gives 75,000 hp (56 MW), shown on the second line of Table VI-5. The LMSC design concept utilizes 2250-hp motors connected through gear boxes to high-efficiency bell-type pumps; an inlet bellmouth, antiswirl guide vanes, and other features to improve efficiency are incorporated.

Volume I of the ISC reports (33) shows that 0.2 trillion BTU (59 gigawatt hours) per year of "environmental energy" will be utilized to produce upwelling. Because this amount of energy is considerably less than is required simply to lift 500,000 AF/day against a head of one foot, further explanation was sought. ISC provided an excerpt from Volume II of their reports, and Mr. Budhraja* explained that 0.2 trillion BTU is not the total energy required. The computations in Volume II show the ISC estimate of total power to be 79,000 hp (59 MW); annual total energy required is then 1.8 trillion BTU (516 GWH). The ISC estimate is not based on engineering studies as extensive as those carried out by LMSC, and appears to be somewhat optimistic. It is unlikely that wave-actuated pumps will be as efficient in design as the pumps described in the LMSC study; and the 5000 cold-water suction pipes needed for the ocean farm can hardly be as efficient as the single cold-water pipe for the LMSC OTEC.

The estimate of Wilcox and Leese (36) that "less than one horse-power per acre-foot of water per day" will be needed is a basis for estimating an upper bound on pumping power: for 100,000 acres at 5 AF/acre/day, pumping power is 500,000 HP (373 MW).

The ISC analysis concludes that the total cost of pumping units for 5,009 buoys will be &25 million.** As noted earlier, this array of buoys with pumps would require 59 MW of power. The capital cost is, therefore, $425/KW. No fuel is required for either system. Assuming operation and maintenance costs

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* Personal communication, November 1976.

** Personal communication with Mr. R. Schneider and Mr. V. Budhraja, November 1976.

are essentially equivalent, the capital cost target for OTEC to be competitive would be \$425/KW for OTEC and the 5,000 16-hp electrically-driven pumping units.

If the pumping power required is 373 MW as shown in Table VI-5, no cost figures for wave-actuated pumps are available and a comparison such as given above cannot be made. However, the economics can be appraised by considering the total energy output (SNG) postulated for the ocean farm: 22 trillion Btu or 6,400 GWH per year. Pumping at a 373 MW rate would require 3,300 GWH/year - about half the total energy output of the farm (also, slightly more than the projected total annual energy production of the UMass OTEC at 400 MW_e and 0.9 capacity factor). Very roughly, the cost of SNG output might then be expected to double, making it noncompetitive. For the ocean farm to be economically viable if pumping power of the order of hundreds of MW is needed, wind- or wave-actuated pumps should be devised, if possible, to supply this large amount of power at acceptable cost. Energy to force upwelling then will not subtract from the farm's energy output.

The remaining question is whether OTEC electricity might supplement wave or wind energy, to produce upwelling when extended periods of calm weather might endanger the kelp crop. On an energy basis, this could not appear to represent a substantial OTEC load; perhaps the 0.2 trillion Btu/year energy requirement noted in the ISC report, mentioned earlier. However, the power requirement would again be subject to the uncertainty given in Table VI-5; if only 60 MW is needed, using OTEC back-up might be sensible. If 373 MW is needed, all other OTEC missions would have to be aborted or suspended in the face of such a peak-power requirement.

At this point, the economics of using OTEC electricity to replace or to supplement wave- or wind-actuated ocean farm pumps are not attractive and ocean farming as an adjunct mission to OTEC cannot be given a high priority. After such ocean farm pumps have been built and tested, and their cost and energy requirements are better known, the economic attractiveness of combining OTEC with ocean farming deserves reexamination - particularly if cold water pumped by OTEC might also be used as part of the ocean farm supply.

Positioning the Ocean Farm. The substrates of the ocean farm are to be positioned by use of diesel engines of about 2.3 hp/acre (1 hp/ha) capacity, driving propellers. The ISC report (33) estimates

1.0 trillion Btu (293 GWH) per year will be required. This is an average power of about 0.45 hp/acre (012 h;/ha), a requirement derived by ISC from considering ocean-current speed distribution as a function of time. Thus, the average power of 0.45 hp/acre corresponds to a speed of about 0.3 knots (0.6 km/hour), and the peak capability of 2.3 hp/acre to a speed of about 1.0 knots (1.9 km/hr), even through the drag increases as the square of speed (which would suggest the required 1-knot propulsor capability is 4.9 hp/acre).

The average power for station-keeping, based on 0.45 hp/acre and assuming 0.7 efficiency, is about 50 MW. The peak power, based on 2.3 hp/acre is about 250 MW. As in the case of the upwelling pumps, propulsors are located in each of the 5,009 buoys at substrate corners. Also, as in the case of the upwelling pumping power requirement, the average power for station-keeping is perhaps an amount of OTEC electricity that would be feasible to supply; but the 250 MW peak power requirement would presumably be severly disruptive of other OTEC missions.

No information was obtained on the estimated cost of the positioning system, hence cost target for OTEC to be competitive cannot be stated.

To date, all field experiments with ocean-farming have been in natural (coastal) habitats or with moored substrates. A problem which may not have received enough attention in analyzing the 100,000-acre ocean farm concept is that of controlling the direction and thrust of 5,009 propulsors distributed throughout a 156-square mile (400 km^2) area. Designing and implementing such a control system, capable of maintaining the requisite tension on all substrate lines without breaking or entangling them, would be an extremely complex and expensive undertaking.

OTEC plants would appear to be compatable with the large kelp biomass farms as a source of power rather than the nutrient water in fact, it appears possible that a 100,000 acre kelp farm might require one ore more OTEC power units depending on the actual size of the pumping and positioning loads.

A major problem associated with the use of OTEC plants to provide power for kelp farms is the possible fluctuation in power requirements for stationkeeping over the range of current conditions that can be encountered for any particular site. If the OTEC system is designed to provide power adequate for peak loads the available capacity will be seriously underutilized and if less power is provided there will be insufficient power during peak loads. If the system is designed to provide power for average loads there will not be enough power during storm conditions when peak loads occur.

A possible solution to this problem would be to design the OTEC power plant to be adequate to handle greater than average loads, but less than peak. Then during average conditions the OTEC plant could produce and store fuel to be used by auxiliary power units such as diesels when maximum load conditions occur. In a sense the OTEC units would be providing peaking fuel on site which would otherwise have to be provided by shipping in fossil fuel to the kelp farm.

SECTION VII

INCENTIVES FOR OTEC IMPLEMENTATION

THE EFFECTS OF FINANCIAL INCENTIVES

The OTEC method of electricity production is very capital intensive. For this reason, those financial incentives which affect the capital costs of OTEC-produced electricity would lower the total levelized busbar electrical cost ($\overline{\text{BBEC}}$), much more than any subsidy of the total annual costs of operating and maintenance. Since the annualized costs per megawatt-hour for operating, maintenance, and fuel are smaller for OTEC than for coal, oil, or nuclear plants, the OTEC capital costs would continue to be a larger share of total costs even when annualized capital costs per megawatt hour of OTEC dropped below that of any of the alternative conventional sources. For this reason we will first concentrate on the effect of financial incentives on the levelized capital costs of OTEC rather than the levelized operating and maintenance costs.

For the analysis reported in here it has been assumed that the incentives would be applied to the early commercial units to be installed in the first years of the decade from 1990 to 2000. These units were assumed to have a "high" capital cost of $1640 per kilowatt which would be representative of the earliest installations.

TAX RELATED INCENTIVES

The most complicated situation arises with incentives involving the corporate income tax. The investment tax credit and the various types of accelerated depreciation are only valuable if there is a corporate income tax and should primarily be viewed as methods of lowering the effective corporate income tax rates. Leveraged leasing can also be viewed as a method by which a user who cannot use these methods (perhaps because the user is writing off losses of prior years against this years income) can "sell" the tax advantages of these methods to an owner of record who can use these methods. Before examining other taxes, let us first examine the effect of those methods which involve the corporate income tax.

Most of the domestic applications of OTEC will involve the U.S. corporate income tax. The corporate income tax is a tax on profits, the difference between the revenues and the costs of production. However, the corporation cannot generally subtract all of the cost of a capital good, such as an OTEC plant, in the year of purchase or in the years in which the expenses of building the capital good occur, but must allocate these costs over the useful life of the equipment. The corporation each year will include among the costs of producing the goods an allocated portion of the original price of the capital goods which it owns. This portion is called depreciation. This leads us to one possible tax preference, accelerated depreciation. Before examining accelerated depreciation, however, it will prove convenient to analyze the effect of a change in the corporate income tax rate.

Changes in the Corporate Income Tax Rate

Although it is possible that the income tax rate might be lowered for the income derived from an OTEC plant, the primary purpose of this section is to set the stage for the following sections. In the case to be examined here, the elimination of the corporate income tax rate will prove to lower the $\overline{\text{BBEC}}$ from 41.71 mills per kilowatt hour to 33.95. None of the other income-tax-linked incentives could do better than this unless the incentive generates accounting losses which shelter non-OTEC taxable income or the incentive results in net payments by the government to the corporation whenever the incentive is larger than the income tax.

Even the rate of the corporate income tax involves some calculation since the state income tax is deductible from federally taxable income. The effective combined rate is

$$\tau = \tau_{\text{federal}} + (1 - \tau_{\text{federal}})\, \tau_{\text{state}}$$

If the federal marginal rate is 0.48 and the state rate is 0.04, this gives a combined rate of about 0.5, which will be used in subsequent calculations. A combined rate of 0.25 could come from some combination such as approximately a 0.235 federal rate and a 0.02 state rate, or 0.219 federal and 0.04 state. Of course, a combined rate of 0.00 would require both state and federal rates to be zero.

A change in the corporate income tax rate necessitates a recalculation of the average after-tax cost of capital to the firm. The after-tax rate of return used here is derived from the following assumptions:

Table VII-1

FINANCIAL ASSUMPTIONS

Symbol	Name	Value
D/V	Ratio of Debt to Total Capitalization	0.5
C/V	Ratio of Common Stock to Total Capitalization	0.4
P/V	Ratio of Preferred Stock to Total Capitalization	0.1
k_d	Annual Rate of Return on Debt	0.08
k_c	Annual Rate of Return on Common Stock	0.13
k_p	Annual Rate of Return on Preferred Stock	0.08
T	Effective Corporate Income Tax Rate	0.50
k	Average Annual After-tax Cost of Capital	0.08

and the following equation

$$k = (1-T)\ k_d \frac{D}{V} + k_c \frac{C}{V} + k_p \frac{P}{V}.$$

where k is the average after-tax cost of capital to the firm. Thus k = 0.08 for the standard case with T = 0.50. The two non-standard cases of T = 0.25 and T = 0.00 result in k = 0.09 and k = 0.10 respectively.

A change in the interest rate results in a change in all present values, including the present value of the tax reductions due to depreciation, the capital recovery factor, and hence the fixed charge rate and the $\overline{\text{BBEC}}$. This is shown in the following table:

Table VII-2

EFFECTS OF CORPORATE INCOME TAX RATES

	STANDARD CASE	HALF RATES	NO TAX
Tax rate, T	0.50	0.25	0.00
After-tax cost of capital, k	0.08	0.09	0.10
Before-tax cost of capital	0.16	0.12	0.10
Present value of depreciation as fraction of total depreciation	0.3753[a]	0.3425[a]	0.3142[a]
Capital recovery factor	0.0888	0.097	0.1061
Fixed charge rate	0.1491[b]	0.1282[b]	0.1180[b]
$\overline{\text{BBEC}}$	41.71[c]	36.50[c]	33.95[c]

[a] Assuming straight-line depreciation and a thirty year life term.

[b] Assuming a ten percent investment tax credit (usable in full), two percent property tax rate, and insurance and other costs of 0.25 percent of capital value. Since various mechanisms exist to enable a non-taxpaying entity to utilize the investment tax credit, this is a realistic case.

[c] Assuming capital costs of $1,640 per KW, operation 75% of year, and operating and maintenance costs of $4.50 per MWH_e, and no salvage value.

The after-tax cost of capital and the capital recovery factor both appear to operate in a paradoxical manner, since both increase when the corporate income tax is reduced. For computational reasons, it is easier to work with the after-tax cost of capital, but the before-tax cost of capital* operates in a manner which is economically more obvious: as the tax (an expense) decreases, the before-tax cost of capital, the fixed charge rate, and the $\overline{\text{BBEC}}$ all decline.

The result of a complete elimination of the corporate income tax would be to lower the fixed charge rate from an annual 14.91 percent to 11.80 percent which (under the assumption of $1640 per kilowatt, operation 75 percent of the year, and $4.5 per megawatt-hour other costs) lowers the $\overline{\text{BBEC}}$ from $41.71 per megawatt-hour to $33.95 per megawatt-hour, a saving of 18.6 percent. Since all the saving is in the levelized capital cost of operating the OTEC unit, attention might better be focused on the fixed charge rate which is lowered 20.9 percent. Changes in the corporate tax rate will cause a greater percentage change in the levelized capital costs than in the levelized $\overline{\text{BBEC}}$, of course, since the $\overline{\text{BBEC}}$ includes operating and maintenance costs which do not depend on the tax rate.

Much the same result would occur in the absence of the investment tax credit. The elimination of the 50 percent effective corporate income tax rate would lower the $\overline{\text{BBEC}}$ from $46.14 per megawatt-hour to $36.60 per megawatt-hour, or 20.7 percent, and the corresponding fixed charge rate would drop from 0.1668 to 0.1286, or 22.9 percent. However, even an non-taxpaying organization (including local governments, non-profit organizations, and profitless corporations) which cannot now make direct use of an investment tax credit may be able to make indirect use via a taxpaying third party.

Since some of the later incentives proposed will be as powerful as the elimination of the corporate income tax, it should be noted that the absolute effect of on $\overline{\text{BBEC}}$ of $7.76 per megawatt hour (or $9.54 without the investment credit) is larger than the entire effect of operating and maintenance costs. ($4.50 per megawatt-hour).

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* The before-tax cost of capital, k, by the equation $k = r(1 - T)$.

Accelerated Depreciation

Accelerated depreciation refers to any method of depreciation which allocates more depreciation to the early years of the life of a piece of capital equipment than would "standard" or "true" depreciation. This lowers profits in the early years of the capital good's useful life and raises it in later years. The sum of the depreciation allowances is the same over the life of the equipment (i.e. original cost less salvage value) in either case. However, with accelerated depreciation for tax purposes, the present value of the depreciation allowances is larger. Furthermore, the present value of profits for tax purposes is lower if all the other revenue and cost items remain unchanged. (If the true engineering depreciation were speeded up then either revenues would drop as less output was produced in later years or other costs would rise as maintenance, operating, or fuel costs rose, or the equipment would be retired sooner.)

In the presence of a corporate income tax, it is advantageous to accelerate depreciation for tax purposes since postponing a tax reduces its present value.

There are two basic ways in which depreciation is calculated for tax purposes. The easiest to treat is the assumption of a shorter lifetime for tax purposes. The second is a change in the shape of the depreciation schedule with a larger proportion of the depreciation occuring in the earlier years. The sum-of-years-digits and the various declining balance methods fall in this category.

The baseline method from which all others will be measured is straight-line depreciation over the 30 year life of the OTEC unit. Under this method, 1/30 of the original capital cost (less salvage value) is taken as depreciation each year over the 30year engineering lifetime of the OTEC unit. The present value of this depreciation will depend on the interest rate:

Table VII-3

EFFECTS OF INTEREST RATE ON THE PRESENT VALUE
OF DEPRECIATION AS A FRACTION OF TOTAL DEPRECIATION*

Interest rate	Present value of depreciation as a fraction of total depreciation
0%	1.0000
1%	.8603
2%	.7465
3%	.6533
4%	.5764
6%	.4588
8%	.3753

* Total depreciation = original cost less salvage value
Assumes straight-line depreciation and 30 year operating life

Of course, at a zero interest rate, the future years are weighted equally with the current years and the present value of the depreciation taken is identical to the total depreciation, namely original cost less salvage value.

Shorter Accounting Lifetimes

Shorter accounting lifetimes for tax purposes increase the amount of depreciation that can be taken in the earlier years of the operation of the OTEC unit. It is standard for the IRS to allow a taxpayer to vary the depreciation schedule 20 percent in either direction. Assuming the corporation is paying taxes in the first place, this provision has as much "symmetry" as would a provision which allowed the ordinary taxpayer to pay any amount from 80 to 120 percent of the tax he otherwise would owe. Thus the ordinary taxpaying corporation would use this provision to lower the accounting lifetime to 24 years (80 percent of 30 years). Furthermore, the IRS will allow a conservative estimation of the engineering lifetime of the piece of equipment involved. Thus the IRS would be likely to allow an accounting lifetime of 20 years (80 percent of a conservative 25 years) without giving the OTEC unit any special treatment. If solar energy promotion were deemed to be a matter of great public urgency, Congress (not the IRS) might permit a very short period such as 5 years or even the same year. (The expenses of research and development of oil exploration may be taken immediately. This "same year" depreciation is called expensing.) At an interest rate of 8%, the effects on depreciation and on the levelized busbar energy cost would be as follows:

Table 4

EFFECTS OF DEPRECIATION PERIOD ON PRESENT VALUE OF DEPRECIATION AND ON $\overline{BBEC}$

Depreciation period in years	Present value of depreciation as fraction of total depreciation[a]	Fixed charge rate[b]	$\overline{BBEC}$[c]
30	.3753	.1491	41.71
24	.4387	.1433	40.28
20	.4909	.1388	39.14
5	.7985	.1115	32.32
same year	1.000	.0936	27.86

[a] Assuming straight line depreciation, and 8% interest rate.

[b] Assuming corporate income tax of 50%, 10% investment tax credit, 2% property taxes, and 0.25% insurance and other costs.

[c] Assuming capital costs of $1640/$KW_e$, operate 75% of year, O&M of $4.5/$MWH_e$

Depreciation can be accelerated by increasing the proportion of the depreciation which is taken in the early years of the accounting lifetime of the equipment involved. Two accelerated methods are recognized* by the tax code for certain types of situations: sum-of-years-digits and declining balance. The declining balance method comes in several versions, with double declining balance being the most accelerated version that the IRS will ever recognize. Since the sum-of-years-digits method has only one version, is usable under the same conditions as the double declining balance method, and is generally more accelerated than double declining balance, we will restrict the present

*The IRS would also allow some special method if the taxpayer could prove that the engineering facts justified that method. For example, if a type of machine typically operated at 100 percent of capacity for 5 years, and then at 50 percent of capacity for 15 more years (with one half the operating, maintenance, and fuel costs) then the IRS would undoubtedly permit a schedule which was the sum of 5 year straight-line depreciation of 1/2 the machine, and 20 year straight line depreciation of the other half.

discussion to sum-of-years-digits and relegate the declining balance method to appendix A.

The sum-of-years-digits method allows the depreciation taken during the n years of the accounting life of the equipment to be proportional to the series n, n-1, n-2, ..., 3, 2, 1. This contrasts with the straight line method where the same amount of depreciation is taken each year. Since $n + (n - 1) + (n - 2) + \ldots + 3 + 2 + 1 = \frac{n(n+1)}{2}$, the fraction of depreciation taken each year is given in Table 5:

Table VII-5

PROPORTION OF DEPRECIATION TAKEN EACH YEAR BY METHOD OF DEPRECIATION

		STRAIGHT-LINE		SUM-OF-YEARS-DIGITS	
1	(1)[a]	1/n	(.05)[a]	$\frac{2n}{n(n+1)}$	(.0952)[a]
2	(2)	1/n	(.05)	$\frac{2(n-1)}{n(n+1)}$	(.0905)
3	(3)	1/n	(.05)	$\frac{2(n-2)}{n(n+1)}$	(.0857)
⋮		⋮	⋮	⋮	⋮
n-2	(18)	1/n	(.05)	$\frac{6}{n(n+1)}$	(.0143)
n-1	(19)	1/n	(.05)	$\frac{4}{n(n+1)}$	(.0095)
n	(20)	1/n	(.05)	$\frac{2}{n(n+1)}$	(.0048)

[a] Figures in parentheses for case where n=20.

The effects of using the sum-of-years-digits depreciation are shown in Table VII-6 for each of several possible accounting lifetimes and in comparison with straight-line depreciation.

Table VII-6

EFFECTS OF DEPRECIATION METHOD AND PERIOD ON FIXED CHARGE RATE AND $\overline{\text{BBEC}}$

Depreciation period in years	Present value of depreciation as fraction of total depreciation[a]		Fixed charge rate[b]		$\overline{\text{BBEC}}$[c]	
	Straight-line	Sum-of-years-digits	Straight-line	Sum-of-years-digits	Straight-line	Sum-of-years-digits
30	.3753	.5038	.1491	.1376	41.71	38.85
24	.4387	.5613	.1433	.1325	40.28	37.57
20	.4909	.6060	.1388	.1286	39.14	36.60
10	.6710	.7477	.1228	.1160	35.15	33.44
5 current	1.0000	1.0000	.0936	.0936	27.86	27.86

[a] Assuming an 8% interest rate

[b] Assuming a corporate income tax rate of 50%, 10 percent investment tax credit, 2% property taxes, and 0.25% insurance and other costs

[c] Assuming capital costs of $1640/$KW_e$, operation 75% of year, operating and maintenance costs of $4.5/$MWH_e$.

The advantage of sum-of-years-digits is most notable with a 30 year depreciation period for the OTEC unit. This advantage of $2.86 per megawatt-hour (or 7.4%) deminishes as the accounting depreciation period is shortened and disappears if it is possible to deduct the capital costs of OTEC units currently.

With sum-of-year-digits depreciation, any depreciation period of 11 years or less results in a $\overline{\text{BBEC}}$ of less than $33.95 per megawatt-hour (the cost with no income tax), which means that to take full advantage of the depreciation, there must be taxable non-OTEC income which is being sheltered. This taxable non-OTEC income may belong to the same coporation or, with an appropriate arrangement, to another taxpayer. Similarly, under straight-line depreciation, no accounting period less than 7 years will result in further lowering of the $\overline{BBEC}$ in the absence of sheltered non-OTEC taxable income.

INVESTMENT TAX CREDIT AND SUBSIDIES

The investment tax credit is one of the most powerful ways of subsidizing a capital investment. In the case of a very capital-intensive method of electricity production such as OTEC, an investment tax credit has a greater potential for lowering the $\overline{BBEC}$ than any of the alternatives which use fuel. While it is very easy to plot the linear effect of an investment tax credit on $\overline{BBEC}$ under the assumption that the tax credit is usable, it is also necessary to take into account the conditions under which the investment tax credit is available.

The first qualification is that the investment tax credit is limited to tangible, depreciable, business equipment and excludes real estate. Purchases of land never qualify, since land is not depreciable. Buildings also do not qualify if they are suitable for other uses. Thus any land needed for the onshore connection of an OTEC unit with an electric grid or industrial facility would not qualify. The unit itself would qualify in its entirety whether or not it was classified as a vessel. The moorings and transmission cables would also qualify. Such a high proportion of the capital costs of OTEC would appear to qualify for the investment tax credit that we have here assumed a complete eligibility since the other conventional and solar technologies tend to be more intensive in the use of land and some also use buildings which are convertible to other uses, this limitation would affect OTEC relatively less than the alternatives.

The second restriction on investment tax credits has a much larger potential impact on OTEC. The total tax credit taken may not exceed 50 percent of the corporation's tax liability. This would not create any special problem if the tax credit were too large to use up in a particular year as a 3 year carry-back and 7 year carry-forward is allowed. However, some utilities find that they are cronically unable to utilize all the investment tax credit that would be allowed in the absence of this limitation. For this reason, some utilities would prefer a straight subsidy. Other possibilities include leasing from another business which can use the credit (Leverage Leasing) or the "refundable" tax credit which has been proposed in the Senate's version of the 1977 energy legislation. A "refundable" tax credit would not only eliminate the 50 percent limitation, but allow a corporation to receive a check for the difference if the tax credit exceeded the tax liability. If the investment tax credit is to be the primary means of promoting OTEC, it is important to be sure that it is directly or indirectly available to all the potential users.

A third restriction that might potentially affect some OTEC units involves the limitation of the full investment tax credit to equipment having a useful life of at least 7 years. Any early development or demonstration unit with a useful life of more than 3 but less than 7 years would only be eligible for 1/3 or 2/3 of the credit to which a longer-lived unit would be entitled. If the OTEC plants were given the special 60-month depreciation treatment given to some special facilities (for pollution control, rehabilitation of low-income rental housing, on-the-job training, and child care), then no credit would be available under existing rules. Since the same accounting lifetime must be used for depreciation and investment tax credit purposes, caution would have to be used in claiming any depreciation period less than 7 years.

The largest potential limitation on the investment tax credit is the restriction of the credit to equipment which is predominantly used in the United States. The worst, but unlikely, situation would involve a restriction of the investment tax credit to OTEC units operating within the 3-mile territorial limit of the United States (excluding Puerto Rico). This interpretation is unlikely since vessels which travel between U. S. Ports (including oil rig "vessels") are currently eligible for the investment tax credit. OTEC units connected (more than temporarily) to foreign shores would clearly not qualify for the investment tax credit. OTEC units near Puerto Rico would qualify under U.S. rules if the profits were subject to the U.S. corporation income tax, but not otherwise.

The effect of the investment tax credit on the $\overline{\text{BBEC}}$ is linear if the limitations listed above do not apply. The investment tax credit is actually somewhat better than the same percentage reduction in the price of the OTEC unit since the purchaser may depreciate the entire price of the unit, including the amount which was offset by the tax credit. The range of plausible values for the tax credit is wide: prior to 1975 the credit was 4 percent for utilities and 7 percent for undustrial enterprises. It is presently 10 percent for both categories. An additional credit for non-oil-or-gas using electricity production may be included in the energy bill now in Congress. At present 20 percent has been proposed for solar systems, but the Senate included a 50 percent refundable credit. Various possibilities are shown in Table VII-7.

Table VII-7

EFFECT OF THE INVESTMENT TAX CREDIT

Investment Tax Credit	Regular Depreciation[a] Fixed Charge Rate[c]	Regular Depreciation[a] BBEC[d]	Accelerated Depreciation[b] Fixed Charge Rate	Accelerated Depreciation[b] $\overline{\text{BBEC}}$
0.00	0.1668	46.14	0.1463	41.03
0.04	0.1597	44.37	0.1392	39.25
0.07	0.1544	43.04	0.1339	37.92
0.10	0.1491	41.71	0.1286	36.59
0.20	0.1313	37.27	0.1108	32.16
0.35	0.1046	30.62	0.0841	25.50
0.50	0.780	23.97	0.0575	18.85

[a] Straight-line with 30 years accounting period.

[b] Sum-of-years-digits with 20 years accounting period.

[c] Assumes an 8 percent after-tax interest rate, incometax rate of 50 percent, 2 percent property taxes and other costs.

[d] Assumes capital costs of $1640/kw, operation 75 percent of year, and operating and maintanance costs of $4.5/MWHe.

Since the part of the OTEC cost which is offset by the investment credit is also depreciable, the fixed charge rate would acutally be negative with a 100 percent credit. Indeed, with accelerated depreciation the $\overline{\text{BBEC}}$ would also be negative. A 100 percent subsidy, however would result in a fixed charge rate of 0.0225 (due to property taxes and insurance) and a $\overline{\text{BBEC}}$ of $10.11 per megawatt-hour.

Clearly the presence or absence of a special investment tax credit will greatly affect the time at which OTEC would become an economic alternative to conventional energy sources. It is very important that OTEC not be excluded as foreign in any significant portion of its market. Assuming that it is eligible, it would be helped more than the conventional technologies due to its capital-intensive nature and also by any special treatment given to solar technologies. It would also be slightly favored over other solar technologies due to the neglible portion of real estate in the capital costs.

INTERACTION OF ACCELERATED DEPRECIATION, INVESTMENT TAX CREDIT AND LEASING

In general there is some competition between accelerated depreciation and investment tax credits as a method of providing financial incentives to the adoption of OTEC. The investment tax credit is not available in full to equipment which is depreciated in less than 7 years for tax purposes. Furthermore, accelerated depreciation reduces the tax liability which may cause the 50 percent limitation to make some of the tax credit unusable. If the tax credit were made refundable, the second limitation would disappear, but the 7-year limitation would remain. The refundable tax credit would be an easier mechanism to extend to non-taxpaying entities by a change in law. In such a case, the credit would become mathematically equivalent to a subsidy or price reduction of the same amount.

Privately owned utilities would generally prefer to own equipment rather than lease it. Including capital in the base to which their allowable rate of return is applied is attractive except for a few periods in which the cost of newly raised capital is higher than the utility is able to utilize. If the utility is unable to use the investment tax credit fully, then the utility would be pushed toward leasing the equipment from a taxpaying entity which can use the credit. If the utility is actually operating at a loss, then leasing would also allow the transfer of depreciation to an entity capable of using it. Since a non-regulated user of OTEC has less incentive to own the capital and a greater likelihood of operating at a loss, the incentives for leasing would be even greater.

Leasing allows the "sale" of tax credits and depreciation so the user can indirectly benefit financially and achieve nearly the same effect as if it could take the benefits directly. The owner can lease the equipment at a lower rate to the user because the owner receives not only the lease payment but also the tax credit and the tax deductions from the depreciation. The owner may be an individual or partnership (or a Subchapter S corporation which is treated as a partnership for tax purposes) since some individuals are in a higher marginal tax bracket (70% plus state taxes) than corporations, thus rendering the tax deductions (but not credits) more valuable to them than to corporations. For example, an 8 percent after-tax rate of return to someone in the 70 percent before-tax rate of return as compared to a 16 percent before-tax rate of return to a taxpayer in the 50 percent bracket.

Leveraged Leasing

In order to increase the rate of return, the owner may wish to borrow (using the OTEC unit as security) and realize the entire tax credit and depreciation-generated tax deductions on only the portion of the money which he raises. This is known as leveraged leasing. The owner may borrow and retain the credits and deductions provided:

- Not more than 80 percent of the capital is raised by borrowing.
- The lease is short enough so that the remaining market value is at lest 20 percent of cost and so that at least 20 percent (at least one year) of the useful life remain.
- The owner rather than the user takes the risks of ownership (e.g. fluctuations in remaining market value).

In order to meet the conditions listed above the OTEC unit must be standardized enough and sufficiently proven so that the useful life can be determined. For this reason it might be advantageous to have the OTEC units modularized, at least in the earlier stages, since some modules may be able to meet these conditions before others. Aircraft engines are often financed separately from the aircraft. If the general use of OTEC is for electricity production, for example, then a heat-exchanger/turbine module may be sufficently proven to be eligible for leveraged leasing even though an experimental core with an ammonia plant is not eligible. The separate financing of modules may also provide a small enough package so that additional individuals, partnerships, or corporations might participate in financing OTEC.

In summary, it is not possible to give a quantitative estimate of the economic impact of the interactions of restrictions on investment tax credits, accelerated depreciation and leasing, but the availability of leasing, especially leveraged leasing, is likely to make the credits and depreciation deductions available indirectly to those unable to use them directly.

Property Taxes

The effect of property taxes on OTEC is rather easy to analyze since the property tax rate is an additive portion of the fixed charge rate. The elimination of the property tax with the present investment tax credit (10%) would lower the fixed charge rate and $\overline{\text{BBEC}}$ given in Table VII-7 from 14.9% and \$36.73 per megawatt-hour with 30 year straight-line depreciation. With accelerated 20 year sum-of-years-digits depreciation, the fixed charge rate would drop from 12.86% to 10.86% and the $\overline{\text{BBEC}}$ would drop from \$36.59 to \$31.61 per megawatt-hour. The elimination of the 2% property tax would lower the $\overline{\text{BBEC}}$ by the same \$4.98 per megawatt-hour for any other set of tax credit and depreciation assumptions.

INTEREST-RATE RELATED INCENTIVES

The financial incentives which affect interest rate used in calculating the fixed charge rate might take the form of outright subsidies, loan guaranties, or eligibility for municipal bond financing. The subsidies are the most basic form and the easiest to analyze.

Interest Rate Subsidies

The interest rate subsidy is most likely to be used by Congress if an above-market rate would otherwise be charged. This would most likely occur in the earliest stages of OTEC deployment when OTEC is not yet considered a proven technology. Table VII-8 shows the considerable effect of the use of a subsidy to lower the 10 to 12 percent rate associated with a risky investment to the 8 percent rate more appropriate for a proven technology:

Table VII-8

EFFECTS OF INTEREST RATES

After-tax cost of capital	Ten percent investment tax credit		No investment tax credit	
	Fixed charge rate	$\overline{BBEC}$[b]	Fixed charge rate[a]	$\overline{BBEC}$[b]
5%	0.0929	$27.69	0.1059	$30.94
6	.1041	30.48	.1186	34.11
7	.1160	33.45	.1321	37.48
8	.1286	36.59	.1463	41.02
10	.1554	43.29	.1766	48.59
12	.1842	50.48	.2091	56.68

[a] Assuming 20 year sum-of-years-digits depreciation and a 50% income tax rate.

[b] Assuming capital costs of $1640/kw, operation 75% of year, and O&M of $4.50/MWH

The differences are large. With a 10 percent investment tax credit, a 4 percent interest rate subsidy (on a 12 percent rate) would lower the $\overline{BBEC}$ by $13.89 per megawatt-hour. The use of an interest rate subsidy (or loan guarantee) might be vital in the early stages before OTEC is considered a proven technology.

Loan Guarantees

The effect of a loan guarantee by the federal government is harder to analyze in terms of the amount of subsidy involved, but easier to analyze in terms of the resulting fixed charge rate and $\overline{BBEC}$. The loan guarantee would eliminate the risk premium in financing that portion of the OTEC device which is covered by the guarantee.

To the extent that the financial markets might charge too much for the risk premium, the loan guarantee would prove cheaper than a subsidy. On the other hand, only the subsidy could lower the financing costs by an amount greater than the risk premium.

Municipal Bond Financing

The term "municipal bond" is used for any state or local bond, including industrial development and pollution control revenue bonds which are issued by a state or local authority to finance the purchase of property which is used by a private firm. The effect is to lower the interest rate since the purchaser of the bond does not pay U.S. income tax on the interest received. Often states exempt the interest on the bonds they issue from their own income tax. Puerto Rico's bonds are automatically exempted from all state taxes. The result is to lower the interest rate. If a risk-free corporation is paying 8%, a risk-free municipal bond might pay 5% or 6%. This suggests the use of a loan guarantee to eliminate the unknown risk premium and then municipal financing to provide further subsidies. However, a subsidy costs the U.S. government less than an equivalent reduction in the interest rate by municipal bond financing.

FINANCIAL INCENTIVES: OVERVIEW AND CONCLUSIONS

Equivalent Methods of Reducing $\overline{\text{BBEC}}$

Many possible incentives would provide the same effect in lowering the fixed charge rate and $\overline{\text{BBEC}}$. If there are no incentives*, then the standard case examined here** would have a fixed charge rate of 0.1668 and a $\overline{\text{BBEC}}$ of $46.14/MWH. Each of the following incentives would lower the fixed charge rate to 0.15 and the $\overline{\text{BBEC}}$ to (approximately) $41.94/MWH:

- An investment tax credit of 9.5%.
- A depreciation period of 15.32 years (with 15 years giving a $\overline{\text{BBEC}}$ of $ 41.81).
- A corporate tax rate of 36%.
- Sum-of-years-digits depreciation of 23.68 years (24 years gives a $\overline{\text{BBEC}}$ of $42.01).

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* Thirty year straight-line depreciation, no investment tax credit.

** Corporate tax rate of 50%, 8% interest rate, $1640/kw capital costs, operation 75% of year, O&M of $4.5/MWH.

- Sum-of-years-digits depreciation and an investment tax credit of 3%.
- Interest rate lowered from 8% to 6.98% (lowering to 7% gives a $\overline{\text{BBEC}}$ of $42.02).

Several of these incentives are, of course, likely to be available with no special treatment of OTEC. For example, a 10 percent investment tax credit combined with 20 year sum-of-years-digits depreciation gives a $\overline{\text{BBEC}}$ of $36.60 per megawatt-hour.

Governmental Ownership

If a state or local government owned an OTEC unit, then a dramatic lowering of OTEC costs would be possible even with no investment tax credit. If the government did not charge "payments in lieu of property taxes" in costing the OTEC unit, then a risk-free interest rate of 6% would result in a fixed charge rate of 0.0751 and a $\overline{\text{BBEC}}$ of $23.26 per megawatt-hour. If the "in-lieu" payments of 2% were included, then a fixed charge rate of 0.0951 and a $\overline{\text{BBEC}}$ of $28.25 per megawatt-hour would result. Either rate is considerably under the possible $36.60 BBEC for private utilities.

The $\overline{\text{BBEC}}$ of $23.26 seems feasible for Puerto Rico if sufficient loan guarantees are provided.

SECTION VIII

TITANIUM AS A CRITICAL MATERIAL

This study has addressed two issues concerning titanium and OTEC. The fist issue is how much impact there would be on titanium metal prices and supplies if OTEC heat exchangers were fabricated of titanium metal. The second issue is how suitable titanium would be as an OTEC product option.

THE TITANIUM INDUSTRY

In 1974, the United States consumed 588 thousand short tons of titanium. Titanium metal accounted for only 5.5 percent of this amount. The titanium metal industry is relatively new as commercial production did not begin until 1950.

The major use of titanium metal in the United States is for transportation equipment in aerospace applications. The remaining twenty percent is used in the chemical and electro-chemical processing industry, in power plants and in marine and ordnance applications. Although expensive when compared to its substitutes such as aluminium and nickel steels, titanium's properties including its high strength-to-weight ratio and its corrosion resistance often make it the obvious choice in certain applications.

The mineral sources of titanium are ilmenite and the far rarer rutile. Rutile is the preferred substance for all types of titanium, and, in fact, is the required material for production of titanium metal. New processes being developed to produce synthetic rutile from ilmenite will relieve some of the strain on rutile supplies.

The major source of domestically consumed rutile is the Australian east coast. In 1975, 97 percent of the natural rutile consumed in the US came from Australia (Table VIII-1). Australia was also a major supplier of synthetic rutile. In contrast, the US produced 76 percent of its 1975 consumption of titanium sponge while lesser amounts were imported from Japan and the U.S.S.R. The U.S.S.R., however, has not been a dependable supply source and the sponge produced there cannot be used in moving parts for aircraft engines since the U.S.S.R. production facilities cannot be inspected.

TABLE VIII-1

MAJOR SOURCES OF US IMPORTS FOR CONSUMPTION[a]

Substance	Major Suppliers	% of US Consumption Supplied (1975)
Natural Rutile	Australia	97
	Canada	NEG.
Synthetic Rutile	Australia	57
	India	11
	Japan	29
	Taiwan	1
Titanium Sponge	Japan	12
	USSR	8
	United Kingdom	3
	Canada	1

[a]Source: Bureau of Mines, Minerals Yearbook, 1975.

Currently, the United States is the major consumer of titanium metal but as the major markets, i.e. aircraft, become saturated, the growth in demand is expected to slow. Worldwide demand, however, is expected to grow at a greater rate as lesser developed countries enter the markets for the products made of titanium metal. Table VIII-2 shows projected growth of titanium metal demand through the year 2020 AD.

TITANIUM HEAT EXCHANGERS

The purpose of this section is to consider the impact on the titanium market of titanium heat exchangers for OTECS. The analysis will be based upon the Lockheed configuration for a 280MWe plant. It is assumed that titanium content per megawatt is constant over the relevant range of plant sizes.

OTEC penetration as described in this report would require significant quantities of titanium metal. This can be attributed to (1) the large amount of titanium required per plant and (2) OTEC's significant projected penetratio after 2000 AD. The weight of the finished titanium requirement of one 280MWe plant as designed by Lockheed is 8145 short tons. Since, including recycling, it takes 4.5 (38) pounds of titanium sponge to produce one pound of finished product, the OTEC plant will require over 36,600 ST of sponge. The she size of this requirement is highlighted when compared to the projected titanium content of a B-1 bomber - 75 short tons (39). If the B-1 program had proceeded, it would have been the largest consumer of titanium metal both in the aggregate and per unit. However, in comparison to the projected OTEC demand, the B-1 requirement was small indeed. For example, if the 240 B-1 bombers planned had been built by 1990, they would have required 18,000 ST of titanium metal. By 1990, OTEC, although very early in the program, will have surpassed this with a cumulative consumption of at least 260,000 short tons.

Table VIII-3 compares projected U.S. demand for titanium metal without the OTEC program to the OTEC derived demand. It is obvious that the additional OTEC

TABLE VIII-2

PROJECTED DOMESTIC AND TOTAL TITANIUM METAL DEMAND

(ST of Titanium Content)[a]

	1973	1980	2000	2020
UNITED STATES	30,000	37,500	70,000	132,000
WORLD	54,000	84,060	235,000	493,000
US as a percent of world demand	56%	45%	30%	27%

[a]Source: Bureau of Mines, Mineral Facts and Figures, 1975; GE-TEMPO

TABLE VIII-3

PROJECTED ANNUAL US AND OTEC TITANIUM DEMAND
(ST Of Titanium Content)[a]

	1973	1980	2000	2020
United States (w/o OTEC)	30,000	37,500	70,000	132,000
OTEC				
Baseline	———	———	418,590	1,479,285
High	———	———	1,217,250	1,806,210

[a]Source: Bureau of Mines, Mineral Facts And Figures, 1975;
GE-TEMPO

demand will significantly impact the US titanium market after 2000 AD. First of all, there will be strains on supply channels. At this time, domestic producers of titanium metal are completely dependent upon foreign sources of rutile and 24 percent of domestically consumed titanium sponge is manufactured outside the country. The US will have increasing competition for these sources as demand in the rest of the world accelerates with development.

There are potential price induced solutions to these supply constraints. At current prices, significant reserves of rutile located both within and outside of the US are considered uneconomic for recovery. For example, the titanium content of US rutile reserves is over three million tons. However, an additional seven million tons is contained in subeconomic domestic deposits. Improved technology and sufficiently higher prices would bring this 7 million tons into the reserve base. This would relieve supply constraints and the current United States dependence on foreign ore sources.

A second solution might be found in the accelerated use of synthetic rutile in the titanium metal production process. Synthetic rutile is made from ilmenite which is cheaper and much more plentiful domestically and internationally than rutile. However, due to the expense of the procedure, titanium metal prices would have to rise in order to induce producers to provide sufficient quantities of titanium made from synthetic ore.

Even if there were sufficient supplies of ores, OTEC titanium demand would necessitate extensive sponge capacity expansion. Additions to annual titanium production capacity cost approximately $10,000 per ton. This estimate is for the production of titanium sponge and does not include the costs of capital for converting the sponge into a finished product.

The capital costs incurred over the 1985 to 2020 period associated with increasing the capacity of the domestic titanium sponge metal industry to meet OTEC demand would range between 15 and 18.5 billion dollars. Table VIII-4 shows how these costs will be allocated over the 1980 to 2020 period for the baseline and high scenarios. It should be noted that these estimates are probably low for two reasons. First of all, the $10,000 cost does not take into account ordinary escalation due to inflation. This is not a problem as

Table VIII-4

OTEC-RELATED TITANIUM INCREASE COSTS
($\$10^6$)

	1982-2000	2001-2010	2010-2020
TOTAL			
BASE	4,185.0	8,235.0	2,358.0
HIGH	12,170.0	5,364.0	920.0
ANNUAL			
BASE	465.0	823.5	235.8
HIGH	1,217.0	536.4	92.0

long as relative prices and costs do not change. However, the significantly increased demand for titanium plant and equipment is likely to cause upward pressures on capital costs.

In summary, it is feasible that OTEC titanium demand could be met domestically. However, it is not clear at this time how much the price of titanium would increase over the time period of interest, i.e. 1980-2020 AD, due to OTEC requirements.

A second factor to be considered in assessing the impact of using titanium for heat exchangers is how much energy is consumed in the production of the titanium going into the heat exchangers. Obviously, it is necessary that less electrical energy be consumed than produced. The titanium content of one 280 MWe plant would require 1612.7×10^6 kwh* of electricity. That same plant will produce 1680×10^6 kwh of electricity per year. This implies that one OTEC plant supplying electricity to the titanium industry could generate sufficient power to produce the titanium metal content of a little over one plant per year. In the year 2020, it will take the electricity generated by 40.5 of the standing 645 plants to produce the titanium needed for the 40 plants coming on line in that year.

TITANIUM METAL PRODUCTION

Titanium metal should be considered as an OTEC product option because it meets a number of the criteria needed to establish a product as high potential application. One of these criteria is the electrical energy intensiveness of the product manufacturing process. Titanium metal is one of the more energy intensive materials, with 7 to 22 Kwh's of electricity being consumed in the production of one pound of metal (sponge). A second criteria is a large product market. Titanium metal is unique in that the market which could be served by the OTEC-produced titanium is dependent upon decisions made in other aspects of the OTEC program. If OTEC heat exchangers are made of titanium, then domestic titanium demand in 2000 will be 6 to 17 times what it would have been without OTEC.

Process Technology

Of the many titanium bearing minerals available in plentiful quantities

* Based upon a Bureau of Mines energy content estimate of 22 kwh/pounds

throughout the world, only two have been considered seriously for exploitation for their titanium values. These ores are:

- Rutile, when in the pure state, essentially titanium dioxide; and
- Ilmenite, a mineral of the general composition FeO x TiO_2 running normally 40-60 percent TiO_2.

Both ores contain substantial quantities of impurities which are deleterions to the successful application of their titanium values. It is necessary to apply complex purification processes to either ore before titanium can be used even as an oxide.

Chlorination of Rutile. The manufacture of TiO_2, the end product of 90 percent of U.S. titanium, proceeds by two processes:

1. Chlorination of rutile, and
2. Sulfation of ilmenite.

Since all proven processes for the production of titanium metal rest on the reduction of the tetrachloride, the sulfate process plays no role in metal supply. All titanium metal produced in the United States has as its source $TiCl_4$ made by chlorinating rutile. Some titanium metal in Japan and the Soviet Union starts from upgraded ilmenite or "artificial" rutile,* but all is produced from the tetrachloride as a base.

In most modern plants, $TiCl_4$, the chlorinator, is heated by electric resistance by passing current through carbon blocks in the bottom of the shaft furnace. The recovery of titanium in modern rutile chlorination plants is quite high, approximately 90 to 95 percent. No figures are available for recoveries of titanium values using the ilmenite chlorination process. However, the complications generated by the large volumes of iron chlorides involved would indicate lower recoveries than for direct chlorination of natural rutile. This would be true also of the direct chorination of upgraded ilmenite in "artificial" rutile. However, the manufacture of artificial rutile from ilmenite ore involves significant yield losses.

Titanium Metal. All industrial production of titanium metal in the world is based upon the production of titanium sponge in an enclosed vessel by an almost explosive reaction with magnesium or sodium metal. This is called the Kroll process. Specifically purified titanium tetrachloride is reduced with magnesium or sodium under an inert atmosphere. Residual chlorides are removed by leaching or by vacuum distillation. Then the sponge is compacted and made into ingot by two or more vacuum arc-melting operations.

Required for the production of one pound titanium metal are approximately 2.2 pounds of rutile, 3.5 pounds of chlorine, 1.25 pounds of magnesium or 2.1 pounds of sodium, 1.03 cubic feet of inert gas, and about 0.3 pounds of petroleum coke. If as is usual, the resultant magnesium and sodium chlorides are recycled with the recovery of metal and chlorine, make-up requirements are about 0.2 pounds of magnesium and one pound of chlorine per pound of titanium. Recycling is not practiced when sodium is used.

Power requirements range from seven to twenty-two Kilowatt hours per pound of sponge. The upper bound takes into account the power used in recycling the magnesium and chlorine. An additional 2 to 2.5 Kilowatt hours per pound of titanium ingot is consumed in the conversion of sponge metal to titanium ingot.

Losses of titanium values in the sponge-making process include production of off-grade sponge (high iron), dissolution during purification by leaching and the loss of 20 mesh fines which expose too much surface area for use in ingot production. It is estimated that 4 percent of the ingot titanium content is involved in losses during sponge manufacture of which about half, approximately 2 percent, can be recycled into usable sponge; the rest is taken as an irrecoverable loss.

Titanium metal car. also be produced by both the iodide and electrolytic processes. The iodide process is expensive and has seen no usage since the 1930's. Various electrolytic processes have been proposed and pilot plants constructed at industrial plants and by the U.S. Bureau of Mines. One company has recently announced the operation of an industrial scale pilot unit which professes to produce extremely high grade metal with exceptional power consumption. This cell and all other titanium reduction cells proposed and seriously considered for industrial operations use a liquid salt as electrolyte and $TiCl_4$ as feedstock. Titanium metal is produced as a solid which is removed from time to time by breaking open the cell. Sludge problems and shorting of the cell by powder build-up in inaccessible areas have proved difficult barriers to industrial success. Several patents have been issued which appear useful in overcoming these difficulties and presumably commercial feasibility has been achieved. Recovery figures on the one unit in industrial operation are not available, but it would be surprising if yields from $TiCl_4$ approached those of magnesium or sodium reduction. The ideal electrolyte cell operating at temperatures high enough to permit tapping of molten titanium -- thereby a continuous high yield operation -- has been elusive. Titanium has a very high melting point and is extremely reactive with refractory linings.

Titanium Ingot and Mill Products. Titanium is so reactive in the molten state that it is not possible to melt titanium alloys in conventional refractory lined furnaces. When molten, titanium will reduce even the most stable of refractory oxides picking up deleterious oxygen in the molten bath and destroying the structural integrity of the lining. Some small production mainly for the production of castings proceeds by the skull melting technique where titanium metal is melted in vacuum; usually by an electric arc, sometimes by an electron beam in a skull of solid titanium maintained solid by water cooling in the crucible shell. The great bulk of ingot production, however, is performed using the consummable vacuum remelt process wherein a mechanically compacted electrode of titanium sponge, scrap, and alloy additions are remelted in a liquid cooled crucible (usually copper) by means of a low voltage DC arc. The presence of volatiles -- especially Mg -- in the sponge and homogeniety problems, have resulted in the general requirements that all titanium be double melted, and of late for certain very critical applications, triple remelted titanium is required. because of the highly exothermic reaction of titanium with water. Explosions generated by the conversion of the thermal energy into steam have destroyed entire melt shops and taken lives. Because of such a disaster, the major British producer has converted all titanium melting facilities into liquid metal cooling. American producers seem to have improved their safety control systems to the point where liquid metal cooling and its attendant inconveniences could be avoided. Recent accidents have indeed been suitably contained. The possibility of loss of capacity through a disastrous explosion remains and ought to be considered an element for consideration of possible shortages.

The peculiar requirement of consumable vacuum remelting imposes some restraints on further processing. Melt rate is essentially a function of ingot diameter. The smaller the ingot diameter the lower the capacity. Further, the safe operation of titanium dictates a large annulus (area between electrode and crucible wall) to prevent arcing to the crucible, hole formation, and intrusion of water. This means that the radius of the electrode must be considerably smaller than that of the ingot -- usually 2 inches. On small diameters particularly, this becomes a very significant percentage of ingot cross-sectional area. Added to this is the requirement that all ingots must be double melted, doubling the annulus effect on electrode size and melt rate. The titanium ingot maker is then under severe pressure to produce very large ingot sizes to maintain through-put and economic viability. He cannot afford to use small diameter ingots to produce small cross-sectional products and even wire, for example, must be made from large ingots.

This focus of the titanium industry on large ingots in turn places constraints on further processing. Instead of a small diameter ingot which can be readily introduced to a rolling mill, the operator is faced with a large ingot which can in most instances only be converted on a large open die hydraulic press. The requirements for certain metallurgical structures (alpha-beta worked) place further restrictions on the efficiency of the cogging operations and during periods of high industrial activity, the availability of press time produces significant imbalances in the titanium pipeline.

Further processing of titanium to mill products parallels that of special steels and indeed many titanium producers regularly convert on the facilities of special steel producers. Attention must be given to atmospheres; special pickling solutions must be used to avoid hydrogen; and special vacuum anneal facilities must be available. However, given the relative sizes of the special steel and titanium industries, it is reasonable that shortages due to inadequate conversion capacity beyond the cogging press should not be expected.

The conversion of titanium alloys into mill products does, however, produce considerable scrap, ranging from mill ends and clippings to loss of whole heats due to analysis or segregation problems. The low recovery of this in-process scrap is a most serious problem. The high leverage of titanium consumption in finished parts on sponge demand is an enormous factor on the stability of the industry. Relatively minor fluctuations in consumer demand produce violent swings in sponge consumption and the history of the titanium industry in the United States has been one of dramatic movement from shortage to glut and back again.

The production of titanium sponge is certainly electrically intensive and would, therefore, meet that criterion for potential success as a product option. A second criterion, however, is the size of the market which could be penetrated by the OTEC plant product.

SECTION IX

POLITICAL AND INSTITUTIONAL ASPECTS OF OTEC DEPLOYMENT

This report addresses the specific political and institutional problems associated with the deployment of a very small number of OTEC's in at least one of the following areas:

Atlantic Ocean between Miami, Florida and Bimini, Bahamas

Carribean Sea between Florida Keys and Cuba

Carribean Sea off the Southeast coast of Puerto Rico

Gulf of Mexico off Tampa Bay, Florida

Gulf of Mexico off Brownsville, Texas

Pacific Ocean off Keahole Point, Hawaii

Atlantic Ocean 300 miles off Brazil

The general question of the political and institutional effects of large numbers of OTEC's is addressed in the OTEC Mission Analysis Phase I Report (40). It should be recognized that the deployment of large numbers of OTEC's will create significantly different problems than will the deployment of one or two in limited locations. Summarizing very briefly the points made in the earlier report, General Electric concluded:

OTEC's will exist in a world in which the 200 mile Economic Resource Zone (ERZ) will be an international reality.

Within the United States' ERZ the onshore ancilliary development problems will create the most difficult political/institutional problems.

If large numbers of OTEC's are located in a small area, navigational problems will be significant. The most probable solution will be the institution of safety fairways and safety zones.

In United States ERZ, there will be requirements for environmental impact statements. Because they will be precedent setting, they will have to be well documented.

There is little likelihood of a serious conflict between fishing interests and OTEC's because they do not compete for common areas of the oceans. To the extent that a problem develops, it is likely that it will revolve around fouled fishing gear. Current maritime precendents already exist to handle such potential incidents.

If the United States or US corporations were to attempt to locate large numbers of OTEC's in international waters, there exist no current provisions in international law which would prohibit the activity. However, the trends in the development of international law would appear less encouraging. If the issue were to become sufficiently salient to the Group of 77, it is possible that OTEC's could be placed under the jurisdiction of an international authority with powers to tax and licence.

This report will address the following issues:

- International problems associated with Miami, Florida Keys, Brownsville, and Brazil OTEC's
- Requirements for Environmental Impact Statements
- Navigational Requirements
- Local concerns
- Potential mariculture problems.

POTENTIAL INTERNATIONAL PROBLEMS

The OTEC's located off Miami, the Florida Keys and Brownsville are all close to the economic resource zones of the Bahamas, Cuba and Mexico respectively. All three nations recognize the 200 mile limit for the ERZ. Bahamas and Mexico passed the laws in 1977.

Keys

In the Cuban case, the Keys are only 75 miles from Cuba. International conventions dictate that where ERZ's overlap, the boundaries are drawn halfway between the coast lines. Unfortunately in the case of the Keys, the water with the greatest temperature gradient in this area is at least half the distance towards Cuba. While there exists the logical possibility of negotiating with Cuba to obtain permission to locate an OTEC in its waters, current political realities would certainly make that a very low probability event. Thus were an OTEC to be located in the Keys area, the OTEC would have to be located within the US economic resource. In addition, according to international law, the United States can be held liable for any environmental damages to Cuban waters resulting from the OTEC's. The primary implication is that the OTEC should be located far enough from Cuban waters to avoid the issue. It should be realized that the political climate between the United States and Cuba is slowly improving and that it is possible that within ten to fifteen years, that some accomocation could be reached. We believe, however, that it is too early to speculate on those possibilities.

The Bahamas and Brownsville cases pose somewhat more complicated problems. In both of these cases, the distinct possibility of negotiation as with the government of Bahamas or Mexico exists.

Bahamas

Bimini, Bahamas is approximately 50 miles from Miami. The Bahamas' ERZ runs roughly parallel to the Florida coast line approximately 25 miles to the East. The Gulf Stream very nearly divides the US's ERZ from Bahamas'. While satisfactory water for OTEC's lies on the American side of the dividing line, the most suitable water lies in the Bahamas' ERZ. If the decision were made to place the OTEC in the US water, there would be little difficulty with the effluent problem because of the rapidly flowing Gulf Stream. While international institutional obstacles might arise if a large number of OTEC's were to be placed in the US ERZ near the Gulf Stream, a single experimental installation is unlikely to cause difficulties.

Alternatively, it is not beyond the realm of possibility to locate the OTEC in Bahama waters. This would require negotiations with the Bahamas. They would be held directly with the Commonwealth of the Bahamas. It is clear that the Ministry of Development which handles all mining rights and issues would have jurisdiction. As is the case for nearly every nation in the world, there is no existing legislation to handle the case of OTECs. The confusion arises because they make use of a valuable resource but do not actually extract minerals in the conventional sense of the word. The Bahamas do have some precedents, however, from the case of oil exploration and extraction. Currently, any foreign nation wishing to make use of potential off-shore oil fields must be granted oil exploration, oil prospecting or oil mining licenses from the Ministry of Development. In addition, the Ministry has established a scale of royalties on crude oil, natural gas and casinghead petroleum spirit, payable directly to the Bahamas Government. It is not unreasonable to expect that a foreign company intending to locate an OTEC in the Bahamas' ERZ would be required to observe similar controls. However, given the developmental status of OTECs it is by no means certain that the controls or royalties would be at all severe.

It should also be recognized that the Bahamas are eager for developmental industries and have established a number of tax incentives for investment as well as the assets of the government-owned Bahamas Development Corporation. If the initial developmental OTECs were partially financed through the US Government, the bureaucratic difficulties of using the vehicle of a company are greater than any benefits. However, were the efforts to be financed by private sources, the possibility of using a company in the Bahamas and then exporting the electricity to the United States could be a viable financial option.

Mexico

The case of Brownsville, Texas is the most uncertain. In the Brownsville area, the best water is within the Mexican ERZ. Like the Bahamas, Mexico has no existing legislation covering the type of controls which would be imposed on them were the United States to attempt to locate one in their ERZ. Additionally, because the only company permitted to prospect or pump oil in Mexico is the government-owned Mexican Petroleum (Petroleós Mexicanos-PEMEX), there is no reasonable precedent from the oil industry. In fact, the novelty of OTECs makes it unclear whether the Ministry of Industry, Commerce and Fisheries or the Ministry of Government would hold jurisdiction. The former appears a more probable authority since it handles all import licensing. However, the Ministry of Government which is roughly the Mexican equivalent of the US Departments of Justice plus Interior and is by far the most powerful of the cabinet positions, could also claim jurisdiction.

More important than the formal legal and jurisdictional problems is the symbolized issue which could arise. Mexico has been a major fighter in the Group 77 Activities concerning the new Law of the Seas and the New Economic Order. One of the central premises of the Group 77 positions is that developing nations should not permit the developed nationas to exploit their natural resources. Regardless of the objection merits of the exploitation arguments as specifically applied to OTECs, the placement of such technology in Mexican waters could easily be translated into a symbol of exploitation. If that were to occur, the costs of negotiation would be far greater than any benefits. This compiled with the additonal difficulty associated with the undetermined jurisdiction within the Mexican Government makes these alternatives appear to have a low expected value.

Brazil

The OTEC to be located off the coast of Brazil will be outside the economic resource zone and in international waters. It will manufacture ammonia to be shipped back to the United States. As we mentioned in the previous report, there are no regulations in the existing law of the sea which would place any limitations on such a placement of OTECs. The possibility exists that such controls could be institutionalized in the future if OTECs becomes sufficiently salient to the developing nations. For single planned experimental installations, there would appear to be few difficulties.

Minor issues which need to be addressed concern regulations concerning the shipment of ammonia back to the United States and the support facilities potentially located in Brazil. There should be no difficulties with the transport of the ammonia back into the United States. Precedent set in the fishing industry provides that as long as the ships transporting the ammonia do not stop in any foreign ports between loading the ammonia from the OTEC and unloading it in a US port, the ammonia is free of all import taxes and duties.

The potential of stationing logistic support for the OTEC in Brazil also creates few problems. Brazil is generally receptive to this category of high technology development and would be unlikely to raise legal or symbolized issues. In fact, the Brazilian navy has been engaged in some research similar to OTECs and might welcome the opportunity for cooperation efforts.

LOCAL UTILITIES AND COMMUNITIES

In addition to international problems the local utilities in the vicinity of the OTEC sites were assessed to determine what the impact of would be on them.

Keahole, Hawaii

The Hawaii Electric Co., a subsiderary of the Hawaiian Electric Co., is an investor owned utility serving the island of Hawaii. The residential rates are very high (7.25¢ for industrial user).

There are no obstructions approaching Keahole Point from the West but once the cable reaches the shore it must be placed underground off to the side of the airport for about one mile.

There is a research group working on OTEC feasibility from the University of Hawaii at Keahole Point; and the government of the state of Hawaii is favorably disposed toward OTEC installations.

Miami, Florida

Florida Power & Light Co., the largest power company in the State, is an investor owned public utility that sells base load power to other smaller power companies in the area. Florida Power & Light Co. has well developed research and development department brain storms far into the future.

Florida Power & Light Co. has a number of the cable type of submarine circuits in the Miami and Miami Beach areas.

The longest cable is seven miles long extending seaward from Key Biscayne serving a University of Miami Sea Lab.

Florida Power & Light Co. also serves the Ft. Meyer/Collier county area. Since Ft. Meyer is hooked into the largest power grid in the State and is very close to a proposed OTEC site, many of the big city drawbacks such as heavy shipping and congestion could be avoided if the hookup to the power grid was located in a smaller city.

Tampa, Florida

The Tampa Power Company, Tampa Electric, is located in Hillsborough County.

Tampa Electric, a investor owned utility has a number of economic interchange agreements with neighboring power companies and would be receptive to a OTEC hookup if it didn't significantly increase costs.

Key West, Florida

City Electric System located in Key West, Florida/Monroe County is a publicly owned facility that depends on fuel oil for its power source. It has no power grid and the costs are relatively high, 33.2 mills per kw hour for residential use. City Electric System has no power grid nor does it plan to develop one but is looking into connecting a cable into the Florida Power & Light power grid on the mainland. OTEC power coming ashore here could not be fully used and would be transmitted to the grid by cable.

New Orleans, LA.

New Orleans, LA receives its electrical power from Louisiana Power & Light. Investor owned Louisiana Power & Light serves 46 parishes, is a member of the Middle South Utility System and the T.V.A. Power Exchange.

The First Super Port is being built off Louisiana and should be in full operation in 1985. Since deep sea ports will require sophisticated construction crews and techniques, and the coordination, costing and controlling needed for deep sea construction; this area possess much of the relevant expertise necessary to construct an OTEC facility.

Mobile, Alabama

Alabama Power Co. a privately owned facility serves Mobile, Alabama/Mobil area. Power is supplied in four ways, hydro electric, fossil fuel, nuclear and combustion turbine. Again OTEC power would probably be cable connected to the grid as well as used locally.

Since Mobile Bay is about ten feet deep except in the safety fairway it would be advantagious to hook up the power grid at Mobile Point or Ft. Gains.

Brownsville, Texas

There are two power companies serving the Brownsville, Texas area: Central Power & Light, an investor owned facility with a power plant supplied power at the outskirts of the City of Brownsville; Public Utility Board Services the City of Brownsville. Both companies are in Cameron County.

ENVIRONMENTAL IMPACT STATEMENT

The deployment of OTECs in the U.S. economic resource zone will require the presentation and acceptance of an environmental impact statement. For the single experimental OTEC being planned, nutrient upwelling is likely to be the only environmental issue seriously addressed. While it is difficult to guess the question in advance, we would expect that there will be a need to have solid answers to concerns of the generation excessive phytoplankton. As we mentioned in the earlier report, the fact that OTECs are a high technology device going into the high seas will be precedent setting and almost certainly arouse some active opposition. This will be exacerbated by the fact that OTECs are associated with an industry currently under public suspicion for antagonism to environmental concerns.

On the positive side, it is not likely that issues clearly associated with large deployments of OTECs will be addressed. Thus, for example, supporters are unlikely to have to seriously discuss onshore developments, fishing or thermal pollution of the Gulf Stream.

NAVIGATION AND CONSTRUCTION STANDARDS

These issues are unlikely to produce any serious difficulties. As we mentioned in the earlier report, OTECs will have to be constructed according to Coast Guard structural requirements. Because OTECs are expensive and vulnerable to heavy weather, it is highly probable that they will be built to exceed these standards.

The navigational concerns are unlikely to pose any problems for isolated OTECs. They will be handled simply by appropriate lighting, designation on navigational charts and the establishment of 500 meter safety zones surrounding the OTECs.

MARICULTURAL ISSUES

One of the possible secondary benefits of OTECs is the use of the effluent to feed edible aquatic life such as shellfish. As a purely economic venture, this scheme would appear to have considerable merit. International demand for food fish has been steadily increasing while supply is decreasing. (The decrease in supply results from quotas introduced as a result of the nearly universal 200 mile E.E.Z.)

While the use of OTECs to produce edible shellfish for commercial markets appears viable, other suggestions that the harvest be used as a part of the U.S. foreign assistance program is more questionable. In general, the problem is that populations which are generally receptive to shellfish as a part of their diets, frequently support moderate to large domestic shellfish industries which could be crippled by a glut of shellfish. A specific example using shrimp shows the effect. Among the worlds populations most receptive to shrimp as a dietary supplement are India's and Indonesia's. Yet these two nations are the world's leading exporters of shrimp. The economic repurcussions of large quantities of additional shrimp in these countries could exceed the benefits produced by the gift.

SUMMARY

Very briefly, the following points are made for OTECs located in U.S. economic resource area:

- On-shore Ancilliary development problems are most important.
- Large numbers of OTECs in a small area would create significant navigational problems. These could be handled through careful placing of safety fairways and safety training.
- Fishing problem not particularly serious. Precedents exist for general fouling problems.

SECTION X

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