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ELECTRIC UTILITY SYSTEM PLANNING STUDIES
FOR OTEC POWER INTEGRATION

Final Report

MASTER

Dist-212
PTB-22

November 30, 1980

Work Performed Under Contract No. AC02-79ET29187

Florida Power Corporation
St. Petersburg, Florida

U.S. Department of Energy

Solar Energy

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**ELECTRIC UTILITY SYSTEM
PLANNING STUDIES
FOR
OTEC POWER INTEGRATION**

**BY
FLORIDA POWER CORPORATION**

FINAL REPORT

NOVEMBER 30, 1980

**DEPT. OF ENERGY CONTRACT
NO. DE-AC02-79ET29187-F**

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GLOSSARY

A.C. OR AC	Alternating current
C or (C)	Degrees Celsius
CORMOD	Corporate model program
CPI	Consumer price index
CT	Combustion turbine
CTRR	Cumulative total revenue requirements
CWIP	Construction work in progress
CWP	Cold water pipe
D.C. or DC	Direct current
DOE	Department of Energy
EEI	Edison Electric Institute
EPRI	Electric Power Research Institute
FCG	Florida Electric Power Coordinating Group
FOR	Forced outage rate
FPC	Florida Power Corporation
FRP	Fiberglass reinforced plastic
GATOR	Generation and Transmission Overall Reliability program
G & T	Generation and Transmission
GWh	Gigawatt hours -- 1,000,000 kilowatt hours
h.s. heavy oil	high sulfur #6 fuel oil
ITC	Investment tax credits
kV or KV	Kilovolts -- 1000 volts
kW or KW	Kilowatts
kWh or KWH	Kilowatt hours
L.C.	Learning curve
LOADFLO	Steady state power flow program
LOLH	Loss of load hours
LOLP	Loss of load probability
mil	One tenth of a cent, or 0.001 dollars
MTTR	Mean time to repair
MW	Megawatts -- 1000 kilowatts
MWe	Megawatts electric
NERC	National Electric Reliability Council
O&M	Operating and maintenance costs or expenses
OTEC	Ocean Thermal Energy Conversion
PECO	Philadelphia Electric Load Flow program
PROMOD*	Probabilistic production costing program
PSD	Prevention of significant deterioration
PUC	Public Utilities Commission
REA	Rural Electrification Administration
SERC	Southeastern Electric Reliability Council
SLAP	Substation Load Allocation Program
SRC	Solvent refined coal
TEXAS	Contingency load flow program by University of Texas, Arlington
TVA	Tennessee Valley Authority
VACAR	Virginia - Carolina region utilities

* Proprietary Name

PREFACE

November 30, 1980

Florida Power Corporation, acting as Contractor for the U.S. Department of Energy under Contract No. DE-AC02-79ET29187, wishes to acknowledge and commend the several sub-contractors who provided valuable technical expertise and support in completing this contract:

Franklin Research Institute, The Benjamin Franklin Parkway, Philadelphia, PA, for overall technical competence, and, in particular, the conscientious and timely efforts of Dr. James R. Roney.

Energy Management Associates, Inc., 100 Northcreek, Atlanta, GA, for the excellent technical support of Dr. James M. Goodrich.

We also wish to acknowledge the continued contributions and support from Dr. Robert L. Sullivan, now of the University of Florida Department of Electrical Engineering in Gainesville, Florida and the constructive comments and direction of Dr. Jeffrey H. Rumbaugh, DOE Program Manager.

R. T. Bowles
Project Manager for the Contract
Director, Corporate Planning

STATEMENT OF WORK OBJECTIVES

Florida Power Corporation, under the U.S. Department of Energy Ocean Thermal Energy Conversion (OTEC) Program, Contract No. DE-AC02-79ET29187, directed its research effort to:

1. identify the extent to which present planning capability can consider OTEC as a viable source,
2. estimate, using present state-of-the-art approaches, the range of values for key parameters that would make OTEC economically competitive in the 1985-2000 time period.

Throughout the 19-month term of this contract, every part of the study program was carried out as a realistic scenario on an actual power system, using real-world assessments and definitions of critical factors and needs. The technical, economic, and political considerations were examined as objectively as any other electrical power source being considered in the planning process of Florida Power Corporation. Where technical expertise in OTEC was absent, qualified subcontractors were called upon to provide the necessary technical background and information.

It must be recognized that every electrical utility in the United States today will have its own individual characteristics based upon such diverse factors as geographic location, customer type and growth, fuel availability and transportation, state regulatory climate, and management philosophy and judgment. It would, therefore, be expected that different conclusions might result from a similar study by another electric utility. However, based on the initial premise that Florida Power Corporation is a logical candidate for an OTEC application and the final premise that the study was objectively carried forward, the full set of original objectives have been identified and documented by this final report.

EXECUTIVE SUMMARY

1. Florida Power Corporation (FPC) conducted an evaluation of the possible integration of OTEC into the FPC system. Existing system planning procedures, assumptions and corporate financial criteria for planning new generating capacity were used without modification.
2. For comparison, a Base Case plan which had been prepared by FPC in 1979 regarding future generating capacity expansion, was used. This included coal-fueled power plants for base load expansion through the late 1980's and 1990's.
3. A baseline configuration for an OTEC plant was developed for review with standard planning procedures. The OTEC plant characteristics and costs were incorporated in considerable detail so that the basic set of assumptions used on OTEC could be identified and adjustments made under different conditions.
4. These basic inputs were examined using the FPC system planning methods. It was found that with the initial set of conditions, OTEC would not be economically viable (cost competitive). The cumulative revenue requirements for a plan which included OTEC exceeded that for the Base Case plan to such an extent that it would not be considered a candidate for construction.
5. Using the same system planning procedures, a number of adjustments were made to the key study assumptions. It was found that two considerations dominate the analysis; the assumed rate of fuel cost escalation, and the projected capital cost of the OTEC plant.

6. The above analysis produced a parametric curve: on one hand, if fuel costs were to escalate at a rate greater than assumed (12% versus the assumed 5% for coal), and if no change were made to the OTEC input assumptions, the basic economic competitive criteria would be equivalent to the principal alternative, coal fueled plants.

Conversely, if the projected cost of the OTEC plant were to be reduced from the assumed \$2256/kW to \$1450/kW, the economic competitiveness criterion would be satisfied. Correspondingly, intermediate combinations of values between these limits could meet the criterion.

7. After corporate financial analysis, it was found that even if the cost competitive criterion were to be reached, the plan including OTEC could not be financed by Florida Power Corporation. This situation is not peculiar to OTEC, but would be experienced with any heavily capital intensive generating source. Although economic competitiveness could look attractive on a life-cycle cost basis, problems with capital formation might override the "free fuel" advantages.

8. Since, under the existing set of conditions for financing new plant capital requirements, FPC could not construct an OTEC plant, some other means of ownership would be necessary to integrate OTEC into the FPC system. An alternative such as a third party owning the plant and selling power to FPC, might prove attractive.

9. There were certain factors of concern to FPC which need to be resolved such as legal maritime jurisdiction, plant protection from weather, collision, and international insurrection. However, there were no fundamental barriers to an FPC purchase of power from some eventual owner of an OTEC unit. To the contrary, current FPC policy supports power purchases.

1. INTRODUCTION

1.1 STUDY PURPOSE AND SCOPE

1.1.1 Introduction to the Study

The decision to choose a new generating plant addition is a complex process for an electric utility company. Due to the long lead times in constructing a new facility, the decision must be made well in advance of the actual need. Thus a forecast of the need for new generating capacity is one of the major inputs to this decision-making process.

System planning, as exercised by major electric utility companies, involves sophisticated methodologies including computer-based models which simulate the electric characteristics of generating plants, transmission systems, and other technical features of the utility's total system. The methodology also includes the necessary elements of the corporate financial status and economic impacts involved in the decision-making process.

Any possible type of generating facility, be it nuclear, coal, or any of the newly developing technologies, must be subjected to a detailed planning evaluation to furnish the information needed by management in its decision making. Thus, one of the means of evaluating a new technology is to have it considered and evaluated by a utility company through the system planning process, and scrutinized by a potential user of the new technology in a manner directly drawn from the user's methods of decision-making for any new capacity additions.

For a number of reasons, Florida Power Corporation is a possible candidate for the application of Ocean Thermal Energy Conversion (OTEC) to meet future electric power generation needs.

Some of these reasons are:

- o Location on the Gulf of Mexico within reach of a 20 degree C (36 degree F) thermal resource (surface to deep water temperature difference)
- o A heavy dependence upon one fuel source -- coal -- for future generating capacity expansion and as a result, diminished fuel source diversity
- o A large (almost 5000 MW) and rapidly growing (6% per year) demand pattern
- o A well developed system planning procedure incorporating advanced computer-based simulation models for technical and economic evaluation of alternatives.

The company's service area borders the Gulf coast of Florida. The "Sun Coast" area in the vicinity of St. Petersburg has been one of the fastest growing areas in the nation and in Florida. One of the candidate sites for large commercial OTEC plants is almost due west of St. Petersburg, as shown in Figure 1-1.

By having Florida Power Corporation (FPC), a company with possible OTEC utilization, exercise its system planning methods to consider this potential source of future generating capacity, a number of highly useful results would be obtained:

- (1) The company would review and consider OTEC and begin formulating a decision. This would, in turn, increase the company's familiarity with and understanding of the new technology.
- (2) Specific, detailed information concerning the suitability of OTEC would be developed and, conversely, problems that might tend to work against its adoption will be exposed. Thus, OTEC developers, whether government or industry, would receive valuable and timely feedback to guide the commercialization of OTEC.
- (3) Should the evaluation of OTEC prove favorable, the first steps toward commercial introduction would be taken by a potential user and the process to commercialization would be facilitated and expedited.

Figure 1-1
OTEC PLANT SITE

1.1.2 Scope of the FPC OTEC Integration Study

The overall study of the application of system planning to OTEC was carried out in four tasks. These tasks were:

Task I - Describe the Current System

Task II - Include the OTEC Alternative

Task III - Perform Parametric Analysis

Task IV - Determine Needed Incentives for Commercialization

Task I was a description of the Florida Power Corporation system and the company's system planning process. Included in this task was a description of the current generation expansion plan completed in 1979. Task II was an evaluation of OTEC as a possible alternative in the generating expansion plan, with a set of baseline OTEC inputs (cost and operating characteristics) with no special incentives included. Task III varied important parameters to explore OTEC competitive conditions. Task IV was a consideration of feasible incentives and institutional factors that might encourage adoption of OTEC as part of the generation expansion plan.

1.1.3 Basic Assumptions and Contractural Ground Rules

Most electric utilities have formalized procedures for planning generating plant capacity additions. These procedures include assumptions and values for important parameters which are developed and used by each company based on individual situations, local conditions, and matters such as company policy. For example, there are assumptions on the future rate of inflation which are important to the procedures used in the planning process, and each company has its own set of assumptions on future inflation rates.

This study, performed for the U.S. Department of Energy, had as a basic condition, the use of existing Florida Power Corporation system planning procedures and the corresponding set of assumptions used by FPC in their normal planning process. Only where specifically

identified, were any numerical values of significant parameters varied for analysis purposes (for example, in Task III where inflation rates were varied to consider the consequences in planning results).

In addition there were necessary assumptions and conditions on the characteristics and numerical values for the OTEC plant included in the analysis. These are stated in the appropriate portions of the report where values or configurations for the OTEC plant are introduced.

It is important to interpret the results of this study with reference to these basic conditions and assumptions. One may postulate other assumptions and reach differing conclusions. However, the contractual scope of this study was to use the existing procedures and assumptions of FPC modified only where required for parametric variation analysis.

1.2 SYSTEM PLANNING, GENERAL DESCRIPTION

1.2.1 Definition and Scope

An electric utility company must formulate plans in a systematic manner for expansion of its generating capacity and transmission system. The decision-making process has a multitude of inputs, future load forecasts, future cost and availability of various energy forms, presently available generating technologies, possible future generating technologies, regulatory constraints, financial market factors, etc. The methodology by which all the factors are considered and evaluated, and a plan developed to meet the needs for future expansion, is UTILITY SYSTEM PLANNING.

System planning may include computer simulations dealing with the physical and electrical characteristics of generating plants and transmission facilities, as well as corporate financial and economic factors and other processes amenable to modeling.

The overall electric power supply system in the United States is today the world's most capital-intensive industry and becomes more so each year. This trend places a burden on the various utility organizations to provide the financing for expansion of their respective systems at a time when capital is both expensive and not readily available. It also raises to new importance the role of those individuals who have the responsibility to determine the least-cost strategy as to how the system should grow: the system planners.

Early in this century, utility systems operated as isolated islands, each containing small clusters of load, generation, and connecting power lines. During the 1920's, the interconnection of these islands by transmission lines began, and a trend toward increasing inter-utility tie-line capacity continues to the present. In some cases, the interconnection was coincident with the merger of relatively small utilities to form larger ones. In virtually all cases, the desire of the public for the convenience of electric service resulted in the

rapid growth of the electric utility industry. Growth and interconnection of neighboring systems brought improved economies of operation, which resulted in more growth. This trend of relatively steady and strong growth continued for more than 50 years until 1974. The growth in system load was accompanied by growth in the size of the generating units, in the voltage levels used in the bulk power transmission system, and in system reliability.

1.2.2 Factors Considered in System Planning

The basic role of the system planner has three critically important objectives: reliability, cost, and financeability. Expansion and growth of the electric power system must be planned so that: (1) the established standards of reliability are satisfied; (2) the total cost of supplying electric service is minimized; and (3) the expansion can be financed. The high level of reliability that has been achieved by the electric power supply system in the United States has been an important factor in the growth and strength of our economy over the years.

1.2.3 Reliability

One of the basic considerations in system planning is reliability. This topic, in the context of system planning covers many aspects. For an electric power system, including generation, transmission and distribution of power to users, reliability is the assurance that the power can be delivered without interruption and within specifications on voltage and other electrical properties. For an overall system to achieve desired reliability, individual components and sub-systems must operate with mechanical and electrical reliability through a combination of low failure rates and redundant or back-up components. One major factor in system reliability is the availability of generating units; i.e., their capability of being placed on-line and

delivering power to the system. The term usually applied to overall generating unit reliability, in this context, is "availability". Another major factor in system reliability is transmission reliability, in which the transformers and transmission lines are the principal elements.

To assure system reliability, a utility must plan to provide sufficient generating capacity and transmission capability, considering possible growth in load demands and other factors. The consideration of system reliability begins with an assessment of the generation and transmission needs of a utility system. Trends in overall load growth for several years and the load pattern from one season to the next are inputs to the system planning problem.

The subject of system reliability touches many technical, economic and institutional issues. It concerns not only how much generating capacity a utility should add, but the type, size, and location of the unit or units it should be build.

The following sub-paragraphs discuss several important issues regarding system reliability.

Diversity

One means of providing system reliability is through the diversity of energy sources. Diversity involves the use of different types of fuels in generating stations (oil, coal, nuclear) or obtaining power from some other source such as purchase from a neighboring utility. History has repeatedly shown that diversity of the types of energy resources the utility should rely upon is extremely important. Those utilities which are heavily dependent on hydro-power may experience power shortages in years of small rainfall and snowfall. Those which are heavily dependent on coal will have problems in the event of a protracted strike by the miners or transportation workers, or by weather conditions which cause the coal piles at the plant to become frozen. Those which are heavily dependent on oil are affected by international events which cut off supplies of imports, and by

protracted periods of severe weather which interrupt fuel deliveries for an extended period. Those which are heavily dependent on nuclear power are subject to orders from regulatory authorities to shut-down a substantial portion of their generating capability because of safety problems.

Diversity and Reliability Through Transmission Interconnections

Another way to achieve diversity is through the interconnection of systems that rely on different energy forms and are located in different geographic areas. In this way, a system which is not affected by a particular occurrence can supply surplus power from its own reserve capacity to an affected system. This creates the questions of how great an investment should be made in ties to other utilities, and what the overall economies of power purchases from neighboring systems are.

Technological Uncertainties

Long-term system reliability is also affected by uncertainties in technology, particularly as the technological uncertainties may affect generating unit availability. Uncertainties exist when a given technology has not established a statistically significant performance record which can be used in the evaluations. This aspect is particularly relevant to this study, which is focused on the application of a new technology. For example, studies may show that a particular technology -- be it a type of fuel cell, a scrubber to reduce sulfur emissions from a power plant, or an OTEC plant -- will probably operate with a certain combination of individual reliabilities of components and sub-systems and a resultant overall generating unit availability. If this particular technology is then used by the utility on a large scale and the generating reliability is significantly lower, then the system reliability will be affected. For this reason, the utility industry is justifiably conservative (cautious) in applying new technologies.

Short Term Aspects of System Reliability

In addition to these long-term aspects of system reliability, there are also short-term aspects. The effect of strikes and weather disturbances on generating plants has already been noted. Another aspect of system reliability must be recognized in transmission planning. In the steady-state sense, system reliability is the system's ability to meet demand within the specified voltage limits and the ratings of transformers and transmission lines. A different aspect of system reliability addresses transient stability considerations; for example, the ability to withstand a sudden outage through the first few seconds or minutes without causing additional loss of facilities -- the cascading effects that may lead to widespread blackout.

Transmission Reliability Analysis

State-of-the-art deterministic transmission planning addresses both steady-state outages and transient system disturbances. Selected events are mathematically simulated by computer to determine whether the simulated transmission system performance (voltage levels, line loadings, frequency, etc.) will be within acceptable limits. The outages and transient disturbances chosen for simulation are based on experience and engineering judgment. The transmission system is then planned to maintain adequate system performance during the occurrence of more likely outages (e.g., failure of a single line). However, some degradation of system performance may be tolerated for less likely circumstances, such as multiple line outages or the loss of a power plant. The goal of this approach is to reduce the chances of a blackout, but if it should occur, to limit its impact in terms of the population affected and time to restore service.

1.2.4 System Expansion Plan Cost and Financeability

It was stated that one of the critical objectives of the system planner is cost. One of the means used by system planning to minimize cost for the production of power in the system is generating unit optimization. Computer models of the entire electric system are also used to determine the optimum utilization of each generating unit as the system is envisaged some years in the future, taking into account new plants (at new and existing sites), new transmission ties, and postulated agreements with neighboring utilities for the purchase of power. These data (basically, the amount of fuel forecasted to be used each month by each plant, over a 20-year period, and the corresponding kWh produced), are then used with other data on plant capital expenditures, operation and maintenance costs, and similar data for transmission lines, the distribution system, and general office expenses, in another computer program to analyze the economic viability of postulated system expansion plans.

Generally, a number of possible system expansion plans are considered and evaluated. The total cost of each plan is calculated in a computer program and used as a criterion for evaluation. The plan with the lowest total cost, or with a small cost difference, is generally selected. This plan, or plans, is subject to further consideration on other criteria. The plan that meets the specified standards for reliability and has the lowest overall costs is the most desirable, if it can be financed. Although a given plan may indicate a lower cost, it may place demands on developing capital that are unfavorable to the corporate financial position.

A common example of this situation is seen in decisions today to delay the completion of power plants being constructed. Even though total costs would be lower if the plant were completed more quickly, its construction is drawn out for a few more months or years, during which inflation takes its toll, because the borrowing limits of the utility has been exceeded, or its earnings do not support the sale of more stock to raise capital.

1.2.5 Summary of System Planning Process

The objective of the system planning function is to determine how the utility system should expand to meet future load demands in the most economical manner, considering the constraints posed by reliability and financing. The factors which are considered in this determination include:

Forecast of future load, so the peak power demands and kWh sales in each month during the period over which the planning study is being made can be derived, considering: (a) the ability of the utility to manage load through its own actions, and (b) the probable impact of future rate increases in producing "conservation".

Future cost and availability of various energy forms.

Remaining economic life of existing generating plants.

Existing, proposed or probable future regulatory constraints placed on different energy sources or technologies.

Cost and availability of power from neighboring systems under both emergency and normal conditions, with availability determined jointly by that system's generating capacity and expected load growth, and by the capability of the bulk power transfer inter-ties.

Cost (capital and operating), availability and reliability of existing generating technologies.

Cost (capital and operating), availability and reliability of new technologies, considering the effect on these three factors of subsidies or other incentives provided by governmental bodies or other organizations.

Reliability of the bulk power transmission system, considering both line outages, equipment failures, and dynamic (stability) phenomena.

Expected rate of inflation and interest costs.

Time frame in which proposed rate increases will be acted upon.

Figure 1-2 is a schematic representation of this process.

Figure 1-2
THE SYSTEM PLANNING PROCESS

1.3 FLORIDA POWER CORPORATION BACKGROUND

1.3.1 The Company and Its Service Area

FPC is one of the larger investor-owned electric utilities in the U.S. having had a peak load in 1979 of 4224 megawatts. FPC operates in the central, northern, and western portions of the State of Florida as indicated in Figure 1-3. Its service area spans the Gulf of Mexico coast from St. Petersburg to about 40 miles west of Apalachicola. The company's headquarters are in St. Petersburg, the largest city in its service area.

The company serves a population of almost 3 million people located in 375 cities, towns, and rural communities. The total area served is about 20,000 square miles representing 32 of Florida's 67 counties. The five operating divisions of the company are also shown in Figure 1-3.

The company is interconnected with two operating companies of the Southern Company: Georgia Power Company to the north and Gulf Power Company to the west. To the south and east, it is connected to Tampa Electric Company and Florida Power & Light Company, plus municipally-owned utilities and rural cooperative electric authorities.

At the present time, each utility operates independently; however, the Florida Electric Coordinating Group (FCG) has been formed to coordinate electric utility planning and operations within the state. The trend is toward more tightly integrated systems. (See Section 1.6.2).

1.3.2 Load Characteristics

For the past six years, the peak demand for the year has occurred in winter, usually during the first several weeks of the calendar year. This reflects the high saturation of electric space heating, an alternative made attractive by the relatively mild year-round climate. Because of recent rapid escalation in the price of fuel oil and increases in the price of natural gas, the trend toward more electricity for space heating is likely to continue. This would produce continued winter peak-load conditions.

Figure 1-3
FLORIDA POWER CORPORATION SERVICE TERRITORY

During winter months, weather related electricity use for space heating is intermittent, producing high short-term peaks with modest average consumption. Energy requirements are higher in the summer. During the long, hot and humid summers, electrically driven space cooling equipment operates at a much higher energy to peak-load ratio, and hence a higher load factor (69 to 79%). System planning must consider seasonal and annual load factors as well as daily peak loads. Annual load factors may decrease in the future for the following reasons:

- Increased installations of electric heat in the winter
- Decreased use (fewer running hours) of space-cooling equipment during the summer, because of customer efforts, to reduce consumption, i.e. conservation.

Currently, the annual load factor is slightly greater than 50%; significantly lower than the average of almost 60% during the period 1968 to 1973, due to the reasons outlined in the preceeding paragraph. The peak demand (kW) has increased at a rate of 8% per year since 1975, and annual kWh sales have increased at an average rate of slightly less than 7% annually during the same period.

During the previous five-year period (1968-1973) peak load and energy sales increased at 14% per year, reflecting more rapid growth of the economy and electricity use.

Sales of electricity to various customer categories are as follows:

	Percent
Residential:	40
Commercial:	22
Industrial:	17
Other Utilities:	18
Public Authorities:	3

This mix has been essentially constant for the past five years; earlier the industrial sector had a somewhat larger share. The ten largest industrial customers account for 65% of the total kWh sales in this sector. These customers are concentrated in phosphate and limerock mining, food processing, and chemical industries. There are a few large, and a greater number of small and medium-sized electronics firms

in this area. Although this industry is noted as being non-energy-intensive, these firms account for about 9% of the total kWh sales in the industrial category.

The number of customers in each category as of the end of 1978 was:

Residential:	649,043
Commercial:	69,736
Industrial:	61,885
Other Utilities:	137
Public Authorities:	2,057

Florida residences are heavily electrified, A survey conducted in 1977 showed the following equipment saturation:

- 85% having electric hot water heating
- 82% having electric space cooling
- 80% having electric cooking
- 52% having electric space heating as the primary source, plus an additional 14% who use electric heating as a secondary source
- 43% having electric clothes dryers.

1.3.3 System Planning Consequences of Load Characteristics

As do other electric utilities, FPC commissions new units ahead of the peak load period to achieve desired system reliability. This is true even though FPC might have an economic incentive to commission a new base-load generating unit a few months after the peak load of the calendar year, since the new base-load unit, with lower production costs than the older units, could displace more expensive generation for a larger number of kilowatt-hours during the summer.

The relatively large percentage of interruptible load (284 MW) in the industrial category is used to provide a "margin" for the peak load, particularly during exceptional events such as coincident forced outages of more than one unit.

The growth of the winter peak may be moderated through use of load management techniques applied to electric water heating and space heating equipment. FPC is currently engaged in testing load management

programs to determine their practicality. The 1979 load forecast assumes that no load management programs will be implemented in the next year. However, FPC will definitely include load management programs in the load forecasts by 1980.

Most of the generating units presently installed are derated by up to 10% during the summer months, because the higher air and water temperatures reduce power production capacity. Also, during the summer months, the maximum current carrying capability of transmission lines is lower than during the winter because of higher ambient temperatures.

1.3.4 Present Power Supply System

Generation.

The FPC system contains a mix of generating units, including oil and natural gas fired combustion turbines for peaking service, residual oil and natural gas fired steam turbine-generators for intermediate service, and coal-fired and nuclear fueled units for base load service. Table 1.1 presents a summary of the installed generating stations and the individual units as of the end of 1978. Total installed capacity was:

Steam turbine units	3381 MW
Combustion turbine units	1486 MW
<hr/>	
Total	4858 MW

Transmission

The FPC bulk power transmission system consists of 230 and 500 kV transmission lines with an underlying subtransmission system consisting of 69 and 115 kV transmission lines. Figure 1-4 shows the bulk power transfer system, consisting of the 500 kV and 230 kV lines, as of the end of 1978. This figure also shows the location of connections with other utilities.

TABLE 1.1 FPC GENERATING STATIONS AND UNITS AS OF 12/31/78

Station	Unit	Winter Capacity	Fuel*	Prime Mover†
Crystal River	-1	383	O	S
	-2	350	C	S
	-3	731	U	S
Anclote	-1	506	O	S
	-2	506	O	S
Bartow	-1	114	O	S
	-2	116	O/G	S
	-3	215	O/G	S
	-P1	51	O	C
	-P2	51	O	C
	-P3	51	O	C
	-P4	51	O	C
Turner	-3	72	O/G	S
	-4	75	O/G	S
	-P1	17	O	C
	-P2	17	O	C
	-P3	81	O	C
	-P4	81	O	C
Intercession City	-P1	55	O	C
	-P2	55	O	C
	-P3	55	O	C
	-P4	55	O	C
	-P5	55	O	C
	-P6	55	O	C
Debary	-P1	47	O	C
	-P2	54	O	C
	-P3	54	O	C
	-P4	47	O	C
	-P5	47	O	C
	-P6	54	O	C
Higgins	-1	40	O/G	S
	-2	41	O/G	S
	-3	42	O	S
	-P1	30	O/G	C
	-P2	30	O/G	C
	-P3	35	O/G	C
	-P4	35	O/G	C
Bayboro	-P1	52	O	C
	-P2	52	O	C
	-P3	52	O	C
	-P4	52	O	C

TABLE 1.1 FPC GENERATING STATIONS AND UNITS AS OF 12/31/78 - Continued

Station	Unit	Winter Capacity	Fuel*	Prime Mover†
Suwanee River	-1	34	O/G	S
	-2	33	O/G	S
	-3	80	O/G	S
Avon Park	-2	44	O/G	S
	-P1	35	O/G	C
	-P2	35	O/G	C
Port St. Joe	-P1	17	O	C
Rio Pinar	-P1	17	O	C

* C = Coal
G = Natural Gas

O = Fuel Oil
U = Uranium

† C = Combustion Turbine
S = Steam Turbine

Figure 1-4
FLORIDA POWER CORPORATION BULK POWER TRANSMISSION SYSTEM

1.4 FLORIDA POWER CORPORATION SYSTEM PLANNING

1.4.1 The System Planning Process

Planning at Florida Power Corporation is a continual process carried out by a System Planning Department reporting to the Director of Corporate Planning. In September of each year, a formal Generation Facility Expansion Plan is prepared and submitted to corporate management and, after review and approval, to the Board of Directors. Formal approval by the Board sets the general policy to be followed, including the specific construction budget, power purchase and sale commitments, and site licensing and acquisition. The procedure followed in preparing this formal report is shown in Figure 1-5. Each step and the associated activities are described in the following paragraphs.

Step 1. Establish Basic Assumptions: The projected health of the economy in the region, population shifts, weather conditions on which peak loads are based, inflation rates and related factors are examined. Policy guidelines regarding outside purchases of power and construction of jointly owned facilities are established. Also, the impact of programs related to cogeneration, solar energy, load management, and other advanced methods is estimated.

Step 2. Prepare Load Forecast: The procedure of preparing a load forecast is diagrammed in Figure 1-6. At the present time, FPC procedure is to forecast the future peak loads (summer and winter) and the annual kWh sales separately for each customer classification, and sum these to obtain the total quantities. In making these forecasts, information on past trends is combined with the known and expected future activities in the region (e.g., any likely penetration of load management techniques, use of solar energy systems, extent to which customers will install more energy efficient systems or apply other conservation measures, etc.) . The company is in the process of implementing an econometric computer model and plans to utilize this in its load forecasting activities.

Step 3. Postulate Alternative System Expansion Plans: Several alternative system expansion scenarios are postulated, considering such

Figure 1-5
GENERATION FACILITY EXPANSION PLANNING PROCEDURE

FLOW CHART - FPC MODEL FOR
LONG-RANGE FORECASTING OF ELECTRIC ENERGY
AND DEMAND

Figure 1-6
LOAD FORECASTING MODEL

factors as the rate of load growth, the results of the prior year's plan, the status of discussions regarding joint ownership of facilities, power purchase and sale agreements, developmental status of new technologies, and actual or proposed regulatory constraints on existing technologies. Some preliminary computer studies are made to learn which of these is likely to be attractive, and to adjust the capacities and in-service dates of new installations or power purchases. During this step, an estimate of the financial risks associated with the different scenarios is made. For example, present, proposed or possible regulatory constraints on the various technologies along with post-operating experience, are considered. Also, the effect of delays in the commercialization of new technologies is evaluated. The purpose of this evaluation is to determine the likely financial consequences to the company of the regulatory constraints or commercialization schedule slippage.

Step 4. Determine System Reliability and Economic Consequences for Each Alternative Scenario: Detailed investigations of each of the alternative scenarios judged to be viable are then conducted. The general sequence is:

Step 4-a: Determine generating system reliability using the PROMOD computer program.

The program is an extremely powerful tool which simulates the operation of the utility's generating facilities, computing the amount of production from each unit that yields optimal overall production costs or fuel costs, within the constraints imposed. The program utilizes probabilistic techniques to represent forced outages, and also simulates scheduled outages. As used in the system planning process, a 20 year period is simulated, with calculations made on a monthly basis using hourly load models.

Figure 1-7 shows the input parameters and outputs from the program. The key output parameter at this stage of the planning process is the loss-of-load probability (LOLP). Florida Power Corporation has established a LOLP criterion of one day in 10 years loss of firm load. This results in an equivalent design criterion based on projected load shape and interchange capacity availability. A generating facility expansion plan which deviates significantly from this criterion is unacceptable; those which come close to it are judged to be worthy of further consideration.

*PURCHASED CAPACITY OR COMPANY-OWNED FACILITY.

†SEASONAL CAPABILITY; MAINTENANCE OUTAGE REQUIREMENTS; ACCEPTABLE FUELS; COMMERCIAL OPERATION, "MATURITY" AND RETIREMENT DATES; HEAT RATE AND AVAILABILITY (UP TO FIVE CAPACITY LEVELS).

Figure 1-7
PROMOD COMPUTER PROGRAM AS USED IN SYSTEM PLANNING STUDIES

Step 4-b Determine the economic impact of the scenario on the company and its customers by using the CORPORATE MODEL computer program.

This program simulates the financial functioning of the company, calculating all expenses and revenues month-by-month over the entire period of the study. It is, therefore, an extremely valuable evaluation tool to aid management in the decision-making functions, and is the cornerstone of FPC's Management Information System.

Figure 1-8 shows the input parameters and outputs from the program, and its relationship to other subsidiary programs with which it is used. The program simulates the necessary line of credit available from banks for short-term financing. When the limit of short-term borrowing is reached, the program simulates the sale of securities of various types for long-term financing. Rate increases are simulated as needed to maintain revenues at the level sufficient to provide a satisfactory rate of return. The key output parameters are: (1) those which indicate whether a particular system expansion scenario can be financed (the frequency and magnitude of rate increases, ability to secure funds through sale of securities); and (2) the present-worth of corporate revenue requirements during the time period simulated in the study. If more than one alternative scenario with acceptable reliability is financable, then the one with the smallest revenue requirement is considered most attractive.

Step 4-c Determine the adequacy of the bulk power transmission system by using conventional LOADFLO and fast linearized LOADFLO programs, plus other studies made in conjunction with other utilities in the region.

All major lines and load centers within FPC are represented in these computer programs, plus those of the other utilities in the region encompassing the entire state of Florida and major portions of adjoining states. The forecasted peak summer and winter loads five years in the future, plus the generating units expected to be operating at this time also are represented. The LOADFLO program solves hundreds of linked non-linear algebraic equations and calculates: (1) the power flow through each line, and (2) the voltage level of each bus. All lines in which the power flow exceeds the normal rating are listed, plus all bus voltages which are either above or below the allowable range. These results show any potential problems during normal peak-load conditions. Alternative solutions to the indicated problems are made in the computer model representation, and the program is rerun until a satisfactory solution is obtained.

After these runs are made using the LOADFLO program, a simpler program which uses linearized forms of the equations, and thus

Figure 1-8
**CORPORATE MODEL COMPUTER PROGRAM AS USED IN
SYSTEM PLANNING STUDIES**

gives "approximate" rather than "exact" solutions is run to perform a contingency analysis. This term applies to the sequential removal of each and every line in the transmission network under study, and calculation of power flows and bus voltages under these circumstances. The key output consists of a listing of power flows and voltages which deviate from the emergency limits. This analysis identifies additional problems in the bulk power transmission system that need further study.

Step 4-d Perform long-range siting and interconnection studies using the same programs.

In addition to this regular and routine set of analyses, others are made to compare alternative sites for new large generating facilities. In this case, the planning horizon is generally 8-20 years in the future, and the computer model may have a more simplified representation. The principle is the same, however, and the results indicate what changes in bulk power transmission system are needed to satisfy the load. The cost of such changes related to each alternative site are then included in the economic analysis which forms a key part of the site selection process.

Representatives from the various electric utilities in the state meet together on a regular basis to keep each other informed concerning both tentative and "firm" plans for changes in the bulk energy supply system (e.g., new plants, scheduled retirements, line up-gradings, new lines, and load forecasts).

This organization, incorporated in 1975, has the name "Florida Electric Power Coordinating Group, Inc." (FCG), and it, in turn, has representatives which meet with other utilities which comprise the Southeastern Reliability Council (SERC). The FCG and other power systems in the SERC region utilize basically the same computer programs to study system interconnections in the 3-20 year planning horizon.

Step 5. Analyze Results and Recommend Plan: This final step analyzes results and recommends a plan which has the lowest revenue requirements yet meets reliability criteria, financial constraints, and scheduling constraints as closely as possible.

1.4.2 Transmission Reliability

Two aspects of reliability must be recognized in planning the expansion of a utility's bulk power transmission system. From a "steady-state" point of view, the reliability of the system measures its ability to meet the load demand (within the specified voltage limits and the rating of transmission lines and transformers). From a "dynamic", or transient, point of view, the reliability of the system reflects its ability to withstand a sudden outage without causing additional loss of lines or generating facilities within the next few seconds or minutes. The latter situation -- the cascading of one failure into several -- can lead to a blackout over an entire region. It is the second aspect that is addressed in part by the contingency analysis cited above in Step 4-c. A more complete evaluation is made by using transient stability computer programs, over a two-year planning horizon, since the programs are extremely data intensive and quite expensive to run.

FPC has developed a new computer program during the past few years. It is called GATOR (Generation And Transmission Overall Reliability). This program utilizes probabilistic methods, similar to those used in PROMOD, together with historic line and generator outage data (i.e., outage rate and restoration time) to calculate the probability that a line will be out of service. It combines these calculations with load flow results and remedial operating procedures to determine the overall system reliability. GATOR is now in use on a trial basis.

1.4.3 Computer Programs Used

The four computer programs used by FPC in system planning are described further in Appendix A.

1.5 The 1979 System Expansion Plan

1.5.1 FPC Basic Assumptions Used In Expansion Planning

- Normal weather conditions will prevail.
- All economic indicators at present point toward a recession of some degree. According to the national economists, this will be a short-term recession. In view of this, assume a reduction in kWh growth, particularly in the residential class. This decline in growth is also due to the cost of other goods and services eroding customer discretionary income, thereby leaving less for electric energy.
- There will be no significant loss of energy sales to solar energy until the late 1980's.
- Future filed rate increases will have no effect on electricity sales during the next two years.
- All of the wholesale load within the service area, along with its associated growth in demand and energy, will be served except the portion of REA and Cooperative loads to be supplied by Seminole Electric Cooperative beginning June 1, 1983.
- The population projection made by the Bureau of Economic and Business Research at the University of Florida is reasonably accurate.
- Any impact due to load management in our system will not become effective until after 1980 and will not be included in the forecast until a corporate decision is made concerning large scale implementation.
- The effects of improved customer equipment efficiency and the increased effectiveness of thermal envelopes due to additional and improved insulation will have a minor impact on the forecast.

- The forecast of the Consumer Price Index (CPI), as developed within FPC, is:

Average Annual Inflation Rates

Years	Rate
1979-1983	7.2%
1984-1988	5.0%
1989-1993	2.6%
1994-1998	2.9%

These figures are the annual averages for each of the five year periods. Rates for individual years within each period may be higher or lower. The CPI figures form the basis for all other escalation assumptions used in the study. Escalation of construction costs of new facilities will be 1.5% higher than the above values. Fuel cost escalation assumptions, particularly assumptions regarding escalation of coal, are developed in a manner consistent with the CPI forecast. Escalation rates for specific fuel types (also expressed as five year averages) are as follows:

Years	Coal	Oil	Distillate	Nuclear
1979-1983	6.1	12.4	14.4	24.4
1983-1988	5.0	8.2	8.2	8.4
1989-1993	5.0	9.0	9.0	5.0
1994-1998	5.0	9.0	9.0	5.0

- Jointly owned generating facilities and power purchases are encouraged. Transmission ties to neighboring systems will be strengthened during the decade of the '80s.
- By 1990, oil consumption will be reduced to 50% of the 1979 usage.
- Capital costs and fuel costs for the alternative types of generating facilities are as shown in Figures 1-9 and 1-10, respectively.

Figure 1-9
**CAPITAL COST (1979 DOLLARS)
ENGINEERING DESIGN BASIS**

Figure 1-10
FUEL COST FORECAST 1979 FACILITY PLAN STUDY

1.5.2 Load Forecast

Figures 1-11 and 1-12 show the number of annual customers and the year-to-year percentage change in this number, both during the past 10 years and during the 1979-1998 period. Figures 1-13 and 1-14 show, for the same time periods, the historic and projected electricity sales (kWh) and growth rate in energy sales. Figures 1-15 and 1-16 show similar data for the peak load demand on the system (kW).

1.5.3 System Expansion Scenarios Considered

Serious consideration was given to various combinations of installing base-load coal-fired generation, installing oil-fired "peaking" generation using combustion turbines, and purchasing capacity from adjacent utility systems. Some system expansion scenarios were eliminated from detailed considerations because of risks associated with uncertain regulatory climate, immature technology, or availability of fuels. For example, additional nuclear-fueled generating capacity, although indicating attractive economics, was not recommended due to regulatory uncertainties. Furthermore, combined cycle generating units using synthetic fuel which also appeared attractive, were not recommended at this time due to uncertain fuel availability.

**Figure 1-11
AVERAGE ANNUAL CUSTOMERS**

Figure 1-12
PERCENT INCREASE ANNUAL CUSTOMERS

**GIGAWATT HOURS
(GWH)**

**Figure 1-13
ANNUAL SALES**

Figure 1-14
PERCENT INCREASE KWH SALES

Figure 1-15
ANNUAL PEAK DEMAND

Figure 1-16
**PERCENT INCREASE ANNUAL PEAK DEMAND
(WITHOUT DEMAND SERVED BY SEMINOLE 1983 AND AFTER)**

1.5.4 Recommended System Expansion Plan

The 1979 system expansion plan that evolved from the 1979 FPC study is one which places major reliance on purchasing power from other utilities during the 1980's, plus constructing five large coal-fired units during this time period and three more during the 1990's. The first two units are now under construction. Ownership of and output from the following two units may be shared with other utilities since only 660 MW from each unit is needed by FPC, but 800 MW is projected to be the most economical unit size to build. The final four units may be completely owned by FPC although joint ownership may be explored at a later time. Table 1.2 presents the load and capacity forecast of the recommended plan.

The results of the system reliability and cost studies showed that the recommended plan had both higher reliability and lower costs than the alternatives. The primary reason for the favorable economics is that load growth in the Southern Company System (adjacent to FPC) has been quite low, and this utility currently has a surplus of coal-fired capacity. The cost of purchasing power from this system is a much more attractive way to provide the company's short-run (1980-1986) capacity requirements than the only viable alternative, peaking units.

Figure 1-17 displays the key data from Table 1.2, plus the corresponding historic data from the period 1968/1969 to 1978/1979. Figure 1-18 shows the scheduled and planned additions to generating facilities and power purchases during the study period. Figure 1-19 displays the Loss-of-Load Probability for the first ten years of the planning period for two cases: adding base-load generating facilities only, and the final plan, with both generation additions and purchased capacity. Figure 1-20 shows the fuel mix that is expected year-by-year during the study period.

TABLE 1.2 LOAD AND CAPACITY FORECAST

(Megawatts)

Year	Inst. Cap.	Net Contract Purch. & Sales	Cap. Avail. @Winter Peak	Capacity Added	Capacity Retired	Inst. Cap. at End	Winter Peak Load	Reserves (%)
1979	4858	65	4923	- (1)	-	4858	4450	10.6
1980	4858	336	5194	245 (2)	-	5103	4750	9.3
1981	5103	656	5759	65 (3)	-	5168	5050	14.0
1982	5168	836	6004	670 (4)	-	5838	5360	12.0
1983	5838	661	6499	- (5)	-	5838	5660	14.8
1984	5838	536	6374	670 (6)	-	6508	5760	10.7
1985	6508	431	6939	- (7)	(44)	6464	6050	14.7
1986	6464	506	6970	660 (8)	-	7124	6140	13.5
1987	7124	406	7530	660 (9)	-	7784	6280	19.9
1988	7784	406	8190	- (10)	-	7784	6610	23.9
1989	7784	406	8190	660 (11)	(130)	8314	6800	20.4
1990	8314	406	8720	950 (12)	(69)	9195	6990	24.7
1991	9195	6	9201	- (13)	(69)	9126	7270	26.6
1992	9126	6	9132	800 (14)	-	9926	7350	24.2
1993	9926	6	9932	- (15)	-	9926	7640	30.0
1994	9926	6	9932	- (16)	-	9926	7700	29.0
1995	9926	6	9932	800 (17)	-	10726	7970	24.6
1996	10726	6	10732	- (18)	-	10726	8130	32.0
1997	10726	6	10732	- (19)	-	10726	8400	27.8
1998	10726	6	10732	- (20)	-	10726	8650	24.1

(1) 50 MW Up-grading; 195 MW Combustion Turbine Units (3)

(2) Combustion Turbine Unit

(3) Crystal River Unit 4 (Coal-fired)

(4) Crystal River Unit 5 (Coal-fired)

(5) Station "X" Unit 1 (Coal-fired)

(6) Station "X" Unit 2 (Coal-fired)

(7) Station "X" Unit 3 (Coal-fired)

(8) Station "Y" Unit 1 (Coal-fired); 150 MW Combustion Turbine Units (3)

(9) Station "Y" Unit 2 (Coal-fired)

(10) Station "Y" Unit 3 (Coal-fired)

Figure 1-17
WINTER PEAK LOAD DEMAND AND CAPACITY AT TIME OF PEAK

Figure 1-18
PURCHASE PLAN

Figure 1-19
L.O.L.P. ANALYSIS

Figure 1-20
FUEL MIX

1.6 REGIONAL SITUATION

1.6.1 Regional Setting

Florida Power Corporation is the second largest electric utility in the state, with 16 percent of the generating capacity. At the present time, each utility operates as an individual entity. Although the transmission ties are free-flowing, power exchanges are done in accordance with existing agreements for the purchase or sale of power; i.e., for capacity purposes, under emergency conditions, or for economy interchange.

Virtually all of the utilities in the state are members of the Florida Coordinating Group (FCG). The utilities in Florida are part of a larger organization, the Southeastern Electric Reliability Council (SERC). SERC is one of nine regional councils whose memberships comprise essentially all of the electric utility systems in the United States and the Canadian systems in the provinces of Ontario, British Columbia, Manitoba, and New Brunswick. Together, the regional councils comprise the National Electric Reliability Council (NERC), which was formed voluntarily by the electric utility industry in 1968 and incorporated in 1975. NERC directs its efforts to augmenting the reliability and adequacy of bulk power supply of the electric utility systems in North America.

The SERC region encompasses all of the states of Florida, Georgia, North and South Carolina, Tennessee and Alabama, and approximately half of Mississippi and Virginia. For coordination purposes, the region is subdivided into four subregions:

- Florida
- The Southern Company (a utility holding company with operating utilities in Florida, Georgia, Alabama, and Mississippi)
- TVA (government-owned generating utility with power plants in Tennessee, Mississippi, and Alabama)
- VACAR (interconnected utilities in Virginia, North and South Carolina)

The Florida subregion is connected only to the Southern Company. At present, this is by two 230 kV lines and several 115 kV lines.

1.6.2 Regional and National Coordination

This section describes more fully the level of coordination that presently exists, and which may exist in the future. Since the greatest coordination will always exist with the nearest neighboring utilities, most emphasis is given here to the FCG.

A listing of all the electric utilities in the state of Florida is presented in Table 1.3. It may be noted that all utilities except two are members of the FCG. At the present time, the FCG has established emergency and operating reserve policies and an economy interchange system. The FCG is composed of a general staff and several major committees. The general staff coordinates the activities of the various committees and is the focal point for data collection, report distribution, and liaison with various government agencies and other utility and consumer organizations.

The controlling authority of the FCG is the Executive Committee. It determines policy for all matters within the scope of the FCG articles of incorporation and bylaws. In addition, the Executive Committee directs the overall operations of the FCG standing committees and the affairs of the FCG corporation. Customarily, the presidents of four investor-owned utilities, three chief executives from the municipal utilities, and two chief executives of rural electric cooperatives serve on this board.

The committees most directly responsible for coordinating FCG activities are the Technical Advisory Group, the Operating Committee, the System Planning Committee, and the Environmental Committee. The Technical Advisory Group develops long-range objectives to meet the overall goal of providing member systems with added reliability at an economical cost. The Technical Advisory Group coordinates the planning of generation and transmission expansion programs of the Florida utilities and oversees the activities of the Operating Committee, the System Planning Committee, and the Environmental Committee.

The Operating Committee is charged with integrating FCG operations to ensure economical and reliable electric service. Its member utilities share spinning reserves; establish policies for scheduled and inadvertent interchange procedures, emergency procedures, and time-error correction; coordinate maintenance schedules; establish and

TABLE 1.3 NET GENERATING CAPACITY OF UTILITIES IN FLORIDA
(1978 Summer Rating)

<u>FCG Members</u>	<u>Generation (MW)</u>
Investor-Owned Utilities	
Florida Power & Light Company	10,941
Florida Power Corporation	3,647
Florida Public Utilities Company	2
Gulf Power Company	1,515
Reedy Creek Utility Company	12
Tampa Electric Company	2,505
	<u>18,622</u>
Municipals	
City of Alachua*	1)
City of Bushnell	1)
Florida Keys Utilities*†	14
Fort Pierce Utilities Authority	116
Gainesville/Alachua County Regional Utilities Board	257)
City of Homestead	52
Jacksonville Electric Authority	1,884
City of Key West Utility Board†	130
City of Kissimmee	36)
Lake Worth Utilities Authority	141
City of Lakeland	372
City of Leesburg*	7)
City of New Smyrna Beach Utilities Commission	26)
City of Ocala	11)
Orlando Utilities Commission	742)
City of Quincy	0
City of St. Cloud	24
Sebring Utilities Commission	29)
City of Starke	10
City of Tallahassee	495)
City of Vero Beach	133
City of Wauchula*	8
	<u>4,489</u>
Cooperatives	
Central Florida Electric Cooperative	0
Choctawhatchee Electric Cooperative	0
Clay Electric Cooperative	0
Glades Electric Cooperative	0
Lee County Electric Cooperative	0
Okefenokee Rural Electric Membership Corporation	0
Peace River Electric Cooperative	0
Seminole Electric Cooperative	14)
Sumter Electric Cooperative	0
Suwannee Valley Electric Cooperative	0
Talquin Electric Cooperative	0
Tri-County Electric Cooperative	0
Withlacoochee River Electric Cooperative	0
	<u>14</u>
Southeastern Power Administration*	36
Total	<u>23,161</u>

* Not a member of FCG.

† Not interconnected with FCG members.

) Includes joint participation in generating unit.

administer guidelines for utilizing underfrequency relays; maintain voice and teletype communication facilities and notification procedures for both normal and emergency conditions; and evaluate system disturbances to determine causes and seek ways of preventing future occurrences. In addition, the Operating Committee oversees the operations of the FCG energy broker system.

The System Planning Committee reviews and analyzes the planning of the electric bulk power supply system in Florida. It is responsible for exchanging planning information among FCG member systems and other organizations; determining whether the planned generating facilities and bulk power transmission grid are adequate and reliable; and recommending corrective planning, design, and operations to ensure an adequate and reliable electric power supply.

A member serving on the Operating and System Planning committees must represent a system interconnected with other FCG utilities and able to meet its own system peak-load demand plus reserve requirements. The non-generating municipal utilities and the non-generating rural electric cooperatives have one representative each on these committees. In addition, any other member of the FCG may attend meetings as an observer. The FCG is currently studying the benefits that would result from centralized power dispatch of all generating units.

Formation of the FCG was voluntary, but was encouraged and supported by both the Florida Public Service Commission and the Southeastern Electric Reliability Council (SERC). In accordance with requirements of the Florida Electric Power Plant Siting Act, FPC (and other utilities in the state) must submit a 10-year site plan report to the Department of Community Affairs on an annual schedule. The last report was submitted in March, 1980. This report contains a summary of existing facilities, the current forecast of electric power demand, a forecast of facilities requirements, and a description and impact analysis for facilities and sites that are under construction or planned.

The National Electric Reliability Council (NERC), in keeping with its charter, devotes its attention solely to matters which have a bearing on the reliability and adequacy of bulk power supply of the electric utility industry in North America. NERC, working with its regional councils, concentrated its early efforts on solving the

problem of cascading trip-outs of the transmission network which had led to wide-spread power outages -- a problem defined by NERC as the "reliability" problem. As this problem eased, the emphasis has shifted to the "adequacy" problems; i.e., providing sufficient generating capability to be able at all times to meet the aggregate electric peak loads of all customers and to supply all their electric energy requirements. Figure 1-21 shows the geographic boundaries on the nine regions which comprise NERC.

The Southeastern Electric Reliability Council is the largest of the nine councils in terms of power generating capability, with 112,233 MW installed at the end of 1978. At that time, SERC had the smallest percentage reserve generating capacity: 21 percent compared with the average value of 31.445 percent for all nine regions.

As was described in Section 1.5.1, the SERC region consists of four subregions: Florida, The Southern Company, TVA, and VACAR. The interconnections are as depicted below:

DEPARTMENT OF ENERGY - ENERGY INFORMATION ADMINISTRATION

Figure 1-21
NINE NERC REGIONS

2. TASK II: INITIAL SYSTEM PLANNING ANALYSIS

2.1 OBJECTIVE OF TASK II

The objective of Task II was to exercise the system planning methodology under two conditions:

- (1) the current planning base case representing the FPC generation expansion plan as prepared in 1979, and
- (2) a case where OTEC is introduced as an alternative generating source at the earliest feasible date.

From this, it was to be determined if OTEC is competitive as an alternative generating source, based on Florida Power Corporation (FPC) system planning methods and economic decision making procedures.

It was anticipated early in the project that OTEC would be not be fully competitive when compared to base-case conditions. Therefore, the concept of Task III was defined to vary several parameters, exploring and quantifying those conditions under which OTEC could become economically competitive. As a consequence of the outcome of Task II, this study serves to identify the nature and quantity of the differences between OTEC, as analyzed, and available alternatives (coal, in the case of FPC) against which it competes. This was useful in guiding the selection of parameters and values to be used in the Task III runs.

2.2 OTEC PARAMETERS

2.2.1 Source of Data Used for Inputs

The OTEC inputs are detailed in Appendix D. This includes the baseline assumptions for plant configuration, operating characteristics, and costs (both capital and O&M). These inputs are summarized in Table 2.1 and 2.2.

TABLE 2.1

OVERALL BASELINE CONFIGURATION FOR OTEC PLANT

BASELINE PLANT SIZE	400 MWe NET
POWER SYSTEM MODULE SIZE	50 MWe
TOTAL NUMBER OF MODULES	8
TYPE OF POWER CYCLE	AMMONIA, CLOSED
PLATFORM TYPE	CONCRETE SPAR
COLD WATER PIPE	FIBERGLASS SUSPENDED OR ELASTOMER INTEGRATED WITH MOORING SYSTEM
POWER CABLE	D.C., 2 CONDUCTOR 1 SPARE
MOORING SYSTEM	MULTI-POINT OR TAUT

TABLE 2.2

OTEC CAPITAL COST INPUTS
(1979 DOLLARS)

COMPONENT	COST (\$/KW)
Heat Exchangers	592
Remainder Power System	396
Platform	490
Seawater System	221
Mooring System	99
Power Cables	458
-----	-----
Total	2256

Most of the information was derived from studies which have been performed for the U.S. Department of Energy by contractors or supporting agencies. Pertinent data have been incorporated into an OTEC Cost Data Bank maintained by one of the consultants on this project. Assumptions concerning the cost values, configuration and operating characteristics have been made and stated by the consultant on OTEC technology (Appendix D).

2.2.2 Compilation of OTEC Inputs Used

Table 2.1 contains the more important data used as inputs representing OTEC. The plant size specified, 400 MWe(net), is representative of the presently projected largest OTEC plant that may exist in the planning future. It is a convenient plant size, particularly since the planned capacity additions by Florida Power Corporation are for 800 MWe coal-fired units.

It was necessarily assumed that OTEC plants of 400 MW size would be available by 1988 in order to include OTEC within the present FPC planning horizon. It is recognized that this would require an unrealistic development schedule, including pilot and demonstration plants.

It was assumed that such a plant would be a first generation design of a full size commercial plant. However, for purposes of cost estimation, it was assumed that this would not be the first unit of this type manufactured, but that the costs would include a learning curve factor; i.e., costs based on the eighth plant manufactured of that type.

The projected site for a first OTEC unit integrated into the FPC system is approximately 140 miles west of St. Petersburg, Florida in the Gulf of Mexico. The assumptions relative to site thermal characteristics and power cables are based on knowledge of this site and the intervening distance.

2.2.3 Discussion of OTEC Inputs

Baseline Configuration for OTEC Plant

The baseline configuration is presented in Table 2.1. It was selected as representative of the largest feasible commercial OTEC plant. The maximum size is consistent with several OTEC platform studies which indicate the size of the platform would be limiting and that 400 MW size would be at "state of the art".

The power module size of 50 MW each is a special feature of OTEC plants. It is projected that any OTEC plant of commercial scale would consist of a set of power modules which include heat exchangers, water pumps, ammonia system including turbine-generators, etc. The module size of 50 MW appears to be near the maximum effective and economic size for a commercial plant. It is possible that commercial OTEC plants could have power modules of lower ratings, in which case the total plant would then have a larger number of modules.

The concrete spar configuration was selected as representative of a full scale platform which would be more likely for a Gulf of Mexico site. Ship-type platforms may not be cost-effective when designed to meet the hurricane survival conditions. Concrete, rather than steel, was chosen to keep total costs down.

The cold water pipe could have one of two most probable configurations; one with an independently suspended fiberglass unit representing lowest cost for an effective design, or one with an integrated elastomeric cold water pipe where the mooring system would provide some of the structural components. It is projected that the cost of these two alternatives are comparable and that present knowledge supports using the fiberglass pipe for cost estimation.

A DC power cable is required for the transmission distance under consideration. It is known that beyond a distance of about 27 miles at voltage levels of 230 kV and above, AC power cables would not be functional. Power cable technology indicates that a + and - pole conducting pair of cables is best for DC transmission. It is presently considered that it would be cost-effective to install three DC marine cables, providing an installed spare, due to the high cost and time required for assembly and deployment of the cable installing equipment

to repair or replace a damaged cable.

The baseline mooring system is consistent with the selected platform type and the candidate site.

Capital Costs

The state of maturity of development of a new technology has a strong influence on costs. In Appendix D, Section 3, there is a discussion of the projected stages of development of an OTEC system. Due to the timing assumed for introduction of OTEC into the FPC plans, a first generation unit had to be selected, with a learning curve factor. This is less costly than a pilot or demonstration unit, but more costly than second generation units or a fully matured technology.

Table 2.2 presents a summary of the cost projections used. These are discussed in detail in Appendix D, Section 4.

Operational Modes and Forced Outage Rates

The key components or systems that influence plant availability are:

1. Seawater pumps,
2. Heat exchangers,
3. Turbine-generators,
4. Power cables.

All other components or systems have either exceedingly low failure rates or backups such that plant power reduction will not occur as a result of component failure.

The projected outage days and resultant power reductions used as input to the overall plant reliability model are as follows:

SYSTEM	OUTAGE DAYS/YEAR	NET POWER DURING OUTAGE (MW)
Seawater pumps	64	375
Heat exchangers	160	390
Turbine-generator	20	350
Power cables	24	240

The derivation of these values is included in Table 2.3.

TABLE 2.3

PERFORMANCE DERIVATIONS

SEAWATER PUMPS

1. Assume 2 pumps per module each for WARM WATER and COLD WATER, total of 4 pumps per module.
2. Failure rate projected as one per year per pump; mean time to repair (MTTR) 2 days.
3. Outage days per year per module: $2 \text{ days per pump} \times 4 = 8 \text{ days}$.
4. Outage days per plant (8 modules): 64 days per year .
5. Power reduction per module per pump outage: 0.5 of module power = 25 MWe reduction; net plant output 375 MWe.

HEAT EXCHANGERS

1. Each module contains five 10 MWe subassemblies, each with a CONDENSER and EVAPORATOR.
2. Subassembly failure rate projected as one per year; MTTR 2 days.
3. Outage days per year per module: $2 \text{ days per subassembly} \times 10 = 20 \text{ days}$.
4. Outage days per year per plant (8 modules): $8 \times 20 = 160$.
5. Power reduction per subassembly: 0.20 of module power = 10 MWe; net power during outage days = 390 MWe.

TURBINE - GENERATOR

1. Assume one turbine/generator set per module.
2. Failure rate projected as 0.5 per year (1 per 2 years).
3. MTTR: 5 days. Outage days per year per module = 2.5.
4. Outage days per plant: $8 \times 2.5 = 20$.
5. Power reduction per module due to outage: 50 MW plant power level during outage: 350 MWe.

POWER CABLES

1. Assume 2 operating cables (+ and - DC legs) and 1 installed spare cable.
2. Assume one major cable failure occurs on an average of once in two years. If one cable fails, spare cable can be placed in service. Consequently, no change in plant output occurs.
3. If it is then assumed a second cable fails prior to repair of the first cable, the remaining single cable can be operated at 120% rated capacity; thus plant output would be limited to 240 MW during such operation ($120\% \times 400 / 2$).
4. Outage time while making new cable installation, or in-place repair, is estimated to be approximately 90 days to mobilize, 30 days to effect repair or install new cable for a total outage time of 120 days.

WEATHER

1. Assume 5 days average per year shut down due to hurricane conditions.

2.2.4 Thermal Resource Data

Site thermal resource characteristics were obtained from DOE. The results for monthly site delta-T (the projected temperature difference between the surface and a 1000 meter depth) is given in Table 2.4.

The power rating of 400 MW for the OTEC plant is considered to be applicable at the evaluated maximum delta-T for the site (average monthly mean). The effect of lower values of delta-T is a reduction in power according to the relationship:

$$P = P_o (\Delta T / \Delta T_o)$$

where ΔT represents the actual delta-T value and ΔT_o and P_o applies to the design point value.

This characteristic of power output as a function of delta-T has an important bearing on OTEC power plant design values and consequent capital costs of the plant. On one hand, the principal components are sized on the basis of the annual average delta-T; i.e., to deliver 400 MW power with a site delta-T of 21.3° C, the annual average for the West Florida Site. During the summer months when the site temperature difference is greater than this annual average, the heat exchangers are capable of extracting more thermal energy and the plant would be capable of delivering more than rated power. Since the ammonia piping, turbine, generator, and power cables are designed for converting and transmitting this energy as electric power, the annual average power generated by the plant would be approximately 400 MW.

A second method of designing the power plant rating is to the maximum delta-T. This method was used in this study, specifying the power rating of 400 MWe at the maximum temperature difference (24.2 °C). All equipment is sized for the maximum and the plant derated below 400 MW during periods of lower temperature difference (Table 2.4). Thus if the OTEC power plant were designed for an output of 400 MWe at a delta-T of 24.2°C, the plant would deliver less than 400 MWe during the periods when the values are below the maximum delta-T, and the average annual power generated would be less than 400 MWe.

TABLE 2.4

OTEC THERMAL RESOURCE DATA
FOR SPECIFIC SITES

WEST FLORIDA SITE

MONTHLY MEAN DELTA-T (C)	
JAN	19.2
FEB	19.2
MAR	18.2
APR	20.2
MAY	21.1
JUN	23.0
JUL	24.2
AUG	24.1
SEP	23.4
OCT	22.3
NOV	20.7
DEC	19.6
ANNUAL AVERAGE	21.3

2.2.5 Operation and Maintenance (O&M) Costs

A detailed analysis of potential O&M costs was made and is presented in Appendix D, Section 6. The resultant calculation indicates 8.2 mils/kWh is a supportable figure, although very approximate.

The overall O&M costs are assumed to be made up of the following major parts:

1. crew cost	3.8 mils/kWhr
2. repairs to power system	1.2
3. platform	0.7
4. power cables	1.8
10% for "others"	0.7

Total	8.2

2.3 BASE CASE PARAMETERS

Section 1 of this report describes the Florida Power Corporation system parameters used in system planning runs conducted in September 1979. This section also describes the generation system expansion plan that resulted from the 1979 study. Further studies made during the several months following this initial study have resulted in some minor alterations in the scheduling of new units and retirements of existing ones.

The recommended system expansion plan consists of a combination of power purchases from other utilities and installations of large coal fired plants during the decade of the 1980's, and installation of additional coal fired plants during the decade of the 1990's. Figure 2-1 shows the overall schedule for generating unit installation.

This planned expansion is based on the load forecast and indicated needs for installed capacity, as discussed in the Section 1. Table 2.5 shows a tabulation of the load forecast and planned installed capacity for the period 1988 to 1998, the second decade in the twenty year planning study period. Below this is a tabulation of the installed capacity by generating type, where the installed capacity figure refers to year end,

The implementation of this planned expansion would result in a mix of fuel used for energy generation. Figure 2-2 shows the percentage of each fuel/energy in the mix for the Base Case.

Figure 2-1
BASE LOAD FACILITY PLAN

Table 2.5

LOAD FORECAST AND INSTALLED CAPACITY

A. BASE CASE

	PEAK * DEMAND	PURCHASED	NET PEAK	INSTALLED ** CAPACITY	RESERVE		LOLH
	MW	MW	MW	MW	MW	%	HRS
1988	6610	406	6204	7751	1547	23	5.5
1989	6800	406	6394	7751	1357	20	5.3
1990	6990	406	6584	8285	1701	24	3.4
1991	7270	6	7264	9166	1902	26	4.4
1992	7350	6	7344	9097	1753	24	5.4
1993	7640	6	7634	9897	2263	30	2.1
1994	7700	6	7694	9897	2203	29	1.9
1995	7970	6	7964	9897	1933	24	2.6
1996	8130	6	8124	10697	2573	32	1.2
1997	8450	6	8444	10697	2253	27	1.8
1998	8450	6	8444	10697	2253	27	1.8

* OCCURS IN JANUARY OF EACH YEAR

** AT TIME OF PEAK DEMAND

INSTALLED CAPACITY BY FUEL TYPE**

A. BASE CASE

	COAL		NUCLEAR		OIL-STEAM		PEAKING		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW
1988	3498	45	726	9	1886	25	1641	21	7751
1989	3498	45	727	9	1886	25	1641	21	7751
1990	4158	50	726	9	1886	23	1515	18	8285
1991	4958	54	726	8	1886	21	1596	17	9166
1992	4958	54	726	8	1886	21	1527	17	9097
1993	5758	58	726	7	1886	19	1527	16	9897
1994	5758	58	726	7	1886	19	1527	16	9897
1995	5758	58	726	7	1886	19	1527	16	9897
1996	6558	61	726	7	1886	18	1527	14	10697
1997	6558	61	726	7	1886	18	1527	14	10697
1998	6558	61	726	7	1886	18	1527	14	10697

Figure 2-2
FUEL MIX

2.4 PRODUCTION COSTING ANALYSIS

2.4.1 PROMOD Inputs

The PROMOD model receives inputs for all the existing generating stations as well as those being studied for possible addition. One required set of input values is the capacity state for each plant under specified failure conditions. As described in Section 2.2, OTEC is treated as having 6 capacity states: 400, 375, 350, 340, 240 and 0 MW.

Appendix B gives an example of the calculation made to translate component failure rates and repair times into capacity probability states. Table 2.6 shows the resulting inputs for the forced outage rates (FOR) and the percent time at each capacity state. Details of these calculations are contained in Appendix C. The 0 MW capacity state is basically the consequence of total plant shutdowns due to weather (5 days per year average); due to the modularity of the power plant, a 0 MW capacity state from mechanical failure or maintenance is negligible. These calculations assume that the failure modes are independent. The forced outage rates are shown at three different levels which are multiples of the eventual FOR after the maturing period for the plant. The ratio 4:2:1 represents the maturing period such that during the first year of operation, the plant has 4 times the eventual rate, during the second year has 2 times the eventual rate, and finally reaches the figure 1.679 at the third year.

Table 2.7 shows the inputs to PROMOD that treat the monthly variation in plant output capacity deration. The plant is derated to account for the seasonal degradation of the thermal resource which reduces net power output. The PROMOD program requires specification of a maintenance outage schedule since it models each generating unit separately. In the case of OTEC, each OTEC power module is analogous to a complete unit in a land based generating station. Therefore the entire station is not scheduled out for maintenance. Instead, 50 MW modules are alternately scheduled for maintenance.

Table 2.6

OTEC OUTAGE RATE INPUTS TO PROMOD

CAPACITY STATE (MW)	PERCENTAGE TIME
400	59.875
375	23.034
350	5.546
340	2.245
240	7.621
0	1.679 *

* Primarily due to adverse weather conditions, including hurricane preparations and occasional actual evacuation.

Table 2.7

OTEC MONTHLY DERATIONS

	MONTH	PERCENTAGE DERATION
1	JANUARY	17.250
2	FEBRUARY	17.250
3	MARCH	25.500
4	APRIL	8.250
5	MAY	0.000
6	JUNE	0.000
7	JULY	0.000
8	AUGUST	0.000
9	SEPTEMBER	0.000
10	OCTOBER	0.000
11	NOVEMBER	3.750
12	DECEMBER	13.750

2.4.2 PROMOD Results

The parameters that cover the Base Case PROMOD runs are described in Section 1 of this report. The load forecast and year-by-year capacity forecast are summarized in the preceding Section 2.3. As is discussed in Section 1, there are two principal outputs of the PROMOD computer program:

- o Annual generation for each type of generating unit, plus fuel cost and cost of purchased power.
- o Generating system reliability data in the form of loss of load hours per year (LOLH). LOLH is defined as the expected average number of hours during a year that a system would not be able to supply its total requirements.

Table 2.8 shows the installed capacity, year-by-year, under the OTEC scenario. The Base Case is shown above for direct comparison. For the OTEC runs, the major difference in capacity forecast is the elimination of the 400 MW power purchase in 1988-89 when the OTEC plant is commissioned, and then the displacement of the 800 MW coal-fired unit scheduled for 1990. However, study results indicated these displacements did not result in sufficient savings to offset the OTEC capital costs.

The initial runs were made with 400 MW of OTEC substituting for 400 MW of purchase of coal-fired generated power during 1988-89, then replacing 400 MW of coal-fired capacity thereafter. Because of the low overall outage rate of an OTEC plant, the reliability of the OTEC case was significantly higher than the Base Case. For a fair comparison, it is necessary to compare generating expansion plans with equal reliability. Therefore adjustments were made in the OTEC case leading to the situation, noted above, in which an 800 MW coal-fired unit was eliminated. The high reliability of the OTEC plant, principally due to having eight power modules comprising a 400 Mwe plant, is one of the major features of this generating system.

The PROMOD results for the Base Case and the OTEC case are shown in Figure 2-3 in which loss of load hours (LOLH) versus years are presented. Although there are year-by-year differences due to shifting

Table 2.8

LOAD FORECAST AND INSTALLED CAPACITY

A. BASE CASE

	PEAK DEMAND	PURCHASED	NET PEAK	INSTALLED CAPACITY	RESERVE		LOLH
	MW	MW	MW	MW	MW	%	HRS/YR
1988	6610	406	6204	7751	1547	23	5.5
1989	6800	406	6394	7751	1357	20	5.3
1990	6990	406	6584	8285	1701	24	3.4
1991	7270	6	7264	9166	1902	26	4.4
1992	7350	6	7344	9097	1753	24	5.4
1993	7640	6	7634	9897	2263	30	2.1
1994	7700	6	7694	9897	2203	29	1.9
1995	7970	6	7964	9897	1933	24	2.6
1996	8130	6	8124	10697	2573	32	1.2
1997	8450	6	8444	10697	2253	27	1.8
1998	8450	6	8444	10697	2253	27	1.8

B. OTEC CASE

	MW	MW	MW	MW	MW	%	HRS/YR
1988	6610	6	6604	8151	1547	23	6.4
1989	6800	6	6794	8151	1357	20	5.7
1990	6990	6	6984	8685	1701	24	3.4
1991	7270	6	7264	8766	1502	21	4.3
1992	7350	6	7344	8697	1353	18	5.7
1993	7640	6	7634	9497	1863	24	2.2
1994	7700	6	7694	9497	1803	23	2.9
1995	7970	6	7964	10297	2333	29	1.8
1996	8130	6	8124	10297	2173	27	2.0
1997	8450	6	8444	10297	1853	22	2.9
1998	8450	6	8444	10297	1853	22	1.9

* OCCURS IN JANUARY OF EACH YEAR

** AT TIME OF PEAK DEMAND

Figure 2-3
RELIABILITY PROFILE

of units (large blocks of capacity) over the time span of the study, the average reliability of the two cases are judged to be basically equivalent. While the time scale of the system planning study is 20 years, the reliability for the first 8 years of either plan, with or without OTEC, are identical, and therefore only the latter years are presented.

Table 2.9 lists the planned installed generating capacity by generating type (coal, nuclear, oil-steam, peaking combustion turbine, and OTEC) for the Base Case and the OTEC Case. It is seen that 400 MW of OTEC capacity added in 1988 represents 5% of the total installed capacity at that time and reduces to 4% in six years. This data is presented graphically in Figure 2-4 for the OTEC Case as compared to the Base Case, and the generating capacity mix is displayed in Figure 2-5.

Table 2.10 lists the generation energy data. These data are needed for the Corporate Model in order to calculate the relative costs involved, as discussed in the next section. This table shows the mix of generating types, and the relative dependence on a given fuel. This data is presented graphically in Figure 2-6 for the OTEC Case (as compared to Figure 2-2 for the Base Case). It is seen that coal will be the principal fuel, in either case, but OTEC does have some effect in reducing the overall dependency on coal. It is noteworthy that OTEC, with 4 to 5 % of the capacity, as shown in Table 2.9, accounts for 10% of the total energy generation, as shown in Table 2.10.

Table 2.9

INSTALLED CAPACITY BY FUEL TYPE **

A. BASE CASE

	COAL		NUCLEAR		OIL-STEAM		PEAKING		OTEC		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW	%	MW
1988	3498	45	726	9	1886	25	1641	21	0	0	7751
1989	3498	45	726	9	1886	25	1641	21	0	0	7751
1990	4158	50	726	9	1886	23	1515	18	0	0	8285
1991	4958	54	726	8	1886	21	1596	17	0	0	9166
1992	4958	55	726	8	1886	21	1527	16	0	0	9097
1993	5758	58	726	7	1886	19	1527	16	0	0	9897
1994	5758	58	726	7	1886	19	1527	16	0	0	9897
1995	5758	58	726	7	1886	19	1527	16	0	0	9897
1996	6558	61	726	7	1886	18	1527	14	0	0	10697
1997	6558	61	726	7	1886	18	1527	14	0	0	10697
1998	6558	61	726	7	1886	18	1527	14	0	0	10697

B. OTEC CASE

	COAL		NUCLEAR		OIL-STEAM		PEAKING		OTEC		TOTAL
	MW	%	MW	%	MW	%	MW	%	MW	%	MW
1988	3498	43	726	9	1886	23	1641	20	400	5	8151
1989	3498	43	726	9	1886	23	1641	20	400	5	8151
1990	4158	48	726	8	1886	22	1515	17	400	5	8685
1991	4158	47	726	8	1886	22	1596	18	400	5	8766
1992	4158	48	726	8	1886	22	1527	17	400	5	8697
1993	4958	52	726	8	1886	20	1527	16	400	4	9497
1994	4958	52	726	8	1886	20	1527	16	400	4	9497
1995	5758	56	726	7	1886	18	1527	15	400	4	10297
1996	5758	56	726	7	1886	18	1527	15	400	4	10297
1997	5758	56	726	7	1886	18	1527	15	400	4	10297
1998	5758	56	726	7	1886	18	1527	15	400	4	10297

** At time of peak demand

Figure 2-4
BASE LOAD FACILITY PLAN

Figure 2-5
CAPACITY MIX

Table 2.10

GENERATION

A. BASE CASE

	LOAD	COAL	NUCLEAR	OIL**	PEAK	OTEC	PURCHASE
	GWH	GWH %	GWH %	GWH %	GWH %	GWH %	GWH %
1988	28514	19695 69	3947 14	3122 11	160 0	0 0	1590 6
1989	29313	20175 69	3886 13	3432 12	195 0	0 0	1625 6
1990	30582	22656 74	3447 12	3000 10	162 0	0 0	1317 4
1991	30708	24436 80	3874 13	2228 9	122 0	0 0	48 0
1992	31891	25590 80	3873 12	2248 7	132 0	0 0	48 0
1993	31916	26233 82	4192 13	1375 5	68 0	0 0	48 0
1994	33098	27700 84	3386 10	1867 6	97 0	0 0	48 0
1995	33656	28094 83	3874 12	1558 5	82 0	0 0	48 0
1996	34692	29840 86	3874 11	890 3	40 0	0 0	48 0
1997	34504	29487 86	3867 11	1047 3	55 0	0 0	48 0
1998	35421	29883 85	4032 11	1376 4	82 0	0 0	48 0

B. OTEC CASE

	LOAD	COAL	NUCLEAR	OIL**	PEAK	OTEC	PURCHASE
	GWH	GWH %	GWH %	GWH %	GWH %	GWH %	GWH %
1988	28511	18312 64	3742 13	3356 12	221 1	2833 10	48 0
1989	29313	19201 66	3893 13	3085 11	161 0	2927 10	48 0
1990	30586	21070 69	3893 13	2489 8	108 0	2978 10	48 0
1991	30709	21530 70	3894 13	2133 7	126 0	2978 10	48 0
1992	31890	22671 71	3739 12	2492 8	148 0	2792 9	48 0
1993	31916	23600 74	3895 12	1332 4	63 0	2978 9	48 0
1994	33098	24419 74	3896 12	1674 5	83 0	2978 9	48 0
1995	33658	25762 77	3899 12	922 3	50 0	2978 9	48 0
1996	34691	26785 77	3744 11	1074 3	55 0	2986 9	48 0
1997	34503	26637 77	3887 11	1086 3	60 0	2786 8	48 0
1998	35424	27387 77	3870 11	1090 3	52 0	2978 8	48 0

** 'OIL' IS STEAM PLANT, 'PEAK' IS COMBUSTION TURBINE

Figure 2-7
GENERATION ENERGY/FUEL MIX -- OTEC CASE

2.5 CORPORATE FINANCIAL ANALYSIS

2.5.1 Corporate Financial Criteria

The principal criterion used by FPC for evaluating a power generating source for competitiveness is to calculate the present value of Cumulative Total Revenue Requirements (CTRR). The CTRR may be thought of as the total amount of money that would be required, if earning funds at the specified interest rate, to pay for the total electric energy consumed for the next twenty years. This is done for each of the alternatives considered, assuming each of the alternative plans is feasible, and a comparison made among them to see which indicates the lowest value for CTRR. If the difference between two values of CTRR is reasonably close, then other factors may determine the final decision.

The plan with the lowest CTRR may have other characteristics which are favorable or unfavorable. However if the difference in CTRR is too great, the more costly alternative is not considered further. Any screening of options which are not considered usable due to such factors as environmental problems, is accomplished in the development of the alternative plans prior to evaluation using the Corporate Model.

2.5.2 Assumptions Used

It is assumed that the company will recover via rate structure all its costs. The model applies rate increases each year as required to stay within the currently approved (issued by Florida Public Service Commission) method of computing revenue requirements.

Construction escalation rate is assumed to be 8.7% until January 1984, when it becomes 6.5%. The spending curve used for OTEC results in an effective inflation rate of 6.8% over its construction period.

The alternative costs used for coal-fired units are estimated at \$689/kW for a first unit and \$586/kW for the second unit at a common site, expressed in 1979 dollars. The estimates for these plant costs are based on experience with current construction costs at Crystal

River 4 and Crystal River 5, two coal-fueled units under construction.

2.5.3 Corporate Model Results

The Corporate Model was run on both cases: the Base Case with coal-fueled stations providing base load generating expansion, and the OTEC Case with OTEC substituting for the 800 MW coal-fueled plant in 1990. The results are presented in Table 5.1.

Table 5.1

PRESENT WORTH OF CUMULATIVE TOTAL REVENUE REQUIREMENTS (1979 - 1997)
(1979 \$ IN BILLIONS)

BASE CASE		:	OTEC CASE	
7%*	12%*	:	7%*	12%*
24.797	16.361	:	25.367	16.731

*Interest Rate

OTEC is unfavorable compared to the Base Case plan with respect to the total revenue requirements (present valued to 1979). The differential in 1979 is \$570,256,000 for 7% and \$370,572,000 for 12% interest rates. Florida Power Corporation would consider such a difference in revenue requirements too large for consideration as a feasible alternative.

The major difference between the Base Case and the OTEC case as reflected in these results is due to the estimated difference in initial capital costs. The coal fueled plant is estimated to cost 689\$/kW, and the OTEC plant was estimated at 2256\$/kW. The cost of fuel for the coal plant is not so great as to make up this considerable difference in plant acquisition cost.

It may be questioned why, with 400 MW of OTEC substituting for 800 MW of coal-fired capacity, there would be such a large difference in Cumulative Total Revenue Requirements. By contrast, when a direct 400 MW for 400 MW substitution was performed, the unfavorable difference

was increased to \$759 million at 7% interest and \$473 million at 12%. Thus the improvement in reliability by OTEC does have a substantial effect on CTRR, but not enough, with the given assumptions, to bring it into direct economic competition.

2.6 TASK II RESULTS

2.6.1 Nature of Task II Results

Given a possible range of costs for OTEC, the capital costs of a competing generation source such as coal-fueled plants, and possible future coal fuel costs, there are varying differences in economic competitiveness. As discussed in Section 2.5, the primary measure of economic competitiveness between two possible generating sources is the Cumulative Total Revenue Requirement (present value) for each alternative. The difference between these figures for the two alternatives is used as a measure of how attractive one is relative to the other on a financial basis.

In Figure 2-8, a graphic representation indicates how Task II established one of the key points on the curve and where Task III furnishes additional information. The vertical axis is a measure of the difference in Cumulative Total Revenue Requirements between the Base Case, with coal-fueled plants providing the needed additional capacity to the system, and the case with OTEC substituting for some of the coal generation. The horizontal axis is OTEC capital cost. On the vertical axis, plus (+) values are disadvantageous to OTEC.

Task II established the point labeled "II". This represents the assumptions currently used by Florida Power Corporation for the capital cost of coal-fueled units, the rate of price escalation for coal, and the cost of an OTEC plant as described in Section 2 of this report. As discussed in Section 5, there is an economically unfavorable difference in Cumulative Total Revenue Requirements for OTEC which is shown as a + value on the vertical axis.

Figure 2-8
ENVELOPE OF OTEC COMPETITIVENESS

2.6.2 Relationship to Task III

During Task III, the values of key parameters were varied in order to examine the conditions that would make OTEC become competitive with coal-fueled generation. First, the capital cost of OTEC was lowered until the curve, in Figure 2-8, crossed the zero value on the horizontal axis. The point labeled IIIa represents this value. At this point OTEC would be considered to have met the first screening criterion as a competitive generation option.

The point labeled IIIb represents the next set of runs for Task III in which the cost of fuel was increased by increasing the rate of escalation until the zero crossover was reached. This established the third point which forms the corners of an envelope of possibilities to determine the relative competitiveness of OTEC as compared to a coal-fueled unit.

The parameters that were considered for adjustment during Task III are:

- Capital cost of OTEC plants
- Fuel escalation rate
- Elimination of spare power cable

2.7 TASK II CONCLUSIONS

2.7.1 Principal Conclusions from Task II

The initial set of system planning studies indicate that OTEC cannot be introduced into the Florida Power Corporation system during the twenty year planning horizon based on the present projection of planning parameters and corporate economics. Instead, a specialized program which could possibly be justified under conditions external to present planning considerations of FPC, would be needed.

The economic projections are such that the principal criterion -- the total revenue requirements -- are unfavorable for OTEC consideration. Considerable changes in the underlying assumptions would be required to bring OTEC into the competitive economic range.

2.7.2 Discussion of Conclusions

It should be emphasized that for Task II, no alteration to the existing Florida Power Corporation planning methodology or to the assumptions used in current planning projections were made.

It was specifically intended that for Task II, OTEC be inserted with no special situations included. The time frame of the planning horizon is such that OTEC had to be assumed as a candidate within ten years (prior to 1990). Thus the projected costs for the OTEC 400 MW unit were for a first generation design for a plant of this size and therefore would not purposefully bias the study in either the favorable or unfavorable direction. If the OTEC plant were to be the first of its kind, then the costs would be higher reflecting the typical initial costs. On the other hand, one could assume a more mature, refined design which would represent lower costs with a 1990 or later inclusion.

It is possible that some special situations could be created for introduction of a new technology such as OTEC into a commercial utility system. Nuclear power did not enter the utility field initially as a fully competing alternative. This option did not become a viable

utility alternative until government development and manufacturing aids were offered. These aids grew principally from the Navy nuclear power program and the federal fuel enrichment process and other federal government involvement in nuclear fuels, materials and reactors. Therefore, some incentives are reasonable and anticipated for initial commercial penetration, beyond the pilot and demonstration plants.

The results of Task II indicate the nature and magnitude of the differences between competing, established generating sources and OTEC as identified and documented directly and precisely by the exercise of an accepted system planning methodology. The results provide a basis for examining the needed conditions and incentives that must be developed in order to make OTEC economically competitive.

3. Task III: SYSTEM PLANNING ANALYSIS; MODIFIED CONDITIONS

3.1 OBJECTIVE OF TASK III

The objective of Task III was to perform a sensitivity analysis upon critical system related variables to determine the necessary conditions required to make OTEC financially competitive with coal-fueled plants. To accomplish this objective, the FPC planning methodology was exercised using three modifications of the input parameters assumed for the computer runs made in Task II. These three scenarios were:

(1) The Modified OTEC Case

Under this scenario the capital cost of an OTEC plant was lowered until the cumulative total revenue requirements (CTRR), were the same as for the Base Case where only coal fired plants are used for base-load generating capacity additions.

(2) The Modified Base Case

Under this scenario, the coal fuel escalation rate was increased until the CTRR was the same as for the OTEC Case results determined in Task II.

(3) The OTEC No Spare Cable Case

Under this scenario, the spare power cable was eliminated from the OTEC plant, thus affecting both the cost and the reliability of the resultant plant.

The results of the first two scenarios provided limiting values of the fundamental economic parameters associated with determining the conditions under which OTEC is competitive, based upon the Florida Power Corporation (FPC) system planning methods and economic decision-making criteria. The third scenario provided a variation which displays the effect of modifying OTEC system design that would lower the total capital investment, but which would also effect system reliability.

Task III serves to identify the nature and quantity of the alterations in cost inputs that must be made in order to close the gap between OTEC, as analyzed in Task II, and the planned capacity expansion plant type (coal, in the case of FPC) against which OTEC must compete. The results of the Production Costing Analysis for these limiting cases are discussed in Section 3.3, and the associated Corporate Financial Analysis in Section 3.4.

The results of Task III were used to guide the selection of parameters and values for Task IV analysis, from which the nature and extent of incentives and other enhancements for adoption of OTEC are explored and presented in Section 4 of this report.

3.2 TASK III PARAMETERS

3.2.1 Modified OTEC Case Parameters

For the first runs of Task III, the capital cost of the OTEC plant was reduced until the principal financial criterion for acceptance (the Cumulative Total Revenue Requirement, CTRR) was equivalent for both the OTEC case and the Base Case, in which coal-fired plants provide base-load expansion. The capital cost of the OTEC plant as used in Task II was \$2256/kW (all dollar values expressed in this section are 1979 dollars). This cost was reduced until CTRR equivalence was reached.

3.2.2 Modified Base Case Parameters

The second set of runs for Task III increased the escalation rate for coal fuel costs until the financial criterion (CTRR) was equivalent for the OTEC Case and the Base Case. The Base Case used a coal fuel escalation rate of 5.0 %/yr. Runs were made for 10% and 15% coal fuel escalation rate to permit interpolation to a "break even" value.

3.2.3 Revised OTEC Design Parameters for Cost/Reliability Comparison

In order to examine the consequences of making a specific alteration in the design configuration of an OTEC plant to achieve some lower cost, and then evaluate the effect on system reliability, the spare power cable specified in the baseline configuration was deleted. The reason for this selection was that it could represent a significant cost reduction (at least 5%). The effect on subsequent plant reliability was measured based upon the baseline OTEC information used in Task II (Appendix D).

Appendix E provides the modifications to the baseline inputs used. The deletion of a spare power cable resulted in an estimated cost saving of \$142/kW, for the cost of the cable and installation. The effect on reliability is to increase the outage rate of the power cable system from 24 to 30 days per year.

The use of this variation in input parameters is more illustrative than conclusive. The intent is to display the possible consequences of such a variation, rather than an absolute measure of the result. It is possible to numerically express the projected reduction in capital costs from elimination of a spare power cable and to adjust the projected outage rates of the cable system resulting from such a change, based on the OTEC baseline inputs used in Task II. But these numbers are subject to considerable variation, as expressed in Appendix E, which points out that the power cable sub-system of OTEC has the greatest technical and cost uncertainties of all the sub-systems. Consequently, one of the reasons for choosing this as a variation of parameters is to furnish an in-depth examination of the OTEC power cable situation, which is crucial for a Gulf of Mexico plant.

3.3 PRODUCTION COST ANALYSIS

3.3.1 PROMOD Inputs

For the Modified OTEC Case (OTEC capital cost reduced until CTRR is equivalent to Base Case), no modifications to PROMOD were required. The results from Task II were directly applicable since the change in plant capital cost influenced only the corporate financial analysis. For the Modified Base Case (fuel cost escalation rate increased until CTRR equivalent to the OTEC Case), PROMOD runs were made with the adjusted values of 10 % and 15 % for the coal cost escalation rate (5% having been the Base Case assumption) and corresponding incremental increases in the escalation rate of other fuel costs. This did not alter the system reliability results, but was required to supply fuel cost input to the corporate financial analysis.

For the OTEC No Spare Cable Case, the change in the outage rate for the power cable resulted in revised values for the OTEC forced outage rates. The revised values are presented in Table 3.1.

3.3.2 PROMOD Results

The only case which resulted in a change in system reliability was the OTEC No Spare Cable Case. None of the scenarios changed the base load generation expansion plan. For the OTEC No Spare Cable Case, there were small increases in LOLH/YR. These results are given in Table 3.2, where the yearly LOLH figures are shown along with the figures from the OTEC Case, taken from Table 2.8B. It is seen that the change from the OTEC Case is relatively small, and no adjustment in the generation expansion plan was warranted. However, the changes in the OTEC plant forced outage rate are very significant in that more power will be required from the other generating units. The change in the generation mix (the fraction of the total MWH generated by each type of power plant) is shown in Table 3.3. This table contains year-by-year values of the Generation Mix as it was in the OTEC Case, and as it is for the OTEC No Spare Cable Case. This change has a large effect on the financial analysis, as will be demonstrated in Section 3.4.

Table 3.1

OTEC FORCED OUTAGE RATES FOR PROMOD

CAPACITY STATE (MW)	PERCENTAGE TIME	
	OTEC CASE	NO SPARE CABLE CASE
400	59.875	47.896
375	23.034	18.424
350	5.546	4.433
340	2.245	1.791
240	7.621	24.097
0	1.679 *	3.359

* Primarily due to adverse weather conditions,
including hurricane preparations and occasional
actual evacuation

TABLE 3.2

SYSTEM RELIABILITY: LOSS OF LOAD HOURS

YEAR	OTEC CASE	OTEC NO SPARE CABLE CASE
	(HRS/YR)	(HRS/YR)
1988	6.4	7.6
1989	5.7	6.5
1990	3.4	3.4
1991	4.3	4.8
1992	5.7	6.2
1993	2.2	2.5
1994	2.9	3.2
1995	1.8	2.0
1996	2.0	2.2
1997	2.9	3.1
1998	1.9	2.1

TABLE 3.3

GENERATION MIX*
(PERCENTAGE OF TOTAL MWH/YR)

YEAR	OTEC CASE**					OTEC NO SPARE CABLE CASE				
	(HRS/YR)					(HRS/YR)				
	COAL	NUCL	OIL	PEAK	OTEC	COAL	NUCL	OIL	PEAK	OTEC
1988	64	13	12	1	10	65	13	12	1	9
1989	66	13	11	S***	10	66	13	11	1	9
1990	69	13	8	S	10	69	13	9	S	9
1991	70	13	7	S	10	71	13	7	S	9
1992	71	12	8	S	9	72	12	8	S	8
1993	74	12	4	S	10	75	12	4	S	9
1994	74	12	5	S	9	75	12	5	S	8
1995	76	12	3	S	9	77	12	3	S	8
1996	77	11	3	S	9	78	11	3	S	8
1997	77	11	3	S	9	78	11	3	S	8
1998	77	11	3	S	9	78	11	3	S	8

* PURCHASED ENERGY LESS THAN 0.2% IN ALL YEARS FOR BOTH CASES

** VALUES ARE SAME AS PRESENTED IN TABLE 2.10B

*** DENOTES LESS THAN 0.5%

3.4 CORPORATE FINANCIAL ANALYSIS

3.4.1 Financial Criteria

As described in Section 2 of this report, the initial criterion used by FPC for evaluating a power generating source for competitiveness is to calculate the present value of Cumulative Total Revenue Requirements (CTRR) as calculated over a twenty year planning future. The CTRR may be thought of as the total amount of money that would be required, if earning funds at the specified discount (interest) rate, to pay for the total electric energy consumed for the study period. This is done for each of the alternatives considered, assuming each of the alternative plans is feasible, and a comparison made among them to see which alternative yields the lowest value for CTRR. If the differences between values of CTRR are reasonably close, then other factors may determine the final decision.

The plan with the lowest CTRR may have other characteristics which are favorable or unfavorable. However, if the difference in CTRR is too great, the more costly alternative is not further considered. Any screening out of options, which are not considered usable due to such factors as high commercial risk, increased use of fuels likely to be in short supply (e.g. fuel oil and natural gas), or environmental problems, is accomplished in the development of the alternative plans prior to evaluation using the Corporate Model.

As stated in Section 2 of this report, Task II compared the Base Case, with coal-fired plants as the planned base load generation expansion, to the OTEC Case where part of the planned expansion included an OTEC unit. The results of Task II were such as to show that the OTEC Case had a CTRR so much larger than the Base Case that it would not be considered by Florida Power Corporation as a feasible alternative. It is the intent of Task III to vary important economic parameters to reduce the difference in CTRR between a generation expansion plan with coal fired plants, and a plan that includes OTEC, and thus satisfy the financial criteria used by Florida Power

Corporation in considering alternatives.

3.4.2 Assumptions Used for Task III

The assumptions used for Task III were largely those used for Task II with two exceptions as will be described. The Task II assumptions that are carried over into Task III include:

- (1) It was assumed that the company will recover via rate structure, all its costs. The Corporate Model applies rate increases as required to stay within the allowed ranges for return, using the methodology of the Florida Public Service Commission.
- (2) Construction cost escalation rate is assumed at 8.7% until January 1984, when it becomes 6.5%. The spending curve used for OTEC results in an effective escalation rate of 6.8% over its construction period.
- (3) The alternative costs used for coal-fired units is estimated at \$689/kW for a first unit and \$586/kW for the second unit at a common site. The estimates for these plant costs are based on experience with current construction costs at Crystal River 4 and Crystal River 5, two coal-fueled units under construction.

The exceptions to Task II assumptions for the Modified OTEC Case and for the Modified Base Case were the variation of two important parameters influencing costs measured by the CTRR: (1) capital cost of the OTEC plant, and (2) fuel cost escalation rate. For the first analysis, the Base Case assumptions were held constant with the capital cost of the OTEC plant reduced until the CTRR of the two cases became approximately equal. During the second analysis, the OTEC capital cost was set at the value assumed in Task II and the fuel cost escalation rate was raised until the CTRR of these two cases became approximately equal. A third analysis, the OTEC No Spare Cable Case, modified the Task II OTEC Case assumptions to eliminate the spare power cable with attendant cost reductions and changes in reliability. This resulted in a reduction of the OTEC capital cost by \$142/kW.

3.4.3 Corporate Model Results

The Corporate Model was run under the three scenario variations: (1) the Modified OTEC Case, (2) the Modified Base Case, and (3) the OTEC No Spare Cable Case. The results are presented in Figures 3-1 and 3-2.

The results show that for the first set of modified conditions, the "break even" OTEC capital cost is \$1450/kW. This implies that for break even (approximately equal CTRR between the Modified OTEC Case and the Base Case) that the ratio of the capital cost of a "fuel free" OTEC plant to the capital cost of a coal fired plant cannot exceed a value of 2.3 under the assumed rates of fuel cost escalation (5 % for coal). This reduced cost of an OTEC plant might be achieved either by direct manufacturing cost reductions, or through some set of financial incentives that would reflect as capital cost reductions. This latter possibility was explored in the Task IV activity.

The results for the Modified Base Case, with the coal fuel cost escalation rate increased to a break-even point, show that the escalation rate must be approximately 12%, as contrasted to the Base Case assumption of 5%, in order for OTEC to be financially competitive. This assumes all other escalation rates stay as they were originally projected, which means the fuel must escalate approximately 7% above the general inflation rate. The possibility or circumstances of such increases in coal fuel cost escalation will also be treated in Task IV.

The results for the OTEC No Spare Cable Case show that although the cost of an OTEC plant might be reduced from the baseline value of \$2256/kW by an amount of \$142/kW by the elimination of a spare power cable, the decrease of system reliability causes only a minor reduction in CTRR. The reduction in plant capital cost is essentially offset by the increased costs due to lower system performance, thus illustrating the interactions that can result from this method of lowering the capital cost of the plant, with the resulting effect upon reliability. Such results, based upon these complex system relationships, make a strong case for utilizing sophisticated system planning methods to augment the decision making process.

These results are presented graphically in the preceeding Figure 3-1.

Figure 3-1
RESULTING ENVELOPE OF OTEC COMPETITIVENESS

Figure 3-2
RESULTING OTEC BREAK-EVEN CURVE

The vertical axis is a measure of the difference in Cumulative Total Revenue Requirements (CTRR) between the Base Case, with coal-fired plants providing the needed additional capacity to the system, and the case with OTEC substituting for some of the coal generation. The horizontal axis is OTEC capital cost. On the vertical axis, plus (+) values are disadvantageous to OTEC.

The overall results are plotted in the preceding Figure 3-2, where the OTEC capital cost to break-even (compared to the Base Case) is plotted against the corresponding coal fuel cost escalation rate (with other fuel escalation rates adjusted proportionally). These diagrams depict the bounds definition of Task III, developing the limiting values of the two most significant factors affecting a comparison between a coal-fired base load expansion plan and a plan that includes OTEC.

As was discussed in Section 2 of this report, achieving an equal or smaller CTRR is only the first criterion that forms the basis for selecting one system expansion plan over any other alternative plan. The other criterion to be satisfied is that the plan is financeable; that is, the utility must be able to finance construction of the plant during a specified period of time when other capital expenditures also have to be financed.

Florida Power Corporation has previously established the capital budget items required during the 1979-1998 time period, and has determined that the Base Case expansion plan, with a combination of purchased power and new coal-fired plants is financeable assuming that required rate increases will be obtained in a timely manner. As was noted previously, the OTEC plant eliminates one 800 MW coal-fired plant in 1990 and moves the in-service date for a second 800 MW coal-fired plant from 1995 to 1994. However, the capital cost for the OTEC unit still causes the OTEC cases to have higher construction costs than the Base Case.

The impact of this greater construction budget in both OTEC scenarios is that the OTEC plan presents a more difficult financing situation. It is possible that the utility could not sell sufficient bonds or issue stock without diluting stockholders equity. This subject is discussed further in Section 6, and methods to solve this problem are the subject of a more detailed examination in Task IV.

3.5 TASK III RESULTS AND CONCLUSIONS

3.5.1 Discussion of Task III Results

Task III arrived at the two limiting values which bound the competitive range for OTEC. On one hand, OTEC capital costs could be reduced (either by direct cost reductions or by some incentive program which effectively reduces plant cost) in such a fashion that the OTEC option becomes competitive. On the other hand, the coal fuel cost escalation rate could increase to a level that also makes OTEC competitive.

Task II established the point labeled "II" on Figure 3-1. This represents the assumptions currently used by Florida Power Corporation for the capital cost of coal-fueled units, the rate of price escalation for coal, and the cost of an OTEC plant as described in the Task II report. The vertical displacement of this point is representative of the economically unfavorable difference in Cumulative Total Revenue Requirements for OTEC which is shown as a "+" value on the vertical axis.

The point labeled "IIIa" represents the point resulting from lowering the capital cost of OTEC until the curve crosses the zero or "breakeven" value on the horizontal axis. At this point OTEC would be considered a competitive candidate. This lowering of OTEC cost could be the result of either direct improvements in design and production, or of incentives that have the effect of lowering the cost to the utility company.

The point labeled "IIIb" represents the next set of runs for Task III in which the coal fuel cost escalation rate was increased until the zero crossover was reached. This established the third point which forms the corners of an envelope of possibilities that determines the relative competitiveness of OTEC.

3.5.2 OTEC Plant Cost Estimates and Possible Variations

There are two categories of possible capital cost reductions for an OTEC plant; those which are direct reductions in price without altering system design factors, and those which accompany some change in design. The former category could include incentives which have the effect for the utility company of a lower capital cost for the plant. For example, investment tax credits could have an effect of lowering the direct cost (on the other hand there are circumstances, such as a situation of tax credit saturation, where an investment tax credit would not produce any advantage). These incentives are discussed in Section 4.

It is also possible that reductions in projected OTEC plant cost could be achieved by revised estimates based on new information on cost of components or systems. This study used cost estimates based on available information at the time of the evaluation. OTEC technology is continuing to be developed in many areas. New preliminary design studies refine the details and often contain design optimization steps which can result in lowered cost estimates for that aspect of the overall design. Laboratory and model experiments are being conducted and the results may modify cost projections. Experience in offshore engineering and power systems may add information to the base upon which OTEC draws. Therefore, it is possible that updated information could substantiate a reduction in projected OTEC plant costs for the assumed baseline plant. For example, during the course of the study, there was some indication that cold water pipe technology developments may warrant somewhat increased cost projections. By contrast, updated information on power cable technology appears that the degree of conservatism used in the cost projections for that system may be relaxed and correspondingly the cost estimates reduced.

The other area where there are possible changes in plant cost could be the consequence of design modifications. Either relatively minor alterations or major modifications in design approach might occur. Some modifications would not have a market effect on plant

availability, yet result in significant cost reductions. Other modifications might have a significant effect on component reliability and plant availability, and trade-offs would have to be made against cost reduction and plant performance variations. The example of the installed spare power cable was chosen to illustrate this type of situation. The OTEC No Spare Cable Case illustrates the effect of cost reductions that also reduce plant availability and thus reliability. In the case explored, the cost of the plant was reduced by 6.3%, (from \$2256/kW to \$2114/kW) by eliminating the spare power cable. However, under the assumptions used, this resulted in a decrease in plant availability due to increased outage time for the power cable system. The net effect was to reduce the CTRR from the original OTEC Case value of \$25,367 million to an OTEC No Spare Cable Case value of \$25,304 million, or a percentage reduction of 0.2%. Thus it is seen that this specific example of cost reduction has a very limited effect on increasing the competitiveness of the OTEC alternative. It should be noted that generalizations related to purposeful degradation of other OTEC components and the associated net effect upon CTRR cannot be made from this investigation, but must be evaluated on a case-specific basis. Should the elimination of a spare cable not have a correspondingly marked reduction in plant availability, the plant capital cost reduction would be very beneficial. This topic is discussed in greater detail in Appendix E.

3.5.3 Conclusions

The primary criterion for considering competitiveness between alternative generation expansion plans, the CTRR, becomes equivalent between the Base Case and the OTEC Case if either the coal fuel cost escalation rate increases to approximately 12% or the capital cost of OTEC effectively is reduced to \$1450/kW. Within these two limits, intermediate combinations produce equivalent values of CTRR.

Reductions in OTEC plant capital costs can be a result of design modifications, fabrication savings, or a result of some incentive

mechanisms that result in a reduced acquisition cost for the utility company.

Cost reductions that reduce system reliability can be counter productive for competitiveness. It was shown, as an example, that deletion of the spare power cable could reduce capital costs by 6.3%, but the change in outage rates would result in a CTRR reduction of only 0.2%. This variation was chosen to illustrate such an effect and is qualitatively useful; however, the quantitative result should not be considered conclusive due to the present state of technical information and operating experience on OTEC power cables.

In the course of this evaluation, which spanned a time of nineteen months, some modification to original assumptions on OTEC technology and costs were required as new information developed. Additional adjustments to conclusions may be warranted by further information which develops after the completion of this study.

It should not be inferred from the results that either reduction of OTEC capital cost to \$1450/kW or increase of the coal fuel cost escalation rate to 12%, or some combination to produce an equivalent CTRR, would insure OTEC adoption as a viable alternative generation expansion plan. Other financial and non-dollar factors must be considered, as discussed in Section 4.

4. INSTITUTIONAL AND FINANCIAL ASPECTS

4.1 INTRODUCTION

4.1.1 Objective of Task IV

In previous tasks, the primary criterion for considering a generation expansion plan, such as might include OTEC, was examined and it was found that there were certain limiting values on OTEC capital cost or on fuel escalation rate that were needed to make OTEC pass this first screening factor. Task IV examined three principal areas: (1) those additional screening criteria that might act against OTEC such as financeability, (2) the incentives or other mechanisms that might effectively lower the cost of OTEC, and (3) other institutional means that could enhance the attractiveness of OTEC as a generating plant option. The final result of completion of Task IV was to provide the range of incentives and barriers impacting OTEC as a potential candidate for future use by FPC.

4.1.2 Scope of Task IV

Task IV was accomplished in two areas:

- (1) Additional corporate planning model runs varying parameters affecting OTEC capital costs through incentives, or alternative ownership methods, and
- (2) Analysis of commercialization incentives and barriers including: structured interviewing and group interactive processes with FPC senior executives to determine critical decision criteria beyond the boundaries and capabilities of the formalized corporate planning models.

Two features were analyzed to explore the possible benefits of financing aids as possible OTEC incentives:

- (1) Placing the total of funds for construction work in progress (CWIP) in the rate base, to reduce the cost of money burden, and
- (2) Increased investment tax credits, beyond the current 10% value allowed. Two higher values, 20% and 30% were investigated.

The motivation behind the first factor analyzed -- full CWIP in the rate base, was that the cost of constructing a power plant includes not only the direct costs of construction, but the interest on funds borrowed for that purpose. During the construction period, under conventional public utility commission procedures, the construction funds are accumulated until the plant is placed in service. Then the utility may apply for rate increase based on placing the capital cost of the new facility within the rate base.

Therefore there is a lag between the time funds are acquired and paid out for construction and the time when the plant is completed and placed in service. There is typically a further lag while application for a rate increase is made and approved by the PUC. The interest on the funds thus committed, typically over several years, is an additional cost to the utility. Allowing full CWIP directly into the rate base would remove this lag and ease the financing costs. This action is something that could be done at the state level, below the federal level of applying renewable energy sources.

The motivation for examining the second factor -- higher investment tax credits (ITC), is to quantify the effect of one of the principal mechanisms widely proposed for stimulating the adoption of new energy technologies. ITC values of 15% exist for solar energy options within present IRS rules, resulting from recent federal legislation to promote solar energy. Many pieces of proposed legislation contain even higher values of ITC, 20% and as high as 30%. It is noteworthy that the offshore petroleum industry was greatly stimulated by the 20% depletion allowance. Although this is not an ITC, it had similar economic effects. Therefore it is beneficial to quantify

the extent of such an incentive on the FPC planning process.

In a sense, an ITC has a similar effect as a subsidy; however, the mechanism is such that it is sufficiently removed from a calculation of plant capital costs that it does not tend to be treated as a capital cost subsidy, rather as a financing incentive/benefit. There are restrictions and limitations on the application of an ITC that may reduce or eliminate any actual benefit. If a company is already experiencing income tax reductions due to previous credits, a situation of saturation may be approached.

There may be some question that both a direct plant capital cost subsidy and a higher ITC would be allowed by law, since they may be considered overlapping. In a pre-legislation workshop held by congressional the staff working out pending OTEC legislation (May 28, 1980), it was suggested that both subsidy and federal loan guarantees might not be acceptable to Congress from a concern for "piling up" incentives. Therefore it is instructive to investigate the relative benefits of these incentive options. If one has a small effect compared to another, it would be helpful to advise policy makers that one incentive is strong and another relatively weak so that they can place emphasis on the proper incentive.

4.2 INPUTS TO TASK IV CORPORATE PLANNING ANALYSIS

4.2.1 Computer Simulation Conditions

The computer simulations listed below were conducted for the following conditions:

- (1) The OTEC Case (with OTEC plant capital cost of \$2256/kW), but with higher investment tax credits than presently used by FPC (10%). Values of 20% and 30% were used. Also full construction work in progress cost (CWIP) was assumed in the rate base,
- (2) The Modified OTEC Case (with OTEC capital cost of \$1450/kW), and other financing assumptions standard,
- (3) The Modified OTEC Case with higher investment tax credits and full CWIP in the rate base.

These computer simulations incorporate the realm of incentives that could be implemented in order to increase the feasibility and acceptability of OTEC. The higher investment tax credit is representative of an indirect federal support that might be included in future legislation. The CWIP in the rate base is representative of incentives that might be implemented at the State level, and eliminates the characteristic lag between the time that funds are paid out for plant construction and the time that those costs can be placed in the rate base to develop earnings for the utility.

4.2.2 Pending Federal Incentives Programs

As part of the inputs to Task IV, the pending federally sponsored incentives programs, including pending legislation, were reviewed. The most significant anticipated incentives are those contained in the set of four Senate and House bills that include subsidies for initial capital cost during commercial introduction of OTEC, loan guarantees, and "one stop" licensing procedures.

4.2.3 Inputs to Executive Interviews and Group Interaction

The intent of the executive interviews and discussions was to obtain their views on circumstances and factors that could either favor or impede the adoption of OTEC as an alternative generating source. There are factors not directly revealed in the system planning analysis that might have significant influence. There are company policies and guidelines which are, in part, a reflection of top management attitudes and perceptions of the best means of running the company. However, there may be pending changes or factors which are not fully reflected in current policy or guidelines issued to planning and operating staffs. The executive interviews and discussions were designed to explore the more subtle aspects and factors that require definition to guide OTEC developers.

A set of questions was formulated to stimulate expressions concerning the potential acceptability of OTEC and other factors influencing decision making that might affect its future commercialization.

The questions and points of discussion were formed to follow along three principal lines:

- (1) Under assumptions of direct economic comparability between OTEC and the Base Case plan, what would then be the feeling about adopting this alternative generating source?
- (2) If the company could not finance OTEC plant construction using existing procedures, what would be the feeling toward power purchases and leases or lease-purchase arrangements?
- (3) What are the feelings toward participation in the development of OTEC prior to cost competitiveness?

4.3 RESULTS OF TASK IV CORPORATE PLANNING ANALYSIS

(1) OTEC Case Compared to Base Case

Computer runs were made for this case with and without full CWIP in the rate base and higher tax credits. There are higher construction expenditures, particularly pronounced during the years 1982 to 1986. This accounts for much of the total difference in CTRR between this OTEC Case and the Base Case.

It was found that the benefits of higher investment tax credits quickly saturate and reach a level of truncation just slightly above 10% ITC. This is attributed to the fact that FPC (typical of many utilities) has had a continual generation expansion pattern over the past years and thus has benefited from the existing 10% ITC to the extent that the federal taxes paid are already reduced. Therefore there is only a small margin for benefit from increased ITC. It should be noted that this is in sharp contrast with one of the main features of much existing and pending federal legislation to further alternative energy technologies. Increased ITC is extensively talked of as a means of stimulating capitalization of new equipment, particularly solar systems.

The upper limit to this benefit is to lower the CTRR only slightly, insufficiently to bring the baseline OTEC into competition.

The effect of full CWIP in the rate base causes only a slight change in CTRR.

(2) Modified OTEC Case, standard financing assumptions:

The principal aspect revealed by these computer simulations is the aspect of financeability. The lower capital cost of the OTEC plant, as determined in Task III, meets the primary screening criterion, the CTRR. Figures 4-1 and 4-2 graphically present results of this case. It may be recalled that this is the case where the CTRR is equivalent between the Base Case and the Modified OTEC Case since the capital cost of the OTEC plant is sufficiently lower than the initial OTEC capital cost.

Figure 4-1
ANNUAL CONSTRUCTION EXPENDITURES
(OTEC @ 1450 \$/KW)

Figure 4-2
TOTAL FUNDS FROM FINANCING

It was found that the magnitude of capital formation and the percentage of capital funds required outside of the company's revenues is well beyond that considered feasible for any new generating capacity addition. Although a plan might offer equivalent CTRR, the ability to raise capital in the financial market must also be considered. There is a limit, based on sound business practice, on the amount a utility can finance, i.e., the amount of stock the company can issue. This is related to the amount of the total sales of the company and the construction funds that can be supported by sales of electric power.

For the OTEC Case, even if the ultimate cost as reflected by the CTRR is favorable, the burden placed on capital formation is excessive, and unless some other form of relief is provided, FPC would not select such an option.

This result clearly reveals the second aspect of commercial competitiveness that OTEC or any alternative energy technology must face; not only must it have a competitive capital cost so that the net cost of power is within range of other alternatives, but the means of acquiring the capital needed for construction must be compatible with the utility company's financial position. This factor is discussed in greater detail later in the report, and is one of the principal areas for recommending future courses of action by OTEC developers.

(3) Modified OTEC Case with higher Investment Tax Credit (ITC) and full Construction Work In Progress (CWIP) in the rate base:

As was shown in the results of (1), little relief is provided by this modification to financial assumptions. The benefit from ITC saturates at a value near 10%, the existing allowed ITC. Although the cost of power becomes slightly less than the competition in this case, the problems with capital formation still persist to an extent that this option would not be chosen by FPC.

This result further focuses attention on the problem of capital formation for a high capital cost energy technology which more than offsets the free-fuel aspect, even if the cost of generated power is below that of the fossil-fuel competition to a modest degree.

4.4 OTHER OWNERSHIP OPTIONS OR PURCHASED POWER

4.4.1 Lease-Purchase Option.

One motivation for investigating the lease-purchase option was to mitigate the capital formation strain on the utility. By setting up the lease-purchase mechanism, it is possible to essentially spread the capital formation over the life of the lease-purchase. As a limiting case, a full 30 year lease-purchase (representing the assumed plant lifetime) was considered. There are several effects of a lease-purchase situation:

(a) the total cost of the lease represents both the capital cost of the plant and the cost of financing the construction,

(b) the burden of capital formation is transferred to the lessor, but the cost of money is not evaded,

(c) the annual cost of the lease includes $1/30$ of the total cost of the plant acquisition and the cost of money,

(d) the revenues derived from the OTEC plant may be modified, depending on the lease-purchase agreement and a PUC ruling on the agreement, by the fraction of the plant cost placed in the rate base; i.e. although the company may draw 400 MW of power from the OTEC plant, for the first year it owns only $1/30$ of the plant, and so on for subsequent years.

The lease-purchase mechanism would have an effect on the relative attractiveness of OTEC to FPC. It offers a means of acquiring a free-fuel but highly capital intensive generating source with considerably less strain on the financing requirements.

4.4.2 Third party owner, with sale of dedicated, guaranteed power:

This option is essentially similar to any negotiated purchase-of-energy option, with some differences:

(a) this arrangement provides for a dedicated source, and further that replacement of energy will be provided, or other financial guarantees such that FPC will not suffer financially from interruptions in delivery from the dedicated source,

(b) a diversity of energy sources is provided (other purchase options would probably be either coal or nuclear power and thus not offer the diversity that OTEC could provide),

(c) a third party owner might accrue some financial benefits that the utility company could not, and thus the net cost of delivered power might be less than if the utility company were to be the owner (e.g., more favorable tax incentives, depreciation allowances, and financing mechanisms).

This arrangement could provide an attractive option. However there are certain reservations that senior management would have that require resolution. These are covered in Section 6.3 of this report. Nevertheless, the purchase of OTEC power from a third party owner has merit.

4.5 RESULTS OF EXECUTIVE DECISION-MAKING REVIEW

4.5.1 Objective and Preparation for the Review

It was stated in Section 4.2.2 that the intent of the executive interviews and discussions was to obtain their views on circumstances and factors that could either favor or impede the adoption of OTEC as an alternative generating source. A set of questions and discussion points were prepared for this session to stimulate expression of those significant points that could only be revealed by such a group interaction. The discussion was forthright, revealing and direct.

4.5.2 Conduct of the Interviews

The meeting was held starting with a presentation by the Corporate Planning Department on the results of the planning studies conducted and conclusions reached in Tasks II and III. The key points covered included:

- The capital cost of an OTEC plant would have to be reduced for a value of CTRR equivalent to the Base Case plan (\$1450/kw for the OTEC plant). It would be presumed that the reduction in capital cost might be achieved through some form of capital construction cost subsidy.
- Even if such a plant cost could be realized, the plant could not be financed, in the time frame studied, under existing procedures. The capital required would exceed the limits allowed by sound business practices for a company the size of Florida Power Corporation.
- The resultant dilution of stock and greatly reduced earnings per share during the construction period would impact the corporate financial standing and risk a reduction in bond ratings.

From this point, the first question was posed to the effect: if adequate compensation were provided to offset the above factors and make OTEC financially attractive (at least competitive when compared to the Base Case), were there any reservations or impediments to adoption that would inhibit the senior executives from reaching a decision in favor of OTEC.

The responses indicated that the senior executives saw many factors in favor of adopting OTEC. These included:

- (1) price stability, with freedom from higher fuel escalation rates,
- (2) fuel diversification, alleviating concern for an overdependence on coal fuel,
- (3) apparent high system reliability (assuming that the OTEC plant did perform as estimated),
- (4) use of a renewable (solar) resource.

Therefore, it was recognized that there are some significant advantages to OTEC generation.

These points were expanded during further discussions. The following sections provide more detailed information on the major points of issue.

4.5.3 Discussions on Ability to Finance

(1) The ability to finance is a problem that causes great concern but is not peculiar to OTEC. Since OTEC is very capital intensive, the problem of ability to finance becomes more extreme. Although a fuel-free generating option is attractive on many points, the present financial situation for utilities does not favor such an option. This can be assumed to apply similarly to a nuclear plant, which is more capital intensive than a coal-fueled plant. Indeed, the utility foresees considerable difficulty in financing the Base Case plan. One expression of the situation was to the effect that current actions of

state and federal regulatory commissions are making it impossible for utilities to finance even conventional plants.

(2) Loan guarantees are of little benefit to a utility, except perhaps to yield slightly lower interest rates. Under normal circumstances, the company is still liable for money borrowed and must pay interest on the full amount. There is no apparent relief from impact on bond ratings and other perceived measures of company financial stability. In effect, the loan guarantee only benefits the lender.

(3) Even with immediate rate increases and full CWIP in the rate base, the plan was not financeable. Increased investment tax credits (greater than the current 10%) offer little benefit during the construction period since such tax credits are near saturation due to other plant capital expenditures. Any additional tax credits would be carried forward and therefore have little effect during the construction period.

(4) These conclusions are not unique to OTEC, but reflect the situation toward all matters of capital formation. OTEC exacerbates these problems. Other "free fuel" options and technologies which tend to be capital intensive would display the same problems.

(5) The problems of capital formation might make a third party ownership arrangement or purchase of OTEC power attractive, as further discussed in Section 4.5.6.

4.5.4 Discussions on Fuel Considerations

(1) OTEC would have an advantage of being a dependable fuel source. There is a concern regarding possible interruption of coal supplies due to labor or transportation difficulties.

(2) The lack of fuel price increase makes OTEC very attractive.

(3) The provision for an alternative source of fuel, and thereby diversity of energy resources, provides an advantage for OTEC.

(4) OTEC does not displace oil usage in the FPC system; it displaces coal. This is because the capacity provided by OTEC units would

supplant presently planned coal capacity. It was felt this would likely be true in other Gulf Coast utilities as well, particularly with the government programs accelerating coal conversions.

(5) FPC is concerned over the apparent single option, coal, being left to utilities. Having ruled out natural gas, oil, and (effectively) nuclear, the regulatory climate has left the utility industry with only one immediate energy source -- coal. Environmental opposition may soon limit coal, leaving the utility and its customers with insufficient, unproven or expensive energy sources. An opinion expressed was that greater emphasis by the federal government on effective coal resource development and utilization might be preferable to the development of something as unproven as OTEC.

(6) The advantages of OTEC over other solar options was recognized. The round-the-clock generation capability of OTEC was considered very important and gives it a substantial advantage over other solar options.

4.5.5 Discussions on Siting Considerations

(1) There was no fundamental aversion to having a power plant located over 100 miles offshore. The technology demonstrated by the offshore petroleum industry in the Gulf of Mexico provides assurance that the technical problems could be managed and that operations would be feasible.

(2) An OTEC plant would eliminate the need for siting 400 to 800 MW of coal fueled plant capacity on the mainland.

(3) Legal problems associated with a location in international waters may more than offset the advantage over mainland siting. There was a strong expression of concern for clarification of these issues. A lack of legal and regulatory clarification would seriously impede OTEC consideration by a utility.

(4) Vulnerability of an OTEC plant to terrorism and acts of warfare are considered serious problems. Susceptibility to collision is also a

concern.

(5) Probably the greatest technical concern expressed over the site situation was the length of underwater power cable involved. The senior executives expressed a lack of confidence in underwater power cable technology for so great an exposure.

4.5.6 Discussions on Future Development of an OTEC Alternative

(1) Any plan for OTEC introduction into the FPC system would have to provide that the cost of electricity would be equal to or less than that of conventional plants.

(2) An OTEC plan would at least have to be equivalent from both the ratepayer and stockholder point of view and be financeable. Actually, it was felt that the economics would have to be favorable to OTEC in order for a utility to assume the additional risks involved. It was felt that the OTEC advantages alone did not offset the risks of a new technology.

(3) The climate for setting up a plan for purchase of power from a third party owner of OTEC is favorable. There were no fundamental objections raised; to the contrary, this was consistent with current company policy. It appears that an arrangement where FPC would not have to develop the construction capital would be the most feasible means of bring OTEC power into the system.

(4) It was felt that both the government and FPC developed valuable information from the present contract between FPC and DOE.

5. TRANSMISSION SYSTEM ANALYSIS

5.1 INTRODUCTION

Power from a distant offshore OTEC plant would be brought ashore via underwater DC transmission cables to some shore location where conversion to AC would take place. This would then be connected to the transmission grid at some chosen voltage level, and at some desirable physical location in the grid.

Several geographic locations are possible for bringing the power ashore. The most likely would be into Pinellas County in the vicinity of St. Petersburg. However, there are other locations that might offer some advantage. These possible sites were screened, and three chosen as suitable points to bring the power ashore and connect into the transmission system. Figure 5-1 shows the transmission system for FPC and for the State of Florida, and the three sites selected for study of connecting OTEC into the system.

The three locations are designated:

Bayboro

Charlotte

Port St. Joe.

The distances from the OTEC site to each of these locations is approximately equal. Bayboro is in the vicinity of St. Petersburg in Pinellas County and is a substation in an area of a major load center. Charlotte is located between Ft. Meyers and Sarasota in another major load center. Port St. Joe is in an area of lesser load.

Both Bayboro and Charlotte are characterized by strong transmission systems and nearby generation, Bayboro is connected to two overhead 115 kV lines and two 115 kV cables. There are 160 MW of combustion turbines at Bayboro, and nearby plants in the 230 kV grid are Bartow (608 MW), and Anclote (932 MW).

Charlotte has three 230 kV lines to the north and to the south. Ft. Myers (1176 MW) is south of Charlotte and Manatee (1528 MW) and Big Bend (1206 MW) are north of Charlotte.

Port St. Joe is a more remote system location, but two 230 kV lines exist in the area, one of which terminates near Plant Lansing Smith in the Southern Company System.

For these three locations, the adequacy of the transmission system to accept OTEC power and the reliability of the transmission system were examined. The adequacy considers principally the power flows and voltage levels under study conditions, and the reliability considers principally outages and interruptions.

5.2 TRANSMISSION ADEQUACY

5.2.1 Objective and Scope of Analysis

The purpose of this study section is to evaluate the adequacy of the State of Florida Bulk Power Transmission System for three scenarios for OTEC power transmission. The adequacy is evaluated in comparison to the Florida Power Corporation transmission and distribution planning criteria. The study was made on a 1988 projected State of Florida base case power system. The system consisted of the existing 1980 transmission system plus all planned utility additions through 1988.

5.2.2 Computer Programs Used

The system was studied using the following computer programs:

- PECO -- The Philadelphia Electric Power Flow Program
- TEXAS -- A fast linearized, decoupled AC power flow for contingency simulation (U. of Texas, Arlington)
- SLAP -- Forecasting and Substation Load Allocation Program (FPC)

The following are brief descriptions of each program:

Philadelphia Electric Power Flow Program (PECO)

Load flow calculations provide power flows and voltages for a specified power system subject to the regulating capability of generators, capacitors and load tap changing transformers, as well as specified interchange between individual power companies. This information is essential for the continuous evaluation of the electrical performance of a power system and for analyzing the effectiveness of alternative plans for system expansion to meet increased load demands. These analyses require the calculation of numerous load flows for both normal and emergency operating conditions.

High-Speed Contingency Load Flow Program (TEXAS)

The TEXAS program utilizes a high-speed contingency load flow algorithm obtained from the University of Texas at Arlington. This new computer load flow technique automatically performs single contingency outage simulations throughout the electric system network. The program performs the equivalent of numerous load flow cases at greatly reduced computer time requirements through the use of high-speed linearized, decoupled load flow techniques. This program provides abbreviated exception reports for the user, based on whether or not there are overloaded transmission lines in the system or buses with abnormal or unacceptable voltage.

Substation Load Allocation Program (SLAP)

The Substation Load Allocation Program (SLAP) used at FPC produces load projections for each substation extending into the future for ten years. The initial area forecast is made by using the past ten years of historical data and applying a specified polynomial curve fitting equation to the various classifications of load. These classifications are breakdowns such as Industrial, REA or Residential Substation Loads. The sum of the peaks projected using the polynomial equations for each area will not necessarily equal the official system net demand forecast. A diversity factor is then developed for each future year and the substation forecast is scaled appropriately. The scaled system forecast substation loads are used for the PECO load flow program input. It is also worthwhile to note that the system forecast used is a 90% confidence level, which means that 90% of future loads will be less than or equal to this figure. The SLAP program projects peak demands on a seasonal basis which is consistent with system forecasting procedures.

5.2.3 Methodology

The approach to the evaluation of the adequacy of the State of Florida Bulk Power System and the three OTEC generation addition alternatives is indicated in Figure 5-2. The procedure and assumptions are, briefly:

1. As a beginning point, the study year was chosen and each individual utility load forecast in the state was obtained for the study year. The individual utility generation and transmission expansion plan through the study year was also obtained.
2. The data was then synthesized into a mathematical model of the power system. The network solution was obtained using the PECO Power Flow Program.
3. The results of the computer runs were then assessed. The key assessment variables included the individual line loadings, the voltage on each bus, and losses.
4. The computer results were also reviewed from a qualitative analysis viewpoint. Factors such as operating flexibility, and future expansion capability were analyzed.
5. Alternative solutions to any problem were made in the computer model representation and the program was reviewed until a satisfactory set of solutions was obtained.

Figure 5-2

5.2.4 Description of Analysis

The projected system load for the study year was 39,986.4 MW. Table 5.1 shows the individual company loads that were used in the study. Table 5.2 contains the generation dispatch and interchange required to meet the load for the study year. Table 5.3 lists the flows on the lines emanating from the OTEC connection buses, before the OTEC generation is added.

The 1988 base case power system under evaluation is depicted in Figure 5-1. The addition of 400 MW of OTEC generation at the three potential locations in this system is indicated in this figure. For modeling simplicity, the DC cable line and the inverter/converter stations at the three OTEC connection points are not included. The OTEC unit is modeled as a real power generator with the capability of 400 MW.

As the output of the OTEC plant would be DC, the shore sites selected for the OTEC connection points must have adequate land available to accommodate inverter stations. The three shore sites selected have adequate land; in addition, approximately 200 MVAR of capacitive reactance will be required with the inverter stations to convert the DC to AC. The additional reactive support could be provided from nearby generators, synchronous condenser, fixed capacitors, or a combination of all three.

AUTOMATIC AREA INTERCHANGE CONTROL

X	AREA IDENTIFICATION	X	CONTROL BUS	X	EXPORT (MW)	X	TOLERANCE
NO.	NAME	NO.	NAME	GEN-MW	ACTUAL DESIRED	(MW)	
1	FLORIDA POWER AND LIGHT	346	230 CAPE K	728.64	761.69	761.70	5.00
2	FLORIDA POWER CORPORATION	558	022 CRYST K2	438.14	63.59	63.40	5.00
3	TAMPA ELECTRIC COMPANY	927	1 B BND2	351.40	0.06	0.00	5.00
4	JACKSONVILLE ELECTRIC AUTHORITY	1209	NS GT	17.97	300.00	300.00	5.00
5	ORLANDO UTILITIES COMMISSION	1297	INDIAN RIV 2	157.79	-147.40	-147.40	5.00
6	LAKELAND	1331	SU 1,2	168.60	134.00	134.00	5.00
7	TALLAHASSEE	1352	014 MPS1	74.32	-11.10	-11.10	5.00
8	GAINESVILLE	1381	013 DEER DH1	80.87	7.40	7.40	5.00
9	SOUTHERN COMPANY	1401	BOWEN 8	2832.09	-0.00	0.0	5.00
10	SEMINOLE ELECTRIC COOP	1193	230 SEMINOLE	1199.65	-1108.24	-1108.00	5.00

Table 5.1

SUMMARY OF INTERCHANGE AND LOSSES

AREA LOSSES INCLUDE TIE LINES. MINUS INDICATES IMPORTS. LINE 1 IS MW, LINE 2 IS MVAR. FLOWS ARE COMPUTED AT NON-OWNER BUSES.

FROM AREA	FROM AREA NAME	AREA LOSSES	TO AREA	NET XCHNG	TO AREA	NET XCHNG	TO AREA	NET XCHNG	TO AREA	NET XCHNG	TO AREA	NET XCHNG
1	FLORIDA POWER AND LIGHT	286.61 473.01	TOTAL	761.69 489.65	2	757.22 230.59	3	-192.52 -63.89	4	112.12 22.89	5	-14.00 -50.79
			9	142.95 -1.71	10	-44.08 352.56						
2	FLORIDA POWER CORPORATION	205.72 780.13	TOTAL	63.59 195.04	1	-757.22 -230.59	3	73.96 -41.47	5	70.31 1.59	6	75.59 14.39
			7	11.10 -14.47	8	11.81 47.29	9	-142.95 61.81	10	720.99 356.48		
3	TAMPA ELECTRIC COMPANY	40.05 445.54	TOTAL	0.06 42.38	1	192.52 63.89	2	-73.96 41.47	6	-118.51 -62.98		
4	JACKSONVILLE ELECTRIC AUTHORITY	21.11 389.74	TOTAL	300.00 106.21	1	-112.12 -22.89	10	412.12 129.10				
5	ORLANDO UTILITIES COMMISSION	22.17 112.10	TOTAL	-147.40 27.78	1	14.00 50.79	2	-70.31 -1.59	6	-91.08 -21.42		
6	LAKE LAND	3.60 61.07	TOTAL	134.00 70.00	2	-75.59 -14.39	3	118.51 62.98	5	91.08 21.42		
7	TALLAHASSEE	6.43 46.78	TOTAL	-11.10 14.47	2	-11.10 14.47						
8	GAINESVILLE	4.07 34.84	TOTAL	7.40 -39.83	2	-11.81 -47.29	10	19.20 7.45				
9	SOUTHERN COMPANY	188.26 330.51	TOTAL	-0.00 -60.10	1	-142.95 1.71	2	142.95 -61.81				
10	SEMINOLE ELECTRIC CORP	16.50 96.64	TOTAL	-1108.24 -845.59	1	44.08 -352.56	2	-720.99 -356.48	4	-412.12 -129.10	8	-19.20 -7.45

Table 5.2

SYSTEM SUMMARY BY AREAS

X	-----AREA IDENTIFICATION-----X	X	ELEMENTS-----X				X	GENERATION-----X		UNUSED	X	LGAD-----X		STATIC	CHARGING
NO.	NAME	BUS	LINE	GEN	LTC	PS	Mw	MVAR	MVAR		Mw	MVAR	MVAR	MVAR	
1	FLOKIDA POWER AND LIGHT	476	608	17	92	0	12839.6	2598.1	4140.9		11792.2	3199.5	1560.9	2470.9	
2	FLORIDA POWER CORPORATION	266	497	32	118	0	5772.1	1753.2	1389.8		5503.0	1555.2	767.7	1228.1	
3	TAMPA ELECTRIC COMPANY	183	228	14	40	0	2420.4	844.2	612.2		2380.2	590.0	233.5	122.4	
4	JACKSONVILLE ELECTRIC AUTHORITY	84	134	15	36	0	2680.0	1199.9	875.1		2358.8	774.8	70.2	143.0	
5	ORLANDO UTILITIES COMMISSION	21	28	4	7	0	591.8	362.8	229.2		717.0	342.0	119.0	61.9	
6	LAKELAND	20	27	3	6	0	502.6	217.5	56.5		365.0	86.4	0.0	7.3	
7	TALLAHASSEE	23	33	6	8	0	481.3	188.2	83.8		486.0	127.0	0.0	8.6	
8	GAINESVILLE	12	16	4	5	0	329.5	87.6	116.4		318.0	92.6	0.0	14.4	
9	SOUTHERN COMPANY	88	179	18	36	0	13965.1	2484.0	5929.0		13776.7	2793.9	580.3	1996.4	
10	SEMINOLE ELECTRIC COOP	119	25	1	0	0	1199.7	85.2	514.8		2290.6	873.3	39.7	57.1	
***** SYSTEM TOTALS ACTUAL 1292 1775 114 348 0 40781.7 9820.5 13947.8 39586.4 10434.4 3371.2 6109.0															
LIMITS 1500 2500 500 500 25															

		X-----TOLERANCES-----X						X-SYSTEM LOSSES-X	
		BUS ABS MM (PU)		TOT ABS MM (PU)		LTC		MW	MVAR
		P	Q	P	Q	VOLTS			
MAXIMUM	40	0.01000	0.01000	0.10000	0.10000	0.00100		794.46	2769.38
ACTUAL	19								

CONVERGENCE CRITERION --- ABSOLUTE BUS MISMATCH

Table 5.3

5.2.5 Results

Case 1 — 1988 Base Case Power System

Under 1988 normal peak load conditions, the power flows on each transmission line and transformer fall below the continuous ratings of the equipment. In addition, adequate voltage is maintained on all substation buses during normal peak load conditions. FPC losses for this case are 205.72 MW.

Under single contingency analysis, no individual component outage caused another element to exceed its emergency rating. Adequate voltage was maintained on all major system buses during single contingency analysis.

Case 2 — 1988 Base Case Power System with 400 MW of OTEC generation added to the Bayboro 230 kV Bus

The Bayboro 230 kV bus is located at the southern tip of peninsular Pinellas County. Being a peninsula and with no tie lines to the south, all the power not generated within the peninsula must be imported over the existing transmission system. At present 400 MW must be imported over the transmission lines. By 1988, this figure will exceed 800 MW.

Florida Power Corporation losses for the base case configuration are 205.72 MW. With the OTEC generation added to Bayboro, the losses are reduced to 180.43. This reduction is due to the import into Pinellas County being reduced by approximately 50%.

With the OTEC generation connected to the Bayboro bus all lines and transformers flow below the normal rating. Under contingency, all line and transformer flows are below the emergency ratings.

Case 3 — 1988 Base Case Power System with 400 MW of OTEC generation added to the Charlotte 230 kV Bus

The Charlotte 230 kV bus is located in Charlotte County, Florida, approximately midway between the cities of Ft. Myers and Sarasota. The three cities are tied together by a strong 230 kV grid that extends along the southwestern Florida coast. In addition to the transmission network, Ft. Myers has 260 MW of generation and Manatee Plant located near Sarasota has 1328 MW of generation.

The OTEC generation connected into the Charlotte 230 kV bus has a minimal effect on the network. Under normal conditions all lines and transformers are below their normal rating. Under first contingency all lines and transformer flows are below their emergency rating.

Case 4 — 1988 Base Case Power System with 400 MW of OTEC added to the Port St. Joe 230 kV Bus

The Port St. Joe 230 kV bus is located in Florida's Panhandle region. The only major generating facility in the area is FPC's Suwannee River Plant with a capacity of 83 MW of fossil generation and 200 MW of combustion turbines. The area does import 400 MW from the Crystal River Generation Complex to serve the load. The power is brought into the area over the Ft. White - Crystal River 230 kV line. With the OTEC generation connected into the Port St. Joe 230 kV, power flows into the area are reduced. The flow on the Crystal River - Ft. White 230 kV line is 202 MW. FPC system losses drop from 205 to 180.72 MW.

Under normal conditions, all lines and transformers are below their normal rating. Under first contingency all lines and transformer flows are below their emergency rating.

5.3 Transmission System Reliability

5.3.1 Purpose

For a 1988 State of Florida base case power system, the transmission adequacy of three OTEC generation addition alternatives was evaluated utilizing a probabilistic computer model. This computer model, termed the Gator 2.0 system, performs single contingency line, transformer, and generator outages. Violations of performance criteria in terms of network separation, component overload, or unacceptable bus voltage are quantified in terms of various expected reliability indices. A description of this system is included in Appendix A.

5.3.2 Description of Cases Considered

The 1988 base case power system under evaluation is depicted in Figure 5-3. The addition of 400 MW of OTEC generation at three locations in this system is indicated in this Figure. Transmission adequacy assessment is performed as follows:

Case 1 - 1988 base case power system

Case 2 - 1988 base case power system with 400 MW of OTEC generation added to the Bayboro 230 kV bus

Case 3 - 1988 base case power system with 400 MW of OTEC generation added to the Charlotte 230 kV bus

Case 4 - 1988 base case power system with 400 MW of OTEC generation added to the Port St. Joe 230 kV bus.

Deterministic assessment has concluded that transmission additions are not required at the three OTEC connections points, thus the only

difference between Case 1 and Cases 2 through 4 is the addition of 400 MW of OTEC generation at the specified 230 kV buses. For modeling simplicity, the DC cable line and the inverter/converter stations are not included. The OTEC unit is modeled as a real power generator with the capability of being dispatched from 0 MW to 400 MW.

5.3.3 Methodology

The approach in the evaluation of the transmission adequacy of the 1988 base system and the three OTEC generation addition alternatives is indicated in Figure 5-4.

The procedure and assumptions are briefly described:

1. As a beginning point, the converged 1988 summer PECO power flow case utilized in the deterministic portion of the OTEC study was the base case used for the probabilistic adequacy assessment (1292 buses, 1775 lines).
2. Due to program limitation in GATOR 2.0 and to conserve computer time, the 1988 base case was reduced to a 195 bus and 271 line network equivalent. Care was taken to model the 115 Kv through 500 kV network in close proximity to the OTEC generation addition buses (Bayboro, Charlotte and Port St. Joe). As depicted in Figure 5-3, the eastern and southerly portion of Florida was truncated. Within the study area, major generation and 230/500 kV lines were modeled between the proposed OTEC generation addition buses.

In order to accurately model the "equivalent" generators at the truncation points, a fast contingency AC load flow (TEXAS) program was run on the large base case, with those lines representing the equivalency points monitored. In this way, realistic megawatt and megavar limits were established for the equivalent generators.

Figure 5-4
METHODOLOGY — OTEC TRANSMISSION ADEQUACY ASSESSMENT

3. In order to verify the accuracy of the reduced base case, a TEXAS 2 fast contingency load flow was run on the reduced system. The results from this contingency program run were compared against the large base case contingency run. In general, the reduced base case accurately represented the large base case for the study area under investigation in Figure 5-3.

4. An extensive reliability data base for the OTEC study was prepared. Excerpts include the following:

a. Customer data - the number of customers at all firm load buses was calculated using 3.5 kW per customer. Percent interruptible load was indicated at known interruptible load buses and equivalency point buses where all or part of the load was outside the system under evaluation.

b. Line/transformer data - Each line/transformer in the base case was represented as a two state stochastic model. Annual failure rates (λ) and restoration times (hours) were based on 1978 Florida Power Component Reliability Data, and calculated as a function of voltage and line mileage. Two substation line terminals were assumed for all lines and transformers.

c. Generation data - In general, generators were represented as a two-state stochastic model. The OTEC unit was represented as a three-state model with 400 MW, 240 MW and 0 MW states. Figures 5-5, 5-6 and 5-7 indicate the process of reducing the OTEC generator/cable combination to a three-state model. Figure 5-5 indicates the series reliability components with the OTEC generator assumed perfectly reliable. Figure 5-6 indicates a nine-state Markov model describing the cable and foul weather modules.

D.C. CABLE 1 & 2 : FAILURE RATE = .5/YR. RESTORATION TIME = 2,880 HRS.

FOUL WEATHER : FAILURE RATE = 1/YR. RESTORATION TIME = 120 HRS.

**Figure 5-5
OTEC RELIABILITY MODEL**

Figure 5-8
MARKOV MODEL OF OTEC GENERATION

Figure 5-7
THREE STATE MARKOV MODEL OF OTEC GENERATION

Utilizing a state combination process referenced in Endrenyi (Reliability Modeling in Electric Power Systems, J. Endrenyi, 1978), this nine-state model was reduced to the three-state model in Figure 5-7.

For the remaining generators in the power system, EEI generator performance data (1968-1977) was utilized for generators outside the Florida Power system and historical performance data used for generators within the Florida Power system consistent with the OTEC generation study.

d. Annual load model - A thirty-eight data point annual stochastic load model was calculated based on a future hourly load model utilized presently at Florida Power Corporation for generation planning studies.

A summer base case was used in the OTEC study but there is little difference between the system peak for the summer of 1988 and the winter of 1987-1988, thus realistic annual reliability computations could be made.

e. Emergency generation redispatch - The GATOR 2.0 program has the capability of redispatching generation to reduce component overload. For the reduced power system, an emergency redispatch list (ERL) was prepared. This list indicates real power limits (MW) for active and inactive generators in the base case. For the upper limit, the maximum summer ratings were used for the generators.

5. On completion of the reduced network equivalent and the reliability data base for that equivalent, the GATOR 2.0 program was run on-peak for the base case and the three OTEC sites under evaluation. These test runs revealed several problems which were resolved.

5.3.4 Results

Table 5.4 contains calculated annual system reliability indices from the Service Reliability Program (SRP) for the final base case run and the three OTEC alternates. In general, there is little difference in system performance between the four cases. This is in part due to the relatively small size of the OTEC unit (400 MW) and the fact that no system modifications were made in the OTEC cases (Cases 2, 3, and 4).

Ranges on critical annual indices are:

Service failure hours	3.7 - 4 hours
Unserviced energy	155 - 200 MWh
Unserviced customer hours	22,038 - 28,606 hrs
Customer interruptions	688 - 832
Megawatts curtailed per occurrence	42 - 52
Customers curtailed per occurrence	602 - 711

A detailed analysis was made with a resulting large amount of output data. The detailed service failure results and system buses losing load are summarized as follows:

1. Case 1 - Base Case. Out of 271 line and 21 generator outages run at 5 different load levels, 32 resulted in service failure (buses losing load). There were no generator outages resulting in service failure.

At the 5 load levels, 52 service failures occurred, 32 on peak, 14 at the 80% load level, 5 at the 64% load level, and 1 at the 50% load level. There were no outstanding areas in the base system with poor performance.

2. Case 2 - Bayboro. With the OTEC unit at the Bayboro 230 kV bus, there is marginal improvement in reliability over the base case. Two line contingencies resulted in load loss in the base case are eliminated in Case 2 (Largo - Seminole and Seminole -

Table 5.4

SUMMARY OF ANNUAL RELIABILITY INDICES
FOR
OTEC TRANSMISSION STUDY

PROBABILITIES	Base Case 1	Bayboro Case 2	Charlotte Case 3	Port St. Joe Case 4
Service Failure Probability (per unit)	0.000 442	0.000 417	0.000 452	0.000 460
Unserviced Energy Probability (per unit)	0.000 000	0.000 000	0.000 000	0.000 000
EXPECTED AVERAGES				
Service Failure Hours (hrs/yr)	3.87	3.66	3.96	4.03
Service Failure Occurrences (occ/yr)	1.17	1.11	1.16	1.26
Unserviced Energy (MWH/yr)	200.35	154.69	196.15	190.29
Unserviced Customer Hours (MWH/yr)	28,537.84	22,037.85	27,976.95	28,606.23
Customer Interruptions (cust int/yr)	831.98	668.40	809.91	785.72
BULK POWER INTERRUPTION INDICES				
Bulk Power Interruption Index	.00430	.00340	.00418	.00433
Bulk Power Energy Curtailment Index	.01447	.01111	.01413	.01379
Bulk Power Supply Average Curtailments	51.73391	42.2300	49.5883	47.19494
SERVICE RELIABILITY INDICES				
System Interruption Frequency Index (int/cust)	.0002	.000	.000	.000
System Interruption Duration Index (hrs/cust)	.0071	.005	.007	.007
System Service Availability (per unit)	1.000	1.000	1.000	1.000
Avg. No. Customers Per Interruption (cust/int)	711.09	602.162	698.198	623.587

Pasadena 230 kV line outages).

3. Case 3 - Charlotte. With the OTEC unit addition at the Charlotte 230 kV bus, there is negligible change in system performance over the base case. In Case 3, one line contingency resulting in service failure in the base case is eliminated (Laurelwood - Ringling 230 kV line outage).

4. Case 4 - Port St. Joe. As in Cases 2 and 3, there is little difference in system performance between the Port St. Joe OTEC alternate and the base system. In Case 4, two additional service failures occur, but these are due to the change in the generation dispatch between the base case and Case 4. With the addition of 400 MW of generation at the Port St. Joe 230 kV bus, the swing machine for Area 2 (Florida Power) is backed down. This changes the power flow slightly, resulting in service failures for two line contingencies (Osceola - Kathleen 500 kV and Clermont East - Windermere 230 kV).

5.4 SUMMARY

In summary, this transmission analysis was conducted to determine the transmission adequacy of a 1988 summer reduced power system network for the State of Florida (Case 1) and three OTEC addition alternates (Cases 2 through 4). There is little change in bulk transmission adequacy between the base case and the alternates with approximately 4 service failure hours and 20 MWh of unserved energy per year.

FCG stability studies run in past years have modeled the loss of one or both units at plants like Manatee, Big Bend and Anclote without finding significant problems. These units are located in the area near the proposed connections at Bayboro or Charlotte. Since these units are larger than the proposed OTEC source, we would not expect the loss of a 400 MW OTEC unit, either the plant or the transmission line, to have a significant impact on system stability.

At Port St. Joe, the loss of the 400 MW source should not cause any transmission problems, but transient voltage dip could cause the momentary loss of some local load due to motor controls. This observation is based upon recent stability studies of transmission requirements for large generators at this location.

The connection of two DC cable sets from the OTEC plant to two different landfalls, to Port St. Joe and to Bayboro or Charlotte, would be of little benefit to the state if a planned 500 kV grid with multiple ties to the Southern Company is completed. The grid would then be so strong that any additional benefits which might be provided by a DC cable connection at two land sites would not be significant.

6. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

6.1 SUMMARY OF STUDY PROCEDURE

The location of Florida Power Corporation is geographically favorable for consideration of an OTEC generating plant. The service area is along the Gulf of Mexico and the thermal resource offshore is suitable for ocean thermal energy conversion. OTEC is of interest to FPC as a new energy resource having several attractive features including generating source diversity, energy from a perpetually renewable source, and non-escalating fuel costs. OTEC power could be integrated into the FPC system, or transmitted to other utilities.

Electric utility system planning, when conducted in a detailed and systematic manner such as FPC uses, is a formal methodology that rigorously examines any potential generating source for suitability in the overall generating, transmission, and distribution system. Evaluation of OTEC by this planning methodology provides detailed information on both positive features and negative aspects of OTEC as an electric power generating source.

FPC uses this methodology annually to prepare a facilities plan looking at a 20-year study horizon. The 1979 plan provided a Base Case against which a plan including OTEC was compared. No modification in the FPC system planning methodology was made to accommodate the OTEC evaluation.

The Base Case included coal-fired generating units for necessary capacity additions from 1988 on, the time period in which it was assumed OTEC would be commercially available. The capital costs for coal-fired units in this time frame were projected to be \$689/kW and

\$586/kW for the first and second units planned at the same site. All costs in this report are in 1979 dollars.

OTEC plant input information included a capital cost of \$2256/kW. Due to modularity of an assumed 400MW OTEC plant, the availability and hence the reliability of such a generating source is quite high. Because of this reliability, a single 400 MW OTEC plant scheduled for service in 1988 would essentially displace 800 MW of coal-fired capacity in 1990.

The first criterion for evaluating competing plans is a measure of the cost of electricity which is expressed as the cumulative total revenue requirements (CTRR) for each plan. Any or all plans within a reasonably close range of CTRR are then considered under the second criterion which is to determine if the plan can be financed. The plan with the most favorable CTRR and which can be financed would then become the recommended generation expansion plan.

6.2 CONCLUSIONS

It was found that under the study assumptions, the OTEC Case was economically unfavorable when compared to the Base Case to the extent that it would not be considered further under the FPC system planning procedures. The major factors leading to this result were the capital cost of the OTEC plant and the assumed coal cost escalation rate.

At this point, parametric analysis was performed in order to quantify breakeven values for OTEC. Two principal parameters, OTEC capital cost and coal fuel cost escalation rate, were varied until a range of breakeven values was established. A reduction in OTEC capital cost to \$1450/kW established one point. An increase of coal cost escalation rate (and corresponding increases in other fuel costs) to 12%, holding OTEC capital cost at \$2256/kW, established another point.

Intermediate values of OTEC capital cost and fuel escalation rate produced a curve of equivalent economic competitiveness.

However, further study revealed that a plan including OTEC, even if the economic competitive values were assumed, could not be financed under existing constraints. The amount of capital required during the construction period was too large for FPC to support.

A number of financial incentives -- capital cost subsidies, investment tax credits, full construction work in progress (CWIP) cost in the rate base, loan guarantees and one-step licensing -- were examined and found not to alter the conclusion on financeability. Obviously, if the capital cost of OTEC were to be so subsidized such that it would approach the capital cost of a coal-fired plant, OTEC would be viable on an economic basis, and financeability would be equivalent to the Base Case. However, this was not considered a credible incentive scenario.

The purchase of power from a third party owner, or some similar arrangement appears to be the most reasonable means of bringing OTEC power into the FPC system. There are no corporate inhibitions to such an arrangement (assuming conditions are contractually agreeable); in fact, established company policy would favor a purchase of OTEC power, provided the cost was competitive with alternative sources. The advantage of diversification of energy supply is recognized as well as the use of a renewable resource.

6.3 DISCUSSION

6.3.1 The Two Sided Problem

There are two sides to the economic problem of introducing OTEC into a utility such as FPC:

- (1) It must be competitive in terms of the cost of electricity to the consumer;
- (2) It must be capable of being financed.

The first factor is quantified by calculating the total cumulative revenue requirements (CTRR) for any generating plant over the specified time period. This is a direct measure of what the rate-payer must support as a consumer of electric power. The system planning studies established relationships between OTEC plant capital costs and the capital cost of the competing technology (coal fueled plants) and the rate of fossil fuel price escalation. It may be concluded that some set of conditions could cause this first factor to be satisfied; by either a higher rate of fuel cost escalation, or by some means of OTEC plant cost reduction.

The second factor is more difficult to overcome. Even if OTEC, with the necessary assumptions were:

- Competitive with respect to the delivered cost of power,
- A technically proven generating source, performing to design specifications, reliable, no surprises, no construction cost overruns, no lengthy shutdowns due to mechanical failure,
- Without impediments from legal jurisdiction, permits, international law, hazards due to collision, or threat from attack;

FPC could not, in the studied time frame, finance an OTEC plant.

6.3.2 The Requirements for OTEC Development

OTEC developers, the industries and the government, must accomplish two things; first develop a suitable technology, and second develop a new mode of ownership of plants and/or sale of power.

This implies that OTEC technical developers must address a market for OTEC plants somewhat different than may have originally been assumed. Rather than utility companies, the market may be a new entity, such as a company or consortium set up to acquire the plants, operate them and sell the product to the utility companies via acceptable sales contracts. Although the third party owner may be the immediate market, the utilities will be the recipients and distributors of OTEC power; therefore, they are part of the market for OTEC plants, but in a secondary role.

The legal, institutional, and financial aspects of OTEC require as much attention as the technical matters. The complexities of arrangements for sale and purchase of power can be considerable for a new technology such as OTEC. Utilities will be sensitive to legal and regulatory factors.

6.4 Recommendations

1. Topic: Third party ownership; power purchases, leases or lease-purchases.

Background Discussion:

It appears that some third party arrangement would be the most feasible means of facilitating OTEC commercialization along the Gulf coast. This implies purchase of OTEC power by a utility such as FPC from the third party (conceivably, utilities could be participants in a third part arrangement through subsidiary operations), or some form of lease or lease-purchase.

There are matters that a utility might find necessary for a purchase of power arrangement, or that the seller might require. These might include one or more of the following:

1. For a seller: guarantee of purchase by a utility.
2. For a utility: guarantee of performance; i.e., availability of power, or compensation for purchase of replacement power.
3. For a utility: "wheeling" provisions for transmission of power to inland users; e.g., if FPC transmits OTEC power to a neighboring utility, the commercial arrangements may be different than for other situations.
4. For a utility: capacity of the transmission system from a technical aspect; e.g., what problems, if any, in existing systems; what requirements for new transmission capability.
5. For a seller and a utility: acceptable regulatory handling by state public utility commissions, and acceptance by other members of associated power pools.
6. For a seller and a utility: concern with lease purchase terms; what incentives to a third party for such an arrangement; what obligations on the utility -- impact on financial standing.

One may conclude from the course of legislative action, on one hand, and the ineffectiveness of the proposed incentives for a utility company, on the other hand, that the present legislation direction reflects inputs of the OTEC manufacturers rather than OTEC users. It is therefore important that future legislative or regulatory activities have an effective input from the utility industry.

Recommended:

Carry out a thorough study of power purchase or lease-purchase arrangements involving third party owners of OTEC plants. Recognize the issues stated above and pay particular attention to the utility's problems and concerns. Involve the utility industry in an appropriate

fashion. It is not too soon to make this study; in fact, from opinions expressed by FPC senior executives, it would be very timely.

2. Topic: Power Cable Technology.

Background Discussion

Of all OTEC technical areas, utilities are most familiar with transmission systems, and to some extent, power cables. There is particular concern for this aspect of OTEC development due to the long run of underwater cable required for an OTEC plant off Florida.

There are factors beyond the development phase, such as testing and qualification of power transmission equipment, that can involve time durations much longer than development of other parts of major OTEC components. It is doubtful that less than several years, after successful development and manufacturing testing, will be adequate for demonstration of power cable technology.

Even if a third party were to be the owner of OTEC plants, they could be expected to follow precedents set by the power industry and utility companies on equipment acceptability. Therefore, the experience that utilities could provide in this area might prove valuable to OTEC development and commercial introduction.

Recommendation:

Involve the utility industry in the OTEC cable development effort. This could include utility assistance at a level that involves their transmission engineering staffs, and solicits their advice on testing, construction and qualification.

3. Topic: Utility Industry Interaction with OTEC Interests . . .

Background Discussion:

This study has proven useful to both the government sponsors and FPC. The contract with FPC involved many levels of staff and included discussions with the very top level of management. Attention was given to detail, and as a result familiarity with OTEC in FPC is substantial. Correspondingly, the product of the study is specific and detailed.

Recommendation:

Maintain and expand information exchange with the utility industry, insuring that it is meaningful.

6.5 CLOSURE

Florida Power Corporation wishes to express its sincere pleasure in having the opportunity to conduct this evaluation. Although the results indicated that OTEC would not be the most economical generating source for FPC during the study period, a number of positive aspects of Ocean Thermal Energy Conversion were revealed. Furthermore, the parametric analysis should provide valuable information and goals for OTEC developers. Producing electric power from a renewable energy source and providing a diversification of energy supply certainly make Ocean Thermal Energy Conversion an exciting and attractive technology. If the situation were to develop such that a commercial enterprise or some government-supported entity could provide OTEC power for purchase by FPC at an economically competitive price, it would certainly be given serious consideration.

APPENDIX A

DESCRIPTIONS OF FPC COMPUTER PROGRAMS UTILIZED FOR SYSTEM PLANNING AND ANALYSIS

- o LOADFLO
- o PROMOD
- o GATOR
- o CORMOD

APPENDIX A.1

"LOADFLO" - PROGRAM FOR CALCULATING POWER FLOWS THROUGHOUT A UTILITY SYSTEM

This program, which is modified from one originally developed for the same purpose by the Philadelphia Electric Company, calculates steady-state power flows throughout the FPC electric utility system. In order to do this properly, it is necessary to include within the computer model a representation of the major electric system elements (generating plants, higher voltage transmission lines, and load centers) in the entire state of Florida and the southern portion of the state of Georgia.

APPENDIX A.2

"PROMOD" - PROGRAM TO DETERMINE SYSTEM PRODUCTION COSTS

The PROMOD III System including standard options contains the following standard features:

- Probabilistic generating unit availability models
- Multiple pumped-hydro projects
- Automatic and prescheduled maintenance scheduling
- Multiple take-or-pay fuel contract logic
- Multiple limited fuel contract logic
- Nuclear fuel cycle cost model
- Spinning reserve model
- Calendar month calculations
- Generalized load and energy forecasts models
- Generalized data handling features
- Economic dispatch modeling with transmission penalty factors
- Unit commitment modeling
- Automatic load adjustment for load management studies
- Calculation of capacity surplus and deficiencies on basis of reliability standard
- Diversity exchange contract modeling
- Readable output report file diagnostic dump
- Generalized output reports including
 - 3 complete input reports
 - 5 monthly reports
 - 5 quarterly reports
 - 5 annual reports
 - 5 study reports
 - 4 annual fuel budget reports
 - 4 study fuel budget reports
 - 20 diagnostic reports
- Report generation restart from calculation results file
- Separate fuel handling cost accounting

- Fuel inventory model
- Both storage and run-of-river hydro models
- Combustion turbine and combined cycle models
- From two to seven capacity segments per generating unit
- Three load periods per week
- Flexible modeling for contract purchases and sales
- Overhaul cost accounting
- Cyclic derations for seasonal unit ratings

The PROMOD III System differs from conventional production costing programs in its treatment of forced outages of generating units and auxiliary equipment. The PROMOD III System offers significant improvement over earlier probabilistic program costing programs. These modeling extensions include:

i) Load Model

Three load duration curves per week permit modeling of weekend maintenance and better representation of pumped hydro operation. Unit commitment now can be modeled more exactly.

ii) Load Management

Both demand and energy forecasts may be specified with the load shape being automatically adjusted using either:

- peak bias
- neutral bias
- valley bias

Annual energy and demand forecasts may be specified after the initial year or these forecasts may be escalated.

iii) Load Shapes

Hourly loads in EEI format are input and converted by the program to the appropriate load shapes. The need for auxiliary program and/or manual calculations to prepare load shapes has been eliminated.

iv) Generating Unit Model

Each generating unit may be represented by from two to seven capacity states. This permits more accurate modeling of partial forced outages and improved economic dispatching. Historical year rate case support testimony can now be performed with great precision.

- v) Reliability Model
PROMOD doubles as both a production costing and system reliability model. If only reliability results are desired, the time-consuming production costing calculations can be bypassed.
- vi) Output Reports
All output reports have been made optional. The user may select output from any of 28 reports.
- vii) Report Period
The time period for generating output reports may be controlled independently from the study period. This permits detailed diagnostic reports to be obtained for a short period of interest without generating massive volumes of output.
- viii) Optional Calculation Speed
Either fast, standard or precision calculation speeds may be specified.
- ix) Limited Fuel Model
A new model for limited fuel sources will soon be available. The allocation of limited fuel is performed on the basis of economics.
- x) Take-or-Pay Fuel Model
A new model for take-or-pay fuel sources will soon be available. The allocation of take-or-pay fuel is performed on the basis of economics. An efficient reallocation scheme has been developed to assure that all take-or-pay fuel is consumed in the event that the economic dispatching results in under utilization of the contractual amount.
- xi) Pumped Storage Model
Full probabilistic modeling is provided for multiple pumped storage projects. With three load duration curves per week the operation of a pumped storage project with a weekly refill cycle can be modeled accurately. The limitation on pumped storage utilization - economics, pumping capacity, generating capacity, storage capacity - is displayed in the period output report.

xii) Startup Priorities

Startup priorities may be automatically assigned by the program based upon unit heat rate and fuel economics or may be specified by the user. Specification of the generalized startup logic option eliminates the use of startup priority entirely. Units are then dispatched purely on the basis of economics (startup costs, incremental heat rates, fuel prices), reserve requirements, and unit minimum downtime restrictions.

xiii) Cost Escalation Factors

Escalation factors are provided for all costs. These escalation factors may be controlled at several levels:

- system wide
- fuel categories
- fuel suppliers
- individual generating units

Input data is minimized since missing values automatically default to the proper value at the next highest level.

xiv) Diagnostic Reports

Special diagnostic reports can be activated. These labeled reports will assist the user in quickly evaluating modeling and/or data discrepancies which were not detected during validation of input data.

xv) Automatic Maintenance Scheduling

Maintenance schedules which levelize the system reliability can be developed automatically thus relieving the user from the tedious effort of preparing maintenance schedules for multiple-year studies.

xvi) Maintenance Schedule Retention

The maintenance schedule generated with the automatic maintenance scheduling module may be permanently saved for future change case studies to assure that identical maintenance schedules are followed. Without this special feature a different number of maintenance outages may result for particular units over the same study period - a situation which makes change case comparative analysis needlessly difficult.

xvii) Generating Unit Derations

Derations may be specified for any unit at any time during the study even after a unit has entered automatic maintenance. Cyclic derations permit seasonal capacity adjustments to be specified easily.

xviii) Firm Energy Transaction Models

Generalized models have been provided for firm energy purchases and sales. The preferred subperiod - day, night, weekend - may be specified for each transaction.

xix) Data Override

A generalized data override capability has been provided which permits any information related to a generating unit, a firm transaction, a fuel type, or a load forecast to be overridden at any time even after it has started escalation or a unit heat rate may be changed to reflect scrubber installation without requiring that the old unit be retired and a new unit with identical characteristics except for the heat rates be commissioned.

xx) Library Files

Permanent library files for generating unit data, automatic maintenance data, load data, transactions data and fuel type data are maintained by the PROMOD System. This simplifies the management of change case studies - instead of requiring a complete data deck for each change case only the override data cards necessary to specify the change case need to be provided.

xxi) Time Varying Forced Outage Rates

As a unit matures its forced outage rates are continuously adjusted rather than being subjected to a step change at its maturity date.

xxii) Banking Model

A model has been developed to estimate the heat required during banking operation of thermal generating units.

xxiii) Reserve Model

A new reserve model has been developed which includes:

- spinning reserve requirement
- fast start reserve requirement

The reserve requirement may be specified either as a fixed MW value which can change from month to month or a fixed percentage of the largest unit and the system peak. The participation in each reserve category may be specified for each unit. Precommissioning operation can be recognized by the reserve model.

xxiv) Combustion Turbine Model

A new combustion turbine model has been developed which permits the loading of a combustion turbine strictly on an economic basis and permits combustion turbines to participate in meeting reserve requirements.

xxv) Nuclear Model

The nuclear logic has been extended to include not only fixed energy cycles but also basic fuel cycle economics. The unit costs of the nuclear fuel cycle components may be used in conjunction with a simplified criticality and depletion model to compute the nuclear fuel cycle cost in c/MBTU based upon projected nuclear unit operation.

xxvi) Calendar Dates

All dates used in the program are input by calendar date eliminating the need to count weeks of the year.

xxvii) Fuel Handling Costs

Fuel handling costs may be specified for each generating unit.

xxviii) Dispatch Penalty Factor

A dispatch penalty factor may be specified for each unit to penalize units at remote sites for transmission losses.

xxix) Inventory Model

An inventory model has been provided for each fuel type. Inventory fuel cost accounting permits application of fuel rate adjustment provisions.

xxx) Fuel Utilization Confidence Levels

Both the expected value and variance of each unit's fuel consumption are computed. With these quantities fuel utilization confidence levels (e.g. 95%) are calculated to determine necessary quantities of fuel to inventory in order to avoid a shortage with 95% confidence (probability). This information is invaluable in fuel budget analysis and fuel ordering.

APPENDIX A.3

"GATOR" - PROGRAM FOR THE ASSESSMENT OF BULK POWER & SUBTRANSMISSION RELIABILITY

GATOR is a sophisticated digital computer program used to calculate bulk power and subtransmission system reliability indices. The program was developed by Florida Power Corporation during 1976-7. The program has the following characteristics:

1. Performs calculations on a frequency and duration basis, rather than based on probability calculations alone.
2. Presents the results in terms of the number of customers affected, as well as the amount of load lost.
3. Takes into account both real and reactive power flows based on system impedances.
4. Includes loss of service due to inadequate system voltages.
5. Is compatible with the existing computer power flow system.
6. Is able to model large power systems in a single run (1500 buses).
7. Keeps to a minimum the amount of data which must be handled by the user.
8. Is able to identify which buses would be interrupted or experience load curtailments, and calculate the loss of load for each contingency observed.
9. Attempts to redispatch generation to alleviate overloaded lines prior to load curtailment.
10. Estimates the amount of unserved energy and the expected number of customer hours of interruption.
11. Is designed such that area studies could be performed easily without running auxiliary programs to reduce or isolate study areas.
12. Is able to accomplish the above tasks within an acceptable amount of computer time.
13. Takes into account seasonal variations in such factors as system configuration, load distribution, equipment failure rates, repair times, scheduled maintenance, power factor, etc.

The flow diagrams on the following pages show the sequence of calculations performed in GATOR. Also shown is a listing of the system reliability indices computed by the program, which comprise the final output.

The order in which remedial measures are accomplished is significant. The order selected is:

- a. Emergency redispatching to minimize line overloading
- b. Load curtailments to eliminate line overloading (interruptible loads first)
- c. Load curtailments required to restore voltages to acceptable values

This order was selected because it seems to approximate the procedure followed in actual practice.

G & T OVERALL RELIABILITY SYSTEM
EMERGENCY REDISPATCH LOGIC

G & T OVERALL RELIABILITY SYSTEM
OVERLOAD LOGIC

G & T OVERALL RELIABILITY SYSTEM
LOW VOLTAGE LOGIC

G & T OVERALL RELIABILITY SYSTEM

G. & T OVERALL RELIABILITY SYSTEM
CALCULATION OF INDICES

ANNUAL
SYSTEM RELIABILITY INDICES

PROBABILITIES:

SERVICE FAILURE PROBABILITY
UNSERVICED ENERGY PROBABILITY

EXPECTED AVERAGES:

SERVICE FAILURE HOURS
SERVICE FAILURE OCCURRENCES
UNSERVICED ENERGY
UNSERVICED CUSTOMER HOURS
CUSTOMER INTERRUPTIONS

BULK POWER INTERRUPTION INDICES:

BULK POWER INTERRUPTION INDEX
BULK POWER ENERGY CURTAILMENT INDEX
BULK POWER SUPPLY AVERAGE CURTAILMENTS PER DISTURBANCE

SERVICE RELIABILITY INDICES:

SYSTEM INTERRUPTION FREQUENCY INDEX
SYSTEM INTERRUPTION DURATION INDEX
CUSTOMER INTERRUPTION DURATION INDEX
SYSTEM SERVICE AVAILABILITY
AVERAGE NO. CUSTOMERS PER INTERRUPTION

"CORMOD" - CORPORATE MODEL PROGRAMS

The Corporate Model consists of a number of closely-associated computer programs which contain the logical formulae and a large data base of current financial data and derived factors to forecast monthly financial results. The Model does not optimize the results; therefore, the user must predetermine the methods by which he can manipulate the Model to achieve the desired results.

This program logic is the distillation of an extensive analysis of prior years' financial results to define the relationships that exist between external events and the financial results of operations. Thus, the Model is responsive to those changes in electric rates, tax rates, wages, customer growth, inflation, etc., that have an impact on the Company. The results of these thousands of calculations are summarized into monthly, or annual, financial statements. There is no restriction on the projection period, although data has been gathered, and is available, for only 20 years.

The results of a study are summarized into monthly, or annual, financial and supporting statements. The basic statements are:

- Income Statement
- Balance Sheet
- Cash Flow
- Fuel and Energy Statistics
- Rate of Return Statistics
- Retained Earnings
- Financial Ratios
- Construction Expenditures

In addition to these statements, the user can construct his own special statements by a Statement Generator which will provide more detail by printing any of the monthly detail in the 700 accounts maintained by the Model.

APPENDIX B

MODELLING OCEAN THERMAL ENERGY
CONVERSION TECHNOLOGY
with
PROMOD

PREPARED FOR:
Florida Power Corporation

PREPARED BY:
D. M. Crawford
M. B. Rosenzweig
J. M. Goodrich
September 26, 1979

I. INTRODUCTION

Energy Management Associates, Inc. will detail in this report the methodology for modelling generation from Ocean Thermal Energy Conversion units (OTEC) using Energy Management Associates' probabilistic production costing program PROMOD III. This document shows how the complex mechanical and operating characteristics of proposed OTEC systems can be reduced to a simpler system. In turn, the simplified OTEC model can be incorporated into PROMOD with no changes required to the PROMOD model. Thus, the user can use the full power of PROMOD to study the economic and operational benefits of OTEC technology.

As Rumbaugh et al (1; p. 46) recently pointed out, there is a hierarchy of models required to adequately assess OTEC economics. It begins with a detailed model of OTEC unit dynamics, progressing to a reduced-order model of system performance, and ending with a "coarse" model for use in generation planning and economic studies. By integrating OTEC technology in PROMOD, PROMOD can serve as the basis for this coarse model.

OTEC technology exploits the ocean thermal gradients off of the United States and its island for the generation of electric energy. Electric generation plants located off-shore could convert the solar energy stored as heat in the oceans to electrical energy. These OTEC units would be connected to land by submarine electric transmission cables that may be as long as 140 miles.

Once the capital costs of building an OTEC unit are spent, then the variable costs of operating the unit are very small. Thus, generation from an installed OTEC unit will be practically free to the power system, and hence should be used as base load generation. Since the OTEC unit will typically be the least expensive generation in a power system, the generation from the unit will be limited only by the unit's availability. Thus, overall availability of the OTEC unit is an important ingredient in OTEC unit modeling.

The only significant approximation required to satisfy the data input requirements of PROMOD is the derivation of outage rates for proposed OTEC units. This derivation within the modelling constraints of PROMOD is explained in the next section. This is followed by a discussion of the implementation of OTEC in PROMOD to investigate the system effects of introducing OTEC units into a utility's generation mix.

B-2

SIMPLIFIED HYPOTHETICAL SYSTEM

Figure 1

TABLE I
AVAILABILITY STATES OF HYPOTHETICAL SYSTEM

State	Pump 1	Pump 2	Turbine	Line 1	Line 2	Probability	Turbine Output (MW)	Transmission Line Limit (MW)	Delivered Bus Power (MW)
1	U	U	U	U	U	.34884	100	100	100
2	D	U	U	U	U	.08721	20	100	20
3	U	D	U	U	U	.23256	80	100	80
4	U	U	D	U	U	.06156	0	100	0
5	U	U	U	D	U	.01836	100	60	60
6	U	U	U	U	D	.03876	100	40	40
7	D	D	U	U	U	.05814	0	100	0
8	D	U	D	U	U	.01539	0	100	0
9	D	U	U	D	U	.00459	20	60	20
10	D	U	U	U	D	.00969	20	40	20
11	U	D	D	U	U	.04104	0	100	0
12	U	D	U	D	U	.01224	80	60	60
13	U	D	U	U	D	.02584	80	40	40
14	U	U	D	D	U	.00324	0	60	0
15	U	U	D	U	D	.00684	0	40	0
16	U	U	U	D	D	.00204	100	0	0
17	D	D	D	U	U	.01026	0	100	0
18	D	D	U	D	U	.00306	0	60	0
19	D	D	U	U	D	.00646	0	40	0
20	D	U	D	D	U	.00081	0	60	0
21	D	U	D	U	D	.00171	0	40	0
22	D	U	U	D	D	.00051	20	0	0
23	U	D	D	D	U	.00216	0	60	0
24	U	D	D	U	D	.00456	0	40	0
25	U	D	U	D	D	.00136	80	0	0
26	U	U	D	D	D	.00036	0	0	0
27	D	D	D	D	U	.00054	0	60	0
28	D	D	D	U	D	.00114	0	4	0
29	D	D	U	D	D	.00034	0	0	0
30	D	U	D	D	D	.00009	0	0	0
31	U	D	D	D	D	.00024	0	0	0
32	D	D	D	D	D	.00006	0	0	0

SUM = 1.00000

U = Up

D = Down

II. AVAILABILITY MODEL FOR OTEC

The overall reliability of proposed OTEC units is not yet established. The proposed off-shore OTEC unit will consist of many components such as large pumps and turbines. Reliability estimates of these components individually do exist, so that an overall reliability estimate of an OTEC unit could be derived from the component estimates. However, PROMOD does not explicitly model the transmission outages that will be important when an OTEC unit is located off-shore. Hence, the desired availability model of the OTEC system for input into PROMOD should incorporate transmission outages into the overall OTEC unit availability.

First, a simple OTEC system is discussed in this section. This example is intended to illustrate the availability model, and is not meant to be a description of any proposed OTEC system. Specifically the different cable ratings and outage rates have been assumed for illustrative purposes only. This system consists of two pumps, a turbine, and two transmission lines, and is shown in Figure 1.

The turbine has a maximum output of 100 MW when both pumps are available. When Pump 1 is available and Pump 2 is not, the turbine is capable of 80 MW. When Pump 1 is out, and Pump 2 is in service, then the turbine is capable of 20 MW. Pump 1's forced outage rate (FOR) is 20%, and Pump 2 has a FOR of 40%. The turbine has a FOR of 15%.

The off-shore OTEC unit is connected to land by two transmission lines. Line 1 has a maximum capacity of 40 MW, and a FOR of 5%. Line 2 has a maximum capacity of 60 MW and an FOR of 10%. Thus, both lines must be available for the turbine's maximum output to be transported from off-shore to land. If Line 1 only is available, then a maximum of 40 MW of turbine output can be transmitted. If Line 2 only is available, then a maximum of 60 MW of turbine output can be transmitted.

The complete OTEC system therefore consists of five components. Since each component can be either up (in-service) or down (out-of-service or failed), then there are $2^5 = 32$ possible states for the OTEC system. If failures of the five components are independent of each other - i.e., if the probability of failure of each component is not affected by the states of any of the other four components - then a simple capacity state diagram can be developed. This will show all of the 32 possible states with their associated probabilities, maximum turbine output, transmission limits, and the power ultimately delivered to the bus.

This capacity-state diagram appears in Table I. The first state shown has all five components in-service (U). The probability of this occurrence, assuming

independence, is $(.80) (.60) (.85) (.95) (.90) = 0.34884$. The turbine output is 100 MW, and the transmission limits is 100 MW, giving a delivered bus power of 100 MW. The second state has Pump 1 failed (D), with the other four components available. The associated probability of this state is $(.20) (.60) (.85) (.95) (.90) = 0.08721$. The turbine output is 20 MW, since only Pump 2 is available. The delivered power to the bus is 20 MW. State 5 is a case in which the OTEC system is transmission tie limited. The OTEC unit is capable of its full 100 MW output, but Line 1 has failed. Since Line 2 is limited to 60 MW, the power delivered to the bus will be 60 MW with probability 0.01836.

By combining all states with the same delivered power to the bus, it is possible to reduce the 32 states to 6 states. These 6 states are shown in Figure 2. The probabilities associated with each of these capacity states are the sum of the probabilities for each of the 32 states with the given delivered power since the states are assumed to be independent.

For a more complex OTEC system, many more than 6 ultimate states could remain after the above reduction procedure. These ultimate capacity states could be further reduced as follows for input into PROMOD. A table of capacities and their probabilities of occurrence as in Figure 2 would be reduced by spreading the probabilities of the many states into a reduced number of states. For instance consider the reduction of the example in Figure 2 to three non-zero states of 25 MW, 70 MW, and 100 MW. This reduction would be accomplished in the following manner. The probability associated with the old 20 MW state would be divided between the new 0 MW state and the new 25 MW state in proportion to their respective capacities. The new 0 MW state would get 20% of the probability and the new 25 MW state would get 80% of the probability associated with the original 20 MW state. Thus, the probability for the new 0 MW state would increase to 0.24221:

$$0.24221 = 0.22191 + (0.2) * (0.10149)$$

By a similar spreading the 25 MW probability takes 80% of the probability of the former 20 MW state, 66.7%, of the probability from the former 40 MW state, and 22.2% of the probability from the former 60 MW state. Thus, the new 25 MW capacity state would have an associated probability of:

$$0.13106 = (0.80)(0.10149) + (0.667)(0.06460) + (0.03060)$$

The new 70 MW state takes its probabilities from the former 40 MW, 60 MW, and 80 MW states. The new 100 MW state takes its probabilities from the former 80 MW and

Figure 2

AVAILABILITY STATES OF
COMPLETE HYPOTHETICAL SYSTEM
(at on-land bus)

Probabilities

(0.22191)

(0.10149)

(0.06460)

(0.03060)

(0.23256)

(0.34884)

100 MW states. The final results appear in Figure 3.

This availability model should be computerized so that the sensitivity of results to changes in OTEC component characteristics can be easily evaluated. The spreading procedure can be expressed algorithmically as follows:

- a) Initialize the availabilities for the N new capacity states k

$$AV_k = 0 \text{ for } k = 0, \dots, N$$

- b) For each old state j with capacity CAP_j , consider the new states k and k+1 where:

$$C_k \leq CAP_j < C_{k+1}$$

- c) Then, the availability AVL_j of the old state j will be spread to new states k and k+1 as:

$$AV_k = AV_k + \left[\frac{C_{k+1} - CAP_j}{C_{k+1} - C_k} \right] * AVL_j$$

$$AV_{k+1} = AV_{k+1} + \left[\frac{CAP_j - C_k}{C_{k+1} - C_k} \right] * AVL_j$$

- d) Return to (b) until all old states are exhausted.

III. ANALYZING OTEC USING PROMOD

The availability model described above can be specified on a monthly basis to account for any monthly changes of any model parameters. For example, since the off-shore temperature differentials vary monthly, the total capacity of the OTEC unit could similarly vary monthly. This presents no problems since PROMOD has the capability to override unit characteristics monthly.

The OTEC unit should be modeled in PROMOD as a thermal unit with up to five non-zero availability states (7 states could be used but the PROMOD Model at Florida Power Corporation is limited to 5 states). Specification of a fuel type with no cost for the OTEC unit and dispatching the unit as a single block (by specifying the unit's minimum operating capacity equal to its maximum operating capacity) will dispatch the unit as base load capacity.

If the unit's minimum operating capacity is set equal to its maximum operating capacity, then an additional capacity state for the unit is created by PROMOD. Thus, the number of original capacity states must be one less than the limit (of 7

Figure 3
REDUCED AVAILABILITY STATES

states maximum, or 5 states as at Florida Power Corporation) so that the additional capacity state created is within the limit. If the user wants to keep as many availability states as possible, then the minimum operating point should be set equal to the minimum non-zero capacity in the availability model. In this case, the OTEC unit will not be block loaded, but will still be dispatched as base load capacity due to its zero fuel cost.

The availability model discussed before would be incorporated as forced outage rates associated with each operating point of the OTEC unit. The non-zero heat rate required by PROMOD for a thermal unit could be set arbitrarily, since the zero fuel cost will guarantee that the OTEC unit is dispatched as base load. Fixed and variable operating and maintenance costs can be specified by the user, and the variable operating costs can be incorporated into the dispatch decision for the OTEC unit at the user's option.

The heat exchangers of the OTEC unit are subject to biofouling from ocean organisms. This biofouling must be cleaned periodically. However, the exact nature of the cleaning process has not yet been determined. For instance, the cleaning may be done all at once by shutting down the entire unit, or perhaps the unit will be partially derated at night or on the weekends for cleaning.

Since the OTEC maintenance requirements are not yet well established, it is fortunate that maintenance requirements for the OTEC unit can be accounted for in PROMOD in several ways. Derations due to maintenance could be incorporated into the availability model. PROMOD could schedule or incorporate maintenance for the OTEC unit as part of PROMOD's ability to directly model weekly maintenance. Maintenance outages specific to either the day, night, or weekend subperiod could be handled, as could partial derations which apply only to a specified subperiod. A maintenance outage rate giving the percent of weekend hours that the OTEC unit is expected to be down for maintenance could also be specified. Thus, PROMOD could handle a variety of types of maintenance requirements which may be required by an OTEC unit.

References:

1. Rumbaugh, J. H., T. F. Garrity, R. Cohen, and R. L. Sullivan, "Thermal energy conversion: tapping the sea depths", IEEE Spectrum, August, 1979, pp. 42-48.

APPENDIX C

OTEC RELIABILITY CALCULATIONS

1. INTRODUCTION

This appendix reviews the procedures used to transfer the information obtained on OTEC system and component outage rates and times to repair, into the six state probability values required by the PROMOD program. The inputs for OTEC values are contained in Appendix D; the PROMOD program is summarized in Appendices A and B.

The OTEC unit was modeled by PROMOD using a 5 state capacity/probability model. The 400 MW unit is comprised of 8 parallel 50 MW modules in series with DC power cables and weather restrictions (see Figure 1). The 50 MW modules are comprised of seawater pumps, heat exchangers and a turbine/generator. FPC was supplied with the failure rate and repair times associated with the equipment comprising a single 50 MW module and the cables, and with weather restrictions (Appendix D).

The strategy used in determining the 5 capacity/probability states and forced outage rate for the entire 400 MW unit was to first determine the capacity/probabilities of the 8 parallel 50 MW modules and finally to combine a single 400 MW unit in series with the DC power cables and weather restrictions.

FIGURE 1

400 MW MODULAR OTEC GENERATING PLANT

2. SINGLE 50 MW MODULE

This section analyzes the individual components that make up a single 50 MW module. The capacity/probability is determined for each of the major components: pumps, heat exchangers, turbine/generator. These components are then combined to determine the capacity/probability of a single 50 MW module.

PUMPS:

The configuration for seawater pumps consists of a warm water and a cold water pump in series, and two such sets in parallel to supply the warm and cold water for each 50 MW module. Each pump has an estimated failure rate of 1 day/year, and a repair duration of 2 days. The corresponding values for λ -1 and μ -1 for a single cold water pump (the values for the warm water pumps are identical) and the compounding of the probabilities of failure and repair times are summarized in Figure 2. This results in probability values for a cold-warm water pump set being in the "up" condition.

Since there are two parallel combinations of these pump sets, it is seen that the pump-set has three capacity states:

50 MW,
25 MW, or
0 MW

for the outage conditions possible. These have probability values as calculated in Figure 3. The result is a set of probabilities for being in each of the three possible capacity states.

FIGURE 2

PUMPS

$\lambda_1 = \lambda_2 = 1 \text{ day/yr} = 0.002740 \text{ failures/day}$
 repair duration = 2 days
 Repair rate = $\mu = 0.5 \text{ repairs/day} = \mu_1 = \mu_2$

P_{up} = probability of being in up state

$$= \frac{\mu_1 \mu_2}{(\lambda_1 + \mu_1)(\lambda_2 + \mu_2)} = \frac{\mu_s}{\lambda_s + \mu_s}$$

$$= \frac{(0.5)(0.5)}{(.002740 + .5)(.002740 + .5)}$$

$$= \frac{.25}{.252747}$$

$$P_{up} = 0.98913$$

$$P_{down} = 1 - P_{up}$$

$$= 1 - 0.98913$$

$$P_{down} = 0.01087$$

FIGURE 3

PUMPS

Power reduction per pump = 25 MW

$$P(50 \text{ MW}) = P_{up1} \times P_{up2} \\ = (0.98913)^2$$

$$P(50 \text{ MW}) = 0.97838$$

$$P(25 \text{ MW}) = 2(0.98913)(0.01087)$$

$$P(25 \text{ MW}) = 0.02150$$

$$P(0 \text{ MW}) = P_{dn1} \times P_{dn2} \\ = (0.01087)^2$$

$$P(0 \text{ MW}) = 0.00012$$

HEAT EXCHANGERS:

The 50 MW module consists of 5 sets of evaporators and condensers. In a manner similar to the preceeding section, the series combination of an evaporator and condenser is analyzed and the probability of being "up" is computed. Each heat exchanger has an estimated failure rate of 1 day/year and a repair duration of 2 days. The probability of being up is 0.98913.

The parallel combinations of 5 such sets was evaluated using a binomial expansion for the 6 possible capacity states of 50, 40, 30, 20, 10, 0 MW with the resulting values for the probabilities in each state:

50 MW	0.94682
40	0.05203
30	0.00114
20	0.00001
10	6.90465×10^{-5}
0	1.51757×10^{-9}

TURBINE/GENERATOR:

The turbine/generator is a single element for a 50 MW module. Estimated failure rates are 1 failure/2 years and repair duration is 5 days/failure. The resulting prprobability of being up (50 MW capacity state) is 0.99320, and of beind down (0 MW capacity state) is 0.00680.

SINGLE 50 MW MODULE:

Assembling these possible capacity states for each component into that for a complete 50 MW module requires evaluating each possible state for the components as follows:

The possible capacity states are:

Pumps: 50, 25 or 0 MW

Heat Exchangers: 50, 40, 30, 20, 10, 0 MW

Turbine/Generator: 50, 0 MW.

The overall module can thus have the following capacity states:

50, 40, 30, 25, 20, 10, 0 MW

For the module to be in the 25 MW state, the turbine/generator must be up, and the heat exchangers must be in one of the states: 50, 40, or 30 MW. The compound probability of being in at least 30 MW state is thus the sum of each of the three: 0.94682, 0.05203, and 0.00114 or a total 0.99999. Then the probability of the module having a 25 MW state is:

$$(0.02150) (0.99999) (0.99320) = 0.02135.$$

Carrying out this analysis for the total of the 7 possible states yields the following probabilities for each state:

50	0.92005
40	0.05056
30	0.00111
25	0.02135
20	0.00001
0	0.00692

The value for 10 MW is deleted due to its very small value.

3. COMBINATION OF PARALLEL MODULES

PARALLEL COMBINATION OF TWO 50 MW MODULES

Since each 50 MW module has 6 possible capacity states (deleting the 10 MW state as insignificant), a parallel combination of two 50 MW modules would have 36 possible combinations. Figure 4 is part of a printout of a computer routine which was utilized to calculate all possible capacity/probability states. These were then ranked by their probability contribution and probabilities for common capacity states summed. Insignificant capacity/probability states were deleted and remaining values rounded off so that the sum of the probabilities became unity. The resulting values are:

100 MW	0.84649
90	0.09305
80	0.00460
75	0.03929
70	0.00013
65	0.00216
55	0.00005
50	0.01319
40	0.00070
25	0.00040
0	0.00005

FIGURE 4

N	C1	C2	P1	P2	PIOT
***	***	***	*****	*****	*****
1	50	50	.92005	.92005	.84649
2	50	40	.92005	.05056	.046518
3	50	30	.92005	.00111	.0010213
4	50	25	.92005	.02135	.019643
5	50	20	.92005	1E-5	9.2005E-6
6	50	0	.92005	.00692	.0063667
7	40	50	.05056	.92005	.046518
8	40	40	.05056	.05056	.0025563
9	40	30	.05056	.00111	5.6122E-5
10	40	25	.05056	.02135	.0010795
11	40	20	.05056	1E-5	5.056E-7
12	40	0	.05056	.00692	3.4988E-4
13	30	50	.00111	.92005	.0010213
14	30	40	.00111	.05056	5.6122E-5
15	30	30	.00111	.00111	1.2321E-6
16	30	25	.00111	.02135	2.3698E-5
17	30	20	.00111	1E-5	1.11E-8
18	30	0	.00111	.00692	7.6812E-6
19	25	50	.02135	.92005	.019643
20	25	40	.02135	.05056	.0010795
21	25	30	.02135	.00111	2.3698E-5
22	25	25	.02135	.02135	4.5582E-4
23	25	20	.02135	1E-5	2.135E-7
24	25	0	.02135	.00692	1.4774E-4
25	20	50	1E-5	.92005	9.2005E-6
26	20	40	1E-5	.05056	5.056E-7
27	20	30	1E-5	.00111	1.11E-8
28	20	25	1E-5	.02135	2.135E-7
29	20	20	1E-5	1E-5	1E-10
30	20	0	1E-5	.00692	6.92E-8
31	0	50	.00692	.92005	.0063667
32	0	40	.00692	.05056	3.4988E-4
33	0	30	.00692	.00111	7.6812E-6
34	0	25	.00692	.02135	1.4774E-4
35	0	20	.00692	1E-5	6.92E-8
36	0	0	.00692	.00692	4.7886E-5

PARALLEL COMBINATION OF 2 100 MW MODULES

The parallel combination of 2 100 MW modules leaves 2 parallel modules each with a capacity of 200 MW and with probabilities shown below.

$$P(200) = 0.71655$$

$$P(190) = 0.15751$$

$$P(180) = 0.01644$$

$$P(175) = 0.06652$$

$$P(170) = 0.00108$$

$$P(165) = 0.01099$$

$$P(155) = 0.00088$$

$$P(150) = 0.02389$$

$$P(140) = 0.00383$$

$$P(130) = 0.00026$$

$$P(125) = 0.00155$$

$$P(115) = 0.00017$$

$$P(100) = 0.00033$$

PARALLEL COMBINATION OF 2 200 MW MODULES

The parallel combination of 2 200 MW modules leaves 1 single 400 MW module in series with the cable module. The single 400 MW module has the capacity probabilities shown on the left. These are then combined into the 5 states shown on the right.

P(400) = .51344	P(400) = .65855
P(390) = .22572	
P(380) = .04837	
P(375) = .09533	P(375) = .25335
P(370) = .00673	
P(365) = .03671	
P(360) = .00061	
P(355) = .00691	
P(350) = .03870	P(350) = .06101
P(345) = .00078	
P(340) = .01449	P(340) = .02109
P(335) = .00005	
P(330) = .00260	
P(325) = .00540	
P(320) = .00028	
P(315) = .00177	
P(310) = .00002	
P(305) = .00027	
P(300) = .00125	P(300) = .00600
P(295) = .00002	
P(290) = .00034	

$$P(280) = .00004$$

$$P(275) = .00012$$

$$P(265) = .00003$$

$$P(250) = .00002$$

1.0000

4. SERIES CONNECTION TO POWER CABLES AND WEATHER RESTRICTIONS

As a result of the preceeding analysis, the 400 MW unit is represented by 5 capacity/probability states and a forced outage rate. The 400 MW unit must be combined in series with the cables and weather restrictions.

The first step was to determine capacity/probability states for the cables, then combine those in series with the 400 MW unit. A Markov Analysis was made on the cables, as diagrammed in Figure 5.

Eight possible states exist. States 1, 2 and 3 allow full load (400 MW) operation. States 4, 5, 6, and 7 allow operation at 240 MW and State 8 is the forced outage state. Applying the analysis yields the following probabilities for the three capacity states for the cable system:

400 MW (States 1 + 2 + 3)	0.92185
240 (States 4 + 5 + 6 + 7)	0.07506
0 (State 8)	0.00309

Combining the 5 states for the 400 MW plant (400, 375, 350, 340 and 300 MW) with the 3 states for the power cables (400, 240 and 0 MW) yields the following states and probabilities:

400 MW	0.60708
375	0.23355
350	0.05624
340	0.01944
300	0.00553
240	0.07506
0	0.00309

DC CABLE MARKOV ANALYSIS

For All Cables:

$\lambda = 0.5$ failures/yr

$\mu = 3.04$ repairs/yr

$r = 0.3288$ yrs/failure

In order to reduce this to the 6 states permitted by the PROMOD program, the 300 MW state was spread between the 240 and 340 MW states to arrive at the required 5 capacity/probability states and forced outage rate. The 240 MW probability becomes 0.07727 and the 340 MW becomes 0.02276.

Finally, the weather restrictions must be added in series. The input data requires that the plant be totally shut down due to extreme weather conditions for 5 days per year (0.98630 probability of being "up"). Multiplying this value by all the non-zero states yields the following 5 capacity/probability states and forced outage rate as used in PROMOD:

400 MW	0.59875
375	0.23034
350	0.05546
340	0.02245
240	0.07621
0	0.01679

APPENDIX D

OTEC DATA INPUTS FOR
UTILITY SYSTEM MODELING

REPORT SUBMITTED TO
FRANKLIN RESEARCH CENTER
AS PART OF THE
FLORIDA POWER CORP. STUDY ON
OTEC SYSTEM PLANNING

J.R. RONEY, OCEAN ENGINEERING CONSULTANT
NOVEMBER 1, 1979

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OTEC COST INPUTS TO UTILITY SYSTEM MODELS

1. INTRODUCTION
 - 1.1 Purpose and Scope of Report
 - 1.2 Categories of Cost Information
 - 1.3 Breakdown of Cost Information
2. BASELINE DESIGN ASSUMPTIONS
 - 2.1 Overall Configuration of OTEC Plant
 - 2.2 Discussion of Baseline Configuration and Alternatives
3. DISCUSSION OF COST INFORMATION
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5. OPERATION AND MAINTENANCE COSTS
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 - 5.2 Repairs Not Handled by On-Board Crew
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6. OTEC EQUIPMENT MAINTENANCE REQUIREMENTS
7. OPERATIONAL MODES AND FORCED OUTAGE RATES
8. THERMAL RESOURCE SITE DATA
9. CONSTRUCTION SCHEDULE AND COST DISTRIBUTION

SUMMARY

This report supplies inputs needed to exercise system planning and modeling procedures with OTEC as a candidate generating system.

The report provide :

1. OTEC Plant cost data; capital acquisition costs; O&M costs.
2. OTEC Plant operational information; failure modes, forced outage rates; factors affecting availability factor.
3. Thermal resource monthly variations.

RESULTS

1. The plant cost data details are contained in Section 4 of this report. The total plant capital cost projected for the baseline OTEC plant appropriate for this study is:

\$2256/kW.

The annual O&M costs are estimated to be 8.2 mils/kWh.

2. The plant operational information indicates four major systems of importance with the following outages and power reductions:

<u>SYSTEM</u>	OUTAGE DAYS PER YEAR	NET POWER DURING OUTAGE DAYS
SEAWATER PUMPS	64	375
HEAT EXCHANGERS	160	390
TURBINE/GENERATOR	20	350
POWER CABLES	24	240

1. INTRODUCTION

1.1 PURPOSE AND SCOPE OF REPORT

There are two principal models used by Florida Power Corporation in planning system expansion or possible addition or replacement of generating units. These are PROMOD and a Corporate Model. These models are discussed in other reports related to the current effort.

Both of these models require technical, operating, cost and other information. Table 1-1 and 1-2 summarizes the needed inputs. Cost data is needed either directly, such as for use in the Corporate Model, or technical features which can affect cost of acquisition or operation of a plant is required. It is the purpose of this report to provide the required cost information, and the other technical information and data which has a direct influence on the cost estimates.

The report not only provides the directly needed data, but a discussion of the factors involved in making the cost projections, and incorporates provisions for adjusting the data as more inputs are received.

1.2 CATEGORIES OF COST INFORMATION

It is convenient and useful to arrange cost information by major OTEC system. There are a number of arrangements in use in the OTEC community, however most tend to follow a breakdown similar to that shown in Table 1-3, which is used in this report. The abbreviated code is used in filing information in a computer data base management system.

TABLE 1 - 1

DATA REQUIREMENTS FOR PROMOD

1. THERMAL RESOURCE - MONTHLY VARIATIONS
2. O & M - MAINTENANCE SCHEDULES
3. CONFIGURATIONS
MODULES
PARALLELS WITH T/G'S, PUMPS, POWER LINES
SHORE SIDE CONVERTER STATIONS
4. OPERATING FEATURES - MINIMUM MODULES FOR PUMPING
5. FORCED OUTAGE RATES
MATURITY PERIODS, 1 ST YEAR, 2 ND YEAR.
6. FIXED AND VARIABLE OPERATING COSTS
CABLE MAINTENANCE

TABLE 1 - 2

DATA REQUIRED FOR CORPORATE MODEL

1. Cost
2. ESCALLATION RATE AS COMPARED TO C.P.I.
3. SPENDING PATTERN BY MONTHS
4. OPERATING AND MAINTENANCE COSTS
5. MANPOWER -- BY TYPE PERSONNEL
6. EXPECTED ITC RATE
7. EXPECTED PLANT LIFE
8. EXPECTED TAX LIFE

TABLE 1 - 3

CATEGORIES FOR COST INFORMATION

		<u>CODE*</u>
1.	HEAT EXCHANGERS	HEX
2.	REMAINDER OF POWER SYSTEM	RPS
3.	PLATFORM	PLF
4.	SEA WATER SYSTEM	SWS
5.	STATION KEEPING SYSTEM	SKS
6.	ENERGY TRANSFER SYSTEM	ETS
7.	SITE AND ENVIRONMENTAL	SEN
8.	FINANCIAL AND INSTITUTIONAL	FIN

* USED IN COMPUTER DATA BASE SYSTEM

1.3 BREAKDOWN OF COST INFORMATION

Cost information is best provided for equipment in at least two categories: labor and material. Cost figures in either category obey somewhat different trends. It is possible to project fully mature design costs as tending toward a material-cost limit. The cost of labor can be used to estimate learning curve trends.

Other parts of cost data where possible to develop, include the costs of deployment and the cost of special fabrication procedures or equipment (generally non-recurring costs).

Table 1-4 indicates the types of cost elements that are desired to be accumulated and tabulated for any system or component. Listed also are matters of risk that are necessarily coupled to any cost estimate. Each cost figure contains some element of risk in the value of certainty of the figure. There is an "intrinsic" risk that may be thought of as the current ability to make an accurate projection, or conversely, the degree to which a cost quotation should have some contingency placed on it due to the nature of the component or system being quoted. For example, a steel fabricated component could be estimated by an experienced engineering design firm with a good degree of accuracy. However, the design might contain some factor of safety which the firm feels is representative of the possible uncertainty in fabricating such a component. The Chief Engineer might require a 50% factor of safety over and above the presumably accurate calculation of the wall thickness of a pressure vessel. This then is an expression of the intrinsic risk of the cost estimate of the component.

The remaining risk elements are secondary or higher order effects.

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TABLE 1-4

COST

COST ELEMENTS

- MATERIAL
- LABOR
- DEPLOYMENT
- FABRICATION
- SYSTEMATICS

RISK ELEMENTS

- INTRINSIC RISK
- FORESEEABILITY
- RESOLVABILITY
 - LEVEL OF EFFORT
 - TIME TO RESOLVE
- ADJUSTABILITY TO UNFORSEEN EVENTS

2. BASELINE CONFIGURATION

2.1 OVERALL CONFIGURATION FOR OTEC PLANT

In order to specify the combinations of systems and components which lead to a determination of possible outages and outage rates, the baseline configuration for the OTEC plant provides this information. The baseline plant is specified at 400 MWe since this is considered to be the largest practical OTEC plant beyond which economy of scale has no advantage and beyond which size the capability of manufacturing and deploying a platform is questionable. Further baseline configuration and size information is contained in Table 2-1.

The 50 Megawatt power module size is based on maximum reasonable dimensions, particularly for the heat exchangers. Thus a 400 MWe plant would contain eight 50 MW power modules. In determining failure rates and the consequent reduction in plant power availability, the effect of each component outage on module and total plant output must be determined. For example, if each 50 MW module were to contain two sets of seawater pumps, it is possible that one pump could be out of service, but the other pump have capability of running over the design point value. Thus the module power would not necessarily be reduced 50%. If each pump could be run at maximum output producing 120% of rated flow, the outage of one pump could limit the power reduction to 60% rather than 50%.

A further feature that can greatly influence the consequences of any individual component outage, is the possibility of cross-connecting components from other parts of the module (if there is more than one component per module) or from other modules. As indicated in the previous paragraph, this can ameliorate the effects of any given outage. This is discussed in greater detail in following sections.

TABLE 2-1

OVERALL BASELINE CONFIGURATION FOR OTEC PLANT

BASELINE PLANT SIZE	400 MWe Net
POWER SYSTEM MODULE SIZE	50 MWe net
TOTAL NUMBER OF MODULES	8
TYPE OF POWER SYSTEM	AMMONIA, CLOSED CYCLE
PLATFORM TYPE	CONCRETE SPAR
COLD WATER PIPE	FIBERGLASS SUSPENDED OR ELASTOMER INTEGRATED WITH MOORING SYSTEM
POWER CABLE	D.C., 2 CONDUCTOR, 1 SPARE
MOORING SYSTEM	MULTI-POINT OR TAUT

2.2. DISCUSSION OR BASELINE CONFIGURATION AND ALTERNATIVES

2.2.1 Plant Size

It was indicated in the previous section that the 400 MWe plant size was the largest practical plant that could be placed on an ocean platform without exceeding the projected state of the art. A 400 Mw plant would require a platform having a displacement of the order of 500,000 tons which is comparable to the largest ocean tankers. This technology is based on a long development of steel ocean vessels and should not be extended specifically by an OTEC requirement. Concrete vessels or large structures could achieve comparable scales of magnitude, and this is a reasonable development that can be expected from this technology.

In addition to the maximum size considerations for the platform, there is indication that any economy of scale tends to flatten out in the vicinity of 400 Mwe total plant size. There is reason to believe that the value for diminishing returns could be somewhat lower, perhaps 200 or 250 MWe. Therefore, it is possible as a relaxation of this baseline, to consider plants of smaller rating than 400 MWe, perhaps down to 250 MWe.

2.2.2 Power System Modules

The value of 50 MWe for power system module size is based on a number of studies and considerations including the set of PSD studies and the platform integration studies. Both of these sets of studies tend toward 50 MWe, or values near this, as the baseline power system size.

It is considered that the current state of the art would support power system modules of 25 MWe size without any further development needed to support the dimensions of the components and systems for modules of this rating. To extrapolate to 50 MWe is a reasonable development, and much of the current programs are directed toward this end.

Beyond 50 MWe, the dimensions of the heat exchangers become so great that it is questionable that economical systems could be developed at such a great scale. For example, the basic diameter of a heat exchanger at the 50 MW size is approximately 60 to 70 ft. Beyond this value, the problems of fabrication, and the need for special facilities for fabrication, and problems of deployment would appear to override any economies of scale obtainable for larger units.

2.2.3 Ammonia, Closed Cycle Power Systems

There is good reason for considerable interest in open cycle OTEC plants, and there are circumstances that an organic working fluid (such as the freon type working fluids) could become advantageous over ammonia as the working fluid. However, the vast majority of work done so far on OTEC power systems has been for closed cycle ammonia type units. The accumulation of information for this type of plant is so great, that any alternative would suffer a large time lag if one were to attempt to bring the state of development up to that of the baseline system. Thus one of the major factors for choosing this as the baseline is the extent of development and the resultant maturity of the stage of development as contrasted to any of the alternatives.

This state of affairs is not by accident or hapinstance. Many analyses have indicated that the ammonia closed cycle system presents the best opportunity for successful commercial OTEC plants. The major problem with other working fluids, under comparable circumstances, is the much higher volume flows of the working fluids required, and thus much larger dimensioned piping and components such as pumps and turbines.

The possibility that open cycle OTEC could close the lag between this mode and closed cycle, insofar as development is concerned, is real. At the present time, it is not possible to project much advance in this technology based on present DOE program plans and budgets. However in the near future, developments could lead to an expanded interest in open cycle and thus a greater consideration as a possible commercial candidate.

2.2.4 Type of Platform

The concrete spar platform is believed to be the most probable configuration for a large commercial OTEC plant sited in the Gulf of Mexico. One of the overriding reasons for this choice is the ability to withstand the extreme storm event better than a surface ship type of platform.

There are four basic classifications of platforms that may be suitable for a Gulf of Mexico sited OTEC plant:

- (1) spar type
- (2) ship or barge surface platform
- (3) semi-submersible
- (4) bottom mounted guyed tower.

The most readily fabricated platform, with existing technology, is the ship or barge type of surface platform. It also offers the potentially lowest cost platform. However, the problems of mooring the platform add to the total system cost so that this advantage may not exist. The most serious problem with the ultimate design of such a platform appears to be the vulnerability to hurricanes. A spar or semi-submersible presents a lower surface above the water and at the air-water interface. Extreme wave and wind effects are more difficult to deal with in the case of the surface ship or barge. The other type platforms are presently projected to be more costly, but the application of concrete technology to the spar is expected to make it competitive.

2.2.5 Cold Water Pipe

The fiberglass reinforced plastic (FRP) cold water pipe is chosen as the most likely physical form and most cost effective for the OTEC plant sited in the Gulf of Mexico. The projected costs for the FRP cold water pipe are significantly below other technically suitable options. The physical suitability and developmental assurity has been discussed in many forums and technical articles. The physical characteristics of the FRP cold water pipe lend themselves to being suspended from either a surface platform or a spar-type structure.

One alternative which may be more suitable for spar platforms is a combined system in which the mooring legs are part of the structure of the CWP. In this concept, the spar would be moored by vertical tension legs consisting of steel cables. These cables could be arranged in a circle and an elastomeric material placed over this structural framework to form a cold water pipe. The higher costs of an elastomer CWP would be offset to a large extent by the combined system costs of the mooring system and CWP as an integrated structure. This represents a development advanced over that of the FRP cold water pipe, and thus it does not seem appropriate to take this configuration as the baseline. However, it may be that in the progress of OTEC development, such an arrangement could become the leading candidate.

3. DISCUSSION OF COST INFORMATION

3.1 MATURITY OF DEVELOPMENT

The cost of an OTEC plant, a system or component depends greatly on the assumptions made on the state of maturity or development of the item under consideration. Whether the item is a developmental unit, an early commercial, or fully matured technology will alter the cost figure over a wide range. There are many possible categories of the status of a plant or component, however the following is a useful means of classification:

CATEGORY	EXAMPLES
Developmental Units	Developmental Pilot Plant Developmental Pre-commercial Developmental Commercial Demo
First Commercial Generation Units	First Commercial Plant First Generation With Learning Curve Matured
Second Generation Units	First Unit of Second Gen. 2nd Gen. with Matured L.C.
Fully Matured Technology	

Many cost estimates do not indicate clearly the category that applies and thus the figure carries an inherent uncertainty which is other than an estimating "error" as such, rather than a lack of specificity.

During the development of cost estimates, any given figure will be in the context of one of the above categories, or a sub-set of one of them, with a coded indication, if appropriate. Table 3-1 is a list of the cost categories corresponding to developmental status that is used in assembly and projection of cost information.

TABLE 3-1

DEVELOPMENTAL STATUS
FOR PLANTS, SYSTEMS
OR COMPONENTS

<u>DEVELOPMENTAL UNITS</u>	1*	PILOT PLANT	DPP**
	2	PRE-COMMERCIAL	DPC
	3	COMMERCIAL DEMO	DCD
<u>FIRST COMMERCIAL GENERATION</u>	4	FIRST COMMERCIAL	FGF
	5	MATURE LEARNING CURVE	FGM
<u>SECOND GENERATION</u>	6	FIRST UNIT 2ND GEN.	SGF
	7	MATURE LEARNING CURVE	SGM
<u>FULLY MATURED TECHNOLOGY</u>	8		FMT

* INDEX NUMBER USED IN CODING DEVELOPMENTAL STATUS

** CODE ABBREVIATION USED TO INDICATE DEVELOPMENTAL STATUS

3.2 OFF-DESIGN POINT VARIATIONS

The principal reason for operating off the design values for an OTEC plant are variations in the thermal resource ΔT . This is discussed in the next sub-section. As a consequence of either a greater or lower value for the temperature difference, the heat transfer in the heat exchangers will change and as a consequence the power output of the plant vary accordingly.

A secondary factor in off design variations, largely as a consequence of the temperature variations, is variations in flows in the water systems. This may be an operational response to the change in temperature differences in order to keep the net power output of the plant closer to rated values. Thus if the temperature difference is lower than the design value, some compensation can be made by operating the seawater system at higher flow rates.

Finally, the other significant area of operating at off-design point values is the electric power transmission system. If one or more of the power cables has a failure or a problem requiring reduced operation, it may be possible to operate the remaining part of the system at over-rated values in order to reduce the effect of the loss of a portion of the system.

Each of these effects are discussed in the following sub-sections. There are some design options that would effect the ability of a part of the system to operate beyond the design-point values. A significant part of the calculation of availability factor for the plant will depend on these capabilities.

3.2.1 Off-Design Value ΔT Operations

One matter that greatly influences the overall cost of operations of an OTEC plant is the treatment of the situation when the actual site ΔT is more or less than the design ΔT for the plant systems. The annual variation in thermal resource tends to follow roughly some sinusoidal pattern with a local-summer peak and local-winter trough. Since the output power of an OTEC plant varies with the ΔT approximately as

$$P = P_o \left[\frac{\Delta T}{\Delta T_o} \right]^2$$

the design of the plant must take into account the possible swings of thermal resource and make cost-effective allowances to accommodate the swings. The following Figure (3-1) represents the thermal data input to the heat exchanger and power system designs and the consequences of the behavior of the temperature differences on the direct cost of the power system, and secondary effects. One of the secondary effects is that the size of the OTEC platform varies with the size of the power system and thus a larger power system specification in order to follow upward swings in the local thermal resource will result in larger and more costly platforms. Likewise, the character of the site thermal resource time variation will result in a characterization of the plant capacity factor. Trade-offs between capital costs to accommodate the variations in ΔT versus loss of available power and resulting lower capacity factor are analyzed in the system design process. A power system that is "undersized" with respect to possible maximum ΔT can

FIGURE 3-1
OFF DESIGN ΔT EFFECTS ON PLANT COMPONENTS

SEA WATER PUMP PERFORMANCE - OFF DESIGN

AMMONIA FLOW VARIATION WITH ΔT

TURBINE POWER AND EFFICIENCY VS. NH_3 FLOW

result in a clipping of the potential output power at some maximum level and consequent effect on developed plant capacity factor. The options available for sizing the principal systems in such a manner that it can accommodate variations in the thermal resource may be diagrammed as follows:

SEA WATER --- HEAT --- AMMONIA SYSTEM & --- POWER
SYSTEM EXCHANGERS TURBINE/GENERATOR CABLE

indicating the principal areas where sizing is important. The sea water system, either warm water or cold water consists of conduits (such as the cold water pipe) and pumps with pump-motors. Generally within the range of reasonable temperature variations, a given warm water inlet conduit can handle much greater than design values with an increase of flow velocity. This could be accomplished with the installed pumps run at greater than design speed. Figure 3-1 indicates the characteristic of pumps as may be employed with an OTEC plant. The pump flow increases approximately directly with pump RPM, but the pump efficiency is not linear. Therefore, the pump would be designed for optimum operation at the design flow rate corresponding to the design power level of the power system. Operating the pumps at greater or lesser speeds would result in less than optimum efficiency; however, the change in the thermal resource could be accommodated. The drop in efficiency is not pronounced over a nominal operating range. The penalty for the increased pumping capability can be absorbed with respect to increased capital equipment, by the pump prime mover, the motors. By providing motors with greater rating than the average value, of sufficient size to run the pumps at the higher speed needed, the

sea water systems can accommodate higher temperature differences with modest increase in capital equipment cost.

A given heat exchanger could evaporate more ammonia if a higher warm temperature sea water source were available, by allowing a larger temperature drop through the evaporator water side a larger quantity of heat can be transferred provided the ammonia side flow can be increased to carry it off. Thus the increased power capability can be accommodated provided the ammonia system can be oversized to take the increased flows. Some oversizing on the turbine and generator is required to achieve this potential increase in outpower beyond the rated ΔT .

Finally, the power transfer system, particularly the power cables must have sufficient capacity to handle the total possible power rate at the maximum output corresponding to the maximum ΔT . This has the potential to be one of the more costly oversize elements in the total OTEC system for plants where the transmission distance is considerable, such as the Gulf of Mexico sites.

The power plant designer must take into account site conditions in making the decisions and trade-offs that are required to size the major plant components. This is not in itself an easy process. In addition, there will be some standardization of plants so that each cannot be "tailored" to the site without losing some of the advantage of maturity of design and learning curve effects on plant costs. Thus there may be designs suitable for Gulf of Mexico sites which do not differ from site to site within the Gulf. Plants for sites in other regions, such as the Caribbean islands, may have major differences in plant component sizes.

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4. COST PROJECTIONS

4.0 INTRODUCTION

This section presents the projected costs for acquisition of an OTEC plant of the baseline configuration. The cost projections are derived from the Cost Data Bank which has been assembled and filed in a computer assisted system. Appendix A contains a display of the major cost information contained.

Each cost element is filed with a three digit code; e.g. 241. The first digit represents one of 8 major OTEC system categories (1 for heat exchangers, 2 for remainder of power system, 3 for platform, etc, as covered in Section 1.2 and Table 1-3). Thus

241

REMAINDER OF POWER SYSTEM (RPS).

The second digit applies to the component or system within this category for which cost information is compiled. Appendix A lists all the categories. These will be covered in each of the following sections in the appropriate place. Thus, for example:

241

AMMONIA SUPPORT SYSTEMS AND TANKAGE.

The third digit applies to the state of development as covered in Section 3.1 and Table 3-1. Thus, for example:

245

FIRST COMMERCIAL GENERATION, MATURE LEARNING CURVE.

For most of the cost projections, the state of development assumed is step 5, FMG, the First Generation Commercial Plant with a Matured Learning Curve. This is typically listed as the 8th plant of this type. Most of the cost elements, or the total plant cost, is related to the preceeding category FGF which is the first unit of this type, by some learning curve factor.

One might expect that the first large commercial OTEC plant would be expected to be the first plant considered by Florida Power Corporation for the Tampa Site (140 miles offshore), and thus the cost information should be based on this plant. However, it is assumed that the government in some form will support the cost difference between the first unit and the mature learning curve unit in order to stimulate commercialization. In other words, the cost to the consumer (utility company) will be seen as the cost of a fully developed plant of this type and that the government will pay the difference by some incentive means, either a subsidy or some tax device.

4.1 COST PROJECTIONS -- HEAT EXCHANGERS

The heat exchanger cost projections are based on the following combination of cost elements from the OTEC Cost Data Bank (Appendix A):

125, 155, 175

implying that plate-type heat exchangers are assumed to be developed for the first large commercial plant which would be installed at the Tampa Site.

The cost figures for these elements are: (\$/KW)

125: Evaporator	280
155: Condenser	280
175: Chlorination System	11
185: Mechanical Cleaning System	20

TOTAL 592

4.2 COST PROJECTIONS -- REMAINDER OF POWER SYSTEM

The remainder of the power system cost projections are based on the following combination of cost elements from the OTEC Cost Data Bank (Appendix A):

214, 222, 232, 244, 252, 262.

It is noted that the third digit is not 5 in most cases implying that the cost figures for a first commercial plant with learning curve are not fully available. The cost figures used are somewhat conservative, based on power system design studies. It is felt to be prudent to use these figures since it is doubtful that large technological advances will take place in these components of the power system. Rather there will be an adaptation of existing technology and a direct scale up. This is in contrast to other parts of the OTEC plants where more extensive developmental effort and research is being conducted that can lead to technological advances resulting in cost reductions.

The cost figures for these elements are: (\$/KW)

214: Turbine/generator	153
222: Ammonia pumps	28.3
232: Ammonia piping and valves	75.2
244: Ammonia support system and tanks	71.6
252: Control systems	44.4
262: Electrical systems	<u>24.4</u>
TOTAL	396

4.3 COST PROJECTIONS -- PLATFORM

The cost projections of the platform system are based on the following cost elements:

315, 325, 335.

The cost projections are based on a concrete spar or equivalently advanced platform. The level 5 in the third digit in each index implies that the platform costs are based on a first generation large commercial plant with learning curve. Therefore, the costs of fabrication facilities will have been absorbed by earlier units in the cost estimations. In the case that such a plant is one of the first to be acquired by a commercial utility, it is assumed that the government or some other underwriting agency will subsidize the first unit cost differences in order to achieve commercial penetration.

The cost figures for these elements are: (\$/KW)

315: Hull structure	244
325: Outfitting	26
335: Deployment	<u>120</u>
TOTAL	490

4.4 COST PROJECTIONS -- SEAWATER SYSTEMS

The cost projections of the seawater system are based on the following cost elements:

415, 425, 435, 445

implying that these elements will have achieved an advanced state including learning curve by the time of acquisition of the plant. The cold water pipe is estimated at the cost of fiberglass reinforced plastic (FRP). In the event that the plant employs an integrated CWP, mooring system with such material as elastomers for the CWP using part of the mooring system for support, it is projected that the cost of such a system will be approximately the same as the combined cost for a FRP cold water pipe and separate mooring system. In other words, the cost advantages gained by the systems integration will be offset by increased cost of the sub-components if elastomer is used for the CWP.

The cost figures for these elements are: (\$/KW)

415: Cold water pipe	95
425: Top connection	13
435: Screens	12
445: Seawater pumps	<u>101</u>
	221

4.5 COST PROJECTIONS -- MOORING SYSTEM

The cost projections of the mooring system are based on the following cost elements:

513, 523, 533

implying that these costs are based on the state of development of a first commercial demonstration. It is felt that the state of the development of mooring systems will be a direct adaptation of the practice of the offshore industry. The research effort in the OTEC program directed to advancing the state of the mooring systems is not such as to lead to an expectation of large advances in this field. At some later time in the program development, when industry has the lead, more cost effective mooring systems may emerge, but for the present, a conservative approach is warranted in cost projection.

The cost figures for the mooring system are: (\$/KW)

513: Mooring lines	58
523: Anchors	12
533: Winches	<u>29</u>
TOTAL	99

4.6 POWER CABLES (ENERGY TRANSFER SYSTEM -- ETS)

The cable cost projections are based on the following cost elements from the OTEC Cost Data Bank:

614, 624, 634

representing the bottom power cable, riser power cable, and shore substation costs. It is noted that the state of development is that of the first commercial generation plant, FGF, rather than the next step (5), the first commercial generation with a learning curve factored in. This is because the costs are not expected to be greatly different at this stage of development. Greater cost reductions can be expected when a larger number of installations are achieved and the production facilities are in "full swing", and when some sharing of cable facilities between plants can be achieved.

The cost figures become:

614: Bottom Power Cable	329
624: Riser Power Cable	97.3
634: Shore Substation	32.2
TOTAL	458.5

It is immediately seen that these cost figures are very high and could be a major factor in inhibiting commercialization of OTEC plants. Therefore, it is recommended as one of the first set of alternative runs of the system planning models, that an alternate set of figures be used based on a more sophisticated cable development effort and resultant costs. These would be projected as the Second Generation State (7) at least if not (8) the fully matured technology. This result could be used to stimulate thought

toward a higher level of development effort on OTEC power cables in order to bring the cost item into a more competitive range.

Thus as an alternative set of cost figures the following combination of cost elements is recommended:

617, 627, 637, 647

with the fourth element added to account for interconnection between plants in an OTEC "park" in order to share transmission cables and reduce costs.

The cost figures in the case are:

617: Bottom Power Cable	130
627: Riser Cable	12
637: Shore Substation	16
647: Bottom Interconnection System	30
TOTAL	188

5. OTEC OPERATION AND MAINTENANCE (O&M) COSTS

SUMMARY

An approximate figure of 7 mils/kwhr has been used for the O&M costs for the overall calculation of costs of OTEC power as delivered. This sub-task report treats the sources of O&M costs and develops estimates supporting the figure used in overall calculations. It will be possible to refine or adjust the basic inputs and recalculate the O&M costs as information develops from preliminary designs. However for the present, the information is limited, and thus must be treated with such data as is available, or using judgements and experience from associated fields.

The overall O&M costs are assumed to be made up of the following major parts:

- (1) plant operating personnel costs, salary and support,
- (2) repair and maintenance costs, not accomplished by normal on board crew, for the power system or platform systems,
- (3) power cable inspection, maintenance, and repair costs.

These are felt to comprise 90% of the projected O&M costs.

The result of the analysis in the following sections is given as follows:

Crew cost	3.8 mils/kWh
Repairs, power system	1.2
Platform	0.7
Power cables	<u>1.8</u>
	7.5
10% for "others"	<u>0.7</u>
Total	8.2

This number is at best significant to only one figure.

5.1 CREW SIZE AND OPERATING COST

As a part of determining the annual operating and maintenance cost (O&M) of an OTEC commercial plant, a major factor is the cost associated with the operating crew. At this early stage of design, it is not possible to precisely define the crew composition and size. However, there have been some preliminary estimates for a small pilot plant, and there are estimates which can be made up from other marine experience that give insight into the probable crew for an OTEC plant.

It is projected that the operating crew of a 400 MW OTEC plant would have the following composition:

Plant Supervisor	1
Shift Supervisors	3 *
Module Supervisors (8 modules)	8
Module shift crew (2/module) x 8	48 *
Total plant shift crew	9 *
On board maintenance staff	12
Hotel (cooks, admin, etc.)	<u>8</u>
	89

* indicates three shift operation

This can be compared to the crew estimates for a single 40 MW pilot plant with a total crew of 34 as listed in the following table from a preliminary design study.

Table 4-4

MANNING LEVEL AND PERSONNEL ACCOMMODATION ALLOTMENT BY RATE

	Men Per Shift	No. of Shifts	Total	Type of Accommodation
Plant Supervisor	1	1	1	Private
Shift Supervisor	1	2	2	Private
Control Room	2	3	6	2 Man SR
Roving	1	3	3	2 Man SR
Deckhand (AB)	1	3	3	2 Man SR
Clerk	2	1	2	2 Man SR
Mech. Foreman	1	1	1	Semi-Private
Elec. Foreman	1	1	1	Semi-Private
Instru. Foreman	1	1	1	Semi-Private
Mechanic	2	1	2	2 Man SR
Electrician	2	1	2	2 Man SR
Instru. Specialist	4	1	4	2 Man SR
Cook	2	1	2	2 Man SR
Messman	2	1	2	2 Man SR
Repair/Janitor	2	1	2	2 Man SR
Misc. & Transient			17	2 Man SR
Total			<hr/> 51	

The operating cost associated with a crew of this composition and size was developed involving the following factors:

1. Number in crew
2. Factor for rotating crew with one onshore segment in off-time or training pipeline,
3. Average salary for crew members, ranging from a high for the plant supervisor to a low for messmen,
4. Salary increase factor for offshore/marine workplace,
5. Salary increase factor for company overhead,
6. Plant capacity factor.

The numerical values used for each of these factors is substantiated in the following sections.

1. Number in Crew. From the preceeding section, the number 89 is reasonable.
2. Rotation/pipeline Factor. It is assumed that 1/3 of the on-board crew will be on shore in R&R, or training. Thus the factor 4/3 is applied to the crew figure.
3. Average Salary for Crew Members. The 12 crew members in the supervisory capacities are offset in salary by approximately 12 in the category of food service or janitorial work. The remainder of the operating and maintenance crew can be expected to have a relatively narrow range of salaries around a median. Current cost estimating for marine work typically uses a figure of \$20/hr and doubles this figure for offshore work, resulting in an effective annual salary figure of approximately \$40,000. Another approach is to assume a salary level somewhat above competition and increase this by a factor of 1.5 for offshore. For the skill levels involved with OTEC, it appears wise to use an average salary of \$30,000 and apply 1.5 as the offshore factor.

4. Factor for Offshore Work. As discussed in the preceeding paragraph, a multiplier of 1.5 is assumed.
5. Factor for Company Overhead. A multiplier of 2 is assumed, representing a 100% overhead rate. This is lower than some industries involved in offshore work but may be somewhat high for utility companies; thus a 100% figure appears a reasonably conservative compromise.
6. Plant Capacity Factor. A figure of 0.8 is assumed. There are some OTEC studies which indicate a higher factor is possible, yet there are others that tend lower. The range of realistic estimates tends to be 0.75 to 0.85, so the 0.8 figure is reasonable for use in the present calculations.

These figures have been selected to be conservative. It is seen in the calculations that the operating crew represents an annual cost equivalent to 3.8 mils/kwhr, and thus a 50% increase in the crew costs would represent less than a 2 mil increase. Thus the effect of the approximations is not strong.

CALCULATION FOR OPERATING COST -- CREW

----- ASSUMPTIONS, INPUTS

NUMBER IN CREW	89
ROTATION (PIPELINE) FACTOR	1.33333
AVERAGE SALARY (\$/YR)	30000
SALARY FACTOR FOR OFFSHORE	1.5
OVERHEAD MULTIPLIER	2
PLANT CAPACITY FACTOR	.8

----- OUTPUT

CREW COST (\$/YR)	OPERATING COST (MILS/KWHR)
----------------------	-------------------------------

1.068E+07

4.231

5.2 REPAIRS NOT HANDLED BY ON BOARD CREW (POWER SYSTEM)

The plant operating personnel will conduct continuing inspection and routine maintenance, and a certain number is allocated for repairs and preventative maintenance. Both the shift crew and the 12 non-shift maintenance personnel will conduct planned maintenance as well as repairs to equipment as failure occurs within the capability of the on-board crew.

One study (TRW PSD I) has calculated that a 10 MW power module would require 3.4 man-years of maintenance, both routine and fault correcting. It is estimated that a 40 MW power module would require the same maintenance except for additions in the heat exchangers. Projecting this to a 400 MW plant would indicate that 40 man-years of maintenance would be required. Of this 12 man-years would be provided by the 12 man on-board crew. Thus an additional cost associated with 28 man-years can be added to the O&M costs for this factor. This translates into an addition of 1.2 mils/kwhr.

This is considered to be a conservative number for manpower since no credit has been given for maintenance by the shift crews. However the cost of parts and repair equipment has not been estimated in the 1.2 mil figure and therefore, on balance, it may be a reasonable figure for planning studies.

5.3 PLATFORM SYSTEMS MAINTENANCE AND OPERATION

The OTEC platform, cold water pipe, mooring system and other associated sub-systems and components will require operation and maintenance similar to an ocean going vessel and to an offshore platform. The basic hull will be designed for a long life and should require only limited maintenance. The cold water pipe itself also should require only limited maintenance. The mooring system probably will require the major expenditure of maintenance costs, particularly with respect to winches and due to periodic replacement of a part of the mooring cables or other tension devices.

Platform system studies performed by Lockheed Corp., Gibbs & Cox, and N. Rosenblatt indicate that a mooring system might consist of a multi-leg system, perhaps with six legs. It is estimated that the wire cables or similar components might need replacement at the rate of approximately one per year. Approximately 5000 ft of this cable with a cost of \$200/ft might be replaced annually, for a cost of $\$1 \times 10^6$ per year. During this annual routine, other platform hull maintenance could be performed using some of the floating equipment deployed for the mooring system maintenance and replacement. This total is estimated very approximately at \$30,000 per day for 30 days or a total of 0.9×10^6 .

The total expenditure for platform systems O & M represents an annual power cost of 0.6 mils/kwhr. It is expected that the O&M for the platform should be considerably less than that for the power system, yet be a significant figure. Therefore the 0.6 mil figure compares reasonable with the 3.4 mil figure for the power system.

5.4 POWER CABLE SYSTEM MAINTENANCE AND OPERATION

Since the information base for estimating any cost associated with the power cable is the most uncertain of all OTEC technologies, the estimation of O&M costs associated with this system is correspondingly uncertain. The maintenance and repair activities will consist of inspection, both by electrical means and direct underwater visual (TV) observation, and repair of cable defects.

The cable defects can be expected to be loss of insulation resistance, and will tend to be localized. Overall complete cable deterioration would not be expected. Therefore, either physical damage to the cable armor and insulation may require localized repair, rather than complete cable replacement.

A pertinent example of this type of situation is the underwater power cables across Long Island Sound. These suffered mechanical damage (believed to be a dragging anchor). In the relatively shallow water (~200 ft) it was possible to conduct either diving operations within the working state of the art, or to lift the cable to the surface for repair. In the case of an OTEC plant, part of the bottom power cable is in exceedingly deep water, and part is in water varying in depth from very shallow to the edge of the continental shelf at a depth of approximately 600 ft. Cable damage is more probable in more shallow water. In the deep ocean, it is not as likely from physical effects directly.

One means of estimating the maintenance costs is to assume a design performance specification which would be required to make the OTEC power competitive. One possible such specification is that the cable should perform for the design life of the plant (30 years) with allowance for one complete replacement spread over the life. This

total replacement might be estimated in current dollars at $\$150 \times 10^6$. This would require an approximate annual maintenance cost of $\$5 \times 10^6$ which represents a O&M cost component of 1.7 mils/kwhr.

This figure is half the O&M cost of the power system. It is reasonable that the allowed cable cost would be of this order of magnitude, otherwise, commercial competitiveness would be difficult.

Other costs associated with the power delivery system involve the on-land D.C. to A.C. converter station, and other sub-systems of the power cable system. It is not likely that these costs will be of the same order of magnitude as the projected cable repair costs.

6. OTEC EQUIPMENT MAINTENANCE REQUIREMENTS

SUMMARY

Equipment maintenance can be divided into the following categories:

1. Power System
2. Platform Systems
3. Power Cable

Most of the power system maintenance is continuing scheduled maintenance performed by general mechanics and electricians. The accompanying tables on the following pages are from a Westinghouse power system study and indicate maintenance activities, skill levels, and equipment for which maintenance must be performed. It is seen that most of the maintenance is "General" indicating inspections, lubrication or calibration, minor adjustments, cleaning, and other operations not usually considered as "repair".

Platform systems maintenance principally involves the hull, the cold water pipe, and the mooring system. The accompanying table "Platform Maintenance Activities" indicates that on-board crew will perform maintenance on the three principal systems not requiring major plant outages or special tools or skills. Other maintenance will be either planned, periodic routing of major sub-systems, or on call repair of failed machinery or hull components. It is not likely that major outages will stem from platform system failures. The cost and time to deploy a repair team is too costly, and the platform systems will be designed to be available, except for planned activities.

Table 6-30
MAINTENANCE ACTIVITY CATEGORIES

CATEGORY	ACTIVITY
1.	<p>Scheduled maintenances activities not requiring system outage.</p> <ul style="list-style-type: none"> ● Inspections ● Lubrication ● Cleaning ● Adjustments ● Calibration ● Data recording (levels, temperature, pressure, wear and vibration/noise changes).
2.	Repair of equipment failures/malfunctions not resulting in system outages.
3.	Repair of failures resulting in forced outages.
4.	Scheduled maintenance activities requiring system outage.

Table 6-31
SKILL LEVELS FOR MAINTENANCE

CATEGORY	SKILL
1.	General mechanics - specifically trained for OTEC
2.	Electronic technicians - specifically trained for OTEC
3.	Divers
4.	Welders (certified)
5.	Special mechanics (turbine-generator, seawater pumps)
6.	Special inspector (welding)
7.	Machinists

Table 6-32
MAINTENANCE PERSONNEL REQUIREMENTS SUMMARY

Maintenance Category	Maintenance Task	Skill Category	No. Required per Task	Man Hours per Year
1 & 2	General	1	2	17,532
1 & 2	General	2	2	17,532
1 & 2	Spare NH ₃ Pump Bowl	7	1	16
1 & 2	Biofouling & Moving Screen Maintenance	3	3	196
3	Heat Exchanger Repair	1	2	131
3	Heat Exchanger Repair	3	3	196
3	Heat Exchanger Repair	4	1	65
3	Heat Exchanger Repair	6	1	65
3	Turbine Repair	5	1	154
3	Generator Repair	5	1	62
3	Seawater Pumps Repair	5	2	134
3	Seawater Pumps Repair	3	3	201
4	Heat Exchanger	1	2	116
4	Heat Exchanger	3	3	174
4	Heat Exchanger	4	1	58
4	Heat Exchanger	6	1	58
4	Seawater Pumps	5	2	194
4	Seawater Pumps	3	3	291
4	Turbine-Generator	5	2	354
				<u>37,529 Hours</u>

Table 6-33
ANNUAL MAINTENANCE MANHOUR REQUIREMENT
BY SKILL CATEGORY

Category	Skill	Annual Manhours
1	OTEC Trained Mechanics	17,779 hours
2	OTEC Trained Electronic Technicians	17,532 hours
3	Divers	1,058 hours
4	Welders	181 hours
5	Special Equipment Mechanics	898 hours
6	Special Inspectors (Welding)	65 hours
7	Machinists	<u>16 hours</u>
	Total Per Year	37,529 hours

OTEC PLATFORM MAINTENANCE ACTIVITIES

SUB-SYSTEM	ON-BOARD CREW ACTIVITIES	SPECIAL ACTIVITIES REQUIRING SPECIAL MAINTENANCE/REPAIR TEAMS
HULL	Inspection, corrosion system operation and consumables replace- ment	Macro-fouling removal, hull repair, welding, etc.
COLD WATER PIPE	Top connection insp., lubrication	Macro-fouling removal, top connection bearing inspection and repair.
MOORING SYSTEM	Inspect, adjust tension, routines on winches	Cable testing, cyclic replacement.

The power cable system will require inspection and maintenance of a relatively routine and minor nature. The major maintenance activity would be associated with degraded cable performance requiring some repair to the cable itself.

Periodic planned maintenance would involve routining of switch gear and other power transfer components comparable to a shore-side sub-station. Most of this could be performed for the on-platform components by the routine on-board crew. Periodic (such as annual) inspections and routining might involved specialists for a period of a few days to two weeks.

Repairs to the power cable would require specialists and very special equipment. It is expected that this could occur less frequently than annually. Direct (visual) inspection of the power cable probably would not be done routinely due to cost and special equipment and personnel needed, but would be scheduled only if there was apparent problems.

Routine inspections would probably be done electrically, including tests conducted with the cable "off line". These tests would be similar to those performed for buried on-land cables.

7. OPERATIONAL MODES AND FORCED OUTAGE RATES

The key components or systems that influence plant availability are:

1. SEAWATER PUMPS
2. HEAT EXCHANGERS
3. TURBINE - GENERATORS
4. POWER CABLES

All other components or systems are either of a nature that they have inherently exceedingly low failure rates, or have backups such that plant power reduction will not occur as a result of the component failure.

This may be represented by a series of the key elements:

The configuration, failure rates, time to repair and consequences on net plant output power are detailed in the following sections:

SEAWATER PUMPS

1. Assume 2 pumps per module for each of WARM WATER and COLD WATER, total of 4 pumps per module.
2. Failure rate projected as once per year per pump; mean time to repair (MTTR) 2 days.
3. Outage days per year per module: 2 days per pump $\times$ 4 = 8 days.
4. Outage days per plant (8 modules): 64 days per year.
5. Power reduction per module per pump outage: 0.5 of module power = 25 MWe reduction; net plant output 375 MWe.

HEAT EXCHANGERS

1. Each module contains 10 MWe subassemblies for each of CONDENSER and EVAPORATOR.
2. Each subassembly failure rate projected as once per year; MTTR 2 days.
3. Outage days per year per module: 2 days per subassembly $\times$ 10 = 20 days.
4. Outage days per plant per plant (8 modules): $8 \times 20 = 160$
5. Power reduction per subassembly: 0.20 of module power = 10 MWe; net power during outage days = 390 MWe.

TURBINE - GENERATOR

1. Assume 1 T/G set per module.
2. Failure rate projected as 0.5 per year (1 per 2 years).
3. Outage days per failure: 5. Outage days per year per module = 2.5.
4. Outage days per plant: $8 \times 2.5 = 20$
5. Power reduction per module due to outage: 50. Plant power level during outage: 350

POWER CABLES

1. Assume 2 operating cables (+ and - D.C. legs) and 1 spare cable.
2. Assume one major cable failure each 2 years. At end of year 2, one cable failed, spare placed in service. No change in plant output.
3. At end of year 4 second cable fails, in service cable runs with seawater ground at 120 % rated capacity.
4. During start of year 4, plant capacity 60% rated due to cable limitation: 240 MWe net.
5. Outage days while making new cable installation, 90 days to mobilize, 30 days to install = 120 days
6. Net outage days per year due to cable failures: 24
7. Net plant power during outage days: 240 MWe.

8. SITE THERMAL RESOURCE DATA

Thermal resource data for the "West Florida" site was obtained from Evans-Hamilton, Inc. (personal communication). The following is a monthly tabulation of the site Delta-T:

MONTH	MONTHLY MEAN DELTA T (C)
JAN	19.2
FEB	19.2
MAR	18.2
APR	20.2
MAY	21.2
JUN	23.0
JUL	24.2
AUG	24.1
SEP	23.4
OCT	22.3
NOV	20.7
DEC	19.6

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9. OTEC CONSTRUCTION COST DISTRIBUTION

SUMMARY

A five year construction period is baseline. Most of the major fabrication would take place over a three year period. The level of expenditure during the three year period would be approximately at a constant rate.

The major cost items in construction would be the platform and the power system. The platform will require approximately 3 year to fabricate with a nearly constant level of effort. The power system will be fabricated from modules. The major components in each module require about 1 year to fabricate. For each of these major components, key operations require from several months to 1/2 year, so that each fabrication facility can support a 2 module per year rate, at least.

The breakdown of construction level of effort will follow the yearly effort:

1. Prior to the start year, 5% in planning and longer lead items.
2. First year, 10% on set up and procurement.
3. 2nd year, first construction year 25%
3. 3rd year, second construction year, 25%
5. 4th year, third construction year, 25%
6. 5th year, deployment 10%.

SOURCE: MITRE CORP.

OTEC GENERIC COMMERCIAL DEVELOPMENT
(FIRST PLANT ON LINE IN A COMPLEX; 400 MW_e (NET) DESIGN CAPACITY)

D-54

LEGEND:

- ▲ Start
- ◆ Commit to Development
- Operation
- * Financial & Operational Agreements

APPENDIX E

ADJUSTMENTS TO OTEC BASELINE INPUTS:

SPARE POWER CABLE COST AND RELIABILITY

PREPARED FOR FLORIDA POWER CORPORATION
BY
J. RONEY, OCEAN ENGINEERING
PRINCETON, NEW JERSEY

APRIL, 1980

REVISED
NOVEMBER, 1980

APPENDIX E

ADJUSTMENTS TO OTEC BASELINE INPUTS:

POWER CABLE COST AND RELIABILITY

ABSTRACT

This Appendix is a supplement to the report -- "OTEC Inputs for Utility System Planning Analysis" -- dated November 1, 1979 and included as Appendix D. This Appendix provides adjusted inputs for the parametric study of deletion of the spare power cable which was assumed as part of the baseline OTEC plant configuration. The adjusted information includes assumed alterations in cost and in power cable system reliability. This Appendix also includes updated information to provide an interpretation of the possible variations in the assumptions used.

The derivation of the DC power cable cost and reliability values used in the baseline OTEC inputs are reviewed. These values are then adjusted for the case of no spare power cable. These estimates are based on currently available information. The relative lack of technical experience in submarine power cables which is applicable to this evaluation resulted in a high degree of conservatism in the projections on cost and reliability.

New information received near the end of the FPC OTEC Evaluation is discussed. This tends to relax some of the conservatism originally used in the projections. The possible adjustments that might be made to the assumptions, the consequent alteration in OTEC power cable numerical values used in the FPC, and the study results are evaluated.

BASELINE POWER CABLE COST INPUTS

The DC power cable cost estimates submitted for Task II consist of the following major factors:

Bottom Power Cable	329	\$/kW
Riser Power Cable	97.3	
Shore Substation	32.2	
Total	458.5	

The cable system cost estimates are based on a set of three cables, two for normal + and - poles, and one installed spare.

It must be stated that the information available to estimate the cost and other technological features of the projected underwater DC power cable system is more sparse than for any other major system of the total OTEC plant. Thus the uncertainty in the numerical values provided is relatively large. The information base from which the cost and performance data was derived for the other OTEC systems (heat exchangers, platform, etc.) is more abundant for two principal reasons: the general technology which is transferrable to OTEC is relatively well established and adapting these to OTEC is reasonable, and there have been OTEC specific studies that supply reasonably good estimates. In most cases, these sources are multiple, having been performed by several study contractors.

In the case of the OTEC power cable system, the basic technological information base is much more narrow. Much of the

existing information is held by non-U.S. companies and is not readily available. Such studies as have been conducted on OTEC are limited and published documentation virtually nonexistent.

BASELINE PERFORMANCE ESTIMATES

The configuration of three installed power cables, providing a + and - DC leg and a spare, assumed that one major cable failure would occur each two years. With an installed spare, there would be no degradation in performance until after four years, assuming that no repair or replacement would be made until a second cable failure occurred. At that time the failure would reduce net plant power transmission to 240 MWe, assuming the remaining cable would be used with a seawater ground return and that the current in the cable could be increased to 120% of its rated value for the time needed to make repairs or install a new cable. The time required to effect a repair is estimated to be 120 days, based on 90 days to mobilize and 30 days for repair or installation operations. An average net outage days per year due to cable failure was estimated as 24 days, being the 120 outage days divided by the average 5 year time span. The possible range of variation of this estimate is discussed in a later section.

NO SPARE CABLE ADJUSTMENTS

If the spare cable were eliminated, it is estimated that 1/3 of the cost of bottom cable and riser cable costs would be saved. No savings for the shore station is estimated for the remaining two cable system, since the same thyristor bank and other basic switch gear would be required for the two conducting cables in service. Only a means of

switching or connecting a spare cable to either pole in the event an in-service cable failure would be required at relatively small incremental cost. Thus the adjusted cost savings become $1/3 \times (329 + 97.3) \text{ \$/kW} = 142 \text{ \$/kW}$ reduction.

With no spare power cable, the total outage days, average over a four year period, is estimated at 30 days per year.

POSSIBLE VARIATIONS IN COST AND PERFORMANCE PROJECTIONS

(Section Added, 11/80)

Capital Cost

The capital cost of the power cable system is dominated by the acquisition cost of the cable, the installation cost, the added cost of an installed spare. The operating and maintenance costs are dominated by the cost of repair or replacement of cables due to in-service failure.

The projected capital cost of the power cable, as described in Appendix D, is approximately \$1 million per mile including installation. The acquisition cost of the cable itself is estimated as approximately half the total, the remaining half being the cost of installation. This cost, being that of a single cable, is consistent with many similar estimates for submarine power cables. However, each OTEC power cable would carry only 200 MWe of power, since for a DC system, the current divides between the two poles. It is within the technology that a comparable cable without appreciable cost increase could carry twice this load. The installation cost would be

approximately the same. Thus if two OTEC plants could share the transmission cable over most of the long distance run, the cost of power cable to each plant would be correspondingly reduced. However the technology for making such a connection is not established, and could require appreciable development effort. Another area where capital cost of the cable system could be reduced is in the projected installation costs. It is possible that more sophisticated installation procedures involving a combined cable trenching, cable laying and backfill operation could be developed. This could greatly reduce the installation cost.

Need for Installed Spare Cables

The assumed requirement for an installed spare power cable is based on existing uncertainty in performance, lack of operational experience on comparable systems, relative pace of development of the technology, and perception of risk involved. This situation induces a high degree of conservatism in design assumptions and results in provision of large margins against failure. The evaluation of OTEC by Florida Power Corporation has spanned a time interval approaching two years, starting in 1979. The operating experience base on submarine power cables was and remains limited. The system providing the most similar set of electrical and physical characteristics to an OTEC installation is the Skagerrak cable system between Denmark and Sweden. This system was commissioned, after initial testing and adjustments, in 1976 reaching full service in 1977. Transmission cable faults were reported, one in 1976 and one in 1977, leading to relatively conservative

assumptions for the OTEC system projections, including the specification of an installed spare cable.

However, information obtained through 1978 and 1979 is more encouraging. A recent report (Reference 1), delivered in August 1980 contains indications that expected failure rates could be appreciably lower. The Skagerrak transmission cable has performed fault free since the 1977 failure. Failures of submarine power cables are usually due to insulation breakdown during laying operation, some difficulty incurred during normal operation, but most frequently due to mechanical damage from anchors or fishing gear. Burying a power cable greatly reduces the likelihood of failure. Therefore it is quite possible that as further experience accumulates, and design information is refined, that the spare cable requirement may be removed, without any significant change in system availability. This would have a marked effect on cable system capital costs.

Operation and Maintenance Costs

A relatively high O&M cost was projected for the baseline OTEC power cable system, principally due to assumed failure rates of the transmission cable and the need to make repairs or replacements. This resulted both in direct costs to O&M and to reduced plant availability during periods when only a single pole was available for power transmission.

Should the higher cable reliability be realized, the need for this portion of O&M costs could be greatly reduced. The O&M cost estimates allocated 1.8 mils/kWh out of a total of 8.2, or 22% of the total.

Thus the reduction of this figure to a much lower value would have a great effect on total O&M costs.

SUMMARY CONCLUSIONS

Using a conservative set of assumptions, the elimination of an installed spare power cable would have a marked effect on system availability, increasing the annual average time from 24 to 30 days during which only a single cable would be available. Thus the capital cost savings of \$142/kW would be somewhat offset by this decrease in reliability.

This conservatism is based on very limited operating experience and other means of assurance of low risk. However, more recently available information has tended to be more favorable than previous indications. Therefore, there is promise that relaxation of the degree of conservatism could be reasonable in the future.

If the spare cable could be eliminated without undue effect on plant availability and if the installation could be accomplished at lower than projected cost, it is feasible that approximately \$200/kW could be reduced from the cost assumptions. The possibility that a 10% reduction in projected plant capital cost could be achieved in the power cable area is strong substantiation for greater attention to this area in present OTEC development efforts.