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DOE/ET/29187-2

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SYSTEM PLANNING ANALYSIS APPLIED TO OTEC
INITIAL CASES BY FLORIDA POWER CORPORATION

Task II Report

March 1980

Work Prepared Under Contract No. AC02-79ET29187

Franklin Research Center
Philadelphia, Pennsylvania

U.S. Department of Energy

Solar Energy

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**SYSTEM PLANNING ANALYSIS
APPLIED TO OTEC
INITIAL CASES
BY
FLORIDA POWER CORPORATION**

**TASK II REPORT
NO. FC-5237-2**

**TO
FLORIDA POWER CORPORATION**

**PREPARED BY
FRANKLIN RESEARCH CENTER**

MARCH 1980

Franklin Research Center

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EXECUTIVE SUMMARY

1. Objective and Scope of Task II

Exercise the FPC system planning methodology on:

- (1) Base Case, 10 year generation expansion plan with coal plants providing base load expansion,
- (2) same, but 400 MW of OTEC substituting for coal burning units with equal resultant system reliability.

Objective and scope discussed in Section 1.

2. OTEC Parameters

OTEC inputs based on reasonable economic projections of direct capital cost and O&M costs for first-generation large commercial plants.

OTEC inputs discussed in Section 2.

3. Base Case Conditions

Base Case conditions for FPC system planning methodology involved base load coal fueled additions during the 1980's and early 1990's.

The FPC system planning methodology and the projected 10 year generation expansion plan presented in detail in Task I Report (DOE/ET/29187-1).

Base Case discussed in Section 3.

4. Production Costing Analysis

First trial runs of PROMOD system planning model substituted OTEC for 400 MW purchases of coal generated power during 1988 - 1989 and then 400 mw coal capacity thereafter. Result showed higher system reliability than Base Case runs.

Reruns with greater coal fueled capacity displacement showed that OTEC could substitute for 400 MW purchases in 1988-1989 and replace the 800 MW coal unit scheduled for 1990 to yield equivalent system reliability. However a 1995 unit would need to be moved to 1994.

OTEC Case results discussed in Section 4.

5. Corporate Financial Analysis

Production costing computer model runs were used as input to Corporate Model to examine corporate financial impact. Present value of total revenue requirements primary indication of relative competitiveness between Base Case and OTEC. Results show present value of total revenue requirements unfavorable to OTEC as compared to coal units. Disparity in excess of allowable range for possible consideration. Results discussed in Section 5.

6. Task II Results and Task III Outlook

Results indicate strong variations over Task II inputs required to make OTEC competitive, as will be examined in Task III. Task III will look at (subject to modification during runs):

- Lower OTEC capital cost until competitive.
- Raise fuel cost escalation until OTEC competitive.
- Reduce capital cost by elimination of spare power cable.

Expectation for Task III discussed in Section 6.

7. Conclusions

Principal problem for OTEC as run in Task II is the differential capital cost for OTEC compared to coal plant. Fuel savings do not make up difference for competitive consideration. Should not conclude from Task II that OTEC is non-competitive. Assumptions for Task II are such as to display range and nature of difference a new technology, such as OTEC, must make up by some means to enter market. Tasks III and IV address this.

1. INTRODUCTION

1.1 Objective

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

It was anticipated that OTEC would be not be fully competitive when compared to base-case conditions. The concept of the next task, Task III, is to vary several parameters, exploring and quantifying those conditions under which OTEC could become economically competitive. These parameters and the possible variations are discussed briefly in Section 6 of this report. As a consequence of the outcome of Task II, this part of the study serves to identify the nature and quantity of any gap between OTEC, as analyzed, and available alternatives (coal, in the case of FPC) against which it competes. This will be useful in guiding the selection of parameters and values to be used in the Task III runs.

In this report, all dollar figures are 1979\$ unless otherwise indicated.

2. OTEC PARAMETERS

2.1 Source of Data Used for Inputs

The OTEC inputs are detailed in Appendix A. 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.

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

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 plants that may exist in the planning future. It is a convenient plant size number, 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. This requires a highly accelerated development schedule including pilot and demonstration plants. The 1988 date was required in order to include OTEC within the present planning horizon

TABLE 2.1

OVERALL BASELINE CONFIGURATION FOR OTEC PLANT

BASILINE 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 SYSPENDED OR ELASTOMER INTEGRATED WITH MOORING SYSTEM
POWER CABLE	D.C. 2 CONDUCTOR 1 SPARE
MOORING SYSTEM	MULTI-POINT OR TAUT

for FPC.

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.

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

2.3 Discussion of OTEC Inputs

2.3.1 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 OTEC plants would 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 as cost-effective when designed to meet 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 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 has been determined by Pirelli (1978) that beyond a distance of about 25 miles, AC underwater power cables would not be effective. Power cable technology indicates that a + and - pole conducting pair is best for DC transmission. It is presently considered that it would be cost-effective to install three cables, providing an installed spare, due to the high cost and time required for assembly and deployment of the cable installing equipment.

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

2.3.2 Capital Costs

The state of maturity of development of a new technology has a strong influence on costs. In Appendix A, 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 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 A, Section 4.

2.3.3 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 the 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
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.

The forced outage rate also includes a factor for total outage periods where the plant may have to be shut down for hurricane or other severe weather.

TABLE 2.2

OTEC CAPITAL COST INPUTS
(1979 \$)

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

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 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 five 10 MWe subassemblies, each with a CONDENSER and EVAPORATOR.
2. 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 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 spare cable.
2. Assume one major cable failure each 2 years. If one cable failed, spare placed in service. No change in plant output.
3. If two cables fail, in service cable runs with seawater ground at 120% rated capacity.
4. Outage days while making new cable installation, 90 days to mobilize, 30 days to install = 120 days.
5. Net outage days per year due to cable failures: 24.
6. Net plant power during outage days: 240 MWe.

WEATHER

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

2.3.4 Thermal Resource Data

Site thermal resource characteristics were obtained from the DOE oceanography contractor, Evans-Hamilton Inc. 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:

$$P = P_o \left(\Delta T / \Delta T_o \right)^2$$

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

2.3.5 Operation and Maintenance (O&M) Costs

A detailed analysis of potential O&M costs was made and is presented in Appendix A, Section 6. The resultant calculation indicates 8.2 mils/kWh (in 1979\$) is a supportable figure, although very approximate.

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

crew cost	3.8 mils/kWh
repairs to power system	1.2
platform	0.7
power cables	1.8
10% for "others"	0.7
<hr/>	
Total	8.2

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

Figure 2-1

OTEC Plant Site

3. BASE CASE PARAMETERS

The Task I Report (DOE/ET/29187-1) describes the Florida Power Corporation system parameters used in system planning runs conducted in September 1979. This report 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 3-1 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 Task I Report. Table 3.1 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 3-2 shows the percentage of each fuel/energy in the mix for the Base Case.

Figure 3-1. Base Load Facility Plan

Table 3.1

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 3-2

4. PRODUCTION COSTING ANALYSIS

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, OTEC is treated as having 6 capacity states: 400, 375, 350, 340, 230 and 0 MW.

Appendix B gives an example of the calculation made to translate component failure rates and repair times into capacity probability states. Figure 4-1 shows the resulting inputs for the forced outage rates (FOR) and the percent time at each capacity state. 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 break-in period for the plant. The ratio 4:2:1 represents the break-in 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.

Figure 4-2 shows the inputs to PROMOD that treats the monthly variation in plant output capacity deration. The plant is derated to account for planned maintenance, and the seasonal degradation of the thermal resource which reduces net power output. Normally the PROMOD program requires specification of a maintenance outage schedule since

FIGURE 4-1

OTEC FORCED OUTAGE RATES

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

FIGURE 4-2

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

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 taken out for maintenance, and there is no separate specification of a maintenance outage; rather the deration includes the maintenance for the modules.

4.2 PROMOD Results

The parameters that cover the Base Case Promod runs are described in the Task I report. The load forecast and year-by-year capacity forecast are summarized in the preceeding Section 3. 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 replacement of the 800 MW coal-fired unit scheduled for 1990. However a 1995 unit would need to be moved to 1994.

Table 4.1 shows the installed capacity, year-by-year, under the OTEC scenario. The Base Case is shown above for direct comparison. As is discussed in the Task I report, there are two principal outputs of the PROMOD computer program:

- o Generating system reliability data in the form of loss of load hours per year (LOLH)
- o Annual generation for each type of generating unit, plus fuel use cost and cost of purchased power.

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

Table 4.1

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

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 PROMOD results for the Base Case and the OTEC case are shown in Figure 4-3 in which the loss of load hours (LOLH) as a function of the year are presented. Although there are year by year differences due to shifting 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. Although the time scale of the system planning study is 20 years, the first 10 years are identical, and therefore only the latter years are presented.

Figure 4-3

Table 4.2 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. This planned generating capacity additions are shown in Figure 4-4. From Table 4.2 it is seen that 400 MW of OTEC capacity added in 1988 represents 5% of the total installed capacity at that time and for six years until it reduces to 4%. This data is presented graphically in Figure 4-5.

Table 4.3 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 4-6 for the OTEC Case (as compared to Figure 3-2 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 Figure 4-5, accounts for 10% of the total energy generation, as shown in Figure 4-6.

Table 4.2

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 4-4

Base Load Facility Plan

BASE CASE

OTEC CASE

CAPACITY MIX

Figure 4-5

Table 4.3

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 4-6

Generation Energy/Fuel Mix -- OTEC Case

5. CORPORATE FINANCIAL ANALYSIS

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 lower 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 out of options which are not considered to be usable due to such factors as environmental problems, is accomplished in the development of the alternative plans prior to evaluation using the Corporate Model.

5.2 Assumptions Used

It is assumed that the company will recover via rate structure all its costs. The model calculates annual rate increases required to

stay within the rate of return specified by Florida Public Service Commission methodology.

Construction 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 inflation rate of 6.8% over its construction period.

The alternative costs used for coal-fired units is estimated at \$583/kW for a first unit and \$496/kW for the second unit at a common site. The estimates for these plant costs include experience with current construction costs at Crystal River 4 and Crystal River 5, two coal-fueled units under construction.

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 583\$/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 that 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 for 400 MW substitution was performed, the unfavorable difference was \$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.

6. TASK II RESULTS AND TASK III OUTLOOK

6.1 Nature of Results Expected

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 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 6-1, a graphic representation indicates how Task II established one of the key points on the curve and where Task III will furnish 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

Figure 6-1

ENVELOPE OF OTEC COMPETITIVENESS

in Cumulative Total Revenue Requirements for OTEC which is shown as a + value on the vertical axis.

6.2 Expected Task III Runs

During Task III, the values of key parameters will be varied in order to examine the conditions that would make OTEC become competitive. First, the capital cost of OTEC will be lowered until the curve crosses the zero value on the horizontal axis. The point, labeled IIIa, represents this value. 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 cost of fuel will be increased (i.e. the rate of escalation increased) until the zero crossover is reached. This will establish 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 will be considered for adjustment during Task III are:

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

7. CONCLUSIONS

7.1 Principal Conclusions from Task II

Florida Power Corporation system planning studies indicate that OTEC cannot be introduced into the Florida Power Corporation system during the ten year planning horizon based on the present projection of planning parameters and corporate economics. Some "specialized" program would be needed. Such a program could possibly be justified under conditions external to Florida Power Corporation present planning considerations.

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 range.

7.2 Discussion of Conclusions

It should be emphasized that 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.

It can be expected that some special situations could be created for introduction of a new technology such as OTEC to integrate the new generating system into a commercial utility system. Nuclear power did not enter the utility field initially as a fully competing alternative. There were and are federal developmental and manufacturing aids, 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 expected for initial commercial penetration, beyond the pilot and demonstration plants.

There should be no misinterpretation of the results of Task II. It is not conclusive that OTEC is non-competitive. The nature and magnitude of the differences between competing, established generating sources and OTEC have been identified and documented directly and precisely by the exercise of an accepted system planning methodology. However, the results do indicate that other conditions and incentives must be considerable. This will be explored further in Task III and IV.

APPENDIX A

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

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 - 1.2 Categories of Cost Information
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7. OPERATIONAL MODES AND FORCED OUTAGE RATES
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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.

The ability to foresee risk relates to the accumulated base of data and knowledge of a particular material, component type or other feature from which experience one can infer the possibility that the specification of a dimension is accurate and that the cost estimate based on that dimension is also accurate. If one knows what to anticipate, rather than being subject to surprises due to unfamiliarity, the risk element in this category is diminished.

The risk element related to resolvability pertains to the level of effort and time needed to resolve an uncertainty. For example, it may be necessary to carry out extensive tests in order to resolve an uncertainty on corrosion life of a material to be used in a system. Conversely, it may be possible to perform a straightforward test in a reasonable time to obtain a bit of mechanical stress data needed. In the latter case the secondary risk of resolvability is lower than in the case where long time and extensive testing is required.

Finally there is an element of adjustability to problems and not be locked in to a concept or system design that would be extremely difficult to abandon and use some alternative. If the design problem can be resolved by using more of a material, e.g. thicker walls, then the adjustment is relatively flexible. On the other hand, the failure of an attachment mechanism or flexible joint mechanism could cause one having to abandon an entire approach to a critical element in a design, and this would thus involve a high degree of risk in this area.

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

BASILINE 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 OF 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:

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- ,which follows, 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 capacity 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

3.38489

$\rightarrow \div 0.8 \Rightarrow 4.231$

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	<u>354</u>
				37,529 Hours

Table 6-33
ANNUAL MAINTENANCE MANHOURLY 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)

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

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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.

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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 an exact description of any proposed OTEC system. 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 as 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)

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 units 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.