CEER–X-72

ENERGY ANALYSIS
AND SOCIOECONOMIC CONSIDERATIONS
FOR PUERTO RICO

By:

MODESTO IRIARTE, Ph.D. – ENGINEERING

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With Special Contributions by:

ANGEL L. RUIZ, Ph.D. – ECONOMICS

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May 1980

CENTER FOR ENERGY AND ENVIRONMENT RESEARCH

UNIVERSITY OF PUERTO RICO — U.S. DEPARTMENT OF ENERGY

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SECTION 1

STUDY PURPOSE, RESULTS AND PROPOSED PROGRAMS

Section 1

STUDY PURPOSE, RESULTS AND PROPOSED PROGRAMS

1.1 INTRODUCTION

The Governor of Puerto Rico has recognized the seriousness of the energy situation by establishing an Energy Office and by approving the Energy Policy document during 1979. Rapidly changing oil prices and fuel oil availability will seriously affect the welfare and socio-economic development of the Island, if no adequate energy alternatives are found in the near future.

The President of the University of Puerto Rico (UPR) has recognized the need of directing well planned efforts towards the development of energy alternatives to compete with commercially available sources of energy. Late in 1978 the President urged the Director of the Center for Energy and Environment Research (CEER) to initiate energy system analyses and assessments of alternative energy scenarios and to identify the most promising and economically viable energy alternatives in accordance with the Energy Policy document. This was a wide-ranging and ambitious task, and the present document is a product of the study.

This Energy Study begins with an analysis of the energy requirement projections up to the year 2020. The cost of electricity produced by commercially available oil, coal and nuclear plants located in Puerto Rico is analyzed for the same period. It will be seen that electricity from nuclear plants has the lowest cost. However, the low cost of electricity produced by nuclear plants, as determined by the Study, is not used as the cost criteria which the other energy alternatives must achieve to be considered attractive for development and commercialization.

Today nuclear plants are associated with socio-political problems at the national and international levels. Mainly for this reason, scenarios involving nuclear plants are not endorsed by the Puerto Rico Energy Policy Document.

1.2 STUDY RESULTS

The Study indicates that electricity produced by nuclear plants is less expensive by a significant factor, in the order of one and one half to two, than the electricity produced by commercially available coal plants. The Study shows that the cost relationship will be maintained for the rest of the century and beyond. High estimates of nuclear plant capital investment and fuel costs were taken from available commercial data.

Coal plants are recognized as a viable alternative in the Puerto Rico Energy Policy Document. The cost of electricity produced by coal burning plants is used as the cost criteria which must be achieved by other energy alternatives for them to be considered as attractive for development and commercialization. The impact on the Island's economy of coal importation for the coal burning plants versus the impact of other energy alternatives such as OTEC, biomass and direct solar energy, provide some socio-economic credit in favor of these renewable energy alternatives. This impact is analyzed in Chapter 5 and is summarized at the end of this section.

Oil fueled power plants are the highest cost energy alternative analyzed in the Study. The use of this alternative should be minimized with a strong, dynamic and aggresive alternative energy development program.

Excluding nuclear plants, the lowest predicted cost of electricity results from power plants burning biomass. With assumed escalation rates of 8% per year until 1985, the average production cost for the first year of electricity from a biomass fueled plant is predicted to be 4.58 cents per kwhr, and with an assumed escalation of 5% per year beyong 1985, the levelized cost of electricity during the lifetime of the plant (assumed to be 35 years) is 7.13 cents per kwhr. By contrast, the corresponding costs for a coal plant equipped with a Flue Gas Desulfurization (FGD) System is 6.35 cents per kwhr for the first year of operation (1985), and 9.59 cents per kwhr levelized cost for the lifetime of the plant (1985-2020). The corresponding cost of electricity from residual fuel oil burning plants shows costs of the order of 160% and 320% of those for the coal burning plant. (Oil fuel costs of $57 per barrel are assumed for 1985 and there is a 9% per year escalation thereafter).

An Ocean Thermal Energy Conversion (OTEC) plant of 250 MW capacity is shown to be economically competitive with coal by the middle of next decade. An initial OTEC pilot demonstration project of 40 MW capacity scheduled to begin operation in 1985 is shown to be non-competitive with coal, but it will have electricity costs much lower than the costs of electricity produced by oil fired steam plants.

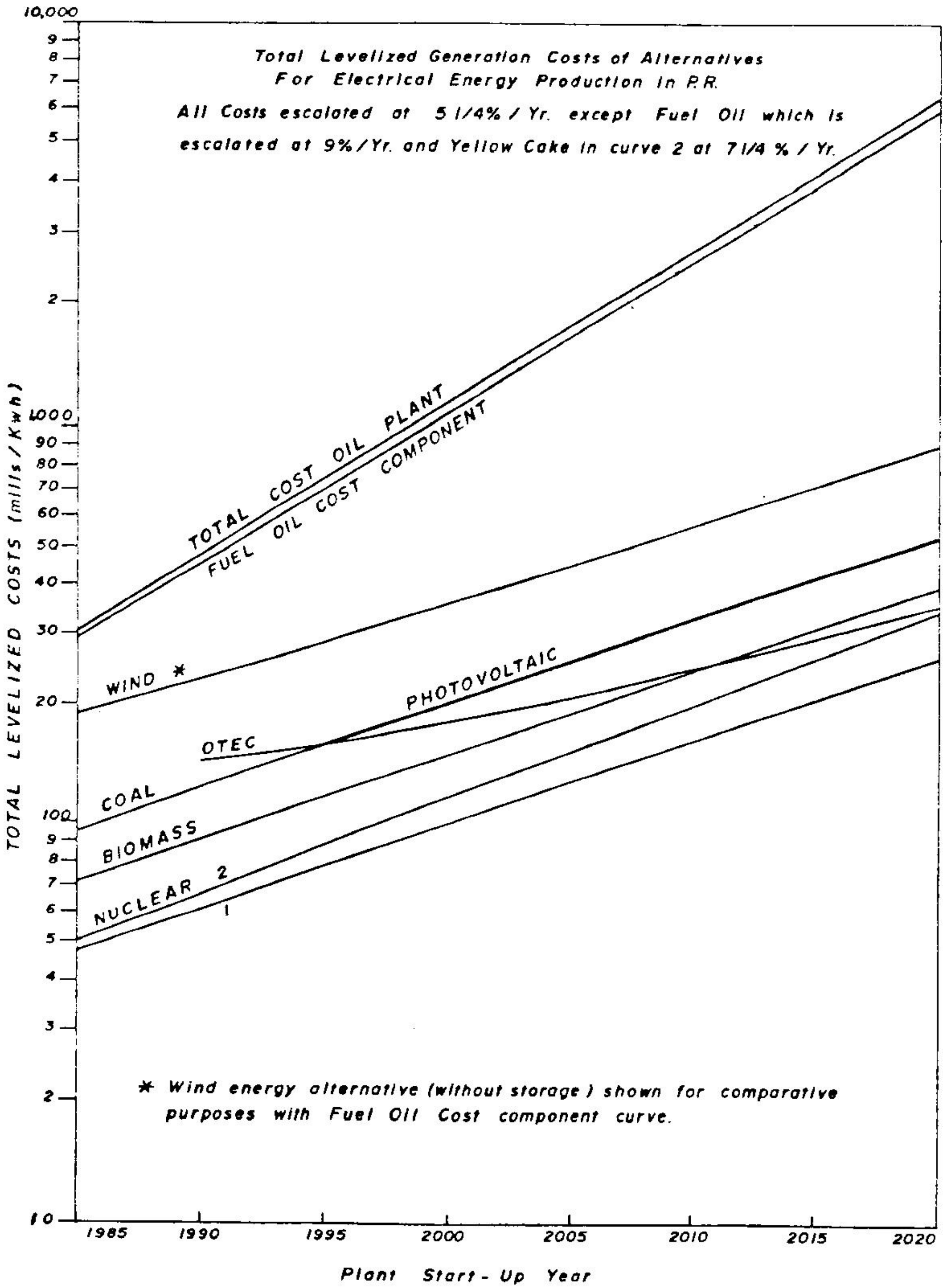
A 250 MW photovoltaic central power installation with electric battery storage projected for operation in 1993 is shown to be highly competitive with coal burning plants. Photovoltaics is emerging as a very attractive possibility for the Puerto Rican scenario and offers a very attractive alternative in case there are difficulties with the OTEC program. Before this Study was undertaken, the competitiveness of photovoltaics was thought to be 20 or more years away. Now it seems that Photovoltaics can be pushed to economic competitiveness within ten years through an adequate Research and Development (R&D) Program. All of the electrical energy generated last year in Puerto Rico could have been generated with solar photovoltaic facilities equipped with electrical battery storage and with a total cell surface collection area of less than 1% of the area of the Island at costs predicted to be similar to coal and initially lower than the costs predicted for OTEC power plants. The technical problems associated with Photovoltaics become rather simple when compared with the technical problems associated with OTEC marine plant facilities. A photovoltaic manufacturing industry would be more feasible for Puerto

Rico than would an OTEC manufacturing enterprise. On the other hand, OTEC has no impact on the use of land resources which is a great advantage for Puerto Rico. The economic attractiveness of these two alternatives, plus the particular advantages of each alternative point towards a judicious and balanced decision to explore both alternatives equally.

Electricity generated from wind power generators, the other alternative studied, is shown to be not economically competitive (by a factor of 2) with electricity produced from coal plants, but it is capable of producing electricity cheaper than oil burning power plants. No storage system was considered in the economic analysis of wind power generation systems for central power stations. This would make the wind power system even more expensive. The Study therefore, shows the central wind power system to be switable for fuel oil displacement, but not as an economically viable base (with storage) energy system.

The multiplying beneficial economic effects of reducing oil imports by the use of renewable energy alternatives is analyzed in Section 5 of the Study. Figure 1.2.1 "Total Levelized Generation Costs of Alternatives" illustrates the predicted production cost of electricity from the alternatives considered. The levelized cost indicated is the "average" cost during the lifetime of the facility with the inflation of operating costs and fuel costs taken into consideration. This levelized cost is plotted against the start-up year, i.e. the year that the facility will start commercial operation. The later a facility is commissioned, the higher are the investment charges due to inflationary factors. However, once a facility is commissioned, the annual investment charges for that facility are not penalized with inflationary factors since the money is supposed to be "sunk" at a specified and fixed bond interest rate. Operation and maintenance charges as well as fuel charges, if any, will continue to escalate during the lifetime of the plant. These charges are taken care of by the levelizing factor.

FIGURE 1.2.1


Total Levelized Generation Costs of Alternatives
For Electrical Energy Production in P.R.
All Costs escalated at 5 1/4% / Yr. except Fuel Oil which is
escalated at 9%/Yr. and Yellow Cake in curve 2 at 7 1/4 % / Yr.
TOTAL COST OIL PLANT
FUEL OIL COST COMPONENT
WIND *
PHOTOVOLTAIC
OTEC
COAL
BIOMASS
NUCLEAR 2
1
* Wind energy alternative (without storage) shown for comparative purposes with Fuel Oil Cost component curve.
TOTAL LEVELIZED COSTS (mills / Kwh)
10,000
9
8
7
6
5
4
3
2
1000
90
80
70
60
50
40
30
20
100
10
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year

The prediction of investment charges for alternatives that are not commercially available and for which no cost investment experience has been accumulated is based mainly on the use of industry learning curve cost predictions and market sales predictions made by the Department of Energy (DOE).

Chapter 5, "Socio-Economic Analysis", contains assessments of the impact of oil price increases on Puerto Rican industrial sectors and of the impact of employment and productivity outputs for two selected alternative energy sources.

Oil price increases will impact severely on the economy of Puerto Rico. Costs increases to industries such as cement, electricity production, construction, mining, alcoholic beverages, transportation and business services were tremendous. The results show that the largest impact is in the important industries in terms of output generation and job creation. This study shows that, all prices constant, the increase in oil prices from 1973 to 1979 (assuming a conservative price of $21.00 per barrel of crude in fiscal year 1979) will induce or have already induced an increase of more than 130% in an estimated producers price index (excluding industry mark-ups). This implies double digit inflation even when there is no increase in other prices. This increase has resulted in an estimated loss of 58,000 jobs and $1,328.2 million in productivity. The prospects for the next five years (to the end of 1984) look no better. The failure to establish a vigorous and aggresive research and development program on energy alternatives for Puerto Rico does not hold any hope for an improved energy situation in the near future.

Nevertheless, the second part of the socio-economic study in chapter 5 was based on the assumption that such a vigorous and aggresive research and development program had been put into action and that the Biomass and OTEC alternatives had been made economically competitive for the time predicted in this study. The impact on employment and output productivity of these two energy alternatives was evaluated by the use of Leontief's open input-output matrix mode. Since the price index structure of 53 economic sectors made by the Puerto Rico Planning Board is based on 1972 prices, that year was used as a reference basis.

For two 300 MW each Biomass Plants and one 250 MW OTEC power plant the study indicates an increase in employment of 67,145 workers and an increase in productivity of $1387 millions. This assume that the reduction in imports will improve the balance of trade, which in turn will increase domestic final demand. The unemployment rate, with other factors constant, could be reduced by about 7% from its 1979 level.

The halt placed on the rising production costs of goods and services (including electricity) from higher fuel oil costs was not taken into consideration in the above result. As mentioned earlier, the impact of higher petroleum costs from 1972 to 1979 has been estimated to have caused the loss of 58,000 jobs and $1328.2 millions in productivity. When both factors are taken into consideration, the implications to the socio-economic well being of Puerto Rico are far-reaching. The dollars spent today by the Puerto Rico Government in a significant R&D program for energy alternatives will show important results on the socio-economic picture. Adequate attention has not been given to this subject up to the present time.

In general, the analysis presented in this study is unique because it focuses on the time schedules and programs required to advance energy alternative systems from economical and commercial points of view.

1.3 ELECTRIC POWER SCENARIOS

Based on these economic analyses, alternative energy scenarios can reasonably be prepared for the rest of the century. Corresponding R&D programs and funding requirements can be developed on a well planned, timely basis.

From the present state of development of the various technologies and from the predicted potential of the various alternatives to compete economically with coal, the following program is envisioned:

1. <u>Biomass Program</u>

   A strong program is required to make the first (300-450 MW) power plant operational by 1986.

2. <u>OTEC Program</u>

   An aggresive program is needed to make the first experimental plant (40 MW) operational by 1985 and first commercial plant (250 MW) operational by 1991.

3. <u>Photovoltaic Program</u>

   A dynamic program is needed so that a large demonstration project can be placed on operation by 199[illegible].

4. <u>Wind Power Turbine Generators</u>

   A program coupled with the operational experience of Culebra's Wind Turbine is required so that a 12.5 MW wind power turbine farm can be placed in operation by 1988, for fuel oil displacement.

Based on estimated needs for additional electrical generation capacity as described in Section 2, a possible scenario has been prepared based on the energy alternatives with economic potentials determined by the Study. This scenario is indicated in Table 1.3.1. The scenario fits approximately the base load generation requirements described in Table 2.1.5b of Section 2. No attempt has been made to substitute existing fuel oil generating plants with energy alternative systems, but rather an ambitious scenario is shown allocating new generation requirements to the renewable energy alternatives that are economically competitive with coal.

As seen from Table 1.3.1, three coal burning plants, one with a 300 MW capacity in 1985 and two with 400 MW capacity each for 1989 and 1990 are included in the scenario. It is estimated that biomass burning plants can be placed in operation as early as 1986 and 1987. No additional biomass plants are indicated because agriculture policies

TABLE 1.3.1
SCHEDULE OF PROPOSED SCENARIOS PROGRAM OBJECTIVES
ELECTRIC PLANTS CAPACITY

Year	Biomass	OTEC	Photovoltaic	Wind	Coal
1980-84	------	-----	------	200KW	-----
1985	------	1-40MW	------	------	1-300MW
1986	1-300MW	-----	------	------	-----
1987	1-300MW	-----	------	------	-----
1988	------	-----	------	12.5MW	-----
1989	------	-----	------	------	1-400MW
1990	------	-----	------	------	1-400MW
1991	------	1-250MW	------	------	------
1992	------	1-250MW	------	------	------
1993	------	------	1-250MW	------	------
1994	------	10250MW	------	------	------
1995	------	------	1-250MW	------	------
1996	------	------	------	------	------
1997	------	------	------	------	------
1998	------	1-500MW	------	------	------
1999	------	1-500MW	------	------	------
2000	------	------	------	------	------

are undefined at this time. The two 300 MW biomass plants will require the planting and harvesting of approximately 75,000 acres of land, about the land acreage actually devoted to sugar cane in Puerto Rico. Coal and biomass plants should be designed to burn either fuel.

No more than 500 MW of power from photovoltaics is shown in the scenario because land usage policies are undefined at present. It is estimated that the two 250 MW photovoltaic installations will require approximately 10,000 acres of land. To generate with photovoltaics all the electricity produced in 1979 in Puerto Rico a total land area of approximately 100 km square or 25,000 acres would be required.

A wind power farm also has the same type of land requirements. The 12.5 MW wind power installation which is evaluated in the Study will require approximately 3000 acres. For these reasons the scenario depends heavily on the OTEC alternative. However, not all the efforts are placed on this alternative because it still has many questions to be answered. The scenario does not present any fixed alternative to be followed, but rather provides a reference alternative on which to base the requirements for R&D Programs.

Table 1.3.2 represents the possible savings in equivalent millions of barrels of oil that can be achieved with the proposed scenario.

Table 1.3.3 illustrates the estimates of energy requirements for Puerto Rico to the year 2000 under the present socio-economic structures with the absence of a strong R&D program on alternate energy sources. A second scenario with lesser consumption projections is calculated in Chapter 2. However, the higher consumption scenario represented in Table 1.3.3 reflects a more difficult situation.

The total fuel oil consumption for electrical generation between the year 1985 and the year 2000 from Table 1.3.3 is 881.9 million barrels. The savings proposed by the scenario indicated in Table 1.3.2 represent only 22% of the energy savings during the period. This further indicates that the energy situations is so dependent on oil that heroic efforts are required to make even a slight reduction in oil importation during the present decade.

TABLE 1.3.2

POSSIBLE EQUIVALENT MILLIONS BARRELS OF OIL

SAVED WITH PROPOSED SCENARIO AT 75% CAPACITY FACTOR

(Million Barrels)[a]

Year	Biomass	OTEC	Photovoltaic	Wind[b]	
1980-84	-----	-----	-----	-----	
1985	-----	.438	-----	-----	
1986	3.285	.438	-----	-----	
1987	6.57	.438	-----	-----	
1988	6.57	.438	-----	.09	
1989	6.57	.438	-----	.09	
1990	6.57	.438	-----	.09	
1991	6.57	2.74 [c]	-----	.09	
1992	6.57	5.48	-----	.09	
1993	6.57	5.48	2.74	.09	
1994	6.57	8.22	2.74	.09	
1995	6.57	8.22	5.48	.09	
1996	6.57	8.22	5.48	.09	
1997	6.57	8.22	5.48	.09	
1998	6.57	13.70	5.48	.09	
1999	6.57	19.20	5.48	.09	
2000	6.57	19.20	5.48	.09	
Totals:	95.265	101.308	38.36	1.17	236.103

(a) Assuming 600 kwh/BBL .

(b) Energy calculated from available wind and turbine characteristics.

(c) Assumes 40MW OTEC Exp. is shut down.

TABLE 1.3.3

ESTIMATES OF PUERTO RICO'S ENERGY REQUIREMENTS TO THE YEAR 2000 UNDER PRESENT SOCIO–ECONOMIC STRUCTURES WITH AN ABSENCE OF STRONG R&D PROGRAMS ON ALTERNATE ENERGY SOURCES

Year	Million Barrels of Oil Imports For				Estimated Unit Price $/BBL [d]	Total Cost ($ Millions)
	Electrical Energy [a]	Gasoline & Diesel [b]	Industry & Other [c]	Total		
1976	21.7	17.6	26.3	64.7		
1977	23.0	18.2	21.5	62.7		
1978	24.5	16.5	23.9	65.0		
1979	26.0	17.0	25.1	68.1	14.70	1001.
1980	27.5	17.9	26.3	71.7	16.78	1203
1981	29.0	18.5	27.7	75.2	19.17	1442
1982	29.7	19.0	29.1	77.8	21.90	1704
1983	31.9	19.8	30.5	82.2	25.00	2055
1984	33.6	20.5	32.0	86.1	28.55	2458
1985	35.3	21.0	33.6	89.9	32.70	2939
1986	36.7	21.4	35.3	93.4	36.29	3390
1987	37.9	21.9	37.1	96.9	40.28	3903
1988	42.2	22.5	38.9	103.6	44.72	4633
1989	44.8	23.1	40.9	108.8	49.60	5396
1990	47.4	23.6	42.9	113.9	55.00	6266
1991	50.8	24.0	45.1	119.9	58.75	7044
1992	53.4	24.5	47.3	125.2	62.75	7856
1993	56.0	25.1	49.7	130.8	67.00	9295
1994	59.1	25.7	52.2	137.0	71.50	9796
1995	62.0	26.0	54.8	142.8	76.50	10924
1996	65.0	26.4	57.5	148.9	81.12	12078
1997	68.1	26.7	60.4	155.2	86.00	13347
1998	71.5	27.4	63.4	162.3	91.15	14793
1999	74.1	27.9	66.6	168.6	96.62	16290
2000	77.6	28.1	69.9	175.6	102.6	18016
Total						$155,829

(a) Statistical Correlations between population and GNP, and between GNP and Electrical Energy Generation. Correlation 99%.

(b) Gasoline Consumption growth projected conservatively between 2 1/2 – 3% per year vs. 6.6% actual growth.

(c) Industrial needs projected at 5% per year growth.

(d) Fuel oil prices escalation indicated is approximately 1980-85: 14.3%/year; 1985-90: 11% year; 1990-95: 6.8%/year and 1995-2000: 6% year.

1.4 NON ELECTRIC ENERGY CONSIDERATIONS

The three principal non-electrical generation energy alternatives from a scale viewpoint which are addressed in the Office of Energy Document "Política Energética de Puerto Rico" are:

a. Solar industrial steam and hot water
b. Fuel synthesis
c. Conservation measures, mainly in transportation.

Preliminary considerations have been given to these topics in CEER document X-31, "Preliminary Report on R&D Program Needs for Energy Alternatives in Puerto Rico" (June 1979)[2].

It is estimated in the CEER-X-31 report that ethanol and industrial solar steam can play a substantial role in reducing oil fuel imports. An electric generation project based on photovoltaics can be designed as a co-generation project (solar steam production and electricity). It has been estimated that a 250 MW electric photovoltaic cogeneration project can produce enough industrial steam to save the equivalent of 3.7 million barrels of oil per year.

Industrial steam can be produced separately by adequately designed solar concentrators. It has been estimated that solar steam production equivalent to the savings of six million barrels of oil per year can probably be achieved with a strong R&D effort.

Ethanol is a potential help for the transportation industry. A proposed CEER project on ethanol to be undertaken at the UPR Rum Pilot Plant has been submitted to DOE. An ethanol project can be economically designed as a cogeneration facility to provide steam for its own needs and to generate electrical energy from baggase. Preliminary estimates indicate that a savings of 7.5 million barrels of oil per year can be achieved with ethanol production.

Energy conservation measures in the transportation industry require special attention. It is difficult, however, to assign specific figures to this program, but it could reach savings as high as 5-10% on oil imports.

Table 1.4.1 indicates the combined total savings which could be obtained through an aggresive R&D effort. In the electrical sector the reduction in fuel oil barrels equivalent is over 26%, and for all sectors the fuel oil barrels equivalent reduction is approximately 21%. When conservation measures in transportation are added, probably a 5-10% additional reduction could be achieved.

All of the above indicate that a strong R&D effort in Puerto Rico can achieve an approximately 1/3 reduction in oil dependence while still maintaining the same level of economic development.

TABLE 1.4.1

POSSIBLE MILLION BARRELS OIL EQUIVALENT SAVED
WITH PROPOSED SCENARIOS AND A STRONG R&D EFFORT

	Electrical Generation				Non Electrical			
Year	Biomass	OTEC	Photovoltaic Elec.	Wind	Gasohol Fuel	Gasohol Cogen (Electric)	Solar Industrial Steam	
1985	-----	.438	------	------	------	------	------	
1986	3.285	.438	------	------	1.87	1.24	------	
1987	6.57	.438	------	------	1.87	1.24	----	
1988	6.57	.438	------	.09	3.74	1.25	2.0	
1989	6.57	.438	------	.09	3.74	1.25	2.0	
1990	6.57	.438	------	.09	5.61	3.7	4.0	
1991	6.57	2.74	------	.09	5.61	3.7	4.0	
1992	6.57	5.48	------	.09	5.61	3.7	4.0	
1993	6.57	5.48	2.74	.09	5.61	3.7	4.0	
1994	6.57	8.22	2.74	.09	7.48	5.0	4 0	
1995	6.57	8.22	5.48	.09	7.48	5.0	6.0	
1996	6.57	8.22	5.48	.09	7.48	5.0	6.0	
1997	6.57	8.22	5.48	.09	7.48	5.0	6.0	
1998	6.57	13.70	5.48	.09	7.48	5.0	6.0	
1999	6.57	19.20	5.48	.09	7.48	5.0	6.0	
2000	6.57	19.20	5.48	.09	7.48	5.0	6 0	
Totals:	95.265	101.308	38.36	1.17	86.02	54.78	60.0	436.9

1.5 RESEARCH AND DEVELOPMENT (R&D) EFFORT REQUIREMENTS

In order to make possible the prompt development of alternative energy sources to fit a scenario similar to that proposed in the previous sections, appropriate research and development (R&D) efforts are required. Such R&D efforts must be coupled with the corresponding demonstration projects to make timely development possible.

The minimum basic scientific and technical information necessary to address the example scenarios proposed to fit the Office of Energy document on Public Energy Policy are described in the document CEER-55 "Proposed Five Year Plan-Energy and Environmental Programs," Draft No.1, December 1979.[52] A summary of the basic research program described in above document is given in Table 1.5.1. To address the demonstration projects themselves, R&D funds in the order of 5-7% of the total capital investment would be required. This figure falls within the historical percentage of capital investment assigned for R&D by large companies such as Corning Glass.

The R&D for the OTEC demonstration project has been increased to double (12.5%) the indicated historical requirement in order to provide for expensive marine work and to make the proposition for securing balance of funds from DOE more attractive. Table 1.5.2 summarizes the R&D requirements for large demonstration projects.

The funding for the basic minimum research program summarized in Table 1.5.1 must be borne by the government. Table 1.5.2 illustrates the capital investment requirements for large demonstration projects. Table 1.5.3 illustrates the R&D funding requirements for the demonstration projects shown in Table 1.5.2. It is assumed that the R&D funds described in Table 1.5.3 are included within those of Table 1.5.2. The funding for the R&D for large demonstration projects as described in Table 1.5.3 can be borne in part by the user institution project budget, by a consortium of private concerns, and/or in part by the government. The discussion of cost sharing formulas is outside of the scope of this work.

TABLE 1.5.1

TOTAL R&D EFFORT REQUIREMENTS FOR GOVERNMENT FUNDING
(1980–Thousand Dollars)

	1982	1983	1984	1985	1986	Total
I. OTEC*	2,200	2,800	3,200	3,200	3,400	14.800
II. BIOMASS*	4,150	2,130	2,380	2,380	2,280	13,320
III. SOLAR ENERGY*	828	995	1,235	1,507	1,710	6,275
IV. GASOHOL	220	220	225	240	-----	905
V. TRANSP. CONSV.*	625	367.5	633	570	387.5	2,583
Total:	8,023	6,512.5	7,673	7,897	7,777.5	37,883

* Funding for these programs is the same as in CEER 5 Year Plan (Draft 1). The revised CEER 5 Year Plan (Draft 2) indicates a considerably reduced program budget due to economic restraints. Such a reduced program budget is not considered adequate for an agressive attack on the energy problem.

TABLE 1.5.2

CAPITAL INVESTMENT IN DEMONSTRATION PROJECTS

(With R&D Efforts in Table 1.5.1)
(Private industry, government corporations, consortiums,
(and government sponsored business investments)

Project	Capacity	Scheduled	Investment Cost (million dollars)/Yr	
OTEC [a]	40MW	1985	$ 209.2	(1980)
OTEC (	250MW	1991		
BIOMASS[a]	300MW	1986	168.	(1978)
PHOTOVOLTAIC[a]	250MW	1993	1,126.	(1980)
WIND	ON SCHEDULE			
ETHANOL PLANT[b] FOR GASOHOL	100 millions gals. per year Ethanol	1986	225.[c]	(1978)
STEAM COGEN[b]				
a) With Ethanol Plant	33 million pounds per day 350° F Steam	1986	250.	(1978)
b) With Photov.[b] Plant	2.2×10^{13} Btu/year or 60 million pounds per day 350° F Steam	1993	440.	(1978)

(a) From Chapter IV this report

(b) From CEER X-31

(c) Using existing sugar mills, costs might be half of those indicated.

TABLE 1.5.3

DEMONSTRATION PROJECTS R&D BUDGET ESTIMATES

(Approximately 5-7% of Capital Investment for R&D except OTEC)

ELECTRICAL

Project	Capacity	Oper. Date	Cost (Millions)	1980-82	1983	1984	1985	1986	1987	1988	1989	1990	Total
PHOTOV.	250MW	1995	1,126(1980$)	-----	.54	.81	1.26	2.72	5.88	7.95	8.55	21.36	
OTEC	40MW	1985	209.2(1980$)	11.0	4.0	5.25	5.90	----	----	----	----	----	
BIOMASS	300MW	1986	168.0(1978$)			NEAR CONVENTIONAL SYSTEM SAME AS FOR BASIC PROGRAM							
WIND	12.5MW	1986	----	----	----	----	----	----	----	----	----	----	

NON-ELECTRICAL

Project	Capacity	Oper. Date	Cost (Millions)	1980-82	1983	1984	1985	1986	1987	1988	1989	1990	Total
ETHANOL	100 million gals/Yr $ millions	1968	225 (1978$)	2.97	2.04	2.21	1.59	1.28	.93	.50	.54	.58	
SOLAR STEAM	33 million lbs/day steam (350° F)	1988	250 (1978$)	.35	.35	.75	1.5	4.25	1.8	2.0	1.0	1.0	

1.6 CONCLUSIONS AND RECOMMENDATIONS

1.6.1 Conclusions

1. Biomass promises to be the most economically attrative short term energy alternatives for central electric stations with costs lower than coal power plants as early as 1985. The needed technological developments for biomass systems require the least effort of all the alternatives.

2. OTEC and Photovoltaics promise to be competitive with coal central power plants with costs similar or slightly higher (less than 1%) than predicted costs of electricity from coal plants as early as 1994. Both alternatives require substantial technological advancements.

3. Wind energy systems without storage can be used economically for fuel oil displacement, but they are not economically competitive with coal power plants.

4. Nuclear power will continue to be the lowest cost power for the rest of the century and beyond.

5. The socio-economic implications for Puerto Rico for the development of local alternative energy sources indicate benefits in the range of billions of dollars of annual increases in productivity and reductions in unemployment by over 7%.

1.6.2 Recommendations

1. Strong R&D programs should be implemented to make possible the use of biomass in planned coal power plants by the mid 1980's.

2. OTEC and Photovoltaics R&D program efforts should be developed to make these alternatives economically viable in the Puerto Rico scenario by the mid 1990's.

3. Solar steam and other energy conservation programs such as ethanol production for gasohol, hybrid vehicle research programs, transportation management and policy studies should receive detailed consideration.

4. Energy Analysis studies should be continued and updated yearly and should be based on the latest economic trends. The equations developed in this work should be programmed for computer parametric and sensitivity studies. The summary of the results with comparisons of previous year's analysis should be published.

SECTION 2

LONG RANGE FORECAST OF PUERTO RICO ENERGY NEEDS

Section 2

LONG RANGE FORECAST OF PUERTO RICO'S ENERGY NEEDS

2.1 ELECTRICAL ENERGY FORECAST

2.1.1 Introduction

The problem of forecasting long range estimates of energy use is a difficult task because of all the uncertainties involved in the development of new technologies and because of changing habits which will affect the estimates considerably. An attempt has been made to forecast for a period in which present embryonic technologies could be extrapolated in a qualitative sense. A 40 year period, to the year 2020, is believed to be long enough to provide for such an extrapolation and to provide energy planners with an overview of the next four decades for the focusing of energy alternatives.

CEER interest is mainly in the energy and fuel alternatives scenarios which are required to power socio-economic development in Puerto Rico; therefore the forecasting has been restricted to the total electrical energy generation which is responsible for the fuel consumed in the electrical plants.

Classical statistical regression analyses were used for predicting electrical power generation requirements.* A simple approach was adopted so as not to complicate the prediction with complex relations and hypotheses. The prediction for non-electrical energy requirements such as gasoline and industrial fuel oil requirements were based on an assumed per cent growth per year considering historical consumptions.

*Statistical Methods for Decision Making, W.A. Chance 1969. IRWIN-DORSEY LMTD., Mokeleton, Ontario

The prediction of electrical energy generation requirements is based on two main factors:

a. Population
b. Economic welfare or per capita income of the population.

These factors were statistically analyzed before the predictions were made. After the mathematical relationships were established, judgements of past experiences and insights into new technologies and changing habits were considered so that the most appropriate relationships could be selected.

The energy prediction will be based simply on a correlation between the total GNP at constant prices and the electrical energy consumed. The GNP will be predicted from the product of population predictions, times the GNP/capita prediction at constant prices. Populations have already been predicted by the Planning Board up to the year 2000 and the GNP predicted to the year 1983. Our predictions will be, therefore, somewhat uncertain for the period 2000-2020.

2.1.2 <u>Population</u>

Population is a very sensitive variable in the prediction of energy needs. Different government programs, welfare programs, and social and religious attitudes may influence population growth to a certain degree. Meléndez* indicates that the growth rate of the economy of a nation responds better to a moderate increase in the population than to a rapid growth rate as is the present case in Puerto Rico where population is doubled in less than 35 years,

*Conferencia sobre Economía y Población, Dr. James A. Santiago Meléndez Serie de Conferencias y Foros: Núm. 4 Departamento de Economía, Universidad de Puerto Rico, Río Piedras, Puerto Rico.

or to a slow population growth rate such as doubling of population every 200 years. A doubling time in the order of 50 years is considered adequate to help economic growth.

A rapid population growth rate causes severe impacts on the nation's substructure and on the balances of resources, and requires higher investments from outside sources. On the other hand, a very slow population growth rate can create a problem when the population matures and there are not enough youths to replace those leaving the labor force. This has been experienced in certain areas of Japan. However, the concept of optimal population growth is difficult to determine because of the many factors involved.

The Planning Board has predicted a population for Puerto Rico of 4,675,000 for the year 2000. City by city predictions have been made up to the year 2000.

The population of Puerto Rico in 1960 was approximately one half of that predicted for the year 2000, thereby indicating a doubling of the population in this 40 year period.

Using a linear regression analysis on historical population data going back to 1962 and using the Planning Board predictions to the year 2000 as input data to the regression analysis in which the total number of input points is 22, the following equation results:

$$y_p = 2166.9 + 65.05\,x$$

where y_p = population in thousands,

x = year referred to 1960 i.e., year less 1960.

Coefficient of determination of above equation, $r^2 = 0.98$, indicating a significant correlation of 99%.

The predicted population calculated in this manner for the year 2020 will be 6,070,110. The approximate doubling time of the present estimated population of 3,338,000 using the above linear relationship is 51.3 years. This is within the satisfactory range for an adequate economical growth as defined by Meléndez.

An exponential regression of population was also attempted. The exponential relation gave the same degree of correlation and coefficient of determination as the linear relationship but the doubling time for the present population was 35 years. Since this should not be the government policy, it was discarded. The exponential relationship was: population equals to 2308.66, times "e" elevated to the exponent 0.02x, x having the same meaning as before.

The predicted population for the year 2020 with this exponential relation was 7,300,580. This was discarded in favor of the more appropriate linear correlation indicating a 6,070,110 population in the year 2020.

The predicted population data to be used in the study is given in Table 2.1.2

2.1.3 Economic Welfare

It will be assumed for the study that the overall economic welfare of the country will be maintained and improved. The Gross National Product (GNP) per capita in constant dollars is a measure of this index. Therefore, if the total economic welfare of the country is to be improved, the GNP per capita in constant dollars should

TABLE 2.1.2

POPULATION BY LINEAR REGRESSION MODEL

Year	Population (millions)
1979	3.47
1980	3.53
1981	3.65
1982	3.72
1983	3.78
1985	3.92
1990	4.26
1995	4.52
2000	4.67
2005	5.09
2010	5.42
2015	5.75
2020	6.07

reflect a small or moderate yearly increase. The total GNP in constant dollars should then reflect a yearly increase in the rate of GNP per capita at least equal to the population growth rate. The total GNP in current dollars should further reflect any increase due to the inflation price factor.

The Gross National Product (GNP) sums up the economic activities of the country in terms of the production of goods and services. The total consumption of electrical energy by all sectors of the economy is very sensitive to this variable and can therefore be satisfactorily correlated. Statistical tests can determine how good the correlation is.

The Planning Board has predicted total GNP values in current dollars up to the year 1983 as indicated in Table 2.1.3 below.

TABLE 2.1.3

ECONOMIC INDEXES
(Planning Board Prediction of GNP)
(Current Dollars in Millions)

	1979	1980	1981	1982	1983
Current $	9835.0	10750.0	11693.0	12710.0	13795.0
Constant $	4047.4	4298.8	4549.7	4814.0	5090.1

Constant dollars were estimated by assuming a 10 point increment in the price index for the year 1979 and a 7 point increment for each of the remaining years. The 1978 GNP price deflator factor relative to 1954 (the year that the Planning Board used to reflect constant prices) is calculated to be 233 from the Planning Board reports on current and constant dollars data. Using the predicted populations for the years 1979-83, the above GNP in constant dollars was converted to GNP per capita.

The data together with historical data back to 1962 were then analyzed by statistical methods. Four types of regression analyses were tried, including linear, exponential, logarithmic and power. The best fit correlated with a 97.5% correlation coefficient or 95% coefficient of determination. This fit was: $y = 546.87\ x^{.27}$, where: y = GNP/capita in constant 1954 dollars, x = year - 1960.

Predicted values with above equation indicate yearly improvements in GNP/capita at constant dollars of the order 0.5 to 1.5% which is considered adequate and on the low side.

The predicted GNP per capita at constant dollars was multiplied by the predicted population to obtain the total predicted GNP at constant dollars.

2.1.4 Electrical Generation

The total electrical generation was correlated with the total GNP and excellent correlations resulted.

1. Linear Correlation: Coeff. of determination 98%; doubling
   Time: 20 years
2. Power Correlation : Coeff. of determination 98%; doubling
   Time: 11 years
3. Log Correlation : Coeff. of determination 97%; doubling
   Time: over 40 years

4. Exp. Correlation : Coeff. of determination 93%; doubling

Time : 5 years

A statistical test indicated excellent correlations on all of these.

Of all of the above correlations the log and exponential correlations were discarded because of poorer correlations relative to the linear and power correlations, and because of the respective very slow and very fast growth rates. The linear and power regression analyses represent reasonable selection projections.

Electric power generation doubled every five years from 1960 to 1970. During the present decade it has doubled every eight years. A doubling time of 11 years for the 1980-90 decade is therefore, not unreasonable. Doubling times of the order of 20 years might be appropriate beyong the year 2000, if the same level of technology and habits are maintained. However, new technologies and new consumer goods will probably impact beyond present expectations. One example could be the development of urban electrical vehicles which require nightly battery charging. On the other hand, energy conservation measures will cancel these additional needs in part. The development of new technologies for producing electrical power from renewable sources might bring costs down and cause an increase in demand. Therefore, the power fit represents an adequate description of future electrical generation production.

The power fit is given by, KWHR gen = (0.0012294) $(GNP)^{1.96} \times 10^{6}$ where the unit for GNP is million dollars at 1954 constant dollars.

Table 2.1.4 indicates the correlation data for population, GNP and Electrical Energy. The figures given for electrical generation are comparable to PREPA forecasts, but they tend to be low estimates. Power Technologies prediction for the year 2000[a] is $38,261 \times 10^6$ KWHR generation which is comparable to our prediction of $42,910 \times 10^6$ KWHR within 5% difference.[b]

The prediction of electrical energy generation for the year 2020 shown in Figure 2.1.4, using the above selected relationship, is 89,120 million kw-hrs, which is slightly over six times the current electrical energy generation.

The linear fit is given by KWHR gen = $-6709.93 + 5.21$ (GNP) $\times 10^6$ where GNP is in millions at 1954 constant dollars. The last column of Table 2.1.4 indicates the kwhr prediction with the linear correlation.

Energy planners and researchers must, therefore, think of energy alternatives for Puerto Rico in a scale as large as six times today's demand by the time when most energy alternatives being researched today could be highly competitive economically. Electrical energy is used around the clock; hence, large storage systems on direct solar derived energy must be looked at in perspective.

(a) "Long Range Sales Forecasting Study for the Puerto Rico Water Resources Authority," Kevin A. Clements and Robert de Mello, Power Technologies, Inc. Schenectady, N.Y. May, 1976.

(b) It should be mentioned that recent experience has shown lower growth rates in electrical energy demand than those used in this study, however, considering the long lead times necessary to place new units in operation (7 to 10 years) we have opted to use the worst case in order to have a safe reference base.

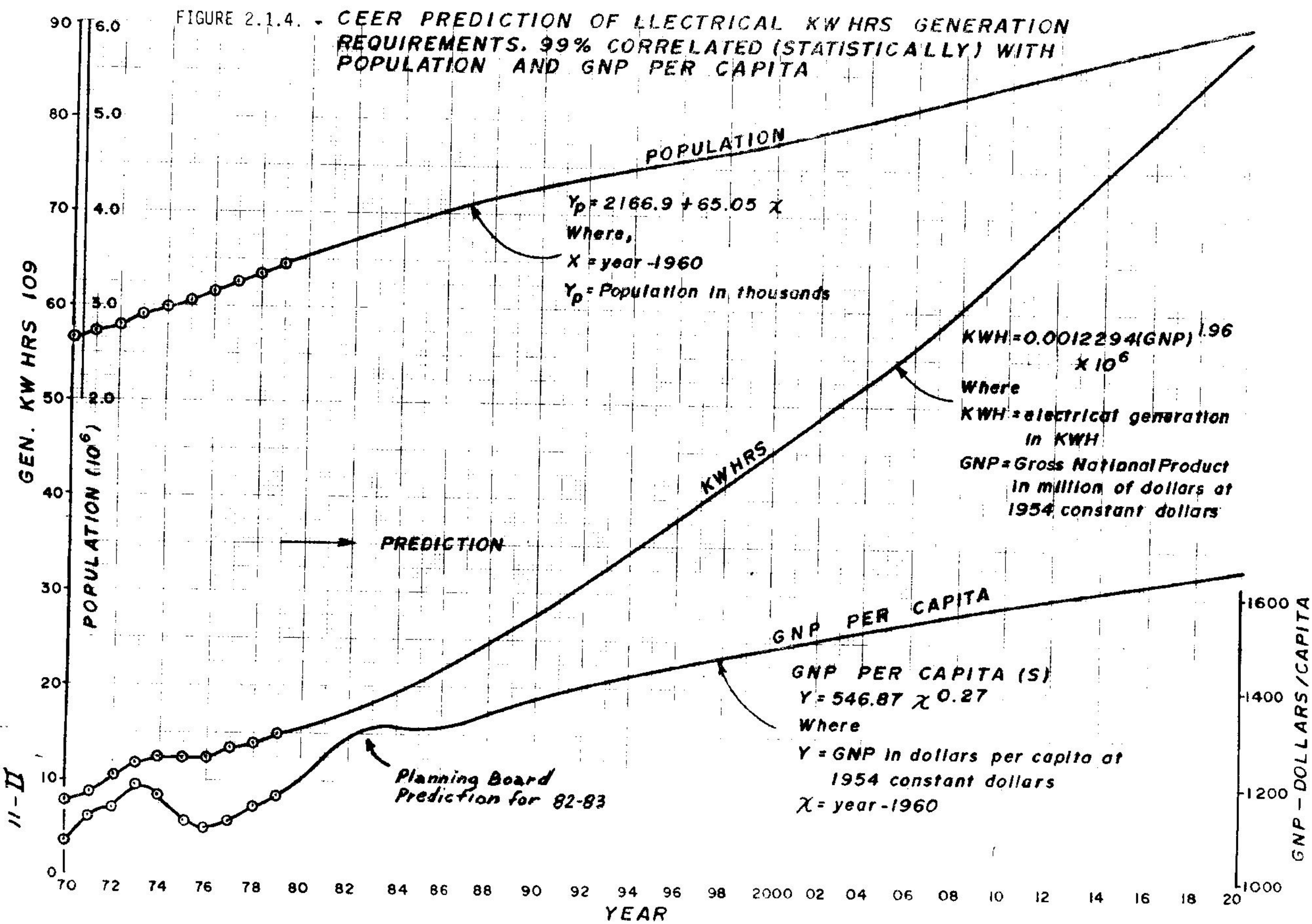
TABLE 2.1.4

GNP, POPULATION AND ELECTRICAL PRODUCTION CORRELATION DATA
(Constant Prices,/1954 Base)

Fiscal Year	GNP/capita $/capita	Population (thousands)	GNP ($millions)	Power Fit Electric Prod. 10^6 KW-hr	Linear Fit Electric Prod. 10^6 KW-hr
1962	694.0	2426	1683.9	2570.7	
1963	736.0	2473	1820.7	2934.5	
1964	768.0	2523	1938.9	3403.2	
1965	817.0	2568	2099.2	3819.2	
1966	861.0	2603	2240.6	4429.8	
1967	892.0	2623	2239.4	5040.7	
1968	927.0	2650	2455.3	5770.9	
1969	1000.0	2685	2684.0	6654.5	
1970	1070.0	2711	2901.4	7539.5	
1971	1120.0	2747	3075.6	8513.3	
1972	1139.0	2823	3215.9	10228.0	
1973	1186.0	2910	3450.3	11778.0	
1974	1168.0	2991	3493.6	12329.3	
1975	1113.0	3076	3424.7	12208.9	
1976	1101.0	3167	3487.3	12349.8	
1977	1116.0	3266	3644.4	13290.4	
1978	1150.0	3338	3837.5	13755.9	
1979	1166.4*	3470	4047.4*	14611.2	
1980	1217.8*	3530*	4298.8*	15429.6	
1981	1246.52*	3650*	4549.7*	16307.2	
1982	1294.1*	3720*	4814.0*	17197.5	
1985	1310.9	3920*	5138.7	23684.0	20047.17
1990	1377.5	4260*	5868.15	30734.0	23845.40
1995	1436.4	4520*	6492.53	37483.0	27096.53
2000	1489.4	4670*	6955.50	42910.0	29507.24
2005	1537.8	5090	7827.40	54106.0	34047.17
2010	1582.5	5420	8577.15	64748.0	37951.10
2015	1624.0	5750	9338.00	76505.0	41912.83
2020	1662·8	6070	10093.20	89120.0	45844.10

* Planning Board Predictions.

FIGURE 2.1.4. - CEER PREDICTION OF ELECTRICAL KW HRS GENERATION REQUIREMENTS. 99% CORRELATED (STATISTICALLY) WITH POPULATION AND GNP PER CAPITA



2.1.5 KW Demand Predictions and Additional Unit Requirements

In order to convert the predicted kw-hr generation into kw peak demands for the purposes of assessing additional unit requirements, a yearly load factor of 77.6% will be used. This is the average load factor recently reported by PREPA. System reserves in order to provide for scheduled maintenance and unscheduled multiple outages could vary between 50% and 75% for an isolated system such as PREPA and as high as 100% for a system with special conditions such as units larger than 10% of system peaks. The ratio of base load units to total system peak should be on the average comparable to the system load factor.

If 50% is used as the reserve margin for the PREPA system and 70% of system generating units is used as a criteria for installing base load units (as is the present condition) a rough indication of PREPA base load units required additions can be determined.

Table 2.1.5b illustrates the calculation of additional base load units for the case of high energy demand scenario obtained through a power correlation. Table 2.1.5c illustrates the calculation of additional base load units for the case of moderate energy demand scenario obtained through a linear correlation. The high energy scenario represents probably an upper limit of energy demand for which some planning attention should be given.

TABLE 2.1.5 (a)

PRESENT BASE LOAD INSTALLED CAPACITY IN THE PREPA SYSTEM (1979)

Unit Ident.	Rated Cap.(MW)ea.	Total Cap.(MW)	Start-Up Date	Retirement Date*
San Juan				
1 to 4	20.0	80.0		Retired
5	44.0	44.0	1956	1991
6	44.0	44.0	1957	1992
7-8	100.0	200.0	1966	2001
9	100.0	100.0	1968	2003
10	100.0	100.0	1969	2004
Palo Seco				
1	82.5	82.5	1960	1995
2	82.5	82.5	1961	1996
3-4	216.0	432.0	1970	2005
SOUCO				
1	44.0	44.0	1958	1993
2	44.0	44.0	1959	1994
3	82.5	82.5	1962	1997
4	82.5	82.5	1963	1998
5	410.0	410.0	1972	2007
6	410.0	410.0	1973	2008
Aguirre				
1-2	450.0	900.0	1975	2010
	Total Capacity (MW)	3058.0		

* A 35 year operating life is assumed.

TABLE 2.1.5 (b)

PEAK LOAD AND NEW BASE LOAD UNIT REQUIREMENTS

High Energy Demand Case (Power Correlation)

Year	Generation KWhr X 10^6	Peak Demand KW X 10^6	Required Inst. Cap. MW	Estimated Previous Inst. Cap.	Required Additional Cap. MW	Required * Base Load Additions MW	Additional Units Required in 5 Yr. Period ending in year indicated
1985	23684	3.484	5226	4200	1026	718	1-40 MW 2-300MW
1990	30734	4.521	6781	5226	1555	1088	2-450 1-250
1995	37483	5.514	8271	6523	1748	1224	2-500 1-250
2000	42910	6.312	9468	8024	1444	1011	2-500
2005	54106	7.959	11938	8636	3302	2311	4-500 1-250
2010	64748	9.525	14287	10218	4069	2848	3-800 1-500
2015	76505	11.254	16881	14287	2594	1816	3-600
2020	89120	13.110	19665	16241	3424	2397	3-800

* Actual base load PREPA capacity as of 1979 is 3058 MW.

TABLE 2.1.5 (c)

PEAK LOAD AND ADDITIONAL BASE LOAD UNIT REQUIREMENTS

MODERATE DEMAND CASE (Linear Correlation)

Year	Generation KWhr X 10^6	Peak Demand KW X 10^6	Required Inst. Cap. MW	Estimated Previous Inst. Cap. MW	Required Additional Cap. MW	Required Base Load Additions MW	Additional Units Required in 5 Yr. Period Ending in Year Indicated
1985	20,047	2.949	4.424	4,200	224	157	1-40 MW 1-100
1990	23,845	3.508	5.262	4,424	838	587	2-300
1995	27,096	3.986	5.979	5,004	975	683	1-250 1-450
2000	27,507	4.341	6.512	5,731	780	546	1-100 1-450
2005	34,047	5.009	7.514	5,680	1,834	1,284	3-450
2010	37,951	5.583	8.375	5,794	2,581	1,807	4-450
2015	41,913	6.166	9.249	8,375	874	612	1-600
2020	45,844	6.744	10.116	9,109	1,007	705	1-600 1-100

2.2 GASOLINE CONSUMPTION PROJECTIONS

A simple, preliminary projection will be made for gasoline and diesel consumption to approximate total future energy requirements. Detailed transportation analyses being performed by Professor Jaro Mayda under other related CEER studies will determine gasoline consumption with greater precision.

Figure 2.2.1 illustrates both the historical and predicted gasoline and diesel consumption in Puerto Rico. Gasoline consumption has been growing at the rate of 6.6% per year. The recent price increases in gasoline and the expected increases will reduce the growth rate considerably. To be on the conservative side, a 2 1/2-3% per year gasoline consumption increase is assumed for the future. This is more appropriate than a regression analysis of historical data because the transportation substructure is changing rapidly to smaller cars and to other more economical modes of transportation.

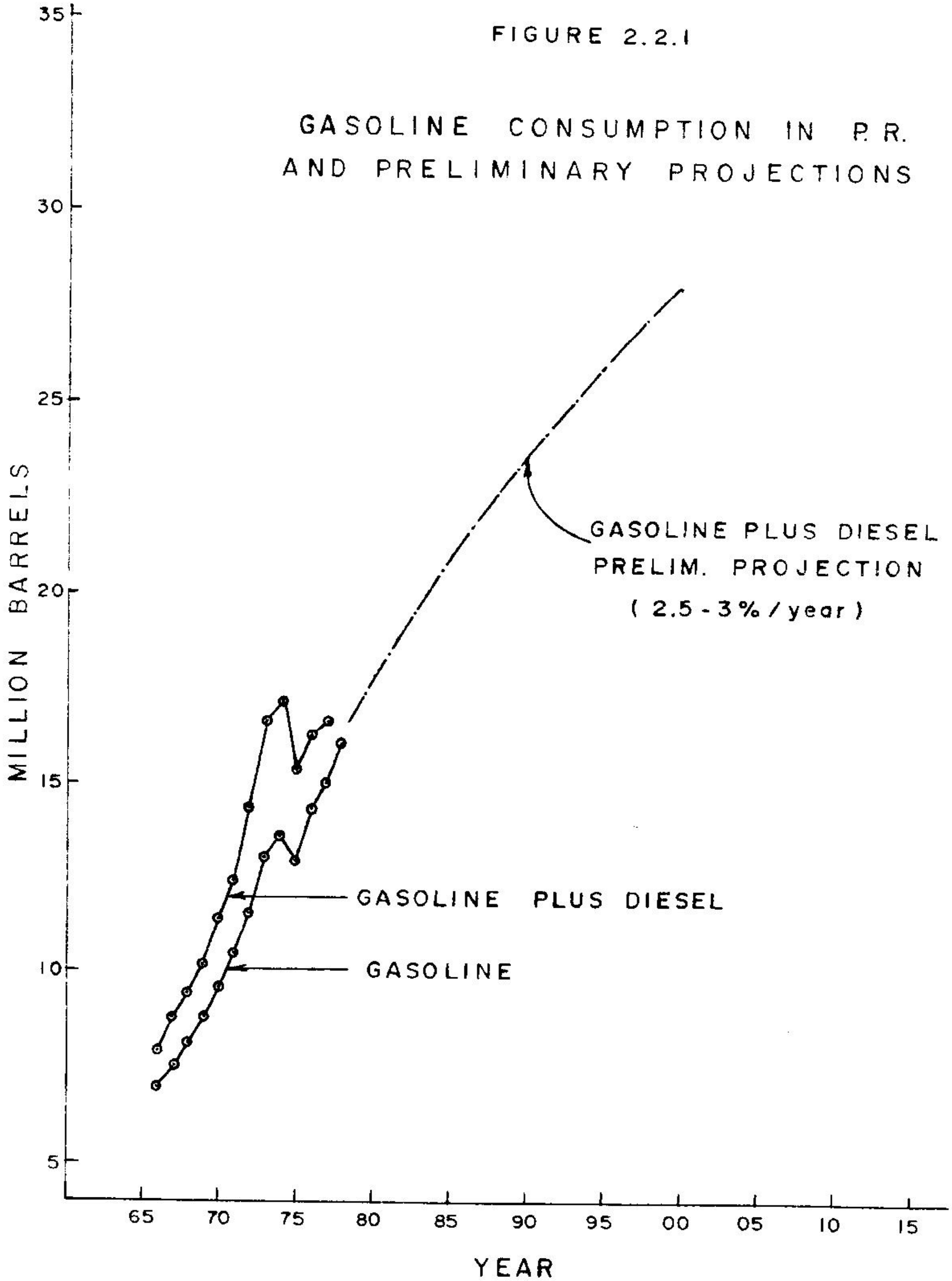


FIGURE 2.2.1
GASOLINE CONSUMPTION IN P.R.
AND PRELIMINARY PROJECTIONS
MILLION BARRELS
35
30
25
20
15
10
5
GASOLINE PLUS DIESEL
PRELIM. PROJECTION
(2.5 - 3% / year)
GASOLINE PLUS DIESEL
GASOLINE
65
70
75
80
85
90
95
00
05
10
15
YEAR

2.3 PETROLEUM CONSUMPTION IN INDUSTRY

A simple analytic projection will be used for the projection of petroleum consumption by the industrial sector in order to predict total needs. Separate CEER studies being performed by Dr. Lewis Smith will predict industrial needs with a higher degree of confidence.

Approximately 15% of the oil consumption in Puerto Rico is used for industrial purposes.

Aromatics petroleum derivatives account for 8.5%, nafta for 4.45%, and the balance is in tars and asphalts, waxes, and ciclohexane. During 1976, 26.3 million barrels of oil were used directly by industry. This figure does not include the fuel used in generating electricity for industry which is accounted for in Section 2.1. The industrial needs for oil will be predicted at 5% per year growth starting from the 1978 level.

2.4 TOTAL OIL REQUIREMENTS

The estimates of the energy requirements for Puerto Rico to the Year 2000 under the present socio-economic structure with some consideration for gasoline price elasticity and the absence of a strong R&D program for energy alternatives is shown in Table 2.2.1

The estimated oil cost indicated in Table 2.2.1 is based on our lowest scenario of predicted oil costs as discussed in Section 3.3.2. Our lowest scenario of predicted fuel oil costs is based on the predictions of PREPA consultant, Arthur D. Little.

TABLE 2.2.1

ESTIMATES OF PUERTO RICO'S ENERGY REQUIREMENTS TO THE YEAR 2000 UNDER PRESENT SOCIO–ECONOMIC STRUCTURES WITH AN ABSENCE OF STRONG R&D PROGRAMS ON ALTERNATE ENERGY SOURCES

Year	Million Barrels of Oil Imports For				Estimated Unit Price $/BBL (d)	Total Cost ($ Millions)
	Electrical Energy (a)	Gasoline & Diesel (b)	Industry & Other (c)	Total		
1976	21.7	17.6	26.3	64.7		
1977	23.0	18.2	21.5	62.7		
1978	24.5	16.5	23.9	65.0		
1979	26.0	17.0	25.1	68.1	14.70	1001.
1980	27.5	17.9	26.3	71.7	16.78	1203
1981	29.0	18.5	27.7	75.2	19.17	1442
1982	29.7	19.0	29.1	77.8	21.90	1704
1983	31.9	19.8	30.5	82.2	25.00	2055
1984	33.6	20.5	32.0	86.1	28.55	2458
1985	35.3	21.0	33.6	89.9	32.70	2939
1986	36.7	21.4	35.3	93.4	36.29	3390
1987	37.9	21.9	37.1	96.9	40.28	3903
1988	42.2	22.5	38.9	103.6	44.72	4633
1989	44.8	23.1	40.9	108.8	49.60	5396
1990	47.4	23.6	42.9	113.9	55.00	6266
1991	50.8	24.0	45.1	119.9	58.75	7044
1992	53.4	24.5	47.3	125.2	62.75	7856
1993	56.0	25.1	49.7	130.8	67.00	9295
1994	59.1	25.7	52.2	137.0	71.50	9796
1995	62.0	26.0	54.8	142.8	76.50	10924
1996	65.0	26.4	57.5	148.9	81.12	12078
1997	68.1	26.7	60.4	155.2	86.00	13347
1998	71.5	27.4	63.4	162.3	91.15	14793
1999	74.1	27.9	66.6	168.6	96.62	16290
2000	77.6	28.1	69.9	175.6	102.6	18016
Total						$155,829

(a) Statistical Correlations between population and GNP, and between GNP and Electrical Energy Generation. Correlation 99%.

(b) Gasoline Consumption growth projected conservatively between 2 1/2 – 3% per year vs. 6.6% actual growth.

(c) Industrial needs projected at 5% per year growth.

(d) Fuel oil prices escalation indicated is approximately 1980-85: 14.3%/year; 1985-90: 11% year; 1990-95: 6.8%/year and 1995-2000: 6% year.

SECTION 3

COST ANALYSIS OF COMMERCIALLY AVAILABLE ALTERNATIVES FOR ELECTRICAL ENERGY PRODUCTION IN PUERTO RICO

Section 3

COSTS ANALYSIS OF COMMERCIALLY AVAILABLE ALTERNATIVES FOR ELECTRICAL ENERGY PRODUCTION IN PUERTO RICO

Three alternatives will be evaluated in this section: coal, nuclear, and oil fueled power plants.

3.0 GENERAL COST CONSIDERATIONS

In the cost analysis of electric power plants, three basic cost categories are considered: capital costs, fuel costs, and operating and maintenance costs.

The following are items that have to be evaluated for electric power plant cost assessments:

a) Investment Cost on per Unit Basis

The investment cost on a per unit basis (cost per Kw) of an electric power plant is heavily dependent on the size of the unit. The economies of scale dictate that the larger the size of the plant, the lower is the unit cost expressed in dollars per Kw.

b) Inflation

In an inflationary economy the cost of equipment depends heavily on the time schedule proposed for commercial operation to begin at the plant project. Inflation factors must be considered. The time that elapses between the cost estimate preparation and the beginning of construction will alter the cost estimates by the inflation factor during that period. During the construction period, inflation will affect costs on the uncompleted portion of the work.

c) Interest During Construction

As funds are invested and allocated during construction, interest on the investment for the period in which the funds are not producing any commercial benefit has to be considered. Construction schedules must be defined.

d) Environmental Considerations

Environmental regulations governing air and water pollution require high capital investment abatement measures. As an example, once through cooling systems might require long outfalls (with specially designed diffusers) to discharge warm waters at the bottom of the ocean so as to enhance quick mixing and to maintain the low temperature profiles that might be required by water quality regulations. Forced mechanical draft cooling towers might offer less intensive capital investment alterantive at higher operating costs.

Air quality regulations can make mandatory the installation of costly wet scrubbers to remove SO_2 from the gaseous stack discharges of coal plants. The installation of static precipitators and fine combustion controls for keeping particulate discharges to the atmosphere to a minimum must also be considered.

e) Site Related Considerations

Site location is another factor that affects the cost of a power plant project considerably. Such factors as terrain topography, site geology and seismic considerations, availability of adequate labor, proximity of electrical transmission facilities, transportation facilities such as marine port and roads, fresh water availability and similar factors can affect the cost of the total project.

3.1 COAL PLANTS

3.1.1 General Considerations

Before considering the cost components of a coal fueled electric generating plant in detail, several general principles should be discussed in relation to the use of coal in Puerto Rico. Since this is the first time that a coal plant is being considered for Puerto Rico, there are no previous experiences or policies or cost records which could be extrapolated.

The type of coal to be used and the environmental restrictions are subjects that need to be addressed. They will substantially affect both the capital cost and the operating cost of the plant.

Appendix A describes the various types of coals and the methods of coal cleaning or "beneficiation" together with the cost implications for Puerto Rico.

As an island far away from coal sources, Puerto Rico will be affected by coal mine problems like strikes, and by land and marine transportation problems which could force frequent changes from one type of coal to another. This will require a boiler design capable of burning poor types of coal with high sulfur contents.

Transportation is the highest component of the cost of coal delivered to the plant site. This cost is assessed by weight. Hence, under normal conditions the transportation of clean or washed coals with minimum refuse, ash content and sulfur represents a cost advantage since more Btu per lb. will be contained in the cleaner coals at the same transportation cost. Additional cost advantages accrued in the operation and maintenance components are discussed in Appendix A.

The problem of sludge disposal on a densely populated island with nearly 1000 persons per square mile in 1980 and with increases estimated to reach nearly 1,700 persons per square mile by 2020, makes the sludge disposal impact on the environment a matter of prime importance. This mandates that sludge disposal problems be minimized if the coal alternative is to be selected. This further points towards the advantage of using clean or highly beneficiated coals. Sludges should be minimized, then stabilized by chemical fixation and used for land fills. This approach makes unrestricted fuel cost optimization procedures mandatory during the lifetime of the plant, since they are the most significant items of the total costs.

The following general criteria will be used to determine the cost of a coal plant in Puerto Rico:

a) Plant design should meet EPA 1976 New Source Performance Standard (NSPS) as revised. Heat rejection systems should comply with latest revision of the Puerto Rico Environmental Quality Board (EQB) Water Pollution Regulations.

b) Boilers have to be able to burn the poor type coals which might be secured under emergency conditions.

c) Clean coals, which have been optimally beneficiated for lowest fuel cost and which will yield lower ash and sulfur residues, will be the normal source of supply.

d) Boiler effluent sludges are to be chemically stabilized for final disposal by trucking. This represents an added operational cost, but has a lower investment cost and a lower environmental impact.

3.1.2 Coal Power Plant Capital Investment Charges

In order to establish some meaningful investment cost relations for considering all of the above factors, a general cost equation will be derived based on the following assumptions:

a) The basic cost will include all direct costs such as land and land rights, the physical plant consisting of structures and site facilities, boiler and turbine plant equipment, electric plant equipment, and contingencies. The basic cost will also include indirect costs such as design and engineering, construction management, construction facilities and equipment services.

b) The investment cost will include the installation of SO_2 wet scrubbers and static precipitators for compliance with air quality regulations. The cost of this type of equipment is dependent upon the characteristics of the coal. For coal types from the Eastern United States with high sulfur content and residual ash, larger volumes of material must be handled. This type of removal system will increase the cost. Limestone scrubbing systems, as opposed to lime systems, must handle larger liquid volumes and are costlier. The use of a limestone scrubbing system will be considered for cost evaluations. Adders or credits must be used when considering different coal types. In this study, high sulfur coal will be assumed to be burned only under emergency or abnormal market conditions.

c) Heat rejection will be to the atmosphere through wet air cooling towers which use forced draft fans.

d) A "middletown" coastal site will be assumed in which there are no particular complex foundations or special seismic requirements.

e) No coal handling facilities are included between the nearby sea port and the plant boiler, nor are the port requirements and coal storage costs considered in the basic plant cost equation. All of these costs will be considered separately.

f) No investment costs for sludge disposal ponds are considered.

g) Basic cost (Co) will be based on early 1978 dollars. Escalation and interest during construction will be applied to the basic cost (Co).

h) Only the cost of the first unit of a two unit design will be considered. If a second unit is built on a two unit construction schedule, the second unit can be assumed to cost between 85 and 96% of the first unit cost if the second unit lags the first by approximately one year. This has been determined from United Engineers and Constructors recent unpublished cost estimates [9] and EPRI-PS-866-SR [14].

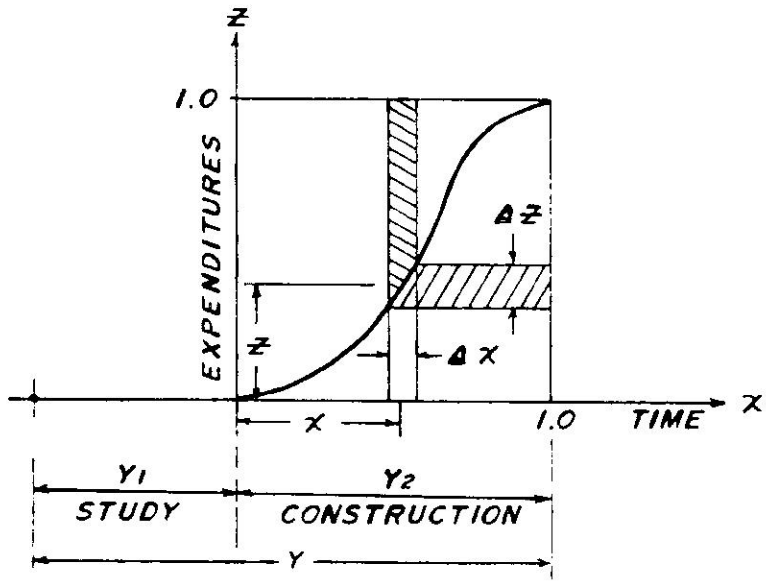
3.1.3 Interest During Construction and Inflation Formula

A complete derivation of the formula is presented in Appendix B. In treating inflation and interest during construction, the following procedures will be used.

Figure 3.1.3 represents the flow of cash outlays for the project. Y_1 represents the number of years between the date of the present estimate, early 1978, and the start of construction. Y_2 is the actual construction time. The abscissa of the curve is expressed in per unit of construction time and the ordinate in per unit of cumulative investment during

Figure 3.1.3

Interest During Construction and Inflation Formulas



Y_1 = years elapsed between Cost estimate analysis and start of construction

Y_2 = construction Time in years

a = area under normalized curve

i_{dc} = ave. interest during construction, % per year

i_f = inflation during construction, ave % per year.

Simple interest carried on ΔZ dollars spent at time X:

$$= (\Delta Z)(1-X)\, i\, Y_2$$

Total Simple interest during construction $= i\, Y_2 \int_0^1 (1-X)\, dz$

$$\text{and } \int_0^1 (1-X)\, dZ = a$$

Simple inflation on unspent dollars during ΔX time at X,

$$= (1-Z)\, \Delta X\, i\, Y_2$$

Total simple inflation during construction $= i\, Y_2 \int_0^1 (1-Z)\, dX$

$$\text{and } \int_0^1 (1-Z)\, dX = 1-a$$

COMBINED INTEREST DURING CONSTR. AND INFLATION

$$\text{COMPOUNDED} = (1+i_f)^{(1-a)Y_2} \cdot (1+i_{dc})^{aY_2} \cdot (1+i_f)^{Y_1}$$

construction. The area under the curve "a" is representative of the construction time fraction which is used to calculate the accrued interest during construction. The area above the curve is equal to 1-a (since the curve has been normalized), and is representative of the time fraction during construction in which the unspent money is subject to inflation.

Interest during construction can be expressed as follows:

$$I_{dc} = (1+i_{dc})^{ay_2}$$

Inflation between the time of the estimate and the completion of the project is then:

$$I_f = (1+i_f)^{Y_1+(1-a)Y_2}$$

The compounded interest rates for combined inflationary and interest during construction charges can be accounted for in a cost equation as follows:

$$C = (K+Co)I_f^{\,Y_1+(1-a)Y_2}\, I_{dc}^{\,ay_2}$$

where:

- C = total cost in \$/Kw
- Co = basic cost in \$/Kw for the base year (1978)
- Y_1 = years elapsed between base year (1978) and beginning of construction
- Y_2 = construction time in years
- I_f = $1 + i_f$, where i_f is the average yearly inflation rate
- I_{dc} = $1 + i_{dc}$, where i_{dc} is the average interest rate during construction
- a = area under the normalized cumulative cash flow curve during construction
- K = other costs which include, site variations from "middletown" site, port, special coal handling

facilities, coal storage and other particular site related costs evaluated at base year (1978).

The S type curve of cummulative cash flow must be defined. For the type of curve defined in Wash 1345 [7] the value of "a" is approximately 42%. Various type S cummulative cash flow curves are given by Budwani [8]. No extreme fluctuation can be expected in the values of "a." In the case study of the coal plant for Puerto Rico to begin operation in 1985, the short construction period that has been proposed gives an S curve with a value of "a" of approximately 0.48. For a straight line approximation of cummulative costs, "a" is 0.5.

3.1.4 Evaluation of Basic Capital Cost, Co

3.1.4.1 Plant with FGD System

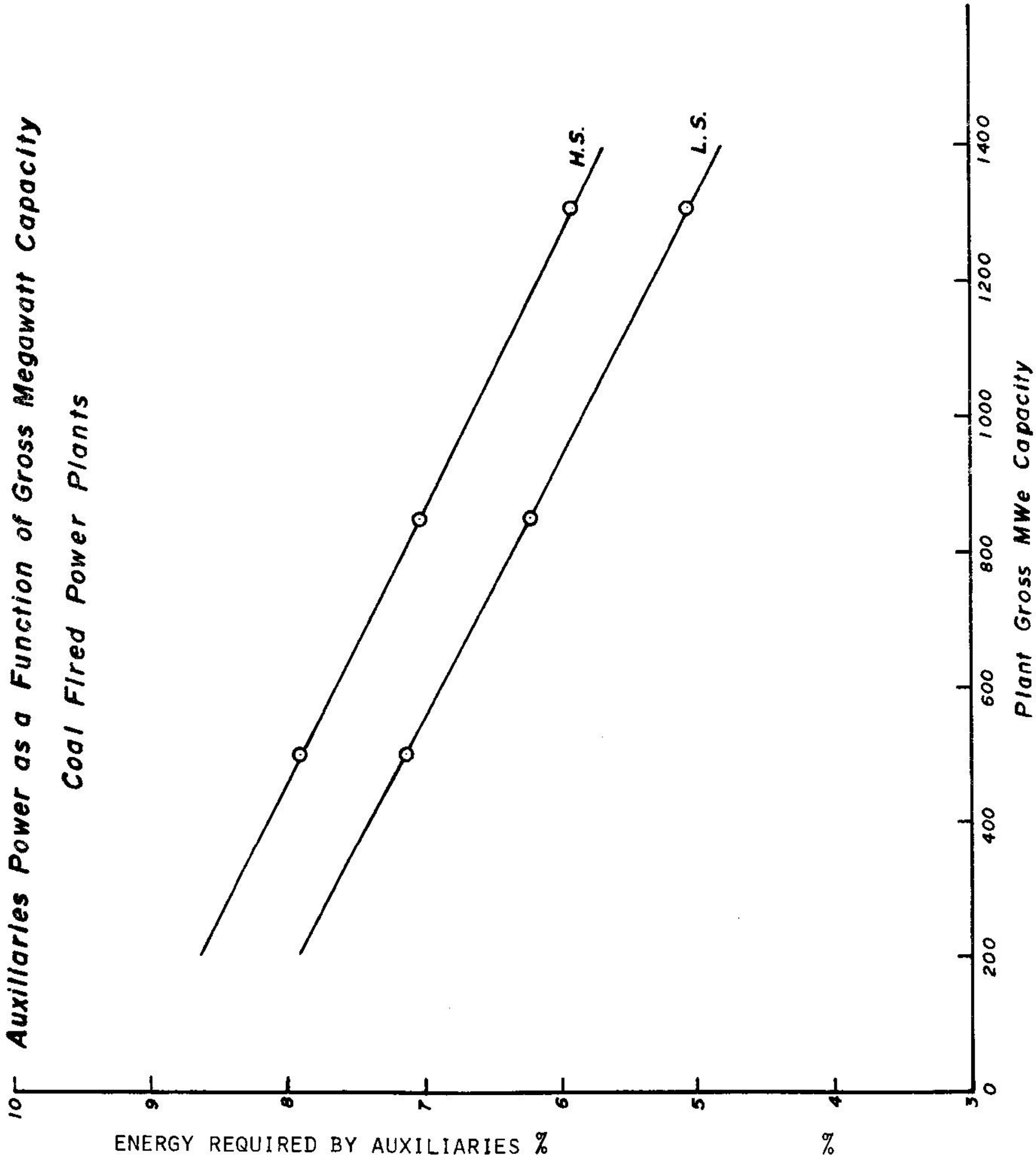
Co will depend upon the size of the plant and will have the conditions already stated as a basis for the coal plant cost equation.

Wash 1345 [7] gives the cost of a 1300 Mwe coal plant under various assumptions using the year 1974 as basis. The estimate, excluding escalation and interest during construction for a plant with SO_2 wet scrubbers, was inflated at 8% per year to correspond to 1978 prices. A cost of $410/net Kw was obtained for a first unit plant based upon the criteria established here. Five dollars per kw (1974 prices) were credited to the natural evaporation tower to allow for forced mechanical draft cooling. A 5.9% auxiliary power was assumed (Figure 3.1.4). The cost estimate as determined from Wash 1345 was found to be too low when compared to other recent estimates. This cost estimate does not comply with the 1976 EPA New Source Performance Standards (NSPS). Therefore, this data point was disregarded.

FIG. 3.1-4

Auxiliaries Power as a Function of Gross Megawatt Capacity

Coal Fired Power Plants



Recent unpublished studies performed by United Engineers and Constructors (UE&C) estimate in great detail the costs of 1300 Mw and 850 Mw units. Based upon the assumptions of our cost equation, the basic costs for a first unit including 10% contingency and 8% escalation for 1 1/2 years (mid 1976 to 1978) were determined to be \$534/Kw for a 1232 Mwe net (1309 Mw gross) coal plant, and \$597/Kw for a 794 Mwe net (854 Mw gross) coal plant. The detailed cost estimates are presented in Appendix C.

De Rienzo presents a recent unit cost estimate for a two-unit station for a 1150 Mwe plant equivalent to \$495/Kw.[10] It is assumed that these are gross Kw. An additional 6% should be added to the unit cost to correct it to the one-unit basis. By correcting De Rienzo's estimate to agree with our basic assumptions, a cost of \$526 per net kw is calculated (see Appendix C).

Kropp, Hansen and Destefanis estimate a cost of \$800/Kw for a 20 Mwe coal plant based on 1978 costs.[11] This estimate is used directly as given (see Appendix C).

The most accurate cost analysis has been prepared for PREPA by Architect Engineer Consultants for a 450 MW gross coal plant.[12] PREPA cost estimates exclude the cost of the turbine because the same was already purchased and is in storage at the Aguirre site. Twenty five million dollars was added to the PREPA estimate for this item. This amount was determined by escalating the original cost. In addition, twelve million dollars was added for the FGD system to allow for the burning of high sulfur content type coal. For the 450 MW PREPA coal plant 7.9% auxiliary power is estimated (including SO_2 wet scrubbers and mechanical draft fans for wet cooling towers). See Figure 3.1.4. Following the UEC format, the PREPA cost estimate is adjusted to $282.18 millions (1978 dollars). See Appendix C - First PREPA estimate.

A second estimate was prepared following the PREPA consultant's format. Separate adjustments were made for the turbine cost and added FGD system. The total cost estimate was $281 millions which agreed very closely with the first estimate of $282.18 millions.

If $2 million is added for land rights, the total estimated cost is $283 millions. The total unit capital investment cost is then $683 per net plant Kw output.

Publication ORAU/1 EA (M) 76-3 was examined for data on capital charges of a 1000 Mwe coal plant.[13] This estimate was made prior to the 1976 NSPS, and so the data point was disregarded.

The Electric Power Research Institute (EPRI) Special Report PS-866-SR (June 1978) was also examined. The lowest estimated cost for a 1000 MW net coal plant is $550/Kw on a two-unit basis, which becomes $573/kw by using a 1/0.96 factor for a one-unit plant. (See Appendix C).

A summary of the cost data for capital investment of coal plants is presented in Table 3.1.4.1 and Figure 3.1.4.1.

Table 3.1.4.1

CAPITAL INVESTMENT FOR COAL PLANTS
BASED ON COST ASSUMPTION OF COST EQUATION
(1 unit - 1978 costs - SO_2 removal
wet cooling tower)

Net MW	Cost/Net Kw	Main References	Year of Reference
20	800	11	1979
414	683	12	1979
794	597	9	1979
1000	573	14	1978
1150	526	10	1978
1232	534	9	1979

A curve fit was performed using the data of Table 3.1.4.1. An exponential regression statistical fit gave a value of determination coefficient of 99%. The cost equation is,

$$C_o = 795.95\ e^{-0.000342MW}$$

Where:

C_o = base cost in \$/net Kw, 1978 dollars

MW = plant size in megawatts

The total capital investment cost C for a coal plant is, therefore, given by the relation:

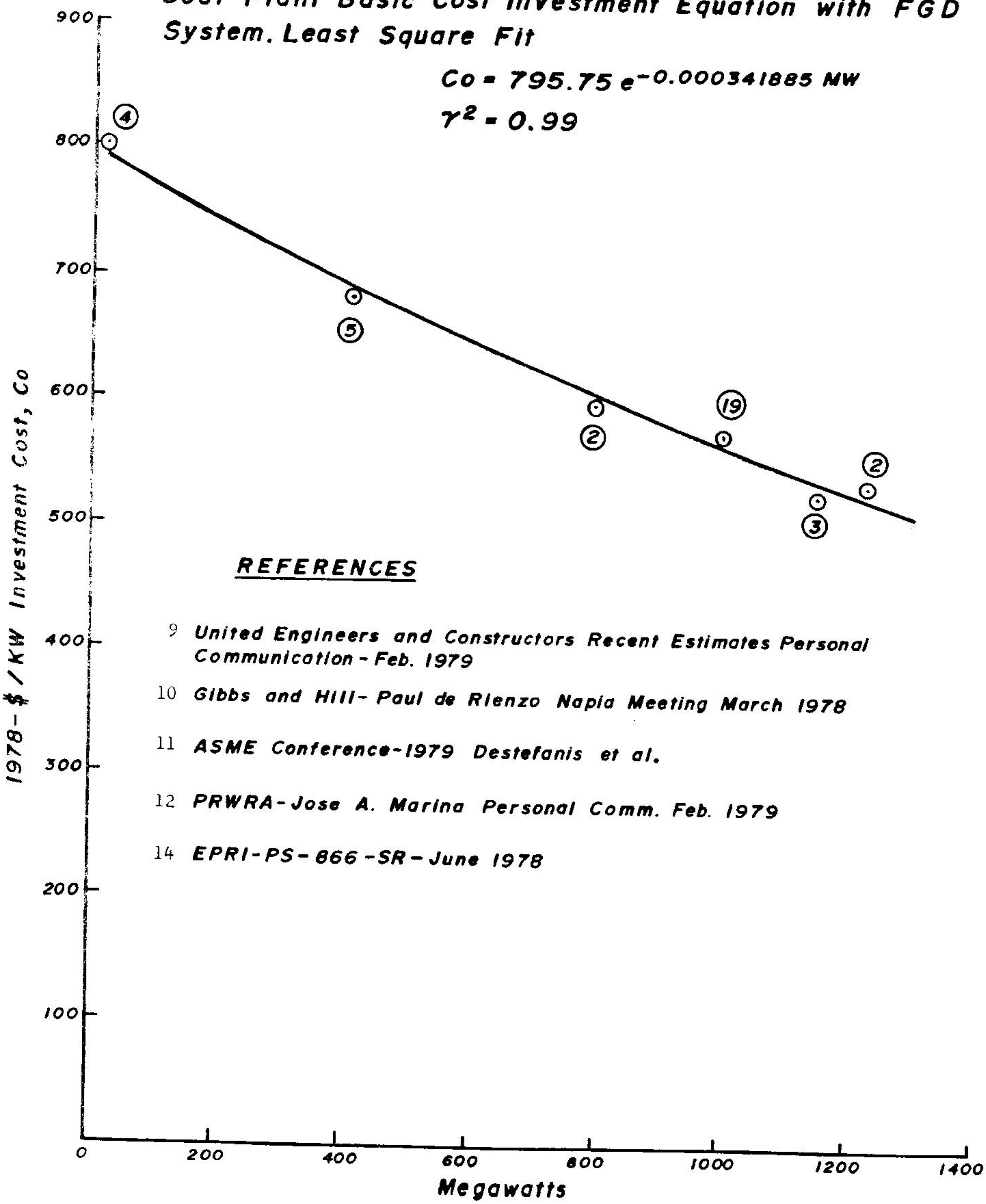
$$C = \left[K + 795.95e^{-0.000342MW}\right] \left[I_f{}^{Y_1} + (1-a)Y_2\ I_{dc}{}^{aY_2}\right] \quad (1)$$

Where K is the sum of special adders for a particular site and utility organization.

This equation is applicable to any coal plant for sizes ranging between 20 Mw and 1300 Mw, which practically covers the entire range of values. The equation is also good for any future date regardless of the inflation rate and interest charges during construction.

FIG. 3.1.4.1

Coal Plant Basic Cost Investment Equation with FGD System. Least Square Fit



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9 United Engineers and Constructors Recent Estimates Personal Communication - Feb. 1979

10 Gibbs and Hill - Paul de Rienzo Napia Meeting March 1978

11 ASME Conference-1979 Destefanis et al.

12 PRWRA - Jose A. Marina Personal Comm. Feb. 1979

14 EPRI-PS-866-SR-June 1978

3.1.4.2 FGD System Investment Costs

The investment costs of the FGD System have been included in the evaluation of Co and in the estimates given in Appendix C. A wide variation for the investment costs in FGD systems is reported in the literature. In Appendix C these costs are reported for the case of United Engineers and Constructors and for the case of the EPRI (Bechtel Study). For the UE&C report the investment costs for FGD system ranges between $73/net kw for the 1232 MW gross unit to $86/net Kw for the 854 Mwe (gross) units escalated to 1978. The EPRI report shows cost ranges from $85 to $155 per Kw.

The 1975 report "Detailed Cost Estimates for Advanced Effluent Desulfurization Processes" [15] describes costs escalated to 1978 at 8%/year as follows:

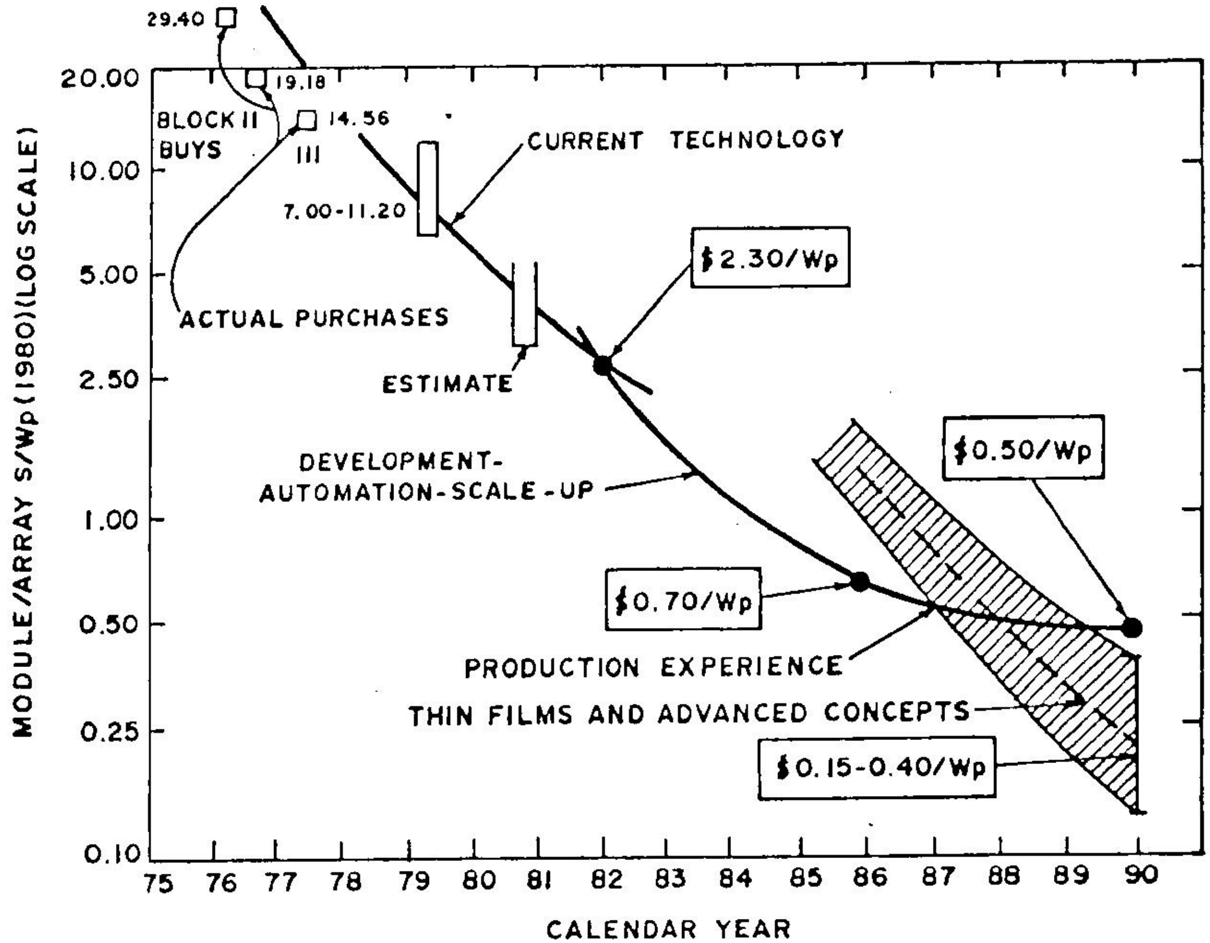
200 Mw units	$79/Kw
500 Mw units	$54.8-61/Kw
1000 Mw units	$45.7/Kw

These latter costs are too low when compared to recent UE&C and EPRI estimates.

The recent UE&C estimates are detailed and are based on the present state of the art. These estimates for FGD system investment costs in $/kw between the 1232 MWe and 854 MWe plants vary inversely with the .45 power of the capacity ratio.

If the same rule is applied to a 450 Mw gross unit, the added investment cost of the FGD system is $114.00 per Kw. This value falls well within the values quoted by EPRI for 1000 Mwe plants (85-155 $/kw).

For the purpose of adjusting coal plant costs for comparison with other alternative energy sources, the following



<u>Figura 11</u>

Pronostico de Precios **Para**
Modulos Fotovoltaícos
Departamento de Energía
Federal, (EUA)
(1980 Dólares)

investment costs for FGD systems will be assumed:

TABLE 3.1.4.2

INVESTMENT COSTS FOR FGD SYSTEMS

1978 CURRENT DOLLARS

Size (Gross)	FGD Cost $/Net Kw
450 Mw	100
854 Mw	85
1232 Mw	75

It should be noted that these costs are included within the evaluation of the cost equation Co.

3.1.5 Evaluation of K-Plant Cost Adders

This portion of the cost equation is not as strongly dependent upon plant size as the other factors and assumptions included in the evaluation of the basic cost equation, Co.

The following items are included in the value of K.

K - Plant Cost Adders

a) Special facilities such as roads, sea-port dredging requirements, coal handling equipment, fresh water supply, etc.

b) Electrical spur lines or cables to tie the power plant to the power system switchyard, including the corresponding H. V. terminal.

c) Cost of a storage pond for effluent disposal.

d) Taxes. This depends on the locality and the conditions, and on private vs. public utility organizations.

e) Other miscellaneous costs not specifically mentioned.

The value of K cannot be computed unless a particular site, locality and utility organization have been identified. In the final economic comparison the sites of Aguirre and Rincón are identified for assessment of the value of K within the PREPA system.

3.1.6 Cost Adders for the Specific Site at Rincón

Since our interest is to compare cost alternatives, those adders which will add the same approximate dollar value to each plant can be disregarded.

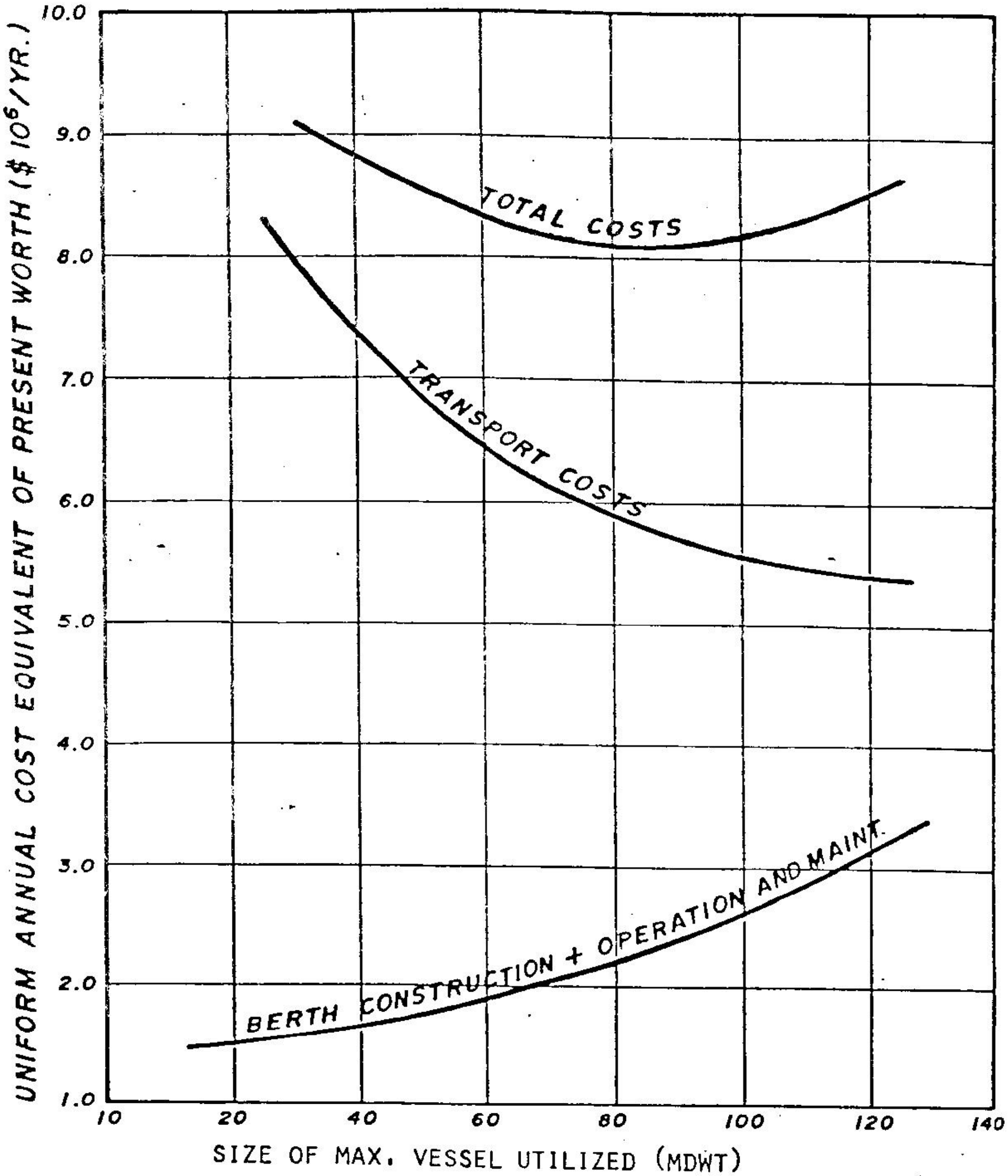
K_1 Special Facilities - Port, Dredging, and Coal Handling Equipment

In the 1974 study of various sites for an oil superport facility in Puerto Rico Van Houten Associates made some preliminary estimates of marine facilities for Rincón.[16] Figure 3.1.6 is taken from the Van Houten report. The size of the marine transportation vessel was the subject of cost analysis optimization. The minimum total cost results in vessels of about 85,000 - 90,000 dead weight tons (DWT). The analysis is based upon the requirements of two 450 MW coal fired units using 1.008 million tons of coal per year. Unfortunately the values of the curve on Figure 3.1.6 cannot be escalated to 1978 because the various components have different escalation rates. PREPA consultants have recently estimated the cost of a seaport facility at Rincón at $84 million dollars.

K_2 Electrical Facilities

These will be the same for all alternatives at the same site and so they will not be considered.

Figure 3.1-6



RINCON STATION

MARINE FACILITIES

OPTIMUN COAL CARRIER SIZE

(Max. thruput rate = 3.6×10^6 Long Tons/Yr.)
July 1974

Van Houten Associates, Inc.

K_3 Waste Disposal System

The Rincón Site does not have sufficient space for disposition of the FGD sludges, which instead must be treated and trucked away. The Authority owns only 143 acres of land in Punta Higuera; therefore land must be acquired even for locating such facilities as the electrical switchyard. The topography is very hilly and no nearby land is suitable for sludge disposal. A simple calculation for the disposal of the sludge from one 450 Mw unit indicates that a 583 acre pond 20 ft. deep will be required for all the solidified sludges during the plant's lifetime of 35 years. This calculation is obtained by assuming a 2.7% sulfur content, an approximately 1 Kw HR generation per lb. of coal, a 75% capacity factor, and a lime/limestone scrubbing system which generates 10 lbs. of sludges with a density of 55 lbs. per cu. ft. for every pound of sulfur removed.[17] A sludge stabilizing facility located at the electric plant site will add approximately $15.00 per gross kw capacity or $6,750,000 total in 1978 dollars.[18, 19, 20, 21, 22]. The sludge stabilizing plant, which is needed to change the sludge characteristics from thixotropic (quick-sand) into a hard material with acceptable structural load bearing properties for land fill (2 tons per square foot), includes miscellaneous equipment such as a pump house, mix tanks, silos for chemicals, flush water tanks, transport pipes, etc. Various proprietary processes such as Synearth (Dravo Corp.), Poz-o-Tech (IV Conversion System) and Chemfix (Carborundum) could be employed.

The alternative to the stabilizing plant will be the direct ponding of the untreated sludges. The land required for sludge disposal during the life of the plant will have to be purchased as a whole at the beginning of the project because of environmental impact considerations. Other costs could be defrayed on a yearly basis as the operation requires. However, assuming that escalation offsets the interest of profits of a deferred investment, the following rough estimate can be made for the direct sludge pumping alternative:

a)	six hundred acres at $4000/per acre	$2,400,000
b)	impounding at $703/acre-ft[(a)]	
	(575)(20)(703)	8,084,500
c)	Environmental control:	
	clay or synthetic lining of pond area	
	and drain control at $30,000/acre[(b)]	18,000,000
		$28,484,500

The impounding the untreated sludges alternative will undoubtedly receive serious opposition because of environmental factors and land use considerations. The capital investment is at least four times more expensive than it is for the alternative of sludge fixation. It has, however, lower operating costs. Whether the lower operating costs are enough to offset the higher investment charges requires a more detailed analysis then this work can provide. We feel that such study will have to be complete enough to include

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(a) Cost estimate made by UE&C for a 1250 Mwe plant and adjusted by discounting land costs at $300 per acre in a U.S. wasteland area.

(b) Average estimate from costs of asphalted surfaces and roof impermeabilization costs in Puerto Rico.

the environmental impact of the unfixed sludge disposal which this study has treated as simply as possible because of the assumption that it is not a viable alternative for Puerto Rico.

In summary, additional cost due to K_3
$15/kw, or $6,750,000

K_4 Taxes, Permits and Fees

Contributions in lieu of taxes are paid by PREPA. All alternatives are affected equally, and since the differential is zero, this factor will be omitted from the study.

Summary of K cost adders for Rincón:

K_1 port	84,000,000.00
K_2 elect. facilities	--
K_3 waste disposal plant	6,750,000.00
K_4 taxes	--
TOTAL	$90,750,000.00

3.1.7 Cost Adders for the Specific Site at Aguirre

K_1	A detailed cost estimate for port facilities at Aguirre has been made by PREPA Consultants. They include navigation channels over two miles long to reach beyond existing coral reefs (12)	$146,000,000.00
K_2	electrical facilities	--
K_3	waste disposal system same as for Rincón Site (see section 3.1.6)	6,750,000.00
K_4	taxes, permits, fees, etc.	--
		$152,750,000.00

The site of Aguirre will be disregarded in the economic evaluations.

3.1.8 Fixed Charges Considerations

3.1.8.1 General

Electric power plants in Puerto Rico are owned by a government public corporation. As such, no property taxes, corporate income taxes, charter licensing taxes, etc. exist. The form of evaluating the fixed annual charges is therefore, greatly simplified. Fixed annual charges consist principally of interest on bond issues, amortization on a sinking fund type of account, plus a small fixed percentage to cover property insurance (property insurance is a function of the capital investment). In addition, an amount to cover plant depreciation is considered. The consideration of plant depreciation in the economic comparison of alternatives has been a subject of discussion for many years. Arguments have been presented both in favor of and against the inclusion of a plant depreciation factor in the economic comparison of alternatives.

PREPA Trust Indenture requires that the electricity rates cover the cost of interest plus amortization, plus a straight line depreciation of investment. This helps to build up capital in order to provide an adequate safety margin to pay the debt. Such a safety margin, known either as "financial coverage" of the outstanding "debt" or as simply "coverage", is calculated by dividing the net revenues (revenues less all operating expenses) in a period of, say, one year, by the committed periodical (or yearly) payments of the debt (Debt Service). The ratio should be at least a minimum of 1.5 which is typical with most public corporations. The greater the coverage or safety margin, the better the financial position of the corporation resulting in better market conditions and lower interest rates for future bond issues.

This is the reason for the inclusion of a depreciation factor in the evaluation of economic alternatives.

The other point of view is that the addition of a plant depreciation factor should be considered once the lowest cost alternative to the public has been determined.

In making the economic comparison of alternatives, one should decide upon the alternative that represents the lowest cash outlay or cost to the consumers (including environmental costs). The addition of the depreciation factor to the amortization of the investment is equivalent to a double type depreciation which builds up an equity or "gain" for the public corporation. If this is included in the economic comparison, it can lead to the selection of an alternative which does not represent the lowest cost to the consumers even though it could be the best equity build-up for the corporation. The economic comparison of alternatives should therefore exclude the depreciation factor.

Once the lowest cost alternative is selected, then the depreciation factor should be considered in making a cash flow study of money and financial requirements of the corporation to determine the "coverage." Other governmental policies and financial considerations should then be accounted for in the analysis, and the modifications should be made as necessary.

3.1.8.2 Capacity Factor

The selection of a plant capacity factor for use in cost comparison of power studies has always been a controversial point. In computer programs of generation expansion of power systems, capacity factors are not set a priori. The scheduled outage rate for maintenance purposes (4-6 weeks per year) and the statistically determined forced outage rate from historical records indirectly fix the upper limit of the capacity factor. The generating units have to compete with each other in an economic incremental dispatch program determined by a series of coordination equations which minimize the total operating costs. The system expansion alternative which produces the total minimum cost is the preferred alternative from an economical point of view. The units having the lowest incremental costs will be more fully loaded and will exhibit the highest capacity factors. The actual operation of a power system follows the same principle of economic dispatch. Hence, capacity factors for coal power utility records are strongly biased to a lower value by the presence of lower incremental costs units such as nuclear and hydro units.

In order to take this into account, Komanoff has defined capacity performance (CP) as that which would have been experienced had the plants in question been fully base-loaded. [23] Komanoff's results have been highly controversial.

Hohenemer, Goble and Fowler present interesting results using the Komanoff statistical analysis. [24, 25]

It is an observed fact that the forced outage rate of the generating units increases with size and complexity. The expectation of capacity factor for a coal plant during the lifetime of the plant should average 75% irrespective of the plant size. For the purpose of developing baseline costs in Puerto Rico of commercially available alternatives for comparison with new alternatives requiring R&D efforts, this simple assumption is adequate.

Station performances are also reported in "20th Steam Station Cost Survey" in Electrical World, Nov. 15, 1977. [26]

Edison Electric Institute (EEI) has probably the most extensive compilation on Capacity Factors (CF), Availability Factor (AF), Equivalent Availability (EA), and Forced Outage Rate (FOR) for coal and nuclear plants of 400 MW and larger.[27] A 75% average lifetime capacity factor for coal plants is considered reasonable. Nevertheless, parametric studies could be performed with capacity factors if necessary.

3.1.8.3 Fixed Charge Rate

Fixed charge rates to be considered consist of the interest plus amortization in sinking fund, or the capital recovery factor plus insurance as discussed before.*

Let F. C. = CRF + INS

The annual cost in mills per kw-hr is then

$$\frac{(C)\ (KW)\qquad (F.C.)}{(8760 \times KW \times CF)} \times 1000 = \frac{(C)}{(C.F.)}\ \frac{(F.C.)}{(8.760)}\ \text{mills/kw-hr}$$

where:

C = capital investment cost $/kw of net plant capacity

C.F. = capacity factor

F.C. = fixed charge rate

Substituting in the previous equation for the value of C, the investment charges in mills/kw-hr (plant with FGD system) is given by: Total Investment Charge =

$$\frac{(795.95e^{-0.000342MW} + K)\ I_f^{Y_1 + (1-a)Y_2}\ I_{dc}^{aY_2}\ F.C.}{(C.F.)(8.760)}\ \text{mills/kwhr}$$

* EPRI-PS-866-SR includes in the fixed charge rate an allowance for what is called Retirement Dispersion to take into account the statistics of unit retirement. An allowance for a retirement dispersion of 0.51% is calculated for a 35 year lifetime. This concept has not yet been fully adopted by the industry and will not be considered here. (Ref. 14).

3.1.8.4 <u>Example of Investment Charges Calculation of a 450 MW Gross Coal Plant for PREPA in Mills/kwhr</u>

Assumed Interest Rate = 9%/Yr.

Plant Life = 35 years

Capital Recovery Factor (CRF) = 0.094636

0.004

Fixed Charge Rate (CF) = 0.098636

Assumed Capacity Factor = 75%

Y_1 = 1 year

Y_2 = 6 years

Co = 683 $/kw*

$$K = \frac{\$90{,}750{,}000.00}{414{,}000.00} = 219.2 \ \$/kw$$

I_f = 1.08

I_{dc} = 1.09

a = 0.48 (see end of section 3.1.3)

$Y_1 + (1-a)Y_2 = 4.12$

$aY_2 = 2.88$

$(1.08)^{4.12} = 1.373$

$(1.09)^{2.88} = 1.282$

1985 Capital Investment Cost:

$C = (683 + 219.2)(1.373)(1.282) = \$1588.04/kw$

$$\text{Cost in mills/kwhr (1985)} = \frac{(1588.04)(0.098636)}{(0.75)(8.760)}$$

Fixed Charges = 23.8 mills/kwhr

---

* The corresponding figure for net capacity is $691/KW which only adds 0.25 mills to the levelized cost.

3.1.9 Coal Fuel Costs for Puerto Rico

3.1.9.1 General

The vulnerability of fuel prices to international actions, such as those of the OPEC cartel, is an established fact. Prices of competitive fuels follow the OPEC oil prices although not necessarily at the same rate. This factor tends to change the prices of competitive fuels at a faster rate than normal.[28] Coal prices and those of other fuels rose dramatically in late 1973 and early 1974.

Prices for coal purchased under long term contracts are more stable, but are not necessarily lower than spot purchase prices. The greater reliability of supply with long-term contracts is the most important consideration when comparing these contracts with spot market purchases which are influenced by short-term market variations.

Coal prices will also respond to changes in production and transportation costs. Because of the high transportation cost, coal has been until the present time a regional type of fuel.

OPEC action has caused coal to be considered as a non-regional type of fuel sooner than it would have otherwise been.

The mine-mouth coal prices will depend upon the inflation rates of materials, equipment, labor, and operation and maintenance costs. This inflation rate has been estimated at 8% per year in other parts of this study, and it is logical to assume that mine-mouth coal costs will increase at the same rate.

Transportation costs should increase at a lower rate than materials and labor costs because this item is highly capital intensive. The investment has already been made and so the escalation does not affect the transportation equipment investment. A six percent (6%) inflation rate on transportation charges should be more accurate. (29)

The indicated escalation rates will be applied in this study to domestic types of coal as well as to foreign types. However, prices from foreign sources could be lower.

Shipment of domestic coals to Puerto Rico must be done in vessels under United States flag, but shipment from foreign countries can be done in foreign vessels. It is a fact that transportation costs in United States vessels are about the highest in the world. Since transportation costs are the biggest component of the total coal cost, it is a real possibility that foreign sources would compete very favorably with United States sources, provided no federal taxes are levied on the foreign coals to protect domestic producers. Any long term contract with foreign sources should be entered into with this in mind.

Figure A-1 in Appendix A presents the coal fields in the Continental U. S. A. Coal fields are divided into four regions according to the total reserves and the low sulfur coal reserves. Appendix A also indicates the distribution of coal reserves in a bar chart.

Coal costs data in the ORNL-4995 Study mentioned earlier are reported up to 1972, but this data is not reliable for future projections. Nevertheless, it is reasonable to assume that Puerto Rico will probably obtain the lowest coal costs found in the United States market from the area of West Virginia and Alabama. This area offers the shortest transportation routes to Puerto Rico. The current low price won't necessarily remain so since special market conditions can change. West Virginia and Alabama coals are excellent and they could be in high demand.

Cost data reported by various sources is presented in the following sections.

3.1.9.1a PREPA Consultants - Coal Price

PREPA Consultants have performed recent detailed price investigations from various suppliers to assess delivered coal costs to Puerto Rico.[12, 22] Table 3.1.9.1(a) is a summary of these investigations.

TABLE 3.1.9.1a

1977 DELIVERED COAL PRICES TO P.R.
(T = Short Ton)

	W. Virginia	Wyoming	Illinois	Alabama	Colombia	South Africa*
FOB Mine $/T	26.31	6.70	22.28	29.00	----	----
Rail Transp. $/T	9.18	9.65	2.75	4.98	----	----
River Transp. $/T	----	6.24	4.50	----	----	----
Ocean Transp. $/T	8.45	8.86	10.78	9.89	----	----
TOTAL $/T	43.94	31.45	40.31	43.87		29.27
MMBTU/T	26.00	17.00	22.00	26.00	----	21.68
$/MMBTU	1.69	1.85	1.83	1.69	1.60	1.35

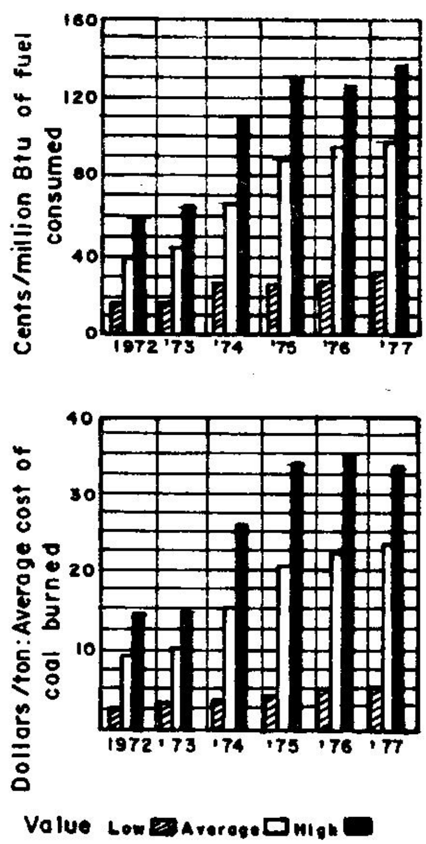
*Prices not considred reliable

3.1.9.1b <u>Burns and Roe Coal Price</u>

Budwani[8] from Burns and Roe indicates an average high value of coal burned by U.S. utilities in 1977 as \$1.35 per MMBTU. When the ocean transportation costs as determined for the lowest fuel costs in Table 3.1.9.1a are added, coal fuel prices for Puerto Rico will be \$1.675 per MMBTU for West Virginia and \$1.73 per MMBTU for Alabama. Budwani's figures agree very closely with Table 3.1.9.1a.

FIGURE 3.1.9.1b

AVERAGE COST OF COAL BURNED BY ELECTRIC UTILITIES DURING 1972-77 PERIOD



The low values are for mine-mouth plants. The calculated average values are derived from average costs for 30 utilities in all parts of the United States.

3.1.9.1c United Engineers and Constructors Coal Price

Recent cost estimates by UE&C for high sulfur and low sulfur coal indicate the following costs:[9]

TABLE 3.1.9.1c

JULY 1976 DELIVERED FUEL COST TO A U.S. MIDDLE-TOWN SITE (UE&C)

	Western Low Sulfur Campbell County, Wyoming	Eastern Hi Sulfur Saint Clair County, Illinois
Mine ($/T)	6.43	19.00
Transp. ($/T)	20.43	9.19
TOTAL ($/T)	26.86	28.19
MMBTU/T	16.33	22.05
$/MMBTU	1.65	1.28

A comparison of the mine costs between Table 3.1.9.1a and 3.1.9.1c indicates an escalation of 4.2% for the Wyoming coal between July 1976 and 1977, and 17.2% escalation for the Illinois coal price. There is no strong discrepancy between Tables 3.1.9.1a and 3.1.9.1c coal mine costs.

3.1.9.1d Summary of Coal Prices

The above analysis shows that the average price (1977 reference base) within the United States can fluctuate between $1.35 - 1.65/MMBTU, excluding the overseas transportation costs. Indicated costs for South

African and Colombian coals look rather low even after the overseas transportation costs are added. A serious economic analysis can not be based upon foreign costs which could change unexpectedly because they do not have a real pricing basis. It will therefore, be more appropriate to base economic comparisons on domestic coals. Nonetheless, any real advantage offered from purchasing low cost foreign coals should be taken into consideration.

It seems that coal costs on the basis of 1.70 per MMBTU (1977 reference base) can be possible for Puerto Rico. Escalation of this cost will be made at 7 1/4% per year. This has been determined by weighing the escalation of the transportation cost component at 6% and of the mine component at 8% for the West Virginia and Alabama coals.

TABLE 3.1.9.1d

COAL COST ASSUMPTIONS
(1977 Base - $1.70/MMBTU)

Escalation	:	7 1/4%/year
Coal Type	:	Alabama and West Virginia
1978 Base	:	$1.82/MMBTU

3.1.9.2 Levelized Fuel Costs in Mills per Kwhr

After the power plant begins commercial operations, the capital investment cost component is not subject to inflation since it has already been spent and the interest on borrowed capital is fixed. However, fuel costs will continue to suffer from inflation. In order to add the capital charge cost component to the fuel cost component, the two have to be on the same basis. A levelized fuel cost during the plant life should then be considered.[30,31] The analysis for calculating the levelized fuel cost is derived in Appendix F. The levelizing factor L can be expressed as,

$$L = \frac{(1 + r)^n - 1}{r\,(1 + r)^n} \cdot \frac{i\,(1 + i)^n}{(1 + i)^n - 1}$$

where:

n = number of years (usually plant life time) for levelization

i = cost of money or discount rate, usually equal to the interest paid on bonds for public corporations.

r = effective discount rate corrected for total inflation, such that $r = \frac{i - u}{1 + u}$ where u is the total average yearly inflation rate of the product.

The levelized fuel cost in mills per kwhr can then be expressed as follows:

$$F_L = \frac{(Pc)(HR)}{1000}(1 + e_f)^Y \cdot \frac{(1 + r)^n - 1}{r(1 + r)^n} \cdot \frac{i(1 + i)^n}{(1 + i)^n - 1}$$

where:

Pc = coal price in dollars per MMBTU for base year, 1978

HR = plant heat rate in BTU/kwhr

Y = number of years between base year of estimate and beginning of commercial operation.

3.1.9.3 Example Calculation of Fuel Cost for PREPA 450 MW Plant.

For the specific case of the PREPA 450 MW plant we have:

Value of Pc:

(a) 1978 base year fuel cost at \$1.82 per MMBTU as determined in Section 3.1.9.1d

(b) carrying charges on coal stock pile 3 month stock equivalent to 1/4 ton in stock per ton burned at 10% carrying charges equals 1/4 (\$1.82/MMBTU) (0.10) or 0.0455 \$/MMBTU.

$\therefore$ Pc = \$1.87/MMBTU

HR = 10,000 Btu/kwhr
Heat rate of a 450,000 KW Plant operating at 75% load factor (12)

e_f = 7.25% (escalation between 1978 and 1985, % per year)

n = 35

i = 9% (PREPA cost of money)

u = 5% (total ave. yearly escalation rate 1985 - 2020).

r = 0.038095, determined from the relationship of r, i, u.

Y = 7 years (1985-1978).

$$F_L = \frac{(1.87)(10,000)}{1,000}(1.0725)^7 \cdot \frac{(1.038095)^{35}-1}{(0.038095)(1.038095)^{35}} \cdot \frac{(0.09)(1.09)^{35}}{(1.09)^{35}-1}$$

$$F_L = (31)(1.81) = 56.11 \text{ mills/kwhr}$$

3.1.10 Operating and Maintenance Costs for Coal Plant with FGD System

No experience exists in Puerto Rico with the operation and maintenance of coal fired or large commercial nuclear plants, therefore, it is not possible to extrapolate historical figures, for the Operating and Maintenance Costs (O & M).

The evaluation of O & M costs in this study is based mainly in the ORNL publication "A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants"[32] and on personal communications with United Engineers and Constructors.

The total O & M costs are composed of staff, fixed and variable maintenance, fixed and variable supplies and expenses, insurance and fees, and administrative and general expenses.

The procedure is based on determining first the total plant manpower requirements from normal experience in other similar plants. Once the average cost per employee for a particular utility is known, the total staff cost can be determined. This is usually the largest single cost item.

Fixed and variable maintenance costs are correlated with the staff cost.

Fixed and variable supplies and expenses are a function of plant capacity and kwhr generation, respectively.

Insurance and fees are a function of plant investment.

Administrative and general expenses are correlated with total fixed costs.

3.1.10.1 Staff Cost

The yearly O & M cost of the plant staff is determined from the following relationship:

$$TSC = \text{Total Staff Cost} = M \times Pm\ (1 + e)^{Y}$$

where:

M = number of regular employees at the plant (excluding transitory labor)

Pm = average annual cost per employee at the time of the estimate (1978 base year). This includes all costs such as salary, fringe benefits, overtime pay, etc.

e = average annual escalation rate for the utility, %/100.

Y = number of years between base year (1978) and beginning of commercial operation of the plant.

Tables 3.1.10.1 and 3.1.10.1a present the manpower requirements.[32]

3.1.10.2 Fixed and Variable Maintenance Costs

a) Fixed Maintenance

The ORNL correlation studies[32] indicate that approximately 75% of the total maintenance material cost for a coal fired plant can be considered the fixed portion of this item. Approximately 45% of the total staff cost is the annual total maintenance material cost.

TABLE 3.1.10.1

STAFF REQUIREMENT FOR COAL–FIRED PLANTS
WITH FGD SYSTEMS

	400-700 MW(e) Unit				701-1300 MW(e) Unit			
	Units per Site				Units per Site			
	1	2	3	4	1	2	3	4
Plant manager's office								
Manager	1	1	1	1	1	1	1	1
Assistant	1	2	3	4	1	2	3	4
Environmental control	1	1	1	1	1	1	1	1
Public relations	1	1	1	1	1	1	1	1
Training	1	1	1	1	1	1	1	1
Safety	1	1	1	1	1	1	1	1
Administrative services	13	14	15	16	13	14	15	16
Health services	1	1	1	2	1	1	1	2
Security	7	7	9	14	7	7	9	14
Subtotal	27	29	33	41	27	29	33	41
Operations								
Supervision (excluding shift)	3	3	5	5	3	3	5	5
Shifts	45	50	60	65	45	50	60	65
Fuel and limestone handling	12	12	12	18	12	12	12	18
Waste systems	15	30	45	60	15	30	45	60
Subtotal	75	95	122	148	75	95	122	148
Maintenance								
Supervision	8	8	10	12	8	8	10	12
Crafts	90	115	135	155	95	120	140	160
Peak maintenance annualized	33	66	99	132	35	70	105	140
Subtotal	131	189	244	299	138	198	255	312
Technical and Engineering								
Waste	1	2	3	4	1	2	3	4
Radiochemical	2	2	3	4	2	2	3	4
Instrumentation and Controls	2	2	3	4	2	2	3	4
Performance, reports, and technicians	14	17	21	24	14	17	21	24
Subtotal	19	23	30	36	19	23	30	36
Total	252	336	429	524	259	345	440	537

TABLE 3.1.10.1a

STAFF REQUIREMENT FOR COAL–FIRED PLANTS
WITHOUT FGD SYSTEMS

	400-700 MW(e) Unit				701-1300 MW(e) Unit			
	Units per Site				Units per Site			
	1	2	3	4	1	2	3	4
Plant manager's office								
Manager	1	1	1	1	1	1	1	1
Assistant	1	2	3	4	1	2	3	4
Environmental control	1	1	1	1	1	1	1	1
Public relations	1	1	1	1	1	1	1	1
Training	1	1	1	1	1	1	1	1
Safety	1	1	1	1	1	1	1	1
Administrative services	12	13	14	15	12	13	14	15
Health services	1	1	1	2	1	1	1	2
Security	7	7	9	14	7	7	9	14
Subtotal	26	28	32	40	26	28	32	40
Operations								
Supervision (excluding shift)	2	2	4	4	2	2	4	4
Shifts	45	50	60	65	45	50	60	65
Fuel handling	12	12	12	18	12	12	12	18
Subtotal	59	64	76	87	59	64	76	87
Maintenance								
Supervision	6	6	8	10	6	6	8	10
Crafts	75	90	100	110	80	95	105	115
Peak maintenance annualized	32	64	96	128	32	64	96	128
Subtotal	113	160	204	248	118	165	209	253
Technical and Engineering								
Radiochemical	2	2	3	4	2	2	3	4
Instrumentation and controls	2	2	3	4	2	2	3	4
Performance, reports, and technicians	12	15	18	21	15	18	21	24
Subtotal	16	19	24	29	19	22	27	32
Total	214	271	336	404	222	279	344	412

The fixed portion of the maintenance cost of a mechanical draft wet cooling tower has been calculated to be \$30,600.00 (1978 dollars).

The inclusion of an FGD system in the plant involves a considerable addition to the staff. The requirements of total maintenance materials for this system are approximately equal to the cost of the required additional staff. One third of this cost is considered fixed and the rest variable.

The fixed maintenance cost is, therefore, given by the following equation.

$$\text{Fixed Maint. Cost} = \left[(0.75)(0.45)\ \text{TSC} + \$30{,}600.00 + (0.33)(\text{ATSC})\right](1 + e)^y$$

where:

TSC = total staff cost

\$30,600.00 = fixed maintenance cost of a wet mechanical cooling tower (evaluated at 1978)

ATSC = cost of the additional staff required for the plant with an FGD system.

b. Variable Maintenance

The variable maintenance cost is comprised of the remaining 25% of the total maintenance materials, plus the variable maintenance cost of the wet cooling tower, plus the additional portion of the differential staff cost for the FGD system.

The variable maintenance cost of the cooling tower is proportional to the kw-hr generation and has been figured by the United Engineers and constructors to be 0.0049 mills per kwhr at constant plant load factor of 80% (1978 dollars).

The total variable maintenance cost is therefore given as:

$$\text{Var. Maint. Cost} = \left[(0.25)(0.45)(TSC) + \frac{0.0049}{1000} \times \text{kw-hr at 80\% CF} + (0.67)(ATSC)\right](1 + e)^y$$

3.1.10.3 Fixed and Variable Supplies and Expenses

a) Fixed Supplies and Expenses

This cost category includes all materials and expenses that are of an expendable nature such as chemicals, lubricants, make-up fluids and gases, records, contract services, etc., and is proportional to the net station KW rating.

The equation for this cost category is:

$$\text{Fixed S \& E} = (\text{Per unit cost})(KW)(1 + e)^y$$

The per unit cost for a coal plant has been determined as \$1.30/kw (1978 dollars).[32]

b) Variable Supplies and Expenses

The variable supplies and expenses include the costs of lime and limestone and the sludge disposal costs.

A limestone wet scrubbing system is used in this study since limestone is abundant in the northern part of Puerto Rico between Isabela and Bayamón and represents an attractive low cost local resource.

Approximately four tons of limestone are required for every ton of dry sulfur content in the coal. The combined five tons of dry sludge are mixed with an equal weight amount of water to produce ten tons of wet sludge. If P_1 is the price of limestone in \$/ton and P_{sd} the disposal cost of a ton of wet sludge by trucking (excluding layering and compacting in the land fill operation), then the variable supplies and expenses for the SO_2 removal system are evaluated as follows:

$$\text{Var. S \& E for } SO_2 \text{ removal} = \frac{\left[ST_r(4P_1 + 10P_{sd}) \times (8760)(CF)\right]}{(1 + e)^y}$$

where:

CF = capacity factor

S = Per unit sulfur content in coal (%/100)

T_r = coal firing rate of the boiler (tons/hr)

P_1 = Cost of limestone (\$/ton)

P_{sd} = Cost of sludge disposal (\$/ton)

3.1.10.4 Insurance

Fossil fueled power plants in Puerto Rico carry only property insurance which is a function of capital investment. Payment of this insurance is covered by adding the corresponding percentage to the Capital Recovery Factor. Past experience shows that in Puerto Rico this factor has fluctuated between 0.33 and 0.40% of capital investment.

Public liability insurance for power plants in the PREPA system is generally taken care by an in house fund. It is difficult to determine a fixed charge for public liability insurance, therefore, no specific charges are made for this item.

3.1.10.5 <u>Administrative and General Expenses (A&G)</u>

It is estimated that the A&G expenses for plants with FGD systems equals 10% of the entire fixed cost. That is:

$$\text{A\&G expenses} = (0.10)\left[TSC + \Delta TSC + FIX\ MAT + FIX\ S\&E\right](1+e)^{y}$$

where:

TSC	=	Plant Staff Cost
FIX MAT	=	Fixed portion of maintenance cost
FIX S&E	=	Fixed portion of supplies and expenses cost
ΔTSC	=	Differential staff cost required for the FGD system

3.1.10.6 <u>Summary General Equation for O&M with FGD System</u>

In summary we have the following set of equations:

$$\text{Tot. Staff Cost} = \left[(TSC + \Delta TSC)\right] \cdot (1 + e)^{y}$$

$$\text{Fixed Maint Cost} = \left[(0.3375)(TSC) + 30{,}600 + (0.33)(\Delta TSC)\right](1+e)^{y}$$

$$\text{Var. Maint Cost} = \left[(0.1125)(TSC) + \frac{0.0049}{1000}(kwhr)(0.80)+(0.67)(\Delta TSC)\right](1+e)^{y}$$

$$\text{Fixed S\&E} = \left[(1.30)(kw)\right](1 + e)^{y}$$

$$\text{Var. S\&E} = \left[(S)(T_r)(4P_1 + 10P_{sd})(8760)(CF)\right](1 + e)^{y}$$

$$\text{A\&G Expenses} = (0.10)\left[TSC + \Delta TSC + (0.3375)\ TSC + 30{,}600 + (0.33)(\Delta TSC) + (1.30)Kw)\right](1 + e)^{y}$$

$$= \left[(0.13375(TSC) + (0.133)(\Delta TSC) + 3060 + (0.13)(Kw)\right](1+e)^{Y}$$

Adding and combining terms we get:

$$\text{Total O \& M Cost with FGD System} = \left\{ (1.384)(TSC) + (2.133)(ATSC) + (4.9 \times 10^{-6})(kwhr)(0.80) + (S)(T_r)(4P_1 + 10P_{sd})(8760)CF + (1.43)(kw) + 33{,}660 \right\} (1 + e)^y$$

The O&M costs of the FGD system included in the above equation are computed by the following formula:

$$\text{O\&M Cost (FGD Syst.)} = \left[(2.133)(\Delta TSC) + S\, T_r(4P_1+10P_{sd}) \times (8760)(CF) \right] (1+e)^y$$

3.1.10.7 Levelization of Operation and Maintenance Costs

Operation and maintenance costs, like fuel costs are subject to inflation during the life of the plant.

In order to have the operating and maintenance (O&M) charges on a levelized basis during the life of the plant, so that it can be added to the fixed capital investment charges and levelized fuel charges a levelizing factor has to be considered. The same levelizing factor described in Section 3.1.9.2 can be used provided the correct total inflation value of u is used for the O&M charges. The levelizing factor is repeated here as:

$$L = \frac{(1 + r)^n - 1}{r\,(1 + r)^n} \cdot \frac{i\,(1 + i)^n}{(1 + i)^n - 1}$$

where:

$r = \dfrac{i - u}{1 + u}$

u = yearly average of the weighted total inflation rate for the O&M charges during the life of the plant.

The levelized O&M charges during the life of the plant, in mills per kilowatt hour, is therefore, given as:

$$\text{O\&M charges (mills/kwhr)} = \frac{\text{O\&M cost (\$) (L)}}{(kw)\ (CF)\ (8.760)}$$

3.1.10.8 Sample Calculation for a 450 MW Coal Plant for PREPA

The cost for an average power plant staff member to PREPA is calculated as $24,000.00 per year*.

From Table 3.1.10.1 the number of persons needed to operate one coal fired unit is 214 and the differential staff for the SO_2 removal system is 38.

TSC = ($24,000.00)(214) = $5,136,000.00

ATSC = ($24,000.00)(38) = $ 912,000.00

Assume: $P_1 = P_{sd}$ = $5.50/ton[22]

C.F. = 75%

S = 3%

T_r = 200 tons/hr (based on 9,800 Btu/kwhr heat rate and 11,000 Btu/lb coal)

e = 8%/yr

Y = 1985 - 1978 = 7 years

$$\text{Total O\&M Cost} = \Big[(1.584)(5{,}136) + (2.133)(912) + (4.9 \times 10^{-6})(450)(8760)(0.80) + (0.03)(200)(14)(5.50)(8.760)(0.75) + (1.43)(450) + 33.66\Big](10)^3(1.08)^7$$

$$= \$23{,}666{,}000.$$

*Actual average base salary obtained by dividing total salaries by total staff is $12,128.00 per person. Normal office hours in PREPA are 7 1/2 but shift personnel work on 8 hours shift. Operators have to work an average of 8 1/2 hours to transfer the shift to the incoming operator. The extra hour is paid at a double rate which makes the shift personnel working day equivalent to 9 1/2 hours. They get an extra pay equivalent to 26.7% of their salary. In addition, all holidays worked are paid at a double rate and substitution for absentees and sick employees adds to the overtime pay. Canceled meal times due to emergencies are paid at a triple rate. Evening andnight shifts have additional differential pay. Fringe benefits add 52% to basic salaries and overtime pay accounts for approximately 26% of extra charges on incremental fringe benefits. Therefore, the total multiplier for average salaries in a power station where shift personnel is involved, is close to 2.

The total generation at 75% capacity factor:

$(414{,}000)(0.75)(8760) = 2.71998 \times 10^9$ kwhr

The total O&M cost in mills/kwhr levelized for the 35 years plant life using the same levelizing factor as for fuel (1.81, inflation factor of 5% per year during plant lifetime and i at 9% per year) is then:

$$\text{Total O\&M Cost} = \frac{23.666 \times 10^9}{2.71998 \times 10^9} \times 1.81$$

$$\text{Total O\&M Cost} = 16 \text{ mills/kwhr}$$

For operation in 1985.

The first year O&M cost is 8.70 mills/kwhr. The FGD system O&M costs included above are 3.14 mills/kwhr for the first year of operation (1985), and 5.68 mills/kwhr levelized for the 35 years of plant operation.

The cost of operation of the FGD System is included in the $23,666,000 figure. However, the FGD operation cost can be calculated separately from the relation at the end of section 3.1.10.6. This separate calculation gives $8,535,935 (1985 dollars) for the operation of the FGD system. The operating cost of the plant without FGD system would then amount to $15,130,065 (1985 dollars). The ratio of total operating cost of the plant to the operating staff cost is calculated as follows:

$$\begin{array}{l} \text{Ratio of O\&M cost to Plant staff cost} \\ \text{(Plant without FGD System)} \end{array} = \frac{\$15{,}130{,}065}{(5{,}136{,}000)(1.08)^7} \cong 1.72$$

and

$$\begin{array}{l} \text{Ratio of O\&M to Plant Staff Cost} \\ \text{(Plant with FGD System)} \end{array} = \frac{23{,}666{,}000}{(6{,}048{,}000)(1.08)^7} = 2.28$$

The ratio of total operating costs of the plant with FGD system to the total operating cost of the plant without FGD system is:

$$\frac{\text{O\&M Cost of plant with FGD}}{\text{O\&M cost of plant without FGD}} = \frac{23{,}666{,}000}{15{,}130{,}065} = 1.56$$

3.1.11 Summary of Total Costs of one 450 MW Plant at Rincon with FGD System

The total levelized costs during the assumed 35 years lifetime of a 450 MW coal plant (Rincon Site) at 75% capacity factor, with an FGD System, a 9% cost of money, a 5% total inflation for cost levelization in fuel and in O&M is:

Capital Charges	:	23.8 mills/kwhr
Fuel Cost	:	56.11 mills/kwhr
O&M	:	16.0 mills/kwhr
Total	:	95.9 (1985 start up)

Escalation at 5% per year of all the above costs is shown in Table 3.1.11.1

TABLE 3.1.11.1

LEVELIZED TOTAL COSTS FOR PLANT START–UP IN YEAR INDICATED WITH 5%/YEAR INFLATION BEYOND 1985

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Levelized Cost in Mills/Kwh	95.9	122.4	156.2	199.4	254.5	324.8	414.5	529.0

If an inflation factor of 7 1/4%/yr. beyond 1985 is used for fuel as well as for O&M, the levelizing factor is L = 2.508. The 1985 cost changes as follows:

Capital Charges	=	23.8	mills/kwhr
Fuel Cost	=	77.76	mills/kwhr
O&M	=	22.07	mills/kwhr
		123.63	mills/kwhr

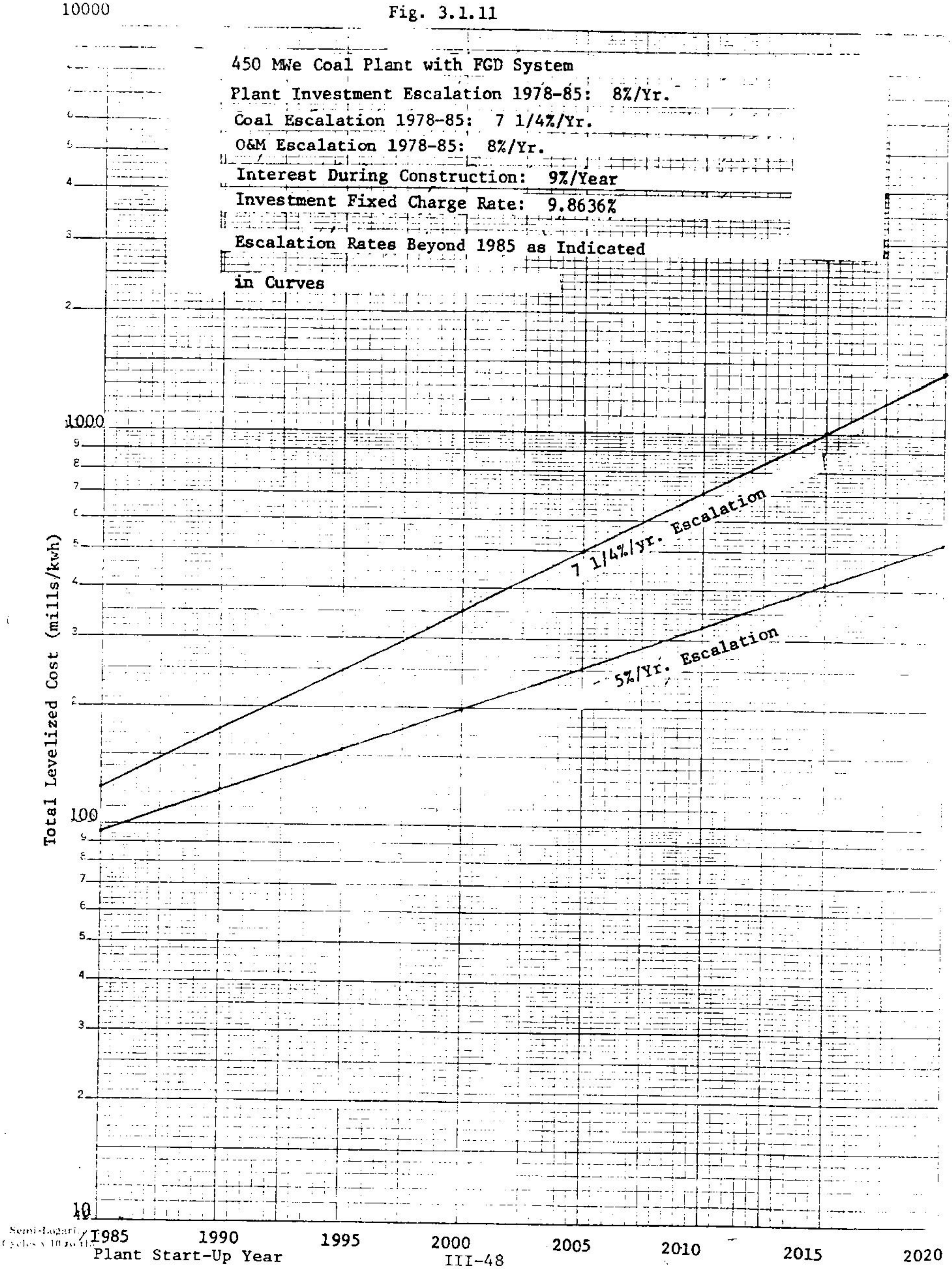
Table 3.1.11.2 indicates the levelized total costs for different start-up years.

TABLE 3.1.11.2

LEVELIZED TOTAL COSTS FOR PLANT START—UP
IN YEAR INDICATED .
WITH 7-1/4%/YEAR INFLATION BEYOND 1985

Start -Up Year	85	90	95	2000	2005	2010	2015	2020
Levelized costs in mills/	123.7	175.5	249.1	353.5	501.6	711.7	1009.9	1433.1

Fig. 3.1.11


450 MWe Coal Plant with FGD System
Plant Investment Escalation 1978-85: 8%/Yr.
Coal Escalation 1978-85: 7 1/4%/Yr.
O&M Escalation 1978-85: 8%/Yr.
Interest During Construction: 9%/Year
Investment Fixed Charge Rate: 9.8636%
Escalation Rates Beyond 1985 as Indicated in Curves
7 1/4%/yr. Escalation
5%/Yr. Escalation
Total Levelized Cost (mills/kwh)
10000
1000
100
10
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year

3.1.12 Example of a Two 450 MW Unit Coal Plant at Rincón with FGD System

The total per unit generating costs are reduced when more than one power production unit is located at the same site. The economies of scale result from the following factors: port facilities and other site developments can be shared and used optimally, there are economies in design, engineering and in construction if the units are constructed on a simultaneous construction schedule with the second unit lagging the first by no more than one year, there are also savings in operating and maintenance costs since some of the personnel can be shared between the two units.

Capital Charges:

As shown in Section 3.1.8.4 the basic cost for a 450 MW coal unit plant is $683/KW for the base year 1978. Economies in the construction of the second unit will amount to an overall reduction of about 5% in the unit cost. Therefore, the basic capital cost of a two unit plant is estimated at $649/KW.

The added costs K include

Total port facilities	$84,000,000
Waste disposal plant at $15.00 per gross KW	13,500,000
	$97,500,000

$$K = \frac{97,500,000}{828,000} = 117.8 \text{ \$/KW}$$

$$C = (K+Co)\ I_F^{\,Y_1 + (1-a)\,Y_2}\ I_{DC}^{\,a\,Y_2}$$

For 1985 operation, with $I_F = 1.08$, $I_{DC} = 1.09$

$$C = (649 + 117.8)(1.373)(1.282) = \$1349.71/\text{KW}$$

Cost in mills/KWhr (1985)

$$= \frac{(1349.71)(0.098636)}{(0.75)(8.760)}$$

$$= 20.3 \text{ mills/KWhr}$$

Fuel Costs:

These vary linearly with output and therefore no economies result from a two unit plant.

With a 5% escalation rate after 1985

$$F_L = 56.11 \text{ mills/KWhr}$$

With a 7.25% escalation rate,

$$F_L = 77.76 \text{ mills/KWhr}$$

Operation and Maintenance Costs (O&M):

From Tables 3.1.10.1 and 1a, the number of persons needed to operate two coal fired units is 271 and the differential staff for the SO_2 removal system is 65.

$$TSC = (\$24,000)(271) = \$6,504,000$$

$$\Delta TSC = (\$24,000)(65) = 1,560,000$$

Utilizing:

$e = 8\%/\text{year}$

$CF = 75\%$

$S = 3\%$

$T_R = 400$ tons/hr

$Y = 7$ years

$P_L = P_{SD} = \$5.50$/ton (Section 3.1.10.8)

Total O&M Cost =

$$\left[(1.584)(6,504) + (2.133)(1,560) + (4.9 \times 10^{-6} \times 900 \times 8760 \times 0.80) + (0.03 \times 400 \times 14 \times 5.50 \times 8.760 \times 0.75) + (1.43 \times 900) + 33.66\right] (10)^3 (1.08)^7$$

$$\text{Total O\&M Cost} = \$21,052.061 \ (10)^3 (1.08)^7$$

$$= \$36,079,533$$

$$\text{Generation at 75\% CF} = (828,000 \times 0.75 \times 8760)$$

$$= 5.43996 \times 10^9 \text{ KWhr}$$

The total O&M cost in mills/KWhr using an inflation rate of 5%/yr for the levelizing factor is:

$$\text{Total O\&M Cost} = \frac{36.080 \times 10^9}{5.43996 \times 10^9} \times 1.81$$

$$= 12 \text{ mills /KWhr}$$

Total Costs:

The total levelized costs during the 35 year lifetime of a two 450 MW units coal plant at Rincón with 75% capacity factor, FGD System, 9% cost of money, 5% total inflation for cost levelization is:

Capital Charges	=	20.3 mills/kwhr
Fuel Costs	=	56.11mills/kwhr
O&M Costs	=	12.0 mills/kwhr
Total 1985 Cost (Levelized)		88.41 mills/kwhr

Table 3.1.12.1 shows the levelized costs for the two unit coal plant at Rincón with different start up years and a 5% inflation rate for all costs beyond 1985.

TABLE 3.1.12.1
LEVELIZED TOTAL COSTS FOR PLANT START-UP
IN YEAR INDICATED FOR A TWO 450 MW UNIT
COAL PLANT WITH 5% PER YEAR INFLATION RATE BEYOND 1985

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Levelized Cost in Mills/KWhr	88.41	112.84	144.01	183.80	234.60	299.39.	382.10	487.67

Assuming an inflation rate of 7.25% beyond 1985 for both fuel and O&M costs, the levelizing factor L is 2.508. The total costs for 1985 are as follows:

Capital Charges	=	20.3 mills/kwhr
Fuel Costs	=	77.76 mills/kwhr
O&M Costs	=	16.63 mills/kwhr
Total 1985 Cost (Levelized)		114.69 mills/kwhr

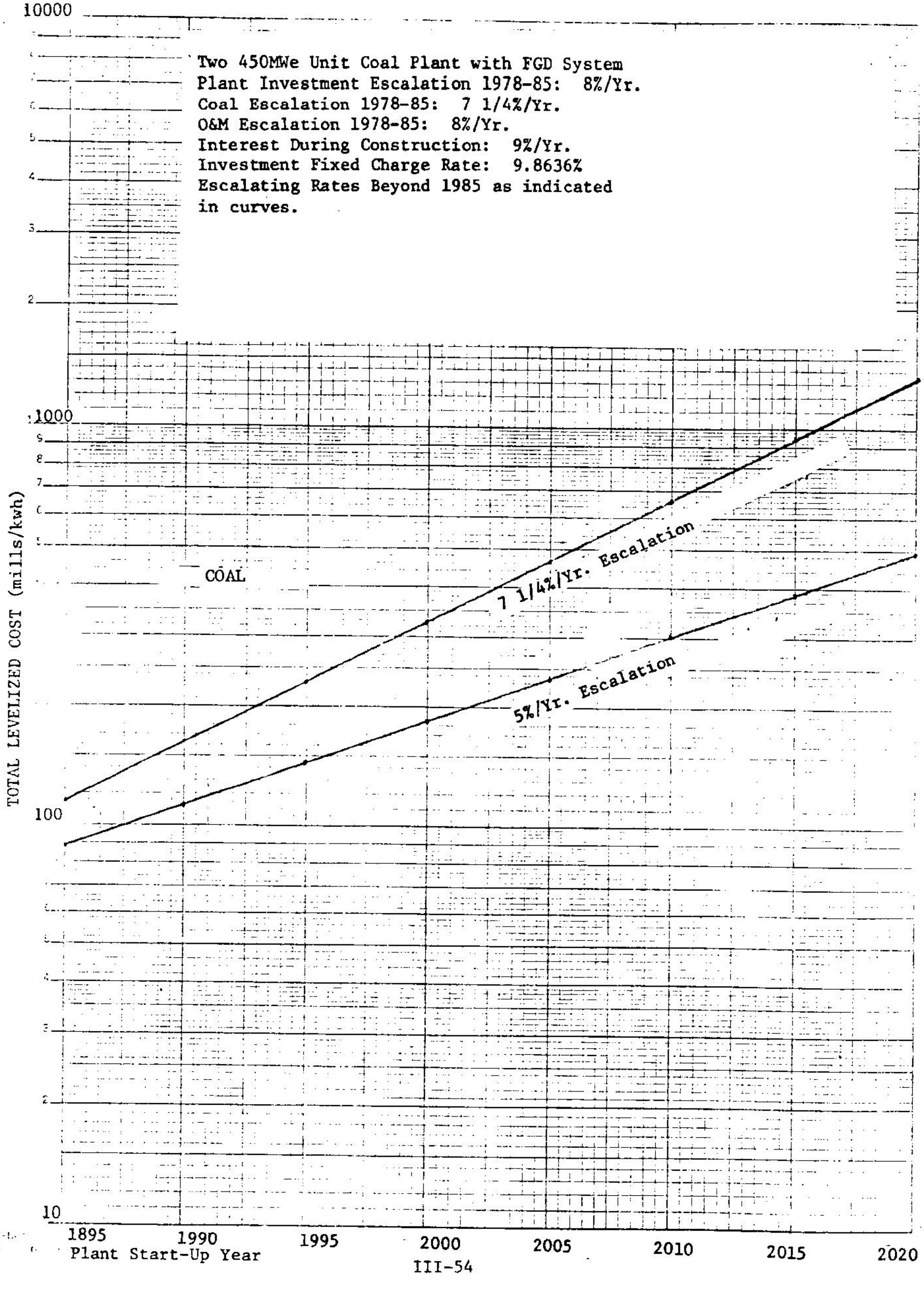
Table 3.1.12.2 indicates the levelized costs for the two 450 MW units plant at Rincón with different start-up years and a 7 1/4% inflation rate for all costs beyond 1985.

TABLE 3.1.12.2

LEVELIZED TOTAL COSTS
FOR A TWO 450 MW UNIT COAL PLANT
START—UP IN YEAR INDICATED
WITH 7-1/4% PER YEAR INFLATION RATE BEYOND 1985

Start—Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Levelized Cost Mills/KWhr	114.69	162.75	230.94	327.71	465.02	659.87	936.36	1328.71

Fig. 3.1.12


10000
Two 450MWe Unit Coal Plant with FGD System
Plant Investment Escalation 1978-85: 8%/Yr.
Coal Escalation 1978-85: 7 1/4%/Yr.
O&M Escalation 1978-85: 8%/Yr.
Interest During Construction: 9%/Yr.
Investment Fixed Charge Rate: 9.8636%
Escalating Rates Beyond 1985 as indicated
in curves.
1000
TOTAL LEVELIZED COST (mills/kwh)
COAL
7 1/4%/Yr. Escalation
5%/Yr. Escalation
100
10
1895
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year

3.2 NUCLEAR PLANTS

3.2.1 General Considerations

This section presents an analysis of the construction, operation and maintenance costs of a nuclear power plant in Puerto Rico.

At present, there are basically two types of nuclear power plants commercially available in the United States.

Boiling Water Reactors (BWR) and Pressurized Water Reactors (PWR). Both systems use slightly enriched uranium as the fuel, and water as the moderator and coolant.

The analysis considers both options with emphasis on the PWR and estimates the costs for the three categories of capital investment, fuel and non-fuel operation and maintenance.

3.2.2 Nuclear Plant Capital Investment

Appendix D contains detailed capital cost estimates for nuclear plants. Various cost estimates are presented for nuclear plants as follows:

(1) New 585 MWe nuclear plant at a site in Northern Puerto Rico. Source of direct cost data estimate is PREPA Consultants[12] and source for estimating costs of engineering services construction management and other indirect costs is UE&C.[9,33,34]
The unit cost is: <u>$775/KW</u>

(2) New 585 MWe nuclear plant at a site in northern Puerto Rico. Source of data is PREPA Consultant Engineers in its entirety.[12]
The 1978 unit cost is: <u>$894/KW</u>

(3) NORCO Unit 1 reactivated for operation in 1986. Source of data is PREPA consultant in its entirety.[12]
The 1978 unit cost is: <u>$817/KW</u>

(4) 1139 MWe PWR Nuclear Plant at a site in Puerto Rico. Source of data is United Engineers & Constructors-NUREG-0241.[33]
The 1978 unit cost is: $685/KW

(5) 1190 MWe BWR Nuclear Plant at a site in Puerto Rico. Source of data is United Engineers & Constructors-NUREG-0242.[34] The 1978 unit cost is: $670/KW

In addition to the above estimates, other sources of data and their estimates are as follows:

(1) EPRI - Report PS-866-SR June 1978
Cost data for 1000 MWe nuclear plant was developed by United Engineers and Constructors. It constitutes the same source of information as the estimates already quoted. Cost for the most comparative Puerto Rico site, the southeast United States is comparable with the figures already quoted.

(2) Gibbs & Hill, Inc.[10]
A total cost of $583/KW (1978) is quoted for a two unit station 1150 MWe, including indirect expenses, engineering construction management and contingency.

(3) ORAU
The Institute for Energy Analysis presents an estimate of $500/KW for a 1-1000 MWe nuclear unit based on 1975 dollars. When escalated to 1978 at 8% per year the cost is $630/KW.

ORAU-76-3 also presents the following estimates:

TABLE 3.2.2(a)

NUCLEAR PLANT COST ESTIMATE

ORAU–76–3[13]

	Dollars of 1985	Dollars of 1978 (1985 costs deflated at 8%/yr)
United Engrs. & Constrs.	950	554
Bechtel	1030	601
Sargent & Lundy	1005	586
General Electric	953	556
Skagit, Washington	1030	601
Tyrone Park, Wis. (800MW)	916	535
Carrol County 2, Ill.	686	400
Davis Besse (906MW)	865	505
Greenwood 2, and 3, Mich. (2 x 1200 MW)	820	479

The UE&C cost estimate presented here was the result of Mr. J.H. Crowley's statement to the Connecticut State Public Utility Control Authority in January 29, 1976. These UE&C estimates are therefore superseded by latter detailed cost estimates by UE&C presented elsewhere in this report. The estimates presented in Table 3.2.2a were found to be on the low side and will not be used in this study to estimate nuclear plant capital costs. Those points where plant sizes are indicated are shown plotted in Figure 3.2.2.

For this study only the highest reported estimates will be used.

Table 3.2.2b summarizes the capital cost data and curve fit used in the nuclear plant capital estimate for this study.

TABLE 3.2.2.(b)

CAPITAL COSTS ESTIMATES
(1978 DOLLARS)

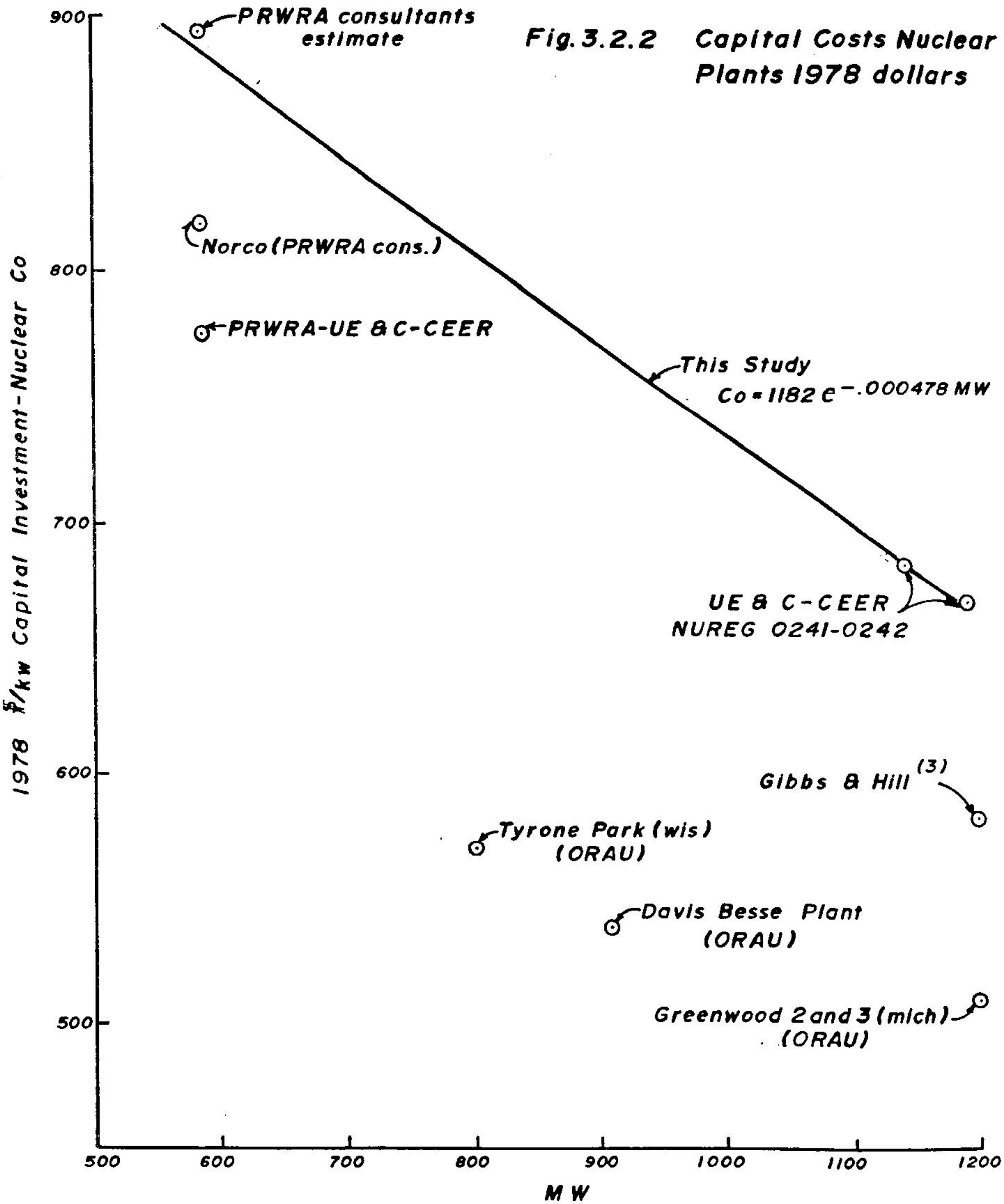
Size, Net	$/KW	Source and Date
585 MW	894	PRWRA (2) – 1979
1139 MW	685	UE&C – 1979
1190 MW	670	UE&C – 1979

$$\text{Exponential Fit (500-1200 MW): } \$/MW = 1182e^{-0.000478MW}$$
$$r^2 = 1.0$$

Figure 3.2.2 presents a plot of the nuclear plant investment cost equation.

The general cost equation can be expressed as:

$$C = (1182e^{-.000478MW} + K)\ I_f^{Y_1} + (1-a)\ Y_2\ I_{dc}^{aY_2}$$



PRWRA consultants estimate
Fig. 3.2.2 Capital Costs Nuclear Plants 1978 dollars
Norco (PRWRA cons.)
PRWRA-UE & C-CEER
This Study
Co = 1182 e^-.000478 MW
UE & C-CEER
NUREG 0241-0242
Gibbs & Hill (3)
Tyrone Park (wis) (ORAU)
Davis Besse Plant (ORAU)
Greenwood 2 and 3 (mich) (ORAU)
1978 $/kw Capital Investment-Nuclear Co
900
800
700
600
500
500
600
700
800
900
1000
1100
1200
MW

where I_f, I_{DC}, Y_1, Y_2, and a are defined in Appendix E.

K are the plant cost adders not included in Co.

The cost in mills per kw-hr is given by: $\text{mills/kwhr} = \frac{(C)(CRF)}{(8.76)(CF)}$

where:

CRF = capital recovery factor plus other costs of money (See Section 3.1.8.1)

CF = plant capacity factor (See Section 3.1.8.2)

For a 585 MWe plant, 1985 at a north coast site in Puerto Rico

K = 0		Y_1	= 0
a = .48		Y_2	= 7
I_f = 1.08		CRF	= .098636
I_{dc} = 1.09		CF	= 0.75

Co = \$894/kw (1978)

$Y_1+(1-a)Y_2 = 3.64$

$aY_2 = 3.36$

1985 investment cost

$C = (894)(1.08)^{3.64}(1.09)^{3.36} = \$1580.35/\text{kw}$

$$\text{cost in mills/kwhr} = \frac{(1580.35)(.098636)}{(.75)(8.760)} = 23.73$$

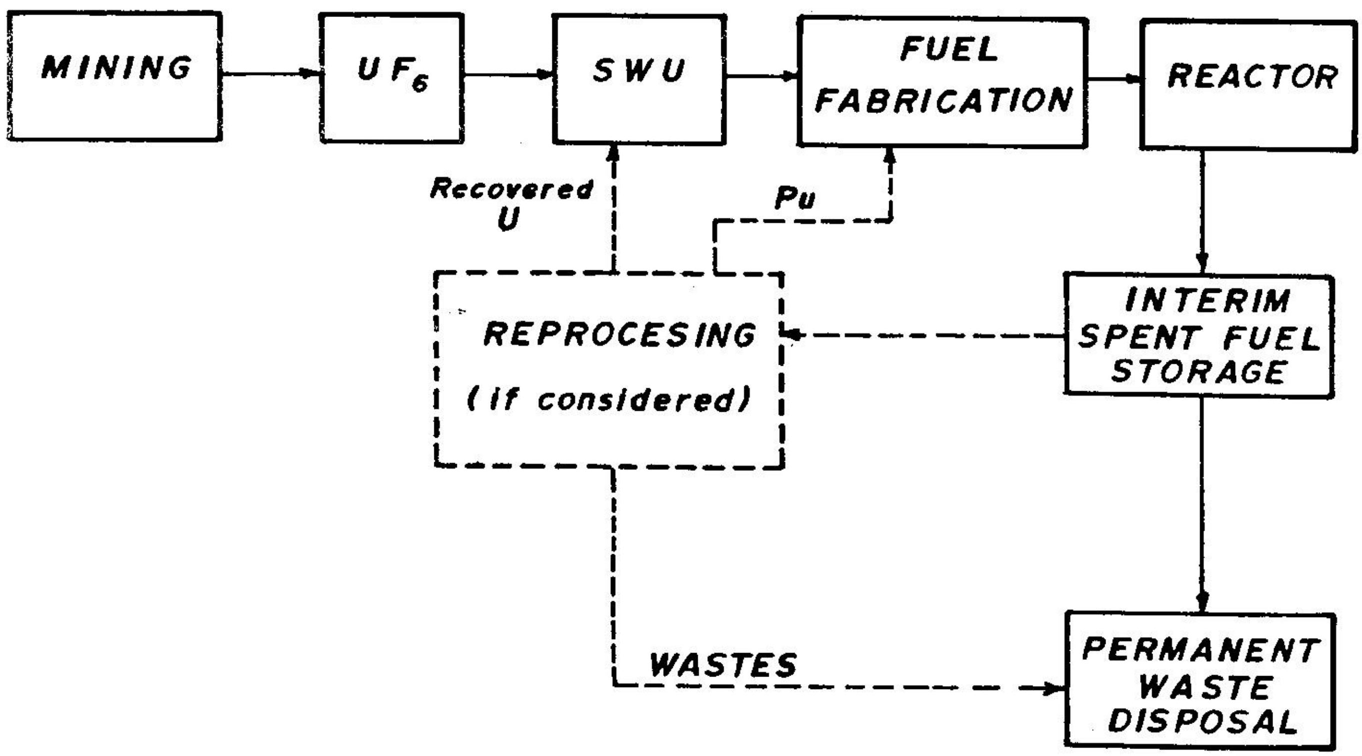
3.2.3 Nuclear Fuel Costs for Puerto Rico

3.2.3.1 General

The evaluation of fuel costs for nuclear plants is a rather complex operation. Figure 3.2.3.1 indicates the various steps involved in the nuclear fuel cycle.

FIGURE 3.2.3.1

THE NUCLEAR FUEL CYCLE



Uranium is widely distributed in nature at very low concentrations in the order of 2-4 ppm in the earth crust and .003 to .004 ppm in the oceans. Coal, lignite, tar sands, shales and oils are also sources of uranium with higher concentrations in the order of 50-200 ppm. Commercial deposits of high grade uranium are in the range of a fraction of a percent, some as high as .75%. The mining costs are inversely proportional to the ore concentration.

The diluted uranium ores are concentrated in mining operation to 85% uranium through a series of physical and chemical processes. The 85% uranium concentrate is in the form of U_3O_8, a yellow clay commonly called yellow cake.

The yellow cake at 85% U_3O_8 concentration is the normally available source of uranium in the opne market. On 1979 the cost of yellow cake is approximately $35-40 per lb.

Uranium, as a commodity, is strongly cost sensitive to the supply-demand relationship. The predicted needs for uranium are therefore important to predict future uranium costs. This will be considered later.

The uranium cake purchased from the various private suppliers must be sent to Government plants for conversion to UF_6, a green salt. This material is suitable for use in gaseous diffusion plants in which the UF_6 is converted into a gaseous phase for physical separation of the isotope U-235.

In these diffusion plants the natural isotopic content of U-235 (0.7%) is increased to desired concentrations in the order of 3% for use in light water reactors(LWR). The depleted uranium tails contain normally 0.2% of the valuable U-235. Charges for conversion are made in terms of dollars per Kg of UF_6. Charges for enrichment are made in terms of dollars per separative work units (\$/SWU). A separative work unit is a measurement of the amount of work performed by the diffusion plants in separating U-235 (the useful fissile material) from the bulk U-238. Depleted uranium tails at 0.2%-U-235 and enriched uranium at ~3% (for LWR) are discharged.

The enriched uranium output from the diffusion plant is in the same chemical form as the uranium fed in, i.e. UF_6.

The enriched UF_6 is then processed by the reactor fuel element manufacturer and converted into UO_2, a black powder.

The use of UO_2 as a nuclear fuel was one of the greatest achievements in nuclear fuel element development during the early part of the 1950-1960 decade. UO_2 is highly stable physically and chemically under intense and prolongued irradiation. Its melting point is close to 5000°F. It has an acceptable thermal conductivity coefficient. It exhibits a fast negative nuclear reactivity coefficient (Doppler coefficient) thereby holding down any nuclear power excursion and shutting down the reactor automatically; this is an important safety consideration. Most important, it has the property of retaining a large fraction of the gross highly radioactive fission products within its matrix, only releasing the gaseous products into the cladding or sealed stainless steel fuel tubes within which the UO_2 fuel resides.

The UO_2 powder is compacted to densities higher than 95% theoretical, and then pelletized into small cylinders. These pellets are used to fill up stainless steel or zircalloy tubes. The tubes are weld sealed and form what is known as a single fuel pin. Various fuel pins are assembled into what is called a fuel assembly. The cost of manufacturing fuel assemblies is normally given in dollars per Kg of uranium manufactured into the assemblies.

After the fuel assemblies are used up in a reactor to produce useful power, they must be stored for a cooling period in a fuel pool within the reactor building. After this they are finally transported in shielded fuel coffins to reprocessing plants where useful by-products (plutonium and unused uranium) are recovered. The charge for this portion is a post operational charge and is normally expressed in $/Kg of uranium disposed.

The recovered uranium and plutonium can be recycled in the reactor resulting in reduced costs. In this study no recycling is assumed.

Pressurized Water Reactor (PWR) fuel cycles normally operate on three batches. At each refueling operation, performed once a year, one third of the fuel assemblies are recovered and replaced with new fresh fuel assemblies, and the remaining fuel assemblies are reshufled within the core. After the first three years of operation all the assemblies reach equilibrium conditions. Each assembly remains in the core for an average of three years or three refuelings after equilibrium condition is reached. The Boiling Water Reactor (BWR) operates on a four batch cycle.

Specific fuel burn-up value for a PWR reactor is of the order of 36,000 MW-days per metric ton of uranium. Therefore a reactor of 600 MWe (equivalent to 1785 MW thermal) operating at a 75% plant capacity factor (275 day operation at full power per year) will generate 490,875 MW days and will require an uranium loading of 13.6 tons. One third of this amount must be replaced yearly. The total dollar inventory tied up in the reactor fuel can be calculated by multiplying the above energy by the unit cost of energy excluding indirect charges. This cost is calculated to be $29 million dollars at the rate of 72.4 cents per million BTU. Interest charges must be accounted for this inventory. These are the indirect charges.

BWR reactors have specific burn up lower than PWR. Values just slightly under 30,000 MWD/ton are typical for BWRs.

The discharged spent fuel elements are stored for a cooling period in a fuel pool designed especifically for this purpose. After six months of cooling down, the spent elements can be shipped in specially shielded casks to reprocessing plants for final disposal. Present NRC regulations concerning final disposition of nuclear wastes are under review.

Recently, a contract design award was announced to Bechtel for the design of a $3 billion nuclear waste solidification facility at DOE's Savannah River Plant near Aiken, S.C.[35] This facility would immobilize high level wastes into a form suitable for permanent disposal.

The fuel pool could be designed and constructed at little added cost to store temporarily all the spent fuel element assemblies discharged during the lifetime of the plant. By that time, many different methods of waste disposal now under design and consideration will have been worked out. The TVA has designed large fuel pools into their reactors and is willing to offer interim storage for spent fuel elements to the industry at a small charge. UE&C estimates at $8,700,000 the extra cost in fuel pool expansion for high density interim spent fuel storage of lifetime discharges of a 1139 MWe PWR reactor plant with 33 refuelings.

The problem of spent fuel disposal is not an insurmountable problem.

3.2.3.2 Nuclear Fuel Unit Costs

A lenghty and complex calculation is involved to determine the total fuel cost in cents per million BTU. Computer programs are available for detailed cost calculation, and detailed "forms" are available for hand calculations.[36] Of particular importance is the treatment of indirect costs or cost of money charges for the capital allocated for the nuclear fuel.

Simple and accurate calculations can be made with certain derived coefficient obtained from sensitivity calculations. The degree of accuracy is good enough for the purposes of this study. The coefficients to be used in this study only apply to light water reactors and are more exact for pressurized water reactors. Average heat rate of the nuclear plants is considered to be in the 10,200-10,300 BTU/kwhr net range. Fuel burn-up of the order of 30,000-35,000 MWe per ton of uranium are typical of these types of plants. The fuel cost coefficients are good for equilibrium cycle costs. The small first core increased cost is neglected.

The following are the cost components ($C_m P_m$) and coefficients (C_n) as determined from sensitivity analyses:[9,28,36]

(1) U_3O_8 (yellow cake) cost component (C_1P_1)
U_3O_8: \$/MMBTU = .00673 x U_3O_8 Cost in $\frac{\$}{\text{lb.}}$

(2) UF_6 conversion cost component (C_2P_2)
UF_6: \$/MMBTU = .005696 x Conversion Cost $\frac{\$}{\text{lb.}}$

(3) Separative or enrichment cost component (C_3P_3)
Enrichment: \$/MMBTU = .00166 x (\$/swu)

(4) Fuel fabrication cost component (C_4P_4)
Fuel Fabr.: \$/MMBTU = .0009174 ($\frac{\$}{\text{lb}}$ of Fabr.)

(5) Spent Fuel Shipping and Disposal (C_5P_5)

(SFSD): $\frac{\$}{MMBTU}$ = .0003957 x ($\frac{\$}{Kg}$ of SFSD)

(6) Indirect Costs

The indirect charges consist of the interest paid on the dollar investment in the fuel core which has been made for a rather long period of time before actual useful energy is produced. This is really a charge on an inventory. The indirect charges can be divided into two parts:

(a) charges for the investment tied up in the nuclear core while it is operating and producing power. These charges are sensitive to the plant capacity factor. The lower the plant capacity factor, the longer the time period and the greater the charges will be. This cost will be designated M_A.

(b) charges for other non-operating periods of time which can be considered approximately constant on the average. This cost will be designated M_B.

The indirect charges during operation M_A can be expressed as:

$$M_A = \frac{(.48783}{CF} \cdot (i) \cdot (C_1P_1 + C_2P_2 + C_3P_3 + C_4P_4)$$

where i = interest of money or cost of money

CF = plant capacity factor

The indirect charge for the other non operating period can be expressed as:

$$M_B = (.25)(T_o)(i) \cdot (C_1P_1 + C_2P_2 + C_3P_3 + C_4P_4 + C_5P_5)$$

where T_o = time in years required for ordering U_3O_8, and UF_6 enrichment. It can be taken as 1.5 years.

The factors of .48783 and 0.25 provide adequate levelling of the funds expenditures during the respective periods considered.

The total fuel costs in \$/MMBTU can be expressed as: Fuel Cost Equation

$$\text{Total Cost \$/MMBTU} = C_1P_1 + C_2P_2 + C_3P_3 + C_4P_4 + C_5P_5 + M_A + M_B$$

3.2.3.3. Cost Component Estimates

(a) Yellow Cake U_3O_8 market predictions

The cost of yellow cake is highly sensitive to the law of supply and demand, as was indicated previously. Assessment of the demand is therefore, very important in determining costs. Larger demands means exploitation of less economical (more diluted concentrations) uranium deposits, and therefore, higher costs.

Table 3.2.3.3a taken from the EPRI report indicates predicted uranium demands.

TABLE 3.2.3.3 (a)
URANIUM REQUIREMENT ESTIMATES*
(U_3O_8 – 1000's short tons-.2% tails)

	No Recycle
1980	170
1985	278
1990	448
1995	680
2000	983

* Based on 5.2×10^{12} kwhr electrical generation by the year 2000.

Figure 3.2.3.3 indicates the S.M. Stoller correlation of cumulative production or demand vs. estimated price taken also from the EPRI report.

(b) <u>Estimate of Nuclear Fuel Cost Components for Present Study</u>

An extensive survey of the literature was performed for cost predictions.

A tabulation summary of the cost survey is presented in Table 3.2.3.3b. It should be pointed out that the references, 29-PREPA consultant S.M. Stoller, 14-EPRI, and 38-PREPA are all-based on the same source, namely S.M. Stoller.[37] The variations might be explained by different escalation rate assumptions between 1977-78 and 1985. The highest value of these three references will be selected and averaged together with the three highest of the remaining five references. However, if any of the remaining five references is lower than the lowest S.M. Stoller based estimate it will be rejected. In this way an adequately weighted and conservatively high average estimate is provided. The estimate will be higher than any S. M. Stoller based prediction, which in themselves are considered safe and conservative by the nuclear industry.

Table 3.2.3.3c illustrates the nuclear fuel costs analysis result for this study following the mentioned procedure.

TABLE 3.2.3.3 .b
SURVEY OF NUCLEAR FUEL COSTS FROM VARIOUS SOURCES
1985 COSTS

Factors ↓ / Source →	(1) ORNL (e) (28)	(2) Almodóvar & Iriarte (39)	(3) PRWRA Consultants SM Stoller (37)	(4) EPRI (a) (14)	(5) PRWRA (38)	(6) ORAU (13)	(7) UE&C (9)	(8) Gibbs & Hill (d) (10)
Ore Cost ($/lb)	20	25	49.20	28.0	46.0	75.0	62.05	60.0
Conversion (($/lb)	1.0	1.80	2.82	1.96	2.0	- (b)	2.96	3.40
Sep.Work ($/SWU)	50	100	103.40	115.0	100.0	150.0	125.66	120
Fuel Fab. ($/lb)	48	53	68.18	51.36	66.81	90.90	111.41	78.40
Spent Fuel Shipp. and Disp. ($/Kg)	-(e)	150	124.0	100.18	100.0	143.60(b)	210.98	275
Interest Charges(%)	8	18	8	-	-	16	16.85	15
$/MMBTU(c)	0.3446	0.468	0.62	0.633	0.66	0.90	1.005	1.14

(a) EPRI Consultants are SM Stoller for uranium pricing and NUS Corporation for cycle cost evaluation.
(b) Conversion costs included in spent fuel shipping and disposal item.
(c) Projected 1985 equilibrium costs (neglects first core increased costs). No recycling.
(d) Escalation at 6% between 1978 costs and 1985 costs included.
(e) ORNL costs of $0.3446/MMBTU include recycling costs at a net charge of 3.21 cents per MMBTU. Assuming a fuel burn up of 36,000MWd/ton of heavy metal (PWR), this will be equal to an equivalent charge of $94.66/kg for shipping and disposal.

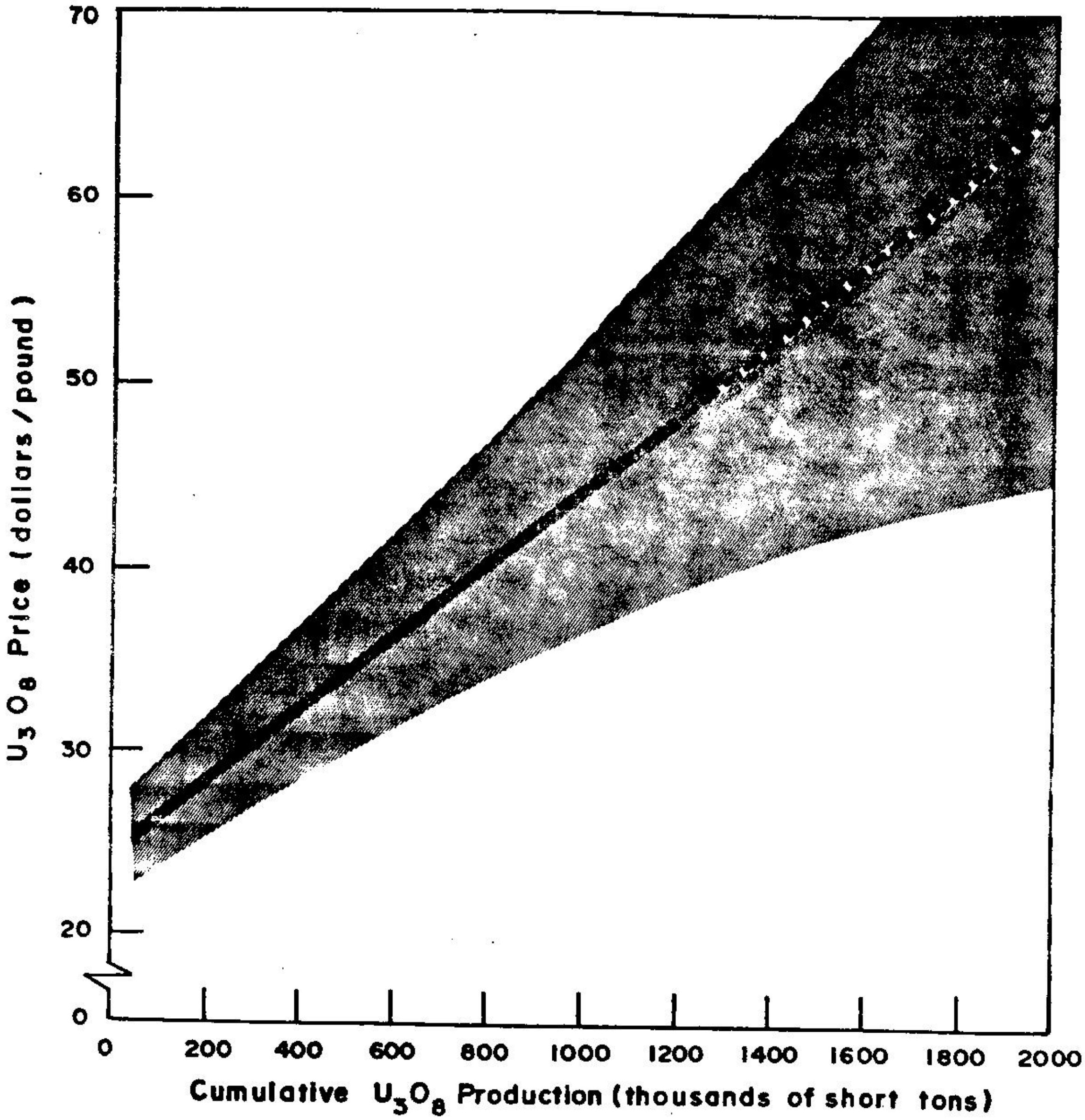


Figure 3.2.3-3 U_3O_8 Projected Price Based on Production: Costs in End-of-the-Year 1977 Dollars

SOURCE: EPRI PS-866-SR Special Report. Technical Assessment Guide, June 1978 (14)

TABLE 3.2.3.3 (c)

NUCLEAR FUEL COSTS – PRESENT STUDY

	1985 Fuel Costs		
	Estimated Unit Costs		Calculated $/MMBTU
Ore Cost	$/lb	61.50	0.414
Conversion	$/lb	3.06	0.017
Sep. Work	$/SWU	127.67	0.212
Fuel Fab.	$/lb	87.00	0.80
Subtotal	-----	------	0.723
Spent Fuel Ship & Disp.	$/Kg	190.00	0.075
TOTAL	----	------	0.798
Indirect Charges (1)	% int.	9%	-----
Operational time(MA)	-----	------	0.042
Non-operational time(MB)	-----	------	0.027
TOTAL	-----	------	0.867

(1) 75% plant capacity factor is used.

(1) 75% plant capacity factor is used.

The cost in mills per kwhr can be expressed as:

$$(\$/\text{MMBTU})\ \frac{(\text{Heat Rate})}{1000}$$

(b) <u>Escalated and levelized fuel costs</u>

Fuel costs are to be escalated from the year 1985 to the corresponding start up year and then levelized for the life of the plant.

The ore cost will normally escalate at a higher rate than the other cost components. The total escalated and levelized fuel cost will be expressed as follows (see Appendix E for levelizing theory).

Nuclear Fuel Cost in dollars/MMBTU

$$= \left[C_1P_1(1+e_{yc})^{Y-1985}\right]L_{yc} +$$

$$\left[C_2P_2+C_3P_3+C_4P_4+C_5P_5+M_A+M_B\right](1+e)^{Y-1985} xL$$

Y = year of estimate , $>$ 1985

e_{yc} = escalation for yellow cake, ave. per year

L_{yc} = levelizing factor for yellow cake

$$= \frac{PW(r_{yc})}{PW(i_{yc})}$$

e = general escalation for material and labor

L = levelizing factor for material and labor

$$= \frac{PW(r)}{PW(i)}$$

(d) Example calculation of fuel cost levelization

Let Y = 1985

u_{yc} = 7 1/4% (ave. yearly escalation of uranium yellow cake during plant life)

u = 5% (ave. yearly escalation of other non-uranium ore charges, labor, materials, and services)

i = 9% (cost of money)

From the above

$$r_{yc} = \frac{i-u_{yc}}{1+u_{yc}} = .01632$$

$$L_{yc} = \frac{PW(at .01632)}{PW(at .09)} = 2.508$$

$$r = \frac{i-u}{1+u} = .038095$$

$$L = \frac{PW(.038095)}{PW\ (.09)} = 1.81295$$

Levelized 1985 Fuel Cost =

$$(.414)(2.508) + (1.81295)(.453)$$

$$= \underline{\$1.86/\text{MMBTU (1985)}}$$

with heat rate of 10,300 BTU/KWH

$$\text{Cost} = (1.86)(10.3) = \underline{\underline{19.15 \text{ mills kwhr}}}$$

3.2.4 Operating and Maintenance (O&M) Cost - LWR

Estimates for a Light Water Reactor Power Plant are considered here

3.2.4.1 Operating and Maintenance Cost Equation

The estimates for operating and maintenance (O&M) costs developed here, are based on the ORNL-TM-6467 report "A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants" and on information obtained by personal communications with UE&C.

According to the ORNL Study, the nonfuel O&M costs for an LWR power plant are comprised of the staff cost, fixed maintenance, fixed and variable supplies and expenses, insurance and operating fees and administrative and general expenses. It should be noted that the maintenance materials cost for a nuclear plant is a fixed expense and does not vary with plant operation time.

(For an LWR plant, the fixed maintenance cost has been determined to be approximately 45% of the total staff cost).

The maintenance costs for a mechanical draft, wet cooling tower has been determined to be $30,630 fixed plus 0.0049 mills per kwhr (1978 dollars).

The fixed and variable supplies and expenses have been correlated with the total net station electrical output and the total kilowatt hour generation respectively. The estimates are $1.47 per KW for the fixed portion and 0.0356 mills/kwhr for the variable portion in 1978 dollars.

Nuclear power plant licensees are required to maintain nuclear liability insurance to a total financial protection of $560 million, according to the Price-Anderson Act. Of this total, a coverage of $140 million is available from commercial insurance pools. An intermediate liability level (called "retrospective premium") of $340 million, is provided between the private insurance and the government liability limits. The remaining $80 million are provided by the federal government.

According to the ORNL-TM-6467 report the associated annual premiums as of June 1978 for one reactor (estimated in 1978 dollars) are as follows:

TABLE 3.2.4.1
ASSOCIATED ANNUAL PREMIUMS

	Coverage $\$10^6$	Premium $\$10^3$
Private Insurance	140	284
Retrospective Premium	340	6
Government Indemnity	80	$6/MWt(up to 3000 mwt)

The operating fees are calculated at $100,000 per year, including the facility routine inspection fees and the owner's inspection-related costs.

The administrative and general expenses are estimated at 15% of the total annual fixed costs, exclusive of insurance and operating fees.

The total annual operating and maintenance costs are therefore summarized as:

$$\text{Total O\&M Cost \$} = \Big[TSC + 0.45\ TSC + 30{,}630 + (4.9 \times 10^{-6} \times kw \times 8760 \times 0.80) + 1.47 \times KW + (35.6 \times 10^{-6} \times KW \times 8760 \times CF) + 290{,}000 + 6 \times MWt + 100{,}000 + 0.15\ (TSC + 0.45TSC + 30{,}630 + 1.47\ KW)\Big]\ (1+e_f)^y$$

where:

TSC	=	total staff cost	CF	=	capacity factor

e_f = average inflation rate of the economy %/yr.

Y = number of years between estimate and commercial operation

Rearranging the terms and adding:

$$\text{Total O\&M Cost (\$)} = (1.6675\ TSC + 1.6905KW + (4.9 \times 10^{-6} \times 8760 \times CF \times kw) + (3.56 \times 10^{-6} \times kw \times 8760 \times CF) + 6 \times MWt + 425{,}225)(1+e_f)y$$

$$\text{O\&M Cost in mills/Kwh} = (\$O\&M)/(KW)(8.76)(CF)$$

To obtain the operating and maintenance cost in mills/KWh levelized for the life of the plant, the above equation is multiplied by the usual levelizing factor

$$\left[\frac{(1+r)^n-1}{r(1+r)^n}\right] \times \left[\frac{i(1+i)^n}{(1+i)^n-1}\right]$$

where:

n = plant life, yrs.

r = $\dfrac{i-u}{1+u}$

u = weighted average inflation rate of the operation and maintenance costs during the n years lifetime of the plant, %/yr

i = rate of interest or cost of money %/yr.

3.2.4.2 Specific Cost Calculation for PREPA 600 MW PWR Power Plant

From Table 3.2.4.2 the staff required for this plant is 208 persons including 56 security personnel. This staff is considerably higher than previous historic figures due to new NRC security regulations. The average yearly cost per person is $24,000 as indicated in Section 3.1; however, we estimate the security personnel cost at $18,000.

The following parameters are used in our example:

Normal O&M staff	=	152
Security related staff	=	56
MWt	=	1785
KW	=	KWe net = 585,000
e_f	=	8%/yr (inflation rate from 1978 to 1985)
Y	=	1985 - 1978 = 7 yrs
CF	=	75%
i	=	9%/yr
u	=	5%/yr
r	=	0.038095 (from the relationship of r, i, u)
n	=	35 yrs

TABLE 3.2.4.2

STAFF REQUIREMENTS FOR LWR PLANTS[32]

	400-700 MW(e) unit				701-1300 MW(e) unit			
	Units per site				Units per site			
	1	2	3	4	1	2	3	4
Plant manager's office								
Manager	1	1	1	1	1	1	1	1
Assistant	1	2	3	4	1	2	3	4
Quality assurance	3	4	5	6	3	4	5	6
Environmental control	1	1	1	1	1	1	1	1
Public relations	1	1	1	1	1	1	1	1
Training	1	1	2	2	1	1	2	2
Safety	1	1	1	1	1	1	1	1
Administrative services	13	15	17	19	13	15	17	19
Health services	1	1	1	2	1	1	1	2
Security	56	56	56	105	56	56	56	112
Subtotal	79	83	88	142	79	83	88	149
Operations								
Supervision (excluding shift)	2	2	4	4	2	2	4	4
Shifts	28	48	68	88	33	58	83	108
Subtotal	30	50	72	92	35	60	87	112
Maintenance								
Supervision	8	8	10	12	8	8	10	12
Crafts	14	22	30	38	16	26	36	46
Peak maintenance annualized	55	110	165	220	55	110	165	220
Subtotal	77	140	205	270	79	144	211	278
Technical and engineering								
Reactor	1	2	3	4	1	2	3	4
Radiochemical	2	2	3	4	2	2	3	4
Instrumentation and controls	2	2	3	4	2	2	3	4
Performance, reports, and technicians	17	21	25	29	17	21	25	29
Subtotal	22	27	34	41	22	27	34	41
TOTAL	208	300	399	545	215	314	420	580
Less security	152	244	343	440	159	258	364	468
Less security and peak maint.	97	134	178	220	104	148	199	248

$$\text{Total O\&M Cost} = (1.6675)(24\times152+18\times56)+(1.6905\times585)+(4.9\times10^{-6}\times8760 \times0.80\times585)+(35.6\times10^{-6}\times8760\times0.75\times585)+(6\times1.785) +(425.225)\quad 10^3(1.08)^7$$

Total O&M Cost = $16,016,841.

$$= \frac{16{,}016.8}{(585\times8.76\times0.75)} = 4.17 \text{ mills/kwh}$$

This cost levelized for the 35 years life of the plant is:

$$\text{O\&M (Lev)} = \left[\frac{(1.038095)^{35} - 1}{0.038095)(1.038095)^{35}}\right]\left[\frac{0.09(1.09)^{35}}{(1.09)^{35} - 1}\right]$$

$$= (4.17)(1.81) = 7.55 \text{ mills/KWh}$$

3.2.5 **Summary of Total Costs of One 600MW Nuclear Plant at a Site in Northern Puerto Rico**

The total 1985 costs are:

Capital Charges	23.73	mills/kwhr.	
Fuel	8.93	"	"
O&M	4.17	"	"
	36.83	"	"

The total levelized costs during 35 years assumed lifetime of a 600MW Nuclear LWR Plant at 75% capacity factor, 9% interest on money, 5% ave. total inflation rate per year after 1985 except for Uranium (U_3O_8) which is escalated at 7 1/4% per year are as follows:

Capital Charges	23.73	mills/kwhr.	
Fuel	19 .15	"	"
O&M	7.55	"	"
1985 START-UP (35 year levelized cost)	50.43		

The levelized costs for other start-up years beyond 1985 are given in Tables 3.2.5a, . b and c for different escalation rates.

TABLE 3.2.5a

600MW LWR PLANT LEVELIZED COSTS, ESCALATION 5% PER YEAR FOR ALL COSTS (MILLS/KWHR)

START-UP YEAR	1985	1990	1995	2000	2005	2010	2015	2020
COSTS	47.47	60.59	77.32	98.69	125.95	160.75	205.16	261.85

TABLE 3.2.5b

600MW LWR PLANT LEVELIZED COSTS, ESCALATION 5% PER YEAR FOR ALL COSTS EXCEPT URANIUM (U_3O_8) AT 7 1/4% PER YEAR (MILLS/KWHR)

START-UP YEAR	1985	1990	1995	2000	2005	2010	2015	2020
U_3O_8 costs (7 1/4% esc)	10.69	15.17	21.52	30.54	43.33	61.50	87.28	123.84
All others (5%/yr)	39.74	50.71	64.73	82.62	105.44	134.57	171.75	219.21
TOTAL	50.43	65.88	86.25	113.16	148.77	196.07	259.03	343.05

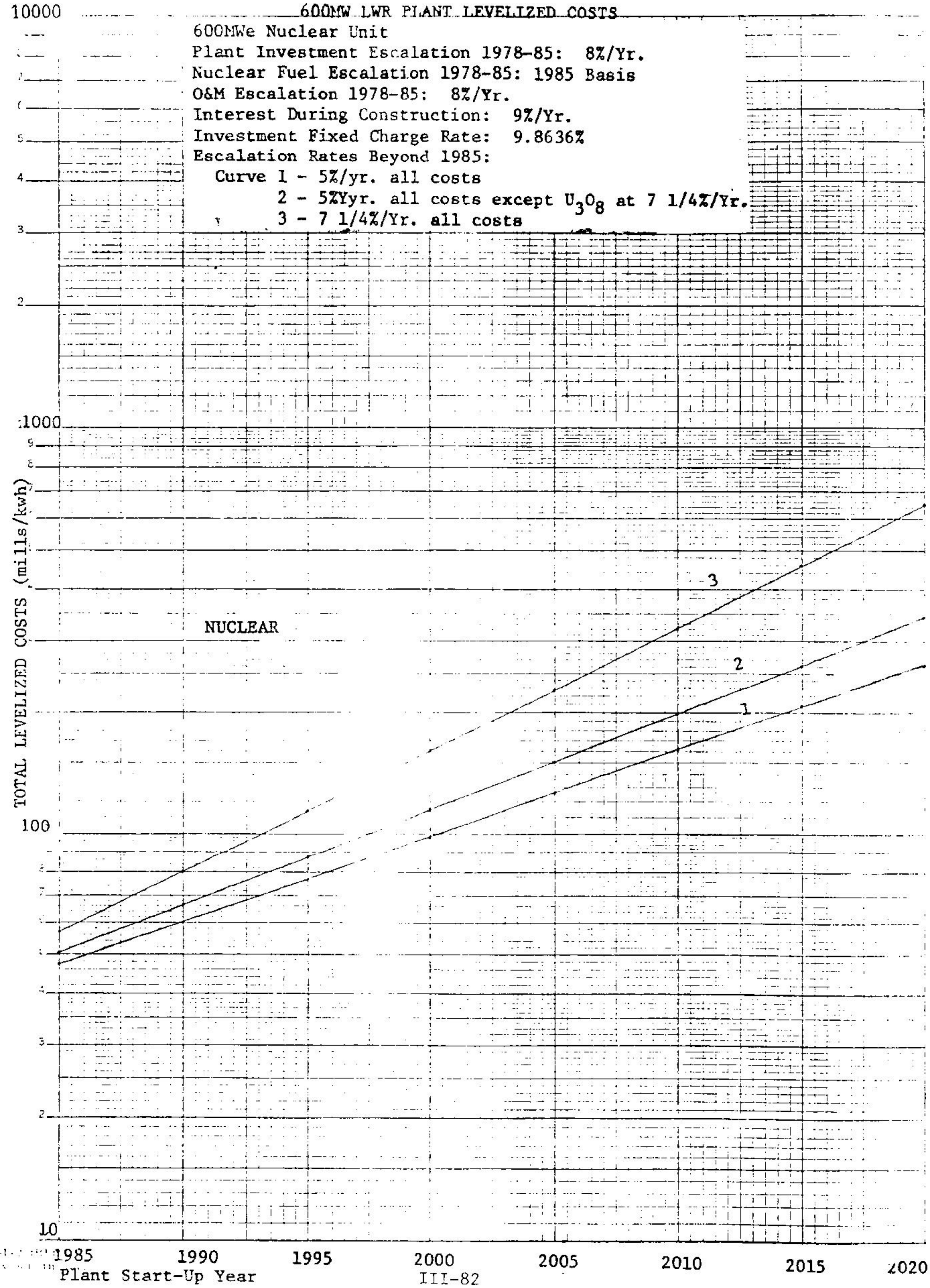
TABLE 3.2.5c

600MW LWR PLANT LEVELIZED COSTS, ESCALATION 7 1/4% PER YEAR FOR ALL COSTS (MILLS/KWHR)

START-UP YEAR	1985	1990	1995	2000	2005	2010	2015	2020
MILLS/KWHR	56.58	80.28	113.93	161.67	229.41	325.53	461.94	655.49

Figure 3.2.5 indicates the plot of the above tables.

FIGURE 3.2.5


600MW LWR PLANT LEVELIZED COSTS
600MWe Nuclear Unit
Plant Investment Escalation 1978-85: 8%/Yr.
Nuclear Fuel Escalation 1978-85: 1985 Basis
O&M Escalation 1978-85: 8%/Yr.
Interest During Construction: 9%/Yr.
Investment Fixed Charge Rate: 9.8636%
Escalation Rates Beyond 1985:
Curve 1 - 5%/yr. all costs
2 - 5%Yyr. all costs except U_3O_8 at 7 1/4%/Yr.
3 - 7 1/4%/Yr. all costs
NUCLEAR
TOTAL LEVELIZED COSTS (mills/kwh)
10000
1000
100
10
1
2
3
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year

3.2.6 Example of Two 600 MW Unit LWR Plant in Northern Puerto Rico

The total levelized unit cost of two 600 MW nuclear units is smaller than that for a one unit plant due to economies in design, engineering and construction and in operation and maintenance.

The costs are estimated for a plant with an assumed lifetime of 35 years, 75% capacity factor, 9% per year interest charge on money, 5% per year average inflation rate after 1985, except for uranium (U_3O_8) which is escalated at 7 1/4% per year.

3.2.6.1. Capital Charges

The total capital investment unit cost for a two unit plant is estimated at 95% of the cost of the one unit plant. However, an additional year is added to the construction schedule so that the second unit will begin operation in 1986 . The cost will therefore be escalated at 5% for the additional year to be consistent with calculations for the other energy alternatives.

The capital charges are 23.67 mills/KWhr.

3.2.6.2 Fuel Costs

The fuel costs previously estimated for one unit are escalated from 1985 to 1986 for the second unit at 5% except for U_3O_8 which is escalated at 7 1/4% and then averaged. Thus, the fuel cost is:

(0.414)(2.508)(1.0725) + (1.81295)(0.453)(1.05) = \$1.98/MMBTU

(1986)

$$\frac{1.86 + 1.98}{2} = \$1.92 \text{ MMBTU} \quad \text{(Levelized average)}$$

with heat rate of 10,300 BTU/KWhr

Fuel cost = (1.92)(10.3) = 19.78 mills/KWhr

3.2.6.3 O&M Costs

According to Table 3.2.4.2, two 600 MW nuclear units will have a total staff of 300, including 56 security related personnel.

Total O&M cost (\$) = (1.6675 TSC + 1.6905 KW + 40.5 x 10^{-6} x 8760 x CF x KW + 6 x MWt + 540,449) $(1.08)^7$

(The inspection related costs included in the above equation are \$100,000 for the first unit and \$80,000 for the second unit)

Normal O&M Staff = 244

Security related staff = 56

KW = 1,170,000

MWt = 3570

CF = 0.75

Total O&M Cost = \$24,496,330.

$$= \frac{24,496,330}{1170 \times 8.76 \times 0.75} = 3.19 \text{ mills/kwhr}$$

The O&M cost levelized for the 35 years plant life at 5% per year u is

Total O&M cost = (3.19)(1.81) = 5.77 mills/KWhr (levelized)

Total Costs:

Capital Charges	23.67 mills/KWhr
Fuel Cost	19.78 " "
O&M Cost	5.77 " "
35 years levelized cost (Start-up in 1985 & 86)	49.22 mills/KWhr

Tables 3.2.6 a, b, and c show the levelized costs for different start-up years beyond 1985 at different escalation rates.

TABLE 3.2.6a

LEVELIZED COSTS FOR A TWO 600MW UNIT LWR PLANT
ESCALATION 5% PER YEAR (ALL COSTS IN MILLS/KWHR)

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Total Cost	46.04	58.76	74.99	95.71	122.16	155.91	198.98	253.96

TABLE 3.2.6b

LEVELIZED COSTS FOR A TWO 600MW UNIT LWR PLANT.
ESCALATION 5% PER YEAR ALL COSTS EXCEPT URANIUM (U_3O_8) at 7 1/4% PER YEAR IN MILLS/KWHR

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
U_3O_8 Cost (7 1/4% Esc)	11.08	15.72	22.31	31.66	44.92	63.75	90.46	128.36
Other Costs (5% Esc.)	38.14	48.68	62.13	79.29	101.20	129.16	164.84	210.38
Total Cost	49.22	64.40	84.44	110.95	146.12	192.91	255.30	338.74

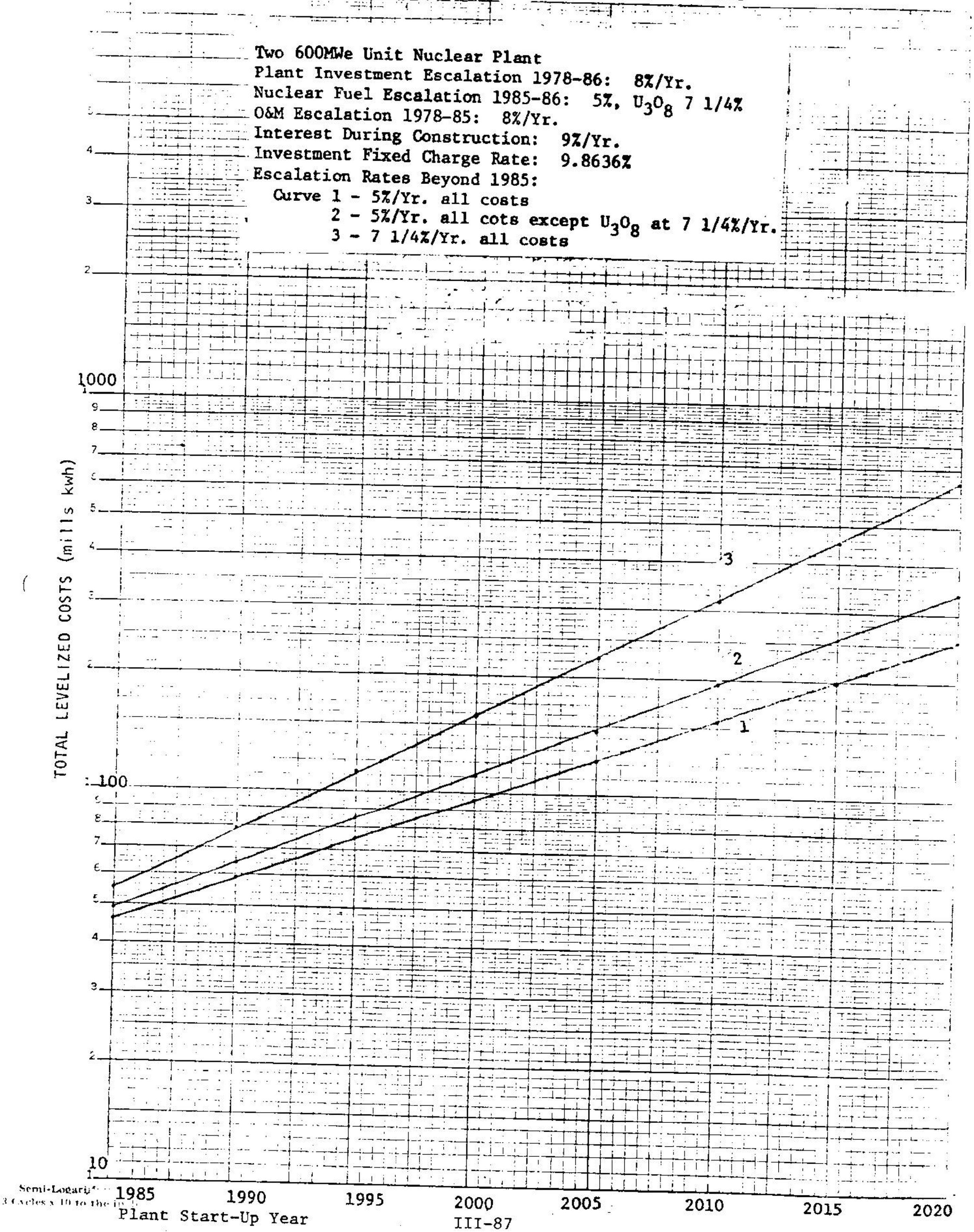
TABLE 3.2.6c

LEVELIZED COSTS FOR A TWO 600MW UNIT LWR PLANT. ESCALATION 7 1/4% PER YEAR
(ALL COSTS IN MILLS/KWHR)

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Total Cost	55.39	78.60	111.53	158.27	224.58	318.69	452.22	641.71

Figure 3.2.6 shows the plot of the above tables.

FIGURE 3.2.6
LEVELIZED COSTS FOR A TWO 600MW UNIT LWR PLANT



3.3 OIL FIRED POWER PLANT

3.3.1 Capital Investment Charges for Residual Oil Fired Plant

Appendix E illustrates the capital cost estimates of oil fired power plants. The following unit costs are estimated:

		1985 Costs
PREPA[12]	450 MW	693.5 \$/KW
EPRI[14]	1000 MW	694* \$/KW

* Minimum indicated cost

EPRI costs vary between 694-822\$/KW for 1000 Mwe units.

The following data is to be used in estimating the capital investment charges:

1. Unit Capital Cost (1985) 693.5 \$/KW
2. Capital Investment fixed charge rate = 9.8636%
3. Plant Capacity Factor = 75%
4. Plant Cost Adders (K) = 0.

Levelized plant capital cost in mills/kwh

$$\frac{(693.5)\ (.098636)}{(.75)\ (8.76)} = 10.4 \text{ mills/kwh.}$$

3.3.2 Fuel Oil Costs

Between oil, coal and nuclear fuel cost predictions, predicting fuel oil costs is probably the most uncertain. The fast escalation of oil costs is expected to continue at an accelerated pace regardless of new findings of oil reserves.

PREPA consultants[12] have recently made some predictions for the cost of residual oil delivered at PREPA power plants. Table 3.3.2a summarizes these predictions.

TABLE 3.3.2a

RESIDUAL FUEL OIL COSTS PREPA CONSULTANTS PREDICTION

		1980	1985	1990	1995	2000
Delivered	High	16.79	36.76	63.88	87.10	117.35
$/BBL	Medium	14.30	28.50	50.40	69.15	91.48
(.5% S)	Low	12.59	24.29	40.08	53.36	71.47

The Electric Power Research Institute (EPRI)[14] predicts real low prices of residual fuel oil. Table 3.3.2b indicates EPRI predictions.

TABLE 3.3.2b

RESIDUAL FUEL OIL COSTS EPRI PREDICTIONS

.3-.5% S Delivered Oil	1980	1985	1990	1995	2000
$/MMBTU	3.04	3.13	3.23	3.41	3.59
$/BBL*	18.24	18.78	19.38	20.46	21.54

*equivalent at 6 MMBTU/BBL

It is evident that EPRI has been underestimated and that even the high values predicted by PREPA consultants are too low. Oil cost today (mid 1979) is even higher than the predictions of PREPA consultants for 1980.

A curve fitting of the PREPA consultants "high" predictions for Residual Fuel Oil Costs indicates the following correlation:

$$C_B = 14.08 + 5.03Y \qquad \text{(Eq 3.3.2)}$$

where

C_B = cost of residual oil in dollars per barrel

Y = year less 1980

Coefficient of determination of fit $r^2 = 1.0$

PREPA consultants oil high price predictions are based on a linear yearly increase of approximately $5.03 per barrel. The average yearly escalation rate for the high estimate in Table 3.3.2a is 10.21%.

The fuel oil costs to be used in this study will be based on a linear equation similar to equation 3.3.2 but adjusted to the present oil market conditions. Our cost equation is:

$$C_B = 25.00 + 6.50Y \qquad \text{(Eq. 3.3.2a)}$$

Equation 3.3.2a will be used up to the year 1985 only when the predicted price of fuel oil is $57.50 per barrel. This corresponds to an average yearly escalation of 19% per year between 1979 and 1985 which is well within recently experienced values.

Beyond the year 1985 an average escalation rate of 9% per year will be used in this study. Using this formulation, the 1995 predicted cost will be \$136.12 per barrel. The value obtained using the linear relation is \$122.50 per barrel. After the year 1995 the compounded escalation rate 9% per year prediction is much larger than the linear relationship of equation 3.2.2a. It is reasonable to assume that after the year 1995 fuel oil costs will begin the real high spiral of escalation dictated by a 9% compounded escalation as compared to a linear relationship. Figure 3.3.2 illustrates the linear and the compounded escalation rates for the period of interest. Interest of money has been taken as 9% per year, therefore the 9% compounded escalation for oil seems to be a reasonable assumption.

3.3.2.1 Levelized Fuel Oil Costs for a 450 MW Oil Fired Power Plant

For a 450 MW oil fired plant the following heat rate is assumed:

Plant net heat rate at 75% load = 9200 Btu/kw hr.

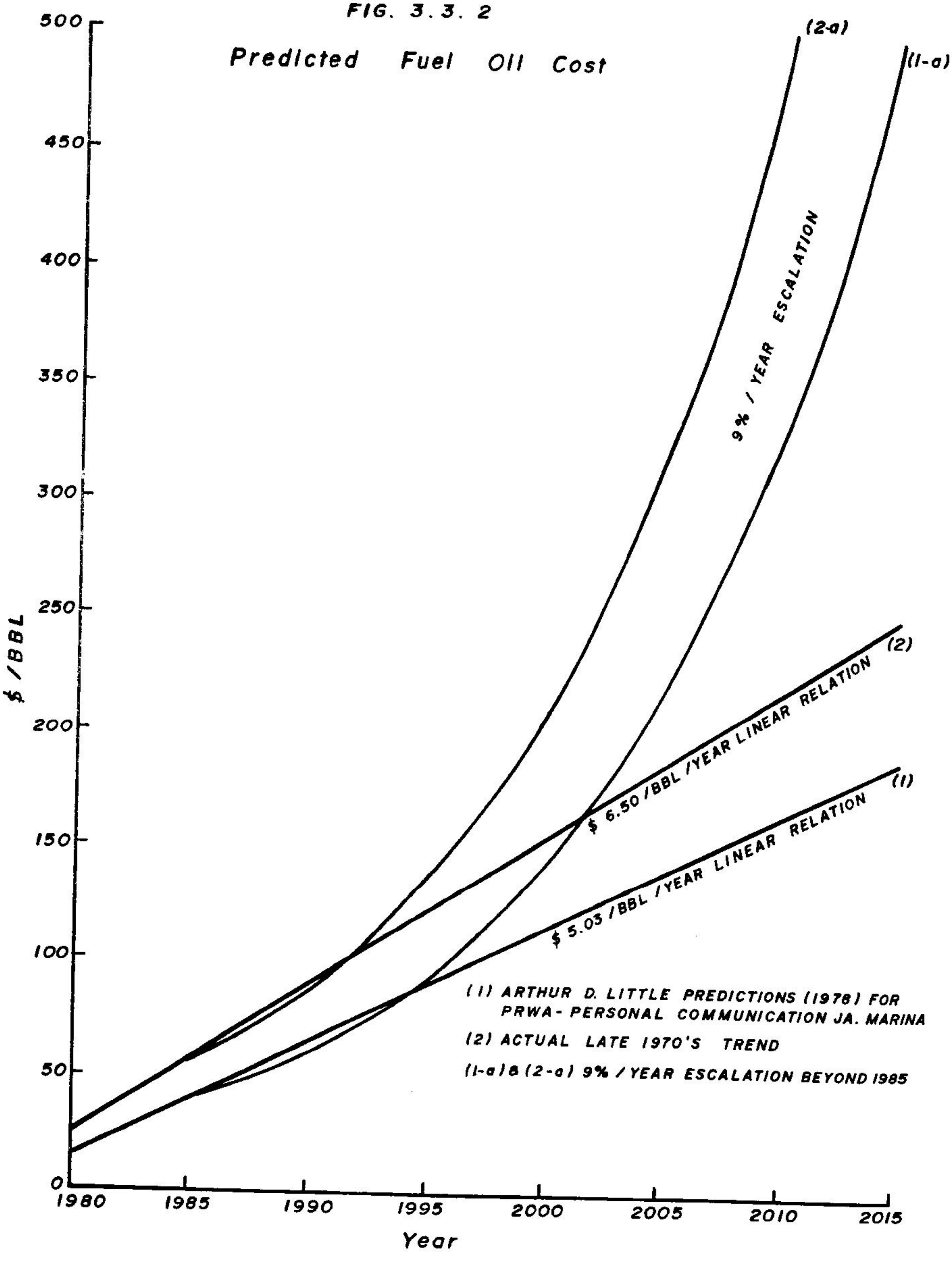
The heat content of a barrel of oil is taken as 6.0 million Btu. The fuel oil cost in mills/kw hr can be expressed as:

$$\text{Oil Cost mills/kwhr} = \frac{\left(\frac{\$}{BBL}\right)(H.R)}{\left(\frac{MMBTU}{BBL}\right) . 10^3} . L$$

where L is the levelizing factor for the continuously escalating fuel price during the lifetime of the plant (Appendix E),

FIG. 3.3. 2

Predicted Fuel Oil Cost



$$L = \frac{(1+r)^n - 1}{r(1+r)^n} \cdot \frac{(i)(1+i)^n}{(1+i)^n - 1}$$

$$\text{and } r = \frac{i-u}{1+u}$$

i, interest or cost of money = 9%

u, fuel escalation rate = 9%

$\therefore \quad r = 0$

The limit of $\frac{(1+r)^n - 1}{r(1+r)^n}$ as r approaches o is

$$\lim_{r \to 0} \frac{(1+r)^n - 1}{r(1+r)^n} = n.$$

$$\therefore L = n \frac{i(1+i)^n}{(1+i)^n - 1} = (35)(0.0946358)$$

$$= 3.3123$$

$$\text{Oil Cost in mills/kwh} = \frac{57.50}{6} \cdot \frac{9200}{10^3} (3.312)$$

$$= (88.16)(3.312)$$

$$= 292 \text{ mills/kwh}$$

The fuel costs in mills/kwhr for various start-up years is shown in Table 3.3. 2c.

TABLE 3.3.2 (c)

OIL FUEL COSTS IN MILLS/KWHR

450 MW OIL PLANT

Start–Up Year	1985	1990	1995	2000	2005	2010	2015	2020
1st. year cost	88.16	135.6	208.7	321.12	494.1	760.2	1169.7	1799.7
Levelized cost	292.0	449.3	691.3	1063.6	1636.5	2517.9	3874.1	5960.9

3.3.3 Operation and Maintenance Costs

Operation and maintenance charges for oil fired power plants have increased considerably during the last decade. Electrical World[26] reports O&M costs of the order of 1.0 mill/kw-hr for oil fired power plants in their 20th. Steam Station Cost Survey.

PREPA experience with oil fired power plants operation is the best source for estimating O&M costs in this study.

The Aguirre Steam Plant located in south Puerto Rico at the Jobos Bay has two 450 MW steam turbo-generator units. Total manpower for the two units is approximately 166 men which yields approximately 0.18 men per MW. This figure compares with Electrical World statistics.[26] PREPA has reported an O&M cost of 1.62 mills/kwh. for the Aguirre Units 1-2 power plant for the mid 1977 to mid 1978 year.[40]

The cost of O&M of oil fired plants is a rather small fraction of the total cost; less than 5% is reported by the 20th Steam Cost Survey of Electrical World. It is unnecessary to develop detailed equations to describe this cost component.

In this study the average O&M cost of the PREPA Aguirre Plant for 1977-78 will be taken as the early 1978 O&M cost for oil fired plants and will be escalated at the rate of 8% per year up to the year 1985 and 5% per year thereafter. Cost levelization during the plant lifetime is made at 5%/year u and 9% per year i.

Table 3.3.3a illustrates the O&M costs for a 450 MW oil plant.

TABLE 3.3.3a

O&M COSTS FOR 450 MW OIL FIRED PLANT
MILLS/KWHR

	1985	1990	1995	2000	2005	2010	2015	2020
Irst. Year cost	2.78	3.55	4.53	5.78	7.38	9.41	12.00	15.30
Levelized cost	5.03	6.42	8.20	10.46	13.35	17.04	21.75	27.76

3.3.4 Total Operating Costs

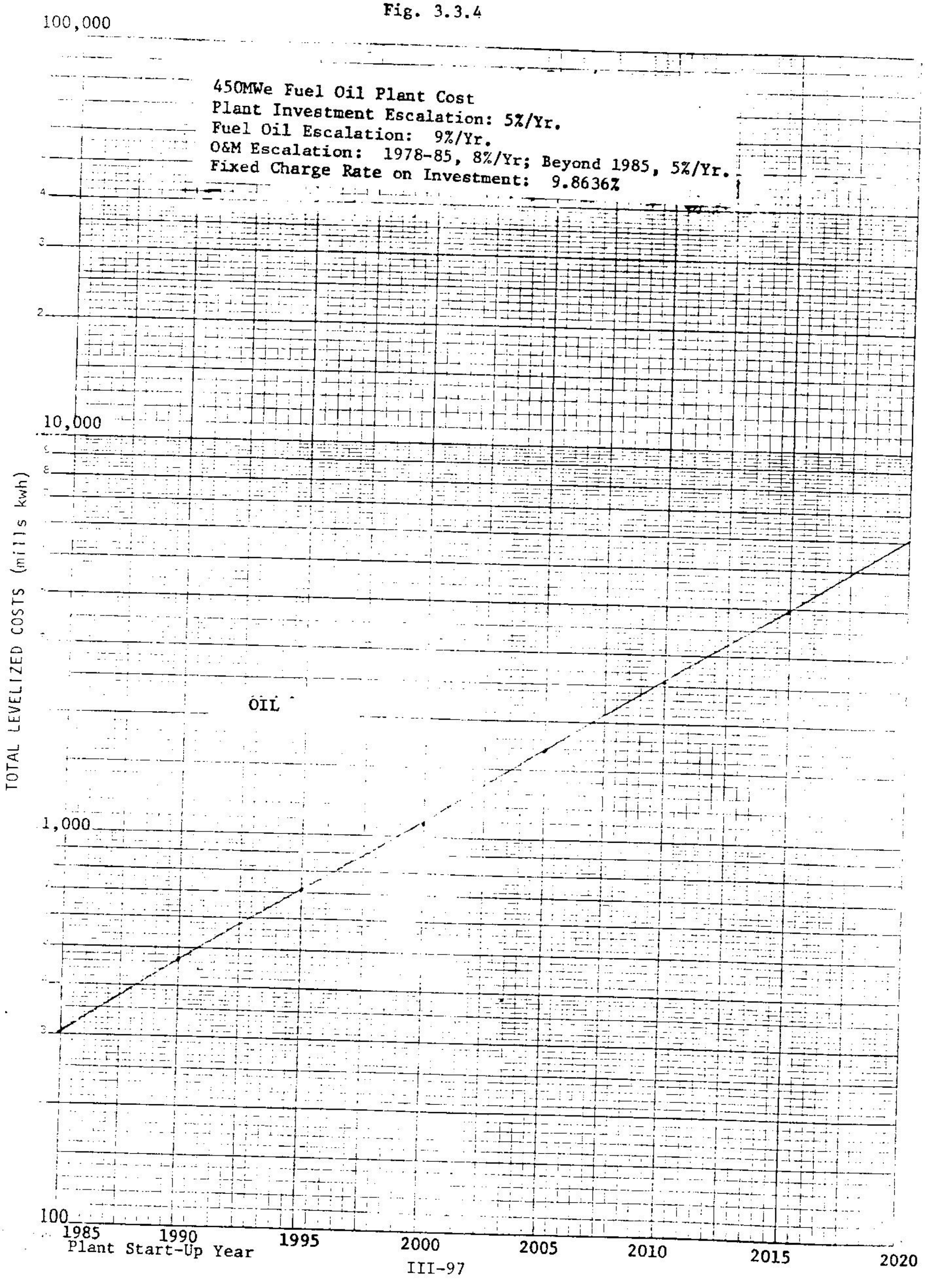
The total operating costs under the assumptions made are shown in Table 3.3.4 and Figure 3.3.4 for plant start-up as indicated.

TABLE 3.3.4

FUEL OIL PLANT TOTAL OPERATING COSTS
MILLS/KWHR

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Fuel	88.16	135.6	208.7	321.12	494.1	760.2	1169.7	1797.7
O&M	2.78	3.55	4.53	5.78	7.38	9.41	12.0	15.3
Total 1st. Year Cost Fuel + O&M	90.94	139.15	213.23	326.9	501.48	769.61	1181.7	1813.0
Lev. Inv.	10.40	13.27	16.94	21.62	27.59	35.22	44.95	57.37
Lev. Fuel	292.00	449.3	691.3	1063.6	1636.5	2517.9	3874.1	5960.9
Lev. O&M	5.03	6.42	8.20	10.46	13.35	17.04	21.75	27.76
Lev. Total	307.43	468.99	716.44	1095.68	1677.44	2570.16	3940.8	6046.03

Fig. 3.3.4


450MWe Fuel Oil Plant Cost
Plant Investment Escalation: 5%/Yr.
Fuel Oil Escalation: 9%/Yr.
O&M Escalation: 1978-85, 8%/Yr; Beyond 1985, 5%/Yr.
Fixed Charge Rate on Investment: 9.8636%
100,000
10,000
1,000
100
TOTAL LEVELIZED COSTS (mills kwh)
OIL
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year

3.3.5 Example of Total Generation Costs for a Two 450MW Unit Oil Fired Power Plant in Puerto Rico

In the estimation of levelized total generation costs for two 450MW oil fired units, account must be taken of the economies that result from engineering, design and construction.

3.3.5.1 Capital Charges

It is estimated that the per unit capital costs of a two unit 450 MW each oil fired power plant is 90% of the single unit plant. That is:

Unit Capital Cost (1985)	624.15	\$/KW
Levelized plant capital cost in mills/KWhr	9.37	mills/KWhr

3.3.5.2 Fuel Costs

The fuel costs in mills per kilowatt-hour are as shown in Table 3.3.2a with a 9% cost of money and a 9% fuel escalation rate.

3.3.5.3 Operation and Maintenance

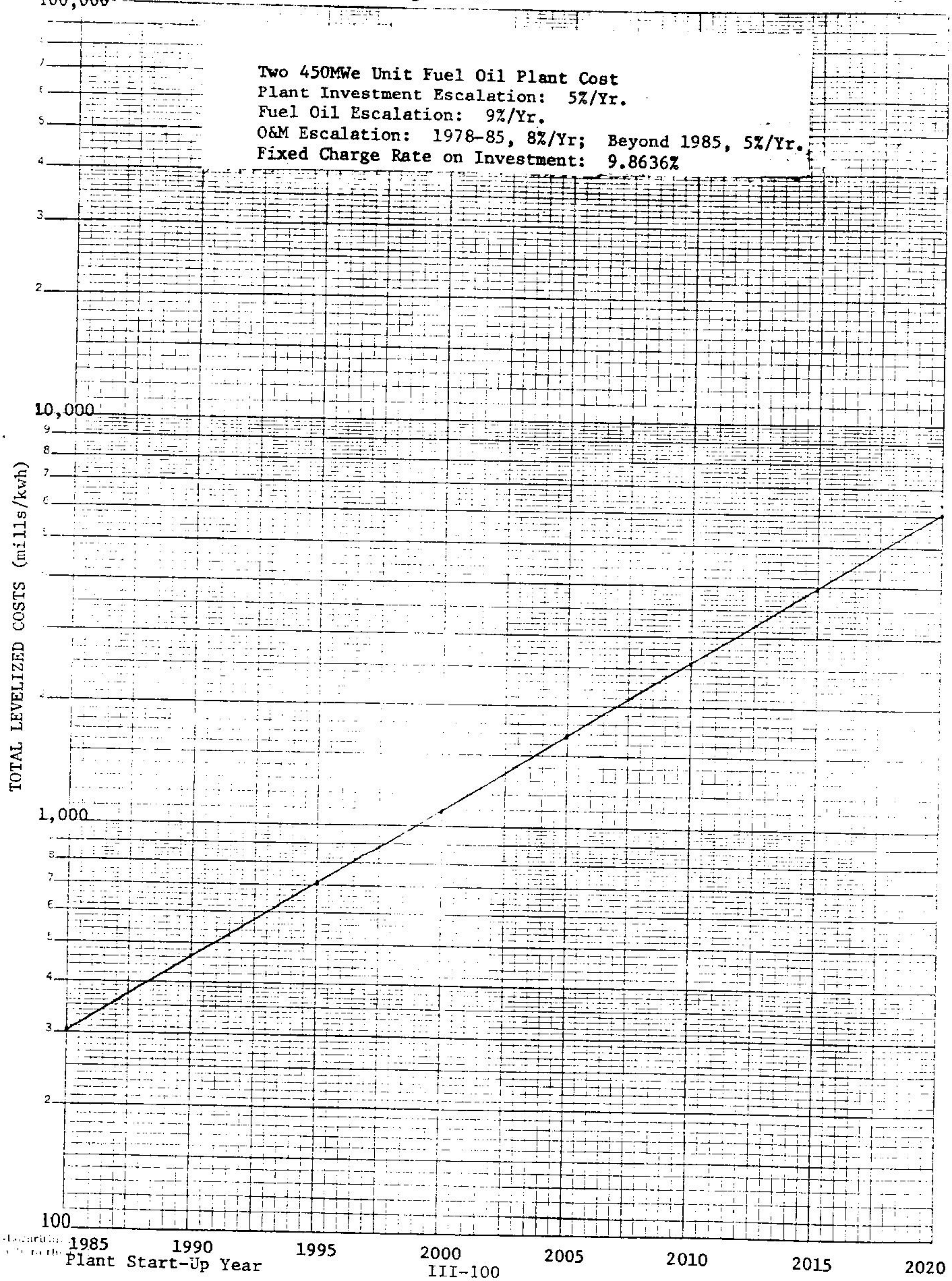
The operation and maintenance costs are as shown on Table 3.3.3a with escalation rate of 8% per year before 1985 and 5% per year thereafter. Cost of money is assumed to be 9% per year. The total operating costs levelized for the 35 years lifetime of the two unit (450mwe ea.) oil fired plant are presented in Table 3.3.5 and Figure 3.3-5.

TABLE 3.3.5

LEVELIZED TOTAL OPERATING COSTS
FOR A TWO-UNIT (450MW ea.) OIL FIRED PLANT.
(Escalation at 5%/Yr. Fuel Oil at 9%/Yr.)

Start–Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Capital Charges	9.37	11.96	15.26	19.48	24.86	31.73	40.50	51.69
Fuel Cost	292.0	449.3	691.3	1063.6	1636.5	2517.9	3874.1	5960.9
O&M Cost	5.03	6.42	8.20	10.46	13.35	17.04	21.75	27,76
TOTAL	306.40	467.68	714.76	1093.54	1674.71	2566.67	3936.35	6040.35

Fig. 3.3.5


Two 450MWe Unit Fuel Oil Plant Cost
Plant Investment Escalation: 5%/Yr.
Fuel Oil Escalation: 9%/Yr.
O&M Escalation: 1978-85, 8%/Yr; Beyond 1985, 5%/Yr.
Fixed Charge Rate on Investment: 9.8636%
100,000
10,000
1,000
100
TOTAL LEVELIZED COSTS (mills/kwh)
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year

3.4 Cost Comparison of Conventional Alternatives for Electrical Energy Production in Puerto Rico.

The total generating costs for electrical energy production in Puerto Rico have been estimated for coal, nuclear and fuel oil alternatives. The analysis includes the three cost categories of Capital Investment, Fuel and Non-fuel Operation and Maintenance.

In order to present a fair cost comparison, the same basic assumptions and economic parameters for cost levelization have been utilized except for particularities affecting each alternative fuel. Those factors equally affecting all the alternatives have been disregarded. The costs for these alternatives are summarized and briefly discussed in this section.

Figures 3.4.1 through 3.4.4 present the total levelized generation costs of the three alternatives for one and two-unit plants, as a function of start-up year. Two different escalation rates (namely 5%/Yr. and 7 1/4%/Yr.) have been used beyond 1985 with exceptions taken for fuel-oil and Yellow-cake which are explained under Sections 3.3.2 and 3.2.3 respectively.

Nuclear plants show the lowest evaluated costs, followed by coal and fuel oil.

It should be noted that since Puerto Rico relies on imported fuel for any of the three alternatives evaluated, this item weights heavily on the total costs, specially fuel oil and coal.

The necessity of new sea-port facilities for the coal alternative adds additional costs to the capital investment for the coal plant which is not necessary for the others.

Economies are realized if two units are constructed at the same site. These result mainly from engineering, design, construction, management and non-fuel operation and maintenance unit cost reductions. Some of the site facilities as well as operating and maintenance personnel can be shared between the units.

Fig. 3.4.1

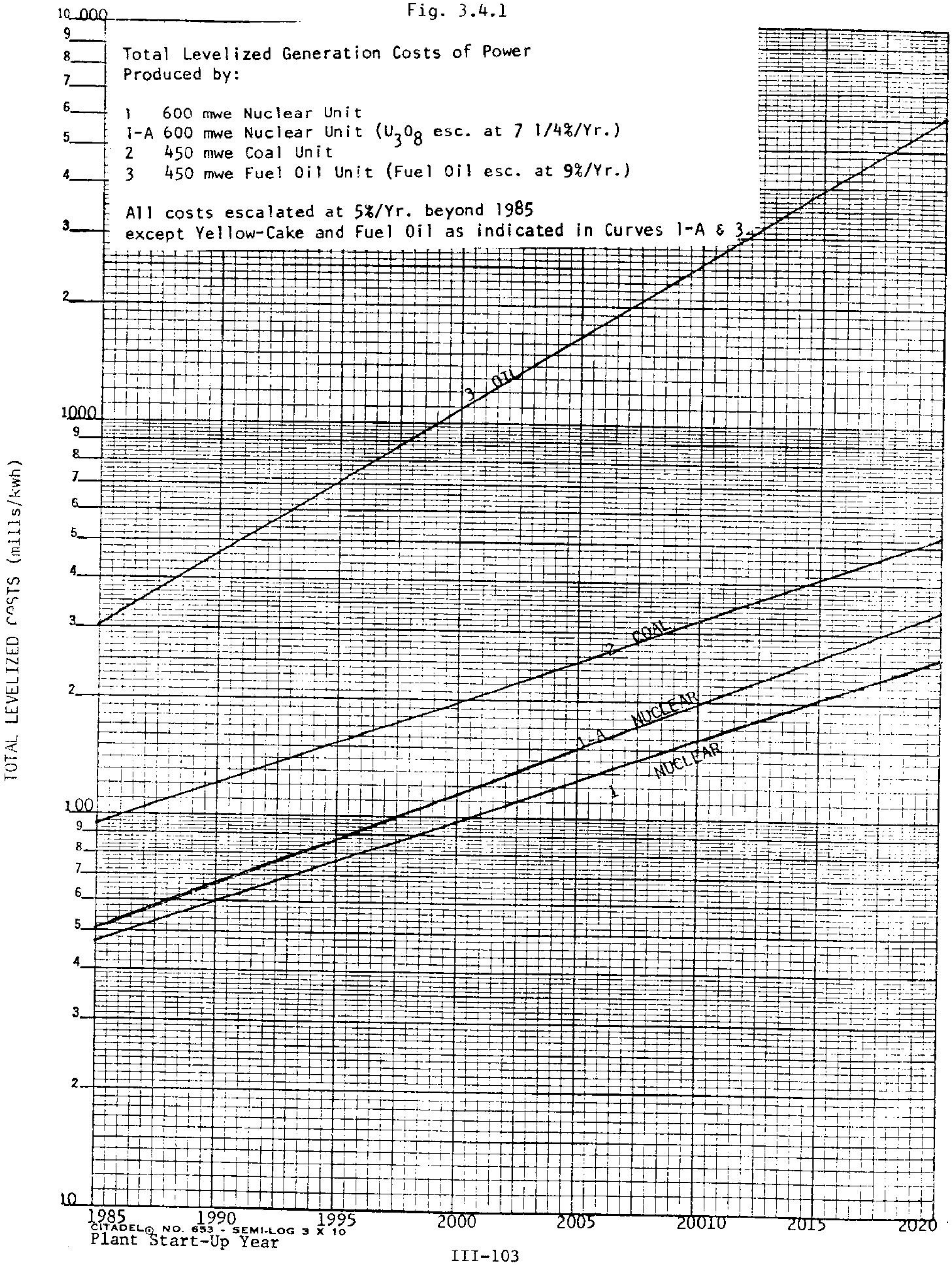

Total Levelized Generation Costs of Power
Produced by:
1 600 mwe Nuclear Unit
1-A 600 mwe Nuclear Unit (U_3O_8 esc. at 7 1/4%/Yr.)
2 450 mwe Coal Unit
3 450 mwe Fuel Oil Unit (Fuel Oil esc. at 9%/Yr.)
All costs escalated at 5%/Yr. beyond 1985
except Yellow-Cake and Fuel Oil as indicated in Curves 1-A & 3.
3 OIL
2 COAL
1-A NUCLEAR
1 NUCLEAR
TOTAL LEVELIZED COSTS (mills/kwh)
10,000
1000
100
10
1985
1990
1995
2000
2005
20010
2015
2020
Plant Start-Up Year
CITADEL® NO. 653 - SEMI-LOG 3 X 10

Fig. 3.4.2

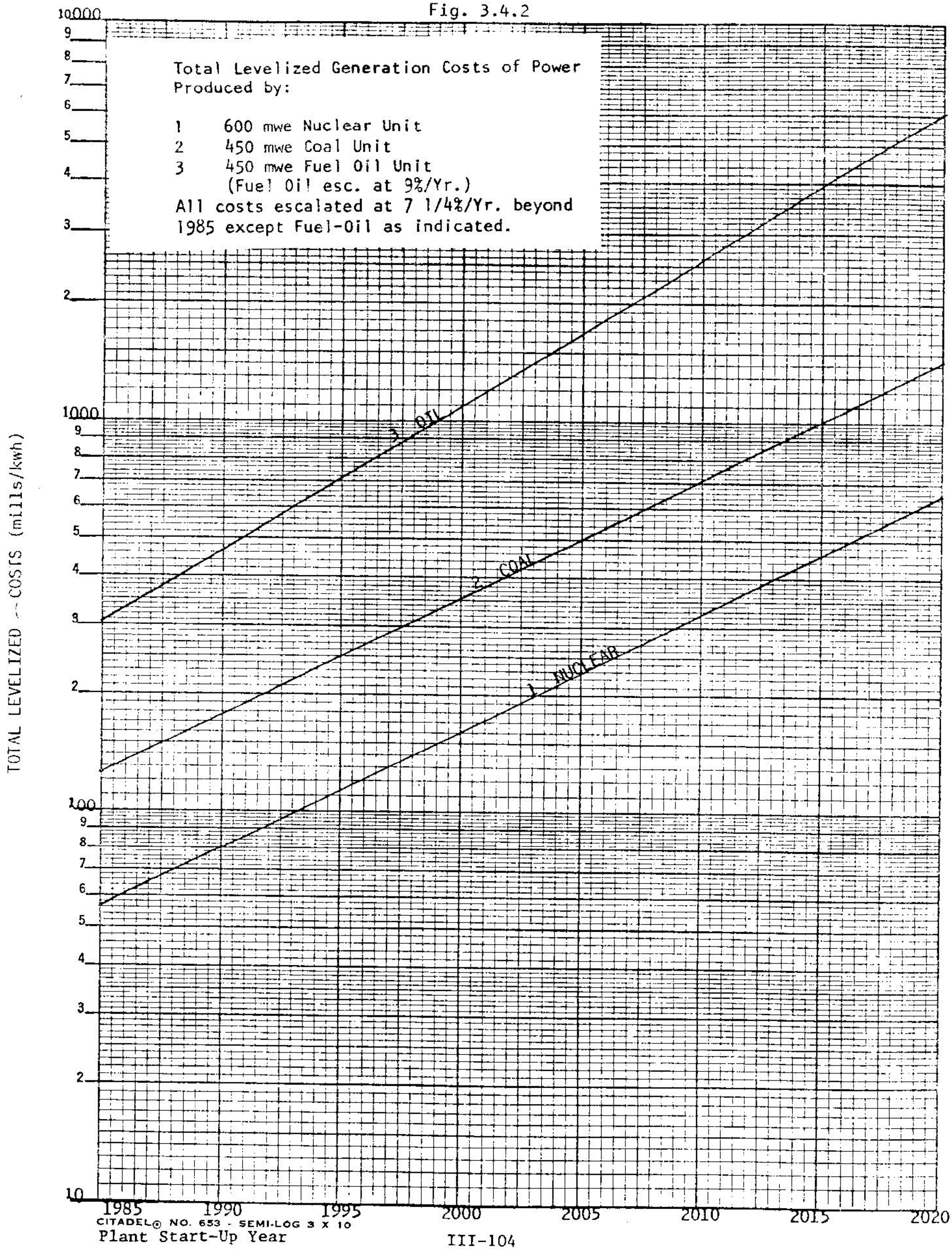

Total Levelized Generation Costs of Power Produced by:
1 600 mwe Nuclear Unit
2 450 mwe Coal Unit
3 450 mwe Fuel Oil Unit
(Fuel Oil esc. at 9%/Yr.)
All costs escalated at 7 1/4%/Yr. beyond 1985 except Fuel-Oil as indicated.
3 OIL
2 COAL
1 NUCLEAR
TOTAL LEVELIZED — COSTS (mills/kwh)
10000
1000
100
10
1985
1990
1995
2000
2005
2010
2015
2020
CITADEL© NO. 653 - SEMI-LOG 3 X 10
Plant Start-Up Year

Fig. 3.4.3

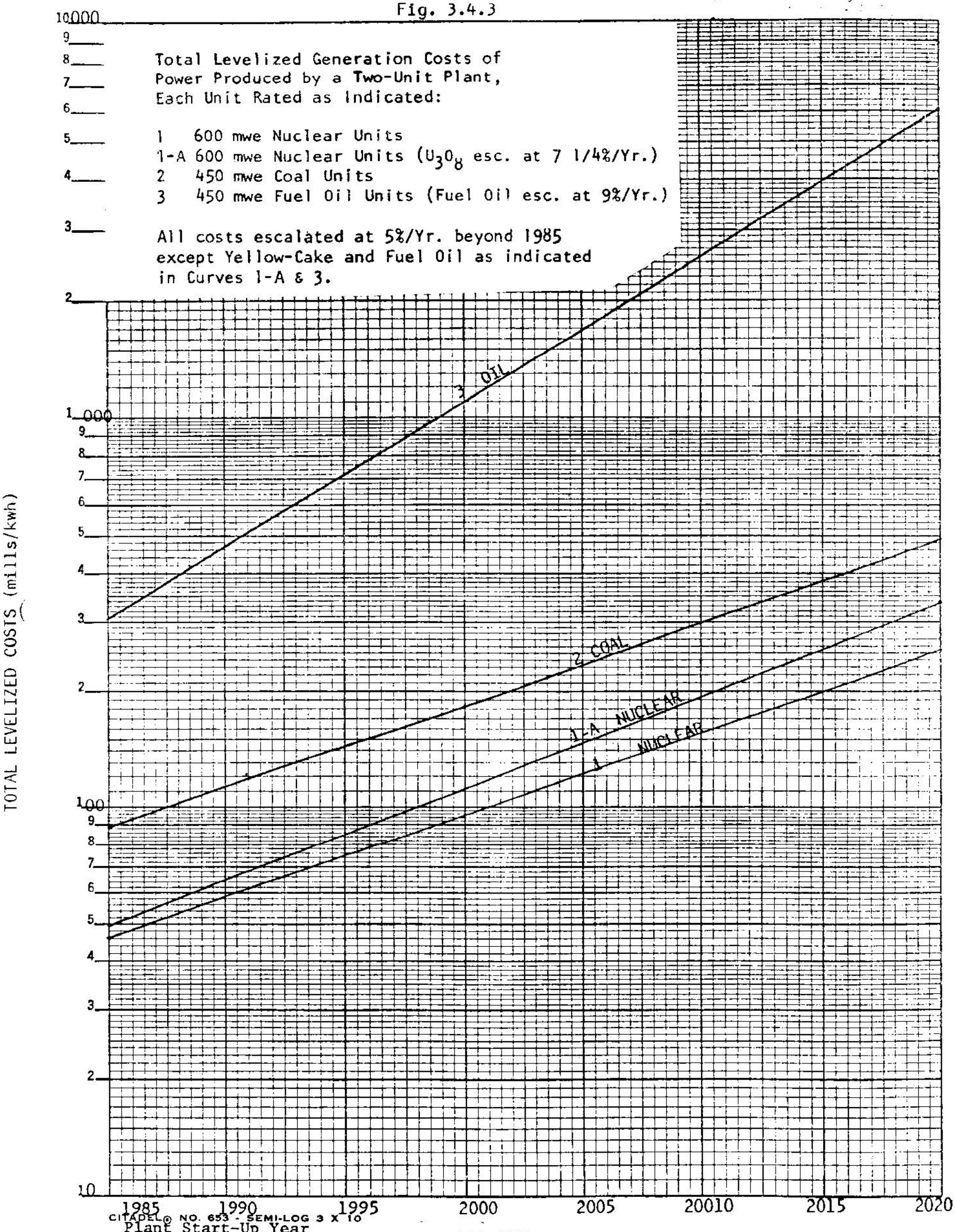
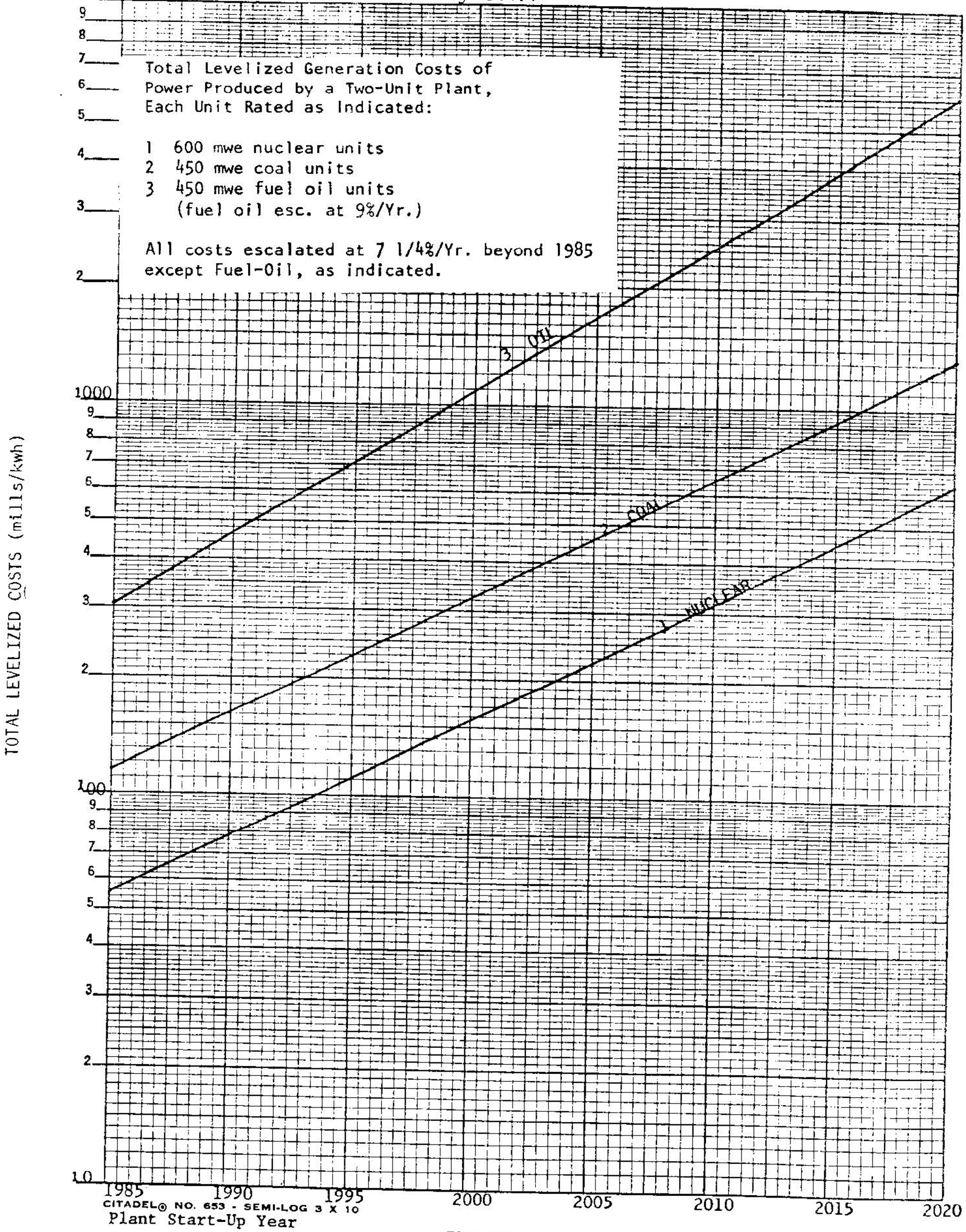

Total Levelized Generation Costs of
Power Produced by a Two-Unit Plant,
Each Unit Rated as Indicated:
1 600 mwe Nuclear Units
1-A 600 mwe Nuclear Units (U_3O_8 esc. at 7 1/4%/Yr.)
2 450 mwe Coal Units
3 450 mwe Fuel Oil Units (Fuel Oil esc. at 9%/Yr.)
All costs escalated at 5%/Yr. beyond 1985
except Yellow-Cake and Fuel Oil as indicated
in Curves 1-A & 3.
3 OIL
2 COAL
1-A NUCLEAR
1 NUCLEAR
TOTAL LEVELIZED COSTS (mills/kwh)
10000
1,000
100
10
1985
1990
1995
2000
2005
20010
2015
2020
Plant Start-Up Year
CITADEL® NO. 653 - SEMI-LOG 3 X 10

Fig. 3.4.4


Total Levelized Generation Costs of
Power Produced by a Two-Unit Plant,
Each Unit Rated as Indicated:
1 600 mwe nuclear units
2 450 mwe coal units
3 450 mwe fuel oil units
(fuel oil esc. at 9%/Yr.)
All costs escalated at 7 1/4%/Yr. beyond 1985
except Fuel-Oil, as indicated.
3 OIL
2 COAL
1 NUCLEAR
TOTAL LEVELIZED COSTS (mills/kwh)
10000
1000
100
10
1985
1990
1995
2000
2005
2010
2015
2020
CITADEL® NO. 653 - SEMI-LOG 3 X 10
Plant Start-Up Year

SECTION 4

LONG RANGE ALTERNATIVES FOR ELECTRICAL ENERGY PRODUCTION

Section 4

LONG RANGE ALTERNATIVES FOR ELECTRICAL ENERGY PRODUCTION

4.0 INTRODUCTION

In order to address the energy situation in Puerto Rico, several long range alternatives for electrical energy production on the Island require an economic evaluation.

Specific objectives are set for each alternative. Such objectives include unit size, approximate date for the start of operation and planning and construction schedules. Unit costs are determined from the most recent and reliable sources. Total production costs are determined and the time at which the alternatives can compete economically with conventional sources is determined for the Puerto Rico scenario.

The long range alternatives considered are:

1. OTEC
2. Photovoltaics
3. Biomass
4. Wind

The logic in selecting and setting the long range scenarios has been based on the information, experience and knowledge generated from Research and Development programs being undertaken by CEER since 1976 and on current available information.

A word of caution is necessary when making economic evaluations and cost projections of new developing technologies. While it is natural to expect lower costs as experience is developed in the manufacture of more units (a learning curve relationship), this in turn depends upon the market demand which might be influenced by drastic changes. Normally, a technological breakthrough will lower the costs predicted by the usual learning curve and this will influence the market demand in a positive direction. On the other hand, environmental problems encountered, accompanied by stiff regulations and complicated licensing procedures, will influence demand in the opposite direction.

Within the context of this clarification, the economic evaluation of different long range electrical energy production alternatives is presented in the following sections.

4.1 OCEAN THERMAL ENERGY CONVERSION (OTEC)

This concept makes use of the temperature differential between deep sea waters (3000 ft) and surface waters to generate electricity. It has the potential of meeting all of the electrical energy needs of Puerto Rico. Ocean based, or floating type or land based plants will have practically no impact on land utilization resources.

It is estimated than an OTEC-10 (4-10 MW modules, 40 MW plant) concept could be operational within 5 years. Economic calculations are performed for the 40 MW plant and for a 250 MW plant operational by 1985 and 1990 respectively. The 40 MW demonstration plant is large enough to lend itself to an extrapolation to at least a five-fold scale in second generation of plants. The purpose of building a 40 MWe demonstration plant is to test the OTEC system with full size modules and sufficiently large components in order to verify the cost estimates for the big scale commercial plants and thereby reduce the uncertainties involved in the preliminary cost estimates and verifying the possibilities of future less expensive technical solutions.

The economic evaluation follows.

4.1.1 40 MWe Demonstration Plant

4.1.1.1 Capital Investment Charges

Several sources were examined for capital investment cost estimates as presented in Appendix G. The most accurate estimate for a 40 MWe land based OTEC plant is that prepared by Deep Oil Technology, Inc. for the specific site of Punta Tuna, Puerto Rico[41]. This estimate gives an installed cost of $5,230/KW (1980).

The design conditions of an OTEC plant depend mostly on the site's oceanographical and meteorological conditions, and these in turn affect the cost of the plant. It is necessary to evaluate the construction cost for a specific site and to make an optimum power system design adapted to the site conditions. In view of the wide range of estimated unit costs presented in the literature and their aforementioned site dependency, we consider the above mentioned unit cost of $5,230/KW (1980) accurate enough for the purpose of the present study.

One additional important consideration that must be addressed is the life of the plant. The useful operating life of a demonstration project is usually shorter than one of a proven technology. The life of the OTEC plant will depend mostly on the life of the materials exposed to the sea water environment and especially the effects on the large sized heat exchangers. Since a large experience exists with structures exposed to the sea water environment and since these have demonstrated long life, it is logical to assume that OTEC plants will be economically operable for many years. For these reasons, the economic calculations will be done for 35 years of operation, so that a fair economic comparison can be made with the conventional alternatives.

The capital investment charges are as follows:

a. Project Investment:

(40,000 KW)($5,230/KW) = $209,200,000 (1980 dollars)

b. Yearly Investment Charges at 9%/yr. cost of money and 35 years operating life:

C R F	=	0.094636
Insurance	=	0.004
Total FCR		0.098636

($209,200,000)(0.098636) = 20,634,651

c. Yearly Energy Production:

Auxiliaries power = 23% (for 21°C Δ T ave.)[42]

Capacity Factor = 75%

(40,000 KW)(0.77)(0.75)(8760) = 202,356,000KWhr.

d. Investment Charges in mills/KWhr:

$$\frac{\$20,634,651 \times 10^3}{202,356 \times 10^3} = 101.97 \text{ mills/KWhr (1980)}$$

4.1.1.2 Operation and Maintenance Costs (O&M)

The O&M costs of an OTEC plant cannot be too far off an equivalent oil plant.

The marine portion, such as hull and other parts and components exposed to sea water, will require more maintenance, but these can probably be taken care of in a larger time cycle than the routine yearly maintenance. This can possibly be accomplished by moving the plant to special shipyard facilities.

The O&M costs will be figured on the basis of an assumed plant staff which will be correlated with total costs.

The following plant staff is assumed:

1	Superintendent
1	Asst. Superintendent
1	Administrative Supervisor
2	Secretaries
1	Clerk
5	Shift Engineers (1/shift)
10	Shift Operators (2/shift)
10	Pump-Turbine Operators (2/shift)
10	Condenser-Evaporator Operators (2/shift)
5	Utility (1/shift)
5	Security (1/shift) and personnel accountability
10	Boat operators (2/shift)
2	Warehouse Clerks
1	Purchaser-Whse. Sup.
1	Chief Mechanical Engineer
1	Asst. Mechanical Engineer
6	Mechanics
1	Electrical Engineer
4	Electricians
1	Instrument Technicians
1	Chemical-Metallurgical Engineer
1	Chemist
2	Asst. Chemists
2	Assts. Technicians
2	Janitors
2	Painters-Drivers
5	Security (land, 1/shift)
1	Janitor (land)
1	Gardener (land)
5	Shift Chauffeurs (1/shift)
104	Total

Average annual staff cost per man $24,000 (1978)
Total staff cost: (104)($24,000) = $2,496,000.
The ratio between staff cost and total O&M cost for a coal plant without FGD system as previously determined is 1.72. Assuming that the same ratio applies to the OTEC plant, we have:

Total O&M cost = (1.72)($2,496,000) = $4,293,120.
The cost in mills per kilowatt-hour is:

$$\frac{\$4,293,120 \times 10^3}{202,356 \times 10^3} = 21.22 \text{ mills/KWhr (1978)}$$

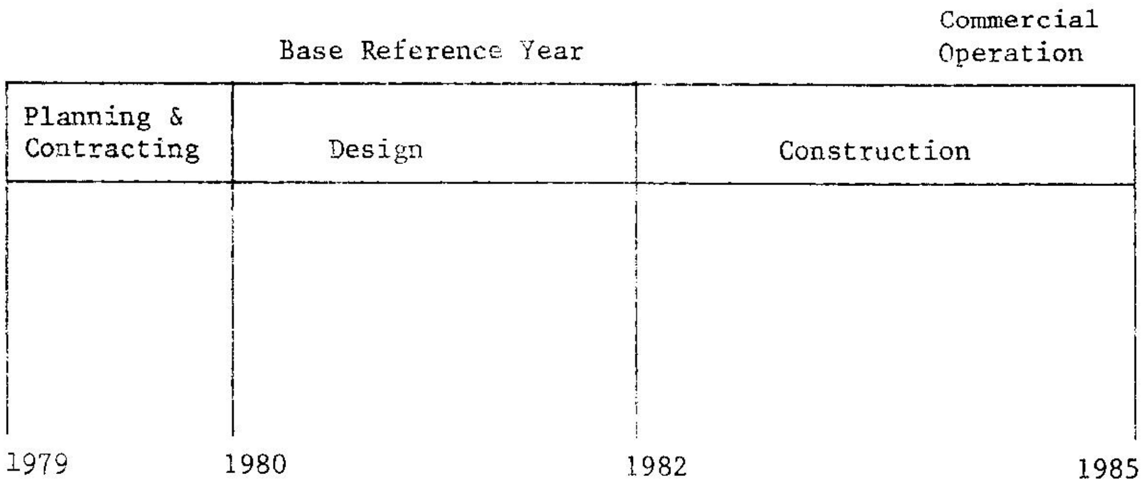
The O&M cost in 1980 dollars with an 8% / yr inflation is $(21.22)(1.08)^2 = 24.75$ mills/KWh.

4.1.1.3 Total Levelized Costs

Since there are no fuel costs in this plant, the total costs are composed of capital investment charges and O&M costs. In terms of 1980 dollars, the total cost of the 40 MWe Demonstration Plant is:

101.97 + 24.75 = 127 mills/KWh

The total levelized cost for operation in 1985 can be estimated by including escalation and interest during construction, fixed charge rate and levelizing the O&M cost during the life of the plant. Assuming 8% escalation per year, one year period planning and contracting arrangements, 2 years design and 3 years construction, the interest during construction and escalation factors can be computed in the following manner:



With a straight line cash flow of construction funds,

Escalation before construction = $(1.08)^2$

Escalation during construction = $(1.08)^{1.5}$

Interest during construction = $(1.08)^{1.5}$

Investment Escalation and Interest during Construction - Total factor = 1.47

O&M Escalation at 8%/year from 1980 to 1985 - $(1.08)^5$ = 1.47

Levelizing factor for 35 years life time at 9% cost of money in a 5% inflationary economy:

$$L = \frac{(1 + r)^n - 1}{r(1 + r)^n} \cdot \frac{i(1 + i)^n}{(1 + i)^n - 1} = 1.81$$

where: $r = \frac{i-u}{1+u} = 0.038095$

Total Levelized Cost (1985)

Investment Charges:

(101.97)(1.47) = 149.9 mills/KWhr

O&M Costs:

(24.75(1.47)(1.81) = 65.85

40 MWe OTEC Plant

Total Levelized Cost = 215.75 mills/KWhr

(For start-up in 1985 and 35 years operation of the plant)

4.1.2 250 MWe OTEC Plant

If the results of the 40 MWe OTEC Demo Project are satisfactory, the next reasonable step considered is the construction of a larger plant in the 250 MW range.

Two factors directly affect the basic plant cost (dollars per kilowatt of installed capacity) of this unit: one, the economies of scale and the other, the learning curve effect.

4.1.2.1 Scale Cost Relationship

The effect of increased size upon costs for large electrical equipment has been determined by experience to be in the form of an exponential reduction of cost in the range of 0.75 to 0.95 between small and bigger units. A unit capacity scale cost factor f_c can be defined as given by an equation of the following form:

$$f_c = \frac{\left[\dfrac{C_b}{C_s}\right]^E}{\left[\dfrac{C_b}{C_s}\right]} = \frac{\text{unit cost of big plant}}{\text{unit cost of small plant}}$$

where C_s and C_b are the capacities of the small size and bigger size units respectively and the exponent E is less than unit and usually not less than 0.75. If the exponent E on the capacity scale cost equation given before is set at 0.95, the value of f_c obtained is 0.95.

For comparison purposes, the cost equation derived in Section 3.1.4 for a coal plant will be exmined.

The coal plant cost equation $C_o = 795.95\ e^{-0.000342MW}$ gives the following result for the scale-cost factor between 100 - 250 MWe:

$$f_c = \frac{e^{-0.000342\ (250)}}{e^{-.000342\ (100)}} = 0.95$$

This agrees with the previously estimated value of f_c. The cost in 1978 dollars of a 100 MWe OTEC plant has been estimated at \$3257/KW (see Appendix G, ref. 42). which extrapolated to 250 MWe gives (\$3257 x 0.95) = \$3,094 per KW. The total cost of a 250,000 KW plant will be \$773,500,000 (1978). The effects of the learning curve are considered next.

4.1.2.2 Capital Cost Learning Curve Relationship

The learning curve effect is a function of the number of units produced. For this study, we assume the following relationship: $C_n = C_1\ M^{(\ln N/\ln 2)} + K$

where: N = unit number

C_n = ave. unit cost of unit N

C_1 = unit cost of unit number 1

K = constant factor independent of learning

M = learning factor cost reduction

It is reasoned that the accumulative average production cost is reduced from the previous cost by a certain factor m every time the number of units produced on a commercial scale is doubled. General Electric, for example, estimates that the production costs of large wind turbine generators can be reduced to 90% of the previous cost every time the number of units is doubled.[43] Washom et. al. propose a 97.5% cost reduction for OTEC plants.[44] Due to the uncertainty in the learning rate estimates and the manufacturing output, we consider a 90% reduction to be reasonable for the purpose of the present study.

A market prediction must then be establised.

Jacobson and Manley from MITRE Corporation predict three scenarios of OTEC market penetration as a function of economic incentives and development strategies.[45] The three scenarios present total installed capacities in the United States for the year 2020 of 2246 and 71 GWe respectively.

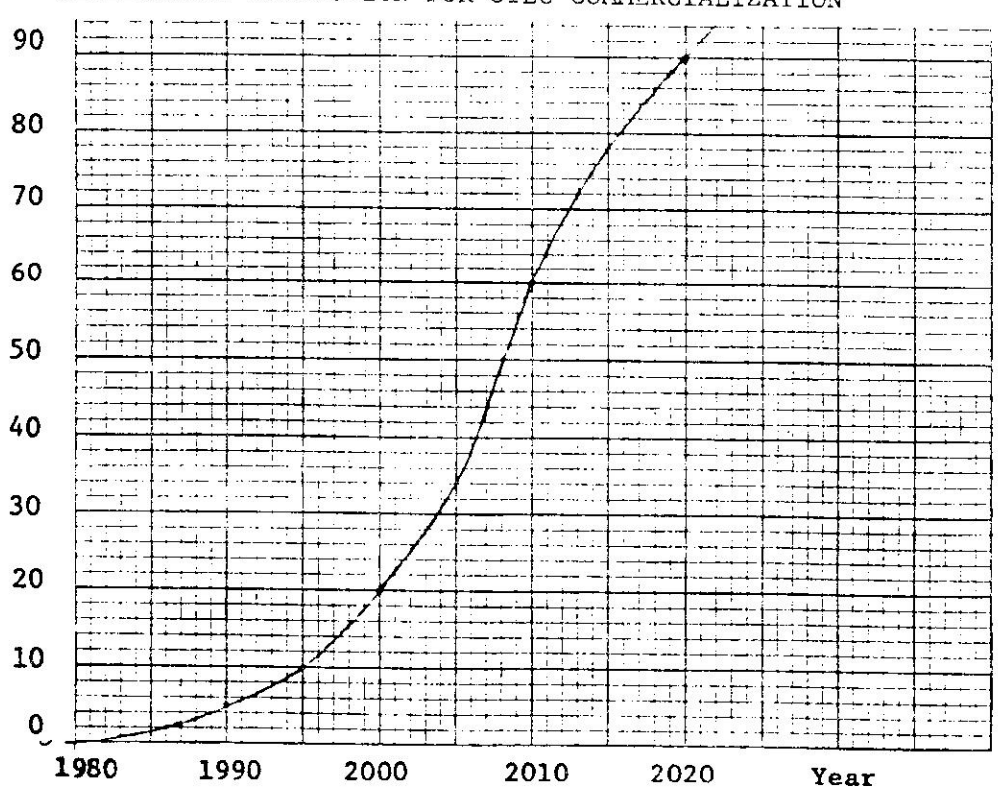
Assuming a market development as depicted in the lowest scenario and the total (22 GMe) been composed of 250 MWe units, a total of 88 units by the year 2020 is predicted.

Rounding up the above figure to 90 units by the year 2020, an S-shaped market curve for OTEC development is projected as per Figure 4.1.2.

MARKET DEVELOPMENT PROJECTION FOR OTEC COMMERCIALIZATION

FIGURE 4.1.2

No. of 250 MWe
OTEC Units



If the unit is to be operable by 1990, it must be ordered during 1983 (assuming seven years necessary lead time) Therefore, no learning curve effect will be considered for this unit. The 1978 cost of the 250 MWe unit for operation in 1990 is $3,094/KW.

The Capital Investment Charges are calculated for the year 1990 based on the following:

FCR = 0.098636

CF = 75%

Aux. Power = 20%

Inflation = 8%/yr. (from '78 to '85)

5%/yr. (from '85 to '90)

Capital Investment Charges =

$$\frac{(3,094)(0.098636)}{(0.75)(0.080)(8.76)} \times (1.08)^7 \times (1.05)^5$$

= 127 mills/KWh

4.1.2.3 Operation and Maintenance Costs

The operation and maintenance costs can be computed as per the 40 MWe Demo Plant with a 20% increase in staff. This staff increase is visualized as 20 additional shift personnel (4 per shift) for Pumps-Condenser-Evaporator and T-G operation.

TSC = (124)(24,000) = $2,976,000.

The ratio between staff cost and total operation and maintenance costs for a coal plant (without FGD) is 1.72 (see Section 3.1.10.8)

Total O&M Cost = ($2,976,000)(1.72) = $5,118,720.

The total levelized cost in mills/KWh using the previously defined parameters as in Section 4.1.2.2. is:

$$\text{O\&M Cost} = \frac{(\$5,118,720)}{(8.76)(0.75)(0.80)(250,000)} (1.08)^7 \times (1.05)^5 (1.81) = 15.42 \text{ mills/KWh}$$

4.1.2.4 Total Estimated Cost for 250 MWe OTEC Plant

The total cost levelized for the 35 years operating life of the plant with 1990 start-up base is thus:

Total Cost = 127 + 15.42 = 142.42

For comparison purposes of the OTEC technology with the conventional alternatives evaluated in Section 3, the costs of the 250 MWe OTEC plant are projected for future start-up years beyond 1990 taking into account the effects of the learning curve and the economic escalation of costs. These are tabulated in Table 4.1.2.4 below and graphically depicted in Figures 4.1.2.4a and b.

It should be kept in mind that the learning effect will become saturated after several units are produced on a commercial scale. At this point, the OTEC cost curves shown in Figures 4.1.2.4 a and b will become straight lines. Due to the uncertainties involved in precisely estimating this occurrence, this effect is not shown in the curves.

TABLE 4.1.2.4

Levelized Total Costs of 250 MWe OTEC Plant in Puerto Rico. Start-Up in Year Indicated and 35 Years Operating Life. Interest During Construction and Escalation Until 1985 at 8%/Yr and 5% year or 7 1/4%/Yr thereafter. Design and construction lead time 7 years.

Start-Up Year	1990	1995	2000	2005	2010	2015	2020
Projected Number of units(N), 7 years earlier than indicated start-up year	1	3	7	16	28	50	72
Learning Coefficient $C_n/C_1=(N)^{(\ln N/\ln 2)}$	1.0	0.846	0.744	0.656	0.603	0.552	0.522
Capital Cost ($/KW) 1985 Dollars	5,303	4,486	3,945	3,478	3,197	2,927	2,768
Capital Investment Charges (mills/KWh) 1985 Dollars	99.52	84.19	74.03	65.27	60.00	54.93	51.95
Levelized O&M Costs 1985 Dollars 5%	12.08	12.08	12.08	12.08	12.08	12.08	12.08
Levelized O&M Costs 1985 Dollars 7 1/4%	16.74	16.74	16.74	16.74	16.74	16.74	16.74
Total Estimated Cost 5%/Yr. Escalation Beyond 1985	142	157	179	205	244	290	353
Total Estimated Cost 7.25%/Yr. Escalation Beyond 1985	165	203	259	333	442	585	796

Fig. 4.1.2.4(a)

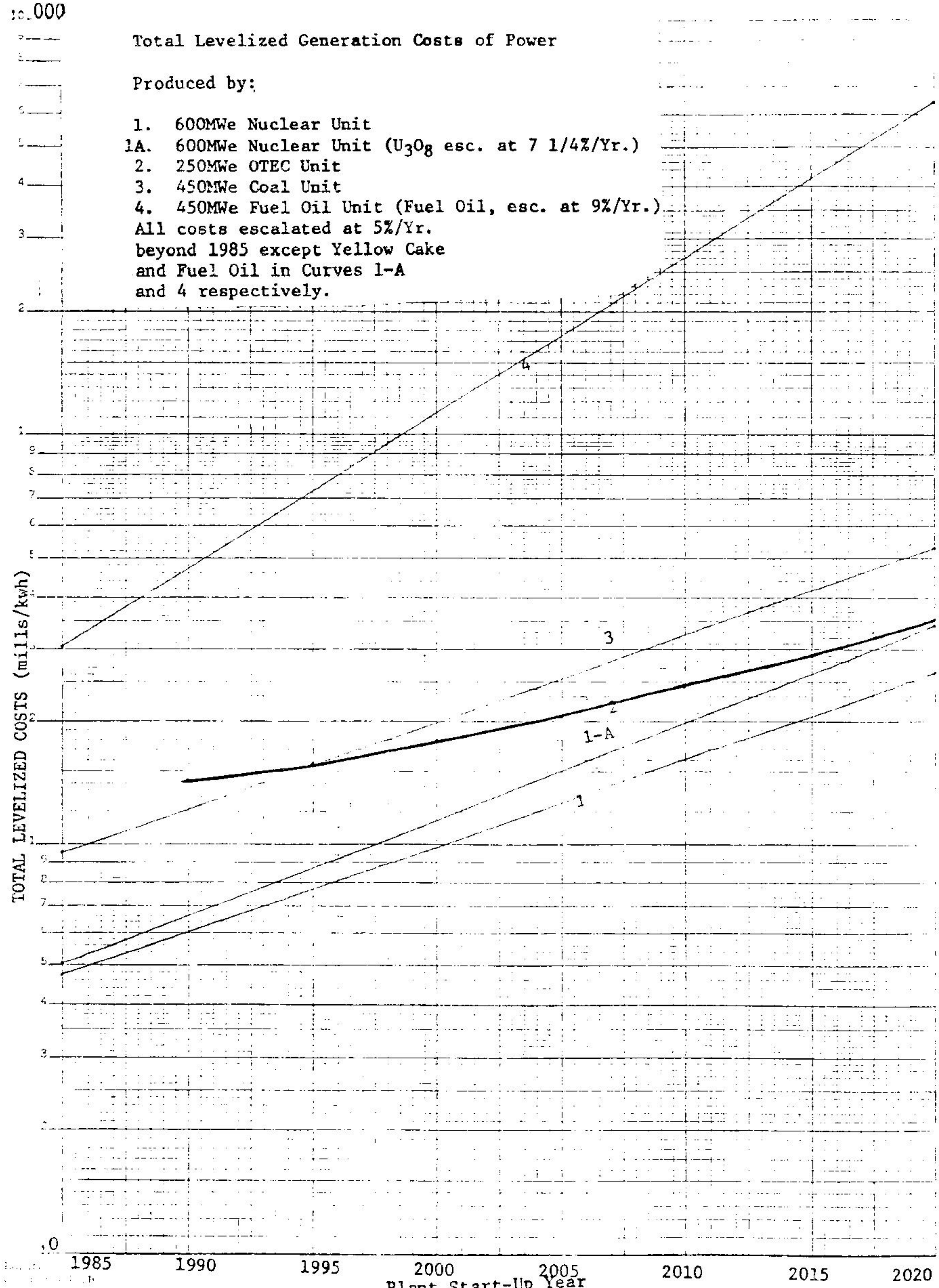

Total Levelized Generation Costs of Power
Produced by:
1. 600MWe Nuclear Unit
1A. 600MWe Nuclear Unit (U_3O_8 esc. at 7 1/4%/Yr.)
2. 250MWe OTEC Unit
3. 450MWe Coal Unit
4. 450MWe Fuel Oil Unit (Fuel Oil, esc. at 9%/Yr.)
All costs escalated at 5%/Yr.
beyond 1985 except Yellow Cake
and Fuel Oil in Curves 1-A
and 4 respectively.
TOTAL LEVELIZED COSTS (mills/kwh)
4
3
2
1-A
1
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year

Fig. 4.1.2.4(b)

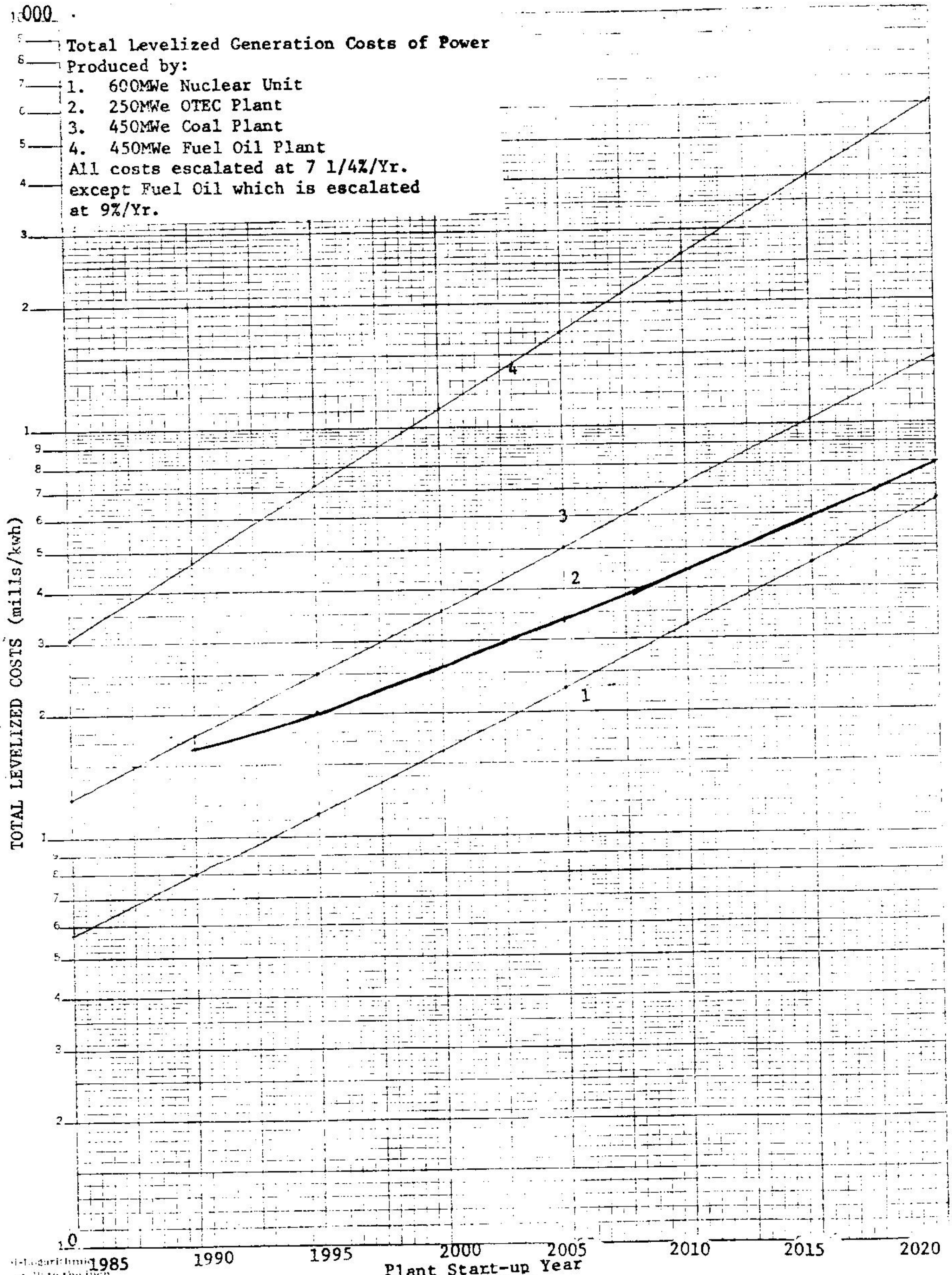

Total Levelized Generation Costs of Power
Produced by:
1. 600MWe Nuclear Unit
2. 250MWe OTEC Plant
3. 450MWe Coal Plant
4. 450MWe Fuel Oil Plant
All costs escalated at 7 1/4%/Yr.
except Fuel Oil which is escalated
at 9%/Yr.
TOTAL LEVELIZED COSTS (mills/kwh)
1000
1.0
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-up Year
1
2
3
4

TABLE 4.1.2.4

Levelized Total Costs of 250 MWe OTEC Plant in Puerto Rico. Start-Up in Year Indicated and 35 Years Operating Life. Interest During Construction and Escalation Until 1985 at 8%/Yr and 5% year or 7 1/4%/Yr thereafter. Design and construction lead time 7 years.

Start-Up Year		1990	1995	2000	2005	2010	2015	2020
Projected Number of units(N), 7 years earlier than indicated start-up year		1	3	7	16	28	50	72
Learning Coefficient $C_n/C_1=(M)$ (ln N/ln2)		1.0	0.846	0.744	0.656	0.603	0.552	0.522
Capital Cost (\$/KW) 1985 Dollars		5,303	4,486	3,945	3,478	3,197	2,927	2,768
Capital Investment Charges (mills/KWh) 1985 Dollars		99.52	84.19	74.03	65.27	60.00	54.93	51.95
Levelized O&M Costs 1985 Dollars	5%	12.08	12.08	12.08	12.08	12.08	12.08	12.08
	7 1/4%	16.74	16.74	16.74	16.74	16.74	16.74	16.74
Total Estimated Cost 5%/Yr. Escalation Beyond 1985		142	157	179	205	244	290	353
Total Estimated Cost 7.25%/Yr. Escalation Beyond 1985		165	203	259	333	442	585	796

4.2 WIND POWER SYSTEMS (WPS)

The potential contribution of wind turbine generators (WTG) to the future electrical energy needs of Puerto Rico is evaluated based on the report "Feasibility Study for the Use of Large Windpower Generators in Puerto Rico",[43] which is included in its entirety as Appendix H. The cost estimates developed in that report are placed under the same bases as the estimates developed for the other alternatives to provide a consistent analysis and a means of economic comparison.

The power costs are calculated using the capital investment costs, operation and maintenance costs, and the annual estimated power output. A construction period of three years is assumed for the whole project as well as a plant life of 35 years.

4.2.1 Capital Investment for WPS

The total capital investment charges for this project in Puerto Rico for operation in 1985 are calculated as follows (see Appendix H)

4.2.1.1 Plant Cost

The present estimated WTG's unit costs are $2.633 million and $1.91 million for 1500 KW and 500 KW units respectively. With a 90% learning curve and assuming a production of 100 units every 5 years, as indicated in Appendix H, the lowest evaluated average cost within the first 100 units would be $1.31 million and $0.95 million, respectively for the two units.

The following itemized costs are taken from Appendix H. Twenty Five WTG units are assumed to be located at one particular site.

TABLE 4.2.1.1

WPS 1979 COSTS

	1.5MW	0.5MW
25 WTG's	$32.75 x 10^6	$23.75 x 10^6
Electrical Interconections (estimated Based on Bureau of Reclamation Studies app. H.)	3.19	3.19
Design and Study (17%)	6.11	4.58
Contingencies, site facilities, supervision (15%)	5.39	4.04
Total Wind Power System Cost (1979)	$47.44 x 10^6	$35.56 x 10^6

4.2.1.2 Land Cost

The estimated land requirements for this project (Figure 7, Appendix H) are 2891 acres (2978 cuerdas). Two options are considered here. One is to buy the land; in this case the land cost will be part of the capital investment and subject to the fixed charge, but the utility will have an asset appreciated in value at the end of the useful life of the facility. The other option is to rent the land; in this case the rental cost will be part of the operating costs of the facility.

The estimated land cost is:

2,978 cds. at \$5,000 = \$14,890,000

It should be noted that the land use for both models is approximately the same. The wind shadowing effect, which determines the separation between units, depends principally on the geometric characteristics of the tower and rotor which are roughly equal in both cases. According to General Electric, the diameters of the rotors of the 1500 and 500 KW turbine generators are 190 and 183 feet respectively.

4.2.1.3 Capital Investment Charges

Basic equation (see Appendix B):

$$C = C_o \, I_f^{\,Y_1 + (1-a)\,Y_2} \; I_{dc}^{\,aY_2} \cdot \frac{FC}{(\text{Av. Power})(8.760)} \text{ mills/kwh}$$

The following parameters are used in the computation:

Interest Rate	= 9%/yr.
Fixed Charge Rate (FC)	= 0.098636
Y_1	= 3 years
Y_2	= 3 years

I_f	= 1.08
I_{dc}	= 1.09
a	= 0.50
$Y_1 + (1-a)\ Y_2$	= 4.5
aY_2	= 1.5
$(1.08)^{4.5}$	= 1.414
$(1.09)^{1.5}$	= 1.138
Wind turbine power:	
1.5 MW nominal	= 288 Kw net
0.5 MW nominal	= 236 Kw net

Substituting the above parameters in the Basic Cost Equation, the following values are obtained for 1985 operation:

TABLE 4.2.1.3
CAPITAL INVESTMENT CHARGES

Wind Power Systems (WPS)	Capital Investment Charges (mills/kwhr)	
	WPS	Land (Purchase option)
25-150KW (28kw net)	119.38	37.47
25-500KW (236 kw net)	109.20	45.73

4.2.2 Operation and Maintenance Costs (O&M)

The operating and maintenance costs have been estimated by General Electric (see Appendix H) to be approximately 2% of the wind turbine-generator cost, including electrical interconnections, site facilities and contingencies. If the land is rented, an annual rental charge will be included in the operating costs. The rental cost is based on a 10% of cost annual rental fee subject to escalation. To be consistent with the calculations performed for the other alternatives, the O&M costs are escalated to 1985 at the rate of 8% per year and then levelized for 35 years of plant life, with inflation at 5% per year.

The total levelized O&M charges in mills/kwh are thus obtained by the following formula:

$$\text{O\&M Cost} = \frac{(\text{Estimated 1979 cost})(1+e)^{Y}(10^{3})L}{\text{Net annual kwh generation as determined from available wind}}$$

Where: L = levelizing Factor = $\dfrac{(1+r)^n - 1}{r(1+r)^n} \cdot \dfrac{i(1+i)^n}{(1+i)^n - 1} = 1.81$

$r = \dfrac{i-u}{1+u} = 0.038095$

i = 9%/yr. u = 5%/yr. e = 8%/yr. Y = 6 years

n = 35 yrs.

The following results are obtained:

TABLE 4.2.2
LEVELIZED O&M COSTS

Wind Power System (WPS)	Levelized O&M Costs (mills/kwh)	
	WPS	Land(Rental Option)
25-1500KW(2.52×10^{6} kwh per unit-App.H)	37.6	67.8
25-500KW (2.07×10^{6} kwh per unit-App.H)	34.4	82.7

4.2.3 Wind Turbine System (WTS) Total Levelized Costs

The total levelized costs for the 25 unit, central station Wind Turbine System power plant, evaluated for Puerto Rico, with a 35 year life, beginning full operation in 1985, can be summarized from Tables 4.2.1 and 4.2.2 as follows:

TABLE 4.2.3

TOTAL LEVELIZED COSTS FOR WIND TURBINE SYSTEM
(25 Units, Central Station, for Operation in 1985
at a Coastal Zone in Puerto Rico)

WPS	Capital Investment Charges(mills/KWh)	O&M Charges(mills/KWh)	Total Power Cost(mills/KWh)
25-1500KW Units:			
Own Land Option	156.85	37.6	194.45
Rented Land Option	119.38	105.4	224.78
25-500KW Units:			
Own Land Option	154.93	34.4	189.33
Rented Land Option	109.20	117.1	226.30

The above results show that electricity generation by central station wind turbine systems in Puerto Rico is a competitive alternative to oil; however, it is an expensive proposition when compared to other renewable alternatives. The extensive use of land resources and the limited power output are major contributors to the high expense.

The differences in cost of power for the four options analyzed are not significant, but it is should be noted that no credit has been taken for the available land between units for other possible uses, nor for land value appreciation.

Other wind energy options are available for use in Puerto Rico, especially in the mid range and small range machines for distributed use around the Island, but their assessment is considered out of the scope of the present work. Nevertheless, such widespread use of smaller units should be investigated.

For purposes of comparison of the wind turbine generator alternative with the other alternatives evaluated in this study, the costs of the two lowest evaluated options of 25 units central station power park are projected for future start-up years beyond 1985, taking into account the learning curve effects and the economic escalation of costs. These are tabulated in Tables 4.2.3 a and b and graphically depicted in Figures 4.2.3 a and b.

It should also be pointed out that energy storage capacity can be provided to the WPS in order to have a continuous electric power output even at periods of low wind speeds. The wind alternative is only economically viable as a fuel oil displacement alternative. Planning installation of wind turbines for coal fuel displacement is an uneconomical proposition.

TABLE 4.2.3(a)

Levelized Total Costs of 25 Unit Wind Turbine Generator Central Power Station in Puerto Rico. Start-Up in Year Indicated and 35 Years Operating Life. Interest Rate at 9%/Yr. and Escalation Until 1985 at 8%/Yr. Escalation after 1985 at 5%/Yr. and 7 1/4%/Yr. Each Unit Rated at 1,500KW.

Start-Up Year		1985	1990	1995	2000	2005	2010	2015	2020
Learning Coefficient $C_n = C_1(m)(\ln N/\ln 2)$		0.497	0.447	0.420	0.402	0.389	0.378	0.369	0.362
Capital Cost 10^6\$ 1979 dollars	WTG	32.75	29.42	27.66	26.48	25.59	24.89	24.32	23.83
	Total	62.33	59.00	57.24	56.05	55.17	54.47	53.90	53.41
Capital Investment Charges (mills/KWh) 1985 dollars		156.85	148.47	144.04	141.07	138.83	137.07	135.64	134.40
Levelized O&M Charges (mills/kwh) 1985 dollars	5%Esc	37.6	34.6	33.0	31.9	31.1	30.5	30.0	29.5
	7 1/4% Esc	52.1	47.9	45.7	44.2	43.1	42.3	41.6	40.9
Total Estimated Cost 5%/Yr. Escalation Beyond 1985		194.5	233.7	288.4	359.6	450.9	567.5	715.9	904.1
Total Estimated Cost 7 1/4%/Yr. Escalation Beyond 1985		209.0	278.7	382.1	529.4	737.6	1032.0	1447.0	2031.0

TABLE 4.2.3(b)

Levelized Total Costs of 25 Unit Wind Turbine Generator Central Power Station in Puerto Rico. Start-Up in Year Indicated and 35 Years Operating Life. Interest Rate at 9%/Yr. and Escalation Until 1985 at 8%/Yr. Escalation after 1985 at 5%/Yr. and 7 1/4%/Yr. Each Unit Rated at 500KW.

Start-Up Year		1985	1990	1995	2000	2005	2010	2015	2020
Learning Coefficient $C_n = C_1 (m)(\ln N/\ln 2)$		0.497	0.447	0.420	0.402	0.389	0.378	0.369	0.362
Capital Cost 10^6\$ 1979 dollars	WTG	23.75	21.34	20.05	19.20	18.58	18.05	17.62	17.29
	Total	50.45	48.04	46.75	45.90	45.28	44.75	44.32	43.99
Capital Investment Charges (mills/KWh) 1985 dollars		154.93	147.53	143.57	140.96	139.05	137.42	136.10	135.09
Levelized O&M Charges (mills/KWh) 1985 dollars	5%E	34.43	31.75	30.32	29.38	28.69	28.10	27.62	27.25
	7 1/4%E	47.70	44.00	42.01	40.71	39.75	38.94	38.27	37.76
Total Estimated Cost 5%/Yr. Escalation Beyond 1985		189.4	228.8	283.3	354.1	445.1	560.5	707.6	895.5
Total Estimated Cost 7 1/4%/Yr. Escalation Beyond 1985		202.6	271.8	373.7	519.1	725.0	1014.7	1423.6	2002.5

Fig. 4.2.3a

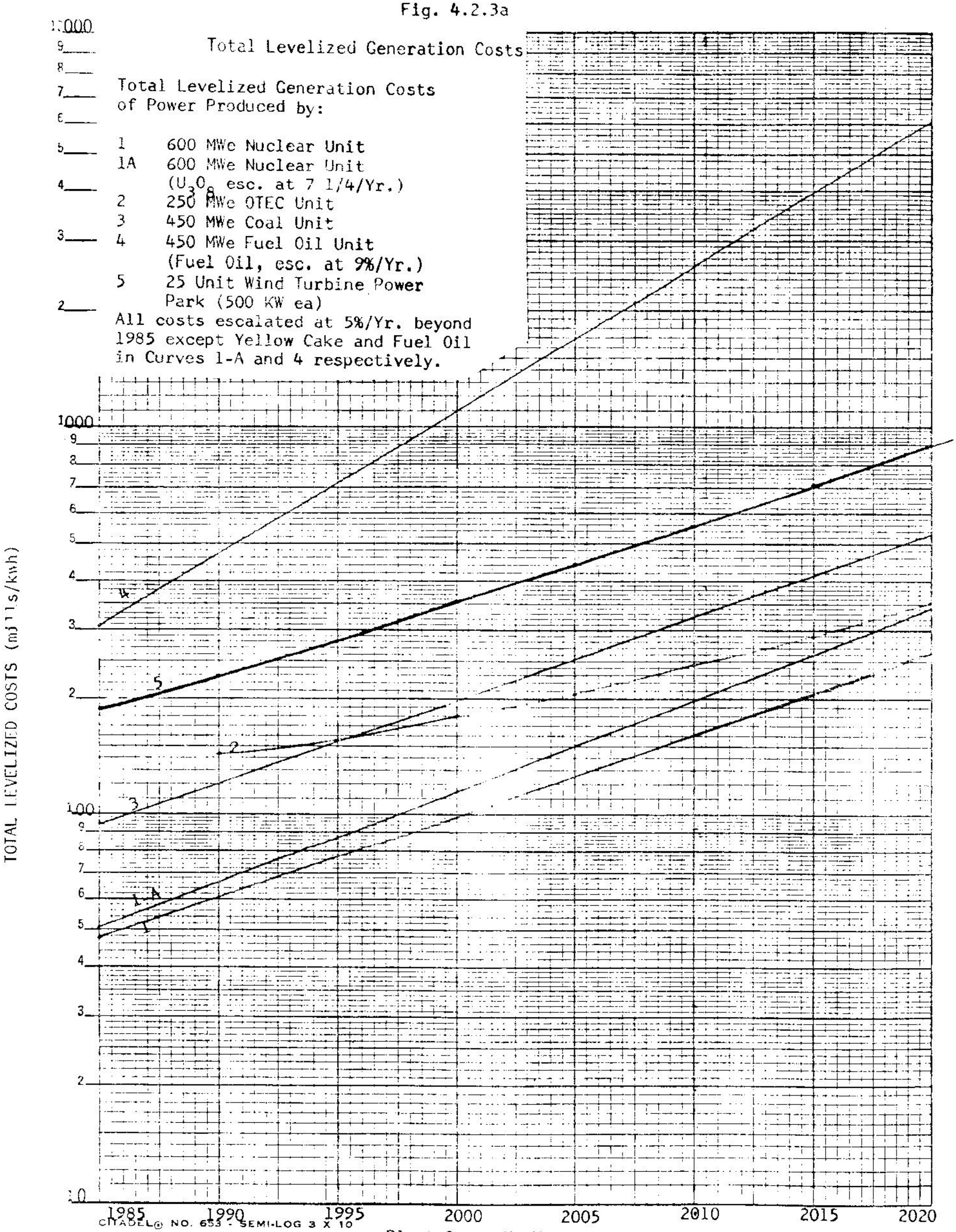
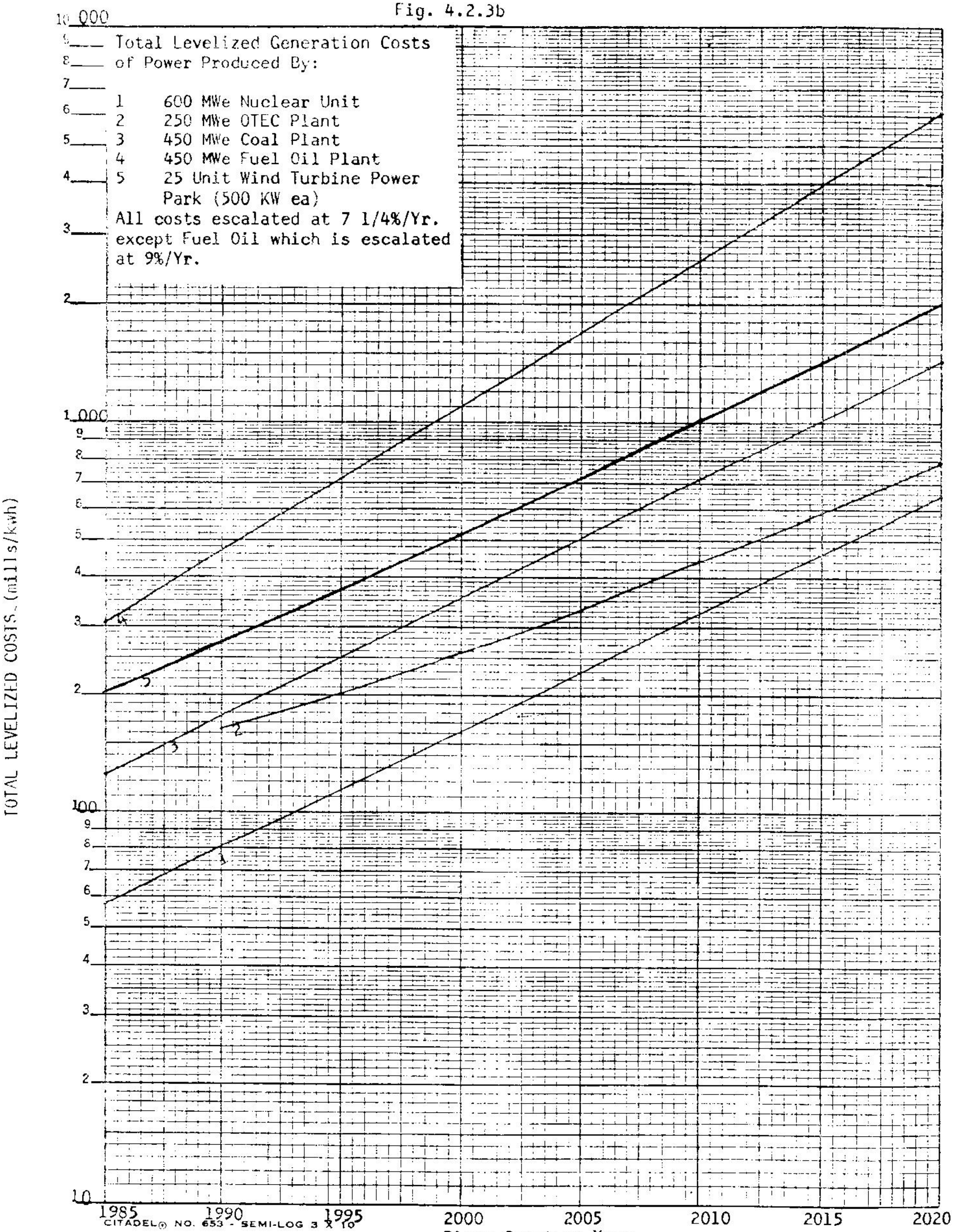

Total Levelized Generation Costs
Total Levelized Generation Costs of Power Produced by:
1 600 MWe Nuclear Unit
1A 600 MWe Nuclear Unit (U_3O_8 esc. at 7 1/4/Yr.)
2 250 MWe OTEC Unit
3 450 MWe Coal Unit
4 450 MWe Fuel Oil Unit (Fuel Oil, esc. at 9%/Yr.)
5 25 Unit Wind Turbine Power Park (500 KW ea)
All costs escalated at 5%/Yr. beyond 1985 except Yellow Cake and Fuel Oil in Curves 1-A and 4 respectively.
TOTAL LEVELIZED COSTS (mills/kwh)
Plant Start-Up Year
1985
1990
1995
2000
2005
2010
2015
2020
1000
100
10
CITADEL NO. 655 - SEMI-LOG 3 X 10

Fig. 4.2.3b


Total Levelized Generation Costs of Power Produced By:
1 600 MWe Nuclear Unit
2 250 MWe OTEC Plant
3 450 MWe Coal Plant
4 450 MWe Fuel Oil Plant
5 25 Unit Wind Turbine Power Park (500 KW ea)
All costs escalated at 7 1/4%/Yr. except Fuel Oil which is escalated at 9%/Yr.
10,000
1,000
100
10
TOTAL LEVELIZED COSTS (mills/kwh)
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-up Year
CITADEL NO. 653 - SEMI-LOG 3 X 10

4.3 BIOMASS FUELED POWER PLANTS

Biomass fuel consists of dried or partially dried forages, grasses or cane, which provide combustible fiber that can be used as fuel in an industrial steam boiler. Existing sugar mill boilers provide an adequate example of boilers which use biomass in the form of sugar cane baggase to substitute for fuel oil burning. Sugar mill boilers, however, are not designed primarily for electrical energy production but to produce steam for the sugar manufacturing process. Their efficiency for electrical energy production is therefore, very low. Sugar mill boilers, however, offer probably the best facilities for developing experimental pilot projects for the development of appropriate large scale techniques for biomass fuel burning, handling, storage and transportation logistics. Such pilot projects could provide detailed technical data for the extrapolation of large scale biomass fuel burning power plants on the level of 300-500 MW.

CEER has been heavily involved during the last three years in the agricultural phase of biomass species selection, growing optimization, harvesting, sun drying and bailing of biomass. Based on the example of a 200 acre farm, cost figures on a BTU basis delivered for biomass have been determined. Efforts are presently being made by CEER to develop a pilot project in which the large scale logistics of biomass burning could be assesed for extrapolation to industrial type of electric power plant boilers. Such a proposal has been submitted to the Government of Puerto Rico.[46]

The "state of the art" for this technology is practically developed and is considered technically feasible. What is needed are boiler specification details and logistic considerations which are obtainable through the pilot project just mentioned. It is reasonable therefore, to assume that there are no basic differences between a coal fired power plant and a biomass fueled power plant.

4.3.1 450 MW Biomass Power Plant

This plant is considered to be similar to a coal fired power plant as addressed in Section 3.1, without the requirements of sea port facilities and FGD System. As such, the three cost components of Capital Investment, Fuel, and Operation and Maintenance costs will be addressed.

4.3.1.1 Capital Investment Charges

The Basic Capital Investment Cost (C_o) of a 450 MW coal fired power plant with an FGD system, as determined in Section 3.1.8.4, is \$691/net kw. With an estimated 8% auxiliaries power requirements for a coal plant with an FGD System, the capital cost per gross kilowatt is \$640/KW.

The FGD System investment cost included in the above figure is \$100/KW (see Section 3.1.4.2). The investment cost of a coal plant without FGD System is, therefore, \$540/gross KW (1978). It will be assumed for the purpose of this Study that a biomass fueled plant is no different cost wise from a coal plant without FGD System.

Assuming that the biomass fueled plant will begin commercial operation in 1985 and assuming that there will be a straight line cash flow of funds during a five year construction time, the capital investment cost is:

$$(540)(1.08)^{1+(0.5)(6)}\ (1.09)^{(0.5)(6)} = \$951/\text{KW (1985)}$$

(see Sections 3.1.8.3 and 3.1.8.4 for details)

With a Fixed Charge Rate of 0.098636, a Plant Capacity Factor of 75% (as for the coal plant), and 35 years of plant operation, the capital investment charges are:

$$\text{Cap. Investment Charges} = \frac{(951)(0.098636)}{(0.75)(8.760)}$$

$$= 14.3 \text{ mills/KWh}$$

4.3.1.2 Biomass Fuel Costs

Biomass fuel costs have been evaluated in separate CEER studies under the Biomass Program. Figure 4.3.1.2 shows a flow diagram for the evaluation of biomass fuel.[47] CEER studies based upon a hypothetical 200 acre energy plantation have estimated biomass fuel cost at \$1.60/MMBTU (1979). A three month stock assumed adds 4 cents/MMBTU to the carrying charges. This cost is escalated at 8% per year until 1985 and then levelized for 35 years of plant operation using the same levelizing factor as was used for coal (See Sections 3.1.9.2 and 3.1.9.3). Table 4.3.1.2 (taken from the CEER Report) illustrates the breakdown of the indicated fuel price in 1979 dollars.

With an assumed net heat rate of 10,000 BTU/KWh,* the levelized fuel charges for the 35 years lifetime of the plant which will being commercial operation in 1985 is thus:

$$F_L = \frac{(1.64)(10,000)}{1,000} (1.08)^6 (1.81)$$

$$F_L = (26)(1.81) = 47 \text{mills/KWh}$$

* A boiler designed for coal as primary fuel will have a higher heat rate when fired with biomass. A boiler designed to burn biomass as primary fuel will have better efficiency than a coal designed plant burning biomass. The indicated heat rate needs to be increased depending on the case by approximately 5-15%.

FIGURE 4.3.1.2

BIOMASS FUEL COST FLOW DIAGRAM

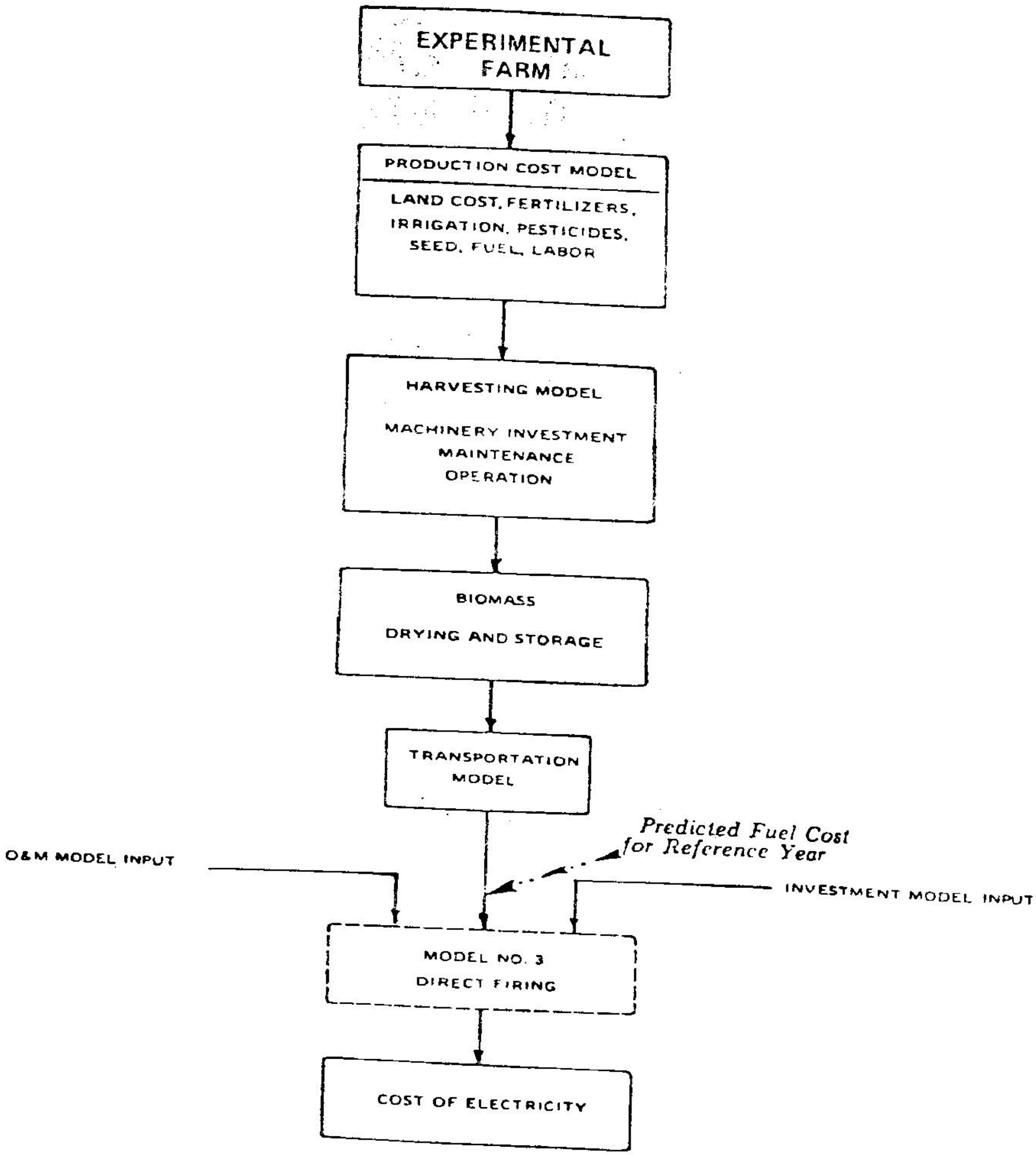


TABLE 4.3.1.2

BIOMASS FUEL COSTS
PRELIMINARY COST ANALYSIS FOR SORDAN 70A PRODUCTION

Land area	: 200 acres
Production Interval	: 6 months
Sordan 70A Yield	: 15 tons/Acre; Total 3,000 Tons of Oven-Dry Material

PRELIMINARY COST ANALYSIS

	Item	Cost ($)
1.	Land Rental, at $50/Acre Year	5,000
2.	Water (Overhead Irrigation), 360 Acre ft.	2,160
3.	Seed, at 60 Lbs./Acre	4,800
4.	Fertilizer	10,000
5.	Pesticides	4,000
6.	Equipment Depreciation (6 mo.)	2,650
7.	Equipment Maintenance (75% of Depreciation)	1,988
8.	Equipment Operation (75% of Depreciation)	1,988
9.	Diesel Fuel	2,200
10.	Day Labor (90.00/day for 140 days)	12,600
11.	Delivery, at 6.00/Ton	18,000
	Subtotal:	65,386
	Plus 10% Error:	6,538
	Total Cost:	71,924

Total Cost/Ton: (71,924 ÷ 3,000): 23.97

Total Cost/Million BTUs (23.97 ÷ 15): 1.59

4.3.1.3 Biomass Power Plant Operation & Maintenance Costs

The O&M costs of the 450 MWe biomass power plant will be assumed to be equal to the O&M costs of a similar coa fired power plant (as evaluated in Section 3.1.10.6) without the FGD system. This can be calculated by setting the sulfur content (S) and the incremental total staff salary necessary to operate the FGD system equal to zero in the O&M cost equation. That is:

$$\text{Total O\&M Cost (1985)} = (1.584)(TSC)+(4.9 \times 10^{-6})(KWh)(0.80)+(1.43)(KW\ )+33{,}660)(1+e)^{y}$$

$$= (\$8{,}828{,}000)(1.08)^{7} = \$15{,}130{,}000$$

with a 75% capacity factor and an 8% assumed auxiliaries power, the levelized fuel cost is calculated as follows (using same levelizing factor as for fuel):

$$\text{O\&M Cost} = \frac{(15{,}130{,}000)(1{,}000)}{(450{,}000)(0.92)(0.75)(8760)} \cdot 1.81$$

$$= (5.5)(1.81) = 10 \text{ mills/KWh}$$

4.3.1.4 Total Levelized Costs of a 450 MWe Biomass Power Plant

The total levelized costs during the 35 years assumed lifetime of a 450 MW biomass power plant, at a 75% capacity factor, a 9%/yr. cost of money, and a 5%/yr. Total escalation for cost levelization in fuel and O&M is:

Capital Charges	:	14.3 mills/KWh
Fuel Cost	:	47.0
O&M Cost	:	10.0
Total		71.3 mills/KWh (1985 start-up)

Escalation of all the above costs at 5% per year, beyond 1985, is shown in Table 4.3.1.4a.

TABLE 4.3.1.4(a)

LEVELIZED TOTAL COSTS FOR PLANT START–UP IN YEAR INDICATED 5%/YEAR INFLATION BEYOND 1985.

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Levelized Cost (mills/KWh)	71.3	91.0	116.1	148.2	189.2	241.4	308.2	393.3

If an inflation factor of 7 1/4%/yr. is used beyond 1985 for fuel as well as O&M, the levelizing factor is L = 2.508. The 1985 levelized cost changes as follows:

Capital Charges	:	14.3 mills/KWh
Fuel Cost	:	65.3
O&M Cost	:	13.8
Total		93.4 mills/KWh (1985 Start-up)

Table 4.3.1.4b indicates the total levelized costs with 7 1/4%/yr inflation, for different start-up years beyond 1985.

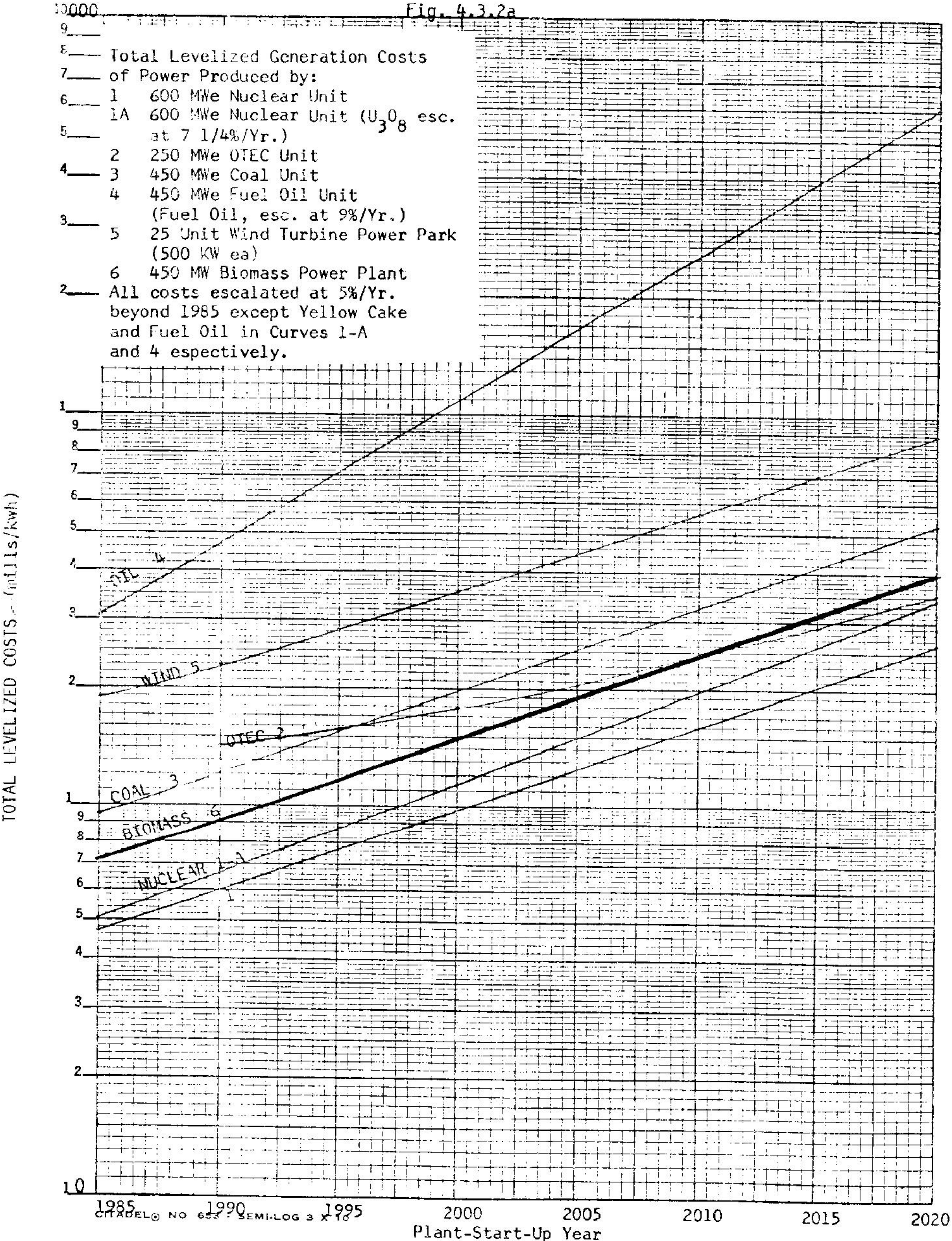
TABLE 4.3.1.4(b)

LEVELIZED TOTAL COSTS FOR PLANT START–UP IN YEAR INDICATED 7-1/4%/YR INFLATION BEYOND 1985

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Levelized Cost (mills/KWh)	93.4	132.5	188.1	266.9	378.7	537.4	762.5	1082.1

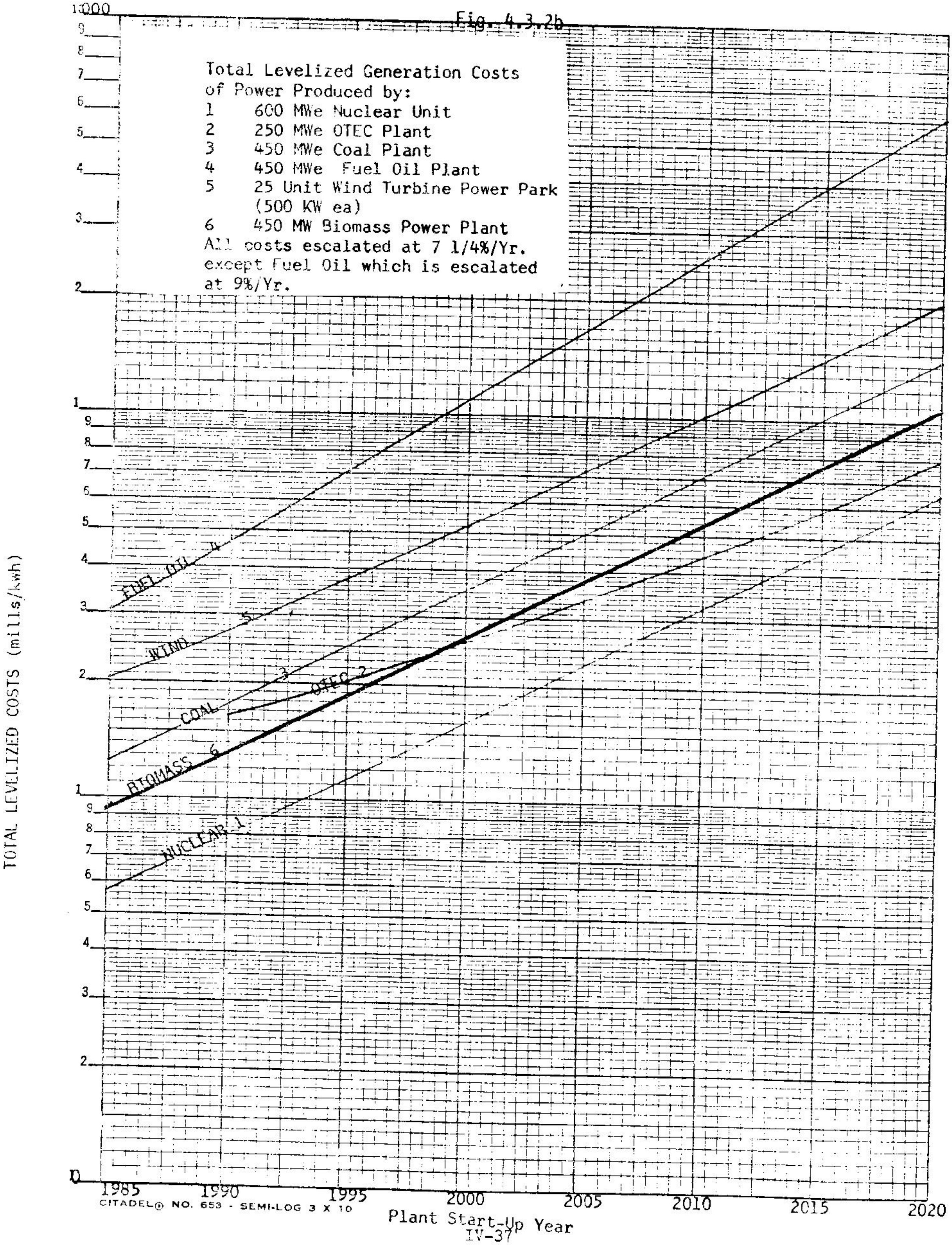
From Figures 4.3.2a and b it can be ssen that biomass fueled plants are economically more attractive than coal plants. The required Research and Development efforts to make possible commercialization of this alternative are described in Reference 2.

Fig. 4.3.2a



Total Levelized Generation Costs
of Power Produced by:
1 600 MWe Nuclear Unit
1A 600 MWe Nuclear Unit (U_3O_8 esc. at 7 1/4%/Yr.)
2 250 MWe OTEC Unit
3 450 MWe Coal Unit
4 450 MWe Fuel Oil Unit (Fuel Oil, esc. at 9%/Yr.)
5 25 Unit Wind Turbine Power Park (500 KW ea)
6 450 MW Biomass Power Plant
All costs escalated at 5%/Yr. beyond 1985 except Yellow Cake and Fuel Oil in Curves 1-A and 4 espectively.
OIL 4
WIND 5
OTEC 2
COAL 3
BIOMASS 6
NUCLEAR 1-A
1
TOTAL LEVELIZED COSTS - (mills/kwh)
1985
1990
1995
2000
2005
2010
2015
2020
Plant-Start-Up Year
CITADEL NO 653 - SEMI-LOG 3 X 10

Fig. 4.3.2b



Total Levelized Generation Costs
of Power Produced by:
1 600 MWe Nuclear Unit
2 250 MWe OTEC Plant
3 450 MWe Coal Plant
4 450 MWe Fuel Oil Plant
5 25 Unit Wind Turbine Power Park (500 KW ea)
6 450 MW Biomass Power Plant
All costs escalated at 7 1/4%/Yr. except Fuel Oil which is escalated at 9%/Yr.
FUEL OIL 4
WIND 5
COAL 3
OTEC 2
BIOMASS 6
NUCLEAR 1
TOTAL LEVELIZED COSTS (mills/kwh)
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start-Up Year
CITADEL® NO. 653 - SEMI-LOG 3 X 10

4.4 PHOTOVOLTAICS

The Photovoltaic process converts direct solar radiation to electricity by using photoelectric cells. There is at present a substantial world wide effort on research and development to improve the viability of photovoltaic systems. Several devices employing different types of photovoltaic cells have been proposed

Most photovoltaic cells are made up of crystalline semiconductors prepared in a fashion so as to produce the generation of an electric current in an external circuit when the semiconductors are exposed to solar radiation.

Applications of electricity generation photovoltaic systems should be viewed in two different perspectives: central station power plants and individual load center (ILC) generating facilities. An ILC photovoltaic generating facility is a small system installed at the point of electrical demand. Since there are periods in which the photovoltaic systems do not produce power, storage capacity can be added or the system can be connected to the utility system to get back-up power. If these small systems are collectively installed, they can contribute a substantial amount of the electrical supply in Puerto Rico

In order to commercialize these systems, it is necessary to reach a point of economic competitiveness between the photovoltaic systems and the commercially available alternatives. Central station photovoltaic power plants will require large land areas because the power produced per unit area of solar collector is small. These plants will be owned and operated by electric utilities.

The present study is directed to analyze central station types of power plants. For purposes of illustration and comparison, a 250 MWe photovoltaic installation in Puerto Rico is evaluated in the present study. This size was selected because it is comparable to the size of power plant unit requirements in the electric system of Puerto Rico. Larger sizes will impose severe restrictions on land resources. A 250 MWe plant will require 4000 acresof land.

4.4.1 Capital Investment of a 250 MWe Photovoltaic Power Plant

It is assumed that a 250 MWe photovoltaic power plant can be installed in Puerto Rico for start-up in 1995. In order for the plant to provide a continuous output, part of the energy produced by the photovoltaics plant during daylight time (approx. 10 hrs.) will be delivered directly to the load, and the balance of the energy generated during the same daylight period will be stored for delivery during night hours (14 hrs). An economic load dispatch program takes into account each unit connected to the grid and minimizes the total system fuel consumption. All units compete with each other and are loaded according to their incremental fuel cost. Since photovoltaic plants don't have any fuel cost and since their output is only during daylight hours, they can probably contribute substantially to improve the economic dispatch of the overall system. However, such an analysis is rather complex and has never been made or proposed. However, it resembles the optimization of a hydrothermal system in which a fictitious water cost γ_η is varied until convergence is obtained with the scheduled hydro-energy use. Such studies will contribute considerably to the optimization of storage capacity for photovoltaics. Future CEER work could address this subject if funds can be secured. Some simple assumptions were made in order to simplify the storage optimization problem.

The hourly generation data of PREPA's power system for three consecutive months was analyzed. This shows that on the average, approximately 60% of the daily electric power generation is produced during the daylight period (7 A.M. to 7 P.M.) and 40% during the night. This period basically coincides with the photovoltaics production period, so that using this simplified criteria, 60% of the photovoltaic plant generation will be dispatched on a load following scheme during the daylight hours and 40% stored in a battery system for delivery during night time on a load following basis. This reduces the capital investment and operating costs of the storage system.

Assuming an average of 10 hours of insolation and electric production per day, the charging rate of the storage system will be, on an average basis, 1.4 times its delivery rate. This provides an emergency "spinning" reserve which is a function of the energy stored. The storage system can be discharged at the same rate that it is charged. Credit for the extra "spinning" reserve capacity can be calculated at the rate of capital cost of a conventional gas turbine, but no credit will be given in this study. Under this assumption 1 kw of plant capacity will have a storage capacity of .4 x 24kwkr per day cycle, or 9.6 kwh per kw of plant capacity.

To account for the absence of solar radiation during cloudy or rainy days and storage system maintenance, a 25% additional energy storage capacity will be provided. Present state of the art indicates solar cell efficiencies from 6 to 25%. Ten percent efficient solar cells are presently commercially available.

Solar array component's efficiencies are assumed as follows:[48]

Solar cells 10% efficient

Electric Battery storage 80% efficient

Electric power conditioning equipment 95% efficient

This gives a 9.5% efficiency for collection and production and 7.6% efficiency for the output of the storage system.

CEER has collected and analyzed solar insolation data for extended periods of time in various locations throughout Puerto Rico. The highest values have been encountered along the southern part of the Island, with the Ponce station registering a yearly average insolation of 5.451 kwh/m^2/day.

Using the above data, the area required to produce 24 kwhs in a 24 h. period, with 60% directly delivered to the load and 40% to the storage system, can be computed as follows:

$$\left(\frac{24}{5.451}\right)\left(\frac{0.60}{0.095} + \frac{0.40}{0.076}\right) = 50.98 \text{ or } 51 \text{ m}^2$$

The average insolation power per square meter is:

$$\frac{5.451}{24} = 0.227 \text{ KW/m}^2$$

4.4.1.1 Basic Plant Cost

The cost of a photovoltaic installation can be approximated by the following relationship:

$$\text{Plant Cost } \frac{\$}{\text{KW}} = \frac{\$ \text{ array cost/m}^2}{(\text{Plant Eff.})(\text{Insolation power/m}^2)}$$

$$+ \text{ Power Conditioning Cost } \frac{(\$)}{\text{KW}} + \text{ Storage Cost } \frac{(\$)}{\text{KW}}$$

The following values are assumed from the present day technology and an extrapolation of the same.

a. Array Cost:

DOE Photovoltaic Program cost predictions are shown in Figure 4.4.1[49,50]. It is estimated that by 1990 the cost of solar array modules for large central station installations will be \$0.15 - 0.40 per peak watt (1980 dollars).

Averaging this cost and considering that peak power is 1000 We/m^2, we have:[51]

Solar photovoltaic collector cell cost:

$$1000 \ \frac{W_p}{m^2} \quad \text{at 10\% eff.} \quad = \quad 100 \ \frac{W_p}{m^2}$$

$$100 \ \frac{W_p}{m^2} \quad \times \quad \frac{\$0.275}{W_p} \quad = \$27.50/m^2 \ \text{(1980 dollars)}$$

b. Installation Cost:

Installation costs for wiring, structures, etc. have been estimated by Schueler at \$41.50 per square meter.[50] The total estimated array cost is \$69.00/m^2 (1980 dollars). Array lifetime is assumed to be 30 years.

c. Storage Cost:

In a very comprehensive study of all solar technologies, the Office of Technology Assessment estimated cost projections for battery storage for large industrial systems using advanced lead acid technology under development by Westinghouse Electric Co.[49]

Battery Cost (proj. for 1990) \$30.00/KWh

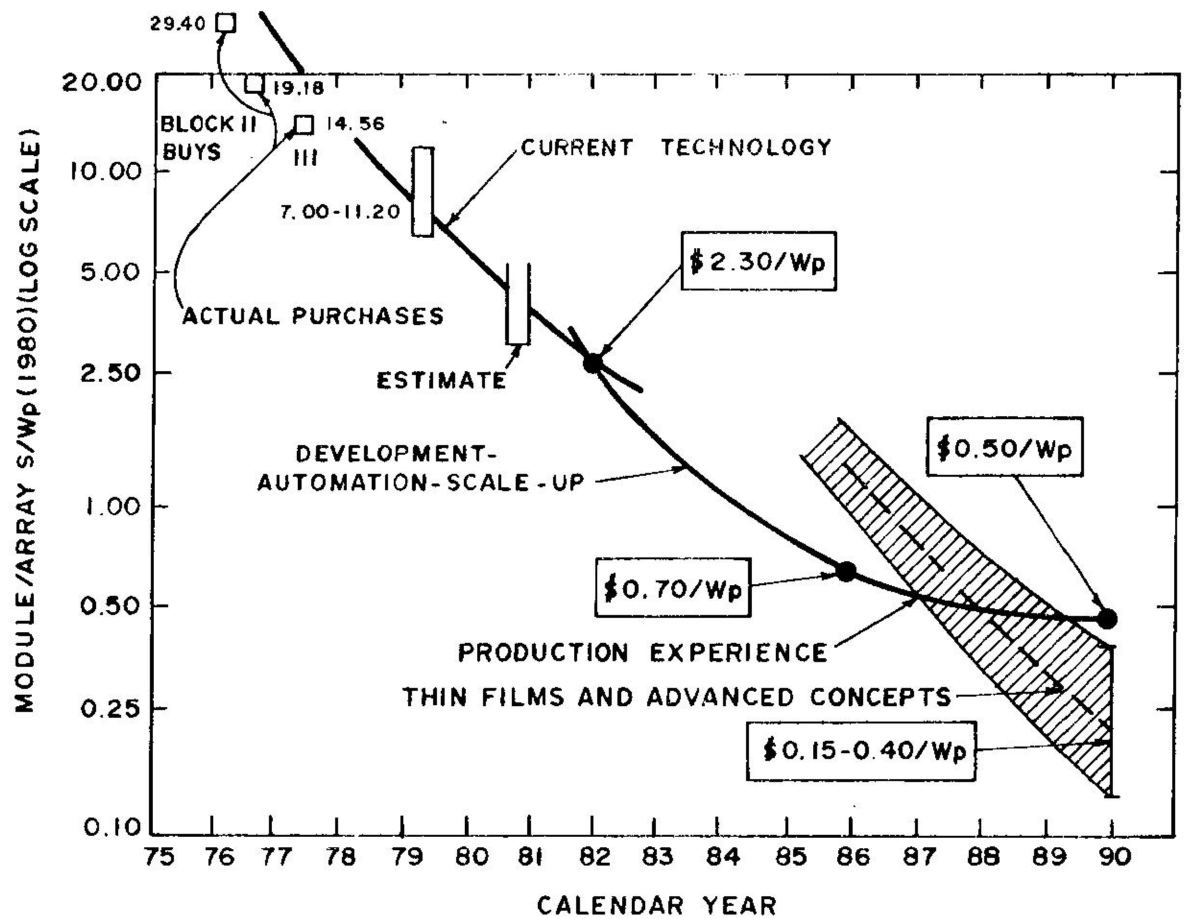


Figure 4.4.1

DOE PHOTOVOLTAIC PROGRAM MODULE/ARRAY
PRICE GOALS AND HISTORY
(1980 Dollars)

(Source: Reference 49 pg. 73)

Installation, building and other costs
$\$(5.7 - 0.7 \log_{10}C)$ KWh

where C is the capacity of the storage system in KWh.

That is:

$$\text{Storage Cost} = 30.00 + (5.7-0.7 \log_{10}1{,}200{,}000)$$
$$= 30.00 + 1.45 = \$31.45/\text{KWh (1980)}$$

The estimated lifetime of the batteries is 10 years, which will necessitate two interim replacements during the plant's operating life.

d. Power Conditioning Cost:

The power conditioning system (PCS) of a photovoltaic power system includes suitable power conversion units, power switches for control of system configuration, and the monitor and control unit. The PCS performs all the power conditioning and switching required to link system sources and sinks under the overall control of the monitor and control unit. Cost projections of PCS were also estimated by the Office of Technology Assessment as follows:

PCS Cost (proj. for 1990) $\$40.00/KW_p$

A lifetime of 30 years is estimated.

Combining the above system component costs we have:

$$\text{Total Basic Plant Cost} = \frac{69.00}{0.227}\left(\frac{0.60}{0.095} + \frac{0.40}{0.076}\right) + (1.25)(31.45)(9.6) + 40.00$$

$$\text{Total Basic Plant Cost} = 3520 + 377 + 40 = \$3937/\text{KW (1980)}$$

4.4.1.2 Total Plant Cost

Since the lifetime of the plant is assumed to be 30 years and the life of the batteries is estimated to be 10 years, two interim replacements are projected for the battery component.

The equivalent capital cost (EC) for a power plant with interim replacements is calculated using the following equation:[14]

$$EC = BPC + CR \left[\frac{CRF(r,N)}{CRF(r,LR)} \; \frac{FCR_r}{FCR_p} \left(1 + \sum_{p=1}^{Nr-1} \left(\frac{1+e}{1+i} \right)^{p \times LR} \right) \right]$$

where: EC = equivalent capital cost

BPC = capital cost of portion of a plant unaffected by interim replacement

CR = capital cost of the interim replacement

CRF(r,N) = capital recovery factor for plant where N is the book life of the plant

CRF(r,LR) = capital recovery factor for the interim replacement where LR is the interim replacement book life

FCR_r = fixed charge rate for the interim replacement

FCR_p = fixed charge rate for the plant

e = inflation rate

i = discount rate or cost of money

Nr = number of replacements

LR = replacement life

The fixed charge rate considered throughout the present study for application to the Puerto Rico Electric Power Authority has been the capital recovery factor plus a small allowance for insurance, hence, the fixed charge rate can be equated to the capital recovery factor in the above equation, thus obtaining:

$$EC = BPC + CR \left[1 + \sum_{p=1}^{Nr-1} \left(\frac{1+e}{1+i} \right)^{pxLR} \right]$$

Substituting in the above equation with the usual values of i = 9%/yr. and e = 5%/yr, we get:

$$\text{Plant Unit Cost} = \frac{\$3560}{KW} + \frac{\$377}{KW} \left[1 + \left(\frac{1.05}{1.09} \right)^{10} + \left(\frac{1.05}{1.09} \right)^{20} \right]$$

$$= 3560 + 377\ (2.16) = \$4374/KW \quad (1980)$$

The area required for the plant at 51 m^2/KW is 3151 acres. An area of 4000 acres will be assumed at $5,000 per acre with a total cost of $20,000,000

The total plant cost is then:

Plant:	(250,000)(4,374)	=	$\$1093.5 \times 10^6$
Land :	(4000)(5,000)	=	20.0×10^6
			$\$1113.5 \times 10^6$

4.4.1.3 Capital Investment Charges

The scheduled and forced outage rate for photovoltaics must be lower than for an OTEC plant. Three weeks outage per year for photovoltaics is more than adequate for forced and scheduled maintenance. This yields a 94% capacity factor. An 85% capacity factor would be more than adequate. The investment charges for the plant for operation in 1995 are calculated using the following parameters:

CF = .85

FCR = 0.101336 (30 years operating life)

Escalation (1980-1985) at 8%/yr.

Escalation (1985-1995) at 5%/yr.

Thus:

Capital Investment Charges =

$$\frac{(1113.5 \times 10^6)(0.101336)(1.08)^5(1.05)^{10}}{(250,000)(8.76)(0.85)} =$$

145 mills/KWh (1995)

4.4.2 Operation & Maintenance Costs (O&M)

O&M costs will be figured on the basis of an assumed plant staff. The area per KW of plant power is 51 m^2; therefore, for a 250 MW module an area of 3151 acres is required. Such large farm electronics and wiring will undoubtedly require personnel. The following is assumed.

Suggested staff for a 150 MWe Photovoltaic Power Plant

1 Superintendent
2 Asst. Superintendents
2 Secretaries
5 Shift Supervisors
10 Shift Operators
2 Electrical Engineers
4 Electricians
4 Electronic Technicians
1 Instrument Engineer
4 Instrument Technicians
1 Mechanical Engineer
3 Mechanics
2 Clerks
2 Janitors
5 Gardeners and general landscapers
20 Security Men (4 Guards/Shift)
5 Shift Chauffeurs
1 Chauffeur (regular hours)
3 Utility Men (general)
2 Chemical Engineers (storage system)
8 Assistant Chemists (storage system)
1 Warehouse (spare parts) supervisor
2 Warehouse Clerks

1 Accountant
1 Purchaser, estimator
1 Clerk
95 Total

Ave. salary per man \$24,000

Total salaries (24,000)(95) = \$2,280,000

Assuming a factor of 1.0 for material replacement, etc., (and this to be a very highly conservative assumption since photovoltaics is a static system).

Year Total OM Cost \$4,560,000

$$\text{mills/KW} = \frac{4,560,000}{(250,000)(8760)(.85)} = 2.45 \text{ mill/KW (1978)}$$

4.4.2.1 Levelized Operation and Maintenance Costs

It should be noted that the lifetime of the other alternatives analyzed in this study has been assumed as 35 years. The lifetime for the photovoltaic plant is assumed as being 30 years because no evidence has been found in the literature to justify more than 30 years lifetime for photovoltiac plants. This introduces a somewhat lower levelizing factor for this calculation:

$$\text{Levelizing Factor} = \frac{(1+r)^n-1}{r(1+r)^n} \cdot \frac{i(1+i)^n}{(1+i)^n-1}$$

$$= (17.699)(0.0973) = 1.72$$

Using the same escalation as for the OTEC plant and the above levelizing factor, the O&M cost of the photovoltaics plant for 1995 commercial operation is:

$$\text{Levelized O\&M Cost} = (2.45)(1.08)^7(1.05)^{10}(1.72) = 11.76 \text{mills/KWh}$$

4.4.3. Total Estimated Cost

The total cost of the 250 MWe photovoltaic plant levelized for the 30 years operating life of the plant with 1995 commercial operation date is thus:

Total Cost = 145 + 11.76 = 156.76 mills/KWh

For comparison purposes of the photovoltaic technology with the other alternatives evaluated in this study, the cost of the 250 MWe photovoltaic plant is projected for future start-up years beyond 1995. It should be noted that no learning curve effects are considered beyond this date, since the learning curve will be saturated by then as shown in Figure 4.4.1.

It should also be mentioned that since photovoltaics plants are modular in design, partial electric output can be obtained during the five year construction period which in reality can be credited to the overall capital investment, and which reduces the interest during construction. These have not been credited in order to have conservative estimates.

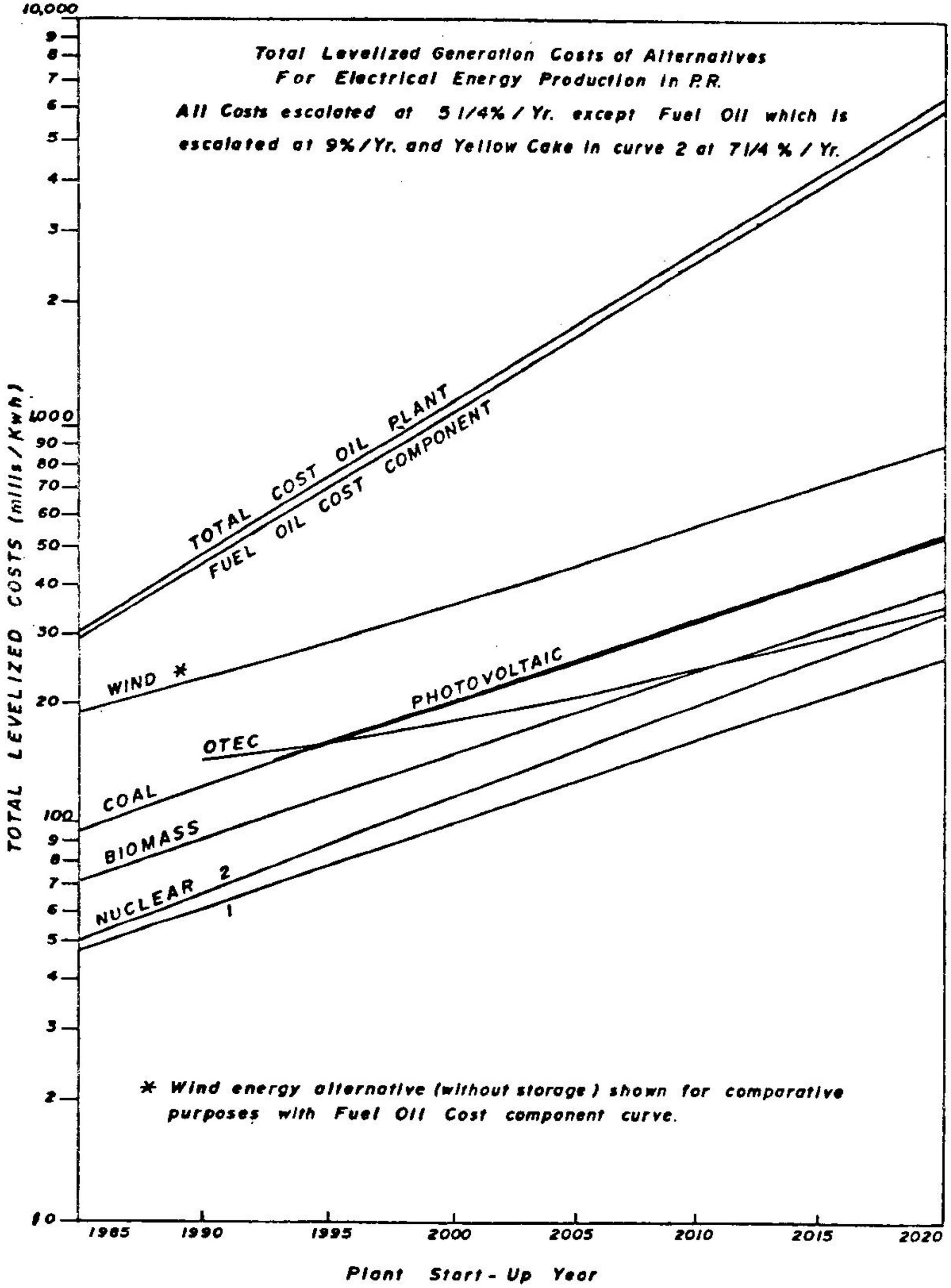
Table 4.4.3.1 presents the plant's costs for commercial operation beyond 1995. These results are graphically depicted in Figures 4.4.3 a and b.

TABLE 4.4.3.1

Total Levelized Costs of a 250MWe Photovoltaics Plant in Puerto Rico. Interest During Construction and Escalation Until 1985 at 8%/Yr. Interest After 1985 at 9%/Yr. and Escalation as Indicated. 30 Years Operating Life.

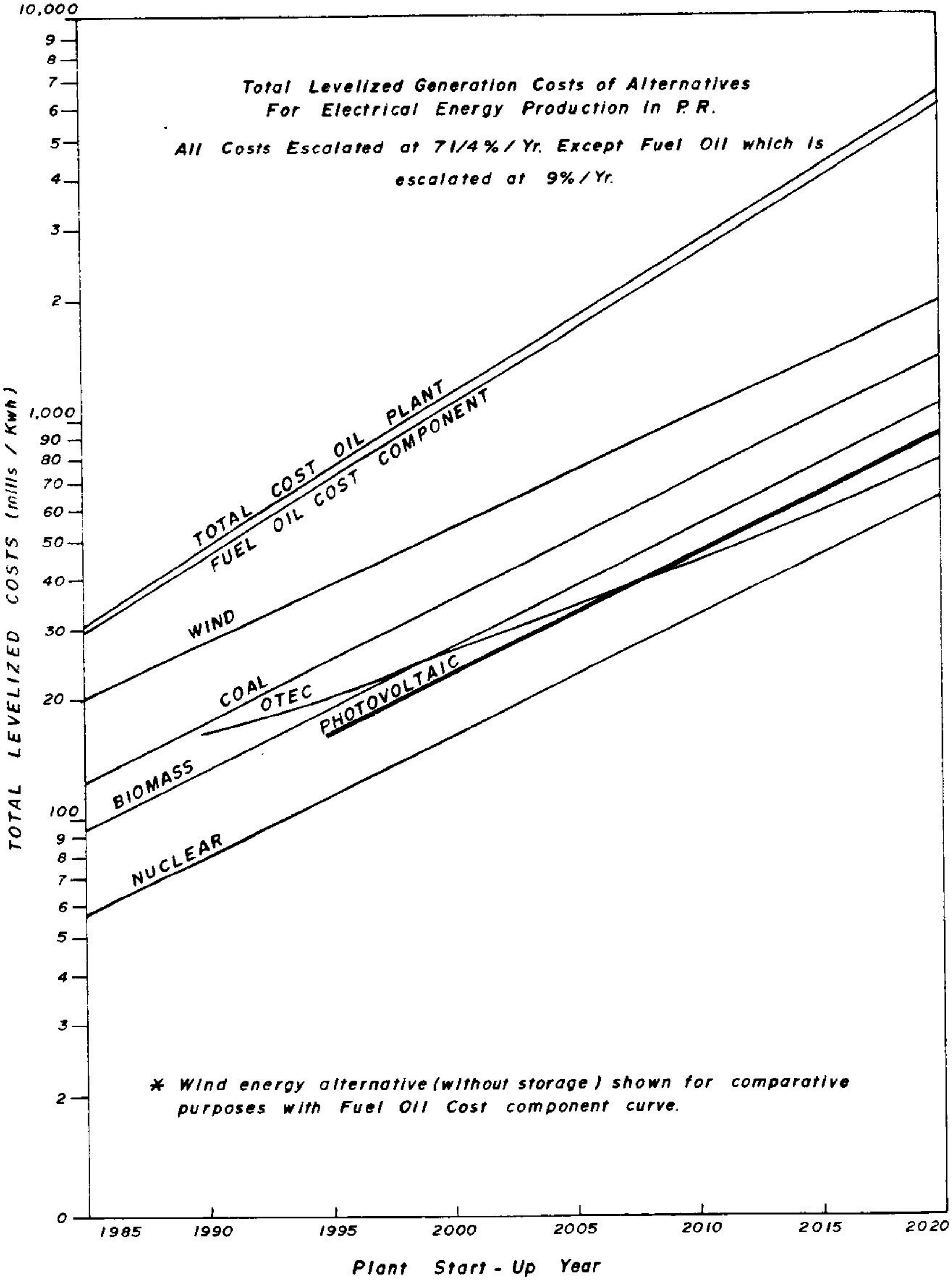
	Start-Up Year	1995	2000	2005	2010	2015	2020
Escalation at 5%/Yr.	Capital Investment Charges (mills/KWh)	145	185.0	236.2	301.4	384.7	491.0
	Levelized O&M Costs (mills/KWh)	11.76	15.0	19.2	24.4	31.2	39.8
	Total Estimated Cost (mills/KWh)	156.8	200.0	255.4	325.8	415.9	530.8
Escalation at 7 1/4%/Yr.	Capital Investment Charges (mills/KWh)	145	205.8	292.0	414.3	587.9	834.2
	Levelized O&M Costs (mills/KWh)	15.66	22.2	31.5	44.7	63.5	90.1
	Total Estimated Cost (mills/KWh)	160.7	228.0	323.5	459.0	651.4	924.3

FIGURE 4.4.3a



Total Levelized Generation Costs of Alternatives
For Electrical Energy Production in P.R.
All Costs escalated at 5 1/4% / Yr. except Fuel Oil which is escalated at 9% / Yr. and Yellow Cake in curve 2 at 7 1/4 % / Yr.
TOTAL COST OIL PLANT
FUEL OIL COST COMPONENT
WIND *
PHOTOVOLTAIC
OTEC
COAL
BIOMASS
NUCLEAR 2
1
* Wind energy alternative (without storage) shown for comparative purposes with Fuel Oil Cost component curve.
TOTAL LEVELIZED COSTS (mills / Kwh)
10,000
1000
100
10
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start - Up Year

Fig. 4. 4. 3b


Total Levelized Generation Costs of Alternatives
For Electrical Energy Production in P. R.
All Costs Escalated at 7 1/4 % / Yr. Except Fuel Oil which is
escalated at 9% / Yr.
TOTAL COST OIL PLANT
FUEL OIL COST COMPONENT
WIND
COAL
OTEC
PHOTOVOLTAIC
BIOMASS
NUCLEAR
10,000
9
8
7
6
5
4
3
2
1,000
90
80
70
60
50
40
30
20
100
0
TOTAL LEVELIZED COSTS (mills / Kwh)
1985
1990
1995
2000
2005
2010
2015
2020
Plant Start - Up Year
* Wind energy alternative (without storage) shown for comparative purposes with Fuel Oil Cost component curve.

SECTION 5

SOCIO–ECONOMIC ANALYSIS

Section 5

SOCIO-ECONOMIC ANALYSIS*

5.1 The Direct and Indirect Impact of Oil Price Increases on Total Costs of Puerto Rican Industrial Sectors an Input-Output Approach

5.1.1 Introduction

The increase in oil prices by the Organization of Petroleum Exporting Countries (OPEC) since late 1973 has had a profound impact on the economies of most nations of the world. The economy of the United States experienced a high rate of inflation followed by one of the most severe recessions in the Post-War period. Economic capacity was reduced by four to five percent and the productivity of existing capital and labor resources declined.[53]

Most studies of the impact of oil price increases have focused mainly on aggregate variables (gross national product, total investment, general level of prices and others). Impacts on intermediate and final demand and on costs and price changes by the industrial sector have been, in most cases, neglected.

The availability of input-output tables of the Puerto Rican economy enable us to use input-output analysis to estimate the direct and indirect impacts of oil price increases sector by sector.

The purpose of this section is to estimate the impact of oil price changes on the cost structure of industries and on the producer's price index by the industrial sector. It will be assumed that the increase in costs (intermediate inputs plus value added) of the industrial sectors will be shifted forward to the intermediate and final consumer. Inflationary impacts on producer's

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prices will be measured. However, purchaser's prices can be also estimated by using mark-ups of the industrial sector.

5.1.2 Methodology and Methamatical Model

5.1.2.1 Methodology

The methodology and the model closely follow the price version of the Leontief's input-output model.[54] Prices in the input-output system are described by the following equations:

1. $P = V(I-A)^{-1}$
2. $V = P(I-A)$

where:

P is a vector of relative prices

I is the identify matrix

A is the input-output coefficient matrix (excluding value added)

V is the row vector of value added expressed in dollars per unit of output.

$(I-A)^{-1}$ is the Leontief's Inverse

The following is a detailed explanation of the methodology and the model used in our calculations. The 53 by 53 total input-output transaction table in producer's prices for the fiscal year 1972 was the starting point.* Two industrial sectors shown in this table are Petroleum Refining and Other Petroleum Products. The row vectors corresponding to these industries show their sales to themselves and to the other 51 sectors used as intermediate inputs in the production process. The latest available data show that the average price per barrel of crude has increased about 7 times from 1973 to 1979 (from approximately $3 per

*Total means the import coefficients are included.

barrel in 1973 to $21.0 in 1979). This price increase has been used as a base for the calculations, and it has been assumed that the increases in costs of the industrial sector are shifted completely to intermediate and final consumers. It has also been assumed that the price elasticity of demand is equal to zero or is negligible for the period covered in this study*.

Since the total expenditures of an industrial sector are equal to its intermediate purchases or from itself and all other sectors intermediate inputs, plus payments to primary factors of production (value added), its total direct cost will increase in response to energy price increases. The change in costs will vary according to the share of the sector's energy inputs. Therefore, our first step was to increase the row vectors of intermediate sales of petroleum refining and other petroleum products by seven times. The resulting increases in total expenditures (increases in costs) were then divided by the total expenditures of the base year (in this case, fiscal year 1972), the year of our latest I-O table to derive a 1 by 53 set of scalars of producer's prices. The second step (second iteration) was to premultiply the price row by row by the "new" transaction matrix (with the inflated petroleum vectors) to obtain new total expenditures. These latter were then divided by the vector of total expenditures that was obtained in the first step to obtain a new set of price indexes. The iterative process continued until relative prices met a convergence criterion.[54]

*The limited scope of this study prohibits entering into the analysis of parametric changes in response to fuel substitutions due to price increses. Some models for analyzing energy impact have taken this latter fact into consideration. See for instance, C.W. Bullar, "An Input-Output Model for Energy Demand Analysis", Center for Advanced Computation, University of Illinois at Urbana-Champaign, Urbana, Illinois (Document No. 146, Dec. 1974).

The convergence criterion used here was 0.01%. In other words, every "round" generates a price index which is then pre-multiplied by the different transaction matrices until the process converges. In this case, the step by step process was not followed since the iterative process was shortened by using the Leontief's inverse matrix.

5.1.2.2 The Mathematical Model

Definitions:

1. $X_j^o = \sum_{i=j}^{n} X_{ij}^o + V_j^o$

2. $X_i^o = \sum_{j=1}^{n} X_{ij}^o + F_i^o$

3. Po = set of 53 scalars each one equal to 1.0 in the base year, except for Petroleum refining and other petroleum products

X_j^o = is equal to a vector of total expenditures for the base year (j = 1 2, ..., 53)

X_{ij}^o = 53 by 53 Transaction matrix in producer's prices (Value of industry i production used as intermediate inputs by j industry) for base year (1972).

V_j^o = value added in the base year (j = i)

X_i^o = value of production equal to intermediate plus final sales for the base year (i = 1, 2,..., 53)

F_i^o = base year final demand (i = 1,2,..., 53)

Equations:

1. $\sum_{k=1}^{m} X_{ij}^k = \sum_{k=1}^{m} P_i^k \, (X_{ij})^k$

2. $\sum_{k=1}^{m} X_j^k = \sum_{i=1}^{n} (X_{ij})^k + V_j^o$

3. $\sum_{k=1}^{m} X_i = \sum_{j=1}^{n} (X_{ij})^k + F_i^o$

4. $P_i^k = \sum_{k=1}^{m} \left(\frac{K_j^k}{X_j^{k-1}} \right)$

where: $i,j = 1,2,3,\ldots,53$ (number of industrial sectors)

$k = 1,2,3,\ldots m$ (number of iterations)

5.1.3 The Results

5.1.3.1 Base Year Data

From 1973 to 1974 petroleum prices experienced a fourfold increase. From 1973 to 1979 price increases amounted to 700 percent, and during fiscal year 1979, 50 percent. This Section will analyze the impact of these price changes on total expenditures (costs) and on the producer's price index. Mathematical proportions (constants) for each industrial sector will determine the inflationary impact of changes in petroleum prices of any magnitude. These latter have been estimated for the 53 industrial sectors of the Input-Output Table and for main industrial sectors, thus making it easier for the policy maker to determine impacts without having to use additional computer time.

The Input-Output Table of 1972 (in its 53 by 53 dimension) includes two petroleum related sectors. The first is Petroleum Refining and the second is Other Petroleum Products. In the first exercise the price of both has been oncreased seven times (the increase of the barrel of crude from 1973 to 1979) to determine the inflationary impact on each sector of the economy. In the second exercise only the Petroleum Refining sector was inflated, and Other Petroleum Products remained constant. Both exercises were repeated, but this time with a four-fold increase in petroleum prices (the increase from 1973 to 1974), and with a 50 percent increase option (inflating both sectors by 10 percent) to give the reader an easy way to estimate inflationary impacts of small increases on petroleum prices.

Following is a detailed account of the results.

Table 5.1.1 shows the base year figures of the intermediate demand for petroleum products used as inputs by 53 industrial sectors and supplied by Petroleum Refining and Other Petroleum Products industries. According to the data presented in this Table, during 1972 a total of $562.7 millions of petroleum products were demanded in our economy. Of these, $491.9 millions were allocated to intermediate demand and $70.8 millions were allocated to consumer demand. The Petroleum Refining industry supplied $433.7 millions (or 77.1 percent of the total of both industries), while other petroleum products supplied only $129.0 millions. The construction industry was responsible for 29.5 percent of the total intermediate demand, while the share of all manufacturing sectors was 36.5 percent. Within the manufacturing sector the petroleum industry's own consumption accounted for 15.6 percent of the total. Within the service sector the most important demands came from electricity, trade and transportation.

Each individual industry can be ranked according to the share of inputs supplied by Petroleum Refining and Other Petroleum Products in the total costs of each

Table 5.1.1

DEMAND FOR FUEL BY INDUSTRIAL SECTOR
PUERTO RICO FISCAL YEAR 1972
(in thousand dollars)

Demanding Sectors	Supplying Sectors: Petroleum Refining	Supplying Sectors: Other Petroleum Products	Total Petroleum Consump-tion	Total Expen-ditures	Petroleum Consumption as a % of Total Expenditures
Agriculture	3,250	1,685	4,935	307,847	1.6
Sugar Cane	1,121	371	1,492	37,552	4.0
Other Agriculture	2,129	1,314	3,443	270,295	1.3
Mining	1,820	1,523	3,343	22,727	14.7
Construction	109,043	36,074	145,117	1,212,858	12.0
Manufacture	140,862	38,548	179,410	4,503,816	4.0
Meat Products	401	327	728	83,100	0.9
Dairy Products	1,846	348	2,194	93,965	2.3
Preserved Fruits and Vegetables	1,313	1,259	2,572	51,978	4.9
Grain Mill Products	1,231	417	1,648	86,023	1.9
Bakery Products	3,230	1,957	5,187	75,727	6.8
Sugar and Confectionary Products	9,208	97	9,305	101,901	9.1
Malt Beverages	2,055	1,336	3,391	94,219	3.6
Alcoholic Beverages	3,961	2,805	6,766	213,773	3.2
Bottled and Canned Soft Drinks	1,956	1,097	3,053	95,615	3.2
Miscellaneous Food Products	1,883	1,108	2,991	257,642	1.2
Tobacco Products	152	97	250	184,385	0.1
Textiles and Apparel	1,824	986	2,810	613,926	0.5
Furniture and Wood Products	704	379	1,083	69,117	1.6
Paper and Allied Products	544	580	1,124	42,865	2.6
Printing and Publishing	950	483	1,433	57,715	2.5
Petrochemical Products	10,671	1,691	12,362	28,105	4.4
Drugs	5,723	4,319	10,042	341,773	2.9
Other Chemical Products	743	351	1,094	49,597	2.2
Petroleum Refining	40,235	3,755	43,990	492,537	8.9
Other Petroleum Products	30,666	2,246	32,912	121,831	27.0
Rubber and Plastics	496	191	687	78,789	0.9
Leather and Leather Products	270	66	336	78,258	0.4
Cement	5,726	68	5,794	51,525	11.2
Other Stone, Clay, and Glass Products	4,279	2,611	6,890	146,333	4.7
Primary Metals	71	12	83	35,365	0.2
Fabricated Metal Products	2,314	837	3,151	154,018	2.0
Machinery Except Electrical	1,705	1,173	2,878	54,602	5.3
Electrical Machinery	4,041	5,118	9,159	285,453	3.2
Transportation Equipment	653	586	1,239	12,758	9.7
Prof./Scientific Instruments	179	43	222	118,562	0.2
Miscellaneous Manufactg. Inds.	1,831	2,205	4,036	79,439	5.1
Transportation	16,745	3,965	20,710	385,774	5.4
Communications	1,040	834	1,874	138,255	1.4
Electricity	45,984	3,710	49,694	318,953	15.6
Aqueduct, Sewer and Gas	1,061	790	1,851	63,998	2.9
Trade	19,644	18,270	37,914	1,625,339	2.3
Finance	3,972	3,317	7,289	219,180	3.3
Insurance	788	532	1,320	83,834	1.6
Real Estate	5,510	5,392	10,902	816,611	1.3
Hotels	464	221	685	105,443	0.6
Personal Services	1,223	316	1,539	85,806	1.8
Business Services	2,653	2,140	4,793	126,351	3.8
Repair Services	1,408	1,167	2,575	86,292	3.0
Amusement and Recreation	635	552	1,187	78,137	1.5
Medical and Health Services	869	510	1,379	215,946	0.6
Other Services	1,241	1,407	2,648	204,591	1.3
Commonwealth Government	3,700	4,000	7,700	1,022,557	0.8
Municipal Government	1,505	811	2,316	207,784	1.1
Federal Government	2,596	91	2,687	238,966	1.1
Total Intermediate Demand	366,013	125,855	491,868	-	4.1
Consumption	67,656	3,191	70,847	-	-

industry. The proportions shown for mining, construction, electricity and cement are the highest. For instance 27% of the total inputs used by Other Petroleum Products is supplied by the petroleum refining industry and by itself (but mostly by Petroleum Refining). In the case of electricity, the share amounts to 15.6 percent, mostly supplied by petroleum refining ($46.0 millions or 14.4 percent in base year 1972).

5.1.3.2 Change in Total Expenditures

The input-output transaction table when read columnwise indicates that total expenditures by any industry j are equal to its intermediate inputs supplied by the industries in the rows (i industries) plus the payments to the "primary" factors of production in the form of wages and salaries, rents, interest and profits (value added). The two industrial sectors supplying these inputs are Petroleum Refining and Other Petroleum Products. These industries import crude oil from other countries and refine it in Puerto Rico into products to be sold to the 53 sectors included in this analysis. Assuming that any increase in the price of the crude oil will be shifted forward to the intermediate and final consumer and that the relation between petroleum inputs to total inputs of each sector remains constant (constant coefficients), the row vectors of the two industries supplying petroleum products were inflated by the 700 percent increase in the barrel of oil. By using an iterative process in the computer* estimates were made of the various "rounds" of increases in

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*The author is grateful to the graduate student Loida Rivera for the many hours she devoted to the programming and computer work. The Program MOTHER (Matrix Operations That Help Economic Research) installed in our computer by Professor Ed Wolff from New York University was used in our research).

total expenditures. Table 5.1.2 shows the results of the iterative process for the first two rounds, the aggregate of the remaining rounds, and the final results after the process converged. For instance, an increase in the average price of the barrel of oil from $3.00 to approximately $21.00 from 1973 to 1979, results in increased Federal Government total expenditures from $239.0 millions to $494.7 millions (costs) which are incurred in providing its services (intermediate plus final sales of services) at increased producer's price (or will continue increasing prices until the response to the shock has converged to a new set of equilibrium prices). Although time periods cannot be attached to the different rounds of cost increases (or price index increase), we can determine with the model the approximate, ceteris paribus,* amount of increase in total expenditures and prices. In this case the Federal Government's cost will increase until it reaches 107 percent (using 1972 as a base year). Assuming the government will pass the same percentage of cost increase to the intermediate and final consumers, then its producer's price index will increase by the same percentage (see Table 5.1.3).

In Table 5.1.3 a producer's price index has been constructed using the 1972, the year of the latest input-output table, as a base fiscal year. The table shows that if Petroleum Refining and Other Petroleum Products cost have increased 7 times as a result of price increases in the barrel of crude, then the producer's price index for each sector has increased or will keep increasing until it reaches the percentage shown in the last column of the table. For instance, the producer's price of cement will increase 67 percent in the first round, 34 percent in the

*We are assuming zero price elasticity of demand for petroleum products, and constant input-output technological coefficients.

total expenditures. Table 5.1.2 shows the results of the iterative process for the first two rounds, the aggregate of the remaining rounds, and the final results after the process converged. For instance , an increase in the average price of the barrel of oil from $3.00 to approximately $21.00 from 1973 to 1979, results in increased Federal Government total expenditures from $239.0 millions to $494.7 millions (costs) which are incurred in providing its services (intermediate plus final sales of services) at increased producer's price (or will continue increasing prices until the response to the shock has converged to a new set of equilibrium prices). Although time periods cannot be attached to the different rounds of cost increases (or price index increase), we can determine with the model the approximate, <u>ceteris paribus</u>,* amount of increase in total expenditures and prices. In this case the Federal Government's cost will increase until it reaches 107 percent (using 1972 as a base year). Assuming the government will pass the same percentage of cost increase to the intermediate and final consumers, then its producer's price index will increase by the same percentage (see Table 5.1.3).

In Table 5.1.3 a producer's price index has been constructed using the 1972, the year of the latest input-output table, as a base fiscal year. The table shows that if Petroleum Refining and Other Petroleum Products cost have increased 7 times as a result of price increases in the barrel of crude, then the producer's price index for each sector has increased or will keep increasing until it reaches the percentage shown in the last column of the table. For instance, the producer's price of cement will increase 67 percent in the first round, 34 percent in the

*We are assuming zero price elasticity of demand for petroleum products, and constant input-output technological coefficients.

Table 5.1.2

RESULTS OF ITERATIVE PROCESS SHOWING ESTIMATED CHANGES IN TOTAL EXPENDITURES AS A RESULT OF SEVEN TIMES INCREASE IN THE AVERAGE PRICE PER BARREL OF CRUDE
(in thousand dollars)

	Total Expendi-tures Base Year $(X_j^{\,o})$	First Round Changes in Total Expendi-tures $(X_j^{\,1})$	Second Round Changes in Total Expendi-tures $(X_j^{\,2})$	Remain-ing Rounds Total Expendi-tures (X^{k-m})	All Rounds Expendi-tures $(\Sigma X_j^{\,k})$
Sugar Cane	37,552	46,504	57,617	33,259	90,876
Other Agriculture	270,295	290,953	331,525	230,689	562,214
Mining	22,727	42,785	69,079	8,193	77,272
Construction	1,212,858	2,083,560	3,009,114	642,589	3,650,702
Meat Products	83,100	87,468	98,570	51,010	149,580
Dairy Products	93,965	107,129	128,202	69,124	197,326
Preserved Fruits and Vegetables	51,978	67,410	94,004	17,749	111,753
Grain Mill Products	86,023	95,911	113,290	51,014	164,304
Bakery Products	75,727	106,849	150,280	30,707	180,987
Sugar and Confectionary Prods.	107,901	157,731	214,049	33,570	247,619
Malt Beverages	94,219	114,565	148,361	78,707	227,068
Alcoholic Beverages	213,773	254,369	311,483	289,219	600,702
Bottled & Canned Soft Drinks	95,615	113,933	146,593	75,234	221,827
Miscellaneous Food Products	257,642	275,588	322,956	153,682	476,638
Tobacco Products	184,285	185,785	194,424	102,275	296,699
Textiles and Apparels	613,926	630,786	675,693	325,006	1,000,699
Furniture and Wood Products	69,117	75,615	86,568	53,048	139,616
Paper and Allied Products	42,865	49,609	62,917	38,244	101,161
Printing and Publishing	57,715	66,313	80,732	53,744	134,476
Petrochemical Products	281,125	355,297	472,249	129,358	601,607
Drugs	341,773	402,025	493,402	408,878	902,281
Other Chemical Products	49,597	56,161	72,026	26,176	98,202
Petroleum Refining	492,537	756,477	1,156,952	79,314	1,236,268
Other Petroleum Products	121,831	319,303	321,634	4,873	326,507
Rubber & Plastics	78,789	82,911	96,137	59,077	155,214
Leather and Leather Prods.	78,258	80,274	85,796	44,895	130,691
Cement	51,525	86,289	115,911	44,332	160,243
Other Stone, Clay, & Glass Prods.	146,333	187,673	272,596	126,893	399,489
Primary Metals	35,365	35,863	37,332	13,240	50,572
Fabricated Metal Prods.	154,018	172,924	198,885	102,990	301,875
Machinery except electrical	54,602	71,870	94,796	35,157	129,953
Electrical Machinery	285,453	340,407	437,430	316,737	754,167
Transportation Equipment	12,758	20,192	30,426	3,306	33,732
Instruments & Related Prods.	118,562	119,894	133,873	110,365	244,238
Miscellaneous Mfg. Inds.	79,439	103,655	156,974	57,511	214,485
Transportation	385,774	510,034	642,709	530,044	1,172,753
Communications	138,255	149,499	169,056	130,957	300,013
Electricity	320,424	621,036	855,494	211,518	1,067,012
Aqueduct, Sewer and Gas	62,527	71,185	87,460	75,735	163,195
Trade	1,625,339	1,852,823	2,215,426	2,189,243	4,404,669
Finance	219,180	262,914	329,711	268,650	598,361
Insurance	83,834	91,754	106,329	78,106	184,435
Real Estate	816,611	882,023	1,017,425	901,611	1,919,036
Hotels	105,443	109,553	123,187	98,243	221,430
Personal Services	85,806	95,040	109,361	94,857	204,218
Business Services	126,351	155,109	196,407	153,585	349,992
Repair Services	86,292	101,742	127,799	103,464	231,263
Amusement and Recreation	78,137	85,259	98,785	75,460	174,245
Medical and Health Services	215,946	224,220	244,677	165,620	410,297
Other Services	204,591	220,479	244,597	213,687	458,284
Commonwealth Government	1,022,557	1,068,757	1,170,830	843,607	2,014,437
Municipal Government	207,784	221,680	276,833	213,537	490,370
Federal Government	238,966	255,088	285,014	209,646	494,660

TABLE 5.1.3

ESTIMATED INCREASES IN THE PRODUCER'S PRICE INDEX RESULTING FROM SEVEN TIMES INCREASES IN THE AVERAGE PRICE PER BARREL OF CRUDE

Industrial Sectors	First Round Price Index (X^1/X^o)	Second Round Price Index (X^2/X^1)	Remaining Rounds Price X^m/X^{m-k}	Total Increase in Price Index (X^k/X^o)
Sugar Cane	1.24	1.24	1.94	2.42
Other Agriculture	1.08	1.14	1.86	2.08
Mining	1.88	1.61	1.91	3.40
Construction	1.72	1.44	1.85	3.01
Meat Products	1.05	1.13	1.62	1.80
Dairy Products	1.14	1.20	1.76	2.10
Preserved Fruits and Vegetables	1.30	1.39	1.46	2.15
Grain Mill Products	1.11	1.18	1.62	1.91
Bakery Products	1.41	1.41	1.57	2.39
Sugar and Confectionary Prods.	1.55	1.36	1.52	2.43
Malt Beverages	1.22	1.29	1.90	2.41
Alcoholic Beverages	1.19	1.22	2.40	2.81
Bottled & Canned Soft Drinks	1.19	1.29	1.84	2.32
Miscellaneous Food Products	1.07	1.17	1.61	1.85
Tobacco Products	1.01	1.05	1.56	1.61
Textiles and Apparels	1.03	1.07	1.53	1.63
Furniture and Wood Products	1.09	1.14	1.79	2.02
Paper and Allied Products	1.16	1.27	1.93	2.36
Printing and Publishing	1.15	1.22	1.96	2.33
Petrochemical Products	1.26	1.33	1.55	2.14
Drugs	1.18	1.23	2.23	2.64
Other Chemical Products	1.13	1.28	1.57	1.98
Petroleum Refining	1.54	1.53	1.44	2.51
Other Petroleum Products	2.62	1.007	1.053	2.68
Rubber & Plastics	1.05	1.16	1.76	1.97
Leather and Leather Prods.	1.03	1.07	1.57	1.67
Cement	1.67	1.34	2.10	3.11
Other Stone, Clay, & Glass Prods.	1.28	1.45	2.00	2.73
Primary Metals	1.01	1.04	1.38	1.43
Fabricated Metal Prods.	1.12	1.15	1.69	1.96
Machinery except electrical	1.32	1.32	1.74	2.38
Electrical Machinery	1.19	1.29	2.16	2.64
Transportation Equipment	1.58	1.51	1.55	2.64
Instruments & Related Prods.	1.01	1.12	1.93	2.06
Miscellaneous Mfg. Inds.	1.30	1.51	1.89	2.70
Transportation	1.32	1.26	2.46	3.04
Communications	1.08	1.13	1.96	2.17
Electricity	1.94	1.38	2.01	3.33
Aqueduct, Sewer and Gas	1.14	1.23	2.24	2.61
Trade	1.14	1.20	2.37	2.71
Finance	1.20	1.25	2.28	2.73
Insurance	1.09	1.16	1.95	2.20
Real Estate	1.08	1.15	2.12	2.35
Hotels	1.04	1.12	1.94	2.10
Personal Services	1.11	1.15	2.12	2.38
Business Services	1.23	1.27	2.27	2.77
Repair Services	1.18	1.26	2.24	2.68
Amusement and Recreation	1.09	1.16	1.98	2.23
Medical and Health Services	1.04	1.09	1.77	1.90
Other Services	1.08	1.11	2.05	2.24
Commonwealth Government	1.05	1.10	1.82	1.97
Municipal Government	1.07	1.25	2.04	2.36
Federal Government	1.07	1.12	7.88	2.07

second round, and 110 percent the remaining rounds (until the process converges) for a total of 311.0 (adding 100 of the base year).[a]

Table 5.1.4 shows three different scenarios of price increases of petroleum products with their corresponding inflationary impacts. The three scenarios are:

1. A 400 percent increase in the barrel of oil corresponding to the period of 1973 to 1974;
2. A 50 percent increase in the average price of petroleum products from fiscal 1978 to 1979[b];
3. A simulation (for reader's convenience) of 10 percent increase in petroleum prices;

Under the first scenario a 400% increase in Petroleum Refining and Other Petroleum Product prices will increase the producer's price index for each sector as shown in the first column. A weighted average for the whole economy will result in about 77% increase in the producer's price index. If it takes six years for the economy to accommodate such a tremendous increase in prices, the average per year change in the producer's price index would have been 10% (double digit inflation). If it takes 7 years, the average price increase would have been 8.5% per year. Both prices, being producer's prices, do not include mark-ups made by the industrial sector which are included in the trade sector. Historically, statistics on percentage price increases show lower results than the statistics from the input-output model. In other words, by taking only oil price increases as causes of the initial shock in the economy and keep-

(a) The producer's price increase is equal to the difference between the figure shown in the last column of Table 3 and 100.0 percent. In the case of cement, the increase was 211.0%, or 311.0-100.0.

(b) According to data supplied to the author by the Government Energy Office.

Table 5.1.4

CHANGE IN PRODUCER'S PRICE INDEX BY INDUSTRIAL SECTOR
IN RESPONSE TO THREE DIFFERENT SCENARIOS OF INCREASE
IN THE PRICE PER BARREL OF CRUDE
(1972 = 100)

Industrial Sector	Producer's Prices Change in Response to: 400 Percent Increase 1/	50 Percent Increase 2/	10 Percent Increase	Multi-plicative Constant
Sugar Cane	1.811	1.101	1.020	4.930
Other Agriculture	1.617	1.077	1.015	6.481
Mining	2.371	1.171	1.034	2.917
Construction	2.148	1.141	1.029	3.483
Meat Products	1.457	1.057	1.011	8.750
Dairy Products	1.629	1.079	1.016	6.364
Preserved Fruits and Vegetables	1.657	1.082	1.016	6.087
Grain Mill Products	1.520	1.065	1.013	7.692
Bakery Products	1.794	1.099	1.020	5.036
Sugar and Confectionary Prods.	1.817	1.102	1.020	4.895
Malt Beverages	2.377	1.172	1.034	2.905
Alcoholic Beverages	2.034	1.129	1.026	3.867
Bottled & Canned Soft Drinks	1.754	1.094	1.019	5.303
Miscellaneous Food Products	1.486	1.061	1.012	8.235
Tobacco Products	1.349	1.044	1.009	11.475
Textiles and Apparels	1.360	1.045	1.009	11.111
Furniture and Wood Products	1.585	1.073	1.015	6.863
Paper and Allied Products	1.777	1.097	1.019	5.147
Printing and Publishing	1.760	1.095	1.019	5.263
Petrochemical Products	1.651	1.081	1.016	6.140
Drugs	1.937	1.117	1.023	4.268
Other Chemical Products	1.560	1.070	1.014	7.143
Petroleum Refining	1.863	1.108	1.022	4.636
Other Petroleum Products	1.960	1.120	1.024	4.167
Rubber & Plastics	1.554	1.069	1.014	7.216
Leather and Leather Prods.	1.383	1.048	1.010	10.448
Cement	2.206	1.151	1.030	3.318
Other Stone, Clay, & Glass Prods.	1.989	1.124	1.025	4.046
Primary Metals	1.246	1.031	1.006	16.279
Fabricated Metal Prods.	1.549	1.069	1.014	7.292
Machinery except electrical	1.789	1.099	1.020	5.072
Electrical Machinery	1.938	1.117	1.023	4.263
Transportation Equipment	1.939	1.117	1.023	4.258
Instruments & Related Prods.	1.606	1.076	1.015	6.604
Miscellaneous Mfg. Inds.	1.971	1.121	1.024	4.118
Transportation	2.166	1.146	1.029	3.431
Communications	1.669	1.084	1.017	5.983
Electricity	2.332	1.166	1.033	3.004
Aqueduct, Sewer and Gas	1.912	1.115	1.023	4.348
Trade	1.977	1.122	1.024	4.094
Finance	1.989	1.124	1.025	4.046
Insurance	1.686	1.086	1.017	5.833
Real Estate	1.771	1.096	1.019	5.185
Hotels	1.629	1.079	1.016	6.364
Personal Services	1.789	1.099	1.020	5.072
Business Services	2.011	1.126	1.025	3.955
Repair Services	1.960	1.120	1.024	4.167
Amusement and Recreation	1.703	1.088	1.018	5.691
Medical and Health Services	1.514	1.064	1.013	7.778
Other Services	1.709	1.089	1.018	5.645
Commonwealth Government	1.554	1.069	1.014	7.216
Municipal Government	1.777	1.097	1.019	5.147
Federal Government	1.611	1.076	1.015	6.542

1/ Historical price increase from 1973 to 1974.
2/ Historical price increase during 1979.

ing all other prices constant, a process of double digit inflation will be introduced into the economy. As Table 5.1.6 shows a 50% increase in oil prices will result in 9.59% increase in industrial costs (or producer's price index) using 1972 as a base year and assuming the initial shock came from the increase in costs of two oil sectors: Petroleum Refining and Other Petroleum Products. If the initial shock should come only from Petroleum Refining sector then producer's price index for the whole economy should increase by 4.8% in response to a 50% increase in oil prices. Table 5.1.6 shows results for the Main Industrial sector and for the whole economy. Table 5.1.5 shows the ranking of industrial sectors classified according to the impact received, that is, increases in the cost of production index which have been assumed to be equal to producer's price index. The ten most impacted sectors were malt beverages, mining, electricity, cement, transportation, construction, alcoholic beverage, business services, other stone, clay, and glass products, and finance. This is only a partial listing of affected industries since many industries do not use fuel directly, but are affected indirectly by the sizeable amounts of electricity they use. Cement and construction industries were hit hard by oil price increases. For instance, the oil price increase of 1973-74 was in great measure responsible for the severe recession suffered by the Puerto Rican economy from 1973 to 1976. Estimates offered elsewhere show that the loss of employment in the construction industry was about 30,000 workers, which induced additional losses of about 16,000 workers in related areas[55]. The inflationary impact of any change in oil prices can be determined by using constants shown in the last column of Table 5.1.4 and deriving equations like the ones shown in Table 5.1.7 for main industrial sectors. For instances, Table 5.1.7 shows that if we increase Petroleum

Table 5.1.5

RANKING (FROM MOST AFFECTED TO LESS AFFECTED) OF INDUSTRIES ACCORDING TO INFLATIONARY IMPACT, IN TERMS OF PRODUCER'S PRICE INDEX, OF 4 TIMES INCREASE OF PETROLEUM PRICES FROM 1973 TO 1974
(1972 = 100)

Industrial Sector	New Producer's Price Index
Malt Beverages	2.377
Mining	2.371
Electricity	2.332
Cement	2.206
Transportation	2.166
Construction	2.148
Alcoholic Beverages	2.034
Business Services	2.011
Other Stone, Clay and Glass Products	1.989
Finance	1.989
Trade	1.977
Miscellaneous Manufacturing Industries	1.971
Other Petroleum and Coal Products	1.960
Repair Services	1.960
Transportation Equipment	1.939
Electrical Machinery	1.938
Drugs	1.937
Aqueduct, Sewer and Gas	1.912
Petroleum Refining	1.861
Sugar and Confectionary Products	1.817
Sugar Cane	1,811
Bakery Products	1.794
Machinery, Except Electrical	1.789
Personal Services	1.789
Paper and Allied Products	1.777
Municipal Government	1.777
Real Estate	1.771
Printing and Publishing	1.760
Bottled and Canned Soft Drinks	1.754
Other Services	1.709
Amusement and Recreation	1.703
Insurance	1.686
Communications	1.669
Preserved Food and Vegetables	1.657
Petrochemical Products	1.651
Dairy Products	1.629
Hotels	1.629
Other Agriculture	1.617
Federal Government	1.611
Professional Instruments	1.606
Furniture and Wood Products	1.585
Other Chemical Products	1.560
Fabricated Metal Products	1.549
Rubber and Plastic Products	1.544
Commonwealth Government	1.544
Grain Mill Products	1.520
Medical and Health Services	1.514
Miscellaneous Food Products	1.486
Meat Products	1.457
Leather and Leather Products	1.383
Textile and Apparels	1.360
Tobacco Products	1.349
Primary Metals	1.246

TABLE 5.1.6

Inflationary Impact by Main Industrial Sector in Response to three Different Scenarios of Petroleum Price Increases (1972 = 100)

Main Industrial Sector	Initial Shock Starting in Petroleum Refining Plus Other Petroleum Products Sectors			Initial Shock Starting in Petroleum Refining Sector		
	700% Incr.	400% Incr.	50% Incr.	700% Incr.	400% Incr.	50% Incr.
Agriculture	212.30	164.17	108.02	156.00	131.71	103.96
Mining	339.97	237.13	117.14	230.69	174.68	109.33
Construction	301.00	214.84	114.35	216.90	166.80	108.35
Manufacturing	221.80	169.60	108.7	154.11	130.92	103.86
Transportation	304.02	216.58	114.57	215.89	166.22	108.28
Communications	217.0	166.86	108.36	150.0	128.57	103.57
Electricity	333.02	233.16	116.64	251.70	186.68	110.84
Trade	270.98	197.70	112.21	173.40	141.94	105.24
Finance, Insurance and Real Estate	241.32	180.75	110.09	180.20	145.83	105.73
Hotels	210.00	162.85	107.86	158.90	133.66	104.21
Remaining Service Sectors	229.35	173.91	109.24	157.2	132.69	104.10
Commonwealth Government	197.01	155.43	106.93	140.40	123.10	102.90
Municipal Government	236.00	177.71	109.71	171.90	141.10	105.14
Federal Government	207.00	161.14	107.64	159.20	133.83	104.23
Total Economy	234.2	176.69	109.59	167.10	138.34	104.79

Table 5.1.7

EQUATIONS TO DETERMINE THE INFLATIONARY IMPACT BY MAIN INDUSTRIAL SECTOR OF OIL PRICE INCREASES (1972 = 100)

	Change Initiated in Petroleum Refining Plus Other Petroleum Products Sectors	Change Initiated in Petroleum Refining Sector
Total Economy (weighted)	$P_i = \Delta P_{r+o}/5.2161 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/10.4322 + 1.0 \times 100$
Agriculture	$P_i = \Delta P_{r+o}/6.233 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/12.613 + 1.0 \times 100$
Mining	$P_i = \Delta P_{r+o}/2.917 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/ 5.356 + 1.0 \times 100$
Construction	$P_i = \Delta P_{r+o}/3.483 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/ 5.988 + 1.0 \times 100$
Manufacturing	$P_i = \Delta P_{r+o}/5.7471 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/12.9366 + 1.0 \times 100$
Transportation	$P_i = \Delta P_{r+o}/3.431 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/ 6.040 + 1.0 \times 100$
Communications	$P_i = \Delta P_{r+o}/5.983 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/14.0 + 1.0 \times 100$
Electricity	$P_i = \Delta P_{r+o}/3.004 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/ 4.6144 + 1.0 \times 100$
Trade	$P_i = \Delta P_{r+o}/4.094 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/ 9.537 + 1.0 \times 100$
Finance, Insurance and Real Estate	$P_i = \Delta P_{r+o}/4.9533 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/ 8.7282 + 1.0 \times 100$
Hotels	$P_i = \Delta P_{r+o}/6.3640 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/11.885 + 1.0 \times 100$
Remaining Service Sectors	$P_i = P_{r+o}/5.4117 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/12.2378 + 1.0 \times 100$
Commonwealth Government	$P_i = \Delta P_{r+o}/7.2160 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/17.327 + 1.0 \times 100$
Municipal Government	$P_i = \Delta P_{r+o}/5.1470 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/ 9.736 + 1.0 \times 100$
Federal Government	$P_i = \Delta P_{r+o}/6.5420 + 1.0 \times 100$	$\Delta P_i = \Delta P_r/11.824 + 1.0 \times 100$

P_i = Producer's Price Index (1972 = 100) of the specific industry (or Total Economy).

ΔP_{r+o} = Change in the prices of the Sectors Petroleum Refining Plus Other Petroleum Products (i.e. 7.0, 4.0 or 0.50 or any other)

ΔP_r = Change in the Price of Petroleum Refining (7.0, 4.0, 0.50 or any other)

Source: Estimation of the author.

Refining Prices by 400% the producer's price index for the whole economy will increase by 138.34 (or 38.34% over base year 1972) or $138.34 = \left[\left(4.0/10.4322\right) + 1.0\right] \times 100$.

This type of equation can be derived for the 53 sectors by using last column of Table 5.1.4.

5.1.4 Conclusions

The purpose of this chapter has been to estimate the impact of oil price increases (using as proxy the increase in the price per barrel of crude) in the cost structure of 53 industrial sectors of the Puerto Rican economy. Assuming that cost increases will be shifted forward to intermediate and final consumers, a producer's price index was estimated for the industrial sectors. Input-output modeling and accounting were used for the analysis. It was found that oil price increases impacted severly the economy of Puerto Rico. Costs increases to industries such as cement, electricity production, construction, mining, alcoholic beverages, transportation, business services, and finance were tremendous. Since electricity costs are highly sensitive to oil price increases, industries with high electricity coefficients such as cement, aqueducts and sewers and hotels were severely impacted. Since 1960 the strategy for economic development has focused on capital and energy intensive industries, and the competitive position of the island has been severely hurt by recent developments. The implications of this for the future prospect of the economy are very serious. The results show that the industries most affected are those that are most important in terms of output generation and job creation. Not only have these latter two variables been affected by oil price increases, but also the general level of price has been affected by the increases. The increase in the general level of prices also known as inflation will be the number one economic problem of the industrial countries of the Western World, including Puerto Rico, for a long term. This Study shows that, keeping all other prices constant, the increase in oil prices from 1973 to 1979 (assuming a conservative price of $21.0 per barrel of crude in fiscal 1979) will induce, or has already induced, more than 130% in an estimated producer's price index, not including mark-ups. This implies double digit inflation, even when other prices are not increasing. It is worth observing that the price increase estimate is higher than the historical price indexes such as those published by the Department of Labor of Puerto Rico and the implicit price deflators of the Puerto Rico Planning Board.

As was mentioned in the introduction, oil price increases were responsible in large part for the inflation and the accompanying losses in actual output employment and potential output in most countries in the Western World during the period of 1973 to 1976. Estimates show that the economy of Puerto Rico lost about $1,328.6 millions in output (intermediate plus final demand) and nearly 58,000 jobs (output at 1972 prices). These figures have serious implications. If we remain dependent on imported oil for all our energy needs, the economic stability of the Island will depend to a great extent on the pricing policies of OPEC. The reader will have an idea of how oil prices will affect costs of industries and prices by examining some of the tables shown in this work.

After studying all the data shown here, one important conclusion emerges: Searching for alternative energy sources is an urgent task which will require the allocation of funds for research and development. As the Krepp's Study specifies:

> "There are no easy solutions to Puerto Rico's basic energy problem. The nearly total reliance on imported petroleum compounded by its highly enclosed and isolated system, and the existence of a large petrochemical infrastructure mean that rapid changes are not possible. Puerto Rico must live with high energy costs. It can, however, develop a strategy which

directs stronger efforts than at present toward:
(1) developing new energy sources for the long run,
(2) greater conservation."[56]

5.2 The Impact in Employment and Output of Two Alternative Energy Source Projects: An Input-Output Approach

5.2.1 Introduction

As expressed in the Plan de Desarrollo Integral (Plan for Integral Development) and in the Message of Governor Romero Barceló to the Legislature of Puerto Rico, the search for alternative sources of energy is a matter of high priority.[57] The Island's dependence on imported oil makes it vulnerable to the pricing policies of the OPEC countries and introduces a great deal of instability into our open economy. According to the recent U. S. Department of Commerce study of the Puerto Rican economy: "As long as Puerto Rico remains dependent on imported oil for essentially all its energy needs, its economic stability will depend significantly on the pricing policies of the oil supplying nations."[57] Oil price increases will continue to have adverse impacts on costs, output, employment, prices and other macroeconomic variables of our economy.

Therefore, it is of strategic importance for our economic well-being to find alternative sources of energy. This process will require the allocation of an increasing amount of resources for research and development, for energy conservation programs, and perhaps for a reorientation of the whole strategy of economic development. In the long run, however, most costs incurred in developing alternative sources of energy will be transformed in benefits to our society. The benefits will be in terms of the reduction of the dependency on imported oil, the decrease in the deficit in trade with foreign countries, the increase in the potential for job creation and output generation, and the reduction in the rate of growth of prices (inflation). These variables are the most common ones affected by oil price changes. However, any project for the generation of energy will require investments in machinery, equipment and construction. The increase in investment will have an important multiplier effect on output, income and employment. Therefore, in a cost-benefit analysis these latter benefits must be added to the ones most commonly analyzed by economists.

The purpose of this section is to estimate the impact on production and employment of the investment needed to start two projects of alternative energy generation. These projects are Biomass and OTEC, and they are part of the alternatives being studied by the Center for Energy and Environment Research (CEER) of the University of Puerto Rico (UPR).

5.2.2 Methodology and Model

An input-output model based on the 1972 input-output table published by the Puerto Rico Planning Board had been used to estimate these impacts.

In the case of Biomass, it is estimated that two 300 MW units as presently planned by PREPA will require about $350.0 millions in investment (1978 dollars) and an increase of $67.0 million (1978 dollars) in agricultural production, and that it will cause a reduction of $231.0 millions in petroleum import.[a] The OTEC project will require $773.0 millions in investment and will cause a $100.0 million reduction in petroleum imports[b] (1978 dollars). The impact on the economy of the increase in investment resulting from the OTEC and Biomass projects and the impact of the $67.0 millions increase in agricultural production of Biomass will be analyzed in this Section.

(a) Based on information provided in Section 3.1.4

(b) Based on information provided in Section 4.1.2

The Leontief's open input-output model was used to estimate investment impact and employment. First, investment figures were deflated by a price index with 1972 as a base year (to make it compatible with 1972 input-output table)* Second, the total investment by suppliers was distributed according to weights derived from the investment vector of 1972 I-O Table. After obtaining the two vectors of investment (one corresponding to Biomass project and the other to the OTEC project), they were post-multiplied by the matrix of direct plus indirect requirements (the so called Leontief's inverse matrix). The solution to the model is the output needed by all sectors of the economy to satisfy the demand for additional investment goods. Output solution was then multiplied by employment coefficients (men per million dollars of output) to obtain the employment needed to produce the output.

To obtain output and employment generated by the increase of agricultural activity, monetary figures were deflated by a price index with 1972 as base year; then the I-O model was solved.

The introduction of these two projects may have the following impacts on the petroleum refining industry, and hence on the economy of Puerto Rico:

1. If petroleum refiniery imports are reduced, production will be reduced, and employment and output will be negatively affected.

2. Imports will not be reduced because a decrease in local sales will be offset by an increase in the industry's exports.

3. Imports and production of refineries (and other sectors of the economy) will be reduced. However, the deficit

*Implicit price deflators for machinery and equipment and construction published by Puerto Rico Planning Board were used.

in the balance of trade will diminish,there will be a favorable effect that could be reflected in an increase in the local components of final demand (consumption, investment, government expenditures and exports).

In the first case petroleum imports from the column vectors of petroleum refineries' intermediate inputs in 1972 I-O matrix were reduced. Imports were deflated to 1972 prices. It was assumed that industry production (intermediate inputs plus value added) was reduced by an amount equal to the reduction in imports. In addition, it was assumed that since production of refineries was reduced, sales to other sectors were also reduced (the row vector of sales) by the share of each sector's oil inputs in their total costs. The price deflator used to deflate oil imports was the one published in 1979 Informe Econômico al Gobernador (page 155) using 1972 as the base year.

In the second hypotheses we assume that the Biomass and OTEC projects will reduce local sales of the petroleum refineries but that their external sales will offset the reduction, thus making it unnecessary to reduce imports and output of refineries and other industrial sectors. In this case exports were increased by the same amount of reduction of local sales (using as proxy the amount of supposed reduction in imports of the first hypothesis). The exports were multiplied by Leontief's inverse matrix to obtain output, and this latter factor was multiplied by the vector of employment coefficients to obtain employment figures.

Finally, in order to analyze the third case, petroleum refinery imports were reduced and the amount was allocated to domestic final demand. Once the vector of final demand was obtained, it was post-multiplied by the inverse matrix to get output changes in the system.

5.2.3 Analysis of the Results

5.2.3.1 Introduction

Table 5.2.1 shows how petroleum imports, investment and agricultural production were affected by the introduction of two projects (Biomass and OTEC) to serve as alternative source of energy input.

Input-output analysis shows the impact on output and employment in the system resulting from the changes in the different variables (investment imports of petroleum and agricultural demand).

TABLE 5.2.1

CHANGE IN INVESTMENT, PETROLEUM IMPORTS AND AGRICULTURAL PRODUCTION AS A RESULT OF THE INITIATION OF TWO ENERGY PROJECTS
(In Million Dollars)

	Biomass (2-300MW)	OTEC (1-250MW)
Increase in Investment		
In Current Prices	\$350.0	\$773.0
At Constant Prices(1972=100)	214.2	457.4
Reduction in Petroleum Refineries Imports		
In Current Prices	231.0	100.0
At Constant Prices(1972=100)	36.4	16.0
Increase in Agricultural Production		
In Current Prices	67.0	----
At Constant Prices	45.0	----

SOURCE: Data in current dollars (1978) are estimated from section 3.1.4 for the Biomass project and from section 4.1.2 for the OTEC project.

5.2.3.2 Agricultural Production

Table 5.2.2 shows the impact of an increase in the demand for agricultural products by the different sectors of the economy.

TABLE 5.2.2

OUTPUT AND EMPLOYMENT GENERATED IN THE SYSTEM BY AN INCREASE IN DEMAND FOR AGRICULTURAL PRODUCTS

(Output in Millions 1972—100)

Industrial Sector	Output*	Employment
Agriculture	46.8	4,228
Mining and Construction	0.3	20
Manufacturing	7.4	231
Transportation, Communications, and Public Utilities	3.0	185
Trade	2.6	240
Finance Insurance and Real Estate	1.2	37
Other Private Services and Government	0.9	77
Required Imports	9.6	—
TOTAL	71.8	5,018

* Output is equal to intermediate sales plus final sales.

Table 5.2.2 shows the following interesting facts:

a. For each million dollar increase in the demand for agricultural products (especially used as intermediate inputs by all sectors), production in the economic system will increase by $1.6 millions. In other words the output multiplier will be 1.6

b. To produce this output it is necessary to import $9.6 millions.

c. Direct plus indirect employment generated amounts to 5,018 jobs, most of them in the agricultural sector.

d. The rates of total employment created to employment created in agricultural is equal to 1.19. This ratio is commonly known as employment multiplier type 1.

Employment figures shown in Table 5.2.2 do not include employment induced by changes in consumption. By using a "closed" Leontief's input-output model, direct and indirect plus induced employment generated by agricultural demand was obtained. This latter amounts to 5,454 jobs.

Impact of Changes in Investment*

Table 5.2.3 shows the impact on output and employment of an increase in investment needed to initiate the Biomass and OTEC energy projects. The benefits in terms of production and employment requirements are considerable. The increase in investment resulting from the Biomass Project will induce an increase of $392.4 million dollars in production in the different sectors. To produce this output (given the level of productivity implied in the labor coefficients) 18,374 new jobs will be required. The OTEC project will increase production by $843.7 millions, and

*Investment here means machinery, equipment and construction in plant.

employment requirements (direct plus indirect) will amount to 39,338 jobs. The increase in employment generated by the investment needed for the two projects will amount to more than 57,712. In other words for each million dollars of increase in investment, output will increase by $1.84 millions (output multiplier of investment demand) and employment will increase by 86.

TABLE 5.2.3

EMPLOYMENT AND OUTPUT GENERATED BY
INVESTMENT NEEDED TO START BIOMASS AND OTEC ENERGY PROJECTS
(Figures in Million Dollars, 1972=100)

	Biomass	OTEC
Initial Investment (1972=100)	$ 214.2	$ 457.4
Output Generated in the System	392.4	843.7
Employment Creation	18,374	39,338
Output per Million Dollars of Investment Demand	1.84	1.84
Employment per Million Dollars of Investment Demand	86	86

SOURCE: Estimates using the Input-Output Model.

What would the reduction in the unemployment rate have been as a result of a $671.6 million dollars increase in investment at constant prices? The latest figures for the unemployment rate are those for the fiscal year 1979. During that year the rate amounted to 17.5%. It is estimated that the increase in investment resulting from Biomass and OTEC projects will reduce the unemployment rate by 6.36 percent to 11.14%.[59]

5.2.3.3 Three Scenarios Based on Petroleum Imports

a. Scenario One: petroleum imports reduction will decrease output in industry and system.

Under this scenario imported petroleum inputs of the Petroleum Refinery Sector will be decreased by $231.0 millions in current dollars ($36.4 millions in 1972 dollars) and by $100.0 millions ($16.0 millions at 1972 dollars) by the establishment of the Biomass and the OTEC Project respectively. It has been assumed that the production of Petroleum Refinery sector will be reduced and that this reduction will have an impact according to each industry's share of petroleum inputs in their total cost of production. Table 5.2.4 shows the results of this scenario.

Table 5.2.4 shows that as a result of reduction in the output of the Petroleum Refinery Sector the output of the system will be reduced by a multiplier of 2.896. In other words, for each million dollars of reduction in output of the sector, the output of the system will decrease by $2.9 million dollars (intermediate plus final sales). For each million dollars of reduction in the output of the system, employment will decrease by 30 workers. The loss in output in this case will be much higher than the loss in jobs because a large share of the loss in output is in the petroleum sector which is a capital intensive industry (employment per million dollar of output of this industry is only 6.53).

TABLE 5.2.4

REDUCTION IN DIRECT PLUS INDIRECT SALES
OF THE DIFFERENT SECTORS OF THE PUERTO RICAN ECONOMY
IN RESPONSE TO A REDUCTION IN PETROLEUM REFINERIES PRODUCTION*
(In Million Dollars, 1972=100)

Industrial Sector	Biomass Project		OTEC Project	
	Output	Employment	Output	Employment
Agriculture	1.71	155	0.75	68
Mining and Construction	6.51	436	2.86	191
Manufacturing	81.12	1528	35.66	671
Petroleum Products	39.27	256	17.26	112
Other Manufacturing	41.85	1272	18.40	559
Transportation, Communications and Public Utilities	7.27	336	3.20	148
Trade	0.66	68	0.29	30
Finance, Insurance and Real Estate	2.05	36	0.90	16
Other Services Plus Government	6.09	558	2.68	246
TOTAL (less Manufacturing)	105.41	3,117	46.43	1,370

* In Input-Output Accounting intermediate plus final sales are equal to intermediate plus primary inputs. In other words total expenditures equal total sales equal total production.

SOURCE: Estimate of the author.

b. Second scenario: no reduction in petroleum refinery output; the reduction in local sales will be matched exactly by an increase in petroleum exports.

Under this scenario the total output of the economy (including value added and imported inputs) will increase by a multiplier of 2.50. If imported inputs are excluded, the output multiplier will be reduced to 1.81. Local production will generate an out 1,000 jobs under the Biomass project and 431 jobs under the OTEC project. The payments to the factors of production (wages, salaries, rents, interests and profits) will increase by $11.4 millions. This scenario is the most probable one since, given the high level of demand for petroleum products a reduction in local sales will be offset by an increase in external sales. Table 5.2.5 shows the output and employment impacts if the Biomass and OTEC projects are introduced.

c. Third Scenario: reduction in Petroleum Imports will improve the Balance of Trade Deficit and the improvement will be reflected in an increase in domestic final demand.

Under this scenario final demand components (domestic) will increase as a result of improvements in the balance of trade position of the Island. Table 5.2.6 shows employment and output creation as a result of increases in the different components of domestic final demand. As

TABLE 5.2.5

EMPLOYMENT AND OUTPUT GAINS
INDUCED BY INCREASES IN EXPORTS OF PETROLEUM REFINERIES
(In Million Dollars, 1972=100)

Industrial Sector	Biomass Project		OTEC Project	
	Output	Employment	Output	Employment
Agriculture	0.11	10	0.05	5
Mining and Construction	0.97	65	0.43	29
Manufacturing	46.93	479	20.63	210
Petroleum Products	39.69	259	17.45	113
Other Manufacturing	7.24	220	3.18	97
Transportation, Communications, and Public Utilities	2.14	99	0.94	43
Trade	2.27	234	1.00	103
Finance, Insurance and Real Estate	1.52	27	0.67	12
Other Services and Government	0.72	66	0.32	29
TOTAL (less manufacturing)	54.66	980	24.03	431

Source: Estimates Using I-O Model.

TABLE 5.2.6

EMPLOYMENT AND OUTPUT IMPACT
RESULTING FROM BALANCE OF TRADE IMPROVEMENT
(In Million Dollars, 1942=100)

Industrial Sector	Biomass Project		OTEC Project	
	Output	Employment	Output	Employment
Agriculture	1.32	120	0.53	48
Mining and Construction	5.29	354	2.12	142
Manufacturing	19.25	529	7.70	212
Petroleum Products	2.32	15	0.93	6
Other Manufacturing	16.93	514	6.77	206
Transportation, Communication, and Public Utilities	9.02	417	3.61	167
Trade	6.96	717	2.78	287
Finance, Insurance and Real Estate	4.80	85	1.92	34
Other Services Plus Government	10.16	931	4.06	372
TOTAL (less manufacturing)	56.80	3.153	22.7	1.262

Source: Estimate using input-output model.

explained before, these were induced by reduction in petroleum imports.

A glance at Table 5.2.6 will show the following facts:

i. The reduction in petroleum imports resulting from the initiation of Biomass energy project will increase the final demand of the economy by the same amount of the reduction. The increase in final demand will increase output by $5.68 millions (output multiplier equals to 1.56 and employment by 3,153. In other words each million dollars of reduction in petroleum imports, if allocated to other components of final demand, will increase output by $1.56 million and employment by 87 jobs.

ii. The total output generated by the two projects will amount to $79.5 millions and employment to 4,415 workers if petroleum imports are reduced by $331.0 millions ($231.0 millions by Biomass and $100 millions by OTEC) at current prices, or $52.4 millions at 1972 prices.

5.2.4 Summary and Conclusions

This section has contained some estimates of impacts on employment and output resulting from the initial establishment of two energy projects, Biomass and OTEC. The following imports have been estimated:

1. Impact on the economy as a result of the initial investment in machinery, equipment and construction.

2. In the case of Biomass the impact of the increase in agricultural production.

3. The impact of a decrease in imports (if any).

In this last case three probable scenarios were considered:

a. A reduction of imports will reduce production of petroleum refineries, and hence reduce their sales to other sectors of the economy.

b. Imports will not decrease as a result of the reduction in local sales; exports will increase because of the strong world demand for petroleum products.

c. The reduction in the balance of trade deficit will increase domestic final demand.

The main findings derived from the analysis are the following:

1. When the Biomass project is introduced, agricultural output will increase. This increase will induce further increases of output and employment in the system amounting to $71.8 million (in 1972 prices) and 5,018 jobs created. In other words, for each million dollars of increase in the demand for agricultural production, output in the system will increase by $1.6 millions and employment by 110 workers.

2. The investment needed to establish the two projects will have a positive effect on the economy of Puerto Rico. Both projects, if established at the same time, will cause on increase in employment by about 58,000 workers, and the output of the system will increase by $1236.1. For each million dollars of investment, output will increase by $1.84 millions and employment by 86.

3. If the reduction in the petroleum imports reduces the output of the industry, its sales to other sector will also be reduced. In this case the reduction in imports will decrease production in the system by a multiplier of 2.869.

4. The probabilities are that there will be no reduction in petroleum output if local sales are reduced since the refineries can increase their exports. In this case, an increase of every million dollars of exports will increase output by $1.56 million and employment by 17.

5. The most likely probability is that the reduction in imports and its favorable effect on the balance of trade will increase the components of domestic final demand and this increase will have a positive effect on output and employment. If domestic final demand is increased by the amount of the reduction in petroleum imports, output will increase by $79.5 millions and employment by 4,415.

6. If we combine all the positive effects with the first scenario (a reduction in output because of the reduction in imports), the total effect of the economy will be that output will increase (on net basis) by $1,156.15 millions and employment by 58,243.

7. If we assume that there will be no reduction in petroleum output, since the decrease in local sales are offset by increases in its exports, then output will increase by $1,386.6 millions and employment by 64.141 workers.

8. Finally, if we assume that reduction in imports will improve the balance of trade and this latter effect

will increase domestic final demand, output will increase by $1387.0 millions and employment by 67,145 workers. If this is the case the unemployment rate, other things constants, could be reduced by about 7% from its 1979 levels.

The above findings show, without much doubt, that the introduction of the two energy projects, Biomass and OTEC will have enormous benefits in terms of output and employment generation given the availability of finance (whether by loans, local savings or direct capital imports).

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APPENDIXES

APPENDIX A

COAL

COAL

General

Coal is the most abundant fossil fuel found in nature. Within the United States, the most reliable source of supply for Puerto Rico, the coal resource (3.2×10^{12} tons) is estimated at an energy content of over 1000 years at the total energy consumption in the United States at the 1970 level. The total of United States coal is approximately 20% of the world total. There are large (unexploited) coal resources in Africa and South America.

The factors limiting the use of such abundant resource are (1) environmental constraints on mining and combustion, (2) coal industry development, and (3) transportation.

Coals are generally classified according to their carbon content and/or calorific values. Anthracites are the highest ranking coals with 86% fixed carbon and less than 8% volatile matter. Physically they are hard and brittle, and they burn with a smokeless blue flame. They are mainly used for domestic and industrial heating, for making briquettes, for bakery ovens, etc. Anthracites are generally unsuitable for pulverized coal furnaces on account of their hard nature. Bituminous coals are classified as low and medium volatile coals because they contain 14 to 31 percent volatile matter and 69-86% fixed carbon. High volatile bituminous, subbituminous and lignite coals, which by definition must contain less than 69% fixed carbon, are classified according to their calorific value as follows:

Bituminous	11,500-14,000 Btu/lb
Subbituminous	8,300-10,500 Btu/lb
Lignites	< 8,300 Btu/lb

In the range of 10,500-11,500 Btu/lb, a coal can be considered bituminous if it agglomerates upon heating; if it does not agglomerate upon heating, it is classified as subbituminous.

Figure A-1 indicates the geographical locations of the various coal reserves in the United States [15,16]. Low sulfur coal is normally coal with 0.5% or less sulfur content. Coal coasts are very sensitive to the sulfur content. The formation of gaseous SO_2 (and SO_3 to lesser extent) during coal burning presents serious health hazards. Present environmetal regulations practically mandate the use of wet scrubbers for most coal types..

Clean Air Act

The Clean Air Act, "Clean Air Act Amendments of 1977, Public Law 95-95", presents considerable restraints on the operation of fossil fuel plants. Coal fired units required to adopt the "best available control technology (BACT)" will at least require scrubbers, electrostatic precipitators, and controlled boiler combustion air/gas systems to control SO_2, particulates, and NO_x emissions.

Sulfur in Coal

Sulfur in coal occurs in three forms: organic, sulfate, and pyritic. Sulfate sulfur compounds are soluble in water and can be removed by washing the coal. Pyritic sulfur is the mineral pyrite. It can be separated by gravitational methods because of the high specific gravity differences (5.0 for pyrite and 1.3-1.7 for coal). Organic sulfur is an integral part of the coal matrix and can not be removed by direct physical processes. It comprises generally 30-70% of the total sulfur content in coal. The only known method to control the sulfur emissions in coal burning due to the organic sulfur presence is by washing the flue gases, a process called Flue Gas Desulfurization (FGD). The methods of removing sulfates and pyritic sulfur by washing and by other physical processes is called coal beneficiation. Coal beneficiation also reduces the ash content of coals.

Coal Cleaning

Coal beneficiation becomes important when transportation charges are significant. The beneficiation process can increase the BTU per lb . content, and hence can lower transportation costs.

Operation costs can also be reduced considerably through ash and sulfur reduction. It is reasonable to consider coal beneficiation for Puerto Rico. Details of coal beneficiation are discussed in "Coal Preparation for Combustion and Conversion" EPRI-AF-791, May 1978.

Table A-1, taken from the EPRI report, indicates the six levels of coal beneficiation:

Level A signifies no preparation at all. Coals are shipped as mined, Run of Mine (ROM) Coal.

Level B indicates breaking only for size control to facilitate transportation and handling.

Level C is coarse coal beneficiation in which the coarse particles are washed and mixed with untreated finer particles segregated through day screening.

Level D represents a deliberate full beneficiation similar to Level C but both the finer and coarser coal particles are washed.

Level E indicates an elaborate beneficiation process. All sizes are washed sometimes after repeated crushing to liberate additional amounts of ash and pyritic sulfur.

Level F represents full beneficiation. It uses level E beneficiation to produce clean coal of the highest quality and also middlings of average quality.

The EPRI doucment reports that costs for levels C-D-E range in the order of $.10 - .40 per MMBTU). Any final consideration for coal beneficiation levels will have to consider many factors entering into the economical and environmental analysis.

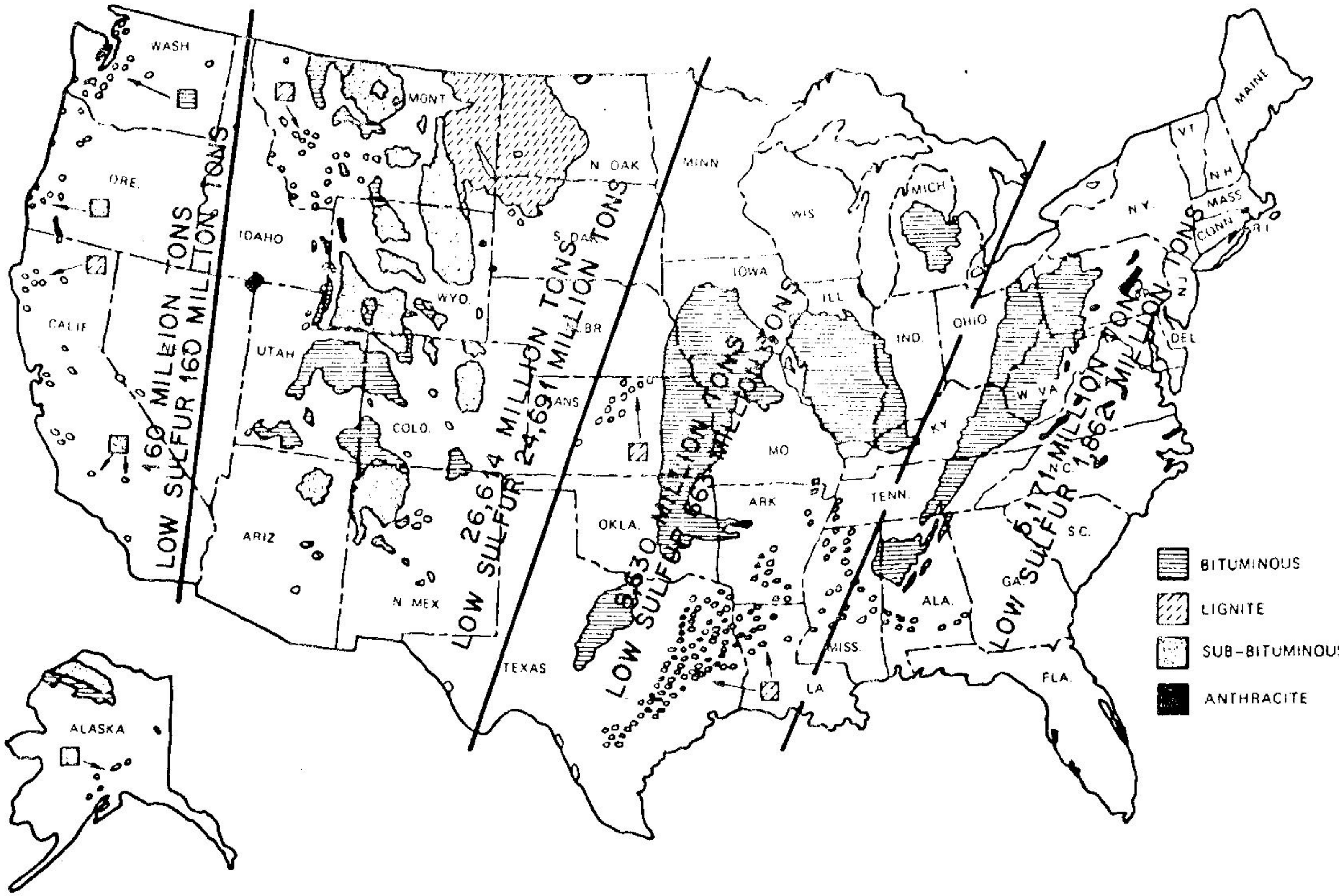


Fig. A-1 Strippable reserves of the conterminous U.S. by region.

Table A-1

LEVELS OF COAL PREPARATION

LEVEL & BRIEF DESIGNATION	SCOPE	YIELD WEIGHT %	RECOVERY BTU %	REDUCTION POTENTIAL		WORK DONE ON RAW COAL*	TYPICAL CIRCUITS & EQUIPMENT USED	REFUSE	COMMENTS
				ASH	SULFUR				
A ABSENCE	NO PREP.	100	100	NONE		NONE – SHIP ROM COAL	NONE	NONE	NOT GENERAL PRACTICE
B BREAKING	TOP SIZE CONTROL ONLY	98–100	100	NONE TO MINOR	NONE	CRUSHING TO 3" OR LESS AND REMOVAL OF COARSE REFUSE	SCALPING SCREEN; CRUSHER, ROTARY BREAKER	DRY LUMPS AND TRASH	GENERAL PRACTICE ON ALL ROM COALS
C COARSE	COARSE BENEFICIATION	75–85	90–95	FAIR TO GOOD	NONE TO MINOR	LEVEL B FOLLOWED BY: DRY SCREEN @ 3/8" & WET BENEFICIATE +3/8" ONLY, SHIP 3/8x0 AS IS.	SAME AS LEVEL B PLUS: VIBR. SCREENS; JIGS; HEAVY MEDIA VESSELS OR CYCLONES DEWATERING, THICKENERS, FILTERS.	+3/8" DRAINED –28M PONDED	USED WHERE –3/8" FRACTION FAIRLY CLEAN OR MUCH ROCK PRESENT IN +3/8" FRACTION.
D DELIBERATE	FINE BENEFICIATION	60–80	80–90	GOOD	FAIR	LEVEL B FOLLOWED BY: WET SCREEN @ 1/4" & WET BENEFICIATE +28M. DISCARD 28Mx0.	SAME AS LEVEL C PLUS CONCENTRATING TABLES OR HYDROCYCLONES. SOME THERMAL DRYING.	+1/4" DRAINED +28M DEWATERED –28M PONDED OR FILTERED	USED WITH COALS HAVING GOOD WASHABILITY CHARACTERISTICS.
E ELABORATE	VERY FINE BENEFICIATION	60–80	80–90	GOOD TO EXCELLENT	FAIR TO GOOD	LEVEL D PLUS WET BENEFICIATE 28Mx0	SAME AS LEVEL D PLUS FLOTATION CIRCUITS. THERMAL DRYING PREVALENT.	SAME AS LEVEL D EXCEPT MORE FINES.	USED WITH COALS HAVING EXCELLENT WASHABILITY CHARACTERISTICS.
F FULL	DEEP CLEANING	60–80	85–95	CLEAN COAL STREAM: EXCELLENT MIDDLING STREAM NONE TO FAIR		LEVEL E AFTER GREATER THAN NORMAL SIZE REDUCTION AND SEPARATION INTO TWO STREAMS: CLEAN COAL AND MIDDLINGS.	SAME AS LEVEL E PLUS ADDITIONAL SIZE REDUCTION.	SUBSTANTIALLY SAME AS LEVEL E	TWO OR MORE WASHED COAL PRODUCTS OF DIFFERENT QUALITIES ARE OBTAINED.

*COAL SIZES SHOWN ARE TYPICAL BUT WILL VARY SOMEWHAT WITH EACH COAL AND PROCESS SELECTED.

APPENDIX B

INTEREST DURING CONSTRUCTION AND INFLATION FORMULA

INTEREST DURING CONSTRUCTION AND INFLATION FORMULA

In treating the inflation and interest during construction costs the following procedures will be used. Figure B represents the flow of cash outlays for the project. Y_1 represents the number of years between the date of the present estimate (early 1978) and the beginning of construction. Y_2 is the actual construction time. Y is the sum of Y_1 and Y_2. The abscissa of the curve is expressed in per unit of construction time and the ordinate in per unit of cumulative investment during construction. The area under curve "a" is proportional to the time fraction during construction which represents the accruing of interest during construction. As an example suppose that at a particular infinitesimal time interval Δx between $x-\Delta x/2$ and $x + \Delta x/2$, an amount of money Δz has been spent. This amount of money (Δz) spent at time $x \pm \Delta x/2$ must carry at least single interest equal to (Δz) $(1-x)$ i, where i is the average yearly interest rate during construction. The value $(\Delta z)(1-x)$ represents the infinitesimal area shown in the figure. If all these infinitesimal interest portions are added, the net result is the area under the curve times i. This represents the single interest charge during construction.

Similarly $(1-(z-\Delta z/2))$ represents the amount of unspent money at time $(x-\Delta x/2)$ and $(1-(z+\Delta z/2))$ represents the amount of unspent money at time $x + \Delta x/2$. Only the amount of unspent money can suffer inflation.

The average unspent funds during the time interval Δx is $\left[(1-(z-\Delta z/2) + (1-(z+\Delta z/2))\right]/2$ or simply $(1-z)/2$.

The average value $(1-z)$ inflated for the small period Δx gives an infinitesimal inflation of $(1-z)\Delta x i_f$, where i_f is the average single inflationary yearly rate. When all these infinitesimals are added up, the sum represents the single inflationary value during construction. Since the curve of Figure B has been normalized, the area above the curve is $(1-a)$. Figure B indicates the total and combined compounded formula.

The charges for compounded interest rates and inflation during construction can be taken care of in a cost equation in the following form:

$$C = (K+Co) \quad (I_f^{\,Y_1+(1-a)Y_2}) \; (I_{dc}^{\,aY_2})$$

where:

C = total cost in \$/Kw

Co = basic cost in \$/Kw for the base year (1978)

Y_1 = years elapsed between base year (1978) and beginning of construction

Y_2 = construction time in years

I_f = $I + i_f$, where i_f is the average inflation rate

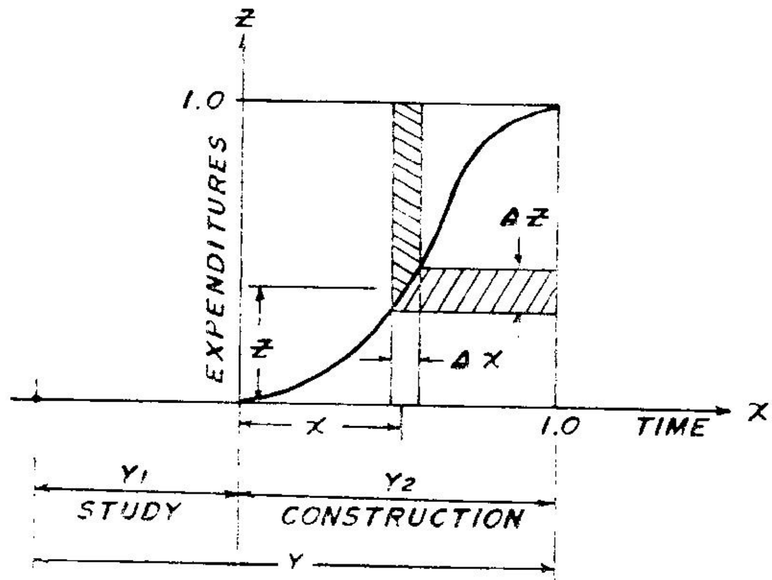
I_{dc} = $1 + i_{dc}$ where i_{dc} is the yearly average interest rate during construction

a = area under the normalized cummulative cash flow curve during construction

K = other costs excluded from Co

APPENDIX B

Interest During Construction and Inflation Formulas



Y_1 = years elapsed between cost estimate analysis and start of construction

Y_2 = construction time in years

a = area under normalized curve

i_{dc} = ave. interest during construction, % per year

i_f = inflation during construction, ave % per year

Simple interest carried on Δz dollars spent at time x:

$$= (\Delta z)(1-x)\, i\, Y_2$$

Total Simple Interest during construction $= i\, Y_2 \int_0^1 (1-x)\, dz$

and $\int_0^1 (1-x)\, dz = a$

Simple inflation on unspent dollars during Δx time at x,

$$= (1-z)\, \Delta x\, i\, Y_2$$

Total simple inflation during construction $= i\, Y_2 \int_0^1 (1-z)\, dx$

and $\int_0^1 (1-z)\, dx = 1-a$

COMBINED INTEREST DURING CONSTR. AND INFLATION

COMPOUNDED $= (1+i_f)^{(1-a)Y_2} \cdot (1+i_{dc})^{aY_2} \cdot (1+i_f)^{Y_1}$

APPENDIX C

COAL PLANT CAPITAL INVESTMENT ESTIMATES

COMMON DESIGN CRITERIA FOR COAL PLANT COST ESTIMATES WITH FGD

- EPA 1976 New Source Performance Standard (NSPS) for Coal Plants:

SO_2 emissions	$<$	1.2 lbs/million BTU
Particulate	$<$	0.10 lb/million BTU
NO_x	$<$	0.7 lb/million BTU

- Heat Rejection System-

  To atmosphere via wet cooling tower (cost adjustments to be made for special case of once through cooling if necessary)

- Special preference will be given to all references making cost estimates with new EPA NSPS standard considerations
- Flue gas desulfurization (FGD) costs estimate to be included for high sulfur coal (3% sulfur content)

United Engineers & Constructors*

1232 Mwe Net Single Coal Fired Unit with FGD

Coal Type	: Bituminnous High Sulfur Eastern	
	Moisture (%wt)	11.31%
	Ash	11.6%
	Sulfur (%wt)	3.2%
	BTU/lb (as received)	11,026
Boiler	Supercritical pressure, single reheat with pressurized furnace	
max rating		9.775 lbs/hr. x 10^6
normal superheater outlet		9.141 " "
normal reheater outlet		7.486 " "
Steam pressure, superheater outlet		3845 psig.
Steam pressure, reheater outlet		650 psig.
steam temp. superheater outlet		1010° F
steam temp. reheater outlet		1000° F
fuel firing rate		550 tons/hr.
Turbogenerator	Cross-Compound, 8 Flow	
Steam flow at H.P. turbine inlet		9.141 lb/m x 10^6
Steam press. at turbine inlet		3512 psia
steam temp. at H.P. turbine inlet		1000°F
turbine back pressure(multipress cond.)		1.7/2.5 HgA
turbine output		1309 Mwe
auxiliary power		77 Mwe

* Personal communication (from ongoing revised costs studies)

Net station output 1232 Mwe

Net Station heat rate 9138 Btu/kw hr.

Mid 1976 Cost Estimate (UE&C 1232 Mwe net) cont.

Acc. No.		$\$ 10^3$
20	Land and land rights	2,000
21	Structure and Improvements	47,187
22	Boiler plant equipment	167,508
23	Turbine Plant Equipment	110,228
24	Electric Plant Equipment	33,523
25	Misc. Plant Equipment	9,857
26	Main Cond. Heat Rej. Syst.	15,850
2.	Total Direct Costs	386,153
91	Construction Services	48,445
92	Home Office Engr. and Services	17,000
93	Field Office Engr. and Services	13,900
9.	Total Indirect Costs	79,345
	Total Base	465,498

Other Costs:

1. Main Power Transt.	1,700
2. Owners cost including consultants and site selection (ave)	34,500
3. Waste disposal equipment and facilities	28,000
4. Spare Parts	2,700

5. Fees and Permits	200
Subtotal	67,100
Grand Subtotal	532,598
10% Contingency	53,260
Total	585,858
Unit Cost Estimate 585,858/1232 =	\$475.53/kw
Early 1978 Unit Cost $(1.08)^{1.5}$ (475.53) =	\$534/kw

United Engineers & Constructors*

794 MWE Net Single Coal Fired Unit with FGD

Coal Type :	Bituminous High Sulfur Eastern	
	Moisture (%wt)	11.31%
	Ash	11.6 %
	Sulfur (% wet)	3.2%
	Btu/lb, as received	11,026
Boiler :	Supercritical pressure, single reheat with balanced draft furnace	
Max. rating		6.53×10^6 lb/hr
Normal superheater outlet		5.81 "
Normal Reheater outlet		5.188 "
Steam Pressure, superheater outlet		3845 psig
Steam Pressure reheater outlet		730
Steam temp.		
superheater outlet		1010°F
reheater outlet		1000°F
Fuel Firing Rate		365 tons/hr.
Turbogenerator		Tandem-Compound-4 flow
Steamflow at HP turbine		5.81×10^6 lb/hr
Steam press. at Turbine Inlet		3512 psia
Steam temp. at HP. turbine inlet		1000°F
Turbine back pressure (multipress cond.)		1.7/2.5 in HgA.

*Personal communication (from ongoing revised cost estimates)

Turbine output	854 Mwe
auxiliary power	60 Mwe
net sta.output	794 Mwe
net sta. heat rate	9482 btu/kw hr.

Mid 1976 Cost Estimate (UE&C 794 Mwe net)

Account No.		$\$10^3$
20	Land and land rights	2,000
21	Structures & Improvements	38,015
22	Boiler plant equipment	120,146
23	Turbine plant equipment	65,182
24	Electric plant equipment	28,931
25	Misc. plant equipment	8,736
26	Main Cond. Heat Rej. Sys.	12,042
2.	Total Direct Costs	275,052
91	Construction Services	35,218
92	Home Engineering and Services	14,350
93	Field Office Engineer.& Services	10,628
9.	Total Indirect Costs	60,195
	Total Base Cost	334,888

Other Costs:

1. Main Power Transf.	1,200
2. Owners Costs Including Consultants,Site Selection,etc.(ave.)	25,575
3. Waste Disposal equipment & facilities	20,500

4.	Spare Parts	1,800
5.	Fees and Permits	200
	Subtotal	49,275
	Grand Sub Total	384,163
	10% Contingency	38,416
	TOTAL	422,579

Unit Cost Estimate 422,579/794 = \$532/kw

Early 1978 Unit Cost Estimate $(1.08)^{1.5}$ x 532 = \$597/kw

United Engineers & Constructors
Costs of FGD Systems

The following costs have been determined from UE&C recent estimates:

1. Added Cost to Boiler Plant Equipment Account #22 - approximately 38-39% of account cost without FGD.
2. Added Cost to Electric Plant Equipment Account # 24 - approximately 16-20% of account cost without FGD.
3. Indirect Costs - approximately 21% of above added costs.
4. Waste Disposal Equipment and Facilities - Increase by a factor of 2 over plant without FGD.

The total FGD system added costs included in the estimates given here are:

1232 Mw (gross) units (mid 1976 costs)

\$61/gross kw

or \$64.8/net kw

854 MWe (gross) units (mid 1976 costs)

\$71.1/gross Kw

\$76.5/net kw

PREPA Engineers and Consultants data*

450 MW Gross Coal Plant

Coal Type:	Bituminous High Sulfur Eastern	
	Moisture (% wt)	11.31%
	Ash	11.6%
	Sulfur (% wt. wet)	3 %
	BTU/lb (as received)	11,000 Btu/lb.
Boiler :	2800 psig pressure, single reheat with balanced draft furnace	
max ratings		
normal superheater outlet		
normal reheater outlet		
Steam pressure, superheater outlet		
	reheater outlet	
Steam Temp.		
	superheater outlet	1010°F
	reheater outlet	1000°F
Fuel Firing Rate		200 tons/HR.
Turbogenerator (TC4F-26")		Tandem-Compound 4 Flow Hitachi Turbine-Gen.
Steam Flow at H. P. Turbine		
Steam Press at Turbine Inlet		2400 psig
Steam Temp. at H. P. inlet		1000°F
Turbine Back Press		2.5" Hg A.

* Data Supplied by J. A. Marina, PREPA

Auxiliary Power	36 Mwe
Net Sta. Power	414 Mwe
Net Sta. Heat Rate	9800 Btu/Kw HR.

Early 1978 PREPA 450MW Coal Plant Adjusted Cost Estimate

1st. Estimate

Acc.No.	FPC Acc. #		Cost $\$10^3$
20	----	Land and land rights	----
21	(311)	Structures & Improvements	16,520
22	(312)	Boiler Plant Equipment (1)	114,220
23	(314)	Turbine Plant Equipment (incl. Heat Rej. System (2)	6,700
24	(315)	Accesory Elect. Equipment	6,030
25	(316)	Misc. Power Plant Equip.	710
26		Main Cond. Heat Rej. Sys. (incl. in 314)	----
2.		Total Direct Costs, unadjusted	144,180
	Adjustments		
	(1) Hitachi T-G		25,000
	(2) FGD System for 3% Sulfurcoal additional cost		12,000
	Total Direct Cost, Adjusted		181,180
91	Construction Services (13%)		23,500
92	Home Engineering Services (6%)		10,900
93	Field Office Engineering Services (4%)		7,250
9	Total Base Cost		222,830

Other Costs:

1) Main Power Transf. (FPC #353)	720
2) Owners Cost including Consultants, Site Selection, etc. (8%)	17,800
3) Waste Disposal equipment and facilities (6%)	13,400
4) Spare Parts (1/2%)	2,228
5) Fees and Permits	200
Subtotal	256,528
10% Contingency	25,652
Total Cost	282,180

Unit Cost 282,180/414 = $682/kw.

2nd. Estimate

PREPA Consultants Estimate for 450 Mw Coal Plant*

FPC Acc.		
311	Structures and Improvements	16,520
312	Boiler Plant Equipment	114,220
314	T-G (and cooling system)	6,700
315	Accessory Electrical Equipment	6,030
316	Misc. Power Plant Equipment	710
353	Main Power Transf.	720
	Total Direct Cost	144,900
Indirect Construction Expense		35,000
Ocean Freight, Litherage and Trucking		6,000
Engineering Design and Construction Management		17,000
Subtotal, Direct and Indirect Cost		202,900
Contingency		41,100
Total (PRWRA Consultants)		244,000

Adjustments

1-	Turbine Generator in Storage by owner not included in above estimate . Total Costs	25,000
2-	Additional FGD system for changing from Western to Eastern (High Sulfur) Coal (PRWRA consultant estimate)	12,000
	Total	$281,000

* José A. Marina, Personal Communication

EPRI Cost Estimate

1000 MWE Net Coal Plant*

Coal Type	Bituminous High Sulfur Southeastern (Central Appalachia)	
	Moisture (% wt)	8.2
	Ash (% wt)	8.2
	Sulfur (% wt)	3.4
	Btu/lb.	12,130
Boiler	2800 psig single reheat with balanced draft	
Max rating		
Normal superheater outlet flow		
Steam temperature, superheater outlet		1000°F
reheater outlet		1000°F
Fuel Firing Rate		
Turbogenerator	Tandem Compound 6 flow	
Steam flow		
Steam Pressure at Turbine Inlet		2400 psig
Steam Temperature at H.P. Turbine		1000°F
Turbine Back Press		
Turbine Output		
Auxiliary Power		
Net Sta Output		1000 MWE
Net Sta. Heat Rate		9850 Btu/kwh

* EPRI PS-866-SR Special Report - June 1978

EPRI Cost Estimate 1000 MWE Coal Plant (Continuation)

(Bechtel Enginners Consultants)

No Breakdown given

Lowest Cost Reported (Table XII-A) is for Southeast region with $550/kw for 2 unit installation.

For one unit installation it is indicated in EPRI reference to divide by .96 the two unit cost estimate.

Plant cost estimate includes common Design Criteria (1976 NSPS - EPA)

End of 1977 (or early 1978) cost estimate $550 \div .96$ or $573/kw

Costs of FGD Systems

Included in above cost is the FGD System estimated at $105.00/kw

Values for the FGD system ranges from $85 - 155/kw.

Gibbs and Hill

(Paul de Rienzo)

1150 MWE Net Coal Plant Estimate*

Coal Type:	Bituminous High Sulfur Eastern	
	Moisture (wt %)	5
	Ash (%)	10
	Sulfur	2.5
	Btu/lb (as received)	12,500
Boiler:		
Max Rating		
Superheater Outlet		
Reheater Outlet		
Steam Pressure : Superheater Out		
reheater out		
Steam Temp., superheater out		
reheater out		
Fuel Firing Rate		
Turbogenerator:		
Steam flow H.P. Turbine		
Steam Press. Turbine Outlet		
Steam Temp H.P. turbine		
Turbine Back Press.		
Turbine Output		
Auxiliary Power		
Net Sta. Output		1150 MWE
Net Sta Heat Rate		9600 Btu/kwh

* The Outlook for Coal and Nuclear Power - De Rienzo
Presented to the National Association of Petroleum Investment Analysts at the 1978 NAPIA meeting March 3, 1978, Wash., D. C.

Gibbs & Hill
(Paul de Rienzo)

2-1150 Mwe Coal Plant Cost Estimate
1978 Plant Costs

Cost for:	
Site Preparation	
Materials	
Equipment	
Structures	
Installation	
Total Base Cost \$/KW	328.0
Cost for:	
Installed Flue Gas Desulfurization	
Sludge Disposal Systems	
Total Costs \$/KW	80.0
Costs for:	
Indirect Expenses	
Engineering	
Construction Management	
Contingencies	
Total Costs \$/KW	87.0
Grand total Cost	495.00
6% added for one unit installation	
(495) ÷ (.94)	\$526[00]/KW

Dravo Cogeneration Company
and Gibbs and Hill*

Cost Estimate for a 20 MWe Coal Power Plant

1978 Capital Costs

Coal type	:	Unspecified
Boiler	:	Unspecified
Turbogenerator	:	Unspecified
Plant Net Output	:	20 MWe
Capital Cost (1978)	:	$800/kw

Assumes plant meets common design criteria for coal plants (EPA, NSPS criteria and wet cooling towers).

* Major Considerations in the Design and Engineering of Cogeneration Facilities R.E.Kropp, E. J. Hansen, and R. Destefanis, Dravo Cogeneration Company and Gibbs & Hill, Inc., March 1979 ASME Conference.

APPENDIX D

NUCLEAR PLANT CAPITAL INVESTMENT ESTIMATES

NEW 585 MW Net Nuclear Estimate #1

Total Direct Cost Data Source: PREPA Consultants
Engineering Services, Construction Management and
Other Indirect Data Source: UE&C
(1978 dollars)

Acc			$ 10^3
20	(320)	Land and land rights	3,000
21	(321)	Structure and Improvements	73,900
22	(322)	Reactor Plant Equipment	124,450
23	(323)	Turbine Plant Equipment	52,100
24	(324)	Electric Plant Equipment	18,400
25	(325)	Miscellaneous Plant Equipment	2,000
26		Main Cond. Heat Rej. System (include in 323)	-----
2		TOTAL DIRECT COST	273,850
91		Construction Services (16.7%)	45,733
92		Home Engineering Services (11.7%)	32,041
93		Field Office Engineering Services (6.8%)	18,621
9		TOTAL BASE COST	370 ,245

Other Costs:

(1)	Main Power Transformer	1,500
(2)	Owners Cost including consultants site selection, etc. (8.6%)	31,841
(3)	Additional waste disposal facilities (1.4%)	5,183
(4)	Spare Parts (.6%)	2,221
(5)	Fees and Permits	1,400
	SUBTOTAL	42,145
	GRAN SUBTOTAL	412,390
	10% Contingency	41,239
	TOTAL	$ 453,629

1978 Unit Cost: $775/KW

New 585 MW Net Nuclear Plant Estimate #2

Data Source: All by PREPA Consultants

1978 dollars

Acc	(FPCA)		$\$10^3$
20	(320)		3,000
21	(321)		73,900
22	(322)		124,450
23	(323)		52,100
24	(324)		18,400
25	(325)		2,000
-		Transmission Plant	1,520
2		Total Direct Cost	275,370
91		Construction Services	90,000
		Engineering, Design, and Constr. Management	60,000
		Ocean & Inland Freight	10,000
		SUBTOTAL	435,370
		Contingency	87,630
		TOTAL	$523,000

Unit Cost: $894/kw

CAPITAL INVESTMENT
NORCO NO.1
PREPA ESTIMATE

1978 dollars

Acc No.	FPC ACCH		$\$10^3$
20	(320)	Land and land rights	2,668
21	(321)	Structures and Improvements	76,689
22	(322)	Reactor Plant Equipment	
23	(323)	Turbine Plant Equipment	136,431
24	(324)	Accesory Electrical Equip.	21,157
25		Misc. Power Plant Equip. (include in 322-23)	---
26		Main Cond. & Heat Rej. System (include in 323)	---
(2)		Total, Direct Costs	$236,945
		Construction Expenses	75,469
		Engineering, Design and Construction Management	47,529
		Code up grading	4,000
		Sub Total Direct and Indirect Cost	$363,943
		PREPA Cost to Date (12/77)	19,777
		PREPA Cost Future	24,520
		PREPA Operator Training and Consultants	5,476
		Offshore Drilling	1,080
		Wells	864
		Offsite telephone and power	81
		Sub Total	$415,741
		Contingency Allowance	62,361
		1978 dollars Total Cost	$478,102

Unit Cost: $817/kw

UE&C
1-1139 MWe PWR*
(mid 1976 dollars)

Acc #		$\$10^3$
20	Land and Land rights	2,000
21	Structure and Improvements	101,376
22	Reactor Plant Equipment	133,481
23	Turbine Plant Equipment	111,281
24	Electric Plant Equipment	39,428
25	Misc. Plant Equipment	11,803
26	Main Cond. Heat Rej. System	21,588
2	Total Direct Cost	420,957
91	Construction Services	70,033
92	Home Office Engrg. Service	49,220
93	Field Office Engrg. Service	28,621
9	Total Indirect Cost	147,874
	Total Base Cost	568,831
	Other Costs:	
	(1) Main Power Transformer	2,000
	(2) Owners Cost including Consultants, Site Selection, etc.	48,850
	(3) Additional Spent Fuel Storage	8,000
	(4) Spare Parts	3,200
	(5) Fees, Permits	1,400
	Sub-total	63,450
	Grand Sub-total	632,281
	10% Contingency	63,228
	Total (mid 1976 dollars)	$695 ,509
	Escalation to early 1978 at 8%/year	85,109
	Total (1978 dollars)	$780,618

Unit Cost: $\$685^{00}$/KW

*Capital Cost: Pressurized Water Reactor Plant, NUREG 0241

UE&C
1-1190 BWR*

Acc.		10^3
20	Land and land rights	2,000
21	Structures and Improvements	113,324
22	Reactor Plant Equipment	125,734
23	Turbine Plant Equipment	116,673
24	Electric Plant Equipment	40,746
25	Misc. Plant Equipment	11,075
26	Main Cond. Heat Rej. System	21,989
2	Total Direct Costs	431,541
91	Construction Services	72,034
92	Home Office Engr. Services	49,634
93	Field Office Engr. Services	29,539
	Total Direct Costs	151,207
	Total Base Cost	582,748
	Other Costs:	
	(1) Main Power Transformer	2,000
	(2) Owners Cost including Consultants, Site selection, etc.	48,850
	(3) Additional Spent Fuel Storage	8,000
	(4) Spare Parts	3,200
	(6) Fees Permits	1,500
	Subtotal	63,550
	Grand Subtotal	646,298
	10% Contingency	64,630
	Total (mid 1976 dollars)	710,928
Escalation	to early 1978 at 3%/year	86,995
	Total (1978 dollars)	$797,923

Unit Cost: $670/KW

* Capital Cost: Boiling Water Reactor Plant, NUREG-0242

APPENDIX E

CAPITAL COST ESTIMATES

RESIDUAL OIL FIRED POWER PLANTS

PREPA CONSULTANTS*

ESTIMATE
FOR
450 MW OIL PLANT (436 Mwe net)

FPC Acc		$\$10^3$
311	Structures and Improvements	14,300
312	Boiler Plant Equipment	63,400
314	Turbine Generator Plant Equip. (excluding turbogenerator)	6,700
315	Accesory Electrical Equipment	5,770
316	Misc. Power Plant Equipment	710
353	Main Power Transformer	720
	Total Direct Cost	91,600
	Indirect Construction Expense	30,000
	Ocean Freight, Litherage, Trucking	5,000
	Engineering, Design and Construction Mgt.	11,000
	Subtotal Direct and Indirect	137,600
	Contingency Allowance	27,400
	Subtotal	165,000
	Escalation Allowance	69,820
	Interest during construction	42,562
		277,382
	Adder for Turbo-Generator Adjustment	25,000
	Total Cost, 1985	$302,382

1985, Capital Cost $693.54/KW

Plant Net Heat Rate (75% Load Factor) 9200 Btu KWHR

* Personal Communication Mr. José A. Marina, PREPA (1979)

EPRI*

1000 MW OIL POWER PLANT

Unit Capital Cost (1978)	4 40.0 $/KW
Most likely range (1978)	405-480 $/KW
Ave. Annual Heat Rate	9500 Btu/kwh.

Cost based on burning residual oil with sulfur content of 0.4% or less to meet the 1976 NSPS Standards.

Cost escalation at 8% per year

1985 cost	754 $/KW
1985 most likely range	694-822 $/KW

* EPRI, PS-866-SR, Special Report, June 1978

APPENDIX F

LEVELIZING FACTOR FORMULA

LEVELIZING FACTOR FORMULA

In power plant economics, it is necessary to have the investment, fuel and operation and maintenance costs on the same basis so that they can be added.

The capital investment charges are multiplied by the fixed charge rate to place them on a fixed annual basis. In order to do the same with fuel and operation and maintenance, they have to be levelized over the life of the plant since they are subject to escalation from year to year.

The derivation of the levelizing factor is presented as follows:

Let Fe_1 = levelized unit fuel cost during plant lifetime of n years

n = plant life in years

PWi = present worth factor of the yearly uniform series values of F_1 at an interest equal to the discount rate i or cost of money

i = discount rate or cost of money

Fo = first year or initial unit fuel cost

u = actual ave. year to year inflation rate of the product, material or service. It is the result of the multiplication of (1 + infl)(1 + escalation) where escalation follows strictly the trend of product availability and the supply-demand market.

r = effective discount rate corrected for total inflation such that $1 + r = (1 + i)/(1 + u)$.

PWr = present worth factor of yearly uniform series values of Fo at interest rate r. (i.e. Fo corrected for inflation).

With the above definitions, then

$$F_e\ (PWi) = Fo\ (PWr)$$

$$\text{or } F_e = \frac{PWr}{PWi} Fo \quad (1)$$

F_o can be expressed as

$$F_o = (1+e_f)^Y\ (1000P_c).\ (HR).10^{-6} \quad (2)$$

Where, F_o = fuel cost in mills per kw-h

P_c = coal price in dollars per MMBTU for base year including all costs such as carrying charges on coal storage.

e_f = fuel escalation factor

Y = number of years between year of fuel cost basis and beginning of commercial operation

HR = plant heat rate in BTU/KWHR.

The levelized fuel cost in mills per kw-hr can be expressed by combining equations 1 and 2 and writing for the full expressions of present worth formulas, as follows:

$$F_1 = (1+e_f)^Y \frac{(P_c)(HR)}{1000} \cdot \frac{(1+r)^n-1}{r\ (1+r)^n} \cdot \frac{i\ (1+i)^n}{(1+i)^n - 1}$$

The levelizing factor L is,

$$L = \frac{(1+r)^n-1}{r(1+r)^n} \cdot \frac{i(1+i)^n}{(1+i)^n-1}$$

APPENDIX G

OTEC PLANTS CAPITAL INVESTMENT ESTIMATES

JOINT EFFORT BETWEEN ELECTROTECHNICAL LABORATORY, MITI, AND RESEARCH AND DEVELOPMENT CENTER, TOSHIBA CORP. FOR MAJOR SPECIFICATIONS AND COSTS OF 100 MW OTEC POWER PLANT*

Item	1975 Design	1976 Design	1978 Design	
			Osumi Project	Toyama Project
Gross power output(kw)	100,000	100,000	100,000	100,000
Net power output(kw)	73,940	77,210	78,770	83,100
Working Fluid	Amonia	Amonia	Amonia	Amonia
W.F. Flow rate(kg/h)	$1.18x10^7$	$1.114x10^7$	$0.99x10^7$	$0.908x10^7$
Warm water temp.(°C)	28	28	28	26
Intake warm water(kg/h)	$9.88x10^8$	$9.74x10^8$	$7.817x10^8$	$6.93x10^8$
Cold water temp.(°C)	7	7	4.56	0.747
Intake cold water(kg/h)	$1.01x10^9$	$8.09x10^8$	$6.156x10^8$	$5.69x10^8$
Evap. heat transfer area (m^2)	$3.2x10^5$	$3.106x10^5$	$2.62x10^5$	$2.14x10^5$
& units	16	8	8	8
Cond.heat transfer area (m^2)	$3.3x10^5$	$3.508x10^5$	$2.94x10^5$	$2.37x10^5$
& units	16	8	8	8
T/G output(kw) & units	25,000;4	25,000;4	25,000;4	25,000;4
Type of platform Barge	Rectangular Barge	Submerged Cylinder	Submerged Cylinder	Surface Ship
Unit construction cost ($/KW)	4286	3542	4291	3257

* An Overview of the Japanese OTEC Development, T. Homa & K. Kamogawa, 6th. OTEC Conference, Shoreham-Americana Hotel, Washington, D. C., June 19-22, 1979.

Deep Oil Technology, Inc. (Fluor Corp.)*

Feasibility Design Studies, Land Based OTEC Plants
(Punta Tuna, Puerto Rico)

Cost Summary, Millions of Dollars (1980)

Item		10 MWe	40 MWe
1.1	Management-Design Phase	0.9	0.9
1.2	Management acquisition/const. & Deployment stage	1.9	1.9
1.3	Management System Operations & Support Phase	1.7	1.7
	General Management Total	4.5	4.5
2.1	Conceptual Design		
2.2	Preliminary Design	1.5	1.5
2.3	Contract Design	2.1	2.1
	Design Total	3.6	3.6
3.1	Platform system	N/A	N/A
3.2	Land Based Containment Syst.	7.4	12.8
3.3	Cold Water Pipe System	38.6	59.7
3.4	Warm Water Pipe System	10.7	16.8
3.5	Power System	13.6	49.6
3.6	Energy Transfer System	0.5	1.5
3.7	Energy Utilization Syst.	N/A	N/A
3.8	Acceptance Testing	2.4	3.4
3.9	Deployment Services	18.7	31.2
3.10	Industrial Facilities	2.1	2.1
3.11	Engineeri		
3.11	Engineering & Detail Design	6.3	6.7
	Const. & Deployment Total	100.3	183.8
	Operation & Support Total	10.7	15.7
	Contingency 10%	11.9	20.8
	OTEC System Total(10^6\$)	131.0	228.4
	Installed Cost	\$11,740/KW	\$5,230/KW

* Unpublished information. February 1979

Additional Reported Cost Estimates of OTEC Plants. Different Sources.

A. EUROCEAN. Association Europeene
Océanique. Bengt A.P.L. Lachmann
10 MWe Plant. Estimated Cost $5000/KW* (1979)

B. Metrek Division - The MITRE Corporation
W. E. Jacobsen & R.N. Manley
400 MWe Plant (Offshore Florida Peninsula)
Estimated Cost $2570/KW (1976 dollars)*

C. Electrotechnical Laboratory - MITI, Research &
Development Center, Toshiba Corp.
T. Homma & H. Kamogawa
1 MWe Plant - Estimated Cost $16700/KW*

D. TWR and Lockheed, National Academy of Sciences
Domestic Potential of Solar and Other Renewable
Energy Sources, Wash. D. C., 1979, Estimated
Costs $2100-$2600 per kw net output. (1975)

* 6th. OTEC Conference. Shoreham-Americana Hotel, Washinton, D.C., June 19-22, 1979.

LIST OF APPENDIXES

APPENDIX H

FEASIBILITY STUDY FOR THE USE OF LARGE WINDWPOWER GENERATORS IN PUERTO RICO

Prepared by:

Dr. Raúl Erlando López

I. Introduction

In the face of continuing rising fuel costs, attention has been focused once more on the windpower systems of yesteryear. Large 1.5 megawatt turbines are being developed for use in electric power grids. By integrating these systems within a fossil-fuel power-plant network, an inexpensive method is achieved for storing and regulating the intermittent and variable output (due to the variation of the wind) that the wind turbines produce. To store the energy from the wind turbines, generation at the powerplants would be reduced an amount equal to the wind power generation. Thus, the fuel that would have been used by the thermoelectric powerplants can be stored for later use. The loads that would have been served by the fossil fuel plants will be served by the energy provided by the wind turbines. This scheme is similar to that being planned for Sweden (1-4) and for the Colorado River Storage Project in the Western United States (5).

PREPA could install wind turbines at sites with high windpower potential and link them to the network. In this way, the energy storage capability of the thermoelectric facilities can be used even if the wind turbines are not colocated with them.

Large wind turbines are being designed, built and tested by the General Electric Company under contract with DOE and Nasa. These 1.5 megawatt, 61.9m-diameter units will be available commercially in the very near future. The initial cost of the wind turbines is anticipated to be very high until full mass production is achieved. However, as more units are acquired by different utilities and production costs decrease while fossil fuel prices increase, a competitive breakeven point will be reached.

A study has been made of the feasibility of integrating large windpower generators to the existing PREPA thermoelectric network in Puerto Rico. the findings of that study are presented in this appendix. Preliminary assessments of windpower, windturbine performance and costs have been made.

II. Windpower assessment

1. Wind Climatology

The island of Puerto Rico lies in the zone of the Trade Winds. This is one of the most persistent wind regimes of the world (6). However, as these northeasterly winds flow over Puerto Rico, they are modified by the topography of the island and by the sealand breeze. This breeze is established by the temperature gradient between land and ocean. These two effects can act to increase or decrease the speed of the Trades in regular diurnal and regional patterns.

During the day, the land heats up while the ocean remains basically at the same temperature. The resulting temperature gradient between land and ocean is further emphasized by the fact that a good portion of the heating occurs at heights of up to 3.000 feet due to the interior (mostly east-west) mountain ranges. As the temperature gradient develops, an inland acceleration of the wind occurs.

On the north coast of the island, this acceleration is directed from north to south adding to the strength of the prevailing northeasterly Trades. Figure 1 schematically portrays this effect. The thermal acceleration in the south coast is directed from south to north, reducing the strength of the Trades and converting them to south easterlies.

The east coast of the island suffers an easterly thermal acceleration which can increase the strength of the Trades considerably. The west coast, however, experiences a westerly thermal acceleration which opposes the north easterly Trades and sometimes

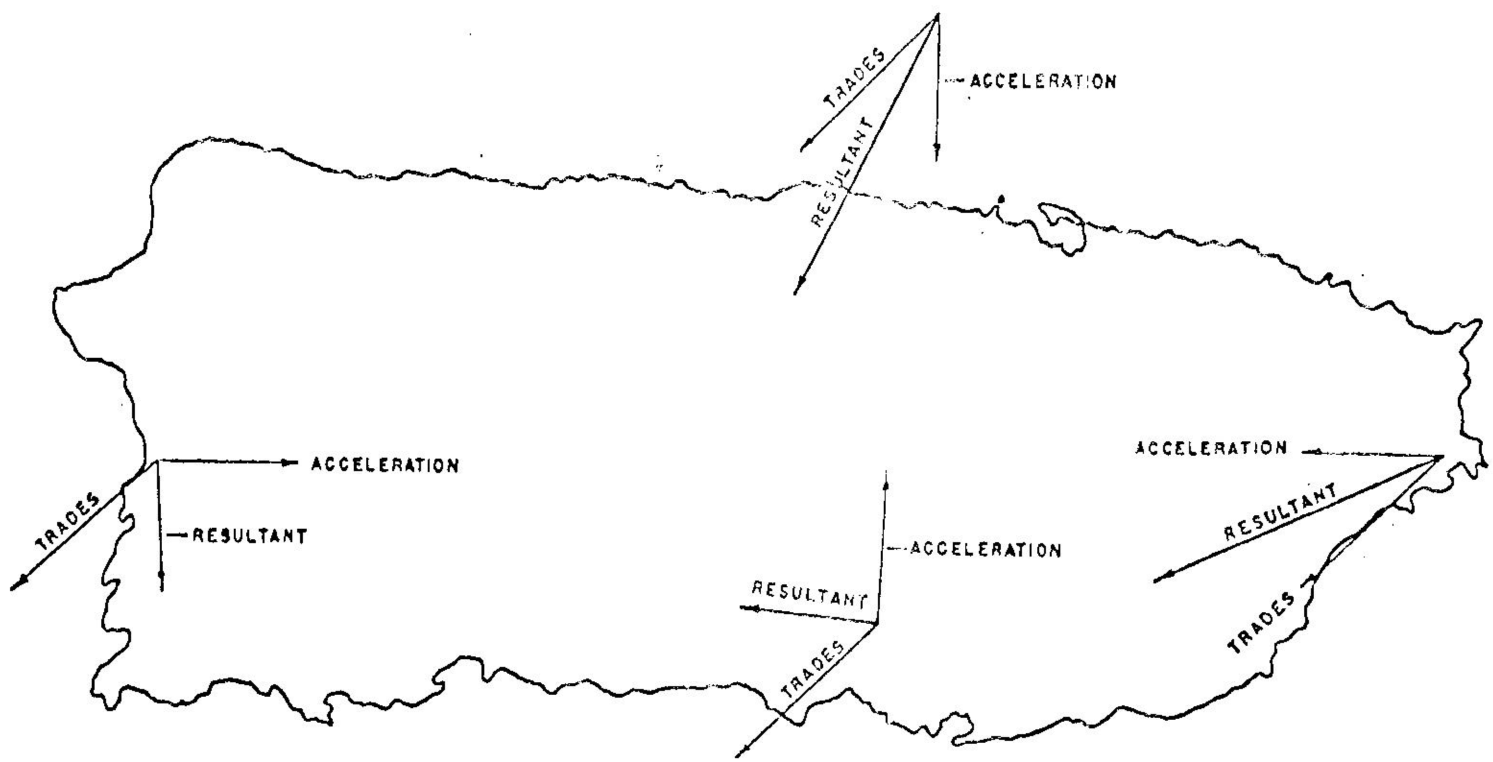


Figure 1. Schematic representation of the effects of the sea breeze on the trade winds during daytime.

reverses them into weaterlies. The resulting winds can be very slow.

During the night, the land cools off and the thermal acceleration is directed toward the ocean. This acceleration is much weaker than the daytime one. The effect of this noctural acceleration is shown in Figure 2. As the Trades flow inland at the north and east coast, they are opposed by this acceleration. Although the wind over the land is not as strong as it is over the ocean, a good breeze is caused by generally weak thermal gradient. During the night the thermal stability of the low layers of the atmosphere increases. This curtails the vertical exchange of momentum between the surface of the island and the Trades flowing over the south and west coast from the north-east. The wind usually dies down and is sustained only by the weak seaward acceleration that is established during the night and early morning.

Thus, climatologically one could expect the highest potential for wind power utilization on the north and east coasts because the wind is higher in these regions during the day and night. Figures 1 and 2 are schematics of the effects of the sea-land breeze on the wind power potential in Puerto Rico. Specific details of these effects depend on the particular topographic configuration of the region, the season and the time of the day. These maps, however, provide a guide for the analysis of the limited wind data available and the extrapolation of the analyses to data-void regions.

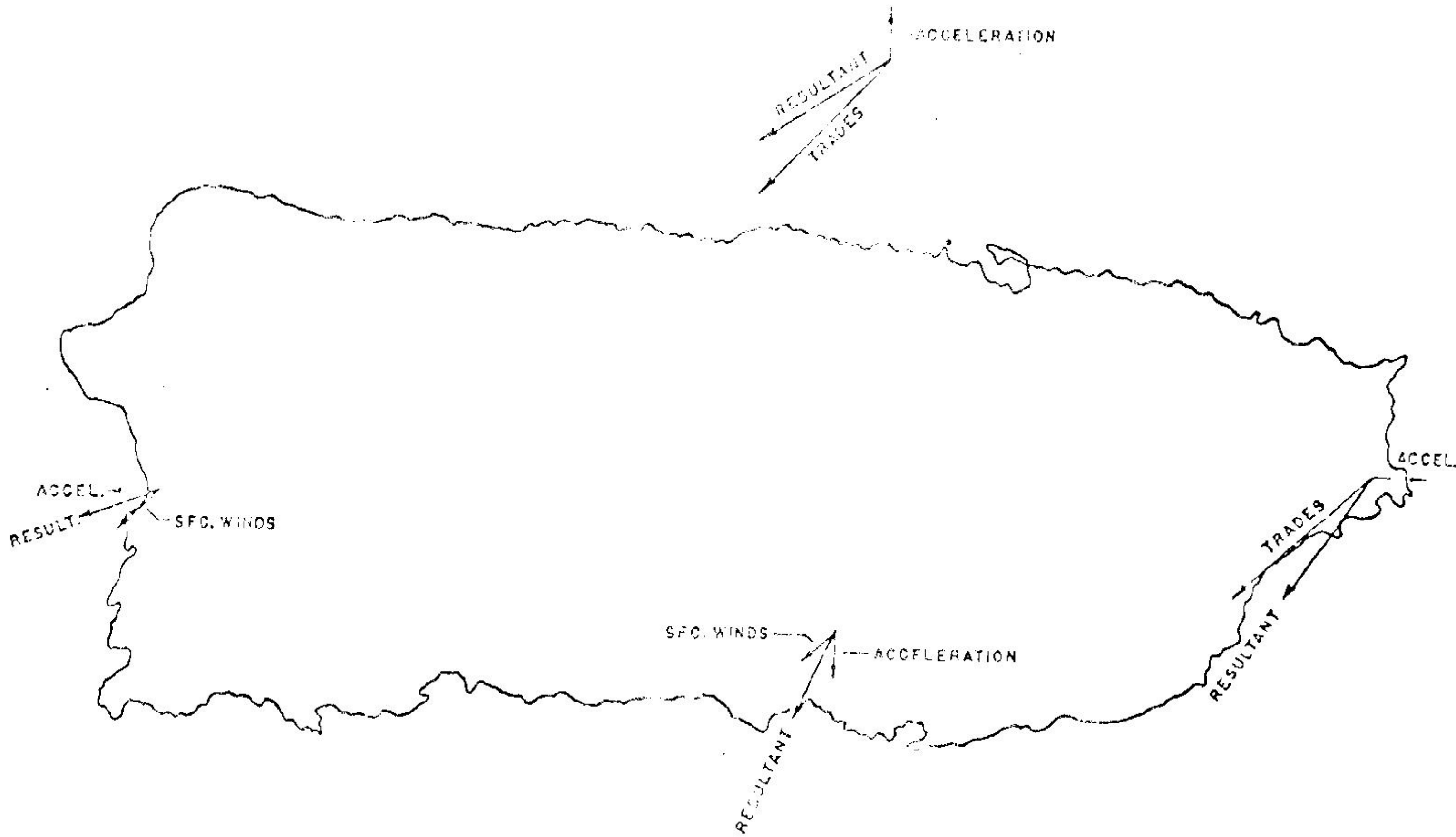


Figure 2. Schematic representation of the effects of the land breeze on the trade wind during nighttime.

2. Diurnal oscillation of the wind speed and the corresponding power at selected stations

Figure 3 portrays the variation of the speed of the wind with the time of the day at representative stations in the north, south and westcoasts of Puerto Rico. The locations of these and other stations are indicated in Figure 4. These values correspond to the standard anemometer height of 10 meters. As expected, San Juan on the north coast experiences the strongest winds. A maximum of 17 mph is observed at 3 P. M. when the Trades are reinforced the greatest by the thermal acceleration produced by the daytime temperature gradient between land and water. The weakest winds (9 mph) occur just before sunrise when the reversed land-water temperature gradient becomes largest. The winds at Guayanilla on the south coast are highest (12 mph) at 1 P. M. but are much lower than at San Juan. Nighttime wind speeds are very low (around 4 mph). Mayaguez on the west coast shows the weakest winds of all three stations with a maximum of only 10 mph at 2 P. M. and a minimum of 2 mph before sunrise. A diurnal summary for a station in the east coast is not readily available.

The differences in the patterns of these diurnal variations in wind speed are reflected in the values of the average wind power density for each of the stations. Table 1 presents the average wind power density in a vertical plane perpendicular to the wind direction (watts/m^2) during a typical day for the stations mentioned above.

These values were obtained from

$$P = \tfrac{1}{2}\rho v^3 \qquad (1)$$

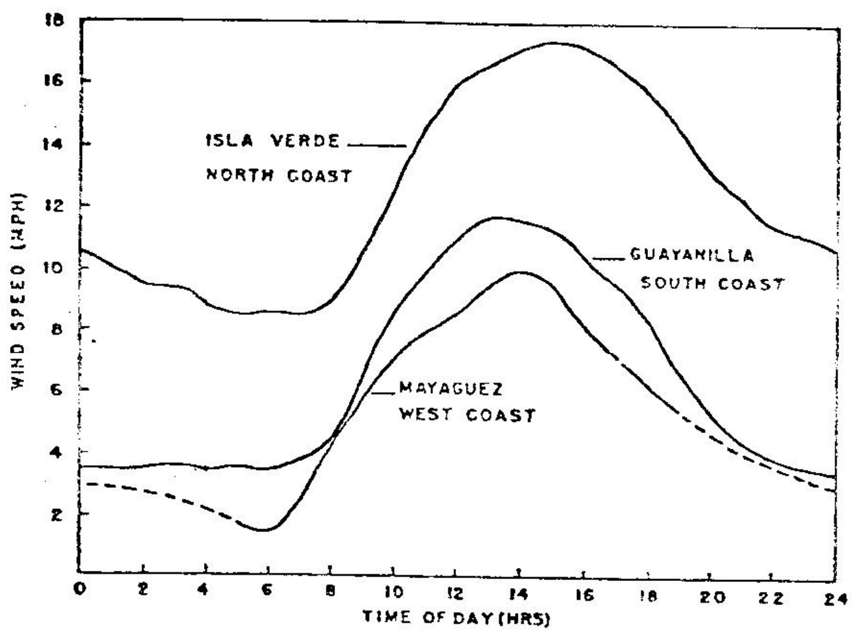


Figure 3. Diurnal oscillation of the wind speed at selected stations. No actual observations were recorded at Mayagüez during the night and early morning hours. All values correspond to a height of 10 meters.

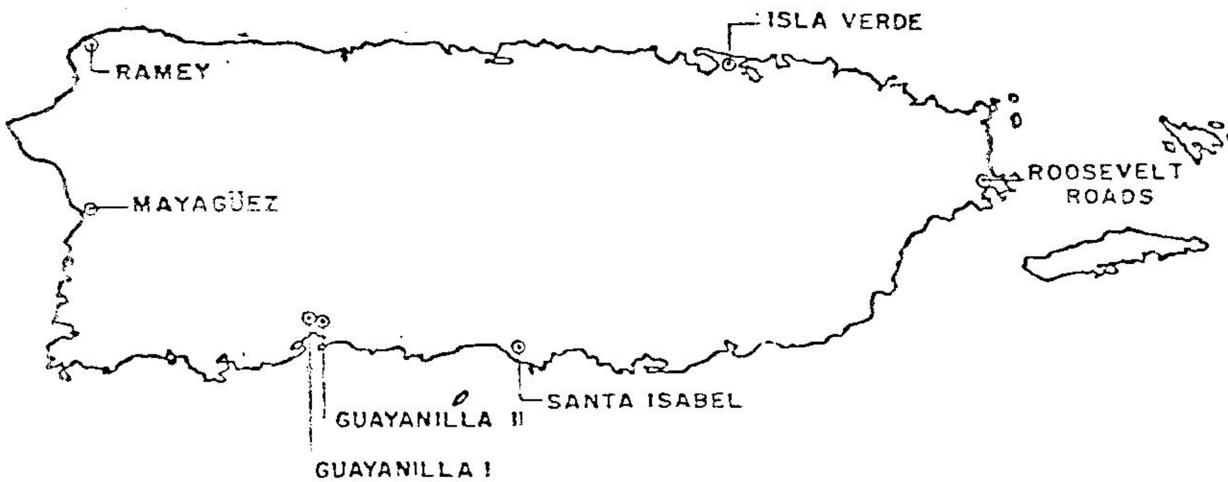


Figure 4. Map of Puerto Rico indicating the locations of meteorological stations for which wind data is available.

Table H.1

Average wind power density in a vertical plane perpendicular to the wind direction (watts/m^2) during a typical day at selected stations in Puerto Rico. Values correspond to an anemometer height of 10 meters.

North Coasts	
Isla Verde	122.5
East Coast	
Roosevelt Roads	93.0
South Coast	
Guayanilla	25.1
West Coast	
Mayaguez	13.5

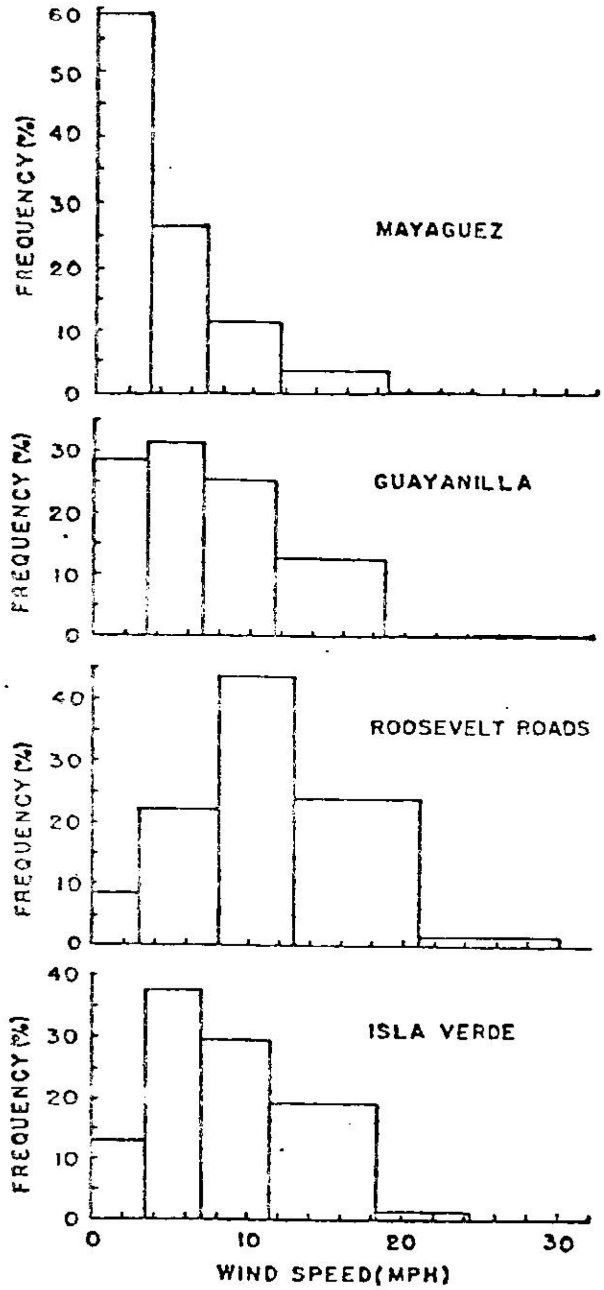


Figure 5. Frequency distribution of hourly wind speeds for representative stations of the west, south, north and east coasts of Puerto Rico.

where p is the power density, ρ the air density at anemometer height, and v is the wind speed. This formula was applied to the wind speeds shown in Figure 3, and an average value obtained for the day. The power density for Roosevelt Roads on the east coast was obtained from a 5 point yearly windspeed frequency distribution.

The north and east coasts have the largest power densities (122.5 and 93.0 w/m^2) with the south and the west coasts having much lower values (25.1 and 13.5 w/m^2). The wind power at Mayaguez is extremely low. The differences in wind power density between stations seem much larger than the differences in the patterns of diurnal wind speed variation. The reason for this effect is that the cube in Equation 1 amplifies seemingly small differences in wind speed when power density is computed.

The different diurnal wind speed patterns produce very different frequency distributions of wind speed during the year. Figure 5 shows frequency distributions for the four stations considered so far. It can be noticed that as one moves from the west coast to the south, and from the north to the east coasts the maximum frequency occurs at higher wind speeds. The maximum frequency for Mayaguez corresponds to 0-4 mph, for Guayanilla 4-8 mph, for Isla Verde 4-8 mph also but at a much larger frequency, and 8-12 mph for Roosevelt Roads.

3. Distribution of wind power potential in Puerto Rico

In order to construct a map of wind power potential for the island, wind data was analyzed for the stations indicated in Figure 4. A detailed frequency distribution of hourly wind speeds was readily available only for Guayanilla I. Distribution with only five or six wind speed classes were used for all other stations. In the latter case, detailed frequency distributions were reconstructed using the following method:

a. obtain a cumulative frequency distribution

b. fit a 2nd order polynomial to this cumulative distribution.

c. compute detailed different distributions from the adjusted curve.

Equation 1 was then applied to each of the wind speed classes (interval 1 mph) and the average wind power density was computed.

The results are presented in Table 2. The results again indicate that the east coast is the region with the highest wind power potential, followed by the north coast. The south and west show only one third the power available in the east. It is interesting to note that the two stations in the north, separated by about 75 miles have very similar power potential. Contrary-wise, the stations in the south although all fairly low, differ considerably among themselves. Guayanilla I is farther inland than Guayanilla II which is more exposed to the sea breeze effects. These local differences stress the need for a detailed wind survey before choosing the final site for a generator plant. The effects of valleys, ridges, exposure, location within the seabreeze circulation, etc., should be carefully considered.

TABLE H-2

Average wind power density in a vertical plane perpendicular to the wind direction (watts/m^2) during the year at selected stations in Puerto Rico. Values correspond to an anemometer height of 10 meters.

North Coast	
Ramey	52
Isla Verde	57
East Coast	
Roosevelt Roads	79
South Coast	
Santa Isabel	21
Guayanilla I (Fomento)	16
Guayanilla II (PPG)	39
West Coast	
Mayaguez	26

The stations available are all within the populated coastal plains. It is important to assess the potential in the mountainous interior as well. To obtain an estimate for the elevated regions the following method was employed:

1. Obtain the frequency distribution of free-air wind speed at heights corresponding to the elevation of the terrain.

2. Apply Equation 1 after obtaning the air density appropriate to the elevation of the terrain.

3. Correct the resulting power for surface friction effects.

The United States Weather Service takes periodic upper air observations at its Isla Verde Airport station. Unfortunately, the data is not readily available in a summarized way by wind speed for different elevations. Colón (7) however, has presented some summarized data for a height of 5.000(7). From this information, a preliminary frequency distribution was reconstructed for free-air wind speed at 5,000 feet.

This height falls within the surface frictional layer which can extend up to 6,000 ft in the region. Thus, the winds at 5,000 feet should be related to the surface winds. A power law of the form:

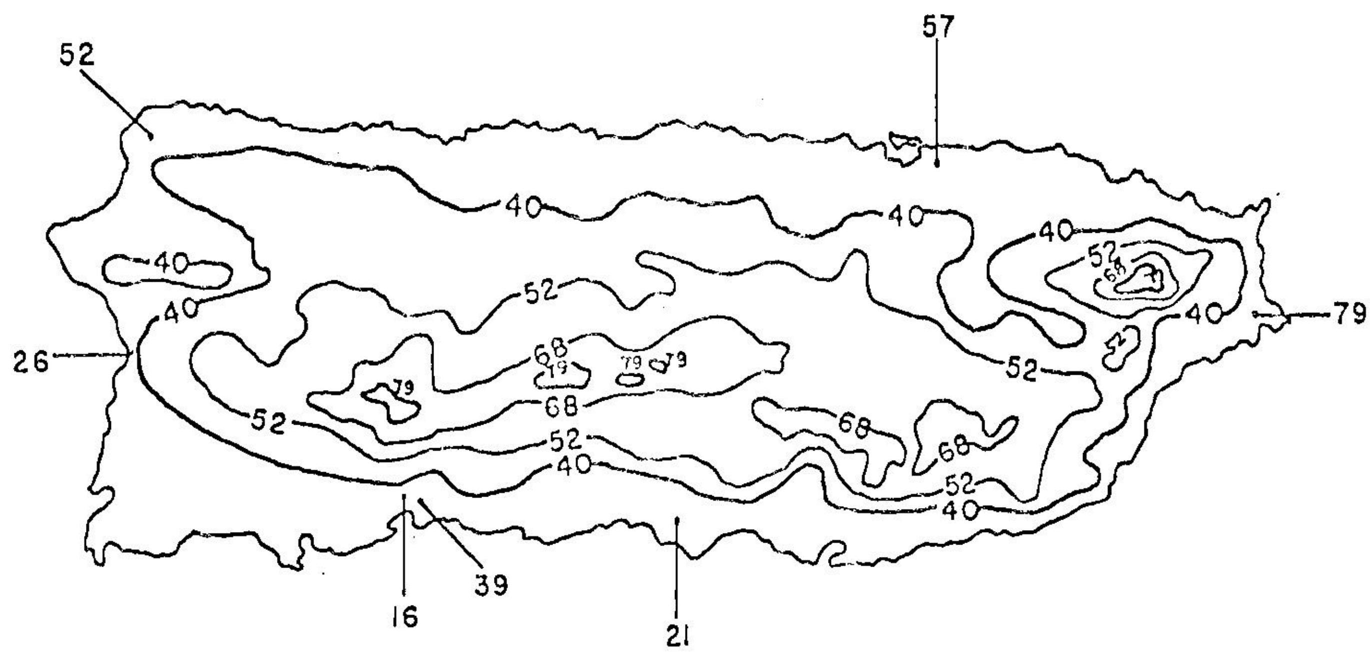
$$U(Z) = U(a) \ (Z/A)^{1/7} \qquad (2)$$

(where u is the wind speed, Z is the height of interest, and a is a reference height) has been used to relate winds at different heights near the surface. When this equation was applied to the average Isla Verde wind speed at 5,000 feet (17.1 mph) and 33 feet (8.4 mph) an excellent fit was achieved. In view of this good fit and for lack of a better relationship, it was assumed in this study that the free-air wind speeds over Isla Verde are related by Equation 2 for the layer of up to 5,000 feet. Thus, the frequency distribution obtained for 5,000 feet was assumed to be valid for the entire layer after correction is made for the decrease in wind speed according to Equation 2.

The wind power was computed from Equation 1 for heights of 500, 1,000, 2,000 and 3,000 feet. The corresponding air density was obtained from the mean West Indies sounding of Jordan [9]. A factor of 1/3 was applied to the computed power to allow for frictional drag effects as the air hits the elevated terrain. The adjusted powers constitute an estimate of the average wind power available at 33 feet over the ground at different eelevations.

Figure 6 is a map of Puerto Rico showing lines of equal wind power density (watts/m^2). The lines follow the 0.5, 1, 2 and 3 thousand feet height contours. The value represented by the lines correspond to the power density computed for those heights as described above. The point values obtained for the coastal stations are indicated separatedly on the map. The effects of river valleys and canyons and local terrain accidents have not been included in this general map. Local values of 85 watts/m^2 are probably possible on the tallest (3,500-4,000 feet) peaks.

It can be seen from this map that the highest wind power potential is found in the east coast and along the island mountain divide. The determination of the optimum location for a wind energy conversion system would have to made after a detailed wind survey at the two more promising areas (east coast and divide). One of the most important factors to consider is the variation of the



$P = \frac{1}{2}\rho v^3$ watts/m^2

Figure 6. Map of Puerto Rico showing lines of equal average wind-power density. These lines follow the approximate height contours of the terrain. Values of specific stations along the coast are plotted separately.

wind speed with height up to the hub height of the proposed turbine. The basic problem is to determine if the accelerating effect of the sea breeze on the coastal plane of the east coast provides a higher wind power at hub height than the stronger speed of the free-air wind as it passes over the top of the tallest mountains at hub heihgts. From this preliminary assessment it seems that an east coastal site would be as advantageous from the point of view of available power, accessibility, construction and operation. In the economic study which follows, the Roosevelt Roads station, will be used in the computations assuming that the wind energy generators would be placed there.

III. Wind turbine performance

Two models of wind turbines are being designed and tested by the General Electric Company: a 500 kW unit, assumed to operate at a 12 mph median wind site, and a 1500 kW unit, assumed to perate at an 18 mph median wind site (7). The proposed design characteristics of these two units were used to estimate the energy that could be generated at a site like Roosevelt Roads.

The wind speeds of the frequency distribution for Roosevelt Roads were adjusted to the height of the hub of the two turbines by using the power law of Equation 2. Then, the characteristic power-vs-wind-speed curve of each turbine was applied to the adjusted wind-speed distribution. The 1,500 kW unit would produce an average yearly power of 288 kW of 2.52×10^6 kWh during the year. The 500 kW turbine would generate an average of 236 kW or 2.07×10^6 kWh during the year. These two figures were used in an analysis of the cost of the power generated by arrays of these turbine, and they are presented in the next section.

These figures were obtained by employing the following concepts:
For a wind frequency distribution f(v), where v is the wind speed, the average power $\overline{P}$ generated by a wind turbine can be obtained as (Justus et al., 1976)

$$\overline{P}=\int_0^\infty f(v)P(v)dv, \tag{2}$$

Here P(v) is the power produced by the turbine as a function of the wind speed. The function P(v) is a characteristic of the particular wind turbine used.

This function can be characterized in terms of 4 parameters:

a. Cut-in speed v_0 (the lowest wind speed necessary to start moving the blades of the turbine)

b. Design speed v_1 (the lowest wind speed at which the turbine produces the maximum power P_m for which it was designed

c. Cut-off speed v_2 (the maximum wind speed at which the turbine can operate)

d. Maximum power P_m.

For speeds below v_0, the generated power is zero. Between v_0 and v_1, the generated power usually varies in a parabolic fashion. When wind speeds above v_1 are experienced, the angle of attack of the blades is changed so that the generation of power is constant at P_m.

Above v_2 the blades are furled so that they do not rotate in order to protect the turbine: the generated power is naturally zero.

Analytically, this pattern can be expressed as:

$$P(v) = \begin{cases} 0, & v \leq v_o \\ A+Bv+Cv^2, & v_o < v \leq v_1 \\ P_m, & v_1 < v \leq v_2 \\ 0, & v > v_2 \end{cases} \tag{3}$$

In this relationship the wind speed is assumed to be given for the height of the hub of the turbine. A, B, and C are the coefficients of the parable that expresses the variation of the generated power between v_0 and v_1.

These coefficients can be obtained from the following conditions:

$$\left.\begin{aligned} A+Bv_o+Cv_o^2 &= 0 \\ A+Bv_1+Cv_1^2 &= P_m \\ A+Bv_c+Cv_c^2 &= P_m(v_c/v_1)^3 \end{aligned}\right\} \tag{4}$$

where $v_c=(v_0+v_1)/2$. This last relationship expresses the concept that the power generated is proportional to the cube of the wind speed.

The assumed power-vs-wind speed curves can be characterized by the following constants.

A. 1500 kw unit

v_0=11.4 mph
v_1=22.5 mph
v_2=50.0 mph
P_m=1500 kw

B. 500 kw unit

v_0=7.9 mph
v_1=16.3 mph
v_2=40.0 mph
P_m=500 kw

These values were substituted in Equation and the coefficients A, B, C were evaluated. This completes the evaluation of the function P(v) of Eqn. 3.

The wind speeds classes of the frequency distribution for Roosevelt Roads were then adjusted to hub height by using the power law of equation 1 (154 and 150 ft for the 1500 and 500 kW units). With all this information, and proper unit conversions, Eqn. 2 was evaluated over the different adjusted wind speed classes of the frequency distribution to yield the average yearly power $\overline{P}$. The procedure was programmed for a TI-59 desk calculator.

IV Economic analysis

1. System configuration

The hydroelectric system of the PRWRA produces approximately 100 x 10^6 kWh every year. To achieve a similar generation it would take approximately 50 wind turbines. Preliminary studies by GE have indicated that the wind turbine units should be installed with a separation equivalent to 15 diameters, or approximately 920 m between units. For a cluster of 50 units that would come to a minimum of 9 square miles of land needed for turbine installation alone. The entire Roosevelt Roads Naval Base for comparison, covers an area of 12.5 square miles. A more manageable cluster of 25 turbines would be more commensurate to the land limitations of the island. It is also possible to have lines of turbines strung along the east and north coasts. For the purposes of this study, a cluster of 25 turbines was considered. An effective layout could be as portrayed in Fig. 7.

2. Land costs

The land needed for the assumed layout is 2,891 acres (2,978 cuerdas). Current land prices in Puerto Rico fluctuate between $5,000 and $25,000 per cuerda (1 cuerda equals .9712 acres). Due to the large amount involved it is reasonable to assume a low wholesale price of $5,000 per cuerda. An 8% yearly increase is assumed in land prices. The present land costs would thus amount to $14.89 millions.

3. Wind turbine generators costs

Preliminary cost estimates provided by GE have indicated that the first production 1.5 kW would cost approximately $2.633 million. The 500 kW unit is estimated to cost 72.5% of this price, or $1.91 million. For initial planning purposes, GE also estimates that the accumulative average production costs can be reduced to 90% of the previous costs, each time the total number of units is doubled.

The manufacture of one turbine has been estimated by GE to take 6 to 9 months. The Bureau of Reclamation (5) is considering plans to purchase 49 turbines in the first 5 years of production. Other companies might enter into the wind turbine manufacturing business. A production of 100 units every 5 years will be assumed in the present study. Assuming a 90 percent learning curve, the average cost of a 1,500 kW system within the first 100 units (first 5 years of production) would be $1.31 million, and $0.95 million for a 500 kW unit. The total cost of the 25 turbines would be $32.75 and $23.75 million for the 1.5 and .5 kW models respectively. These costs include equipment, assembly, delivery, erection, land preparation and check out costs.

Every year the purchase is delayed the price will come down on the account of increased experience in the part of the manufacturer, but on the other hand, the price will go up on account of inflation.

4. Electrical connection costs and overhead

The Bureau of Reclamation has prepared a preliminary design as the basis for an estimate of the electrical interconnection costs for their wind turbine array of 49 units as well as the transmission facilities required to tie into their existing transmission grid. Their array would be twice as big as the one assumed for this study. Their costs have been estimated to

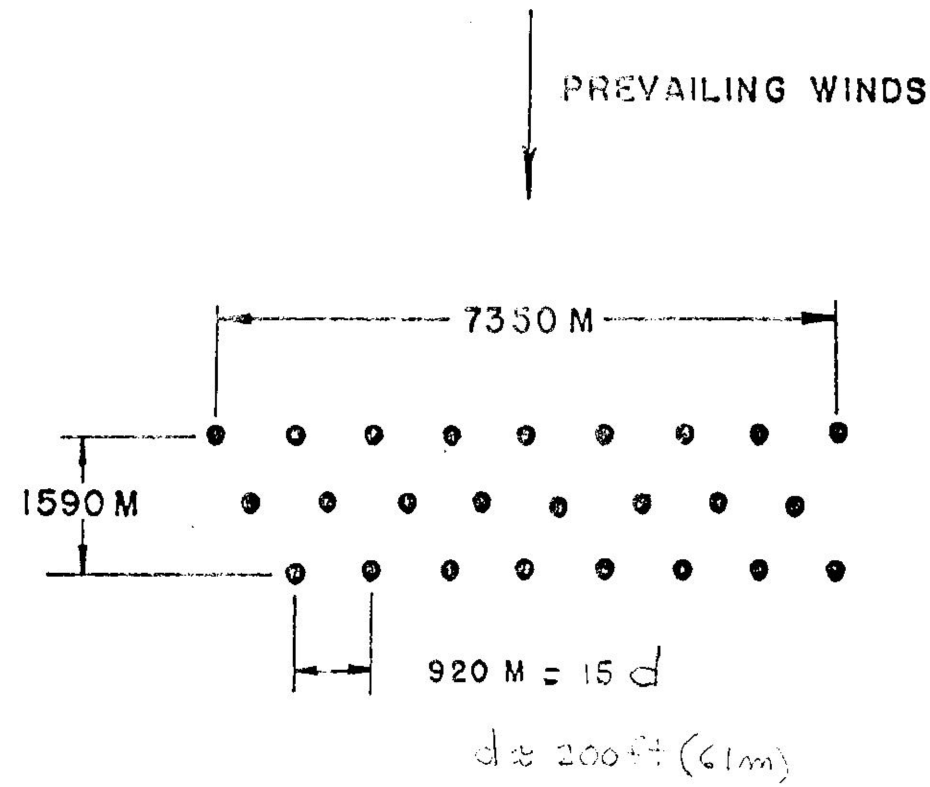


Fig. 7. Suggested layout for a cluster of 25 wind generators.

be \$6.37 million for their Wyoming site. Half of that amount could be assumed for the array of 25 units in Puerto Rico, or \$3.19 million.

A design overhead of 17% has been added to cover engineering design and preliminary and environmental studies. An allowance for additional site facilities, contingencies and construction supervision of 15% has also been included.

The total capital investment for the system at this time is summarized in Table 3. The total cost for the wind turbine system comes to \$62.33 and \$50.45 million, if developed at the present time, for the 1.5 and .5 MW models respectively.

Table 3. Capital Investment Summary

Item	Capital Cost (million dollars) 1.5 MW	0.5 MW
1. Wind turbine generators (25 units)	32.75	23.75
2. Electrical interconnection	3.19	3.19
3. Design and study overhead (17%)	6.11	4.58
4. Contingencies, site facilities, supervision (15%)	5.39	4.04
5. Total wind power system	47.44	35.56
6. Land costs	14.89	14.89
Total capital investment	62.33	50.45

5. Wind turbine power costs

The power costs can be calculated using the capital investment costs, land costs, operation and maintenance costs, and the annual estimated power output. A construction period of 3 years is assumed, as well as a plant life of 35 years and an interest rate of 8%.

It was assumed that construction expenditures would occur uniformly throughout the 3-year construction period and the interest during construction was computed at compound interest for half of the construction years ($1.08^{1.5}$). The interest on the land cost was computed at compound interest for the 3 years of construction. Amortization of the total wind turbine investment (construction plus construction interest) was computed using a total capital fixed charge rate of 11.743% as is customary for the PRWRA while amortization of the land investment costs (land plus land interest) was assumed at 8% compound interest over the assumed 35-year life of the plant. GE has assumed that the maintenance and operation costs will be approximately 2 percent of the wind turbine costs. These costs were assumed to include the generators, electrical interconnections, and contingencies and site facilities.

Table 4 summarizes the estimated power costs. The total cost comes to \$8.68 and \$6.92 million for output of 63.00 and 51.75 million of kWh respectively, the power costs for the two wind turbine systems come out to be 137.8 and 137.7 mills/kWh.

Table 4. Power Costs

Item	Costs (million dollars) 1.5 MW	0.5 MW
1. Total construction costs	47.44	35.56
2. Construction interest on construction costs	5.81	4.35
3. Land costs	14.89	14.89
4. Construction interest on land costs	3.87	3.87
5. Annual fixed charge on construction costs (1+2)	6.25	4.69
6. Capital recovery on land costs (3+4)	1.61	1.61
7. Operation and maintenance cost per year	.82	.62
8. Total annual cost (5,6,7)	8.68	6.92
9. Annual power output (10^6 kWh)	63.00	51.75
10 Power cost (mills/kWh)	137.8	137.7

The Bureau of Reclamation estimated a power cost of 21.1 mills/kWh for a similar system in Wyoming. The great difference in the two figures results from 3 very important factors:

a. the wind power available in the Wyoming site is 3 times as much as in the Roosevelt Roads site.

b. the capital fixed charge rate for Wyoming was assumed at 8.41 percent, while the PRWRA reported a rate of 11.743 percent.

c. land costs in Wyoming were figured at $200 per acre while a wholesale price of $5,000 per acre was assumed for Puerto Rico.

It is interesting to note that both turbine models would produce energy at the same cost but the larger turbine would produce 18% more total power. Thus, it would be advantageous to use the larger machines. In what follows only the 1.5 kW turbine model will be considered.

V Economic projections

The estimate of 138 mills/kWh applies to the cost of power if construction was completed within the next 5 years. For simplicity, no inflation factor was included for this period. Certainly, the uncertainty in the learning rate estimates and the manufacturing output do not warrant a more detailed approach. As construction is delayed beyond this period, however, the price will change considerably: down on account of increased experience in the part of the manufacturer, but up on account of inflation.

A projection of the wind power costs was made for a period of 40 years. This projection was made in eight 5-year steps assuming the production of 100 additional turbines in each 5 year period with a corresponding 90% learning rate. A compound 8% inflation rate was also assumed starting from the costs of the estimate of Table 4. It was further assumed that the learning rate takes into consideration the inflation in the production process.

Table 5 presents the capital investment costs for each of the eight 5-year periods. The greatest drop in the price of the generators occurs in second step. The learning curve is basically an exponential curve which drops very fast at the beginning and stabilizes very fast. Other costs, especially for land, escalate very fast on account of the assumed 8% inflation. Actually, land and interconnection costs become several times the cost of the turbines themselves. If an additonal inflation increase is added to the cost of the turbines the situation becomes hopeless very fast. The largest item becomes the land costs after 10 years of delay. If the land could be secured free of charge, e.g., land belonging to the Commonwealth of Puerto Rico, or land already belonging to the PRWRA could be used, the costs could be reduced dramatically.

Table 5. Forty year projection of capital investment (million dollars)

	Years							
	0-5	6-10	11-15	16-20	21-25	26-30	31-35	36-40
1. 25 generators	32.75	26.15	24.15	22.90	22.08	21.4	20.85	20.40
2 Electrical interconnections	3.19	4.69	6.89	10.11	14.86	21.85	32.10	47.16
3. Design overhead (17%)	6.11	5.24	5.28	5.61	6.28	7.35	9.00	11.49
4. Contingencies (15%)	5.39	4.63	4.66	4.95	5.54	6.49	7.94	10.13
	47.44	40.71	40.98	43.57	48.76	57.09	69.89	89.18
5. Land costs	14.89	21.88	32.15	47.23	69.40	101.97	149.83	220.15
	62.33	62.59	73.13	90.80	118.16	159.06	219.72	309.33

Table 6 shows a summary of the power cost estimates for each of the 5-year periods. Again, the effect of inflation overcomes the advantage from the learning rate. Line 9 of the table shows the savings of oil barrels that the wind system could achieve assuming that the efficient thermoelectric plant uses one barrel to generate 600 kWh. Line 11 indicates the equivalent cost of each barrel saved in dollars.

Figs 8 and 9 portray graphically the investment cost of each kW produced and the equivalent cost of each barrel of oil that could be saved by the wind energy conversion system. For reference, the portion that the land and the turbine purchase would account for is also portrayed in Fig. 8. It should be realized that in the computations figured above, no provision has been made for outages or auxiliary power for the turbine. In view of the inaccuracies in some of the assumptions this correction becomes insignificant. If a more detailed estimate is desired, however, the total annual power output could be reduced by a factor of .90X.99 which is a reasonable figure for outage and auxiliary power, respectively.

Line 12 of Table 6 shows the equivalent cost of each barrel of oil saved if the land cost could be eliminated. The equivalent cost could be around 60-70 dollars per barrel for the next 25 years. In view of the present upward trend in oil cost, the equivalent price could become competitive in the foreseable future. Land cost could be eliminated by using land already owned by PRWRA or ceded to PRWRA free of charge. Fig. 9 portrays graphically the equivalent cost of a barrel of oil under these assumptions.

Table 6. Forty year projection of power costs (million dollars)

	YEARS 0-5	6-10	11-15	16-20	21-25	26-30	31-35	36-40
1. Total construction costs	47.44	40.71	40.98	43.57	48.76	57.09	69.89	89.18
2. Construction interest on construction costs	5.81	4.98	5.01	5.33	5.97	6.99	8.55	10.91
3. Land costs	14.89	21.88	32.15	47.23	69.40	101.97	149.83	220.15
4. Construction interest on land costs	3.87	5.68	8.35	12.27	18.02	26.48	38.91	57.18
5. Annual fixed charge (1+2) on construction costs	6.25	5.37	5.39	5.74	6.43	7.52	9.21	11.75
6. Capital recovery on land costs (3+4)	1.61	2.36	3.47	5.11	7.50	11.02	16.19	23.79
7. Operation and maintenance costs per year	.83	.71	.71	.76	.85	.99	1.21	1.55
8. Total Annual cost (5+6+7)	8.68	8.44	9.57	11.61	14.78	19.53	26.61	37.09
9. Annual power output (10^6 kWh)	63.00 (105,000 barrels of oil)							
10. Power cost (mills/kWh)	137.8	134.0	151.9	184.3	234.6	310.0	422.4	588.7
11. Equivalent oil costs ($/BBL)	75	80	91	111	141	186	253	353
12. Equivalent oil costs not including land costs ($/BBL)	67	58	58	62	69	81	99	127

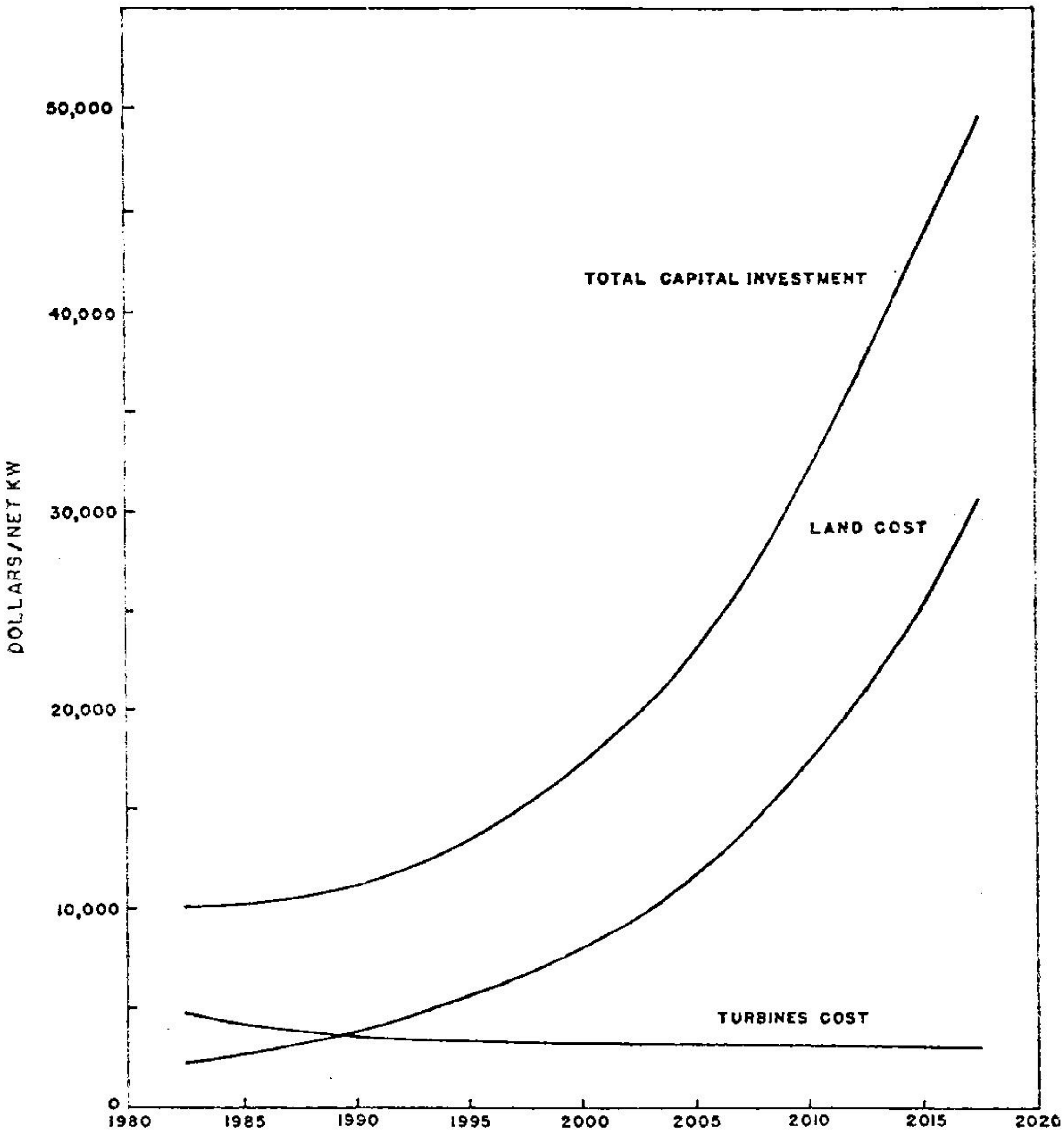


Fig. 8. Forty-year projection of the equivalent cost of each kW produced by the wind-energy conversion system.

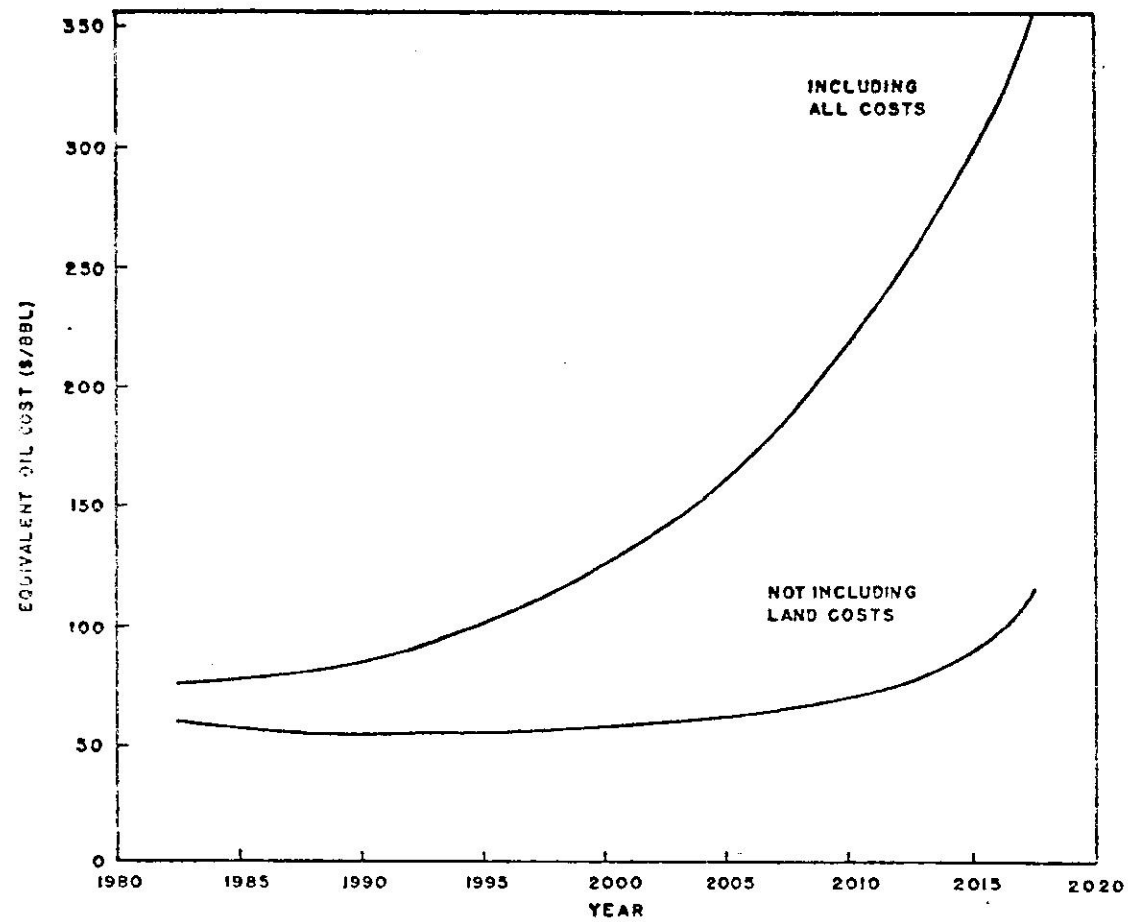


Fig. 9. Forty-year projection of the equivalent cost of each barrel of oil saved by the wind-energy conversion system.

VI Summary

A study has been made of the possibility of integrating large windpower generators to the existing PRWRA thermo-electric network in Puerto Rico. Climatologically, one would expect the highest potential for wind power utilization in the north and east coasts because the sea breeze acts to intensify the prevailing winds in those regions. Actually, an inspection of the available stations around the island reveals that the largest power densities are found in the north and east coasts. The power at the south and west coasts being very low. Estimates of wind power density for other regions, especially the mountainous interior, indicate that no appreciable advantage is found in the mountains over the eastern coastal plains.

A station in the east coast, Roosevelt Roads, was subsequently chosen for detailed analysis. Applying the design characteristics of the GE 1.5 and .5 MW to the wind speed distribution for this station reveals that an average power of 288 kW and 236 kW respectively, could be generated throughout the year.

A system of 25 turbines is proposed. Estimates of capital investment, operation and maintenance were made for systems of the two models. The total power costs were estimated at 137.8 and 137.7 mill/kWh. Three major factors account for such an elevated production cost:

(1) the wind power potential is moderate
(2) the capital fixed charge is very high
(3) land costs are extremely high.

A 40 year economic projection was performed. In general, reductions due to the assumed learning curve were more than compensated by the inflation rate of 8%. The largest item being the escalation of the already high land cost. If land costs could, somehow, be eliminated, the equivalent cost of each barrel of oil saved could be around 60-70 dollars for the next 25 years. A price that could become competitive in the foreseable future. Land costs could be eliminated by using land already owned by PRWRA or ceded to PRWRA free of charge.

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