CEER-X-72 ENERGY ANALYSIS AND SOCIOECONOMIC CONSIDERATIONS FOR PUERTO RICO
With Special Contributions by
May 1980
CENTER FOR ENERGY AND ENVIRONMENT RESEARCH

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University of Puerto Rico
U.S. DEPARTMENT OF ENERGY

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Energy Policy Document. This was a wide-ranging and ambitious policy, 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 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 provides 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 most expensive energy alternative analyzed in the study. The use of this alternative should be minimized with a strong, dynamic, and aggressive alternative energy development program. Excluding nuclear plants, the lowest predicted cost of electricity, with escalation rates of 8% per year until 1985, results from power plants burning biomass. With assumed cost for the first year of electricity from a biomass-fueled plant predicted to be 6.58 cents per kWh, and with an assumed escalation of 5% per year beyond 1985, the levelized cost of electricity during the lifetime of the plant (assumed to be 35 years) is 7.13 cents per kWh.

By contrast, the corresponding costs for a coal plant equipped with a Flue Gas Desulfurization (FGD) System is 6.35 cents per kWh for the first year of operation (1985), and 9.59 cents per kWh for the lifetime of the plant (1985-2020). The corresponding cost of electricity from residual fuel oil burning plants shows costs of 1.607 and 3.202 times 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 the 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 those of electricity produced by oil-fired steam plants.

A 250 MW photovoltaic central power installation with electric battery storage projected for operation in 1983 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.

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 suitable for fuel 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 over the lifetime of the facility, taking into account the inflation of operating costs and fuel costs. 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 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 considered "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 AM Costs escalated at 5.25%/ Year except Fuel Oil which is escalated at 9.417% and Yellow Cake escalated at 2.61% per year. TOTAL LEVELIZED COSTS (mills/ kWh) of Wind energy (alternative energy source) shown for comparison purposes with Fuel Oil Cost component curve.

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 the impact of employment and productivity outputs for two selected alternative energy sources. Increases will severely impact the economy of Puerto Rico. Cost increases to industries such as cement, electricity, construction, mining, alcoholic beverages, transportation, and business services were tremendous. The results show that the largest declines were in the important industries in terms of output generation and job creation. This study shows that, oil prices rose significantly from 1973 to 1979 (assuming a...).

The conservative price of $21.00 per barrel of crude in fiscal year 1979 remained constant. This induced or has already induced an increase of more than 130% in the estimated producer's 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 aggressive 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 aggressive 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 using the open input-output matrix model of Leontief. 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 million. This assumes that the reduction in support 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 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 8,000 jobs.

$1328.2 million 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 as 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.

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

1. Biomass Program: A strong program is required to make the first (450 MW) Power plant operational by 1985.

2. Solar Program: An aggressive program is needed to make the first experiment (49 MW) operational by 1985 and first commercial plant (250 MW) operational by 1991.

3. Photovoltaic Program: A dynamic program is needed so that a large demonstration project can be placed in operation by 1990.

4. Wind Power Turbine Generators Program: 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.

Section 2, No attempt has been made to substitute existing fuel oil generating plants with alternative energy systems. Instead, an ambitious scenario is shown allocating new generation requirements to renewable energy alternatives that are economically competitive with coal. As seen from Table 1.3.1, three coal-burning plants, one with 300 MW capacity in 1985 and two with 400 MW each for 1989 and 1990, are included in the scenario. It is estimated that biomass burning plants can be operational as early as 1986 and 1987. No additional biomass plants are indicated because agriculture policies are not defined at this time.

Year 1980-84 1985 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000
Biomass 1300MW +300MW
TABLE 1.3.1
OTEC 1.40MW 1.250MW 250MW 10250MW 1-500MW 1-500MW
Photovoltaic 1-260MW 1-250MW
Wind 200KW 1-85MW
SCHEDULE OF PROPOSED SCENARIOS
PROGRAM OBJECTIVES ELECTRIC PLANTS CAPACITY
Coal 1-300MW 400MW 1.4000

The envisioned 300 MW biomass plants will require the planting and harvesting of approximately 75,000 acres of land, about the same 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 all the electricity produced in 1979 in Puerto Rico with photovoltaics, a total land area of approximately 100 square kilometers 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 3,000 acres. For these reasons, the scenario depends heavily on the OTEC alternative. However, not all 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 up 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 situation is so dependent on oil that heroic efforts are required to make even a slight reduction in oil importation during the present decade.

Year TABLE 1.3.2 POSSIBLE EQUIVALENT MILLIONS BARRELS OF OIL SAVED WITH PROPOSED SCENARIO AT 75% CAPACITY FACTOR

Biomass (Million Barrels), Solar Photovoltaic, Wind Energy

1980-1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000

3.285, 687, 687, 687, 657, 657, 657, 657, 697, 657, 657, 687, 687, 657, 687, 438, 438, 438, 438, 438, 438, 2744, 5.48, 5.48, 322, 322, 322, 322, 1370, 19.20, 19.20, 274, 274, 274, 548, 548, 5.48, 548, 5.48, 5.48

Totals: 95.265, 101.308

(a) Assuming 600 kwh/BBL
(b) Energy calculated from available wind and turbine characteristics
(c) Assumes 40MW- OTEC Exp. is shut down 38.36 17 236.103,

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

Million Barrels of Oil Imports For Electrical Gasoline

The corrected text:

Industry Estimated Unit Total Cost Year Energy(#) & Diesel) & Other (©) Total Price ($/BBL) ($ Millions) (Millions) 1976 0.7 76 3a 1977 230 13200 $627 1978 24 165-38 65.0 1379260 70281811470 1001 1980 275 7 31678 1203 181.290 5 2777521817 1442 1982 20.7 120281778 21.90 $704 1983 9 198 0.0522 25.00 2055 1984 33.6 205 208681285 2458 1985 35.3 20 36 8993270 2959 1986 36.7 24 3538629 3390 1987 37.9 29 74 9890.28 3903 1988 42.2 25 389 1036 44.72 4633 1989 44.8 231 409 1088 49.60 5396 1990 47.4 236 429139 55.00 6266 1991 50.8 240 451 1199 58.75 7048 1992 53.4 25 473195262 7856 1993 56.0 25.1 497 1308 67.00 9205 1995 60.0 27 5221370 71.80 9706 1995 62.0 20.8 48 1828 76.50 10924 1996 50.2 84 575 1489 81.2 12078 1997 63 267 604 155.2 86.00 13347 1998 71.8 74 634 162.3 14793 1999 74.4 279 666 168.6 96.62 16290 2000 77.6 28.1 699 178.6 102.6 18016

{a} Statistical Correlations between population and GNP, and between GNP and Electrical Energy Generation, Correlation 99.7 {b} Gasoline Consumption growth projected conservatively between 2 1/2 ~ 3% per year vs. 6.6% actual growth, (c) Industrial trends 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.

ELECTRIC ENERGY CONSIDERATIONS

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

1. Solar industrial steam
2. Hot water by Fuel synthesis
3. Conservation measures, mainly in transportation.

Preliminary considerations have been given to these topics in CHER document A-31, "Preliminary Report on RED Program Needs for Energy Alternatives in Puerto Rico" (June 1979).

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 are crucial. 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 aid 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 bagasse. 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 aggressive 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%. If transportation conservation measures are added, probably an additional 5-10% 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

[Table content not provided]

1.5 RESEARCH AND [text cut off]

DEVELOPMENT (R&D) EFFORT REQUIREMENTS

In order to facilitate 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 necessary. Such R&D efforts must be paired with 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-SS "Proposed Five Year Plan-Energy and Environmental Programs," Draft No.1, December 1979. A summary of the basic research program described in the 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's 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 document.

Work.
TABLE 15.1 TOTAL R&D EFFORT REQUIREMENTS FOR GOVERNMENT FUNDING (1980-Thousand Dollars)

1982 | 1983 | 1984 | 1985 | 1986 | Total

OTEC* 2,200 | 2,800 | 3,200 | 3,200 | 3,400 | 14,800
Biomass* 4,150 | 2,190 | 2,380 | 2,380 | 2,280 | 13,320
Solar Energy* 828 | 951 | 1,235 | 1,507 | 1,710 | 6,275
Gasohol 220 | 220 | 225 | 240 | 905
Transp. Cons. 625 | 3,675 | 633 | 870 | 387 | 5,258
Total 20,023 | 6,5125 | 7,673 | 7,897 | 7,775 | 37,883

*Funding for these programs is the same as in CEER 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 aggressive attack on the energy problem.

TABLE 1.52 CAPITAL INVESTMENT IN DEMONSTRATION PROJECTS: (With R&D Efforts in Table 1.5.1) (Private industry, government corporations, consortiums, and government-sponsored business investments)

Investment Cost | Project Capacity | Scheduled | (million dollars)/yr

OTEC (a) 100mw | 1985 | $209.2 (1980)
OTEC 250NW | 1991
Biomass*? 100K | 1986 | $168 (1978)
Photovoltaic!®) 260mw | 1993 | $1,126 (1980)
Ethanol Plant 100 million gals. for Gasohol per year | 1986 | $228 (1978)
Steam Cogen(b) with Ethanol 33 million lbs per day 350 F Steam | 1986 | $250 (1978)

Photovol.®) 2.2.x 10"2 Plant Btu/year or 60 million lbs 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.

Unfortunately, the remaining text provided is unclear and seems to be a series of codes or abbreviations. Could you provide more context or clarify what the text should translate to?

RECOMMENDATIONS.

1.6.1 Cone Biomass promises to be the most economically attractive 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. OTEC and Photovoltaics promise to be competitive with coal central power plants with costs similar or slightly higher (less than 12%) than predicted costs of electricity from coal plants as early as 1994. Both alternatives require substantial technological advancements. Wind energy systems without storage can be used economically for fuel oil displacement, but they are not economically competitive with coal power plants. Nuclear power will continue to be the lowest cost power for the rest of the century and beyond. 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 72%.

1.6.2 Recommendations: Strong R&D programs should be implemented to make possible the use of biomass in planned coal power plants by the mid 1980's. OTEC and Photovoltaics R&D program efforts should be developed to make these alternatives economically viable in the Puerto Rico scenario by the mid 1960's. 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. 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 1 Electrical Energy Forecast 2.bt Introduction

The problem of forecasting long-range estimates of energy use is a difficult task due to the uncertainties involved in the development of new technologies and changes in habits that can significantly affect these estimates. Attempts have been made to forecast a period in which current embryonic technologies can be extrapolated in a qualitative sense. A 49-year period, up to the year 2020, is believed to be long enough for such extrapolation and to provide energy planners with an overview of the next four decades, focusing on energy alternatives. The primary interest is in the energy and fuel alternative scenarios required to power socio-economic development in Puerto Rico. Therefore, the forecasting has been limited 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 to avoid complicating 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 percentage growth per year, considering historical consumptions.

Statistical Methods for Decision Making, W.A. Chance 1969. Train-Dorsey Ltd., 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, judgments 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 Gross National Product at constant prices and the...

Electrical energy consumed. The C8P will be predicted from the product of population predictions, times the 125. Population per capita prediction at constant pi have already been predicted by the Planning Board up to the year 2000 and the ONP predicted to the year 1983. Our predictions will be, therefore, somewhat uncertain for the period 2000-2020.

2.1.2 Population
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. Melendez 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 has doubled in less than 3 years. (Ref: Conferencia sobre Economía y Población, Dr. James A. Santiago Melendez, Serie de Conferencias y Foros: No. 4, Department of Economics, University of Puerto Rico, Rio Piedras, Puerto Rico).

In contrast, a slow population growth rate, such as a doubling of population every 200 years, is not ideal. 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 infrastructure 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 linear regression analysis on historical population data going back to 1962, and incorporating the Planning Board's predictions up to the year 2000 as input data for the regression analysis (with a total number of input points being 22), the following equation resulted: $Yp = 2166.9 + 65.05x$. Here, Yp represents the population in thousands and x refers to the year in relation to 1960, i.e., year minus 1960.

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This indicates a positive correlation of 4. The predicted population calculated in this manner for the year 2020 will be 6,070,110. The approximate doubling time for the current estimated population of 7,338,000 is 51.3 years. This allows for adequate economic growth as defined by Meléndes. An exponential regression of the population was also attempted.

The exponential relation provided the same degree of correlation and coefficient of determination as the linear relationship, but the doubling time for the current population was 35 years. Considering this is not in line with government policy, it was discarded. The exponential relationship was represented as population equals to 2308.65 times 'eM' raised to the exponent 0.02%, with 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 population of 6,070,110 in the year 2020. The predicted population data to be used in the study is provided in Table 2.1.2.

TABLE 2.1.2

POPULATION BY LINEAR REGRESSION MODEL

Population (in millions): 3.47, 3.53, 3.65, 3.72, 3.78, 3.92, 4.26, 4.92, 4.67, 5.09, 5.42, 5.75, 6.07

Economic Welfare

For the purpose of this study, it is assumed that the overall economic welfare of the country will be maintained and improved. The Gross National Product (GNP) per capita in constant dollars serves as 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 reflect a small or moderate yearly increase. The total GNP in constant dollars should

Chen refers to the yearly increase in the rate of ONP per capita at least equal to the population growth rate. The total ONP 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	107500	116930	127100	137950
Constant $	4047.4	42088	4589.7	48140	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. During 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: $y = 546.87 * e^{0.77x}$, where: y = GNP/capita in constant 1954 dollars, x = year - 1960.

Predicted values with the above equation indicate yearly improvements in GNP/capita at constant dollars of the order 0.5 to 1.5% which is considered on the low side. The predicted GNP per capita at constant dollars was multiplied by the

Predicted population is used to obtain the total predicted GNP at constant dollars. Electrical Generation: The total electrical generation was correlated with the total GNP, and excellent correlations resulted.

1. Linear Correlation: Coefficient of determination is 98%; doubling time is 20 years.
2. Power Correlation: Coefficient of determination is 98.7; doubling time is 11 years.
3. Log Correlation: Coefficient of determination is 97.2; doubling time is over 40 years.

4. Exponential Correlation: Coefficient of determination is 93%; doubling time is 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 their 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 beyond 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 increased demand. Therefore, the power fit represents an adequate description of future electrical generation production.

The power fit is given by, KHER gen = (0.001294) cour)" 96 fat 1954 constant dollars. x 10° where the unit for GXP is million 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 is 38,261 x 10^6 kWh generation which is comparable to our prediction of 42,910 x 10^6 kWh, within a 5% difference. 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 kWh, which is slightly above the current electrical energy generation. The linear fit is given by KWh gen = -6709.03 + 5.21 (exp) x 10^6 where GxP is in millions at 1954 constant dollars. The last column of Table 2.1.4 indicates the kWh prediction with the linear correlation. Energy planners and researchers must, therefore, think of energy alternatives for Puerto Rico on a scale as large as six times today's demand by the time most energy alternatives being researched today could be highly competitive economically. Electrical energy is used around the clock; hence, large storage systems for 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)

See: Power Fit, Linear Fit

Year	GNP/Capita	Population (thousands)	GNP (millions)	Electric Prod. (kWh)

1962	6,940	2,826	1,683.9	2,870.7
1963	7,360	2,473	1,820.7	20,345
1964	7,680	2,823	1,936.9	3,403.2
1965	8,170	2,568	2,090.2	3,819.2
1966	8,610	2,603	2,408	4,429.8
1967	8,920	2,623	2,239.4	5,080.7
1968	9,270	2,650	2,553	5,770.9

The PREPA system, with 70% of its system generating units used as a criteria for installing base load units (as is the present condition), provides a rough indication of required additions to PREPA base load units. Table 2.1.5 illustrates the calculation of additional base load units for the case of a high energy demand scenario, obtained through a power correlation. Table 2.1.5 also illustrates the calculation of additional base load units for the case of a moderate energy demand scenario, obtained through a linear correlation. The high energy scenario represents a probable 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)	Total Cap.(MW)	Start-Up Date	Retirement Date*
San Juan	200	200	Retired	
5	440	440	1956	1991
6	440	440	1957	1992
78	1000	200.0	1966	2001
2	100.0	100.0	1968	2003
10	1000	100.0	1969	2008
Pato Seco	825	225	1960	1995
2	825	825	1961	1996
4	2160	4320	1970	2008
Souco	440	440	1958	1993
2	440	400	1959	1998
3	825	225	1962	1997
4	825	225	1963	1998

5 | 4100 | 4100 | 1972 | 2007

6 | 4100 | 4100 | 1973 | 2008

4500 | 900.0 | 1975 | 2010

Total Capacity (MW) | 3058.0

*A 35-year operating life is assumed

The remaining portions of the text appear to be garbled and may need to be re-typed correctly.

"Jewry" ASV9 ONVWAA 3LvH3GON SANAWAYINDAY LIND GVO 3S¥8 TYNOLLIGAY ONY GvOT Avad -15 m

2.2 GASOLINE CONSUMPTION PROJECTIONS

A simple, preliminary projection will be made for gasoline and diesel consumption to approximate total future energy requirements. The 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 gasoline consumption increase is assumed for the future. This is more appropriate than a regression analysis of historical data because the transportation infrastructure is changing rapidly to smaller cars and to other more economical modes of transportation.

FIGURE 2.21 GASOLINE CONSUMPTION IN PR AND PRELIMINARY PROJECTIONS

GASOLINE PLUS DIESEL = PRELIM. PROJECTION (2.5-3% per 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. Levis 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. Aromatic petroleum derivatives account for 8.5%, nafta for 4.45%, and the balance is in tars and asphalts, waxes, and cyclohexane. During 1976, 26.3 million barrels of oil were used directly by the industry. This figure does not include the fuel used in generating electricity for the industry which is accounted for in Section 2.1.

The industrial needs for oil will be predicted at a 5% per year growth rate.

Starting from the 1978 level, 'TOTAL OIL REQUIREMENTS' estimates the energy requirements for Puerto Rico up to the year 2000 under the present socio-economic structure. This takes into consideration the price elasticity of gasoline and the absence of a strong R&D program for energy alternatives, as 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 ALTERNATIVE ENERGY SOURCES.

Million Barrels of Oil Imports For Electrical, Gasoline Industry, Estimated Unit Total Cost Year Energy, Diesel & Other Total Price $/BBL, $Millions.

The data in the table could not be corrected as it appears to be incomplete and incoherent.

(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 ~ 2% per year vs. 6.64 actual growth.

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

(d) Future oil prices escalation indicated is approximately 1980-85: 14.34/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 (COST ANALYSIS OF COMMERCIALLY AVAILABLE ALTERNATIVES FOR ELECTRICAL 3.0 ENERGY PRODUCTION IN PUERTO RICO)

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

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 a 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 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 are also a consideration.

The text might offer a less intensive capital investment alternative at higher operating costs. Air quality regulations can mandate 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. Site-related considerations, such as location, affect the cost of a power plant project considerably. Factors such as terrain topography, site geology, seismic considerations, labor availability, proximity to electrical transmission facilities, transportation facilities like marine ports and roads, and fresh water availability can affect the total project cost.

COAL PLANTS 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 a coal plant is being considered for Puerto Rico, there are no previous experiences, policies, or cost records that 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 and operating costs of the plant. Appendix A describes the various types of coals and the methods of coal cleaning or "beneficiation," along 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 issues, 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.

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 landfills. This approach makes unrestricted fuel cost optimization processes 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:

1) Plant design should meet the EPA 1976 New Source Performance Standard (NSPS) as revised.
2) Heat rejection systems should comply with the latest revision of the Puerto Rico Environmental Quality Board (EQB) Water Pollution Regulations.
3) Boilers have to be able to burn the poor type coals which might be secured under emergency conditions.
4) Clean coals, which have been optimally beneficiated for the lowest fuel cost and which will yield lower ash and sulfur residues, will be the normal source of supply.
5) 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.

In order to establish some meaningful investment cost relations for considering all of the above factors, a general cost...

The equation will be derived based on the following assumptions:

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

2) The investment cost will include the installation of SO2 wet scrubbers and static precipitators for compliance with air quality regulations. The cost of this equipment is dependent upon the characteristics of the coal. For coal types in the 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 is assumed to be burned only under emergency or abnormal market conditions.

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

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

3.1.3 Seismic requirements.

a) No coal handling facilities are included between the nearby seaport 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.

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

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

d) Only the cost of the first unit of a two-unit design will be considered. If a second unit is built...

In a two-unit construction schedule, the cost of the second unit can be estimated to be between 85 and 96% of the first unit, if the second unit's construction starts approximately one year later than the first. This estimation is based on recent unpublished cost estimates from United Engineers and Constructors.

The interest during construction and inflation formula are significant factors in construction. A complete derivation of the formula is presented in Appendix B. For handling inflation and interest during construction, the following procedures will be used:

Figure 3.1.3 represents the cash flow for the project expenses. Y1 represents the number of years between the date of the current estimate, early 1978, and the start of construction. Y2 is the actual construction time. The curve's x-axis (abscissa) represents the unit of construction time, and the y-axis (ordinate) represents the cumulative investment per unit.

Figure 3.1.3 illustrates interest during construction and inflation formulas. The area under the curve represents the fraction of the construction time, which is used to calculate the accrued interest during construction. The area above the curve equals Ln(a), considering the curve has been normalized, and it represents the time fraction during construction in which the unspent money is subject to inflation.

Interest during construction can be expressed as follows: 48 Tyg = (tig 92). Inflation between the time of the estimate and the project completion is then determined.

The compounded interest rate for combined inflationary and interest during construction charges can be accounted for in a cost equation as follows: Yella, ay, iY 2 2 (Keto). Tye where: total cost in $/Kw Co =

The area under the curve is representative of construction time, which is used to calculate accrued interest during construction. The area above the curve equals Ln(a) and represents the fraction of time during construction when unspent money is subject to inflation.

The basic cost in $/Kw for the base year (1978) is denoted as Y, which represents years elapsed between the base year (1978) and the beginning of construction. Yy denotes construction time in years. Ig is calculated as 1+ ig, where ig is the average yearly inflation. Tye 7 14 refers to iggy, where gg is the average interest rate during construction.

The area under the normalized cumulative cash flow curve during construction is represented as 2. K includes other costs which encompass site variations from the "Middleton" site, port, unique coal handling facilities, coal storage, and other site-specific costs evaluated at the base year (1978).

The $ type curve of cumulative cash flow must be defined. For the type of curve defined in Wash 1345 (7), it is approximately 422. Various type $ cumulative cash flow curves are given by Budvani ©, so extreme fluctuations can be expected in the values of "a."

In a case study of the coal plant for Puerto Rico projected to begin operation in 1985, the short construction period proposed gives a $ curve with a value of "a" of approximately 0.48. For a straight line approximation of cumulative costs, "a1" is 0.5.

Evaluation of Basic Capital Cost, Co Plant with FCD System Co will depend on the size of the plant and will use the conditions already stated as a basis for the coal plant cost equation. Wash 1345 provides the cost of a 1300 Mwe coal plant under various assumptions using 1974 as the base year. The estimate, excluding escalation and interest during construction for a plant with SO2 wet scrubbers, was inflated at 8% per year to match 1978 prices.

A cost of $410/net Mwe was calculated for a first unit plant based on the criteria established here. Five dollars per kw (1974 prices) were credited to the natural evaporation tower to account for forced mechanical draft cooling. A 5.9% auxiliary power estimate was determined from Wash 1345 (Figure 3.1.4). The cost 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.

AY20D09 29MM 55019 Word as I saw S4U0/d 48M0d paid 1009 41120009 Homebase2W $8019 Jo UoHOUNY D SD JeMog saJ40))1xnNY era old for ENERGY REQUIRED BY AUXILIARIES

Recent unpublished studies performed by United Engineers and Constructors (UEC) 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 BE escalation for 1 1/2 years (mid 1976 to 1978) were determined to be $524/kW for a 1252 MW net (1309 MW gross) coal plant, and $597/kW for a 1279 MW 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 MW plant equivalent to $495/kW. It is assumed that these are gross kW. An additional 62 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).

Ksopp, Hansen, and Destefanis estimate a cost of $800/kW for a 20 MW coal plant based on 1976 costs. 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. 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 cost plant, 7.9% auxiliary power is estimated (including 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 million (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 FOD system. The total cost estimate was $281 million which agreed very closely with the first estimate of $282.18 million. If $2 million is added for land rights, the total estimated cost is $283 million. The total unit capital investment cost is then $683 per net plant Kw output. Publication ORAU/IEA (M) 76-3 was examined for data on capital charges of a 1000 Mwe coal plant. 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. CAPITAL INVESTMENT FOR COAL PLANTS BASED ON COST ASSUMPTION OF COST EQUATION (1 unit ~ 1978 cost - $0, removal wet cooling tower) Net 164 Cost/Net Kw Main Reference 20 800 a as 683 a 796 397 9 11000 573 w 1150 526 10 has 534 9 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 = 795.95 * e^-00003428
Where: c = base cost in $/net Kw, 1978 dollars
Mi = plant size in megawatts
The total capital investment cost c for a coal plant is, therefore, given by the relation: c= [x + 795.95 e^-0.000240m | [rf t or, tye 2] ©
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. 1-13

FIG.3.1.41 Coal Plant Basic Cost Investment Equation with FGD 9007 i @ 10 a 300] 1978-$7KW Investment Cost, co » 00k System. Least Square Fit Co* 795.75 e~0.000341005 NW 7240.99

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EPRI-PS~ 666 -SR- June 1978

00 190 oo 700 7305 7200 7700 Megawatts

POD 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 UESC 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 MW (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" describes costs escalated to 1978 at $2/year as follows:

200 MW units $79/kw
500 MW units $54.8-61/KW
1000 MW units $46.5-7/KW

These latter costs are too low when compared to recent UESC and EPRI estimates. The recent UESC 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 MW and 856 MW 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 MW plants ($85-155 $/KW).

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

Associates have made some preliminary estimates of marine facilities for Rincon. Figure 3.1.6 is taken from the Van Nouten 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 MM 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 Rincon at $84 million dollars. These will be the same for all alternatives at the same site and so they will not be considered.

Figure 3.1-6

10.0 COSTS 70 & = 8 = = § = = 3 & = % $ 5 . & § 5 3 2 . 5 8 z § 2 = = = FS § g 3 5 30 20 | penry EO 16 20 76 %o 30 706 “120140

SIZE OF MAX, VESSEL UTILIZED (MDWT)

RINCON STATION MARINE FACILITIES OPTIMUM COAL CARRIER SIZE (max. throughput rate = 3.6 x 108 Long Tons/Yr.)

1976 Van Nooten Associates, Inc.

Waste Disposal System

The Rincon site does not have sufficient space for disposition of the FGD sludges, which instead must be treated and trucked away. The Authority only owns 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 sludge stabilizing facility located.

At the electric plant site, adding will approximately cost $15.00 per gross kW capacity or a total of $6,750,000 in 1978 dollars (18 195 20, 215 22). The sludge stabilizing plant, which is needed to change the sludge of sulfur removal characteristics from thixotropic (quick-sand) into a hard material with acceptable structural load-bearing properties for landfill (2 tons per square foot), includes miscellaneous equipment such as a pump house, six tanks, silos for chemicals, flush water tanks, transport pipes, etc. Various proprietary processes such as Synearth (Dravo Corp.), Tech IV Conversion System, and Chenfix (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. Other costs could be defrayed on a yearly basis as the operation requires. Because of environmental impact consideration: 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:

1) Six hundred acres at $4000 per acre: $2,400,000

2) Impounding at $703 per acre (575) (20) (703): $8,084,500

3) Environmental control: clay or synthetic lining of pond area and drain control at $30,000 per acre: $18,000,000

Total: $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 more detailed analysis than this work can provide. We feel that such study will have to be complete enough to include cost estimate made by VESC 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 created, should be understood as simply as possible because of the assumption that it is not a viable alternative for Puerto Rico. In summary, the additional cost due to f. 815/kw is $6,750,000 K.

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 Rincon:

- K, pore '84,000,000.00
- K, elect. facilities
- K, waste disposal plant 6,750,000.00
- K, taxes ‘Tora. 390,750,000.00

3.1.7 Cost Adders for the Specific Site at Aguirre

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.

- K, electrical facilities
- Waste disposal system same Rincon Site (see section 3.1.6) 6,750,000.00
- Taxes, permits, fees, etc. $153,750,000.05

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

3.1.8.1 Fixed charges Considerations

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 text should be revised as follows:

The argument against the inclusion of a 'plant depreciation factor' in the economic comparison of alternatives is based on the requirements of PREPA Trust Indenture. This stipulates that electricity rates must cover the cost of interest plus amortization, along with a straight-line depreciation of the investment. This provision helps to accumulate capital to provide an adequate safety margin for debt repayment. Such a safety margin, also known as "financial coverage" of the outstanding debt or simply "coverage", is calculated by dividing the net revenues (revenues minus all operating expenses) over a specific period (e.g., one year) by the committed periodic (or yearly) payments of the debt (Debt Service). The ratio should be at least a minimum of 1.5, which is typical for most public corporations. The greater the coverage or safety margin, the better the financial position of the corporation, leading to better market conditions and lower interest rates for future bond issues.

3.1.8.2 This explains the reason for including a depreciation factor in the evaluation of economic alternatives. The other viewpoint suggests that the addition of a plant depreciation factor should only be considered once the lowest-cost alternative for the public has been identified. In making an economic comparison of alternatives, the choice should be based on 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 can result in a double depreciation, which creates an equity or "gain" for the public corporation. If this is included in the economic comparison, it may lead to the selection of an alternative that does not represent the lowest cost to consumers, even though it could offer the best equity build-up for the corporation. Therefore, the economic comparison of alternatives should exclude the depreciation factor. Only after the lowest-cost alternative is selected should the depreciation factor be considered in making a cash flow study.

Money and financial requirements of the corporation are used to determine the "coverage." Other governmental policies and financial considerations should then be taken into account in the analysis.

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 in advance. The scheduled outage rate for maintenance purposes (4-6 weeks per year) and any necessary modifications, as well as the statistically determined forced outage rate from historical records indirectly determine 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 minimum total cost is the preferred alternative from an economical point of view. The units with 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. Capacity factors for coal power utility records are strongly biased to a lower value due to the presence of lower incremental cost units such as nuclear and hydro units. 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. Komanoff's results have been highly controversial.

Hohenener, Goble, and Fowler present interesting results using the Komanoff statistical analysis. It is an observed fact that the forced outage rate of the generating units increases with size and complexity. The expected capacity factor for a coal plant over its lifetime should average 75%, irrespective of the plant size. This is important for the purpose of developing baseline costs.

The text with the corrections is as follows:

Puerto Rico has commercially available alternatives for comparison with new alternatives requiring R&D efforts, and this simple assumption is adequate. Station performances are also reported in "20th Steam Station Cost Survey" in Electrical World, November 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 75.2 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. = ORF + Ins.
The annual cost in mills per kWh is then (C * F.C. * 1000) / (8760 * CF), 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 PCD system) is given by: Total Investment Charge = (295,950 * 0.00032 * 4) / (8760 * CF)

EPRI-PS-800-SH 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 Example of Investment Charges
Calculation of a 450 MW Gross Assumed Interest Rate = 9%/Yr.
Plant Life = 35 years
Capital Recovery Factor (CRF) = 0.094636
Fixed Charge Rate (CF) = 0.098636
Assumed Capacity Factor = 75%
y = 1 year
% = 6 years
co = 683 $/kWh
K = $90,750,000.00 = 219.2 $/kw

1.09 a = 0.48 (refer to the end of section 3.1.3), 4a2 ex = 2.88, 2.08 = 1.373, 2.09 = 0.88, 1.282 = 10985. Capital Investment Cost: © = (683 + 219.2)(1.373)(1.282) = $1588.06/k0. Cost in mills/kwhr (1985) = (1588.04)(0.098636). Fixed Charges = 23.8 mille/kwhe. The corresponding figure for net capacity is $691/KW which only adds 0.25 mills to the levelized cost.

Goal Fuel Costs for Puerto Rico Generation: 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 (28) rate than normal. 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 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 to spot market purchases, which are influenced by short-term market variations.

Coal prices will also respond to changes in production and transportation costs. Due to high transportation costs, coal has been, until now, a regional type of fuel. OPEC action has accelerated coal's consideration as a non-regional type of fuel. 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.

The six percent (6%) inflation rate on transportation charges should be more accurate. (29) The indicated inflation 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 among 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 are excellent and investigations from various suppliers to assess coal costs to Puerto Rico are underway. (+ 22) (Page Break 3.1.9.18) PREPA Consultants have performed recent detailed summary of these investigations. TABLE 3.1.9.10 presents 1977 Delivered Coal Prices to P.R. (per short ton): W. Virginia, Wyoming, Illinois, Alabama, Colombia, South Africa.

6.70 22.28 29.00 - Rail Transport. s/t 9.18 9.65 2.75 4.98 - River Transport. st 6.28 4.50 - Ocean Transport. si 8.45 8.96 10.78 9.89 — TOTAL $/T 43.98 31.45 40.31 43.87 29.27 - BTUs/T 26.00 17.00 22.00 26.00 21.68 - $ per BTU 1.69 1.85 1.83 1.69 1.35 'Prices not considered reliable m2.

3.1,9.1b Burns and Roe Coal Price. Budwani 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 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 3.1.9.1 AVERAGE COST OF COAL BURNED BY ELECTRIC UTILITIES DURING 1972-77 PERIOD Cents /million Btu of fuel Value content. 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.

Recent cost estimates by VESC for high sulfur and low sulfur coal indicate the following costs:

TABLE 3.1.9.16 JULY 1976 DELIVERED FUEL COST TO A U.S. MIDDLE-TOWN SITE (wet) Western Low Sulfur Eastern Hi Sulfur Combet County, Wyoming Saint Clair County, Illinois Mine ($/T) 6.43 19.00 Transp. ($/T) 20.43 3.19, TOTAL ($/T) 26.85 28.19 - BTUs/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 3.1.9.1b 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 dollars) within the United States can fluctuate between $1.35 - 1.65/MMBTU, excluding the overseas transportation costs. Indicated costs for Southern based prices within the United States can vary.

African and Colombian coals look rather low even after the overseas transportation costs are added. A serious

Economic analysis cannot be based upon foreign costs, which could change unexpectedly because they do not have a real pricing basis. Therefore, it will 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 3.1.9.18 Coal Cost Assumptions (1977 base ~ $1.70/MMBTU) Escalation: 7 1/4%/year. Coal Type: Alabama and West Virginia. 1978 Base: $1.82/MMBTU.

(Page Break)

9.2 Levelized Fuel Costs in Mille per Kwh

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. The analysis for calculating the levelized fuel cost is derived in Appendix F.

The levelizing factor L can be expressed as:

GQ(tor-r) | tae ne Gem rare a+

Where:

n= number of years (usually plant life time) for levelization
A= 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 = i-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:

y a saea" Pe) (HR) (1 + 1+m"-1 | say) / 1000

Where:

Pe= coal price in dollars per MMBTU for base year, 1978
HR= plant heat rate in BTU/kwhr
Y= number of years.

Years between the base year of estimate and the beginning of commercial operation: 1-33

3.1.9.3 Example Calculation of Fuel Cost for PREPA 450 MW Plan

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

Value of Pe: @ 3) 1978 base year fuel cost at $1.82 per MTU determined in Section 3.1.9.4, carrying charges on coal stockpile 3 month stock equivalent to 1/4 ton in stock per ton burned at 10% carrying charges equals 1/4 ($1.82/MTU) (0.10) or 0.0655 $/ton.

Pe HR “e FL = $1.87/@re = 10,000 Btu/kWh Heat rate of a 450,000 MW Plant operating at 73% Load factor (12) = 7.25% (escalation between 1978 and 1985, X'per year) = 35 + 9 (PREPA cost of money) = 5% (total average yearly escalation rate 1985 = 2020). = 0.038095, determined from the relationship of r, i, u = 7 years (1985-1978). = ($0.87/10,000) (1.0725)^7 . (1.038095)^35 = 1 7,000 (0.638095) (1.038095) 35 + (0.09) (1.09)^35 cost = ($0.81) = 56.11 $/MWh

3.1.9.4 Operating and Maintenance Costs for Coal Plant with OD 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 on the ORNL publication “A Procedure for Estimating Nonfuel Operation and Maintenance Costs for Large Steam Electric Power Plants” 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.

Section 3.10.1 and 3.1.10.2: Insurance and fees are a function of plant investment. Administrative and general expenses are correlated with total fixed costs.

Yearly O & M Plant Staff Cost: The annual O & M cost of the plant staff is determined from the following relationship:
TSC = Total Staff Cost = M x Pm (1 +e)
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.
e = Average annual escalation rate for the utility, x/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.

Fixed and Variable Maintenance Costs:
a) Fixed Maintenance - The ORL correlation studies indicate that approximately 75% of the total maintenance material cost for 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.

TABLE 3.1.101 STAFF REQUIREMENT FOR COAL-FIRED PLANTS WITH FGD SYSTEMS.
400-700 MW(e) Unit___707-1300 MW(e) Unit
Units per Site for each are as follows:

Plant manager's office - Manager: 1, Assistant: 1
Environmental control, Public relations, Training, Safety, Administrative services, Health services, Security: 1 each.

Operations: Supervision (excluding shift): 3, Shift: 4, Fuel and limestone handling: 12, Waste systems: 13.

Maintenance: 8, Peak maintenance annualized: 33.

Technical and Engineering: Waste: 1, Radiochemical: 2.

Instrumentation and Controls. There are 238 performance reports, with the 47th being technical. Subtotal is 923. The total is a range between 252-396-423 to 524-259-345-440-537.

TABLE 31.10.13

STAFF REQUIREMENT FOR COAL-FIRED PLANTS WITHOUT FGD SYSTEMS (400-700 MWe) Unit and (701-1300 MWe) Unit.

Plant manager's office: 1 Manager, 1 Assistant, 4 staff members.

Environmental control: 1 staff member.

Public relations: 1 staff member.

Training: 1 staff member.

Safety: 1 staff member.

Administrative services: 4 staff members, 15 in 2013, 12 currently.

Health services: 1 staff member, 4 in previous years, 4 currently, 2 incoming.

Security: 7 staff members, with 8 incoming.

Subtotal: 22 staff members.

Operations Supervision (excluding shift): 2 staff members, 4 incoming.

Shifts: 45 to 50 staff members, fluctuating to 60.

Fuel handling: 2 staff members, 1 incoming, 2 current, 2 outgoing, 8 on stand-by.

Subtotal: 50 to 64 staff members, fluctuating to 78.

Maintenance Supervision: 6 staff members, 8 incoming.

Crafts: Range of 78 to 90 staff members, fluctuating to 110.

Peak maintenance annualized: 326 to 496 staff members, fluctuating to 128.

Subtotal: 113 to 160 staff members, fluctuating to 204-248.

Technical and Engineering Radiochemical: 2 staff members, 3 incoming, 4 current, 6 outgoing.

Instrumentation and controls: 2 staff members, 23 incoming.

Performance, reports, and technicians: 2 staff members.

Subtotal: 6 to 9 staff members, 4 incoming.

Total: 24 to 271 staff members, fluctuating to 336-404.

The fixed portion of the maintenance cost of the mechanical draft wet cooling tower has been calculated to be $30,600.00 (in 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.

Fixed maintenance cost = [(0.75)(0.45) 180 + $20,600.00 + additional cost] + 0

Where:

TSC = total staff cost

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

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

Variable Maintenance

The variable maintenance cost is comprised of the remaining 25% of the total maintenance materials, plus the additional staff cost.

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 power generation and has been figured by the United Engineers and Constructors to be 0.0049 mills per kWh at a constant plant load factor of 80% (1978 dollars). The total variable maintenance cost is therefore given as: Var. maint. cost = [(0.25)(0.489)(0.50) + 1000 rene + 80% + (0.62 CaSO)] rate.

Fixed and Variable Supplies and Expenses
1) 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 gas records, contract services, etc., and is proportional to the net addition KW rating. The equation for this cost category is: Fixed cost = (Per unit cost) (Ku)(1 +e). The per unit cost for a coal plant has been determined as $1.30/kW (1978 dollars).

2) 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. Limestone represents an attractive low-cost local resource. Approximately four tons of limestone are required for every ton of dry sulfur content in the coal. A combined five tons of dry sludge are mixed with an equal weight amount of water to produce ten tons of wet sludge. If P1 is the price of limestone in $/ton and P2 is the disposal cost of a ton of wet sludge by trucking (excluding layering and compacting in the landfill operation), then the variable supplies and expenses for the SO_2 removal system are evaluated as follows:

Var. cost for SO_2 removal = “ST1(4P1 + 10P2) x (8760xCF)
where:
CF = capacity factor
S = Per unit sulfur content in coal (2/100)
T1 = coal firing rate of the boiler (tons/hr)
P1 = Cost of Limestone

($/ton) A Page ~ Cost of sludge disposal ($3/ton) Insurance for fossil fuelled power plants in Puerto Rico only covers property, which is a function of capital investment. The 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 of 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.

3.16105 Administrative and General Expenses (A&G)

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

TSC = Plant State Cost
FIXMAT = Fixed portion of maintenance
FIX S&E = Fixed portion of supplies and expenses cost
ATSC + Differential staff cost required for the FOD system

3.1,10.6 Summary General Equation for O&M with FOD system

In summary, we have the following set of equations:

Fixed S&E = [eso an) a+ 0
Var. S&E = [£79 GP} + 10Pg4) (8760) (cF)] (1 + &)"
A&G Expenses = (0.10) [TSC + Ats¢ + (0.3375) TSC + 30,600 + (0.32) (ATSC) + (1.30)KW)] (1 +e)"

Adding and combining we get:

Total O&M Cost with FOD System = /1.584) (TSC) + (2.133) (ATSC) + (4.9 x 10°6) (Cewne)(0.80)+(S) (Z_) (4P1 + 10%y4) (8760) cF + (1.43) Ga) + 35,966) + ey

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

O&M cost (FOD Syst.) = [(2,133) (TSC) + § T,(4P,+10P—Q)x (8760) ¢cF)] (ae)

2.1,20.7 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, should be included so that it can be added to the fine 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 w is used for the O&M charges. The levelizing factor is repeated here as: BeGemta. Saerar a where: ro oeieu ee = 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 O&M charges (mills/kWhr) = O&M cost per year.

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 $26,000.00 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 SO2 removal system is 38.

SC = ($24,000.00) (214) = $5,236,000.00
ATSC = ($24,000.00) (38) = $ 912,000.00

Assume: Py = Pug = $5.50/ton, ce = 152, oo % = 200 tons/hr (based on 9,800 Btu/kWhr heat rate and 11,000 Btu/lb coal), e = year Y = 1985 - 1978 = 7 years.

Total O&M cost = [(1.584)(5,136) +42.133) (912) + (4.9 x 10^6) (430) (8760)(0.80) + (0.03) (200) (14) (5.50) (6.760) 0.75) + casas caey + 33.08]00)%C.057 = $23,666,000.

The 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 office personnel work on 8-hour shifts. 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's working day equivalent to 9 1/2 hours. They get extra pay equivalent to 26.7% of their salary. In addition, all holidays worked are paid at a double rate and substitutions for absent and sick employees add to the overtime pay. Cancelled meal times are also included.

Due to emergencies, pay is at a triple rate. Evening and night 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 x 109 kWh. The total O&M cost in mills/kWh levelized for the 35 years plant life using the same levelizing factor fuel (1.81, inflation factor of 5% per year during plant lifetime and i at 9% per year) is then:

Total OM Cost = 23.656 x 10^9 / 2.71998 x 10^9 * 1.81

Total OM Cost = 16 mills/kWh

For operation in 1985, the first year O&M cost is 8.70 mills/kWh. O&M costs included above are 3.14 mills/kWh for the first year of operation (1985), and 5.68 mills/kWh 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:

Ratio of O&M cost to Plant staff cost = $15,130,065 (Plant without FGD System) / $6,136,000 = 1.08

Ratio of O&M to Plant Staff Cost = $23,666,000 (Plant with FGD System) / $6,136,000 = 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:

Cost of plant with FGD / Cost of plant without FGD = $23,666,000 / $15,130,085 = 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 plant are...

The coal plant (Rincon Site) operating at a 75% capacity factor and equipped with a POD System, with a 9% cost of money and a 5% total inflation for cost levelization in fuel and in O&M, has the following costs: Capital charges are 23.8 mills/kWh, while the fuel cost is $6.11 mills/kWh. The O&M cost is 16.0 mills/kWh, totaling to 95.9 mills/kWh (1985 start-up). The escalation at 5% per year for all these costs is shown in Table 3.1-11.1.

TABLE 3.1.111: 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: 959 | 1224 | 1562 | 1994 | 2545 | 3248 | 4145 | 5290

Using an inflation factor of 7 1/4%/yr. beyond 1985 for fuel and O&M, the levelizing factor is L = 2,508. The 1985 cost changes as follows: Capital charges are 23.8 mills/kWh, Fuel Cost is 17.16 mills/kWh, and O&M cost is 22.07 mills/kWh, totaling to 123.63 mills/kWh.

Table 3.1.1.2 indicates the levelized total costs for different start-up years.

TABLE 3.1.112: 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: 1237 | 1755 | 2491 | 3535 | 5016 | 7117 | 10099 | 14931

Fig. 3.1.11 shows the total levelized cost for a coal plant with POD system, considering plant investment escalation from 1978-85 at 6%/year, with start-up year 2020.

Here is an example of a two-unit, 450 MW coal plant at Rincon with a POD 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: shared port facilities and other site developments, economies in design, engineering, and construction if the units are constructed simultaneously 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 \$384,000,000, waste disposal plant at \$15.00 per gross KW \$13,500,000, totaling \$397,300,000.

K+ 97,500,000 = 117.8 \$/KW
C= (K+TC0) Tp TO) 2 tye 2%

For 1985 operation, with Ty = 1.08, Tye = 1.09 = (649 + 127.8)(1.373) (1.262) = \$1349.71/KW

Fuel Costs: These vary linearly with output and therefore no economies result from a two unit plant. With a 5% escalation rate after 1985, Fy = 56.21 mills/KWh. With a 7.252% escalation rate, FL = 77.76 mills/KWh.

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 is 65 staff for the SO2 removal.

Total O&M Cost = \$21,052,061 (1.08)7 = \$36,079,533

Generation at 75% CF = (828,000 x 0.75 x 8760) = 5.43996 x 10^9 KWh

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

Total O&M Cost = 35.080 x 10^9 x 1.81 = 12 mills/KWh

The costs during the 35-year lifetime of two 450 MW unit coal plants at Rincéa with 75% capacity factor, FGD System, 9% cost of money, 5% total inflation for cost levelization are:

Capital charges = 20.3 mills/KWh
Fuel Costs = 56.11 mills/KWh
O&M costs = 12.0 mills/KWh

Total 1985 Cost (Levelized) = 88.41 mills/KWh

Table 3.1.12.1 shows the levelized costs for the two unit coal plant at Rincéa with different start-up years and a...'

5% inflation rate applies to all costs beyond 1985.

TABLE 3.1121: LEVELIZED TOTAL COSTS FOR PLANT START-UP IN THE INDICATED YEAR 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 Mill$/KWhr: 88.41, 112.84, 144.01, 183.90, 294.60, 299.39, 362.10, 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 mill$/KWhr
Fuel Costs = 77.76 mill$/KWhr
O&M Costs = 16.63 mill$/KWhr

Total 1985 Cost (Levelized) = 114.69 mill$/KWhr

Table 3.1.12.2 indicates the levelized costs for the two 450 MW units plant at Rincéa with different start-up years and a 7.25% inflation rate for all costs beyond 1985.

TABLE 3.1122: LEVELIZED TOTAL COSTS FOR A TWO 450 MW UNIT COAL PLANT START-UP IN THE INDICATED YEAR WITH A 7.25% PER YEAR INFLATION RATE BEYOND 1985

Start-Up Year: 1985, 1990, 1995, 2000, 2005, 2010, 2015, 2020

Levelized Cost in Mill$/KWhr: 114.69, 162.75, 230.94, 327.71, 465.02, 659.87, 936.36, 1928.71

The 450 MW Unit Coal Plant with FOD system has an investment escalation from 1976-85 at 82% per year. The coal escalation from 1978-85 is 7.25% per year, and the O&M escalation from 1978 and beyond is 9% per year.

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

3.2.2 Nuclear Plant Capital Investment

Appendix D contains detailed capital investment information.

Cost estimates for nuclear plants. Various cost estimates are presented for nuclear plants as follows:

(1) New 585 MW nuclear plant at a site in Northern Puerto Rico. The source of direct cost data estimate is from PREPA Consultants, and the source for estimating costs of engineering services,

construction management, and other indirect costs is from UESC. The unit cost is: $775/MW

(2) New 585 MW nuclear plant at a site in northern Puerto Rico. The source of data is PREPA Consultant Engineers in its entirety. The 1978 unit cost is: $894/KW

(3) NORCO Unit 1 reactivated for operation in 1986. The source of data is PREPA consultant in its entirety. The 1978 unit cost is: $817/KW

(4) 1139 MW PWR Nuclear Plant at a site in Puerto Rico. The source of data is United Engineers & Constructors-NUREG-0241. The 1978 unit cost is: $685/kW

(5) 1190 MW BWR Nuclear Plant at a site in Puerto Rico. The source of data is United Engineers & Constructors-NUREG-024234. The 1978 unit cost is: $670/kW

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

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

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

- The Institute for Energy Analysis: 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 3.22 - NUCLEAR PLANT COST ESTIMATE (ORAU-76-3) in Dollars of 1985 and Dollars of 1978 (1985 costs deflated at 8%/yr):

- United Engineers & Constructors: $980 (1985), $554 (1978)
- Bechtel: $1030 (1985), $601 (1978)
- Sargent & Lundy: $1005 (1985), $586 (1978)

General Electric 953 556, Skagit, Washington, 1030 601, Tyrone Park, Wis., (BOOMW) 816 535, Carrot County, 2nd, 686 400 Davis Besse (906M) 865 505, Greenwood 2nd 3, Mich. 820 479 (2x 1200 MW) meters?

The UEEC cost estimate presented here was the result of Mr. J.H Crowley's statement to the Connecticut State Public Utility Control Authority on January 29, 1976. These UESC estimates have since been superseded by later detailed costs by UESC presented elsewhere in this report. The estimates presented in Table 3.2.2a appeared to be on the low side and will not be used in this study to estimate nuclear plant capital costs. The 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.(0) CAPITAL COSTS ESTIMATES (1978 DOLLARS) $/KW Source and Date, 508 PRWRA (2) - 1979, 685 UESC - 1979, 670 UESC - 1979.

Exponential Fit (500-1200 MW): $/MW = 11825*0.000478*68

Figure 3.2.2 presents the plot of the nuclear plant investment cost equation. The general cost equation can be expressed as: © = 82g*0.0004781*yp*t+Clea)*Wp*1, ap mmrs8.

1978 Capital Investment - Nuclear Co, 9007 GT, PRWRA consultants estimate, Fig.3.2.2 Capital Costs Nuclear Plants 1978 dollars, Georgetown consultants, OT PRWRA-UE &C-CEER, This Study Co*nez ¢~.000470 MW, 700 UE a C-CEER NUREG 241-0242.

Where Te, Tyg, Yys, Yps, and a are defined in Appendix E. K are the plant cost adders not included in Co. The cost in mills per kwehr is given by: mills/kwhr = (C) (CRF) (CECA), 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 MW plant, 1985 at a north coast site in Puerto Rico - y= 0 as ue, y= 0.7, y= 1.08, CRF = 0.098636, Tye = 1.09, ce = 0.75, co.

$894/twr (1978) YtG-a¥y, = 3.64 at = 3.36. The investment cost for 1985 is calculated as follows: (894) (1.08)2 + (1.09)3 + 36 = $1580.35. The cost in mitte/evie = (1580-35) (2098636) = $95.75.

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
Fuel Fabrication, Reactor Mining, Interim Spent Fuel Storage, Permanent Wastes, Waste Disposal.

Uranium is widely distributed in nature at very low concentrations, in the order of 2-4 ppm in the earth's crust and .003 - .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, with some as high as 0.75%. The mining costs are inversely proportional to the ore concentration.

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

The yellow cake at 85% U_3O_8 concentration is the normally available source of uranium in the open market. In 1979, the cost of yellow cake was 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 in predicting future uranium costs. This will be considered later.

The uranium cake purchased from various private suppliers must be sent to government plants for conversion to UF_4, a green salt. This material is suitable for use in gaseous diffusion plants, where the UF_4 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 of around 3% for use in light water.

Reactors (LWR). The depleted uranium tails normally contain 0.22 of the valuable U-235. Charges for conversion are made in terms of dollars per Kg of EG. Charges for enrichment are made in terms of dollars per SWU (Separative Work Unit). 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 approximately 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 prolonged irradiation. Its melting point is close to 5000°F. It has an acceptable thermal conductivity coefficient. It exhibits a significant 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 importantly, 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. 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 reshuffled 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 MWD/MTU. 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 MWD and will require an uranium loading of 13.6 MTU. 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/MTU are typical for BWRs. The discharged spent fuel elements are stored for a cooling period.

Spent fuel is stored for a period in a fuel pool designed specifically 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 for Bechtel for the design of a $3 billion nuclear waste solidification facility at DOE's Savannah River Plant near Aiken, SC. 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 temporarily store all the spent fuel element assemblies discharged during the lifespan 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. UESC estimates 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 to be $8,700,000. The problem of spent fuel disposal is not an insurmountable problem.

3.2.3.2 Nuclear Fuel Unit Cost

A lengthy 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. 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 coefficients obtained for sensitivity analysis.

The degrees of freedom for the purposes of this study are not discussed. The coefficients to be used in this study only apply to light water reactors and are more exact for pressurized water reactors. The average heat rate of the nuclear plants is considered to be in the 10,200-10,300 BTU/kwhr net range.

Range. Fuel burn-up of the order of 30,000-35,000 MWd per ton of uranium are typical of these types of plants. The fuel reactivity calculation of accuracy is good enough and cost coefficients are good for equilibrium cycle costs. The small first core increased cost is neglected. The following are the cost components (CaPy) and coefficients (C,) as determined from sensitivity analyses:

(1) 30g (Yellow cake) cost component (C1Py) 30g: $/M@TU = .00673 x U3O8 Cost in ab.
(2) UF6 conversion cost component (C2P,) Fg: $/M@TU = ,005696 x Conversion Cost
(3) Separative or enrichment cost component (C3P) Enrichment: $/M@BTU = .00166 x (S/sw)
(4) Fuel fabrication cost component (C4P,) Fuel Fabr.: $/@@TU = .0909174 (Cost of Fabr.)

(5) Spent fuel shipping and disposal (C5P5) (SSP): $ = 0003957 x (Cost of SSP)
(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 Y.
(b) Charges for other non-operating periods of time which can be considered approximately constant on the average. This cost will be designated My. The indirect charges during operation My can be expressed as: (49783 My = CATER. Capacity. Cost + Y + Costs + 02) 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: My = (628)(T9) (G) » (C1Py + C2Py + C3P + C4P + C5P5) where T, = time in years required for ordering U3O8, and UF6 enrichment. It can be taken as 1.5 years.

The factors of .48763 and 0.25

The text should be corrected as follows:

The text should provide adequate leveling of fund expenditures during the respective periods considered. The total fuel costs in $/MMETU can be expressed as: Fuel Cost Equation Total Cost $/MMETU = CP, + 2 3.2.3.3.

Cost Component Estimates

(a) Yellow Cake U3O8 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 mean exploitation of less economical (more diluted concentrations) uranium deposits, and therefore, higher costs. Table 3.2.3.3.4, taken from the EPRI report, indicates predicted uranium demands.

Table 3.23.3 (a) Uranium Requirement Estimates* (U3O8 ~ 1000's short tons-2% tail)

No Recycle:
1980 170
1985 278
1990 408
1995 680
2000 983

*Based on 5.2 x 10^5 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. An extensive survey of the literature was performed for cost predictions. A tabulation summary of the cost survey is presented in Table 3.2.3.36.

It should be pointed out that the references, 29-PREPA consultant S.M. Stoller, McRPRT, and 38-PREPA, are all based on the same source, namely S.M. Stoller. 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 estimate will be provided, which will be higher than any S.M. Stoller based prediction. These predictions are considered safe and conservative by the nuclear industry.

Table 3.2.3.36 illustrates the cost analysis of the nuclear fuel result for this study.

Following the mentioned procedure. 11-69

Procedure areas are as follows: A199; 268, 30, E8AE; substantially used 09 out of TR3M S142 “(aya) Tev6N Kneey 30 voa/pmHOOONE is IE Forge Menansay “nteibt 400 s2H9> 12° Jo oBse4> you've seen H3se0 AUTTO\IN apparently MLMIDIVE.

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US OG Price (dollars /pound) 40 200 400 600 800 1000 1200 1400 1600 1800 2000 Cumulative Production (thousands of short tons) Figure 3.2.3-3 USQG Projected Price Based on Production: Costs In End-of-the- Year 1977 Dollars

SOURCE: EPRI P5a866-58 5 Special Report. Technical Assessment Guide, June 1978 (14) * Guides NR71

TABLE 32.3.3 (c) NUCLEAR FUEL COSTS — PRESENT STUDY TT 1985

Fuel Costs: Estimated Unit Costs Calculated $7/MMBTU ‘Ore Cost $ 61.50 ata Conversion $ 3.06 0.017 Sep. Work $/SWU 127.87 0.212 Fuel Fab. $/lb 87.00 0.80) Subtotal : 0.723

Spent Fuel Ship & Disp. 190.00 0.075

TOTAL cost: 0.798

Indirect Charges (1) Operational time(MA) 0.042

Suspension time severity avg. (1) 75% plant capacity factor is used. (75% plane capacity factor is us)

The cost in mills per kWh can be expressed as (sheer y Giese Rate) () Escalated and levelized fuel « Fasslated and levelized fuel costs

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

Mr-72

Nuclear Fuel Cost in dollars per T@TU + [orrrareye) 1985 year + 1985 1 [Goratearavcarascsesong) case) * @ year

Year = year of estimate

">1985" Escalation for yellow cake, average per year = levelizing factor for yellow cake = general escalation for material and labor = levelizing factor for material and labor = Pa PH

Example calculation of fuel cost levelization:

Let Y = 1985 year

i = 7.25% (average yearly escalation of uranium yellow cake during plant life)
= 5% (average yearly escalation of other non-uranium ore charges, labor, materials, and services)
= 9% (cost of money)

From the above,
"Year = 0.16x2 year = Pufat.01632) = 2.508

m1-73

ro du = 0.038095
L = Pu(0.038095)_ = 1.81295 PH (0.09)

Levelized 1985 Fuel Cost = (414) (2.508) + (1.81295)(.453) = $1.86/million metric British thermal unit (mmBTU) (1985)

With a heat rate of 10,300 BTU/kWh,
Cost = (1.86)(10.3) = 19.15 cents per kWh

mr74

3.2.4 Operating and Maintenance (O&M) Cost - LMR Estimates for a Light Water Reactor Power Plant are considered here.

Operating and Maintenance Cost Equation:

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

According to the ORNL study, the non-fuel O&M costs for a nuclear 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 have been

The text should be:

The determined cost is $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, both 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 ORSL-T4-6467 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 Premium $10

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, excluding insurance and operating fees.

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

$$\text{Total cost} = [1.47 + 0.045 + 30{,}630 + (4.9 \times 10^{3} * KW * 8760 * 0.80) + 1.47 * KW + (35.6 \times 10^{-5} * KW * 8760 * CF) + 280{,}000 + 6 * MW + 100{,}000 + 0.15 * (1.47 + 0.045 + 30{,}630 + 1.47)] * CF$$

Where:

TSC = total staff cost

CF = capacity factor

c = average inflation rate of the economy per year

Y = number of years between estimate and commercial operation

Rearranging the terms and adding:

$$\text{Total O\&M Cost (\$)} = (1.6675 * TSC + 1.6905 * KW + (4.9 \times 10^{3} * 8760 * CF * KW) + (3.56 \times 10^{6} * KW * CF))$$

The corrected text is as follows:

3.2.4.2 Specific Cost Calculation for REPA 600 MWe PWR Power Plant

TABLE 3.2.4.2 STAFF REQUIREMENTS FOR LWR PLANTS (4200-700 MWe unit, 701-1300 MWe unit)

Unit personnel:

Plant manager's office: Manager | Assistant 1 | 2 | 3 | 4
Quality assurance: 3 | 4 | 5 | 6
Environmental control: Sr | Jr
Public relations: Sn
Training: 2 | 2 | 4 | 4 | 2 | 2
Safety: ee
Administrative services: 8 | 7 | 8 | 8
Health services: 2 | 4 | 12
Security: 56 | 85 | 56 | 10 | 58 | 88
Subtotal: eT

Operations (Supervision excluding shift): 2 | 2 | kk
Shifts: 2% | 4% | 68 | 85 | 56 | 8 | 10 | 8
Subtotal: 2 | 5 | 72 | 2 | 3 | 6 | 85 | 82

Maintenance Supervision: 2 | 8 | 2 | 8 | 8 | w2
Craft: "2 | 2B | 1
Peak maintenance annualized: 8 | 110 | 220 | 55 | 110 | 165 | 220
Subtotal: n | 40 | 210 | 79 | 148 | att | 298

Technical and engineering:
Reactor: 1 | 2 | 3 | 4
Radiochemical: 2 | 2 | 3 | 4
Instrumentation and control: 2 | 2 | 2 | 2
Performance, reports, and technicians: 1 | 7 | at | 28 | th
Subtotal: nye | H | 2D | Ww

TOTAL: 208 | 300 | 909 | 545 | 215 | 314 | 420 | 50
Less security: 152 | 244 | 342 | 440 | 159 | 253"

Escalation 1978-65: 62%. Interest during construction 9%, except type at 7%. White site content 1985, 1990, 1995, 2000, 2005, 2010, a “plan” start-up year pre-2020.

3.2.6 Example of a 600 MW Unit LKK 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 for money, 5% per year average inflation rate after 1985, except for uranium (U308) 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 cost:

The fuel costs previously estimated for one unit are escalated from 1985 to 1986 for the second unit at 5%, except for U308, which is escalated at 7 1/4% and then averaged. Thus, the fuel costs are:

(0.424)(2.508)(1.0725) + (2.81295)(0.453)(2.05) = $1.98/million BTU

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

3.2.6.3 O&M Cost:

According to Table 3.2.4.2, two 600 MW nuclear units will have a total staff of 200, 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 Mit + 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
Bu = 1,170,000
Wie = 3570
CF = 0.75

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

24,496,330 = 5.29 attas; T70 x 8.76 x 0.75 = 719 Bills/kWh. The O&M cost, levelized for the 35-year plant life at 5% per year, is as follows: Total O&M cost = (3.19)(1.81) = 5.77 mill/KWh (levelized).

Total Costs: Capital Charges 23.67 mills/KWh, Fuel Cost, 19.78 * 0.6. The cost for 35 years levelized cost is 9.22 mill/KWh (Start-up in 1985 & 86).

Tables 3.2.6a, 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 LMR PLANT ESCALATION 5% PER YEAR (ALL COSTS IN MILLS/KWh)

Year	1995	2000	2005	2010	2015	2020
Cost	149.9	95.0	22.16	85.5	190.98	8.0

TABLE 3.2.6b LEVELIZED COSTS FOR A TWO 600MW UNIT LMR PLANT. ESCALATION 5% PER YEAR ALL COSTS EXCEPT URANIUM (U3O8) at 7 1/42% PER YEAR IN MILLS/KWh

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Total Cost	103.05	75.85	85.59	2.08	35.72	22.31	31.66	04.92
Other Costs (5% Esc.)	38.14	42.68	62.13	79.29	102.20	129.16	164.84	210.38
Total cost	49.22	64.40	80.60	120.95	246.12	192.93	255.30	538.74

TABLE 3.2.6c LEVELIZED COSTS FOR A TWO 600MW UNIT LMR PLANT. ESCALATION 7 1/42% PER YEAR (ALL COSTS IN MILLS /KWh)

Start-Up Year	1985	1990	1995	2000	2005	2010	2015	2020
Total cost	55.38	79.60	112.53	158.27	224.58	318.69	452.27	600.00

Figure 3.2.6 shows the plot of the above tables.

FIGURE 3.2.6 30000, LEVELIZED COSTS FOR A TWO 600MW UNIT LMR PLANT
Key data:
- Base Year Nuclear Plant Plane Investment Escalation 1978-86: 6%/Year
- Fuel Escalation 1985-86: 5%/Year
- O&M Escalation 1978-85: 8%/Year
- Interest During Construction: 9%/Year
- Investment Fixed Charge Rate: 9.06%/Year
- Escalation Rates Beyond 1985: Curve F 5%/Year, Fuel cost 7.5%/Year, All costs except U3O8 at 7 1/42%

TOTAL LEVELIZED COSTS (mills/kWh)
Plant Start-Up Year: 1980 - 2005

3.3 3.3.1 OIL FIRED POWER

Plant 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 Constant Dollar Value 450? 9. 693.5 $/KW. For 1000 MW units, the cost is 6968 $/KW.

The minimum indicated cost according to EPRI varies between 694-8225/KW for 1000 MW 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 = 9.86362
3. Plant Capacity Factor = 1
4. Plant Cost Adders (K) = 0

Levelized plant capital cost in mills/kWh (693.5) (.098636) = 10.4 mills/kWh.

Fuel Costs: Among 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 have recently made some predictions for the cost of residual oil delivered at PREPA power plants.

Table 3.3.28 summarizes these predictions.

TABLE 3.3.20 RESIDUAL FUEL OIL COSTS PREPA CONSULTANTS PREDICTION

1980-1985 +1990 -1998-2000 Delivered High 16.79 36.76 63.88 7.10 117.35 $/t

Medium 16.30 28.50 50.40 69.18 91.48 $/t

Low 12.59 24.29 40.08 53.36 71.47 $/t

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

TABLE 3.3.20 RESIDUAL FUEL OIL COSTS EPRI PREDICTIONS 305% S Delivered Oil 1980 1985 1990 1995 2000, per barrel 3.08 3.13 3.23 3.4 3.89 $/Barrel

Equivalent at 6 MMBTU/BBL 18.24 18.78 19.38 20.46 21.54

It is evident that EPRI has been underestimating, 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: Cy = 0.8 + 5.0r (equation 3.3.2) where Cy = cost of residual oil in

The price of dollars per barrel is denoted as Y= year minus 1980. The coefficient of determination of fit, r2, equals 1.0. PREPA consultants' 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 3.3.28 is 10.212. 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: Cy = 25.00 + 6.50v (eq. 3.3.28). Equation 3.3.24 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.

3.3.22 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 of 9% per year prediction is much larger than the linear relationship of equation 3.2.28. It is reasonable to assume that after the year 1995, fuel oil costs will begin to escalate significantly, 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. The interest rate of money has been taken as 9% per year, therefore the 9% compounded escalation for oil seems to be a reasonable assumption.

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 equals 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: Cost mills/kw hr = O41 where L is the levelizing factor for the continuously escalating fuel price during the lifetime of the plant (Appendix).

To be continued...

Fig. 3.3.2 shows Arthur O. Little's Predicted Fuel Oil Cost (1) predictions for 1970, and (2) the actual late 1970's trend. There is a 9% per year escalation beyond 1968.

In these calculations, the interest or cost of money is 9% and the fuel escalation rate is 9 times. The result is 3.3123. The cost in mills/kWh is 57.50, 9200. The calculation (3.31 x 103) equals (68.16 x 3.312), which results in 292 mills/kwt.

The fuel costs in mills/kWh for various start-up years are shown in Table 3.3.2c.

TABLE 3.3.2 (c) OIL FUEL COSTS IN MILLS/KWHR FOR A 450 MW OIL PLANT

Start-Up Year: 1985, 1990, 1995, 2000, 2005, 2010, 2015, 2020
1st Year Cost: 88.16, 135.6, 208.7, 921.12, 494.1, 760.2, 1169.7, 1790.7
Levelized Cost: 292.0, 449.3, 691.3, 10636, 16365, 2517.9, 9874.1, 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 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's 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's statistics. 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 years.

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's 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, the cost will be escalated at the rate of 8% per year up to the year 1985.

The text appears to be a combination of data, tables, and paragraphs from a document discussing costs related to an oil-fired power plant. Here's an attempt to fix it:

"Costs per year thereafter are leveled during the plant's lifetime at $5/year, with a 9% annual inflation rate. Table 3.3.3a illustrates the O&M costs for a 2,450 MW oil-fired plant.

TABLE 3.3.3a: O&M COSTS FOR 450 MW OIL FIRED PLANT (MILLS/KWH)

Year	Inst. Cost	Levelized Cost
1965	2.78	5.03
1990	3.55	6.42
1985	4.53	8.20
2000	5.78	10.46
2005	7.38	13.35
2010	9.41	17.08
2015	12.00	21.75
2020	15.30	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 the plant start indicated.

3.3.5 Example of Total Generation Costs for Two 450MW Oil-Fired Units in Puerto Rico

In the estimation of levelized total generation costs for two 450MW oil-fired units, consideration must be given to 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) is $624.15/MW. The levelized plant capital cost is 9.37 mills/KWh.

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 92% fuel efficiency rate."

(Note: Some sections of the original text were indecipherable and could not be fixed.)

Escalation 3.3.5.3 Operation and Maintenance

The operation and maintenance costs are shown in Table 3.3.3a, with an escalation rate of 8% per year before 1985 and 5% per year thereafter. The cost of money is assumed to be 9% per year. The total operating costs, levelized for the 35-year lifetime of the two units (450MW each) of the oil-fired plant, are presented in Table 3.3.5 and Figure 3.35.

TABLE 3.3.5 LEVELIZED TOTAL OPERATING COSTS FOR A TWO-UNIT (450MW each)
OIL-FIRED PLANT (Escalation at 5%/Yr. Fuel Oil at 9%/Yr.)
Start-Up Year: 1985, 1980-1995, 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: 2920, 4493, 691.3, 1063.6, 16365, 25179, 3874.1, 59609
O&M Cost: 5.03, 6.42, 8.20, 10.46, 13.35, 17.04, 24.75, 27.76
TOTAL: 906.40, 467.68, 714.76, 1093.54, 1674.71, 2566.67, 3936.35, 6040.35

TOTAL LEVELIZED COSTS (cents/kWh) for 490MW Unit
Fuel: 0.81
Plant cost: 0.81
Balance of plant investment: 0.81
Escalation: 9.2%/yr., O&M Escalation: 1976-85, 8.2%/yr.; Beyond 1985, 5.8%/yr.
Fixed Charge Rate: 5.0%

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 5.2%/Yr. and 7.1%/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, especially 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 with cost reductions. Some of the site facilities as well as operating and maintenance personnel can be shared between the units.

TOTAL LEVELIZED COSTS (cents/kwh)

Fig. 3.41 Total Levelized Generation Costs of Power Produced by:

1. 600 MW Nuclear Unit (U_3O_8 cost at 7 1/4%/Yr.)
2. 450 MW Coal unit
3. 450 MW Fuel Oil Unit (Fuel oil cost at 2%/Yr.)

All costs escalated at 5%/Yr. beyond 1985 except Yellow-Cake and Fuel Oil as indicated in Curves I-A & I-B.

TOTAL LEVELIZED COSTS (cents/kwh)

1. 600 MW Nuclear unit
2. 450 MW Coal Unit
3. 350 MW Fuel Oil unit (Fuel oil cost at 2%/Yr.)

All costs escalated at 7 1/4%/Yr. beyond 1985 except Fuel-Oil as Indicated.

TOTAL LEVELIZED COSTS (cents/kwh)

Fig. 3.4.3 Total Levelized Generation Costs of Power Produced by a Two-Unit Plant, Each Unit Rated as Indicated:

1. 600 MW Nuclear Units
2. 450 MW Coal Units
3. 350 MW Fuel Oil Units (Fuel oil cost at 2%/Yr.)

All costs escalated at 5%/Yr. beyond 1985 except Yellow-Cake and Fuel Oil as indicated in Curves I-A & I-B.

TOTAL LEVELIZED COSTS (cents/kwh)

Generation Costs of Power Produced by a Two-unit

Plant, Each Unit Rated as Indicated:
1. 600 MWe nuclear units
2. 2450 MWe coal units
3. 3-450 MWe fuel oil units (fuel oil cost at $38/yr.)

All costs escalated at 7.48%/yr. beyond 1985 except Fuel-Oil, as indicated. 'Base Year'

SECTION 4: LONG RANGE ALTERNATIVES FOR ELECTRICAL ENERGY PRODUCTION

Section 4: LONG RANGE ALTERNATIVES FOR ENERGY PRODUCTION

INTRODUCTION: In order to address the energy situation in Puerto Rico, alternatives for electrical energy production from 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 construction schedules. Unit costs are determined from the most recent and reliable sources. Total production costs are determined and the size at which the alternatives compete economically with conventional sources is for the Puerto Rico scenario. The long range alternatives considered are:

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

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

The following sections present alternatives for energy production. One of these alternatives is Ocean Thermal Energy Conversion (OTEC). This concept utilizes the temperature difference between deep sea waters (3000 ft) and surface waters to generate electricity. It has the potential to meet all the electrical energy needs of Puerto Rico. Both ocean-based or floating type and land-based plants will have practically no impact on land utilization. It is estimated that an OTEC-10 (4-10 ¥6 module, 40 MW plant) concept could be operational within 5 years. Economic calculations are performed for the 40% 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 the second generation of plants. The purpose of building a 40 MW demonstration plant is to test the OTEC system with full size modules and sufficiently large components in order to verify the cost estimates for large scale commercial plants and thereby reduce the uncertainties involved in the preliminary cost estimates and verify the possibilities of future less expensive technical solutions. The economic evaluation follows.

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 MW land-based OTEC plant is that prepared by Deep Oil Technology, Inc. for the specific site of Punta Tuna, Puerto Rico. This estimate gives an installed cost of $5,230/kW (1980).

The design conditions of an OTEC plant depend mostly on the site's oceanographic 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 dependency, we consider the above-mentioned unit cost.

The text should read as follows:

A sum of $5,230/Ki (1980) is accurate enough for the purpose of the present study. One additional important consideration that must be addressed is the lifespan of the plant. The useful operating life of a demonstration project is usually shorter than that of a proven technology.

The life of the OTEC plant will mostly depend on the lifespan of the materials exposed to the seawater environment, especially the effects on the large-sized heat exchangers. Experience exists with structures exposed to the seawater environment, and 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:

(60,000 KH) (95,2207) = $209,200,000 (1980 dollars)

b. Yearly investment charges at 9%/yr. cost of money and 35 years operating life CRE = 0.094636 for 0.08655”

($209,200,000) (0.098635) = $20,636,651

c. Yearly energy production:

base power @ 23% (for 21°C & 7% availability factor)

#752 (49,090 ») (0.77) (0.75) (8760) = 202,356,000Khr.

4. Investment charges in mills/Khr:

$20,524,651» 10° yr9; matte (sitar (1980) i 06M

The 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 seawater, 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
2 Assistant Superintendents
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
Facility (/shift): 5
Security (1/shift): 5
Personnel Accountability: 10
Boat Operators (2/shift): 2
Warehouse Clerks: 1
Purchaser-Warehouse Sup: 1
Chief Mechanical Engineer: 1
Asst. Mechanical Engineer: 1
Mechanics: 6
Electrical Engineer: 1
Electricians: 1
Instrument Technicians: 1
Chemical-Metallurgical Engineer: 1
Chemist Assts.: 1
Technicians: 2
Janitors: 2
Painters-Drivers: 5

Security (land, 1/shift): 4
Asst. Chemists: 2
Janitor (land): 1
Gardener (Land): 1
Shift Chauffeurs (1/shift): 5
Total: 106

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 3.86.
O&M cost in 1980 dollars with an 8% / yr inflation is (21.22)(1.08)^2 = 24.75 mills/kWh.

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 MW Demonstration Plant is: 301.97 + 24.75 = 326.72 mills/kWh.

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

Contracting: 1980
Commercial Base Reference Year Operation: 1982
Design: 1985

With a straight line cash flow of construction funds, escalation before construction = (1.08)^2. Escalation during construction = (1.08)^5. Interest during construction = (1.08)^9. Investment: TBD.

"Escalation and Interest during Construction ~ Total factor = at 0% Escalation at 8% per year from 1980 to 1985 ~ (1.08)5 = 1.47. The Levelizing factor for 35 years lifetime at 9% cost of money in a 5% inflationary economy: sa + y® Tae = 1.81 where: r= source i.e Total Levelized Cost (1985). Investment Charges: (201.97) (1.47) = 297.09M. Cost: (26.75) (1.47) (1.81) = 71.18M.

The 40 MWe OTEC Plant Total Levelized Cost = 215.75 mills/KWhr (For start-up in 1985 and 35 years operation of the plant).

250 Me 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 MWe 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. Unit capacity scale cost factor can be defined as given by an equation of the following form:

f = unit cost of big plant / unit cost of small plant

Where f, and G, are the capacities of the small size and bigger size units respectively and the exponent is usually not less than 0.75. If the exponent E on the capacity scale cost equation E is less than 1 unit and usually not less than 0.75. If the exponent given before is set at 0.95, the value of f obtained is 0.95.

For comparison purposes in Section 3.1.4 for a coal plant will be examined.

The coal plant cost equation C = 795.95 + 0.0002 gives the following result for the scale-cost factor between 200 - 250 MWe:

C = 795.95*(250) ^0.95

This agrees with the previously estimated value of f. The cost in 1978 dollars of a 100 MWe OTEC plant has been estimated at $3257/KW (see Appendix 6, ref, 42), which extrapolated to 250 MWe gives $3257 x 0.95 = $3,094 per KW.

The total cost of a 250,000 K plant will be $773,500,000 (1978). The effects of the learning curve are considered next.

4.1.2 Capital Cost Learning Curve Relationship

The Learning curve effect is a function of the number of units produced. For this study, we assume we originate the following relationship: C, = where: N= unit number, Gq = average unit cost of unit 8, Cy = unit cost of unit number 1, K = constant factor independent of learning, B= learning factor cost reduction.

It is reasoned that the accumulative average production cost is reduced from the previous cost by a certain factor 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. We propose a 97.5% cost reduction for OTEC plants.

Due to the Washington et al. 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 established. Jacobson and Manley from MITRE Corporation predict three scenarios of OTEC market penetration as a function of economic incentives and development strategies. The three scenarios present total installed capacities in the United States for the year 2020 of 2246 and TL GWe respectively.

Assuming market development as depicted in the lowest scenario and the total (22 GWe) being 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 83 (assuming seven years necessary lead time) earlier. Therefore, no learning curve effect will be considered for this unit.

The 1978 cost of the 250 YWe unit for operation in 1990 is $3,094/xW. The Capital Investment Charges are calculated for the year 1990 based on the following: Fer = 0.098636 or = 158, Aux. Power = 20%, Inflation = 8%/yr, (from '78 to '85), Stiyr (from '85 to '90). Capital Investment Charges = 34084 x (0.098636) x (1.08)? x (1.0895 x (9. 75) x (0.080) x (8. 76) 08) and c = 127 units /cm.

4.1.2.3 Operation and Maintenance Costs

The operation and maintenance costs can be computed as per the 40 Mie Deno 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. Sc = (124)(24,000) = $2,976,000. The ratio between staff cost and total operation and maintenance costs for a coal plant (without F6D) is 1.72 (see Section 3.1.0.8). Total O&M Cost = ($2,976,000) x (1.72) = $5,118,720. The total levelized cost in mills/KWh using the previously defined parameters as in Section 4.1.2.2. O&M Cost =($5,118,720 x ca.08)" divided by (50,000) x (2.05) x (1.81) = 15.42 mills/KWh.

4.1.2.4 Total Projected Cost for 250 Yale 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 Mie OTEC plant are projected beyond 1990, taking into account the effects of the learning curve and the economic escalation of costs. These costs are tabulated in Table 4.1.2.4 below and graphically depicted in Figures 4.1.2.4 a 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.

Levelized Total Costs

"Of 250 MW OTEC Plant in Puerto Rico. The year indicated and 35 years operating life. TABLE 4.1.2.4 Interest during construction and escalation until 1985 at Bt/yr and 7th year or 7 2/8/year thereafter, design and construction time 7 years. Start 2020 | Step-up year 1 1990 1995 | 2000 2005 | 2010 2015 Constant cost (5/8) + | 1985 Dollars | 0.552 | 3,945 | 3,478 | 3,197 | 2,927 constant investment | | Guarantee (annual cost/sale) | | | 1985 Dollars constant) | 108 | as needed | at 0.59 | 1985 Dollars | 5,303 | 4,486 | 3,905 | 3,478 | 3,197 | 2,927 | 2,768 | | capital investment | | | 1985 Dollars | 9952 | 74.03 | 65.27 | 60.00 | 54.95 | 51.98 | revised cost control | | | 1985 Dollars

Fig. 6.1.2.408 Total Levelized Generation Costs of Power Produced by: - - Commercial Nuclear Unit 1000MW Nuclear Unit (Esc. at 7 2/42/year.) 250MW OTEC Unit. All costs escalated at 5%/yr. beyond 1985 except Yellow Cake and Fuel Oil in Curves 1 and 4 respectively.

Fig. 4.1.2.400 Total Levelized Generation Costs of Power Produced by: a commercial nuclear unit - and a 250MW OTEC Plant. TOTAL LEVELIZED COSTS (mills/kWh)

Levelized Total Costs of 250 MW OTEC Plant in Puerto Rico. Up in Year Indicated and 35 Years Operating Life. 7% escalation thereafter. TABLE 4.1.2.4 Design and construction lead time: 7 years. Interest During Construction and Escalation until 1985 at 8%/Yr and 7th year or more. Start year | 1980 | 1985 | 1990 | 1995 | 2000 | 2005 | 2010 | 2015 | | | | 1985 Dollars | 5,303 | 4,486 | 3,905 | 3,478 | 3,197 | 2,927 | 2,768 | | capital investment | | | 1985 Dollars"

The following is the corrected version of the text:

An estimated total cost calculation is as follows:

42 WIND POWER SYSTEMS (UPS)

The potential contribution of wind turbine generators (#16) 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", which is included in its entirety as Appendix H. The costs from that report are placed under the same basis developed for the other alternative estimates developed in this analysis, providing 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 as well as a plant life of 35 years for the whole project.

4.2.1 Capital Investment for Wind Power Systems

The total capital investment charges for this project in Puerto Rico for operation in 1985 are calculated as follows (see Appendix 1):

4.2.1.1 Plant Costs

The present estimated wind turbine generator'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 M, 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 units are assumed to be located at one particular site.

TABLE 4.2.1.1 Wind Power System 1979 COSTS

25 Wind Turbine Generators

$32.75 x 10^6

$23.75 x 10^6

Electrical Interconnections (estimated)

3.19

3.19

Based on Bureau of Reclamation Studies (Appendix 4.)

Design and Study (17%)

458

Contingencies, site facilities, supervision (15%)

539

4.08

Total Wind Power System Cost (1979)

$47.44 x 10^6

$35.56 x 10^6

The estimated land requirements for this project (Figure 7, Appendix H) are

2891 acres (2978 cuerdas). There are two options to consider. One is to purchase the land; in this case, the cost of the land will be part of the capital investment and subject to a fixed charge. However, the utility will have an asset appreciated in value at the end of the facility's useful life. The other option is to rent the land, which will be part of the operating costs of the facility. In this case, the rental cost will be the estimated land cost: 2,978 cds. at $5,009 = $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. 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 5)
Wind Power ETO
The following parameters are used in the computation:
Interest Rate Fixed Charge Rate (FC)
4 = 3 years
1 = 3 years
$/year = 0.098636

ly = 1.08
Tee = 1.09
a = 0.50 %

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 (cents/kWhr)
25-150KW (28kw net)
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 1) 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 1-20% annual rental fee subject to adjustment.

Escalation. To ensure consistency with the calculations performed for other alternatives, the O&M

costs are escalated to 1985 at a rate of 8% per year and then levelized for 35 years of plant life, factoring in inflation at 5% per year. The total levelized O&M charges in mills/kWh are thus obtained by the following formula: (estimated 1979 costs) * L * 0.22L. The O&M cost is determined from available wind data.

Where:
L = Levelizing factor = $(i)^{(n)}/(1 - (1 + i)^{(n)})$
i = 8% per year (annual discount rate)
n = 35 years (plant life)

The following results are obtained:

TABLE 4.2.2 LEVELIZED O&M COSTS

Wind Power System (WPS)	O&M Costs (mills/kWh)
WPS Land (Rental Option) 25-1500KW	(2.52x10^-3 kWh per unit App.H) 37.6
WPS Land (Rental Option) 25-500KW	(2.07x10^-3 kWh per unit App.H) 34.4

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 Coastal Zone in Puerto Rico)

	Capital Investment (mills/KWh)	O&M Charges (mills/KWh)	Total Power Cost (mills/KWh)
25-1500KW Units (Own Land Option)	156.85	6	194.45
25-1500KW Units (Rented Land Option)	119.38	105.4	224.78
25-500KW Units (Own Land Option)	154.93	8.4	189.33
25-500KW Units (Rented Land Option)	108.20	118	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. It 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 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 plant 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 power system 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.

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Total Levelized Costs (as per figure 8.2.33) are the Total Levelized Generation Costs of Power Produced by: 2600 Mie Nuclear Unit, 1A G00 Mie Nuclear Unit (Wog, escalated at 7 174 per year), 258 Five Office Units, 4850 Whe Coal Unit, 450 Mie Fuel Oil Unit (Fock Oy escalated at 8 per year), 525 Unit Nine Turbine Power Park (500 hours)

All costs escalated at 4% per year beyond 1985 except Yellow Cake and Fuel Oil in Curves 1-A and respectively. The plant started up in the year 2000.

Total Levelized Costs (as per figure 4.2.30) are all costs escalated at 7 1/4% per year except Fuel Oil which is escalated separately. The Total Levelized Generation Costs of Power Produced by 600 Mie Nuclear Unit, 250 Mie UTEC Plant, 450 Mie Coal Plant, 4850 Mie Fuel Oil Plant, 25 Unit Wind Turbine Power Park (300 hours)

Biomass Fueled Power Plants: Biomass fuel consists of dried or partially dried forage, 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 bagasse to substitute for fuel oil burning. Sugar mill boilers, however, are not designed 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 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 300-500 scale. CORK has been heavily involved during the last three years in the agricultural sector.

The phase of biomass species selection includes proving ratios, harvesting, sun drying, and bailing of biomass. Based on figures, a BTU 6 has been determined. CEER is currently making efforts to develop a pilot project in which the large-scale logistics of biomass burning could be assessed for extrapolation to industrial type of electric power plant boilers. Such a proposal has been submitted to the Government of Puerto Rico.

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.

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 seaport facilities and FGD System. As such, the three cost components of Capital Investment, Fuel, and Operation and Maintenance costs will be addressed.

4.3.14 Capital Investment charges: The Basic Capital Investment Cost (Cy) of a 450 MW coal-fired power plant with an FGD system, as determined in Section 3.1.8.4, is $691/MW. With an estimated 8% auxiliary power requirements for a coal plant with an FGD system, the capital cost per gross kilowatt is $640.

The FGD System investment cost included in the $100/KW (see Section 3.1.4.2). The investment cost of a coal plant without an FGD system is $540/gross KW (1978). For the purpose of this study, it is assumed that a biomass-fueled plant is no different cost-wise from a coal plant without an FGD system.

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

IST 540 1.08 €0-996 1.09-5 5 9951/EW 1985 (See sections 3.1.8.3 and 3.1.8.4 for details) 1.29.

With a fixed charge rate of 0.099636, a plant capacity factor of 75% (as for the coal plant), and 35 years of plant operation, the capital investment charges equals €14.3 million.

4.3.1.2 Biomass Fuel Costs

Biomass fuel costs have been evaluated in separate CEER studies under the Sionsss Program. Figure 4.3.2.2 shows a flow of 47 core studies ran for the evaluation based upon an energy plantation have estimated a biomass fuel cost at $1.60/million BTU in 1979.

A three stock assumed adds 4 cents/million BTU to the carrying cost. This cost is escalated at 8% per year until 1985 and then levelized for 25 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 begin commercial operation in 1985 is thus:

FL = (1.66)(10,000) (1.08)8(1.81) 1,000 L + (2601.81) = €47 million.

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 by approximately 5-15%.

Figure 4.3.1.2 Biomass Fuel Cost Flow Diagram: Experimental Farm. Please refer to the diagram for further details.

Table 4.3.1.2 Biomass Fuel Costs Preliminary Cost Analysis for Sordan 70A Production

Land area: 200 acres
Production Interval: 6 months
Sordan 70R Yield: 15 tons/Acre; Total 3,000 Tons of Oven-Dry Material

Preliminary Cost Analysis:
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: Data missing.

43,000 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 21,200 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

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 coal 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:

Total O&M Cost = (1.584) (TSC)+(4.9 x 107%) (Kiam) (0.80)+(1.43) (KW 433,660) (1985) (G4 =

($8,828,000)(1.08)^7 = 15,130,000

With a 75% capacity factor and an 8% assumed auxiliary power, the levelized fuel cost is calculated as follows (using same levelizing factor as for fuel):

O&M Cost = (15,130,000) (1,000) = 10 watts/kW

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 MWe biomass power plant, at a 75% capacity factor, a 9% per year cost of money, and a 5% per year 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.
Total: 71.3 mills/kWh (1985 start-up)

Escalation of all the above costs at 5% per year, beyond 1985, is shown in Table 4.3.1.6a

TABLE 4.3.1.6(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 71.9 91.0 116.1 148.2 189.2 241.6 308.2 393.3. (mills/KWh)

If an Inflation factor of 7% per year is used beyond 1985 for fuel as well as O&M, the levelizing 1-34

TABLE 4.3.1.45: LEVELIZED TOTAL COSTS FOR PLANT START-UP IN YEAR INDICATED WITH 7-1/4 /YR INFLATION BEYOND 1985

Start-Up Year: 1985, 1990, 1995, 2000, 2005, 2010, 2015, 2020

Levelized Cost (per kWh): 93.4, 132, 188.1, 266.9, 378.7, 537.4, 762.5, 1082.1

From Figures 4.3.2a and b, it can be seen 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.

TOTAL LEVELIZED COSTS (mills/kWh)

Total Levelized Generation Costs of Power Produced by:

600 MWe Nuclear Unit

250 MWe OTEC Unit
450 MWe Coal Unit
450 MWe Fuel Oil Unit
Wind Turbine Power Park (5009 a)
450 MWe Biomass Power Plant

All costs escalated at 5%/yr beyond 1985 except for Yellow Cake and Fuel Oil in Curves "A" and "B" respectively.

TOTAL LEVELIZED COSTS (mills/kWh)

Total Levelized Generation Costs of Power Produced by:

600 MWe Nuclear Unit
250 MWe OTEC Plant
450 MWe Coal Plant
450 MWe Fuel Oil Plant
Wind Turbine Power Park (5009 a)
450 MWe Biomass Power Plant

All costs escalate at 7%/yr except for Fuel SHL which is escalated at 5%/yr.

4.4 PHOTOVOLTAICS

The Photovoltaic process converts direct solar radiation to electricity using photoelectric cells. There is currently a substantial worldwide 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 is generated in an external circuit when semiconductors are exposed to solar radiation. The applications of electricity generation by photovoltaic systems for a control station can be viewed from two different perspectives: power plant and individual load center (ILC) generating facilities. A photovoltaic generating facility is a small system installed at the point of electrical demand. Since there are periods when the photovoltaic systems do not produce power, storage capacity can be added or the system can be connected to the utility system for backup 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 commercially available alternatives.

Central station photovoltaic power plants will require large land areas because the power produced per unit area of solar 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 MW photovoltaic installation in Puerto Rico is evaluated in this 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 MW plant will require 4000 acres of land.

4.4.1 Capital Investment of a 250 MW Photovoltaic Power Plant

It is assumed that a 250 MW photovoltaic power plant can be installed in Puerto Rico for startup in 1995. In order for the plant to provide a continuous output, part of the energy produced by the photovoltaics plant during daylight time (approximately 10 hours) 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 the 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 y, is varied until balance 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 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 nighttime 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.

The text has been calculated at the rate of the capital cost of a conventional gas turbine, but no credit will be given in this study. Under this assumption, 1 ky of plant capacity will have a storage capacity of 0.4 x 2ékvkr per day cycle, or 9.6 kWh per ky of plant capacity. To account for the absence of solar radiation during cloudy or rainy days and storage system maintenance, an additional 292 energy storage capacity will be provided. The present state of the art indicates solar cell efficiencies range from 6 to 25%. Commercially available solar cells are presently 10% efficient. The efficiencies of solar array components are assumed as follows: Solar cells are 10% efficient, electric battery storage is 80% efficient, and electric power conditioning equipment is 95% efficient. This results in a 9.5% efficiency for collection and production and a 7.6% efficiency for the output of the storage system.

CER 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 kevh/m^2/day. Using the above data, the area required to produce 26 kWh in a 24-hour period, with

60% directly delivered to the load and 40% to the storage system, can be computed as follows: 2% * (0.60 * ST) * (0.095). The average insolation power per square meter is: SL 6 0.227 Kw/m^2 * 4.4141 Basic PI ec.

The cost of a photovoltaic installation can be approximated by the following relationship: $ array cost/m^2, plane cost 2 * (plant EF.) * (insolation powerTe^2) + Power Conditioning cost ($) + storage cost ($). The following values are assumed from the present-day technology and an extrapolation of the 1-01.

a. Array Cost: DOE Photovoltaic Program cost predictions are shown in Figure 4.4.1°9°59. 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).

Corrected Text:

Averaging this cost and considering that peak power is 1000 W/m², we have: Solar photovoltaic collector cell cost: ¥4, too Me at 10% eff. = 100 ze # = $27.50/m² (1980 dollars) voo Ye x go.275.

Installation Cost: Installation costs for wiring, structures, etc. have been estimated by Schueler at $41.50 per square meter. The total estimated array cost is $69.00/m² (1980 dollars). The array life is assumed to be 30 years.

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. The projected battery cost for 1990 is $30.00/kWh.

Installation, building and other costs $5.7 = 0.7 268490

Storage Cost = $30.00 + (5.7-0.7 log10 1,200,000) = $30.00 + 1.45 = $31.45/kWh (1980 dollars)

The estimated lifetime of the batteries is 10 years, which will necessitate two interim replacements during the plant's operating life. 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 are estimated by the Office of Technology Assessment as follows:

PCS Cost (projected for 1990) $40.00/kWh. A lifetime of 30 years is estimated.

Combining the above system component costs we have:

Total Basic Plant Cost = $69.00 (0.60 + 0.40) + (1.25) ($31.45) (9.6) 0.227 (0.095 0.076) + $40.00
Total Basic Plant Cost =

3520 + 377 + 40 = $3937/KW (1980) Ref44

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:

Ec = mre + on; SRECEAR

where:
Bo Bre = cee ra, act cue ns see
[ES J 1% | Set CE YP y
Equivalent capital cost
Capital cost of portion of a plant unaffected by interim replacement
Capital cost of the interim replacement
CRE(r,N) = capital recovery factor for plant where W is the book life of the plant,
CR(z,LR)= capital recovery factor for the interim replacement where LR is the interim replacement book Life
+ Fixed charge rate for the interim replacement
= Fixed charge rate for the plant
= Inflation rate
= Discount rate or cost of money
+ Number of replacements
= Replacement Life

The fixed charge rate considered throughout the present study for application to the Puerto Rico Electric Power Authority has been rvab5.

Capital recovery factor plus a small allowance for Sertoli each was equated to the capital recovery factor in the above equation, thus obtaining:

Ec = ext] kes pce cri i +t 4 Pei, ae J

Substituting in the above equation with the usual values of {= 9%/yr. and @ = 5%/yr, we get:

Plant Unit Cost = $3560 + $377
W = 3560 + 377 (2.18) = $3937/KW (1980)

The area required for the plant is 91 m^2/KW or 225 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 the following:
Plant: (250,000) (4,374) = $1093.5 x 10^6
Land : (4000)(5,000) = 20.0 x 10^6
Total: $1193.5 x 10^6

4.4.1.3 Capital Investment Charges

The scheduled and forced outage rate for photovoltaics must be lower than that 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 is assumed for the OTEC plant.

The factor would be more than adequate. The investment charges for the plant for operation in 1995 are calculated using the following parameter: 146.

Cr = 85 FOR = 0.101336 (30 years operating life) Escalation (1950-1985) at 8%/yr. Escalation (1985-1995) at 5%/yr.

Thus: Capital Investment Charges = 1113.5 x 106) (0.101336) (1.08)^5(1.05)^10 = (250,000) (8.76) (0.8145 mill/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 KWh of plant power is 51m therefore, for a 250 KWh module an area of 3151 acres is required. Such large scale electronics and wiring will undoubtedly require personnel.

The following is assumed. Suggested staff for a 150 MWh Photovoltaic Power Plant:

1 Superintendent, Assistant Superintendents, Secretaries, Shift Supervisors, Shift Operators, Electrical Engineers, Electricians, Electronic Technicians, Instrument Engineer, Instrument Technicians, Mechanical Engineer, Mechanics, Clerks, Janitors, Gardeners and general landscapers, Security men (4 Guards/shift), Chauffeurs, Chauffeur (regular hours), Utility Men (general), Chemical Engineers (storage system assistance), Chemists, Warehouse (9 Warehouse Clerks)

2 Accountants, 1 Purchaser, 1 Estimator, 1 Clerk, 35 Total Avg. salary per person $24,000 Total salaries (24,000)(35) = $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 O&M Cost $4,560,000 mills/KW = 4,560,000 = 2.45 mill/KWh (1978) (230,000) (8760) (.85)

It should be noted that the lifetime of the other alternatives analyzed in this study has been assumed as 35 years. The lifetime for this assumed plant is being assumed as 30 years.

The equation is: Levelized Cost = (Data cost) + (2.45) (1.08)^7(1.05)^10(1.72) = 11.76 mills/KWh

6.4.3, Total Estimated The total cost of the 250 MWh photovoltaic plant levelized for the 30 years operating life of the plant.

Total Levelized Generation Costs of Alternatives For Electrical Energy Production in PR. 1 Escalated at 7UA%/ Yr Except Fuel Oil which is a #1 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 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 cost and price changes by the industrial sector have been, in most cases, neglected.

The availability of input-output tables of the Puerto Rican economy enables 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 prices will be measured. However, purchaser's prices can also be estimated by using.

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Components of the industrial sector. "5" signifies the import code: Methodology and Mathematical Model S.t+22 Methodology, our methodology, and price version of the Leontief's input-output model. We closely follow the Prices in the input-output system which are described by the following equations: 2 in the identity matrix A is the output-input coefficient matrix (excluding value added) V in the row vector of value added, expressed in dollars per unit of output. Key of relative prices. 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 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 barrel in 1973 to $21 in 1979). This price increase has been turned into costs of the industrial sector and 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, used as a base for the calculations. It has been estimated that the increase in the total expenditures of an industrial sector are equal to its intermediate purchases from itself and all other sectors, 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 multiply the row vectors of intermediate sales of petroleum and other petroleum products by seven times the resulting increases in total.

The text appears to be discussing a method of calculating price indices with respect to energy expenditures, using an input-output model. Due to the format and typographical errors, the text is somewhat disjointed. A possible correction could be:

Expenditures, or increases in costs, were then divided by the total expenditure of the base year (in this case, fiscal year 1972), as shown in our latest table. This division was done to derive prices. The second step, or second iteration, was to pre-multiply the price row by the "new" transaction matrix (featuring inflated petroleum vectors) to obtain the expenditures. These expenditures were then divided by the vector of total expenditures obtained in the first step to get a new set of price indexes. This iterative process, involving a set of scalars from the producer's new total, continued until relative prices met a convergence criterion.

The limited scope of this study prohibits a detailed analysis of economic changes due to fuel substitutions caused by price increases. Some models for analyzing energy impact have taken this into consideration, such as C. Y. Bullar's "An Input-Output Model for Energy Demand Analysis", published by the Center for Advanced Computation at the 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 that is pre-multiplied by different transaction matrices until the process converges. In this case, the step-by-step process was not followed as the iterative process was shortened using Leontief’s inverse matrix.

In terms of the mathematical model definitions:

1. Po = set of 53 scalars, each one equal to 1.0 in the base year, except for petroleum refining and other petroleum products.
2. The total expenditures for the base year are represented by a vector.
3. A 53x53 transaction matrix in producer's prices represents the value of industry production fed as intermediate inputs by the industry for the base year (1972).
4. Value added in the base year.
5. XP = value of production equal to intermediate and final sales for the base year.

6. Y = base year final demand.

Where: 53 (number of industrial sectors), (number of iterations) 5.1.3

The Results Based on Yearly Data: From 1973 to 1974, petroleum prices experienced a fourfold increase. From 1973 to 1979, the price increase amounted to 700 percent, and during the fiscal year 1979, it was 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 estimates have been made 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 increased 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 with a fourfold 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 changes.

Following is a detailed account of the results. Table 5.1 shows the base year figures of the intermediate demand for petroleum products used by 53 industrial sectors and supplied by Petroleum Refining and Other Petroleum Products industries. According to the data presented, in 1972 a total of 3962.7 million units of petroleum products were produced in our economy. Of these, $491.9 million were allocated to intermediate demand and $70.8 million were allocated to consumer demand. The Petroleum

The refining industry supplied $433.7 million (or 77.1 percent of the total of both industries), while other petroleum products supplied only $129.0 million. The construction industry was responsible for 29.5 percent 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 significant 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 Data: Two for Fuel by Industrial Sector and in Fiscal Year 1999.

Demanding sectors included Agriculture, Other Agriculture, Methane Services, Fermented Products, and various others. The most notable demands came from the sectors of Construction, Electricity, Trade, Transportation, and Communications.

The proportions shown for mining, construction, electricity, and cement are the highest. For 27% of the total inputs used by Other Petroleum Products are supplied by the petroleum refining industry and by self (but mostly by Petroleum Refining). In the case of electricity, the share amounts to 15.6 percent, mostly supplied by petroleum refining ($46.0 million or 14.4 percent in the base year 1972).

5.1.3.2 Change in Total Expenditure

The input-output transaction table, when read column-wise, indicates that the total

Expenditures by any industry 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 industry 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 price of a barrel of oil. By using an iterative process in the computer, estimates were made of the various "rounds" of increases. We are 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 work.

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 million to $496.7 million (costs that are incurred in providing its final sales of services) at increased producer's price (or it will continue raising 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 cost index increase), we can determine this with the model.

"Approximate, ceteris paribus,* amount of 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 1972, the year of the latest input-output table, as a base fiscal year. The table shows that as 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 second. We are assuming zero price elasticity of demand for petroleum products, and constant input-output technological coefficient.

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 $3.09 to approximately $21.00 from 1973 to 1979, resulted in Government total increased Federal expenditures from $239.0 billion to $494.7 billion (costs) which are incurred in providing its services (intermediate plus final sales of services) at increased producer's price (or will continue raising prices until the response to the shock has converged to a new set of equilibrium prices). Although time periods cannot be attached to the after 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."

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 1972, the year of the latest output table, as a base fiscal year. The table shows that if Petroleum Refining and Other Petroleum Products costs have increased 7 times as a result of price increase, the price index for each sector has increased or will keep increasing. For instance, the producer's price of cement will increase 67 percent in the first round, 24 percent in the second. 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 INCREASES IN THE EXPENDITURES AS A RESULT OF PRICE CHANGES

(Values are per thousand dollars)
First, Second, and Third Round Changes for ALL sectors

- Preserved Fruits and Vegetables
- Textiles and Apparels
- Paper and Miscellaneous Products
- Printing and Publishing
- Petrochemical Products
- Other Chemical Products
- Petroleum Refining, Other Petroleum Products
- Other Stone, Clay, & Glass Products
- Primary Metals, Fabricated Metal Products
- Machinery except electrical
- Transportation Equipment, Instruments & Related Products
- Miscellaneous Manufacturing
- Wholesale and Retail Trade
- Finance, Insurance, and Real Estate
- Personal Services
- Business Services
- Educational and Health Services
- Other Services
- Government Enterprise

- Federal Government

ESTIMATED INCREASES

"Douases DV" does not produce a clear piece mark, resulting in seeing the exchange rate as "average price per barrel". The oxen serial sectors, including dairy products, show partial increases in rates which may affect the prices at a steady pace. The health services and municipal government sectors also indicate a boom in rates.

In the second round, and 110 percent in the remaining rounds (until the process converges), a total of 311.0 is added, including 100 of the base year. 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 450 percent increase in the average price of petroleum products from fiscal 1978 to 1979.

3. A simulation (for reader's convenience) of a 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 a 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 keeping in mind that the producer's price increase is equal to the difference between the figure shown in the last column of Table 3.

The text should read as follows:

"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 Dept.

Table Select (Change in Producer's Price Index by Industrial Sector in Response to Oil Price Increase)

We can see the Producer's Prices Change in response to an average 50 percent increase in oil prices.

The following sectors were affected: Meat Products, Grain Mill Products, Sugar and Confectionery

Products, Beverages, Tobacco, Rubber and Plastic Products, Leather and Leather Products, Stone, Clay, and Glass Products, Refinery Products, Basic Metal Products, and Medical and Health Services.

Keeping all other prices constant, a process of double-digit inflation will be introduced into the economy. As Table 5.1.6 shows, a $2 increase in oil prices will result in a 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 Petroleum Refining and Other Petroleum Products. If the initial shock should come only from the Petroleum Refining sector, then the 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 sectors in costs of two oil sectors 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 the Producer's price index. The ten most impacted sectors were malt beverages, mining, etc."

Electricity, cement, transportation, construction, alcoholic beverages, business services, other stone, clay, and glass products, and finance. This is only a partial listing of affected industries as many industries do not use fuel directly, but are affected indirectly. Cement and construction industries were hit hard by oil price increases. For instance, the oil price increase of 1973-74 was largely 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. 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 instances. Table 5.1.7 shows that if we increase petroleum we...

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 A 6% INCREASE OF PETROLEUM PRICES FROM 1973 TO 1974 (1972 = 100)

Transportation
Construction
Alcoholic Beverages
Business Services
Other Stone, Clay and Glass Products
Finance
Trade
Miscellaneous Manufacturing Industries
Other Petroleum and Coal Products
Repair Services
Transportation Equipment
Electrical Machinery
Drugs, Chemicals, Rubber and Plastic Products
Steel and Other Metals
Petroleum Refining

Sugar and Confectionery Products
Sugar Cane
Battery Products
Machinery, Except Electrical
Personal Services
Paper and Allied Products
Municipal Government
Real Estate
Printing and Publishing
Bottled and Canned Soft Drinks
Other Services
Amusement and Recreation
Communications
Preserved Fruits and Vegetables
Petrochemical Products
Dairy Products
Hotels
Other Agriculture
Federal Government
Professional Instruments
Furniture and Wood Products
Other Chemical Products
Fabricated Metal Products
Rubber and Plastic Products

5.1.4 Conclusion

The purpose of this chapter has been to estimate the impact of oil price increases (using as a proxy the increase in the price per barrel of crude) on 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 the economy of Puerto Rico was severely impacted by these price increases.

Cost 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, capital and energy-intensive industries, and the competitive position of the island have 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 to output generation and job creation.

Not only have these latter two variables been affected by the 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.

The price per barrel of crude oil was $21.0 in fiscal 1979. This 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 increases, such as those published by the Department of Labor of Puerto Rico and the implicit price deflators of the Puerto Rico Planning, are higher than the historical price trend. As was mentioned in the introduction, oil price increases were responsible in large part for the inflation and the accompanying losses.

From 1973 to 1975, estimates show that the economy of Puerto Rico lost about $82,328.65 million 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 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 towards: (1) developing new energy sources for the long run, (2) greater conservation."

The impact on employment and output of two alternative energy source projects is discussed in the next section. (Page Break)

Section 5.2: The Impact on Employment and Output of Two Alternative Energy Source Projects: An...

5.2.1 Input-Output Approach Introduction

As outlined in the Plan de Desarrollo Integral (Plan for Integral Development) and in Governor Ronero BarcelS's message to the Puerto Rican Legislature, finding alternative energy sources is a high priority. The Island's reliance on imported oil makes it vulnerable to the pricing policies of the OPEC countries, introducing a large risk to our open economy. According to a recent U.S. Department of Commerce study on the Puerto Rican economy, "As long as Puerto Rico remains dependent on imported oil for virtually all its energy needs, its economic stability will significantly depend on the pricing policies of oil supplying nations."

Oil price increases continue to negatively impact costs, output, employment, prices, and other macroeconomic variables of our economy. Therefore, it is strategically critical for our economic wellbeing to discover alternative energy sources. This process will necessitate the allocation of an increasing number of resources for research and development, energy conservation programs, and possibly a reorientation of our entire economic development strategy.

In the long run, most costs associated with developing alternative energy sources will convert into benefits for our society. These benefits include reducing dependency on imported oil, decreasing the trade deficit with foreign countries, creating job opportunities, boosting output generation, and slowing the rate of price growth (inflation). These variables are the most commonly affected by oil price changes.

However, any energy generation project will require investments in machinery, equipment, and construction. This increase in investment will have a significant multiplier effect on output, income, and employment. Therefore, in a cost-benefit analysis, these benefits must be considered alongside the ones most commonly analyzed.

Economics: 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 has 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 million 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 million in petroleum imports. The OTEC project will require $773.0 million in investment and will cause a $100.0 million reduction in petroleum imports (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 million 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. Deflated by a price index compatible with 1977 investment figures, these figures were used as a base year (to make it compatible with the input-output table). Second, the total investment 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 (also called Leontief's inverse matrix). The solution of the model is the output needed by all sectors of the economy to satisfy the demand for additional investment goods. Output 2

By employing coefficients (one per ten dollars of output) we can obtain the expansion needed to increase output and employment generated by the increase in agricultural activity. Monetary figures were deflated by an index with 1972 as the base year; then the 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 refinery 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 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 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 the 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 imports was the one published in the 1979 Economic Report to the Governor (page 155) using 1972 as the base year. In the second hypothesis, 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.

Refineries and other industrial sectors. In this case, exports were increased by the same amount of reduction of local sales (using as a 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 sources of energy input. Input-output analysis shows the impact on output and employment in the system resulting from 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 OTEC (2:300mW) (1-250mW)

Increase in Investment
In Current Prices: $950.0 $730

At Constant Prices(1972=100): 2142 457.4

Reduction in Petroleum Refinery imports
In Current Prices: 210 100.0
At Constant Prices(1972=100): 364 16.0

Increase in Agricultural Production
In Current Prices: 670
At Constant Prices: 450

5.2.4 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 1972-100 (Industrial Sector, Output, Employment)"

Agriculture: 468, 4208
Mining and Construction: 903, 20
Manufacturing: 7, 231
Transportation, Communications:

For each increase in investment of a million dollars, output will increase by $1.84 million (output multiplier of investment demand) and employment will increase by 86. TABLE 5.23 shows the employment and output generated by the investment needed to start biomass and OTEC energy projects. (Figures in Million Dollars, 1972=100) Biomass's initial investment (1972=100) is $242 and $4574 for OTEC. The output generated in the system is 3924 for Biomass and 8437 for OTEC. Employment creation is 18374 for Biomass and 39,338 for OTEC. Output per Million Dollars of Investment Demand is 1.84 for both. Employment per Million Dollars of Investment Demand is 86 for both.

What would the reduction in the unemployment rate have been as a result of a $3671.6 million 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 percent.

5.2.3.3 These Scenarios Based on Petroleum Imports

Scenario One: petroleum imports reduction will decrease output in the industry and system. Under this scenario, imported petroleum inputs of the Petroleum Refinery Sector will be decreased by

$231.0 million in current dollars ($536.4 million in 1972 dollars) and by $100.0 million ($16.0 million at 1972 dollars) by the establishment of the Biomass and the OTEC Project respectively. It has been assumed that the production of the 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 every million dollars of reduction in the system's output, 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 and capital-intensive industry (employment per million dollar of output in this industry is only 6.53).

Table 5.24 details the 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 Output	Biomass Project Employment	TEC Project Output	TEC Project Employment
Mining and Construction	85078			
Manufacturing		438	288	
Petroleum Products	3927	256	17.28	
Other Manufacturing	4185	1272	18.40	
Transportation, Communications and Public Utilities	727		38-3208	
Trade	066		6802820	
Finance, Insurance and Real Estate	205		35	0808
Other Services Plus Government	609		58268248	
TOTAL (less Manufacturing)	0541	3,117	4643	1,370

Second scenario: 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 about 1,000 jobs under the Biomass project and 431 jobs under the OTEC project. The payments to the factors of production (wages, salaries, and profits) will increase by $11.4 million. 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 exports. Table 5.2.5 shows the output and employment impacts if the Biomass and OTEC projects are introduced.

Third Scenario: A 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 land. Table 5.2.6 shows employment and output creation as a result of increases in the different components of domestic final demand.

TABLE 5.2.6 EMPLOYMENT AND OUTPUT GAINS INDUCED BY INCREASES IN EXPORTS OF PETROLEUM REFINERIES (in Million Dollars, 1972-100)

Industrial Sector	Biomass Project	Output	Employment	OTEC Project	Output	Employment
Agriculture	10	0.08	-	-	-	
Mining and Construction	0.97	0.43	29	-	-	
Manufacturing	4,693,470	2,063	210	-	-	
Petroleum Products	3,369	2.59	1,745	3	-	
Other Manufacturing	724	20	318	97	-	
Transportation, Communications, and Public Utilities	2,1498	0.94	43	-	-	
Trade	227	8	1.00	103	-	
Finance, Insurance and Real Estate	1,627	0.87	2	-	-	
Other Services and Government	68	0.32	20	-	-	
TOTAL	5,465	980	2,403	-	-	
Less Manufacturing	-	-	-	-	-	

Source: Estimates USM9 10 Model.

As 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 million (output multiplier equal to 3,153). In other words, each million is to...

1.56 and a reduction in petroleum imports. If allocated to other components of final demand, it will increase output by $1.56 million and employment by 87 jobs. 44. The total output generated by the two projects will amount to $79.5 million and employment to 4,415 workers if petroleum is reduced by $331.0 million ($231.0 million by Biomass and $100 million by OTEC) at current prices, or $52.4

million 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 impacts have been estimated: Impact on the economy as a result of the initial investment in machinery, equipment, and construction.

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 thus reduce their sales to other sectors of the economy.

b. Imports will not decrease as a result of the reduction in local sales; exports might increase because of the strong world demand for petroleum.

c. The reduction in the balance of trade deficit will finance 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 a further increase 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 will increase by $1.6 million 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 an increase in employment by about 58,000 workers, and the output of

The system will increase by $1236.1. For each additional dollar, it will increase by $1.84 million and employment by 86.

3. The reduction in the petroleum imports reduces the output of the industry, its sales to other sectors will also be reduced. In this case, the reduction in imports will decrease production in the system by a multiplier of 2.869. The probabilities are that there will be no reduction in petroleum output if local sales are reduced since this means for every dollar of exports the refineries can increase their exports. In this case, an increase of every dollar 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 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 million 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 on the economy will be that output will increase (on net basis) by $1,156.15 million 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 million 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 $1,357.0 million and employment by 67,145 workers. If this is the case, the unemployment rate, other things constant, 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, Nicnass and OTEC, will have enormous benefits in terms of output and employment generation given the availability.

Finance involves two aspects: loans and local savings or direct capital imports.

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APPENDICES

Z

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 x 10^9 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 resources include (1) environmental constraints on mining and combustion, (2) coal industry development, and (3) transportation. Costs are generally classified according to their carbon content and/or calorific values. Anthracites are the highest-ranking coals with 86-87% 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 briquette ovens, etc. Anthracites are generally unsuitable for use in pulverized coal furnaces on account of their hard nature. Bituminous coals are classified as low and medium volatile coals because they contain 16 to 31 percent volatile matter and 69-56% 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, and lignite = 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. Low sulfur coal is normally coal with 0.5% or less sulfur content. Coal costs are very sensitive to the sulfur content. The formation of gaseous SO2 (and SO3 to a lesser extent) during coal burning presents serious health hazards. Current environmental regulations practically mandate the use of wet scrubbers for most coal types. The Clean Air Act, specifically the "Clean Air Act Amendments of 1977, Public Law 95-95", presents considerable restraints on the operation of fossil fuel plants. Coal-fired units are required to adopt the "best available control" which at least requires scrubbers, electrostatic precipitators, and controlled boiler combustion air/gas systems to control emissions. Sulfur in coal occurs in three forms: organic, sulfate, and pyritic.

Pyritic 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 cannot be removed by direct physical processes. It generally comprises 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 are called coal beneficiation. Coal beneficiation also reduces the ash content of coal. Coal cleaning or 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 use in "Coal Preparation for Combustion and Conversion" EPRI-AP-791, May 1978, Puerto Rico. Details of coal beneficiation are discussed. Table A1, taken from the EPRI report, indicates the six levels of 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. 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 need crushing to liberate additional amounts of ash and pyritic sulfur, and are washed, sometimes after removing. Level F represents full beneficiation, using all levels of cleaning.

Beneficiation to produce clean coal of the highest quality and also middlings of average quality. The ERT document reports that costs for levels C-D-E range in the order of $.10 - .40 per Y81TC. Any final consideration for coal beneficiation levels will have to consider many factors entering into the economical and environmental analysis.

Not Available 109 4081R837 for use.

APPENDIX 8: 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 3 represents the flow of cash outlays for the project. Y1 represents the number of years between the date of the present estimate (early 1978) and the beginning of construction. Y2 is the actual construction time, Y is a function of Y1 and Y2. The abscissa of the curve is expressed in per unit of conservation time and the ordinate in per unit of cumulative investment during construction. The area under curve "e" 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 dx between x-dx/2 and x + dx/2, an amount of money dZ has been spent. This amount of money (dZ) spent at time x + dx/2 must carry at least single interest equal to (dZ)(1-x)i, where i is the average yearly interest rate during construction. The value (dZ)(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 accrued during construction. Similarly, (1-(2-dZ/2)) represents the amount of unspent money at time (x+dx/2) and (1+dZ/2) represents the amount of unspent money at time x + dx/2. Only the amount of unspent money can suffer inflation.

The average unspent funds during the time interval dx is.

The text appears to be a combination of mathematical formulas and incomplete sentences, making it a bit challenging to correct. However, I'll try my best to make it more coherent:

[(1-(e^(t/2)) + Qo(282/20))/2, or simply (1-2)/2, 'The average value (1-2) inflated for the small period x gives an infinitesimal inflation of (1-z)axig, where ig is the average single 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 (t-a). Figure 8 indicates the total and combined compounded formula. Charges for compounded interest rate and inflation during construction can be taken care of by the equation in the following form: F = (e^et), THC. The cost in $/kw, So, is the basic cost in $/kw for the base year (1978) and 1 + years elapsed between the base year (1978) and the beginning of construction. Y is the construction time in years, T is 1+ ig, where ig is the average inflation rate, and d is 1+ ige, where ige is the yearly average interest rate during construction. * is the area under the normalized cumulative cash flow curve during K, which represents other costs.

APPENDIX B. Interest During Construction and Inflation Formulas

EXPENDITURES

Study on Construction: y+ years elapsed between cost estimate analysis and start of construction. Time in years or area under normalized curve (6c) average interest during construction, $i per year. If inflation during construction, average % per year. Simple interest carried on A® dollars spent at time x. = (az-K) and (Rk) dB20. Simple inflation on unspent dollars during AX time at xy HUB) AX L. Total simple inflation during construction = t Ye [ti-#)0 x and [eta via.

COMBINED INTEREST DURING CONSTRUCTION AND INFLATION COMPOUNDED = C1 4ig HOT Hye) OF arte.

APPENDIX C. Power Plant Capital Investment Estimates

< 1.2 Ah/emission 870 Particulate << 0.10 Ah/emission. It is <0.7 Ah/emission. A heat rejection system will be used to release heat into the atmosphere via a wet cooling tower (cost adjustments to be made for special cases of once-through cooling if necessary). Special preference will be given to all references making cost estimates.

With new H°A NSPS standard considerations, Flue gas desulfurization (FGD) cost estimates are expected to be included for high sulfur coal (3% sulfur content).

United Engineers & Constructors!

1232 MW Net Single Goal Fired Unit with FGD

Coal type: Bituminous High Sulfur Eastern

Moisture (wt) 1.31%

Ash and sulfur (wt) 3.2%

BTU/lb (as received) 11,026

Supercritical pressure, single reheat with pressurized furnace max rating 9.775 lbs/hr. x 10° normal superheater outlet temp., normal reheater outlet 7.486.

Steam pressure, superheater outlet 3845 psig.

Steam pressure, reheater outlet 650 psig.

Steam temperature, superheater outlet 1000° F

Steam temperature, reheater outlet 1000° F

Fuel firing rate 550 tons/hr.

Turbogenerator: Cross-Compound, 8 Flow

Steam flow at H.P. turbine inlet 9.141 lbs/min x 106

Steam pressure at turbine inlet 3522 psia

Steam temperature at H.P. turbine inlet 1000°F

Turbine back pressure (minus press cond.) AUP

Ter auxiliary power 77 Yee

* Personal communication (from ongoing revised costs studies)

Net station output 1232 MW

Net Station heat rate 9238 Btu/kW hr.

Mid 1976 Cost Estimate (UEEC 1232 MWe net) cont.

Acc. No. $103 20

Land and land rights 2,000

Structures and Improvements 47,187

Boiler plant equipment 167,508

Turbine Plant Equipment 110,228

Electric Plant Equipment 93,523

Secondary Plant Equipment 857

Main Condenser Heat Recovery system 15,850

Total Direct Costs 386,153

Construction Services 48,465

Home office Engineering and Services 17,000

Field office Engineering and Services 13,900

Total Indirect costs 79,345

Total Base Cost 465,498

Main Power Transfer 1,700

Other costs including consultants and site selection (average) 34,500

Waste disposal equipment and facilities

Spare Parts 2,700

Fees and Permits 200

Subtotal 67,100

Grand Subtotal 532,598

Contingency 53,260

Total 585,858

Unit Cost Estimate 585,858/1232 = $475.53/MW

Early 1978 Unit cost (1.08)1-5 (475.53) = $534/MW

United Engineers & Constructors

194 MW Net Single Coal Fired Unit with

The corrected text will be:

FOD Goal Type: Bituminous High Sulfur Eastern Moisture (Zt)
Base Ash: 1.6%
Sulfur (% wet): 3.2%
Btu/lb, as received: 11,026
Boiler + Supercritical pressure, single reheat with balanced draft furnace max. rating: 6.53 x 105 lb/hr
Normal superheater outlet: 5.81
Normal Reheater outlet: 5.188
Steam Pressure, superheater outlet: 3865 psig
Steam Pressure, reheater outlet: 730 psig
Steam temp. superheater outlet: 1010°F
Reheater outlet: 600°F
Fuel Firing Rate: 365 tons/hr
Turbogenerator: Tandem-Compound-4 flow

Steam flow at HP turbine: 5.81 x 10 lb/hr
Steam pressure at Turbine Inlet: 3512 psia
Steam temp. at HP. turbine inlet: 600°F
Turbine back pressure (multipress cond.): 1.7/2.5 in Hg

Page Break

Turbine output: 854 MW
Auxiliary power: 60 MW
Net station output: 796 MW
Net station heat rate: 9682 btu/kw hr
1976 Cost Estimate (VESC 794 MW net) Account No. $103.20
Land and land rights: 2,000
Structures & Improvements: 38,015
Boiler plant equipment: 120,146
Turbine plant equipment: 65,182
Electric plant equipment: 28,931
Misc. plant equipment: 8,736
Main Cond. Heat Rej. Sys.: 12,042
Total Direct Costs: 275,082.05
Construction Services: 35,218.02
Home Engineering and Services: 14,350.93
Field Office Engineering & Services: 10,628

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Other Costs: 12
Total Indirect costs: 60,195
Total Base Cost: 334,088
Main Power Transf.: 1,200
Other Costs Including Consultants, Site Selection, etc. (ave.): 25,575
Waste Disposal equipment & facilities: 20,500

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Spare Parts: 1,800
Fees and Permits: 200
Subtotal: 49,275
Grand Subtotal: 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
Engineers & Constructors Costs of FGD Systems
The following costs have been determined from VESC recent estimates:
Added Cost to Boiler Plant Equipment Account #22: approximately 38-39% of account cost without FOD
Added Cost to Electric Plant Equipment Account #24: approximately 16-20% of account cost.

Please note that the temperature of the reheater outlet and the temperature at the HP turbine inlet is mentioned as "00°F", which seems incorrect. You might want to check the original data for this values.

Without FOD.

3. Indirect Costs - approximately 21% of above added costs.

4. Waste Disposal Equipment and Facilities - Increase by a factor of 2 over plant without FOD.

The total FOD system added costs included in the estimates given here are 1232 MW (gross) units (mid 1976 costs) $64.8/gross kW or $64.8/net kW for 854 MW (gross) units (mid 1976 costs) $71.4/gross kW or $76.5/net kW.

PREPA Engineers and Consultants data:

450 MW Gross Coal Plant

Coal Type: Bituminous High Sulfur Eastern

Moisture (% by volume): N/A

Ash: N/A

Sulfur (% by weight, wet): 3H

BTU/lb (as received): 11,000

Boiler: 2800 psig pressure, single reheat with balanced grate furnace

Max ratings:

Normal superheater outlet

Normal reheater outlet

Steam pressure: Superheater outlet, Reheater outlet

Steam Temperature: Superheater outlet, Reheater outlet

Rate Turbogenerator (Tc4P-26"):

Steam Flow at H.P. Turbine

Steam Pressure at Turbine Inlet

Steam Temperature at H.P. inlet

Turbine Back Pressure: 1010°F

Tandem-Compound 4 Flow Hitachi Turbine-Gen: 2400 psig, 1000°F, 2.5" Hg A.

Auxiliary Power

Net Station Heat Rate: 36 MW, 414 MW, 9800 Btu/Kw HR.

Land and Land Rights

Boiler Plant Equipment

Main Cond. Heat Rej. System

Total Direct Cost: Adjusted

Adjustments

FOP System for 3% Sulfur Coal: Additional Cost

Total Direct Cost: Adjusted

Construction Services

Home Engineering Services

Field Office Engineering Services

Total Base Cost: $222,830

Other Costs

Main Power Transfer (FEC #353): 720

Owners Cost including Consultants, Site Selection, etc. (82): 17,800

Waste Disposal Equipment and Facilities (62): 13,400

Spare Parts (1/22): 2,228

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 50 My Coal Plane ® PPC Ace. au Structures and Improvements: 31 Boiler Plant Equipment aus 16 (and cooling system), 3 Accessory Electrical Equipment, 318 Mac. Power Plant Equipment, 383 Main Power Trans. Total Direct cost, Indirect Construction Expense, Ocean Freight, Lighterage and Trucking, Engineering Design and Construction Management. Subtotal of Direct and Indirect cost is a Contingency Total (PRURA consultants). Adjustments: Turbine Generator in Storage by owner not included in above estimate. Total Costs: 2- Additional FED system for changing from Western to Eastern (High Sulfur) coal (PRURA consultant 16,520 114,220 6,700 6,030 no 0 144,900 35,000 6,000 17,000 202,900 41,100 264,000 25,000 12,000 $281,000)

EPRI Cost Estimate: 1000 147 Key Coal Type. Boiler Max rating: Bituminous High Sulfur Southeastern (Central Appalachia) Moisture (wt%) 8.2, Ash (wt%) 8.2, Sulfur (wt%) 3.04, Btu/lb. 12,130 2800 psig single reheat with balanced draft. Normal superheater outlet flow, Steam temperature, superheater outlet 1000°F, reheater outlet story, Fuel Firing Rate, Turbogenerator Tandem Compound flow, Steam flow, Steam Pressure at Turbine inlet 2400 psig, Steam Temperature at H.P. Turbine 1000°F, Turbine Back Pressure, Turbine output, Auxiliary Power, Net Station output 1000, Net Station. Heat Rate 9850 Btu/kweh.
Reference: EPRI P5-866-8R Special Report ~ June 1978

EPRI Cost Estimate: 1000 MWe Coal Plant (Continuation) (Bechtel Engineers 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 the two unit cost estimate by .96. Plant cost estimate includes common Design Criteria (1976 NSPS - EPA). End of 1977 (or early 1978) cost estimate: 550 + .96 or $573/kw. Cost of FD Systems: Included in the above cost is the FGD System estimated at $105.00/kw. Values for the FGD system range from $85 ~ 155/kw.

Gibbs and HALL (Paul de Rienzo) 1130 MWe Net Coal Plant

"Construction Services (36.72), Home Engineering Services and Field Office Engineering Services (6.82). TOTAL BASE COST includes other costs such as: (1) Main Power Transformer, (2) Other costs including consultants, site selection, etc. (8.62), (3) Additional waste disposal facilities (43), (4) Spare Parts (.62), (5) Fees and other costs. SUBTOTAL and 10% Contingency bring the TOTAL 1978 Unit cost to $775.

New 585 MW Net Nuclear Plant Estimate #2. Data Source: ALL by PREPA. Costs are in 1978 dollars.

Costs include: Land (320), Structures and Improvements (322), Reactor Plant Equipment (323), Turbine Plant Equipment (324), and Other Costs (325), bringing the TOTAL Direct Cost to 5,370. Other expenses include Construction Services (90,000), Engineering, Design, and Construction Management (60,000), and Inland Freight (10,000). After adding a Contingency of 877,630, the TOTAL cost is $323,000. Unit Cost: $896/kW.

CAPITAL INVESTMENT for NORCO W0.1 PREPA ESTIMATE (in 1978 dollars) includes: Land and land rights (103), Structures and Improvements (2,668), Reactor Plant Equipment, Turbine Plant Equipment (76,689), Accessory Electrical Equipment (136,431), and Miscellaneous Power Plant Equipment (included in 322-23). The Total Direct Costs also include Construction Expenses, Engineering, Design, and Construction Management and Code upgrading (4,000).

SUBTOTAL of Direct and Indirect Cost is SI6U93. PREPA Cost to Date (12/77) is 19,777. Future PREPA Cost is estimated to be 24,520. Other costs include PREPA Operator Training and Consultants (5,476), LE80 364 Offsite telephone and power Bt. After adding a Contingency Allowance of 62,361 (1978 dollars), the Total Cost is Ba78,102. Unit Cost: $817/kW.

Estimate for 11139 We PARA (in mid 1976 dollars). Costs include: Land and Land rights, Structures and Improvements, Reactor Plant Equipment, Turbine Plant Equipment, Electric Plant Equipment, Miscellaneous Plant Equipment, and Main Cond. Heat Rej. System. Total Direct Costs also include Construction Services, and Home Office Engineering."

Corrected Text:

Service 3: Field Office Engineering
Service 9: Total Indirect Cost
Total Base Cost

Other costs:
(1) Main Power Transformer: $2,000
(2) Others Cost including Consultants, Site Selection, etc.: $101,375
(3) Additional Spent Fuel: $133,48
(4) Spare Parts: $11,281
(5) Fees, Permits: $395428

Total, Grand Sub-total: $12,803
10% Contingency: $21588
Total (mid 1976 dollars): $330,957
Escalation to early 1978 at 8%/year: $70,033
Total (1978 dollars): $49,220

Unit cost: $968509/kW
Capital Cost: Pressurized Water Reactor Plant, NUREG 0241

VEIC 11190 BR

Land and Land rights: $2,000
Structures and Improvements: $13,324
Reactor Plant Equipment: $125,734
Turbine Plant Equipment: $116,673
Electric Plant Equipment: $40,746
Misc. Plant Equipment: $12,075
Main Cond. Heat Rej. System: $21,989

Total Direct costs: $1 construction
Services 92 Home Office Eng. Services
23 Field Office Eng. Services
Total Direct Costs
Total Base Cost

Costs:
(1) Main Power Transformer: $2,000
(2) Others Cost including Consultants, Site Selection, etc.: $48,850
(3) Additional Spent Fuel Storage: $8,000
(4) Spare Parts: $3,200
(5) Fees, Permits: $3,500

Subtotal: $53,350
Grand Subtotal: $646,298
10% Contingency: $94,630
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
CAPITAL COST ESTIMATES
RESIDUAL, OIL-FIRED POWER PLANTS

PREPA CONSULTANTS ESTIMATE FOR 450 MW OIL PLANT (436 MW net FPC)

(1) Structures and Improvements: $14,300
(2) Boiler Plant Equipment: $63,400
(3) Turbine Generator Plant Equipment (excluding turbo generator): $6,700

(4) Accessory Electrical Equipment: $3,770
(5) Misc. Power Plant Equipment: $710
(6) Main Power Transformer: $29

Total Direct Cost: $21,600
Indirect Construction Expense: $30,000
Ocean Freight, Litherage, Trucking: $5,000
Engineering, Design and Construction Management: $11,000

Subtotal Direct and Indirect 337,600
Contingency Allowance 27,400
Subtotal 165,000
Escalation Allowance 69,820
Interest during construction 42,569
Allowance for Turbo-Generator Adjustment 25,000
Total cost, 1985 307,382
1985, Capital Cost $693.54/kw
Plant Net Heat Rate (75% Load Factor) 9200 Btu
EWR (Personal Communication Mr. José A. Marina, PREPA, 1979) £2

PRICE 1000_kwh OIL POWER PLANT
Unit Capital Cost (1978) 440.0 $/kw
Most Likely range (1978) 405-480 $/kw
Average 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 756 $
1985 most likely range 694-822 $/kw
EPRI, PS-866-SR, Special Report, June 1978 £3

APPENDIX F
LEVELIZING FACTOR FORMULA

LEVELIZING FACTOR FORMULA
LEVELIZING FACTOR FOR OIL

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. 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 Fcy = levelized unit fuel cost during plant lifetime of n years
n= plant Life in years
Pui = present worth factor of the yearly uniform series values of Fy at an interest equal to the discount rate or cost of money
i= discount rate or cost of money
Fo = first year or initial unit fuel cost
a = actual average 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 L+ r= (a/i)
Pe= present worth factor of yearly uniform values of Fo at an interest equal to the discount rate or cost of money.

Interest rate r. (corrected for inflation). With the above definitions, the equation F(A) = Fo (Pir) or Fe = Pir Fo ay Pa Fa can be expressed as follows: Case 1 = (0.00r.). (Ref. 20-6). Where, F = fuel cost in mills per kWh, P = coal price in dollars per MBTU for base year including all costs such as carrying charges on coal storage, e = fuel escalation factor, x = number of years between year of fuel cost basis and beginning of commercial operation, BR = plant heat rate in BTU/KHR, the fuel cost in mills per kWh can be expressed with present worth formulas, as follows: Fs Gtep ¥ 90m . Gena . The levelizing factor L is, L = Gra . rade “Gy Ba.

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.

1975 | 1976 | Source: A278 Toyama. Project | Construction Power | 100,000 | 100,000 | 100,000 | 100,000. Anonin Vpeonia Anovia | 0.908220 | 28 | 26. Water flow rate (m^3/s) | 0.586x10^8 | 5.22x10^8 | 6.90x10^8. Heat exchange area (m^2) | 3.21x10^5 | 3.10x10^5. Units | 16 + 8 | 8 + 8. Type of platform | Submerged | Surface. Unit construction cost (mil $) | 206.

Source: Overview of the OTEC Development, T. Homa & K. Kanogava, 6th OTEC Conference, Shoreham-American Hotel, Washington D.C., June 19-22, 1979.

Technology, Inc. (Fluor Corp.) Cost Summary, Millions of Dollars: Management-Design Phase, Management Acquisition & Development Stage, Management System Operations Support Phase (General), Management Conceptual Design, Land Based Containment.

System Cone Water Pipe System, More Water Pipe Systems, Energy Transfer System, Energy Utilization System, Acceptance Testing, Deployment Services, Industrial Facilities Engineering & Construction, Deployment Total Operation & Support Total, OTEC System Total (Extracted *Published information. 'Wind Based OTEC Plants in Puerto Rico) 2980) 18.7 size February 1979.

Additional Reported Cost Estimates of OTEC from Different Sources. AL HUROCEAN, European Oceanic Association, Bengt A.P.L. Lachmann 20 MW Plant. Estimated Cost $5000/KW* (1979), Mitre Division - The MITRE Corporation, Jacobsen & Manley 100 MW Plant (Offshore Florida Peninsula). Estimated Cost $2579/KW (1976 dollars)*. Electrotechnical Laboratory - MITI, Research & Development Center, Toshiba Corp. Cost $16700/KW* Co, 1979, Estimated per capita (1975) Costs $220-8. FGak, CIEE Conference, Shoreham Americana Hotel, Washington, D.C., June 19-22, 1979.

Appendix A B V, LIST OF APPENDICES: Coal Interest During Construction and Inflation Formula, Coal Plant Capital Investment Estimates, Nuclear Plant Capital Investment Estimates, Capital Cost Estimates Residual Oil Fired Power Plants, Levelizing Factor Formula, and Capital Investment Estimates, Feasibility Study for the Use of Large Windpower Generators in Puerto Rico.

APPENDIX # FEASIBILITY STUDY FOR THE USE OF LARGE WIND POWER GENERATORS IN PUERTO RICO. Prepared by: Dr. Raúl Erlindo López.

Introduction: In the face of continuing rising fuel costs, attention has been focused once more on the wind power 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 utilizing the intermittent and variable output (due to the variation of the wind) that the wind turbines produce. Energy from the wind turbines, generation load can be reduced an amount equal to the fuel that would have been used by the

Power plants can be served by the energy provided by wind turbines. This scheme is similar to those 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 power 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 co-located 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 wind power generators into the existing PREPA thermoelectric network in Puerto Rico. The findings of that study are presented in this appendix. Preliminary assessments of wind power, wind turbine performance, and costs have been made.

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 land 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 Trade Winds in various local and regional patterns. During the day, the land heats up while the ocean stays at the same temperature. The resulting temperature gradient between land and ocean can affect the direction of the wind.

The text occurs mostly in east-west mountain ranges. A temperature gradient develops, leading to an inland acceleration. 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 on the south coast is directed from south to north, reducing the strength of the Trades and converting them into southeasterlies. The east coast of the island suffers an easterly thermal acceleration which can increase the strength of the Trades considerably.

However, the west coast experiences a westerly thermal acceleration which opposes the northeasterly Trades and sometimes reverses them into westerlies. 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 nocturnal 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 a generally weak thermal gradient.

During the night, the vertical exchange of the low layers of the atmosphere between the surface of the island and the wind moving over the south and west coast from the ocean usually slows 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. However, these maps provide a guide for the analysis of these effects.

The text has limited wind data available, and the analyses are extrapolated to regions void of data.

Diurnal oscillation of the wind speed and its corresponding figure is portrayed in Figure 3. This visualizes the variation of wind speed with the time of the day at representative stations in the north, south, and west coasts of Puerto Rico. The locations of these and other stations are indicated in Figure 4. The 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 trade winds 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 the highest (22 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 on 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 overall readings.

Figure 3: Diurnal oscillation of the wind speed at selected stations. No actual observations were recorded at Mayaguez during the night and early morning hours. All values correspond to a height of 10 meters.

Isla Verde:

Figure 4: A 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*) during a typical day at selected stations in Puerto Rico. The values correspond to an anemometer height of 10 meters. On the North Coasts, Isla Verde has 122.5, the East Coast's Roosevelt Roads has 93.0, South Coasts' Guayanitia has 25.2, and the West Coast's Mayaguez has 13.5.

Figure 5 shows the frequency distribution of hourly wind speeds for representative stations of the west, south, north, and east coasts of Puerto Rico.

In this context, p is the power density, ρ is 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 was obtained for the day. The power density for Roosevelt Roads on the east coast was obtained from a 5 point yearly wind speed frequency distribution.

The north and east coasts have the largest power densities (222.5 and 93.0 w/m*) with the south and the west coasts having much lower values (25.1 and 13.5 w/m*). The wind power at Mayaguez is extremely low. The differences in wind power density between stations are 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 it's 4-8 mph, for Isla Verde it's also 4-8 mph but at a much larger frequency, and 8-12 mph for Roosevelt Roads.

In order to construct a map of wind power potential...

The potential for the island's wind data was analyzed for the stations indicated in Figure 4. A detailed frequency distribution of hourly wind speeds was readily available only for Guayanilia I. Distributions 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 function.

This was then applied to each of the wind speed distributions from the adjusted level (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. Conversely, 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 sea breeze circulation, etc., should be carefully considered.

TABLE H-2
Average wind power density in a vertical plane perpendicular to the wind direction (watts/m2) during the year at selected stations in Puerto Rico. Values correspond to an anemometer height of 10 meters.

North Coast
Ramey
Isla Verde

East Coast
Roosevelt Roads 173

South Coast
Isabela
San Juan
Guayanilla I (Fomento) 16
Guayanilla II (PPG) 33

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 this, it would require further data collection and analysis.

In 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 obtaining 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 size observations at its Isla Verde Airport station. Unfortunately, the data is not readily available in a summarized way by wind speed for different elevations. Colon (7), however, has presented some summarized data for a height of 5,000 feet. 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 feet 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)n (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, and 2,000 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 air hits the elevated terrain. The adjusted powers constitute an average of the available wind power.

At 23 feet over the ground, different elevations are observed. Figure 6 is a map of Puerto Rico showing lines of equal wind density (watts/m²). The lines follow the 0.5, 1, 2, and 3 thousand feet height contours. The value represented by the lines corresponds to the power density computed for those heights as described above. The point values obtained for the coastal stations are indicated separately on the map. The effects of river valleys, canyons, and local terrain accidents have not been included in this general map. Local values of 85 watts/m² are probably possible on the tallest (3,500-6,000 feet) peaks. It can be seen from this map that the highest wind power potential is found on the east coast and along the island mountain divide. The determination of the optimum location for a wind energy conversion system would have to be 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 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 heights. 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. 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 operate at an 18 mph median wind site. The proposed design characteristics of these two units were used to estimate the energy.

The following text 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 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 or 2.52 x 10^6 kWh during the year. The 500 kW turbine would generate an average of 236 kW or 2.07 x 10^6 kWh during the year. These figures were used in an analysis of the cost of the power generated by arrays of these turbines and 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 F generated by a wind turbine can be obtained as (Justus et al., 1976) Fe = f(v) P(v), where 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. The function can be characterized in terms of speed v0 (the lowest wind speed necessary to start moving the blades of the turbine), design speed vy (the lowest wind speed at which the turbine produces the maximum power Pm for which it was designed), cut-off speed v2 (the maximum wind speed at which the turbine can operate), and maximum power Pm. For speeds below v0, the generated power is zero. Between v0 and v2, the generated power usually varies in a parabolic fashion. When wind speeds above v2 are experienced, the angle of attack of the blades is changed so that the generation of power is constant at Pm.

Above v2, 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 follows: v < v0, v0 ≤ v < vy, vy ≤ v < v2, v ≥ v2. 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 equation.

The parable that expresses the variation of the generated power between Vp and Vie coefficients can be obtained from the following equation:

ABV ICve2=P(vg/¥y)

Where Vo=(Votv1)/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:

- AL 1500 kW unit
- B. 500 kW unit
- Vorll-4 mph
- Vor7-9. mph
- Vye22.5 mph
- Vyei6.3 mph
- ¥2750.0 mph
- V2"40.0 mph
- F5r1500 Ir 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 speed classes of the frequency distribution for Roosevelt Roads were then adjusted to hub height by using the power law of equation 2 (154 and 150 £ 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.

The procedure was programmed for a 72-59 desk calculator.

XV Economic analysis System configuration

The hydroelectric system of the PRNRA produces approximately 100 x 196 kWh every year. To achieve a similar generation, it would take approximately 50 wind turbines. Preliminary studies by GB 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 size of the island. It is also possible to have the turbines on both the south and north coasts. For the purpose of the 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

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 in land prices is expected. Thus, the present land costs amount to $14.89 million.

3. Wind Turbine Generators Costs

Preliminary cost estimates provided by GE indicate that the first production 1.5 kW unit 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 99% of the previous costs, each time the total number of units is doubled.

The manufacturing of one turbine is estimated by GE to take between 6 to 9 months. The Bureau of Reclamation is considering 49 turbines for the first 5 years of production. Other companies might enter the wind turbine manufacturing business. A production of 100 units every 5 years will be assumed in this 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 million and $23.75 million for the 1.5 kW and 500 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 decrease due to increased experience on the part of the manufacturer. However, the price will increase due to inflation.

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 system.

Transmission grid. Their array would be twice as big as the one assumed for this study. Their costs have been estimated to 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 1.8 MW and 0.5 MW models respectively.

Table 3. Capital Investment Summary
Item Capital Cost (million dollars)

1.8 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%) 4.58
4. Contingencies, site facilities, supervision (15%) 5.39 4.08
5. Total wind power system 47.44 35.56
6. Land costs 14.89 24.89
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 (1.5 years). The interest on the land cost was computed at amortization of the total wind turbine investment (construction compound interest for the 3 years of construction plus construction interest) was computed using a total capital fixed charge rate of

Break---

11.7438, as is customary for the PRWRA, the amortization of the land investment costs (land plus land interest) was assumed at 8% compound interest over the assumed 35-year lifespan of the plant. CE 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, contingencies, and site facilities. Table 4 summarizes the estimated power costs. The total costs come to $8.68 and $6.92 million for output of 63.00 and 51.75 million kWh respectively. The power costs for the two wind turbine systems come out to be 137.8 and mille/kWh H.28.

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 5.82 4.35

3. Land costs 14.09 14.89

4. Construction interest on land costs 3.87 3.87

5. Annual fixed charge on construction costs (142) 6.25 4.69

6. Capital recovery on land costs (3+4) 1.62 1.6

7. Operation and maintenance cost per year -82 +62

8. Total annual cost (5,6,7) 6.92

9. Annual power output (106 kWh) 63.00 51.75

10. Power cost (mills/kWh) 237.8 137.7 H.29

The Bureau of Reclamation estimated a power cost of 21.1 mille/kWh for a similar system in Wyoming. The great difference in the two figures results from three very important factors:

a. The wind power available at the Wyoming site is three times as much as at 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.

Economic Projections - Breakdown

The estimate of 138 mills/kWh applies to the cost of power if construction is completed within the next 5 years. For simplicity, no inflation factor was included for this period. The uncertainty in the learning rate estimates and the manufacturing output do not warrant a more detailed approach.

However, should construction be delayed beyond this period, the price will alter significantly. It could decrease due to increased experience on the part of the manufacturer, but it could also rise due to 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.

An 8% compound inflation rate was also assumed, starting from the costs of the estimate in Table 4. It was further assumed that the learning rate takes into account inflation in the production process.

Table 5 presents the capital investment costs for each of the eight 5-year periods. The most significant drop in the price of the generators occurs in the second step. The learning curve is essentially an exponential curve, which drops very fast at the beginning and stabilizes quickly.

Other costs, especially for land, escalate very quickly due to the assumed 8% inflation. In fact, land and interconnection costs become several times the cost of the turbines themselves. If an additional inflation increase is added to the cost of the turbines, the situation becomes untenable very quickly. The largest item becomes the land costs after 40 years of delay.

However, if the land could be secured free of charge, for example, land belonging to the Commonwealth of Puerto Rico, or land already belonging to the PRWRA, costs could be dramatically reduced.

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Table 5. Forty-year projection of capital investment (in million dollars):

0-5 years: 32.75 (25 generators) + 2.19 (Electrical Interconnections)

6-10 years: 26.15

11-15 years: 26.15

16-20 years: 22.90

21-25 years: 22.08

26-30 years: 21.4

31-35 years: 20.85

36-40 years: 20.40

6.89 10.11 14.86 21.85 32.10 47.16
2. Position Overhead (279) 6.12 5.24 5.28 5.62 6.29 7.98 9.00 22-49
4. Contingencies (5%) 5.39 4.63 4.66 4.95 5.54 6.49 7.96 0223 47.44 40.71 40.90 43.87 48.76 57.09 69.09 69.18
5. Land Cost 16.89 21.86 92.15 67.29 69.40 101.97 149.83 220.15 62.39 62.59 79.13 90.60 118.16 159.06 219.72 309.33

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. Figures 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 Figure 8. It should be realized that in the computations 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 foreseeable future. Land cost could be eliminated by using land already owned by PRWRA or ceded to PRWRA free of charge. Figure 9 portrays graphically the equivalent cost of a barrel of oil under these assumptions.

#33

Errors were seen across page 19-98.

Summary: A study has been made on the possibility of integrating large wind power 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.

However, an inspection of the available stations around the island reveals that the largest power densities are found in the north and east coasts, with 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.

The land cost is 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. 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. This price could become competitive in the foreseeable future. Land costs could be eliminated by using land already owned by PRWRA or ceded to PRWRA free of charge.

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