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SOCIETAL IMPACT OF ALTERNATIVE ENERGY SOURCES

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ACKNOWLEDGEMENTS

This study was motivated by the general concern that escalating costs of solar equipment were rendering solar-generated electric power less and less competitive with conventionally fueled electric power. Consequently, the Division of Central Solar Technology requested that a study be initiated to evaluate the externalities associated with alternative energy sources in hopes that these additional considerations would help to stem, and perhaps reverse, the tide against solar applications. Aside from the request to consider "societal impacts," the specific approach to be adopted was left completely to our discretion. In this regard, the author is grateful to J.H. Kamin, not only for his suggestions concerning the formulation of the approach, but also for his material contributions to several sections in the body of the text. In addition, the author is indebted to M.B. Watson for his careful reading of the text and for his substantive suggestions for improving its tone and clarity.

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1.0

INTRODUCTION

This report describes the current status of a study into societal impacts of alternative energy sources. Its motivation was provided by the fact that most studies conclude that the cost of electrical energy from solar plants is higher than that from equivalent fossil fuel plants when the calculations are based solely on direct (or internal) costs. The objective of this study is to determine whether a consideration of external costs would modify this conclusion substantially. Accordingly, it is necessary to formulate an operational definition of societal impact which would lend itself to quantification and thus make alternative energy sources objectively comparable.

The kinds of external impacts which are considered in the present analysis include financial impacts, environmental impacts, and the effects of various government policies. Specific impacts within these categories are identified and a method of quantification developed for each so that their effects may be combined into a representative number. The method used to combine the identified internal and external factors is cost-benefit analysis.

1.1 COST-BENEFIT ANALYSIS

Cost-benefit analysis is a popular economic methodology useful for evaluating whether or not government investment in a project is in the public interest. The method is similar in form to the conventional methods of capital budgeting for evaluating private investment decisions. Instead of enumerating cash flows, however, which capital budgeting uses to measure a project's contribution to investors' welfare, cost-benefit analysis measures benefits of a project to society by the net additional consumption opportunities that the project would make available to society as a whole. Assuming the project is not large enough to affect the price of its output, the gross benefit is measured at each point in time by the value of the quantity of good or service produced by the project that society would purchase at the competitive market price. If the competitive market price is not available, a market price is imputed by the analyst.

Instead of subtracting cash outflows from cash inflows at each point in time to measure the private net cash flow available to investors, as in capital budgeting, cost-benefit analysis seeks to identify social costs in terms of real resources required at each point in time to yield the social benefits. Therefore, the cost computation does not include transfers of funds among individuals in society that do not affect the application of real resources to the project. For example, taxes (except those that fall unequally on alternative energy sources) and interest or dividends paid out of earnings from the project are assumed only to affect the distribution of income and not the quantity of real resources produced or consumed, or their prices. The computation does include, at each point in time, the direct cash outlays for labor, physical capital, materials, energy, and any other real resources required by the project.

Cost-benefit analysis assumes that society as a whole, just as individuals do, places a lower present value on cash receipts or expenditures the further in the future they occur. Hence the calculation multiplies the difference between the dollar measures of benefits and costs at each point in time by an appropriate discount factor preparatory to calculating the present value of the net benefit. The discount factor may also include an additional component for risk under the assumption that society prefers less risk to more risk, other things being equal.

1.2 NET NATIONAL ECONOMIC BENEFITS

The cost-benefit analysis of the construction and operation of each alternative type of power plant (oil, coal, or solar) is implemented by calculating its Net National Economic Benefits (NNEB). With this methodology, the problem of determining a standard of quantification for the impacts of direct and indirect factors is solved immediately because they are measured in terms of the common denominator of their dollar values. The question of the definition of "societal" is resolved by adopting a national perspective. Net national economic benefits are defined as the present value of a future stream of benefits minus the present value of a future stream of costs. Symbolically,

$$NNEB = \sum_t \frac{1}{(1 + D)^t} \left[BV(t) - FC(t) - \sum_i GP_i(t) - \sum_j EC_j(t) - \sum_k R_k(t) \right]$$

where D is the social discount rate and BV(t) is the time-dependent value of the electricity produced by the plant in question. The other terms are defined more fully in Table 1-1.

Table 1-1

DEFINITION OF TERMS USED IN NNEB ANALYSIS

FC(t)		-	Cost of Plant, Operation & Maintenance, Fuel
$GP_j(t)$		-	Cost Impact of Government Policies
	e.g.,		Taxes & Subsidies RD&D Funding Pollution Control Criteria Strategic Petroleum Reserve National Security
$EC_j(t)$		-	Environment Costs
	e.g.,		Pollution (Air, Water,Thermal) Health Effects Property Damage Waste Management Aesthetic Effects
$R_j(t)$		-	Resource Depletion
	e.g.,		Materials Land Usage Water Requirements

This methodology is used to compare alternative power sources applicable for intermediate and peaking load applications. "100 MW_e" coal, oil, and solar plants hypothetically located in Arizona and Florida are evaluated in terms of net national economic benefits as far into the future as 2050. These two States were selected to exercise the methodology where the numbers associated with both the coal and solar plants are expected to be appreciably different. Other States could have been selected to fulfill the same objective.

One very attractive feature of the formal structure of the NNEB analysis is its simplicity. It is essentially additive in nature so that as new categories of external effects are discovered and values are developed for them, they may be added without negating the calculations which have gone before. Also, corrections or new modes of treatment of old data may be dealt with individually without disturbing the main body of the analysis. Thus the NNEB expression serves as an analytical foundation which can be built upon as new information becomes available.

Section 2.0 describes the manner in which the data for the NNEB analysis was developed The topics selected for treatment include those which are expected to manifest the most significant societal impacts as well as a sampling of relevant impacts which illustrate a variety of data sources and analytical methods. Section 3.0 describes some details relevant to the calculation of some of the externalities.

The final section contains the conclusions derived from the application of the data developed in Section 2.0 to the NNEB equation. The results are summarized in graphs showing NNEB plotted vs. operational date for each of the alternate energy generation plants. These graphs show that for plants which become operational in the period of interest, 1985-2020, the social value of the solar alternative is significantly greater than oil, while it surpasses coal beyond 1995.

As was stated above, this document represents a status report on the study of societal impacts. Given the short performance time and the limited resources available to the project, completion of the study was not expected. A more realistic goal of the study, given the existing constraints, is to define the approach to be used, develop data in areas where significant impacts are expected, and test the behavior of the selected methodology under alternative assumptions. A great deal more work remains to be done, particularly in the areas of pollution impacts and resource depletion. As the treatment of external impacts in the NNEB expressions becomes more comprehensive, the differences between the net national economic benefits for alternative sources will become increasingly valid as representations of their actual relative merits.

2.0

DATA DEVELOPMENT

There is considerable difficulty associated with the development of data which are to be used in the net national economic benefits analysis. This difficulty stems from several sources which will be described in an attempt to give some appreciation for the variance inherent in the input data.

First, there is a certain amount of disagreement in cost estimates derived for mature technologies such as construction and operation costs of fossil fuel plants. These spreads are typically of the order of 20 percent and may be satisfactorily resolved by averaging the estimates of several experienced groups. Beyond this is the fact that reliable cost data do not exist for some of the more advanced concepts being considered. Some pollution control equipment and solar plant construction, operation, and maintenance costs fall into this category. For these, forecasts provided by engineering studies and whatever consensus can be found in the technical community are employed.

Second, is the problem of how to treat the data so as to derive numbers which may be used in the NNEB calculation. Pollution is a case in point. It is generally conceded that pollution is offensive, damaging to materials and vegetation, and injurious to health. Quantifying these effects in dollar terms, however, is difficult. For example, it is clear that the quantity of pollution is not as significant as its concentration, and interactive effects of certain pollutants in combination have been observed. In addition, the health effects of the several pollutants are imperfectly understood because of inadequate research. Thus, the problem of quantifying the impact of releasing a ton of a given pollutant into the air is doubly difficult.

Third, there is the constant requirement to correctly account for internal and external costs. For example, should the term "resource depletion" include elements called "material requirements" and "land requirements," or will these costs already have been adequately accounted for in the construction cost estimates? What fraction of the health cost of coal mine workers has already been internalized (and thus appears in the cost of coal to utilities), and what fraction must be counted as an environmental impact?

Finally, there is the problem of projecting estimates far into the future. In appreciation of all these uncertainties, data have been developed with great care. Moreover, at each step the underlying assumptions together with plausibility arguments have been presented to substantiate data selections. On occasion (e.g., choice of a social discount rate) the plausibility arguments identify a range of values that is appropriate for investigation. Thus, an attempt was made not only to develop data of reasonable quality, but also to give the reader an appreciation for the uncertainties involved.

2.1 THE SOCIAL DISCOUNT RATE

2.1.1 Reasons for Discounting

Before the development of organized financial markets or modern banking systems, merchants often discounted bills or notes held by their customers who needed to liquidate these assets before maturity. The merchant paid or gave credit for less than the bill's face value (i.e., bought it at a discount) in return for transfer to him of the right to collect the face amount from the original borrower. When the obligation was paid at maturity, the merchant earned interest on his purchase price. Thus, discounting of a future benefit or cost, whether it occurs singly or as part of a stream over time, is just the process of computing the present value of a claim on (liability for) the future benefit (cost).

An example will serve to relate the familiar mechanics of discounting to the above paradigm. If the going rate of compound interest is r percent per year and the use of one dollar is postponed for t years, the amount repaid at the end of t years would be $\$1\ (1+r)^t$. Therefore, the present value to a lender or to a borrower of a one-dollar cash flow t years hence is $\$1/(1+r)^t$. The present value to the lender (borrower) of one dollar t years from now is less than one dollar because he is willing to sell (buy) $\$1/(1+r)^t$ now in exchange for the future return (repayment) of one dollar.

Three factors cause the rate of interest to be positive. Individuals prefer consumption earlier over later in time. Hence, they require a financial incentive to postpone consumption when they lend money. Investments, social or private, are risky, and most individuals are risk-averse. Hence, investors require a financial incentive to invest in projects with uncertain outcomes. In an inflationary economic environment, borrowers expect to repay their loans in dollars having lower purchasing power and lenders expect to receive such dollars. Interest rates adjust to these expectations. Lenders require interest rates high enough to compensate for the expected loss of purchasing power per dollar and borrowers are willing to pay the higher rates because their choices between the present and the future are in terms of utilization of real resources.

The above observations, which are presented in terms of private investments, also pertain to social investments. Since governments, as well as individuals and corporations, borrow and lend at positive interest rates, it follows that "society," which is comprised of these groups, requires an economic incentive for postponing consumption and bearing risk. Therefore, societal benefits and costs should be discounted in evaluating social investment alternatives just as private cash flows should be in evaluating private investment alternatives.

If benefits and costs were constant over a project's lifetime, all that would be necessary to decide whether benefits exceeded costs would be comparison of the annual figures. Since this is generally not the case (e.g., costs may be relatively higher earlier in time and benefits may build up over time) the analysis of social investment alternatives should discount benefits and costs to a present value for the purpose of comparison.

2.1.2 Selection of a Social Discount Rate

Market rates of interest at any point in time are determined not only by investors' required returns for time and risk, but also by the distribution of returns on available investment opportunities. Investors bid for available returns and collectively determine a structure of asset prices which establishes a capital market equilibrium. Prices of capital assets fluctuate as they do because new information is constantly coming to the capital markets causing investors to adjust the compositions of their holdings.

In the private sector, investors have a considerable selection of securities from which to choose so that equilibrium rates of return are determined both by available expected returns and investor preferences. On the relatively riskless side of the spectrum, Treasury and municipal fixed income obligations are traded in active, organized markets. Thus, average returns required by investors in fixed income government securities are observable. The same is true for corporate bonds and equity instruments. In the public sector, taxpayers are the "equity holders," and returns to them are not easily measured. Thus, the discount rate cannot be inferred as objectively from returns on financing instruments for public sector projects as for private sector projects.

Rates of return available in the private sector are generally regarded as higher and gestation periods for investments are generally considered shorter than in the public sector. Relevant risks may also be higher in private sector investments. Individuals' time preferences are often regarded as being lower relative to public sector investments than those in the private sector. The reason for this lower rate of time preference, as Marglin[(1)] argues, is that individuals are willing to accept government's investment in projects which are considered to be in the public interest but have low rates of return or diffuse benefits because government sponsorship eliminates the problem of potential beneficiaries evading their share of the costs. Because there is no clear, objective method for choosing the social discount rate, the rate is treated parametrically in the net national economic benefits calculation. However, the range in which this parameter is permitted to vary is defined by observed rates of return on securities used to finance capital projects in the public and private sectors.

The real rate of return on a Treasury Bill is taken as the lower bound to the social rate of discount. Treasury Bills are riskless since principal and interest are a direct obligation of the Federal Government. Hence, the social discount rate on projects whose outcomes are uncertain to a greater or lesser degree must be above the Treasury Bill rate. A recent study[2] showed that the real rate of return on Treasury Bills, excluding inflation, has been relatively stable over the long period at about two percent per annum. This was also the rate of return that Treasury Bills yielded during the noninflationary 1950's. Since the benefit-cost calculation is expressed in terms of real dollar values, the real discount rate is the one that is relevant rather than the nominal rate which includes inflation.

The average real rate of return on investments in the private sector provides a benchmark for an upper bound to the social discount rate to be used in the benefit-cost calculation. The historical pre-tax combined return on U.S. corporate capital (debt and equity) has averaged about 10.7 percent per annum adjusted for inflation over the 1926-to-1973 period. (This estimate was derived by The Aerospace Corporation, based on the security price data of the Center for Research in Security Prices, University of Chicago.) The U.S. Office of Management and Budget has estimated a 10 percent rate in its Circular A-94 Revised.

The inflation rate adjustment assumed in deriving the 10 percent number was two percent per annum. While this inflation rate reflects the experience from the end of World War I to the mid-1970's, including periods of depression, war, and prosperity, the post-World War II rate of four percent might be a more relevant measure of expected inflation over the time period anticipated by the present benefit-cost calculation. Subtracting an additional two percent from the 10 percent figure leaves eight percent as the upper bound for the social discount rate. Accordingly, the net national economic benefits of alternative social investments analyzed by this study are computed at social discount rates in the range between two and eight percent.

2.2 VALUE OF ENERGY PRODUCED

The measure of gross economic benefits derived from a power plant will be the market value of the energy it produces. The quantity of energy produced by the solar plant depends on the local insolation and the plant configuration. For the particular central receiver design assumed in this study, the capacity factor is about 36 percent in Arizona and 29 percent in Florida. The alternative oil and coal plants are assumed to operate with the same capacity factors, and hence, to produce the same output of energy.

Prices of electricity to commercial, industrial, and residential users have been projected for each State to the year 2015 by Sherman H. Clark Associates.(3) The data of Figures 2-1 and 2-2 are weighted average busbar costs where the weights are proportioned to the total energy generated by each vintage of each type of power plant in the year of the projection. The costs of power transmission and distribution are added to the weighted average busbar costs to obtain market price projections. In extrapolating the curves beyond the year 2015 to 2050, the slope of the curve at the year 2015 was preserved.

2.3 INTERNAL COSTS

The "internal" costs of the power plant are represented by the construction costs, operation and maintenance costs, and fuel costs. Construction costs for coal-fired and oil-fired plants were obtained by averaging estimates made by the Federal Power Commission, the Stearns-Rogers Company, and EBASCO after expressing each in 1978 dollars. Estimates of operation and maintenance costs are those of Sherman H. Clark Associates. These costs appear in Table 2-1. No escalation beyond inflation is assumed so these costs remain constant for the entire time span of interest.

Table 2-1

INTERNAL COST ASSUMPTIONS
(In 1978 Dollars)

Type of Plant	Construction	O&M
Coal-Fired	\$638/kW	\$5.60/kW-yr
Oil-Fired	\$564/kW	\$3.60/kW-yr

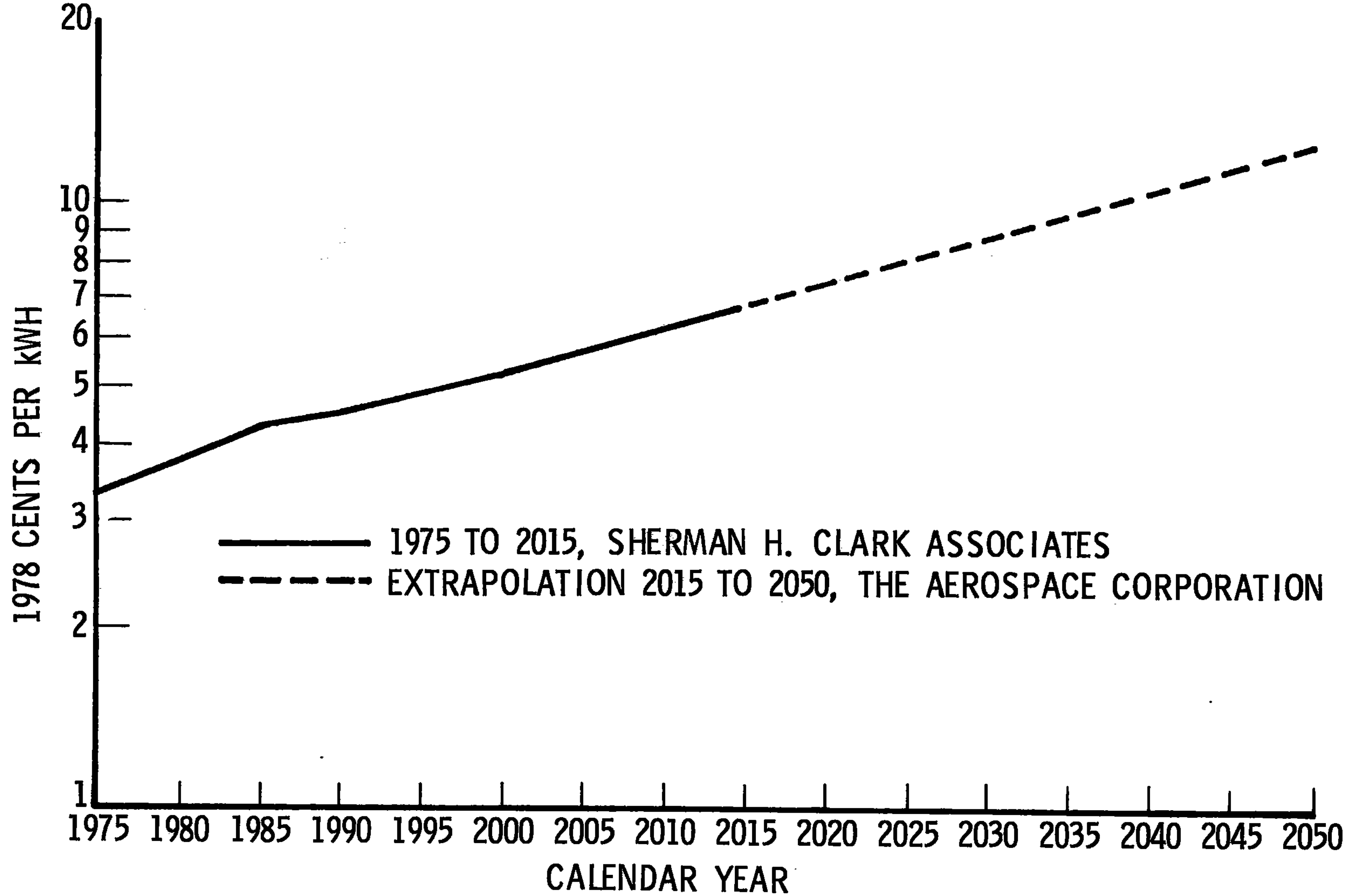


Figure 2-1. Price of Electricity vs Year - Arizona

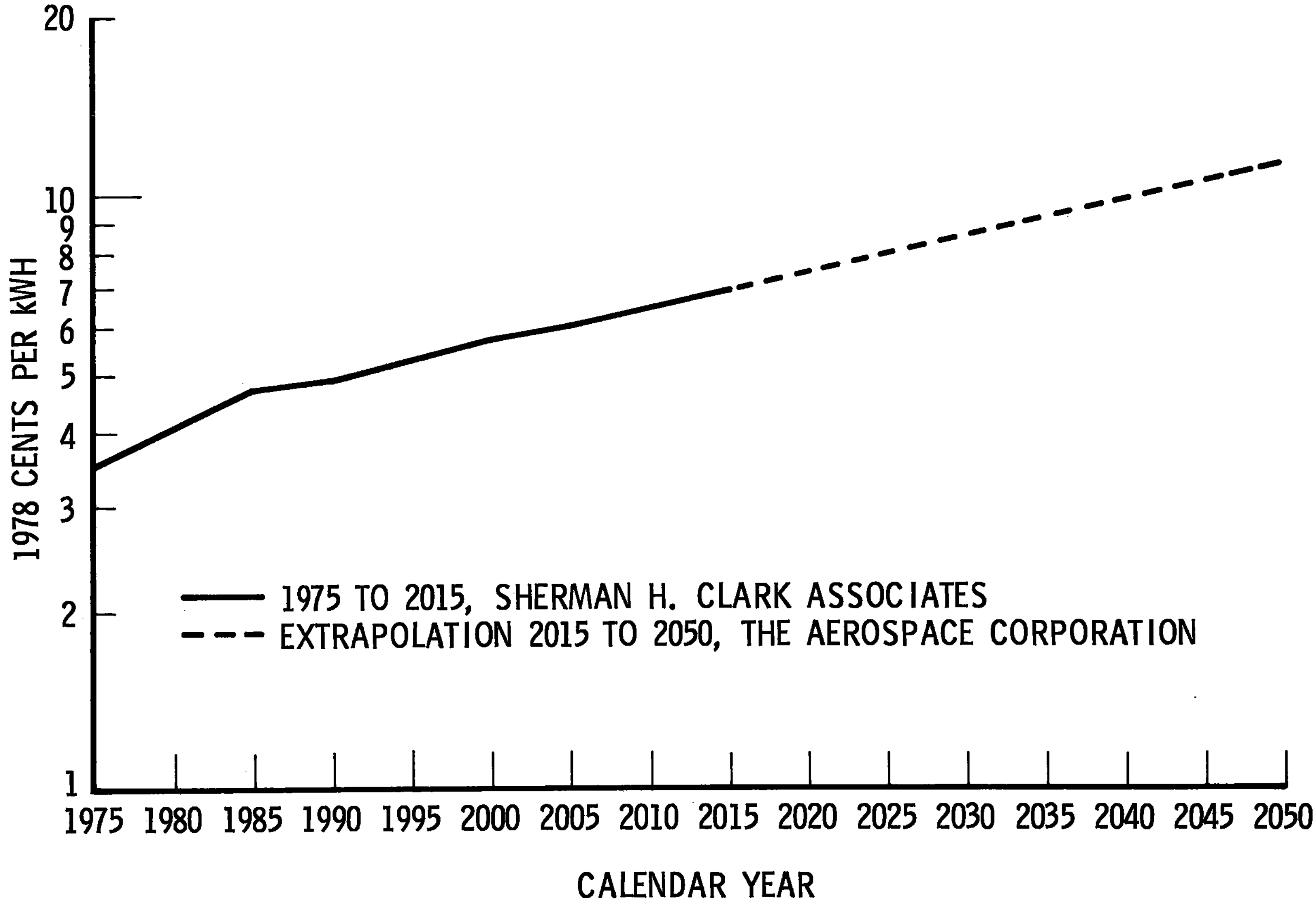


Figure 2-2. Price of Electricity vs Year - Florida

The capital costs of SO_x scrubbers for coal plants were derived from estimates provided by Reference 3. Figure 2-3 shows that they project pollution abatement costs rising at a decreasing rate with time, finally leveling off around the year 2000. This time pattern is due to expected increasingly strict requirements to the year 2000 offset by technological advances and economies of large scale production. Construction, and operation and maintenance costs for a central solar receiver plant with six hours of thermal storage are based on a 1977 study[4] by McDonnell Douglas Astronautics Company. Beyond the year 2000, construction cost estimates are based on an application of a methodology developed by Sandia Laboratories. This is essentially a savings through mass-production argument wherein unit costs for heliostats are projected to decrease as the installation rate for solar plants increases. These data appear in Figure 2-4. Annual O&M costs were taken to be one percent of the plant construction cost.

Fuel prices to the coal and oil-fired plants in Arizona and Florida are based on projections to the year 2015 taken from Reference 3. Extrapolations to the year 2050 were made by assuming that the trends at 2015 would continue. However, the extrapolated price of coal per million Btus was not permitted to rise above that of oil because future prices of substitutes are expected to be determined by the price of oil. These data are illustrated in Figures 2-5 and 2-6.

2.4 TAX POLICIES

This section describes Federal tax and subsidy policies that can act in non-neutral ways to affect the market decisions that involve energy demand and supply. If a tax is imposed with reasonable uniformity on energy products, it is not relevant for the NNEB calculation. However, because tax preferences and subsidies are applied unequally on different modes of energy production, comparisons of NNEBs of alternative energy sources would be distorted if adjustments were not made. In particular, comparison of the NNEBs of solar energy sources and directly or indirectly subsidized conventional alternatives would be biased against the solar source.

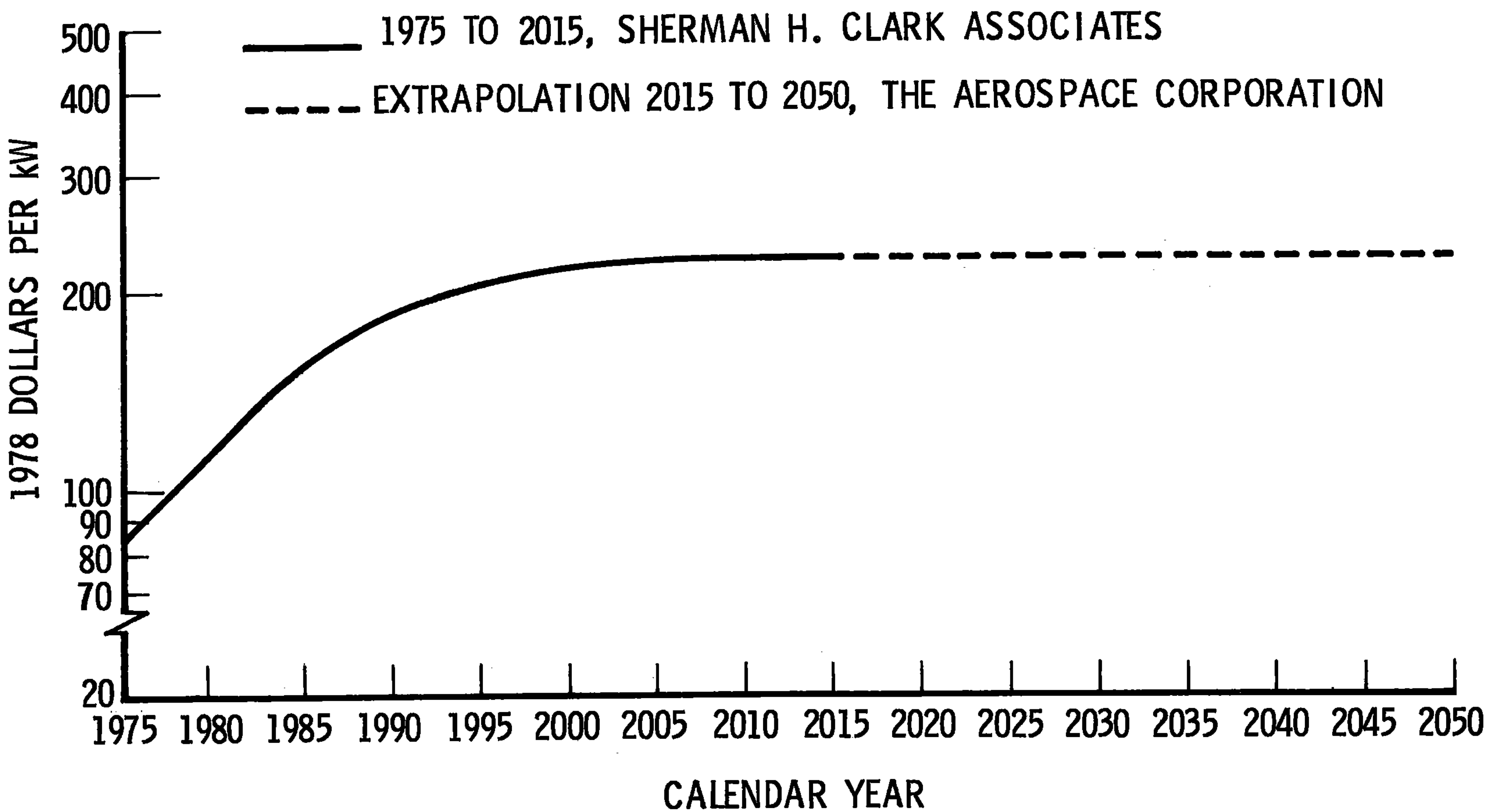


Figure 2-3. Capital Cost for Pollution Control - SO_x Removal

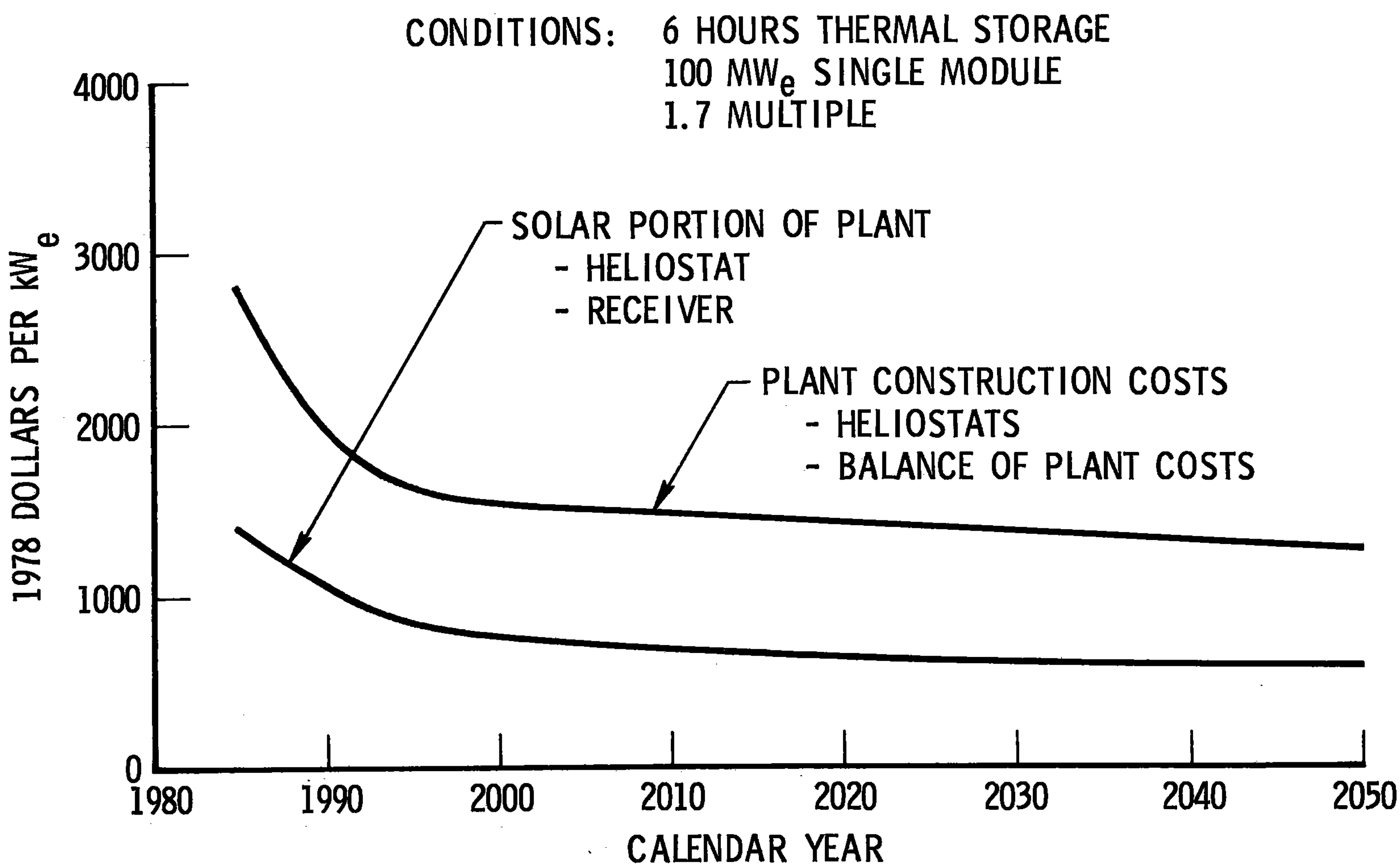


Figure 2-4. Long Range Commercial Plant Costs - Central Solar Receiver

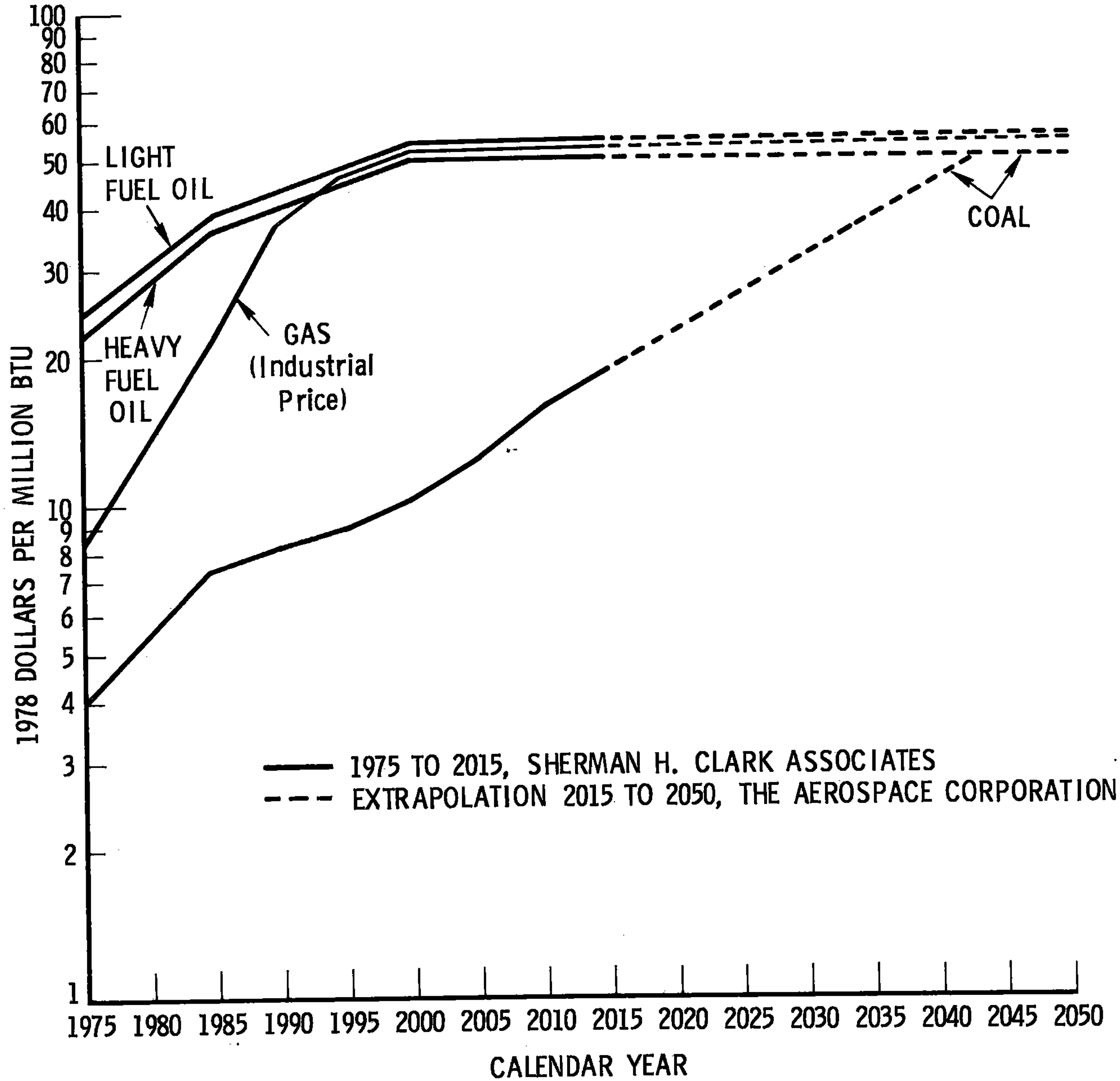


Figure 2-5. Fuel Prices to Power Plants - Arizona

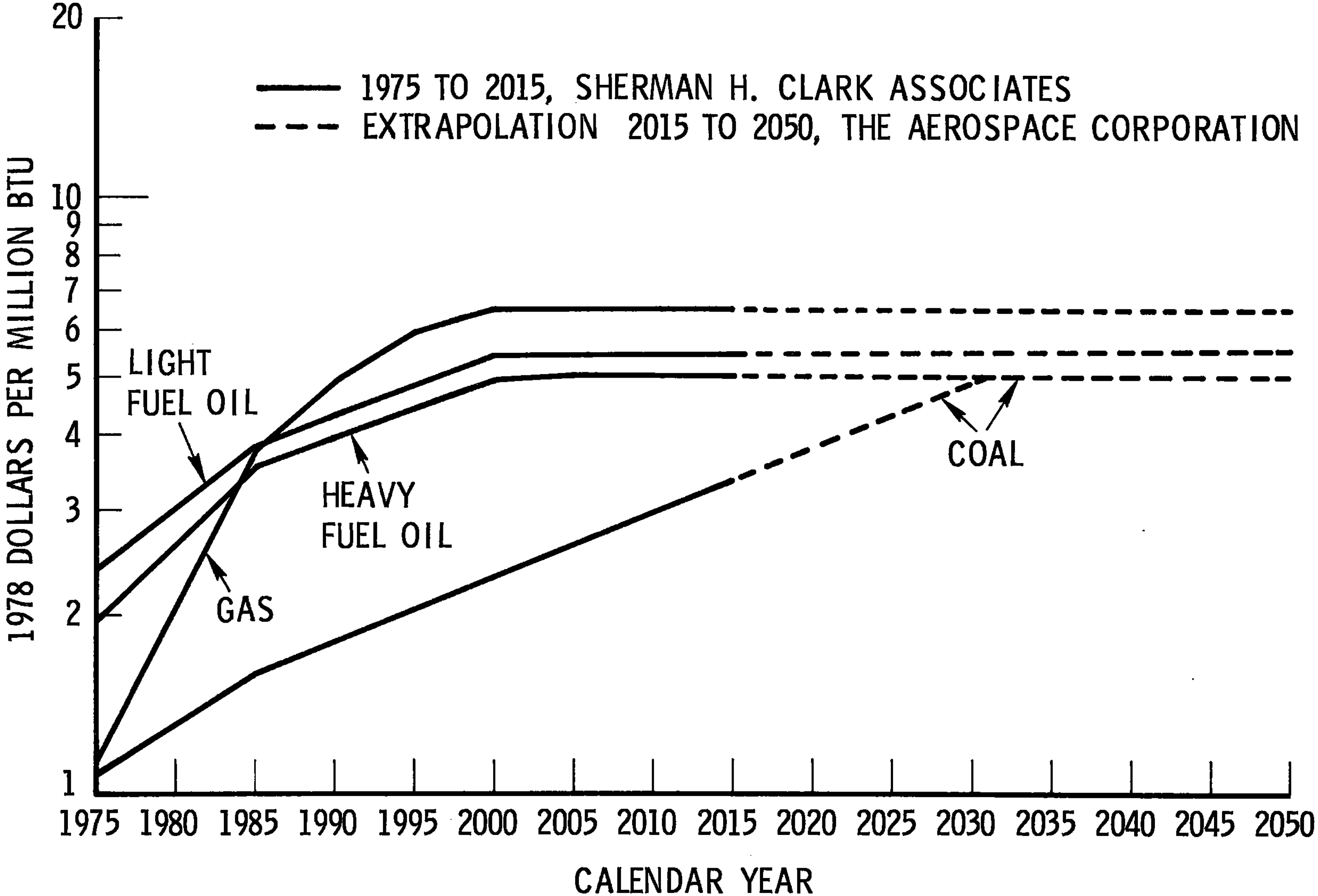


Figure 2-6. Fuel Prices to Power Plants - Florida

In the present analysis, emphasis is placed on the special Federal income tax preferences relating to oil and coal. These include percentage depletion, the expensing intangible drilling costs and foreign tax credits. Only the first two, of course, pertain to the coal industry.

2.4.1 Percentage Depletion

The extractive industries deal with depleting assets. Thus, as the material is removed from the ground, the original deposit is correspondingly reduced. To recognize the cost of the diminishing asset, the law permits a depletion deduction from the income tax liability. A justification for granting a depletion allowance was given by Mr. Justice Brandeis in U.S. vs. Luday, 274 U.S. 295 (1917), where he said:

> "The depletion charge permitted as a deduction from gross income in determining the taxable income of mines for any year represents the reduction in the mineral contents of the reserves from which the product is taken. The depletion affected by operation is likened to the using up of raw material in making the product of a manufacturing establishment. As the cost of the raw material must be deducted from the gross income before the net income can be determined, so the estimated cost of the part of the reserve used up is allowed."

Later the Supreme Court confirmed this interpretation when it stated in Anderson vs. Helvering, 320 U.S. 404 (1940) that:

> "Oil and gas reserves, like other materials in place, are recognized as wasting assets. The production of oil and gas, like the mining of ore, is treated as an income-producing operation, not as a conversion of capital investment as upon a sale, and is said to resemble a manufacturing business carried on by the use of the soil....The granting of an arbitrary deduction, in the interests of convenience, of a percentage of the gross income derived from the severance of oil and gas, merely emphasizes the underlying theory of the allowance as a tax free return of the capital consumed in the production of gross income through severance."

In essence, then, the depletion deduction is grounded in economic principle, authorized by Congressional action, and legitimized by the Supreme Court of the

United States. Superficially, it appears that Congress and the Court were attempting to draw a parallel with the depreciation treatment of capital assets permitted in other businesses. However, the fact that the depletion allowance permits a deduction of a fraction of the revenues each year rather than a fraction of the cost leads to the unequal tax treatment of the extractive industries relative to other industries.

To get some perspective on the origin of the treatment of percentage depletion it may be useful to trace some highlights in the history[5] of this feature of the income tax law. Originally, the income tax law provided a deduction for depletion of all mineral deposits not to exceed five percent of the gross value of the output at the mine or well for which the computation was made. Because this provision was sometimes not sufficient to recoup the cost over the life of the property, a new act was passed in 1916 which provided that the total depletion allowable over the life of the property could not exceed the capital originally invested. It also stated that the recovery of the investment for any year must be in the same ratio that the recovery of minerals for the taxable year bears to the estimated total recoverable reserves in the property. This was clearly an attempt to tie the depletion deduction to the cost of the property.

An important change of concept occurred in 1918 when an effort was made to stimulate exploration and extraction of our natural resources for which World War I had created such demand. The new law stated that, "where the fair market value of the property is materially disproportionate to the cost, the depletion allowance shall be based on the fair market value of the property at the time of the discovery, or within 30 days thereafter . . . ."

This provision represented a sharp departure from depletion based on cost and resulted in a great expansion of exploration activity for natural resources, especially oil and gas. It also introduced administrative difficulties, particularly those associated with determinations of discovery value. So pressure for additional legislation mounted.

In the Revenue Act of 1926, discovery value depletion was replaced by percentage depletion in the case of oil and gas. Under this provision, any producer of oil and gas or owner of an interest therein, such as a royalty owner, was entitled to deduct 27 percent of his gross income from the sale of oil and gas, but not to exceed 50 percent of his net income from the property. In 1932 this provision was extended to include coal, metals, and sulphur, but at the rate of 5, 15, and 23 percent, respectively, all being limited to 50 percent of the net income.

In the period between 1932 and the outbreak of World War II, the new percentage depletion concept was being applied to limited sections of the mining industry without great awareness on the part of producers of other minerals. With the start of World War II, however, the demand for minerals in the United States was once again greatly expanded and it became necessary to encourage mineral production in many categories not already covered. The Revenue Acts formulated during the war extended percentage depletion to minerals such as feldspar, beryl, mica, potash, flake graphite, rock asphalt, talc, and vermiculite, all at 15 percent. It was the expressed intention of Congress to limit percentage depletion on these minerals to the period of the war emergency. However, with the completion of the war, the right to percentage depletion was not only continued for these minerals, but was extended to others.

The Tax Reform Act of 1969 reduced the depletion allowance for oil and gas from 27-1/2 to 22 percent. However, G.P. Jenkins[(6)] concludes that this adjustment had a negligible effect on the after-tax income of the large, international oil producers, and that a considerably larger reduction (e.g., 15 percent had been proposed by Senator Proxmire) would have had similarly unimportant consequences. These conclusions result from a consideration of the excess foreign tax credits which the international producers accumulate annually. On the other hand, such a reduction could very well be important to domestic producers.

In 1975, in response to the reported record profits of the oil industry and record prices for oil, the Congress repealed the percentage depletion allowance for about 200 of the largest oil companies, but left it intact for almost 10,000 smaller "independents."

This brief history of the depletion allowance was presented to illustrate that, like most tax measures, it is an instrument of government policy. As such, it is subject to changes under pressures from public and private interests. Its opponents claim that in no other business is the investor permitted to recover tax-free his original investment cost many times over, and that this special treatment artificially stimulates inefficient, wasteful exploration and use of a scarce natural resource. Its defenders claim that special treatment is necessary to encourage the search for new reserves, and the elimination of these tax advantages will lead to price increases to the public. The intent of this section is not to espouse or support either point of view, but to quantify the hidden costs associated with the depletion allowance and other special tax treatments so that the true costs of alternative fuels will be more accurately represented in the NNEB calculation.

2.4.2 Intangible Drilling Expenses

The law permits the taxpayer to charge off as incurred the costs of drilling for oil and gas, whether the hole is producing or dry. These costs include labor and supplies, but exclude depreciable property used in the drilling. The latter is eligible for the same tax treatment available to business generally -- normal depreciation schedules and the investment tax credit. All other businesses are bound by the tax rules to spread their costs over the life of their capital investment. The effect of taking the entire tax benefit immediately is tantamount to an interest free loan from the government.

Brannon[7] has estimated the net value of tax benefits from percentage depletion and expensing of intangible drilling costs for some of the extractive industries. These calculations are difficult for lack of data, so reasonable inferences were made from what data was available. He began with the statutory rates for percentage depletion applied to gross income, applied adjustments for the minimum tax rate, net income limitations, and cost depletion that would have been allowed, then added a term for drilling expenses expressed as depletion to find the net tax benefit. His conclusions are summarized in Tables 2-2 and 2-3.

Table 2-2

NET BENEFIT OF PERCENTAGE DEPLETION AND EXPENSING OF INTANGIBLE DRILLING COSTS AS A PERCENTAGE OF MINE OR WELL MOUTH PRICE

	Oil & Gas	Coal
Gross Rate	22%	10.0%
Net Benefit	21%	4.4%

Table 2-3

NET VALUE OF TAX BENEFITS AS PERCENTAGE OF DELIVERED PRICE TO ELECTRIC COMPANIES

	Oil	Gas	Coal	Gas From Coal
Tax Value as % of Price at Mine/Well Mouth	19.4	19.4	4.0	4.0
Ratio of Price at Mine/Well Mouth to Delivered Price to Electric Company	.70	.61	.83	.33
Tax Value as % of Delivered Price	13.6	11.8	3.4	1.3

The net benefit can be translated quite easily into a price equivalent, since with a corporate tax rate of 48 percent it would be necessary to raise the price by 48/52 or 92 percent of the net benefit to yield equivalent income to the producer.

This well or mine-mouth comparison does not provide a full comparison of the distorting effects of the tax provisions on user costs because the final user buys a number of services, some of which are performed in the mining stage and others in the manufacturing and distribution stages. The tax benefits, however, relate only to the mining services. A way to make the effects of the tax benefits comparable is to express them as percentages of the price in a common application, such as the generation of electricity. These computations are carried out in Table 2-3 where the results indicate a rather uneven impact of the tax provisions. The benefits range from an effective price reduction of 13.6 percent enjoyed by oil to 1.3 percent for gas derived from coal. Solar energy, of course, would enjoy none of these benefits.

2.4.3 Foreign Tax Credit

A United States taxpayer conducting a business abroad is subject to taxes in the country in which the income is earned. If the foreign tax is a tax on income or a tax in lieu of an income tax, the U.S. company is permitted to deduct the foreign tax from its U.S. tax liability arising from that foreign income.

Among the energy industries, foreign business is an important factor only for oil and gas. Further, the oil and gas situation is unique because a limited number of foreign countries have successfully organized a cartel, the Organization of Petroleum Exporting Countries (OPEC) to enforce their demands for higher revenues for their oil. The remarkable cohesion of this cartel to date is related to the combination of extraordinarily high profits and extraordinarily high foreign government exactions.

The OPEC countries impose income tax on oil and gas operations at a higher rate than the income tax on normal domestic business in those countries. Effectively, the government is the owner of the gas and drilling rights. Typically, the owner of a mineral in the ground is able to charge a royalty for the right to drill and extract it, and the amount of the royalty varies with the prospective profit from extraction. In the Mid-East, particularly, the oil reserves are much richer than are reserves in the U.S. and extraction costs are much lower. Consequently, one might expect that royalties for drilling rights would be relatively high in these areas. Despite this, the nominal royalty rate is no higher than 12-1/2 percent, which is commensurate with U.S. standards.

An additional peculiarity of the foreign tax on oil profits arises because the OPEC governments are particularly concerned about the price at which the oil producers sell oil to their own refineries. Since the tax rate in the OPEC countries is 60 percent and higher, the companies could save taxes by selling to their refineries at a low price. In that case, the revenues of the host countries would be subject to the price manipulations of the integrated oil companies. To forestall this maneuver, the OPEC countries adopted the practice of computing the tax on gross sales at a hypothetical "posted" price without regard to the actual sales price. This practice converts the tax to something very close to an excise tax, which would normally be ineligible for a foreign tax credit.

The origin of the foreign tax credit is said to go back to 1950 when it had already become obvious that the huge oil reserves of the Middle East were of enormous economic and strategic importance to the United States and the West European democracies. And the biggest reserves of all were in Saudi Arabia where ARAMCO held the concessions for oil production and development. Thus, when King Ibn Saud asked for a larger share of the oil revenues -- he wanted the same arrangement the oil companies had negotiated with Venezuela not long before — discussions were initiated between ARAMCO, the State Department, and the Treasury Department to produce a solution that would give the King what he wanted at no cost to the oil company. Under the terms of the arrangement, ARAMCO would make additional payments to the King, but these would be regarded by the American government not as royalties on oil production, but as income taxes paid to a foreign government. The distinction is important. Under U.S. tax laws, royalties are treated as deductible business expenses, meaning that the tax benefit is only 48 cents on the dollar. But foreign taxes may be treated as credits and subtracted dollar for dollar from the company's U.S. tax liability.

Another way to look at this is to note that if the Federal government were to rule that these payments to foreign governments are truly royalties, then income taxes would be forthcoming from the oil companies. These payments would then relieve the general public of a portion of its own tax bill. Thus, in effect, a portion of the cost to the consumer of imported resources is included in his income tax.

To estimate the value of this tax arrangement in terms of the price of imported oil the after-tax profit of an international oil company are described under two different circumstances: one, representing the current situation in which payments made to the host countries are called, for the most part, income taxes; and the other, in which these payments are considered, for the most part, royalties, so that a U.S. tax liability remains. In the latter case, the total payments to the host countries will be assumed to be the same as in the former case, and the oil company will be assumed to raise its prices so that its net after-tax profits remain unchanged. This price increase, then, should represent the additional cost of oil to the consumer included in his Federal taxes.

Writing the after-tax profits in these two ways yields:

$$G - E - A + C_T = (G' - E - R')(1 - .48) \tag{1}$$

The left-hand side of equation (1) represents the present case where

> G is the gross income (price per barrel X number of barrels);
>
> E is the expenses (assumed to be proportional to G, i.e.,
>
> $E = eG$, where, according to some estimates $e \approx .03$);
>
> A is the payment to the host country ($A = aG$);

and C_T is the excess foreign tax credit which is generated when the ostensible foreign tax rate is larger than the 48 percent imposed in the U.S. Prior to the 1975 tax changes, the excess credit could be applied toward the U.S. tax liability on other foreign income and therefore could be included in net profits. The value of the excess tax credit may be represented as

$$C_T = A - (G - E)\,.48 \tag{2}$$

On the right-hand side of equation (1):

> G' is the gross income based on the price that just compensates for the less favorable tax treatment;
>
> E is the expenses (assumed to be the same); and
>
> R' is the royalty income to the host country.

Thus, the first factor represents the taxable income, and multiplication by the second factor yields the after-tax income. To insure that the host country income is the same in both cases, A is set equal to R'.

Equation (1) then becomes

$$G\,(1 - e) = G' - G\,(e + a),$$

So that

$$G' = G\,(1 + a). \tag{3}$$

The experience of the recent past teaches that a, the fraction of the sales price which is taken by the host country, ranges between 60 and 85 percent. In the present examples, a = .75 is chosen as representative. If such a price increase were instituted, a net result would be that the host countries would continue to receive the same income, A = .75G, that they are currently receiving. Further, the oil company would realize the same net profit as under the favorable tax treatment, but they would have a U.S. tax liability, .75G. The U.S. consumers of oil products would pay an amount (1 + a)G, or 75 percent more than they now pay, but U.S. taxpayers would find their tax bills reduced by the same absolute amount.

To the extent that the make-up of the group of U.S. taxpayers is the same as that of U.S. consumers of oil products, the increased cost of oil would be exactly made up by the tax savings. The only difference is that now the costs for oil would not appear artificially low for being partly covered by federal income tax payments.

The effect of the foreign tax credit, therefore, is to make the costs of oil products appear artificially low. Calculations of these tax benefits in the generation of electricity applying the same factor found in Table 2-3 for the ratio of the price at the well mouth to the delivered price, are presented in Table 2-4.

Table 2-4

NET VALUE OF FOREIGN TAX CREDITS AS PERCENTAGE OF DELIVERED PRICE TO ELECTRIC COMPANIES

	Oil	Gas
Tax Value as % of Price at Well Mouth	75	75
Ratio of Price at Well Mouth to Delivered Price to Electric Company	70	61
Tax Value as % of Delivered Price	52	46

In an interesting aside, the effect of the tax benefits discussed above on the busbar costs of electrical energy were estimated. Table 2-5 summarizes these findings when applied to 100 MW_e electricity generating plants. Results of previous studies(8,9) indicate that fuel costs constitute about 68 percent of busbar energy costs for oil plants, 32 percent for gas burning plants, and 31 percent for coal plants.

Table 2-5

NET VALUE OF TAX BENEFITS AS PERCENTAGE OF BUSBAR COSTS OF ELECTRICAL ENERGY TO CONSUMER

	Oil	Gas	Coal	Coal From Coal
Depletion + Intangible Drilling Costs	9.2	3.8	1.0	.4
Foreign Tax Credit	35.	14.7	---	---

Legislative corrections to the tax laws are made from time to time when the incentives envisaged by the original laws are no longer required, or when the public desire for closing "loopholes" is recognized. In 1975, it was decreed that future foreign tax credits would be limited to foreign oil-related income. That is, credits could no longer be used to offset income from other foreign sources. Furthermore, tax credit carry-forwards generated in years prior to 1975 could be applied only to foreign oil-related income. The Tax Reform Act of 1976 limited foreign tax credits on extraction income to 48 percent of that income.

The effect of these changes depends on how the payments to the host countries are viewed. Again, consider two cases wherein the after-tax income to the oil companies and the total payments to the host countries remain the same. The formalism for describing these two cases is similar to that of Equation (1); however, because foreign tax credits are now limited to 48 percent of the net income, there are no excess tax credits which may be applied to non-oil businesses. Therefore the new situation is represented by Equation (4) where the symbols have the same meanings they had for Equation (1).

$$G\text{-}E\text{-}A = (G' - E - R')\,(1 - .48) \tag{4}$$

Payments to the host countries are represented by A on the left-hand side, but R' on the right-hand side to stress the fact that for case 2, these payments are considered to be royalties. Substituting A = R' in Equation (4) yields

$$G' = \frac{G}{.52}\left[1 - .48\,(e + a)\right] \tag{5}$$

and

$$G' \quad 1.36\,G$$

That is, if payments to host countries were treated as royalties instead of offsets against U.S. income tax liability, the market price of oil would be up to 36 percent higher. Stated another way, as much as 36 percent of the cost of oil is being borne by the American taypayer.

Revising the data of Table 2-4 in the light of the new tax laws, yields the numbers summarized in Table 2-6. These are the numbers used in the NNEB calculations.

Table 2-6

NET VALUE OF FOREIGN TAX CREDITS AS PERCENTAGE OF DELIVERED PRICE TO ELECTRIC COMPANIES

	Oil	Gas
Tax Value as % of Price at Well Mouth	36	36
Ratio of Price at Well Mouth to Delivered Price to Electric Company	70	61
Tax Value as % of Delivered Price	25	22

2.5 STRATEGIC PETROLEUM RESERVE

The establishment of a strategic petroleum reserve imposes a Government policy cost on an oil plant, external to the construction and operating costs, which is not borne by an alternative domestic energy source. This cost is proportional to the capacity of the reserve which, in turn, is related to the steady-state rate of flow of oil imports expected in the energy policy assumptions. Adoption of an equivalent solar plant in place of an oil plant would permit the quantity of oil imports each year to be reduced by the amount of crude oil required to generate the annual electrical energy output of the oil plant. This section summarizes the history[10] of the strategic petroleum reserve concept and outlines the methodology employed in the present benefit-cost calculations.

Restriction of oil exports by the major oil exporting nations would be economically disruptive to the United States, and the possible limitation of oil exports to friendly nations dependent on oil imports restricts American options in international diplomacy. Hence, minimization of the political and economic effect of a potential cessation or significant reduction of oil exports is a major U.S. policy objective. One element of the strategy for achieving this objective is the creation of a strategic petroleum reserve to supplement private inventories in the event of an oil embargo.

The 1975 Energy Policy and Conservation Act authorized storage of 150 million barrels of crude oil by December 1978, 500 million barrels by 1982, and, ultimately, one billion barrels. In the 1978 Budget, President Carter accelerated the program to achieve 500 million barrels by 1980 and one billion barrels by 1985.

The 21 April 1977 Wall Street Journal summary of the Carter energy plan stated that a "one billion barrel reserve would allow the U.S. to withstand a 'serious supply interruption' for 10 months." At today's rate of imports one billion barrels represents a four-month supply.

Alternative methods of satisfying the oil storage objective have been considered. One alternative is to store petroleum products in dispersed locations near final markets. Another is to store crude oil in a few large installations and to withdraw it as needed for refining and distribution. The crude oil storage option has been estimated to be substantially less expensive than the products storage option and it has the additional advantage of forestalling possible exposure of some regions to shortages because of misestimates of future requirements.

The capital cost of the storage facility is estimated to be \$1.50 per barrel (1977 dollars) in the 1978 Budget with one cent to two cents per barrel recurring annual maintenance cost. The cost of the oil fill itself is computed at the import price of \$14.50 per barrel (based on 1977 prices) because this represents the price of the incremental source of crude. Budget authorizations for the strategic reserve totalled \$800 million in 1976 and 1977. Outlays from 1977 through 1980 are estimated at \$8.6 billion in the 1979 U.S. Government Budget.

The computation of the cost of the strategic crude oil reserve required to supply a 100 MW_e oil plant is based on the energy content of the fuel required to generate the plant's output at the assumed capacity factor. A plant with a 36 percent capacity factor (e.g., the present Arizona example) generates 315.4 billion kilowatt hours of energy per year. Taking 30 percent for the average thermal efficiency of a U.S. oil plant yields the requirement of 3.6 trillion Btu's of input energy annually. This translates to about 641,000 barrels of crude oil per year. Since the stockpile would represent a four-month supply, the strategic reserve capacity attributable to this oil plant is 214,000 barrels.

The benefit-cost calculation assumes that President Carter's objectives are met. It also assumes that the filling rate is constant between 1978 and 1980 until the first 500 billion barrels of capacity are filled, and then constant at a lower rate until the next 500 billion barrels are filled in 1985. The computation uses the projected foreign crude oil acquisition price in 1985 from Reference 3 and assumes that the price increases at a uniform rate from the present price until then.

Although one function contemplated for the strategic reserve is to supplement domestic inventories and other sources of supply, no schedule of withdrawals is presented in the Budget, so an assumption of such a schedule would be completely speculative. In addition, even if some oil were withdrawn, it would soon have to be replaced to maintain the reserve's effectiveness as a deterrent to an embargo. Therefore, it is assumed that there is no return of oil from the strategic reserve and the calculation does not include any benefits from this source. Thus, the cost of the reserve is simply computed from the construction cost, oil acquisition costs, and the recurring operating expenses. Tables 2-7 and 2-8 present the price and quantity assumptions used in calculating the cost of the strategic petroleum reserve attributable to the oil plant.

It is assumed that a solar plant would reduce dependence on imported oil and thereby permit the size of the strategic reserve to be reduced without compromising the government policy objective of providing a given number of month's supply in reserve. The feasible amount of reduction for the Arizona example is 214,000 barrels per plant. The value of this benefit is part of the difference between the computed net national economic benefits of a solar plant and that of an oil plant with an equivalent energy output.

2.6 COAL SURFACE MINING RECLAMATION COSTS

In spite of the fact that reclamation costs per acre of strip-mined land may be high compared with its prior economic use, society is demanding reclamation in order to preserve its range of future options. Furthermore, it is clear that these costs are to be borne by current mining operations so it is important to attempt to quantify

Table 2-7. Cost of Strategic Petroleum Reserve Attributable to 100 MW_e Oil Plant in Arizona

Year	Cumulative No. Barrels in Total Reserve (Millions)	No. Barrels Attributable to Oil Plant (Thousands)	Price/Barrel (1978 Dollars)	Fuel Cost Attributable to Oil Plant (Thousands)	Capital Cost at $1.60/Bbl to Oil Plant (Thousands)	Maintenance Cost/Year at 1.5¢/Bbl (1978 Dollars)
1978	150	32.1	14.93	479	51.4	481
1979	325	37.4	15.47	579	59.8	1043
1980	500	37.5	16.02	601	60.0	1605
1981	600	21.4	16.60	355	34.2	1926
1982	700	21.4	17.20	368	34.2	2247
1983	800	21.4	17.82	381	34.2	2568
1984	900	21.4	18.46	395	34.2	2889
1985	1000	21.4	19.12	409	34.2	3210
	Total	214.0				

Table 2-8. Cost of Strategic Petroleum Reserve Attributable to 100 MW_e Oil Plant in Florida

Year	Cumulative No. Barrels in Total Reserve (Millions)	No. Barrels Attributable to Oil Plant (Thousands)	Price/Barrel (1978 Dollars)	Fuel Cost Attributable to Oil Plant (Thousands	Capital Cost at $1.60/Bbl to Oil Plant (Thousands)	Maintenance Cost/Year at 1.5¢/Bbl (1978 Dollars)
1978	150	25.8	14.93	385	41.3	387
1979	325	30.1	15.47	466	48.2	839
1980	500	30.1	16.02	482	48.2	1291
1981	600	17.2	16.60	286	27.5	1549
1982	700	17.2	17.20	296	27.5	1807
1983	800	17.2	17.82	307	27.5	2065
1984	900	17.2	18.46	318	27.5	2323
1985	1000	17.2	19.12	329	27.5	2581
	Total	172.0				

these to see what impact they will have on the net national economic benefits associated with coal. Of the several studies performed to evaluate these costs, major reliance was placed on recent work performed at the Bureau of Mines.[11]

The Bureau of Mines estimated reclamation costs for 13 surface coal mines in nine states west of the Mississippi. Cost estimates were based on data obtained from company records, interviews with industry personnel, and on-site observations.

The term "mined land reclamation" refers to returning the disturbed land to a condition and/or use equal to or higher than that prior to mining. Local, State, and Federal regulations governing reclamation were used as a guide for the study.

Four regions, designated A, B, C and D, were selected for presentation of the study results:

> Region A is the coal mining area of Kansas and Missouri in the western region of the interior coal province which includes part of Arkansas, Kansas, Iowa, Missouri and Oklahoma.
>
> Region B is the east Texas part of the Texas region of the Gulf coal province. The Texas region is in east and south Texas, southern Arkansas, and northwest Louisiana.
>
> Region C consists of two locations. One is the Four Corners area of Arizona and New Mexico and the other is Routt County, Colorado, both in the Rocky Mountain coal province, which includes parts of Arizona, Colorado, Montana, New Mexico, Utah and Wyoming.
>
> Region D is the Northern Great Plains coal province, in eastern Montana, western North Dakota, northwestern South Dakota and northeastern Wyoming.

The fact that reclamation costs are quite site-dependent emerges from Table 2-9 where total reclamation costs have been summarized on a per-acre, per-ton and per-10^6 Btu basis. The costs appearing in the table are given in 1978 dollars. These were derived from the original work (1976 dollars) by applying an escalation factor of six percent per year. The costs in the table are reasonably well supported by the

Table 2-9. Estimated Mined-Land Reclamation Costs (1978 Dollars)

Region	A Sites 1-6	B Site 1	C Sites 1&2	C Site 3	D Site 1	D Site 2	D Site 3
Total* Reclamation Costs							
Average Per Acre	2875	1265	3240	2500	5780	3595	2860
Range Per Acre	1860-4800	985-3430	2105-5770	1910-3220	4810-8245	3055-7260	2520-4120
Average Per Ton	0.69	0.14	0.17	0.25	0.17	0.39	0.08
Range Per Ton	.50-.96	.09-.38	.14-.30	.18-.32	.15-.26	.33-.80	.07-.11
Average Per 10^6 Btu	.0306	.0086	.0094	.0113	.0102	.0282	.0052
Range Per 10^6 Btu	.0212-.0404	.0070-.0244	.0069-.0128	.0084-.0142	.0085-.0144	.0239-.0570	.0046-.0074

*Includes:

(1) Design, Engineering & Overhead

(2) Bond & Permit Fees

(3) Back Filling & Grading

(4) Revegetation

results of studies sponsored by the EPA[12] and by the NAS and NAE;[13] although more recently the Peabody Coal Company,[14] in challenging some of the regulations adopted by the Interior Department, has estimated reclamation costs in the vicinity of $11,000 per acre, or roughy $1.50 per ton of surface mined coal.

Reference to Table 2-9 reveals that reclamation costs range from a fraction of a cent to 5.7 cents per million Btu. The costs adopted for calculating reclamation costs associated with the Arizona based coal plant were taken from the box labeled "Region C." However, since coal for the Florida plant is expected to be taken from underground mines in West Virginia, no surface reclamation costs were included for this case. The further question of what costs must be incurred to halt the pollution of streams by ground water percolating through abandoned underground mines has not been addressed.

2.7 IMPACT OF INCREASED ENERGY PRICES ON THE GROSS NATIONAL PRODUCT

Empirical evidence strongly suggests that the quadrupling of oil prices in late 1973 reduced the productive capacity of the U.S. economy by about 4.5 percent. This decline corresponds to permanently lost opportunities for consumption or investment of about $96 billion in 1978. On average, this amounts to approximately $1000 lost income per U.S. worker per year.

The above interpretation of recent economic history rests on current work in macroeconomic theory and empirical research.[15,16,17] The conclusions are based on evidence concerning the relationship between the rate of inflation and the rate of growth of the money supply and the response of the price level to non-monetary phenomena.

The potential output of the U.S. economy may be modelled by a production function (Y) whose principal input factors of production are capital, labor, and energy. For many processes now in place, the mix of these factors was selected with certain expectations for absolute and relative factor prices. In a world where the mix of

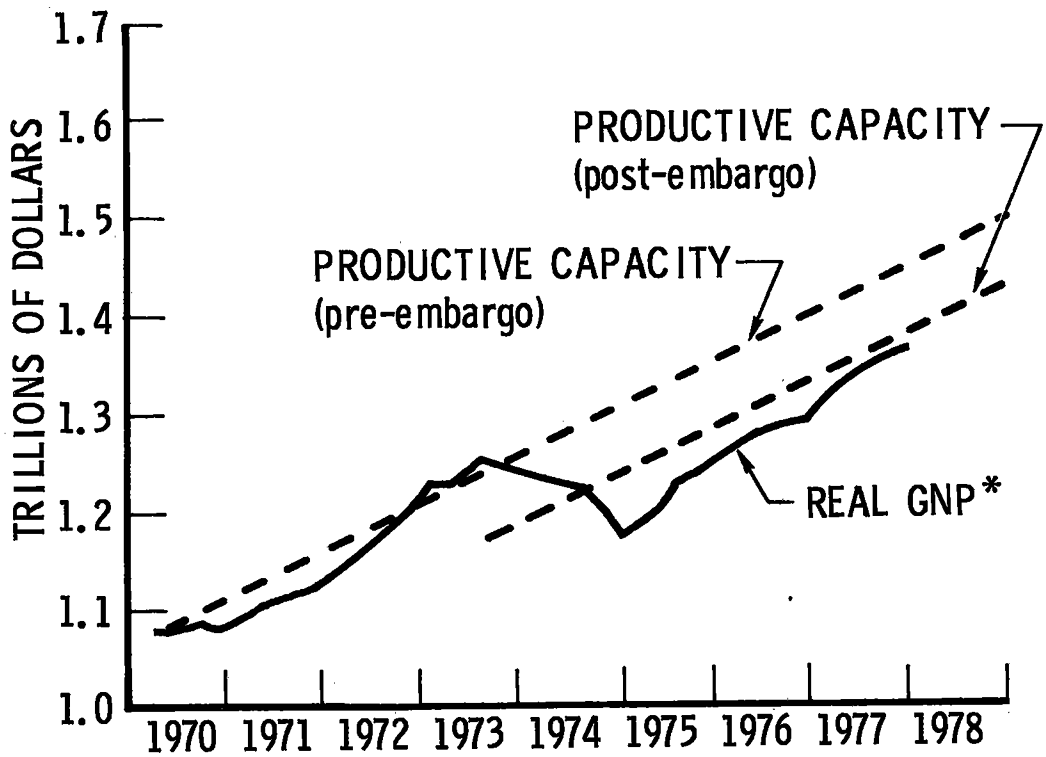
PRODUCTION FUNCTION

$$Y = Ae^{rt} L^{\alpha} K^{\beta} E^{\gamma}$$

Y	=	OUTPUT
L	=	LABOR (MAN-HOURS)
K	=	EFFECTIVE FLOW OF CAPITAL SERVICES
E	=	FLOW OF ENERGY RESOURCES
r	=	LONG-TERM GROWTH FACTOR
α, β, γ	=	OUTPUT ELASTICITIES OF RESPECTIVE INPUTS

factors of production is expensive to change once production processes are in place, an unexpected increase in a factor price diminishes the efficiency of vintage capital. The immediate effect is a contraction of productive capacity. Vested production processes cannot be used profitably at the same rate as had been consistent with prior expectations about energy prices. With aggregate demand unchanged, the decrease in the rate of production results in an increase in the level of prices.

The effect of the exogenous shock from the 1973-74 energy price jump on the productive capacity of the economy is shown in Figure 2-7. The impact on the price level and unemployment are illustrated in Figures 2-8 and 2-9. Figure 2-8 shows that the Consumer Price Index increased by about 4.5 percent following the quadrupling of oil prices relative to the trend of the price level predicted by the long-term relationship between inflation (i.e., the rate of growth of prices) and the rate of growth of the money supply, as described in Karnosky.[15] Significantly, the trend of the price level settled down to a trajectory parallel to that predicted by the long-term money growth rate, suggesting that the rise in the price level subsequent to the abrupt oil price increase is a permanent one-time superposition of a "step function" on the trend of the general price level. It is apparent from Figure 2-7 that the productive capacity of the U.S. economy as measured by the level of the growth-trend trajectory of potential (i.e., full employment) GNP, suffered a



SOURCE: U.S. DEPARTMENT OF COMMERCE
*IN 1972 DOLLARS

Figure 2-7. U.S. GNP

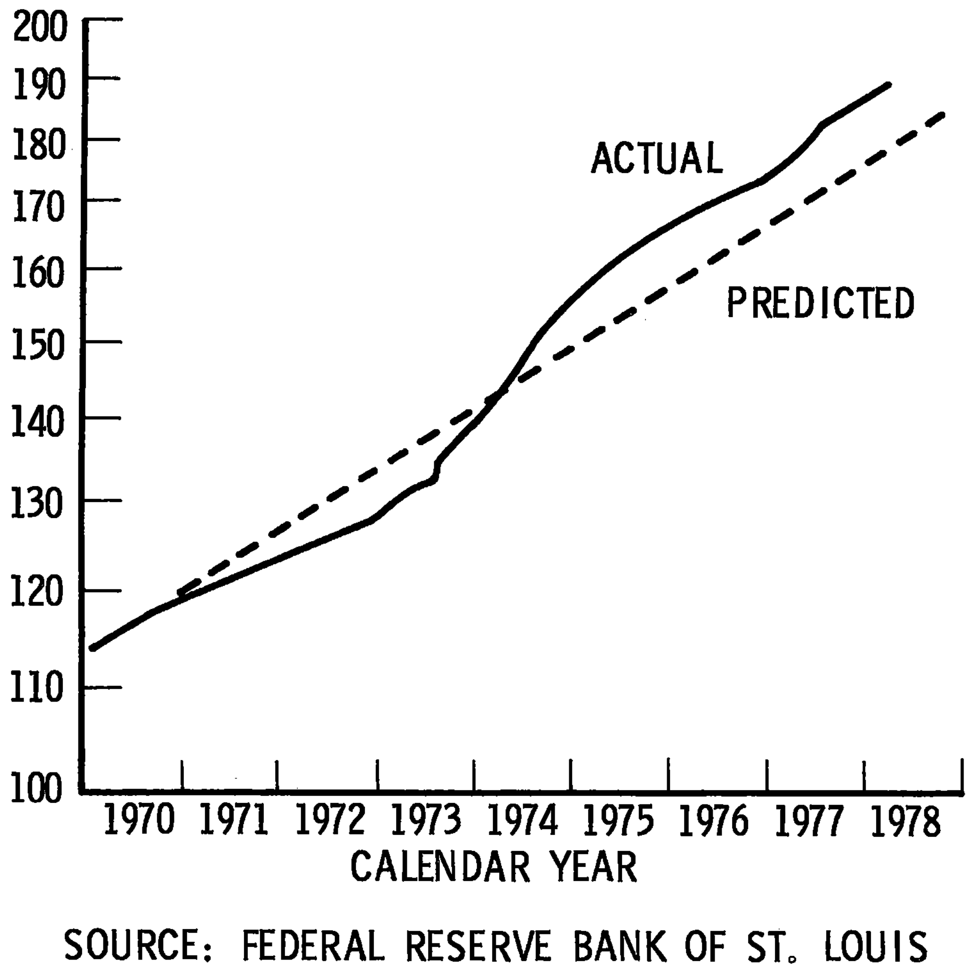
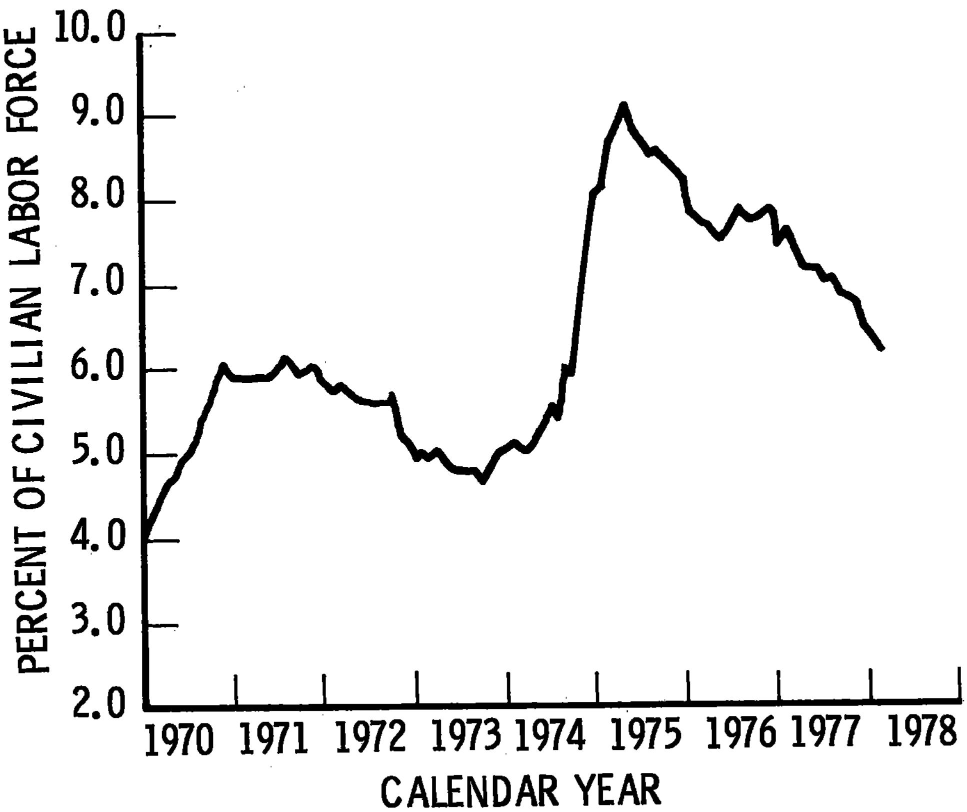


Figure 2-8. Consumer Price Index

permanent one-time decline of 4.5 percent subsequent to the embargo incident. The decline in potential real output represents permanently lost opportunitities for consumption and investment, and therefore represents the total real economic cost of the oil price increase. In Figure 2-9, the plot of the unemployment rate against time suggests that the rapid increase in unemployment that was associated with the increase of energy prices and drop of productive efficiency is being gradually reversed as labor finds alternative employment and labor-intensive processes are substituted for energy-intensive ones. This evidence combined with that of Figures 2-7 and 2-8 indicates, however, that the falling rate of unemployment is occurring in the context of an economy with reduced productive capacity. In other words, full employment occurs at a lower rate of aggregate output and hence at a lower rate of real income per capita.

Measures that would reduce dependence on foreign energy sources could help to insulate the U.S. economy from similar shocks in the future. Although some arguments[18] might be made for the sufficiency of oil supplies in the foreseeable future and the stability (or instability) of the OPEC consortium, the difficulty remains that an inordinate portion of the oil reserves is concentrated in a relatively few Middle East countries. Hence, as the events of 1973 dramatically demonstrated, uncertainty exists as to how much oil the key producing countries will choose to supply, under what conditions, and at what price.

Measures to mitigate the effects of further increases in the price of energy would include reduction in the relative energy component of the U.S. productive capacity, that is, promotion of energy conservation and efficiency programs. The effect of this would be to reduce the relative cost of energy in the production function and thus maintain to some extent the productive capacity of plant-in-place. Further, it should be noted that it was the large energy price increase in 1973-74 which caused the shock to the economy, not the fact that the fuel was imported. Therefore, one should expect similar results if large price increases were to occur for domestic energy sources. If these resulted from a collusive arrangement among U.S. companies similar to OPEC, they would violate anti-trust laws; therefore they are



SOURCE: U.S. DEPARTMENT OF LABOR

Figure 2-9. Unemployment Rate

not likely to arise for this reason. Significant increases in production costs, however, as recovery costs rise, could result in large increases of domestic energy prices.

The remedy, therefore, is not solely to develop alterative domestic sources of energy. For if energy prices, in general, are projected to rise significantly relative to prices for labor and capital, we may expect further erosion of our productive capacity. On the other hand, if these price changes occur gradually enough, the productive plant could be expected to adapt to higher energy costs so that the economy would not suffer the kind of shock that was experienced in response to the 1973 price rise.

Thus, a long-term goal of government energy policy might be to mitigate the impact of rising real costs of energy on potential output. This might be done by subsidizing domestic energy users in such a way that they would perceive energy prices to rise at manageable rates. Thus by keeping the ratios of prices of labor, capital and energy in reasonable alignment, significant fractions of the productive capacity of the country could not be suddenly made obsolete. Further, permitting the ratios to change gradually would encourage an orderly adaptation of the productive plant which would resist declining efficiency in an environment of rising energy prices. It appears, therefore, that these subsidies should be of a temporary nature, specifically designed to smooth out too rapid or too large jumps in energy prices.

Alternatively, it has been suggested that decontrol of all energy prices might result in relatively slow, small increases in energy prices in response to market forces. If sufficient domestic sources were available, they might neutralize the monopoly power of OPEC, which has up to now been able to overcome the resistance of the market to sudden large price increases. Of the indigenous alternative energy sources, the inexhaustible ones such as solar are unique in that they are immune to increases in conventional energy prices. Further, solar costs are likely to decline with technological advances and large-scale production. Thus, eventually, the real cost of energy from solar plants, including all societal impacts, could be lower than that from conventional plants and might provide a stabilizing influence on all energy prices. Therefore, government subsidies to encourage the rapid installation of solar plants could be an attractive investment.

The computed reduction in potential GNP is based on the result(16) that, for a Cobb-Douglas production function, when a resource whose price increases is a substitute for capital, the percentage reduction in the nation's output capacity is equal to the percentage rise in its long-run average cost. That is,

$$\frac{\Delta Y}{Y} = - \frac{\Delta \overline{C}}{\overline{C}} \tag{6}$$

The long-run average cost depends on the market price of each resource employed. Thus, if P_i is the price of the ith resource and Q_i is the quantity of the ith resource used, then the average cost of the output is,

$$\overline{C} = \frac{1}{Y} \sum_i P_i \, Q_i \tag{7}$$

If now, the price of one of the resources, say energy, is permitted to change (while the prices and quantities used of the other resources are held fixed),

$$\frac{\partial \overline{C}}{\overline{C}} = \frac{1}{Y\overline{C}} \left(Q_E \, \partial P_E + P_E \, \partial Q_E\right) - \frac{\partial Y}{Y} \tag{8}$$

A firm in the private sector would maximize profits by employing energy at a rate such that the value of the additional product obtained from employing more energy would equal its price. From the production function, the marginal product of energy is

$$\frac{\partial Y}{\partial Q_E} = \gamma \frac{Y}{Q_E}$$

Hence,

$$P_E = \gamma \frac{Y}{Q_E} \, \overline{C} \tag{9}$$

This represents the aggregate demand curve for energy, since the price per unit of aggregate output is $\overline{C}$.

Writing this expression as

$$\gamma = \frac{P_E Q_E}{Y\overline{C}}$$

makes it clear that γ is the fraction of the cost of energy in the total cost of production. Using this equation to eliminate $Y\overline{C}$ from the expression for $\partial\overline{C}/\overline{C}$, yields

$$\frac{\partial \overline{C}}{\overline{C}} = \gamma\left(\frac{\partial P_E}{P_E} + \frac{\partial Q_E}{Q_E}\right) - \frac{\partial Y}{Y} \tag{10}$$

The last two terms on the right cancel since, from the production function,

$$\frac{\partial Y}{Y} = \gamma \frac{\partial Q_E}{Q_E}$$

Hence,

$$\frac{\Delta Y}{Y} = - \frac{\Delta \overline{C}}{\overline{C}} = - \gamma \frac{\Delta P_E}{P_E} \tag{11}$$

Taking into account that there are several components which make up the average price of energy (e.g., oil, gas, nuclear, etc.), Equation (11) may be rewritten using the following relationship for the average price per unit of energy.

$$P_E = \frac{\sum_i P_{E_i} Q_{E_i}}{\sum_i Q_{E_i}} \tag{12}$$

where E_i is the ith energy resource.

Thus

$$\frac{\Delta P_E}{P_E} = \frac{\sum_i \Delta P_{E_i} Q_{E_i}}{\sum_i P_{E_i} Q_{E_i}} = \frac{1}{C_E} \sum_i \Delta P_{E_i} Q_{E_i} \tag{13}$$

Substituting (13) into (11) yields

$$\frac{\Delta Y}{Y} = - \gamma \frac{1}{C_E} \sum_i \Delta P_{E_i} Q_{E_i} \tag{14}$$

where $C_E = \sum_i P_{E_i} Q_{E_I}$ is the total cost of all fuels consumed.

At this point the assumption is introduced that each individual price change yields its own separable impact on the potential GNP. That is, from the basic form of Equation (14)

$$\frac{\Delta Y}{Y} = \frac{\sum_i \Delta Y_i}{Y} = - \frac{\gamma}{C_E} \sum_i \Delta P_{E_i} Q_{E_i}$$

the summation signs are removed and it is assumed that

$$\frac{\Delta Y_i}{Y} = - \gamma \frac{Q_{E_i} \Delta P_{E_i}}{C_E} \tag{14}$$

This is the expression that was used in calculating the contribution to the impact on potential GNP of price increases in each type of fuel.

2.8 AIR POLLUTION

The electric power industry impacts man's environment in several undesirable ways. More than 60 percent of the energy consumed is disposed of as waste heat; nuclear plants are concerned with radioactive effluents; and the burning of fossil fuels releases pollutants into the air. Of the many different contaminants discharged into the air from fossil fuel plants, the particulates, sulfur oxides, nitrogen oxides, and hydrocarbons have received the greatest attention. In spite of this, not enough is known about the effects of polluted air on the health of humans, animals and plants, nor about damage to property and the aesthetic quality of man's surroundings.

2.8.1 Particulates

The most obvious impacts of particulates are that they darken the atmosphere and soil the surroundings wherever they deposit, although substantial evidence exists that respiratory damages ensue from exposure. Coal[19,20] is a far greater source of particulate matter than other fuels. Depending on the ash content and heating value (Btu/lb) of the coal, anywhere from 5 to 13 lbs of particulates may be released to the atmosphere per million Btu burned in the absence of controls. Particulate control standards have been in effect for many years, and one of the most widely used devices for meeting these standards in the electric power industry is the electrostatic precipitator. Experience has shown that modern units may be relied upon to be 97.5% efficient in removing particulates from the effluent. Unfortunately, this efficiency figure refers to the total mass removed from the effluent stream and not to removal from the entire spectrum of particle sizes. There is also evidence that the small particulates ($\sim 1\ \mu m$), for which the precipitators are least efficient, are also the ones that have the greatest impact on human health.

Since 1971, the EPA New-Source Performance Standards limited particulate emissions to 0.1 lbs/million Btu. The new standard, based on EPA interpretation of the 1977 Clean Air Act Amendments, calls for .03 lbs/million Btu and meeting it will require larger precipitators, scrubbers, bag-house filters, or perhaps, some combination of these. A recently announced[21] TVA installation of 10 bag-house filters for meeting the latest criterion is expected to cost about $50/kW.

2.8.2 Sulphur Oxides

Although the exact effects of the sulphur oxides are imperfectly known, it is generally recognized that these pollutants are among the most harmful to human and animal health. They also damage vegetation and are corrosive to materials. Current new-source emission standards call for a maximum of 1.2 lbs/million Btu to be released from coal plants and 0.8 lbs/million Btu from oil plants. New standards embodied in the 1977 Clean Air Act Amendments call for 90% removal of sulphur to levels as low as 0.2 lbs/million Btu. These standards will be met by coal refining techniques and advanced combustion and stack gas scrubber technologies. Capital costs of current scrubber installations are in the $85-100/kW range. Figure 2-3 reflects the projected costs of pollution control equipment taking into account the advanced technology required to meet ever stricter emission standards.

2.8.3 Nitrogen Oxides

Nitrogen oxide formation is mainly governed by the combustion process. Production is increased at higher temperatures and higher concentrations of air. A longer residence of the hot gas in the boiler and a more rapid cooling of the gas emerging from the boiler also increase emissions. Among the abatement techniques which have been found useful are two-stage combustion, flue gas recirculation, and the injection of steam or water into the boiler. These methods have been found to be reasonably effective for oil plants, but not yet for coal-fired plants. However, advanced combustion techniques such as the combined cycle and the fluidized bed are expected to produce much lower levels of nitrogen oxides.

2.8.4 Costs of Air Pollution Damage

Relatively few studies on the costs associated with air pollution have been performed. Barrett and Waddell[22,23,24] have made careful assessments of the published studies, and their work has been used as the basis for the cost estimates to be inserted into the net national economic benefits calculation.

National total annual costs were developed in 1968 and 1970 for effects on health, vegetation, materials, and residential property values. The values which emerge are considered by the authors to be reasonable, conservative estimates. In the absence of better evidence, they attributed the health costs of air pollution to particulates and the sulfur oxides. For example, 54 percent, or $3.272 billion of the $6.069 billion in health losses, is attributed to sulfur oxide pollution since this pollutant comprises about 54 percent of the national emissions of sulfur oxides and particulates combined.

The cost of air pollution damage to residential property was $5.2 billion in 1968. This cost is attributed to the sulfur oxides and particulates, and distributed in direct proportion to the emitted quantitites of the two pollutants.

In the case of materials, the costs of most of the effects are allocated in proportion to the pollutants emitted except for CO, which is omitted because there is no evidence that CO produces material damage. The corrosion of galvanized steel is attributed solely to SO_x. The fading of dyes and degradation of elastomers is attributed to oxidants and nitrogen oxides.

Two studies on pollution damage to vegetation reveal that oxidants are responsible for about 90 percent of observable crop losses. Work by Waddel indicates that SO_x accounts for direct damages assessed at about $13 million. The remainder of the pollution cost is attributed to particulates. These data for 1968 are summarized in Table 2-11, while the data for 1970 appear in Table 2-12.

Although no cost figures could be developed for various levels of pollution, since the total annual costs are strictly related to the pollution levels of the respective years, a linear relationship was assumed in deriving a cost per unit of each major pollution component to simplify the use of these numbers in the analysis.

Table 2-13 presents a summary of the total costs per ton if the individual pollutants distilled from the data of Tables 2-10, 2-11, and 2-12. Taking into account the precision of the basic data, it was judged reasonable to average the 1968 and 1970 data and consider the average to be expressed in 1969 dollars. This average was then expressed in 1978 dollars by assuming an escalation factor of six percent per year.

Table 2-10. Estimate of Nationwide Emissions

	Type of Emission (10^6 tons/yr)				
Year	CO	Particulates	SO_x	HC	NO_x
1968	100.1	28.3	33.2	32.0	20.6
1970	148.7	26.1	33.9	34.9	22.8

Table 2-11. National Total Annual Costs of Pollution (1968)

Effects	Costs of Emissions (10^9 dollars)			
	SO_x	Parti-culates	NO_x and Oxidants	Total
Residential Property	2.808	2.392	--	5.200
Materials	2.202	0.691	1.859	4.752
Health	3.272	2.788	--	6.060
Vegetation	0.013	0.007	0.100	0.120
Total	8.295	5.878	1.959	16.132

Table 2-12. National Total Annual Costs of Pollution (1970)

Effects	Costs of Emissions (10^9 dollars) "Best Estimates"		
	SO_x	Parti-culates	NO_x and Oxidants
Residential Property	2.900	2.900	--
Materials	0.600	0.200	0.900
Health	1.900	2.700	--
Vegetation	--	--	0.200
Total	5.400	5.800	1.100

Table 2-13. Annual Costs Per Ton of Pollutants Emitted

Pollutant	Costs (dollars/ton)			
	1968	1970	Average (1969 dollars)	Average (1978 dollars)
SO_x	250	160	200	337
Particulates	208	222	215	363
NO_x and Oxidants	37.5	48.2	43	73

3.0

CALCULATIONS

The NNEB calculations are performed by analyzing the impact of each alternative 100 MW_e plant as if it were independent of the other plants in the utility grid. This approach permits a straight-forward evaluation of alternative energy futures in which a given type of energy source is introduced at various rates into an existing system. However, since a basic premise of the calculations is that the size of the plant capacity added is too small to materially affect the system, some care will have to be exercised in adapting the single plant results to energy futures calling for additions of alternate energy sources greater than about 10 percent of the total.

3.1 VALUE OF ELECTRICAL ENERGY PRODUCED

The average price of electricity includes prices for residential, commercial, and industrial usage weighted by the quantitites projected for each sector in the Sherman H. Clark Associates report.[3] Since the price is the average for all installed capacity (e.g., coal, oil, nuclear), and since the capacity of each alternative type of plant was taken to be the same, the market value of the electrical energy produced by each alternative is the same. This leads to some welcome insensitivities in the final comparison of NNEB's for solar and fossil fuel plants. In computing the difference between NNEB's of solar and fossil fuel plants, the value of electrical energy term cancels out and the result depends only on the associated costs, not on the output prices used.

3.2 TAXES

Since imported oil is considered to be the marginal (i.e., price determining) source of supply, and depletion allowances are no longer permitted to the major oil companies, only foreign tax credits are considered among the hidden costs of oil. These are entered as 25 percent of fuel costs from Table 2-6. Depletion allowances and expensing of intangible drilling costs are entered as 3.4 percent of fuel costs for the coal plants.

3.3 STRATEGIC PETROLEUM RESERVE

The oil plant's share of the costs associated with establishing the strategic petroleum reserve is determined by the ratio of three months fuel requirements for operating the oil plant to the total quantity in the oil reserve. It includes construction and filling costs. These initial costs, incurred prior to 1985 (data of Table 2-6), are escalated by the social discount rate to the operational date of the plant. After that, only maintenance costs are charged.

This procedure eliminates the need to guess the date of occurrence of a possible future oil embargo when oil would have to be withdrawn from the reserve. Instead, it assumes that after the termination of an embargo the petroleum stocks would be replenished and the value of the oil removed would equal that of the oil replaced. Thus, the value of any oil retrieved from the reserve does not contribute to the measured benefits of the reserve.

3.4 IMPACT ON POTENTIAL GROSS NATIONAL PRODUCT

The present computation uses five-year fuel price changes. There are several reasons for applying the price projections in this manner. The projections of Reference (3) are presented in five-year steps and any attempts at interpolation would convey no additional information. A five-year interval turns out to be short enough for the assumption that percentage changes in fuel prices are "small" to be fairly well approximated. Finally, considering the length of the period of projection, 1985-2050, a more frequent interval than five years would add considerably to the volume of calculations and intermediate outputs without adding significant insight.

As was stated in Section 2.7, γ is the fraction of the cost of energy in the cost of the total output. Rasche and Tatom cite evidence[25] that the cost share of energy in total factor costs was stable throughout the 1960's at 12 percent. They also note that the quadrupling of oil prices in 1973-1974 had the effect of increasing average energy prices by 45 percent in the same period. If no other factor prices changed, this increase in energy prices would cause the ratio of energy costs to the costs of all factors to increase from 12 to 16.5 percent.

It is assumed that this ratio remains constant throughout the projection period. Clearly, continued increases in the price of energy would cause the ratio to rise even further. However, the stability of the ratio during the 1960's may have been due to adjustments of the proportions of energy (E), labor (L), and capital (K) in response to changes in P_E, P_L, or P_K. Thus, rising energy prices in the projection period might be expected to induce adjustments which would tend to keep the ratio reasonably constant. In any case, increasing the ratio would augment that computed potential output cost, so the assumption of constancy would tend to underestimate the effect.

The projections[3] for energy price and consumption extend from 1985 to 2015. However, it is considered desirable to extend the present computation beyond 2015, and 2050 is chosen as the end of the projection period. This is because the lifetime of an electricity generating plant is commonly taken to be 30 years; thus, extending the data base to 2050 permits NNEB calculations for plants which become operational in the interval 1985 to 2020. This is considered sufficiently long to provide a reliable indication of the trend of NNEB for each alternate energy source.

The extension of the projections of energy consumption from 2015 to 2050 is made by extrapolating trends in the data of reference (3). The extrapolation process is somewhat heuristic, and an element of judgment as to what appears to be reasonable inevitably enters into the determination of the extended projections. The rates of growth of the projections for total energy consumption for each end-user type (e.g., residential, commercial, industrial, and power plants) attenuated with time toward the year 2015. The projections for each State are extrapolated at the "steady-state" rate of growth if that was reached prior to the 2010-2015 period or at the rate of growth in the 2010-2015 period if the growth rate was still declining by then.

Projections for the consumption of each type of energy were made by extrapolating the consumption data for the common fuel types with readily recognizable growth patterns. The projected consumption of nuclear energy was then derived by subtracting the sum of the other projections from the projected total consumption of energy from all fuel types. This procedure was necessary because simple projection of the growth rate would have given nuclear an overwhelming share of the total power plant fuel market by 2050 and would have yielded a projection of power plant energy consumption, based on summing the contributions of individual fuel types, inconsistent with a projection based on the growth rate of total energy consumption by power plants.

Fuel prices extracted from the projections of Figures 2-5 and 2-6 were used to compute ΔP_{E_i} over five-year intervals. Q_{E_i} was obtained from the sum of consumption projections for fuel type E_i across end-user categories.

The reduction of potential output in each five-year interval due to ΔP_{E_i} over the interval is computed as follows. The 1975 potential output for the U.S. implied by the Rasche-Tatom production function (Figure 2-7) is inflated to 1978 dollars from 1972 dollars by multiplying by $(1.06)^6$ to yield a 1975 potential GNP of $\$1.844 \times 10^{12}$. The 1975 potential output for each State is calculated by multiplying the U.S. potential GNP by the ratio of energy consumption in the State to the U.S. as a whole. This is equivalent to assuming that the production function (e.g., technology) in each State is the same as that for the nation as a whole. Potential output for each State in 1985, which is the reference time for computation of present values in this study, is projected from the 1975 base by applying the 3.4 percent per annum average compound growth rate manifested in the potential output from 1952 to 1975. The percent reduction of potential output is calculated using equation (14) with = .165. This is multiplied by the 1985 projected value to determine the amount of potential output reduction for the State. This amount is subtracted from the "before" potential output to determine an "after" value of potential output which serves as the base for projection of potential output (at a 3.4 percent per annual growth rate) for the next five-year interval. Then the procedure is repeated for 1990, etc. In this way a series of potential output reductions every five years from 1985 to 2050 due to fuel price increases is developed for Florida and Arizona for both coal and oil.

To recapitulate, the change in the potential output (Y) of the State in every five-year interval is given by

$$- \Delta Y = .165 \frac{Q \Delta P}{C_E} Y$$

where Q is the quantity of energy used by the plant per year, C_E is the total annual cost of fuels consumed in the State, and ΔP is the change in the price of fuel over the five-year interval.

ΔY is a real social cost in that it represents the value of permanently lost consumption and investment opportunities to the American public. Since this cost includes the increased cost of fuel, it was decided to extract the fuel price increase and calculate a net social cost (Y') exclusive of the fuel price increase. This permits the insertion of total fuel costs into the NNEB calculations without the possibility of double counting.

Thus, the net change in the nation's potential output attributable to the new power plant is

$$- \Delta Y' = (.165 \frac{Y}{C_E} -1) \; Q \, \Delta P$$

These impacts are calculated for each five-year interval and accumulated from the year the plant becomes operational through its postulated 30-year lifetime.

3.5 POLLUTION

Pollution cost calculations are based on the assumption that all plants which become operational in 1985 and beyond meet the standards set forth in the 1977 EPA Clean Air Act Amendments. The quantitites of pollutants assumed to be emitted from fossil fuel plants are summarized in Table 3-1. The difference in SO_2 emissions from coal plants in Florida and Arizona is based on the assumption that 3.5 percent sulfur coal will be used in Florida and 0.5 percent sulfur coal, in Arizona.

Table 3-1

1977 EPA Clean Air Act Standards

Pollutant	lbs/10^6 Btu	
	Coal	Oil
Particulates	.03	.03
SO_2	.7 (Florida) .2 (Arizona)	.2
NO_x	.6	.3

The dollar values of the damages produced by these pollutants are extracted from Table 2-13. As was noted, these were derived by assuming a linear relation between pollution level and dollar value. A more reasonable non-linear relationship would yield a larger or smaller value depending on what the ambient pollution level was when the contribution of the incremental plant was added. A more serious problem, however, is the concern which has been voiced by workers in the field that these dollar values are seriously underestimated by, perhaps, a factor of five.

4.0

CONCLUSIONS

Internal and external economic benefits and costs are reduced to the common units of measurement of constant 1978 dollars. For each type of plant these are integrated into a single figure of merit by discounting the time-dependent cash flows associated with the benefits and costs by a four percent social discount rate back to the year plant operation commenced. Each type of plant is assumed to have a lifetime of 30 years, and calculations were made for plants installed on the five-year marks between 1985 and 2020.

The results of the NNEB calculations are presented graphically in Figure 4-1 for Arizona and Figure 4-3 for Florida. Figures 4-2 and 4-4 show the differentials (ΔNNEB) for solar-oil and solar-coal for Arizona and Florida, respectively.

In Arizona, the solar-oil differential starts at \$120 million per plant in 1985, rises quickly to \$275 million per plant about 1995, then rises very gradually to \$290 million per plant by the year 2020. These quantities may be compared with a \$270 million construction cost for a 100 MW_e solar plant in 1985. Thus, for the entire period of interest, construction of solar plants bears a social value significantly higher than that for oil plants. On the other hand, the Arizona solar-coal differential starts at -\$150 million per plant in 1985, rises steeply at first, then more gradually to reach \$150 million per plant in 2020. The curve crosses zero shortly before 1995, that is solar plants which become operational after 1995 bear a higher social value than coal plants; prior to 1995 the reverse is true.

In Florida, the solar-oil differential starts at \$60 million per plant in 1985, rises quickly to \$220 million in 1995, then rises more slowly to about \$250 million per plant in 2020. The solar-coal differential starts at -\$125 million per plant in 1985, rises rapidly through zero about 1991, and reaches about \$145 million per plant by the year 2020.

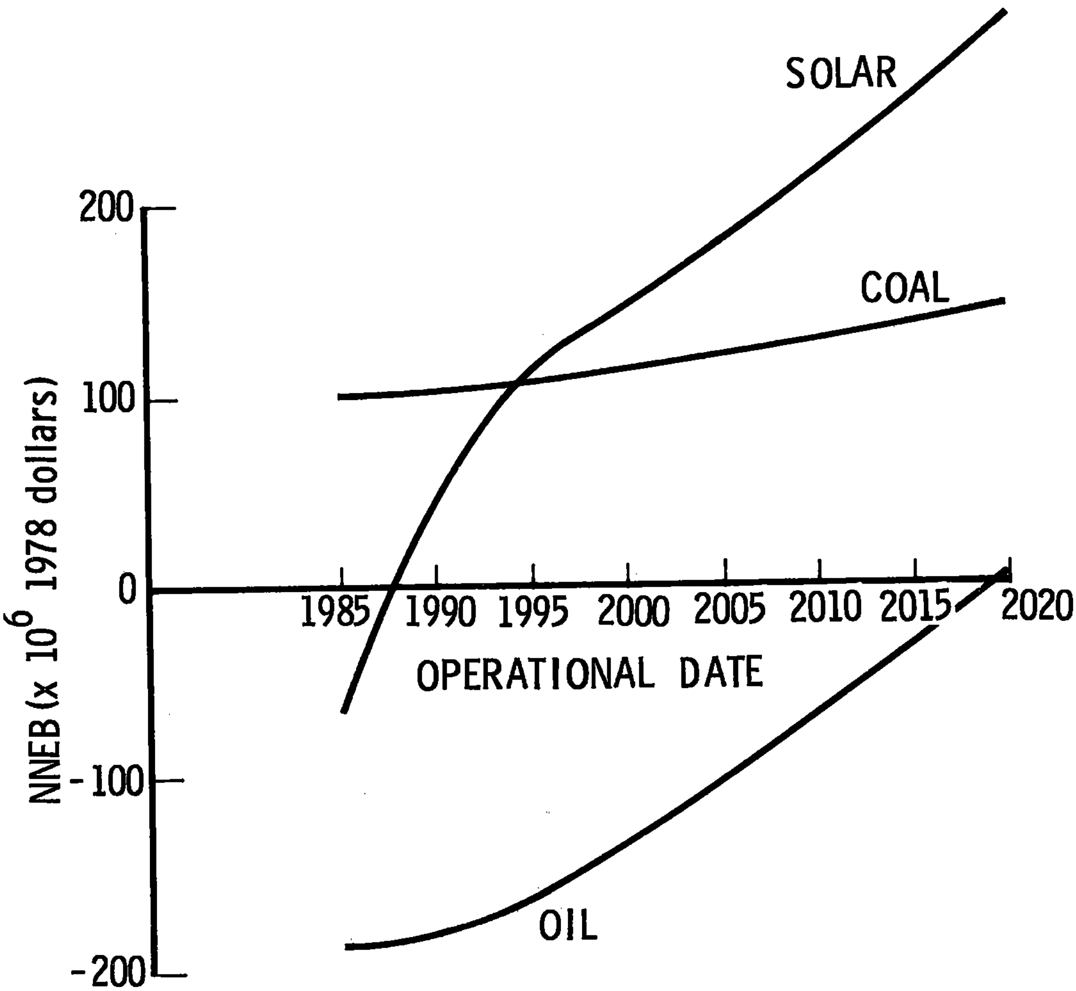


Figure 4-1. Net National Economic Benefits - Arizona Plants

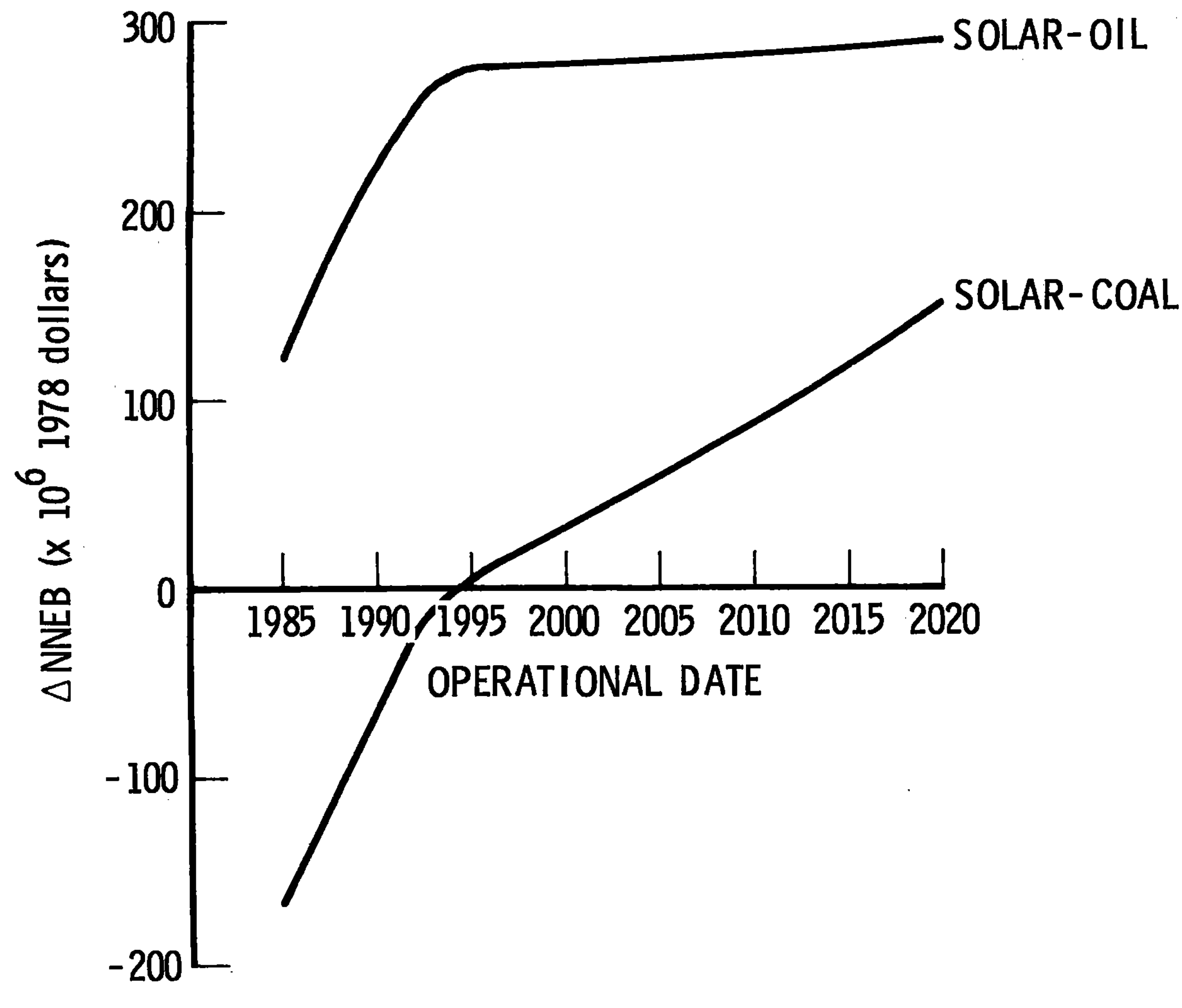


Figure 4-2. Differential Net National Economic Benefits - Arizona Plants

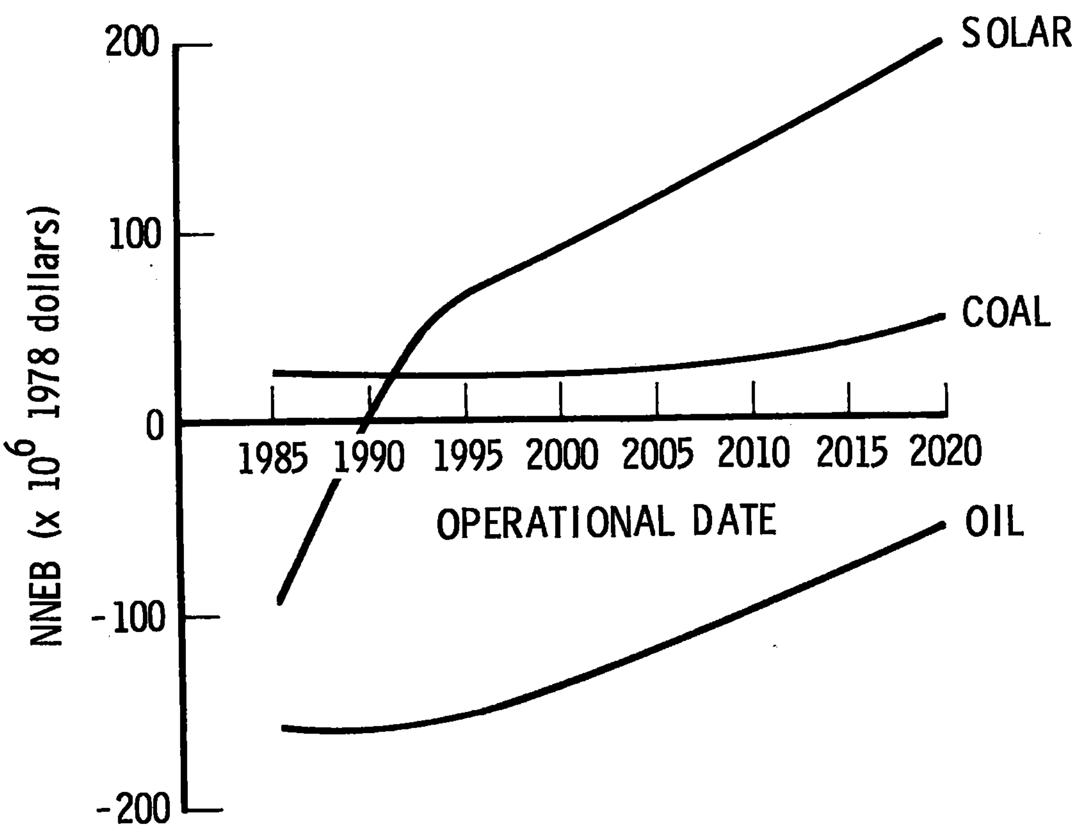


Figure 4-3. Net National Economic Benefits - Florida Plants

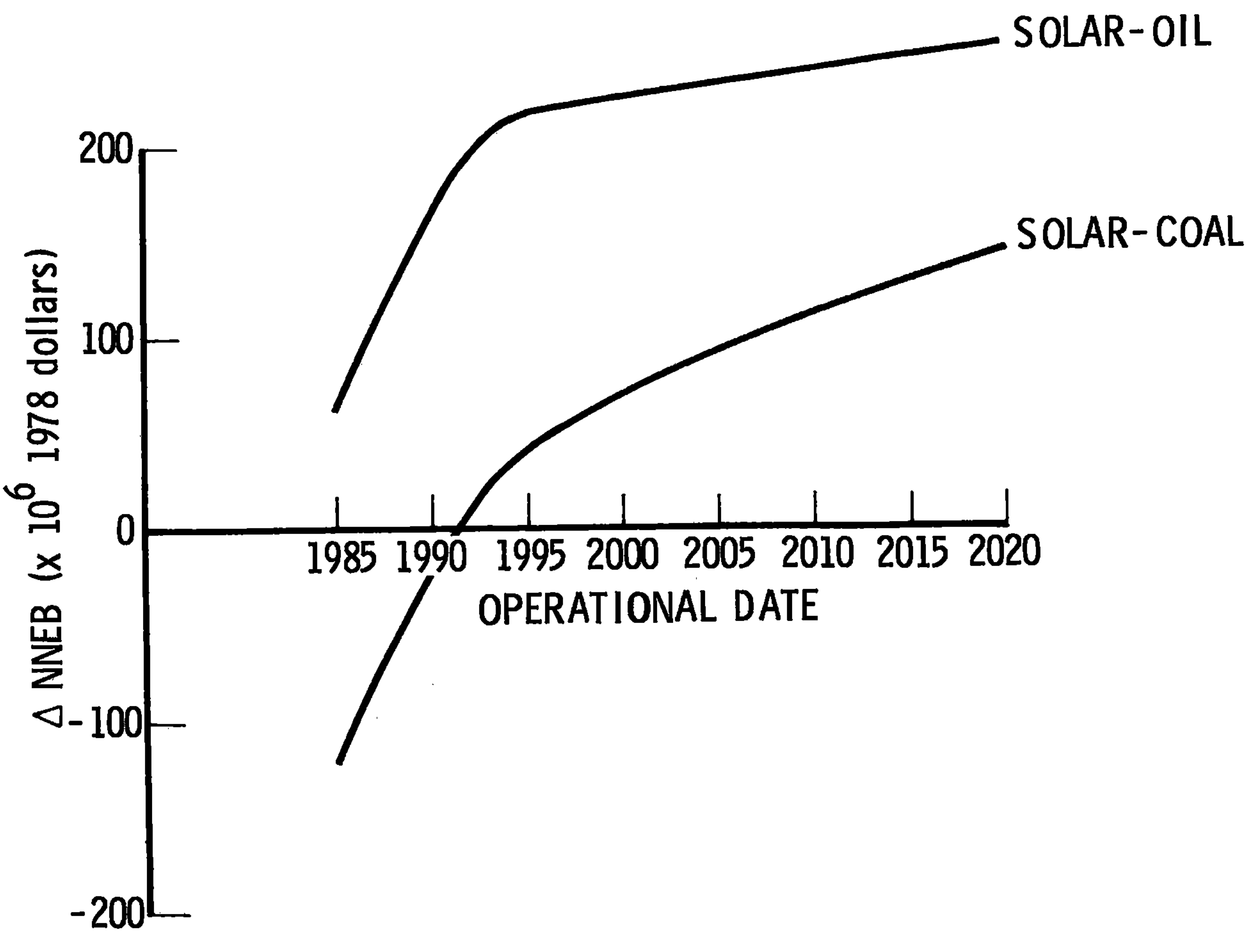


Figure 4-4. Differential Net National Economic Benefits - Florida Plants

The early history of the differential curves is dominated by the projected behavior of solar plant construction costs. Reference to Figure 2-4 shows that a marked decrease in cost of construction per kW is expected in the period 1985-1995, followed by stability, in 1978 dollars, for the rest of the period of interest. If this marked decrease is not realized, then the net national economic benefit of solar plants may not dominate those of the fossil-fuel plants quite so decisively; in fact, it may not surpass that of coal at all. However, because the technology is new, this initial decline in construction costs appears to be the most reasonable thing to expect.

The later history of the differential curves is dominated by rising fuel costs and application of the social discount rate to all costs back to the date the plant commenced operation. For example, because the relative benefits of solar energy are more pronounced in a plant's later years (when absence of fuel costs and non-polluting operation have overcome the initial large capital outlay), the size of the social discount rate strongly effects the relative net national economic benefits of solar and fossil-fuel plants. For the example illustrated in Figures 4-1, 4-2, 4-3 and 4-4, the social discount rate selected was four percent. If it had been chosen smaller, solar would have dominated the fossil fuels even more strongly; if it had been chosen larger, solar would have appeared less attractive. Figures 4-5, 4-6 and 4-7 have been supplied to show the time-dependent behavior of each component of the NNEB calculations.

This study attempts to determine whether the consideration of externalities could overcome the apparent economic superiority of fossil-fuel plants over solar plants. Although it seems to have succeeded in doing this, it must be stressed that the study is in its preliminary stages. Aside from the fact that it would be desirable to examine more closely a few of the externalities already identified, a number of externalities have yet to be included. For example, health and environmental effects associated with construction of the solar and fossil-fuel plants have not been considered; nor have effects due to accidents related to transporting fuel. The costs of regulation, land use, and waste disposal need attention. And there are the big problems like what fraction of the national defense budget should be charged against

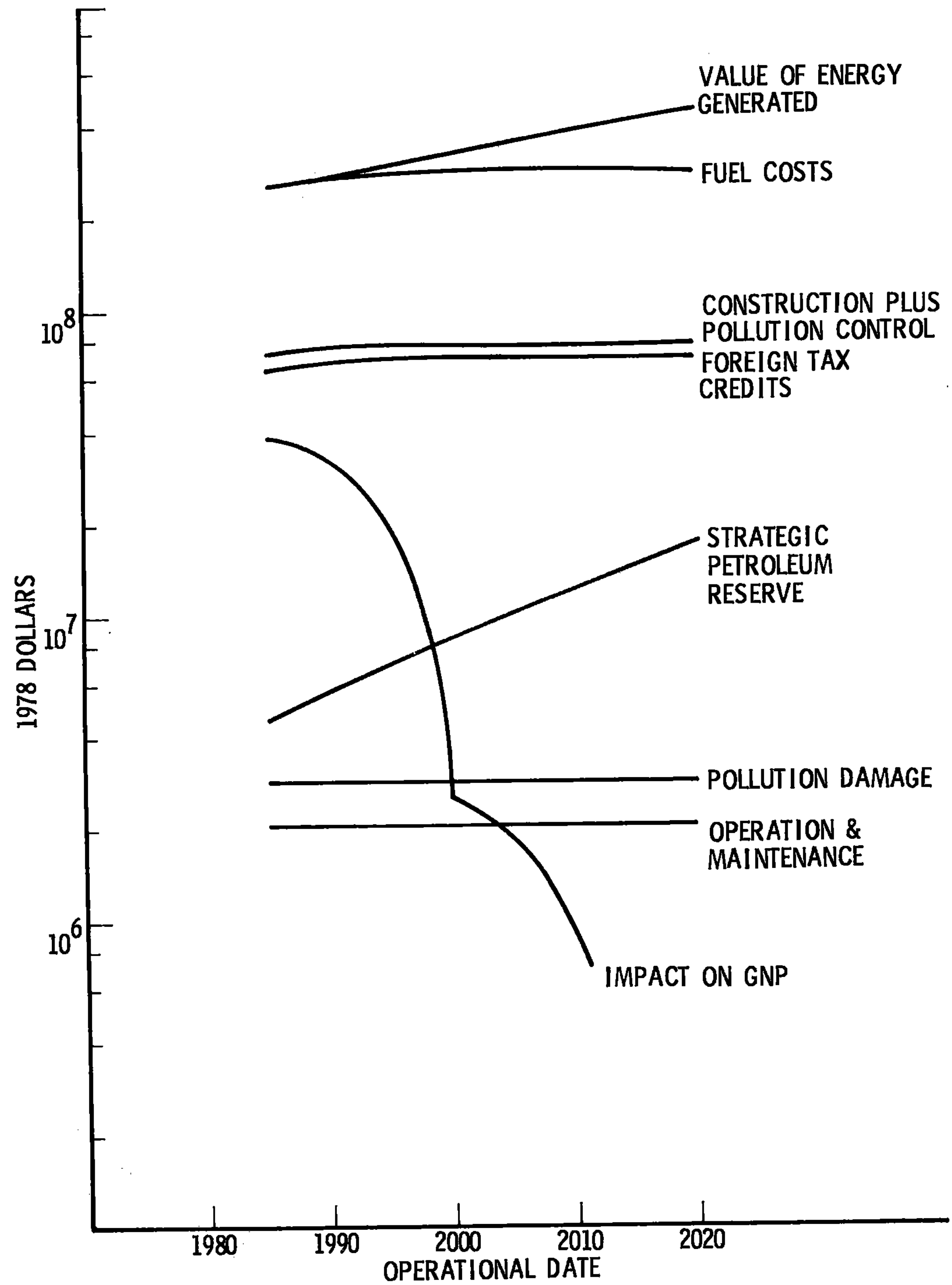


Figure 4-5. Components of NNEB Calculations
Arizona Oil Plant

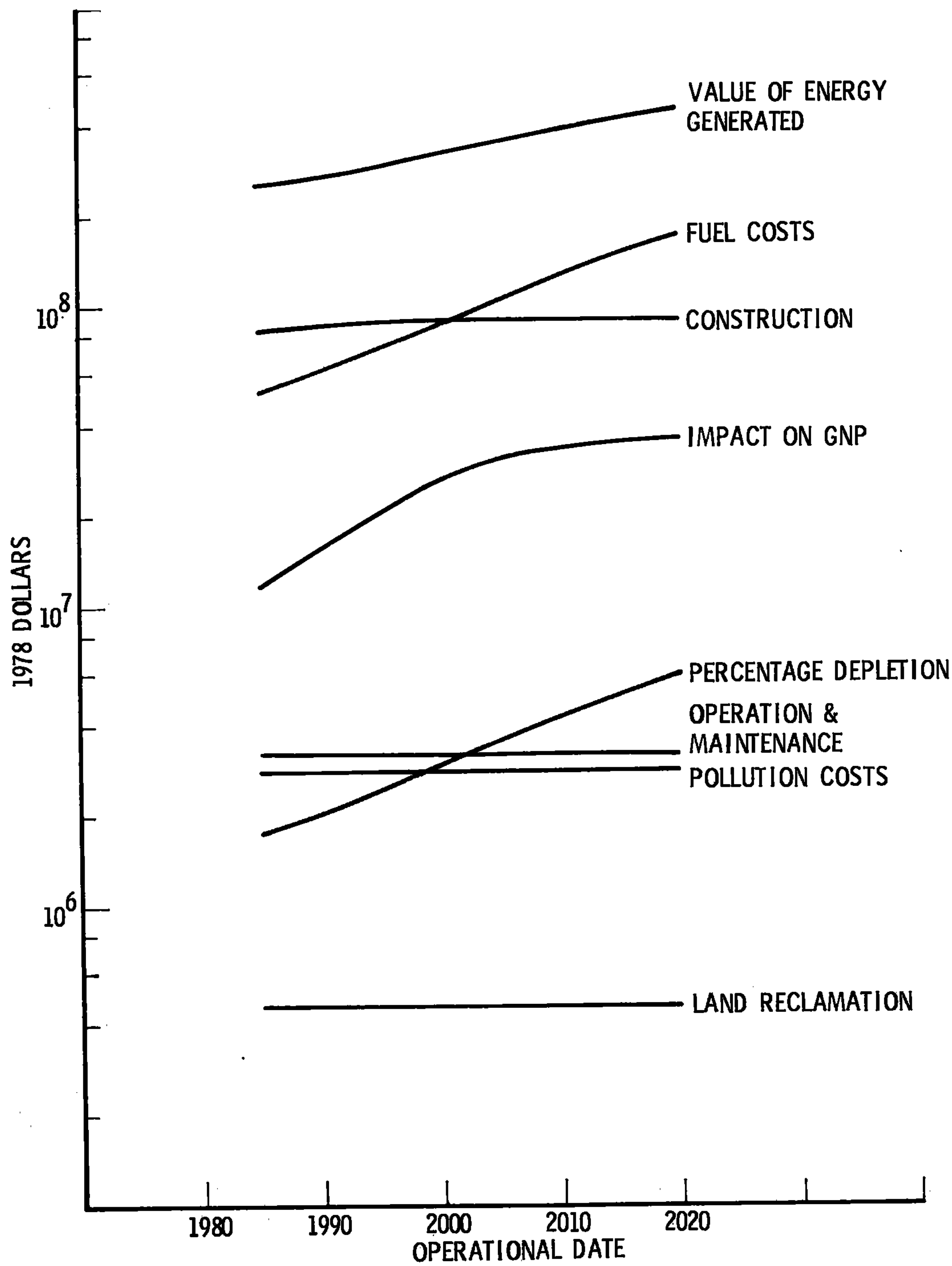


Figure 4-6. Components of NNEB Calculations
Arizona Coal Plant

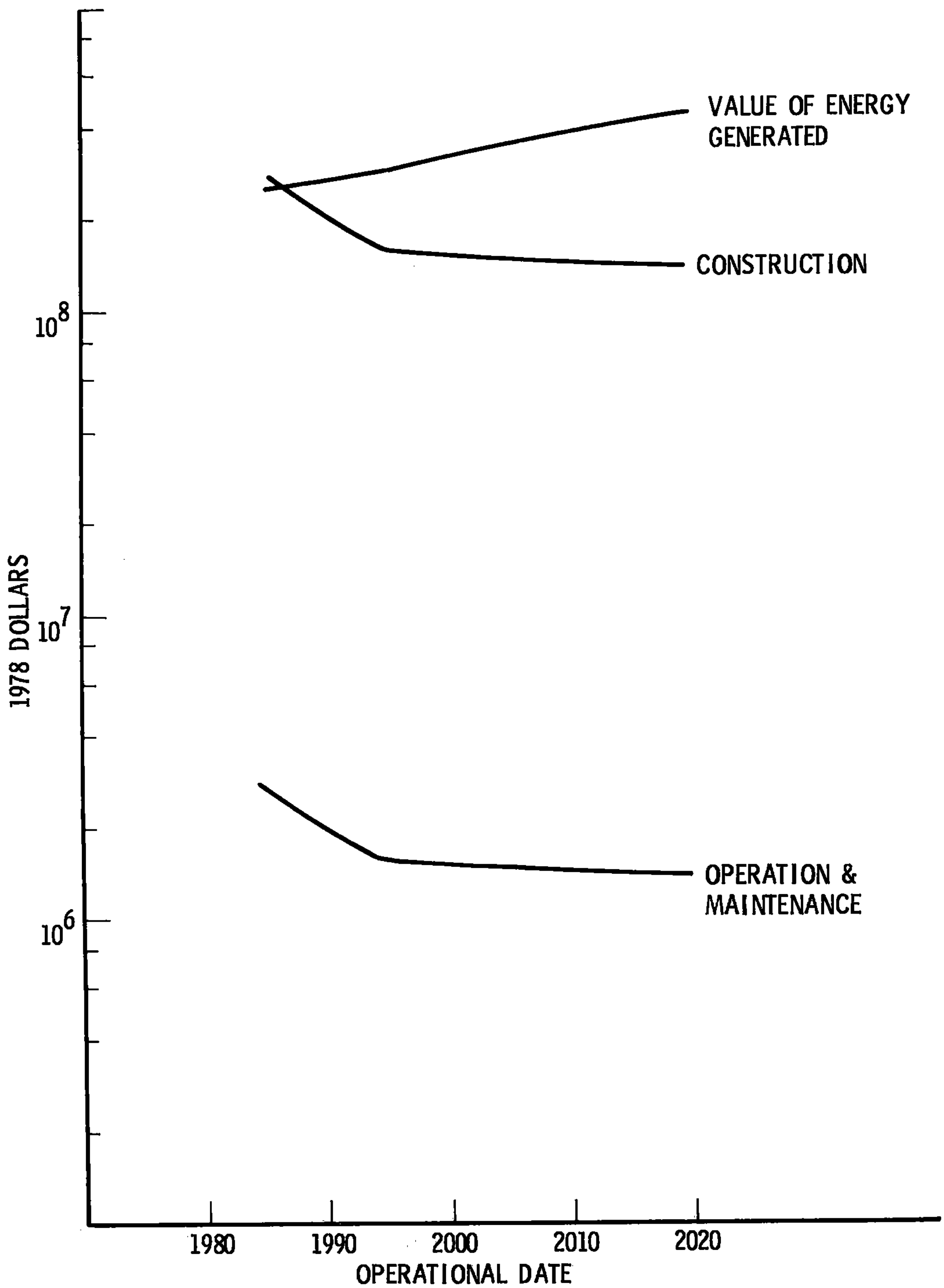


Figure 4-7. Components of NNEB Calculations
Arizona Solar Plant

oil for the purpose of keeping the sea lanes from the Middle East open, and how does one quantify (in 1978 dollars) the effect on the world's weather of loading the atmosphere with CO_2 from the excessive burning of fossil fuels?

Finally, this study introduces a methodology for comparing the societal impacts of alternative energy sources. A set of externalities is selected both for the expected magnitudes of their contributions and the range of effects and treatments which they illustrate. The results, admittedly incomplete, show a persuasive superiority of solar over oil plants which become operational in the period 1985-2020, and a respectable superiority over coal after 1995. A more complete analysis incorporating externalities identified in the preceding paragraph would be highly desirable; although some reflection on the influence of these externalities on the calculations indicates that their effect will be to enhance the already superior social value of solar over fossil fuel plants in the period of interest.

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