Chapter 8

Conventional v. Alternative Technologies: Utility and Nonutility Decisions

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Chapter 8

Conventional v. Alternative Technologies: Utility and Nonutility Decisions

INTRODUCTION

Deployment of the technologies addressed in this assessment in the 1990s hinges on investment decisions made by both electric utilities and nonutility power producers. They are the primary (and in some cases, the only) markets for these new technologies. Their investment decisions will determine the future commercial viability of the technologies. Investment in these technologies will only occur if they can compete with existing electricity-generating technologies. In addition, the new technologies will have to compete amongst themselves for limited sources of capital.

This chapter focuses primarily on the process of technology choice by utilities and nonutility entities, and the relative economics of the various new generating technologies. The first and second sections discuss these issues for utilities and nonutilities. The third section provides cross-technology comparisons on issues concerning deployment, environmental impact, and ease of siting. Emphasis in the latter section will be on the nonquantifiable issues which cannot be addressed in cost and profitability calculations.

UTILITY INVESTMENT IN POWER GENERATION

Overview

Electric utilities in the United States are regulated to meet customer electricity demands at all times with reliable and reasonable cost power. If customer demand increases, sufficient generating capacity must be available. Utility planners attempt to examine all options available to them to meet this demand; traditionally, the least cost option—or at least what was thought to be least cost—has been the preferred option. Recent demand and operating cost uncertainties have forced the consideration of other investment criteria, e.g., financial health, and has complicated the traditional decision making process. This section focuses on electric utility decisionmaking and, using the methodology of the utility decisionmaking process, compares new technologies and load management with traditional utility options such as conventional pulverized coal-fired plants and utility-owned combustion turbines.

Utility Decisionmaking

Electric utilities operate under a different set of decision rules and constraints than other businesses (see box 8A for a brief description). In return for the privilege to operate as a monopoly, investor-owned electric utilities are subject to government regulation of prices, profits, and service quality.[1] Because of this regulation, utilities cannot maximize profit. For example, a utility must install added capacity to meet increased de-

[1] Publicly owned utilities are also subject to governmental control and oversight of utility operations and finances. The source of control can be municipal government, local entities, or the Federal Government. Since investor-owned utilities (IOU) account for the majority of U.S. energy sales to ultimate customers (76 percent—see table 7-1), emphasis will be placed on IOU decisionmaking. Moreover, many publicly owned utilities, primarily municipally owned utilities, are distribution-only utilities and do not invest in powerplants. Nevertheless, these municipal utilities will be very Interested in demand side alternatives, e.g., load management.

Box 8A.—Traditional Industrial Investment [illegible]

Traditional industrial investment decisions can generally be characterized as based on maximizing profits within a specific budget constraint. From a collection of different capital projects (e.g., plant expansion, new product lines, etc.) an optimum mix of projects is chosen to maximize the value of [illegible] discounted cash flow [illegible] measures of this value, such as the net present value, the internal rate of return, or the payback period. Brief definitions of these terms are:

- *Net Present Value:* The net present value is equal to the present value of future returns, discounted at the marginal cost of capital, minus the present value of the cost of the investment.
- *Internal Rate of Return:* The rate of return on an asset investment. The internal rate of return is calculated by finding the discount rate that equates the present value of future cash flows to the cost of the investment.
- *Payback Period:* The length of time required for the net revenues of an investment to return the cost of the investment.

Industrial firms also often use a minimum acceptable rate of return (or "hurdle rate") for screening alternatives. The level of the hurdle rate varies [illegible] to the level of risk involved in the investment.

SOURCE: [illegible] 1978).

and, even though it may decrease profits.[2] Electric utilities have a legal obligation to serve all the demand of their customers at any time.[3] Utilities normally construct enough extra capacity to provide a reserve margin against the possibility of being unable to serve customer load if a generating unit fails.

Utility decisionmakers also have obligations: 1) to ratepayers to minimize their rate burden over time, and 2) to their stockholders to maximize the utilities' financial health. The accepted means of accomplishing this is to minimize costs within reliability, regulatory, environmental, and financial constraints.[4]

Utility Planning Process

Electric utility decisionmaking on new plants is a four-step process: load forecasting, generation planning, transmission planning, and distribution planning. Table 8-1 lists the different characteristics of these power planning functions. The first step, load forecasting, determines the need for additional plants. Typical forecasting techniques include time series analysis, econometric modeling, and end-use models. In the past, utilities could rely on simple trend analysis to project future demand based on past growth rates, e.g., 7 percent a year. Recent unpredictable demand growth, however, has made this method undependable and more sophisticated methods are gaining wider acceptance.

Generation planning focuses on two important questions: the capacity needed for adequate reserve margins and the mix of capacity needed for least cost operation. Capacity expansion models are used to examine possible generation alternatives and to determine the least costly mix of future generation additions. Next, the operation costs and reliability of this generation mix are examined. Finally, the impact of the candidate capacity plan on the utility's financial position is assessed. These modeling and analysis functions often rely on complex optimization and simulation models.[5] Transmission and distribution plan-

[2] G. R. Corey, "Plant Investment Decision Making in the Electric Power Industry," *Discounting for Time and Risk in Energy Policy,* Robert C. Lind (cd.) (Baltimore, MD: Resources for the Future/Johns Hopkins, 1982), pp. 377-403.

[3] Garfield and Lovejoy provide a good summary of this Obligation: "public utilities are further distinguished from other sectors of business by the legal requirement to serve every financially responsible customer in their service areas, at reasonable rates, and without unjust discrimination." (P.J. Garfield and W.F. Lovejoy, *Public Utility Economics* (Englewood Cliffs, NJ: Prentice-Hall, 1964), p. 1.

[4] A large body of economics literatu re is devoted to the incentive (or lack of incentive) for cost minimization under rate of return regulation. The seminal piece by H. Averch and L. Johnson (H. Averch and L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review, vol. 52, No. 6, 1962,* pp. 1053-1069) argues that rate-of-return regulation provides an opposite incentive towards capital maximization.

[5] Good reviews of generation planning models have been done by S. Lee, et al. (S. Lee, et al., *Comparative Analysis of Generation Planning Models for Application to Regional Power System Planning* (Palo Alto, CA: System Control, Inc., 1978); and D. Anderson (D. Anderson, "Models for Determining Least Cost Investment in Electricity Supply," *Bell Journal of Economics,* vol. 3, spring 1972).

Table 8-1 .—Typical Power Planning Functions

Tasks	Primary considerations	Data requirements	Major outputs and objectives	Typical plan horizon
Load ***forecasting:*** • Energy forecast • Peak demand	• Changing weather patterns • Short/long-term trends in national/local economic variables • Changes in energy consumption patterns from: —Load management —Conservation —New technologies	• Historical consumption data • Weather data • Economic data –GNP —Employment —Many others • Appliance use data	• Short- and intermediate-range energy forecasts for cash management, financial planning, construction planning, and distribution planning • Long-range energy sales forecast for use in selecting generation equipment mix, timing, and characteristics • Short and intermediate peak demand forecast for interconnection/ purchase power requirements • Long-term peak demand forecasts	Short: O-1 year Intermediate: 1-5 years Long: 10-30 years
Generation planning: • Capacity studies . Production costing • Investment analysis . Siting studies	• System reliability • Pool requirements • New energy conversion technologies/costs • Capital availability • Regulatory requirements	• Peak load • Energy sales • Capital/equipment costs • Equipment operating and maintenance characteristics • Fuel costs • Construction cost “S” curves (expenditure patterns)	• Selection of site size, timing, and energy conversion technology for energy supply • Location of facility	10-30 years
Transmission piannhg: • Load flow studies • Stability studies	• System reliability • Changes in major load center locations • Interconnection requirements	• Energy sources . Load flows • Load stability	• Location, size, and timing of transmission facilities to support system needs	2-10 years
Distribution pianning: • Substation • Major distribution	• Changes in service area growth patterns	• Load growth by area • New developments • Major industrial customers	. Location, size, and timing of new substation and major distribution lines	1-3 years

SOURCE Theodore Barry & Associates, *A Study of the E/ectrw Uti/ity /rrdustry* (Los Angeles, CA: Theodore Barry & Associates, 1980)

ning activities are used to assure system adequacy and reliability given projected demand and generation facility location.

In the past, this planning process was straightforward–electric demands could be predicted accurately and generation planning was not unduly hampered by financial and environmental constraints. The situation is now considerably changed. A survey of electric utility executives indicates that the following major changes have affected their planning function the most in recent years: unpredictable demand growth, longer lead-times, and uncertain technology costs. Chapter 3 discusses these changes in depth.

[6]Theodore Barry & Associates, *A Study of the U.S. Electric Utility Industry* (Los Angeles, CA: Theodore Barry & Associates, 1980), p. IV-6.

These new factors have complicated the utility planning process. Utilities are required by Federal statutes, regulatory commissions, consumers, and stockholders to investigate all the possible costs and consequences, e.g., environmental impacts, of a generation alternative prior to investment. Consideration of many of these factors has been incorporated into structured regulatory proceedings like powerplant siting, but many of the issues and consequences can only be included in utility decision making through judgments made by utility executives and planners. The current inactivity in new plant construction start-ups is due in par-t to the reluctance of utility decisionmakers to make these judgments. These factors are discussed in greater detail in subsection entitled Required Project *Characteristics.*

Comparative Analysis

As mentioned earlier, unlike unregulated firms, utilities have not based their investment decisions strictly on profit maximization. Instead, they have traditionally examined all available means of meeting customer demand (both generation and demand-side options) and then selected the alternative that is least costly in terms of the revenue required from the consumers. This comparison approach, known as the minimum revenue requirement approach, is derived from standard utility rate-making techniques (see box 8B). It has been used throughout the industry[8] One recent survey indicated that 91 percent of investor-owned electric and combination electric and gas systems used a minimum revenue requirement approach.9

In this analysis, the comparative costs of the new technologies and of the conventional alternatives were arrived at by applying the minimum revenue requirement concept to each investment alternative and then deriving its levelized cost. OTA staff developed a cost analysis model using standard utility accounting and investment decision methodologies for comparison purposes. [10] This model projects yearly revenue requirements, i.e., costs, taxes, and allowed rate of return, for the expected life of a new plant. Levelized costs in cents per kilowatt-hour are derived from this revenue requirement stream, and form the basis of cross-technology cost comparisons, (Appendix 8A discusses the levelized cost estimation in much greater detail.)

Box 8B.—Rate-Making Fundamentals

The primary form of public utility regulation is the determination of the rates utilities can charge for their services. State public utility commissions (PUCs) traditionally have controlled rates for intrastate sales of electricity, while the Federal Government has had jurisdiction over sales for resale in interstate commerce since 1935.

Determining the rates a utility charges for its services is a two-step process. The PUC must decide first, how much money the utility needs (the revenue requirement) and second, how those funds will be collected (the rate structure or rate schedule). A utility's revenue requirement is the total number of dollars required to cover its operating expenses and to provide a fair profit. The revenue requirement is usually expressed in a formula such as the one that follows:

$$RR = E + d + T + (V - D)R$$

where:

RR	= revenue requirement
E	= operating expenses (e.g., fuel, maintenance, and insurance)
d	= annual depreciation expense
T	= taxes, including income taxes
V	= gross valuation of the property serving the public
D	= accrued depreciation
R	= rate of return (a percentage)
(V—D)	= rate base (net valuation)
(V—D)R	= profit, expressed as earnings on the rate base, plus interest on debt

The revenue requirement is then distributed among the various groups or classes of customers in a fair and reasonable manner. Each class' cost to serve must be transformed into a rate design, a price which, when applied to the units of utility services billed, will produce revenue sufficient to cover the class cost to serve and in turn the overall revenue requirement.

Basic Assumptions

In order to compare different technologies on a consistent basis, several assumptions had to be made. The technologies considered for utility investment were assumed to be electric-only technologies—no cogeneration technologies were considered. Cost estimates calculated in this model were made on a constant dollar (1983) ba-

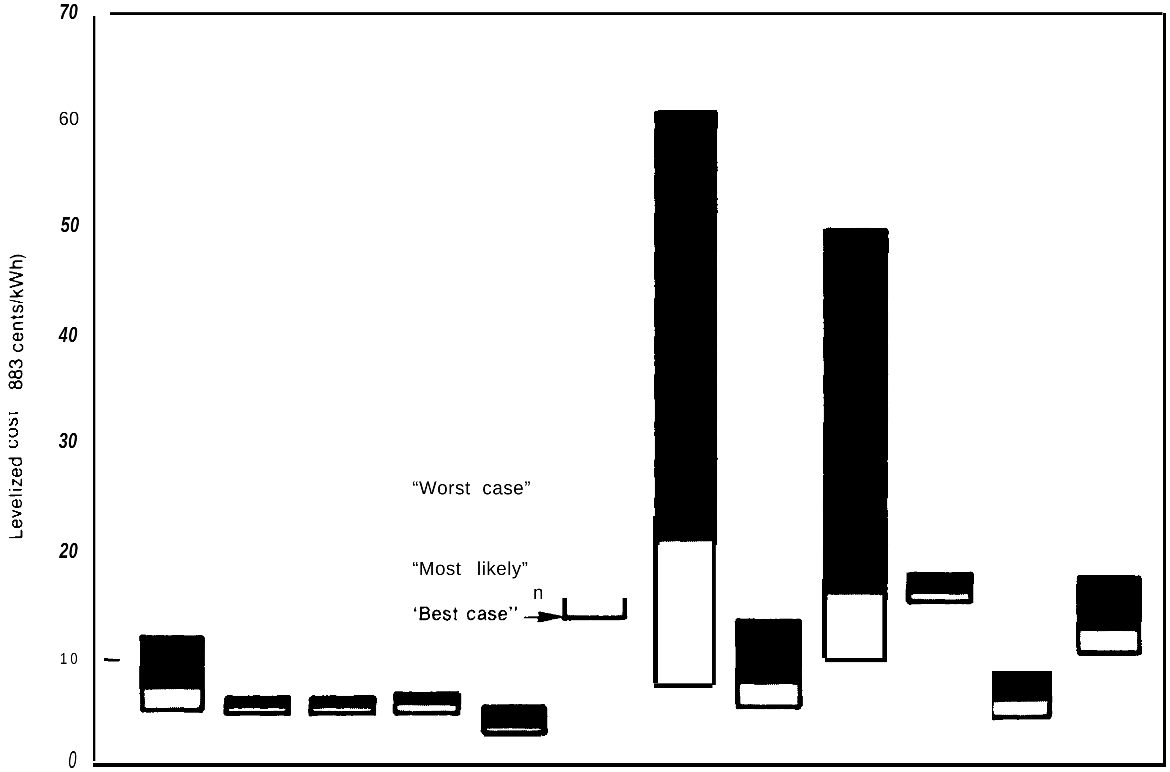
[7]"Available" in this context refers to the technologies utilities perceive as being able to meet their needs. The utility planners may feel that adequate information on a technology or commercial demonstrations are not sufficiently available for new technologies, and will not consider the technology.

[8]Publicly owned utilities perform a similar comparison. The components of revenue requirement will be different-reflecting factors such as rate of return.

[9]G. R. Corey, "Plant Investment Decision Making in the Electric Power Industry, " op. cit., 1982,

[10]The analysis structure used to develop the OTA model was derived from the techniques used by Philadelphia Electric Co. 's Rates Division (Philadelphia Electric Co., *Engineering Economics Course* (Philadelphia, PA: Philadelphia Electric Co., Rates Division, Finance and Accounting Department, January 1980), p. 2-2.).

Figure 8-1.—Technology Cost Range: Utility Ownership—West



	Geo-thermal	AFBC	IGCC	Coal	Life ext (coal)	Solar parabolic dish	Photo-voltaics	Wind	Fuel cell	Com-bustion turbine	Battery storage	CAES
Size (MWe)	50	150	500	500	537	10	10	20	11	150	20	220
Cap cost ($/kW)[a]	1450	1420	1275	1474	400	2500	2633	1050	1430	350	500	582
Capacity factor	70%	70%	70%	70%	70%	25%	35%	30%	25%	10%	N/A	N/A
Levelized cost[b]	7.41	5.42	5.21	5.53	3.25	17.26	20.52	7.13	15.28	15.40	6.20	11.73

NOTE: **Basic assumptions —** discount rate: 5% (real); debt interest rate: 5% (real); base year dollars: 1983; Federal tax rate: 46%; Federal depreciation: 10- and 15-year ACRS; State tax rate: 9.6%; Insurance rate: 0.25% of capital cost; property tax rate: 2.3% of capital cost; Investment Tax Credit: 10%; debt portion: 50%; gas price escalation: 2% per year; oil price escalation: 2% per year; coal price escalation: 1% per year.

[a]Represents instantaneous capital cost in 1983 dollars.

[b]Levelized busbar cost under most likely cost and performance scenario.

SOURCE: Office of Technology Assessment.

sis. This allows the comparison of technologies with different reference years, lead-times, and lifetimes. Figure 8-1 lists the basic parameters that are assumed not to vary across technologies. Later in this section, the sensitivity of the costs to changes in these parameters will be addressed.

For the basic cost comparison, the technologies were examined for three scenarios: worst case, most likely case, and best case. These scenarios were derived from the parameter ranges included in the cost and performance projections developed in chapters 4 and 5. The worst case scenario incorporates the "worst" (most pessimistic) values for each parameter, while the best case uses the "best" (most optimistic) values. For example, the worst case uses the high end of the capital *cost* range, but uses the low end of the capacity factor range. In addition, the worst case scenario assumes little improvement in current technology conditions. Comparison of the worst and best case scenarios provides a range of levelized costs. The most-likely case numbers represent OTA's best estimates of future utility costs.

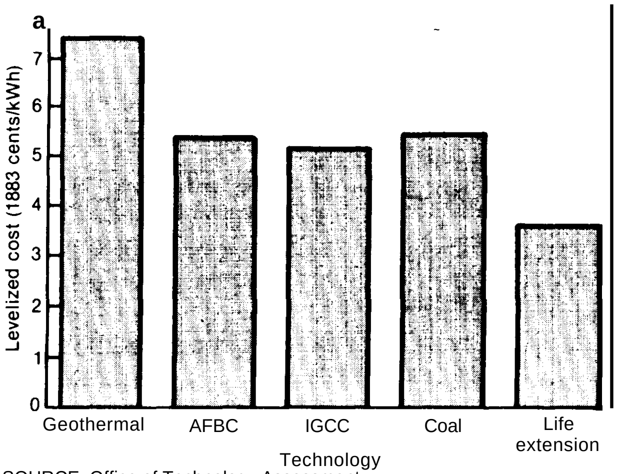
Cross-Technology Cost Comparison

The results of the comparative cost analysis are shown in figure 8-1. Costs for pulverized coal-fired plants, combustion turbines, and coal plant life extension were included for comparison purposes.

One of the striking features of the results shown in figure 8-1 is the wide cost ranges for solar photovoltaics and fuel cells. Both of these technologies are currently in early stages of development relative to the other technologies in the figure and are currently not competitive with other technologies. Nevertheless, as figure 8-1 shows, these technologies have the potential of significant cost reductions, and they could compete with peaking technologies, e.g., combustion turbines, or even base load technologies. To become competitive, however, they must be deployed in significant numbers, and important research, development, and deployment questions must be resolved (see chapter 4).

Comparison of the new base load technologies–geothermal, atmospheric fluidized-bed combustors (AFBC), and integrated coal gasification/combined-cycle (IGCC)–with the primary conventional alternatives—pulverized coal-fired plants with flue gas desulfurization (FGD) and existing coal plant life extension—indicates that all of these new technologies are likely to be competitive with current technology in the 1990s. Figure 8-2 shows levelized costs for each of these technologies under the most likely case. These resu lts indicate that coal powerplant betterment is the cheapest source of base load power. Among the new technologies, IGCC appears to be the best competitor followed by AFBC. The competitiveness of these new "clean coal" technologies is important because both produce less negative environmental impacts than conventional coal-burning technologies. The potentially attractive economics of the plant betterment option, however, could lead to extended use of old, dirtier coal plants, many without scrubbers. Geothermal plants are also attractive in terms of comparative cost, but the site-specific nature of geothermal power will probably limit widespread deployment,

Figure 8-2.— Base Load Technology Costs: Utility Ownership—West



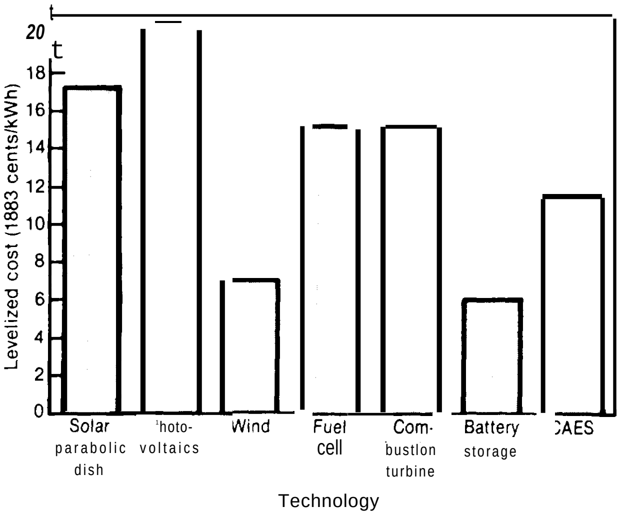
SOURCE: Office of Technology Assessment.

The new, intermittent, and peaking technologies addressed in this assessment are also expected to compete favorably with current technologies in the 1990s, Figure 8-3 shows the most likely-case costs for solar thermal electric, solar photovoltaics, wind, fuel cells, battery storage, and compressed air energy storage (CAES), as well as the most likely costs for combustion turbine powerplants. Wind power from utility-owned small turbines (<400 kW) in wind farms shows the lowest cost among the new generation technologies. The expected future levelized cost of wind technology is significantly lower than the other non-base load technologies. Wind also has the potential of competing with the base load technologies (see figure 8-2). The relatively low cost estimates for the storage technologies indicate that these technologies could compete favorably with peaking technologies to satisfy peak electric loads.

Sensitivity to Uncertainty

Despite the optimism reflected in the cross-technology comparison, the projections of these future costs for the new technologies are subject to a great deal of uncertainty. This uncertainty is reflected in the levelized cost ranges in figure 8-1. Several of the technologies–solar photovoltaics, wind and fuel cells—show particularly wide

Fiqure 8-3.— Peaking/Intermittent Technology Costs: Utility-Ownership—West



SOURCE. Off Ice of Technology Assessment

cost ranges. Unless resolved, this uncertainty, and the investment risk it represents, will probably hamper widespread deployment of many new technologies well into the 1990s.

A sensitivity analysis was performed for each technology considered in this assessment. This analysis highlights the most sensitive parameters and provides insight into the technological developments that could produce the most improvement in future cost and performance. The sensitivity of a technology's levelized cost to changes in key parameters—capital cost, operation and maintenance (O&M) cost, capacity factor, and fuel cost—was tested by varying each parameter above and below the base case estimate by 25 percent. This analysis indicates, for example, that a 1 ()-percent increase in wind farm capital cost could cause our most likely estimate of utility levelized costs to increase 1.5 cents/kWh or about 21 percent.

In general, the results of sensitivity analyses for all the technologies indicate that the three most critical parameters are capital cost, capacity factor, and fuel cost. The capacity factor is the most critical parameter for electric utility operation, Fuel costs were also very important for non solar technologies, but capacity factor consistently produced the largest variations in levelized costs. A somewhat surprising result from the analysis was that capital cost changes do not produce as much variation as these other parameters. Nevertheless, the relative importance of each of these parameters varies according to duty cycle, heat rate, and capital intensiveness. For example, fuel costs are the most sensitive parameter for combustion turbines, but capacity factor is more important for fuel cells. This is because of the lower capital costs and higher heat rates of combustion turbines.

A possible explanation for the relative importance of capacity factor vis-a-vis capital cost is found by examining the levelized cost formula.[11] The numerator of the formula is the levelized annual revenue requirement. The denominator is average kilowatt-hour production. Increases in capacity factor will directly increase electricity production and reduce levelized costs. Capital costs are recovered through economic depreciation over a number of years (1 5 years under present tax law). The levelization calculation discounts the depreciation costs more in later years than in early years. Thus, changes in initial capital cost do not produce as significant and direct an effect. This suggests that utilities are likely to continue to be very concerned with the availability and reliability of future generating options since these factors cause significant levelized life-cycle cost uncertainty.

Utility Strategic Options

Most utilities have put off decisions on new, large coal or nuclear plants. To commit large sums of capital to such long lead-time projects in the highly uncertain investment environment which has prevailed in this industry since the 1970s, they think, is too financially risky. Instead, many utilities are considering a variety of strategic options that will defer the need for such large-scale commitments. Chapters 3 and 5 discuss these options in detail. The discussion that follows focuses primarily on three of these options, namely life extension and rehabilitation of existing generating facilities, increased reliance on load management, and construction of small modular plants.

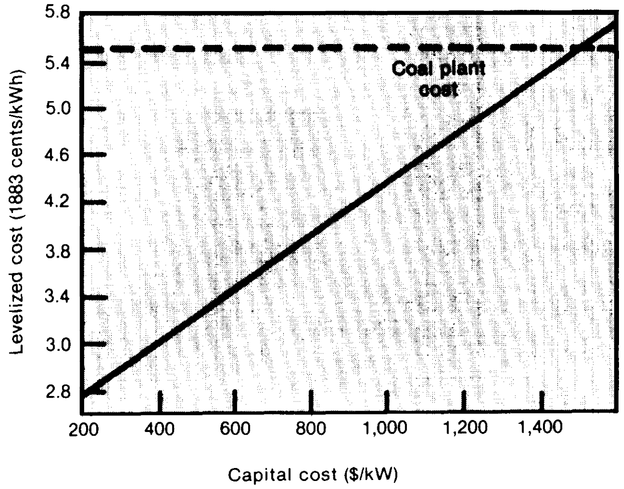
[11]The general form of the levelized cost formula is:

$$\frac{\text{levelized annual revenue requirement}}{\text{average annual electricity production}}$$

Plant betterment—i.e., life extension and rehabilitation of existing generating facilities–is a way to defer new generation investment. The capacity base for this option is sizable–by the year 2000, nearly a third of the existing U.S. fossil generating capacity will be more than 30 years old. In addition, the capital investment required–$200 to $800/kW–is relatively small. The attractiveness of this option is partially explained by its low expected levelized cost. As can be seen in figure 8-2, the expected costs of existing coal plant betterment are lower than both conventional and new base load generating technologies. Moreover, figure 8-4 shows that capital cost levels for life extension up to $1 ,500/kW can produce lower cost power than conventional pulverized coal plants with FGD, or an IGCC plant. Additional OTA modeling efforts[12] using EPRI Regional Systems datals indicate that at the system level, at least in the Southeast, fossil life extension (coal, oil, and gas-fired units) could produce overall utility system revenue requirements[14] as much as 5 percent lower than a capacity expansion plan based on large unit construction (the base case) to meet the same load. Nevertheless, the results also indicate that focusing plant betterment activity solely on oil and gas units could produce higher revenue requirements than the base case.1[5]

Load management is the other primary nongeneration option available to utilities. Its principal goals are to permit a higher proportion of demand to be served by lower cost electricity (from base load sources) and to defer the need for new generating capacity. There is the potential for sizable amounts of load management in the United States. For example, in the Southeast, a 5.4 percent potential peak load reduction in the summer and 3.3 percent in the winter appears possible.[16] Further analysis of these load management projections for the full EPRI Southeast Region typical utility by OTA indicates that load management could reduce future utility revenue requirements by up to 1.5 percent. At this level of peak reduction, the greatest reduction in revenue requirements is achieved by: 1) shifting the energy avoided at the peak to off-peak periods, and 2) coupling load management to the early retirement of oil and gas units.[17] While these results suggest net benefit from load management for the region, results for individual utilities or other regions may be different.

Figure 8-4.—Life Extension Costs: Sensitivity to Capital Cost



NOTE: Assumes 537 MW plant size after life extension (7.5 percent capacity increase), 2-year lead time, 20-year lifetime, 70% capacity factor, 9.5 mills/kWh O&M cost, and a 9,106 Btu/kWh heat rate (5% efficiency increase). All other parameters are the same as listed in figure 8-1.

SOURCE: Office of Technology Assessment.

12A state-of-the-art utility simulation model, the Utility System Analysis Model (USAM) by Lotus Consulting Co., was used for this analysis.

13Electric power Research Institute, *The EPRI Regional Systems* (Palo Alto, CA: Electric Power Research Institute, July 1981), EPRI P-1 950-SR. The load and system data used by OTA were the basic EPRI typical utility data sets that were modified by Lotus Consulting Co. to include plant additions.

14This value refers to a levelization of the utility system revenue requirements (using a 5 percent discount rate) over the 10-year period between 1990 and 2000.

15The assumptions used in this analysis were: 1) all plants which are 25 to 35 years old in 1985 through 2000 will have their life extended; 2) plant efficiency is increased by 5 percent, capacity is increased by 5 percent, and 10 years are added to design plant lifetime; 3) the plant betterment costs $200/kW (based on the new plant size); and 4) future capacity is deferred to achieve the same reserve margins as in the base case.

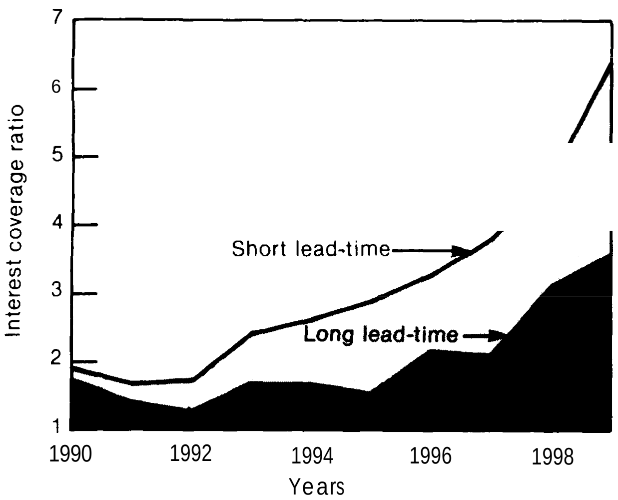
16Electrotek Concepts, Inc., *Future Cost and Performance of New Load Management Technologies,* final report to the Office of Technology Assessment, January 1985, OTA Solicitation US-84-7. For the Southeast, 5.4 percent reduction equals 891 MW in 1990.

17The basic assumptions used in this analysis are the same as for the plant betterment analysis. The capital costs of the utility load management program (calculated by Electrotek to be $191 /kW) are annualized and expensed over the life of the equipment. Further analysis by OTA has shown that utility revenue requirements do not significantly differ when expensing or capitalizing the load management program.

Comparison of the results for the plant life extension and load management cases in a typical Southeast utility indicates that plant life extension is the more attractive option at currently projected load management levels and assumed program costs,

Of particular interest to many utilities are the potential benefits of increased flexibility and financial performance offered by small-scale, short lead-time generating plants. OTA modeling studies indicate that under uncertain demand growth, the cash flow benefits of such plants in the short term could be considerable .18 For example, as shown in figure 8-5, the interest coverage ratio, which measures a utility's ability to repay its debt obligations—and is the principal consideration in bond rating decisions, tends to decline for a utility engaged in a major construction project as outlays are made during the construction period. Under the low demand growth scenario in figure 8-5,19 investment in a series of small modular plants results in a considerably better interest coverage ratio trend, even with a 10 percent capital cost premium (per kilowatt) associated with the smaller plants. The primary reason for the difference in financial performance is the ability of the smaller plant to track demand growth. Under the low demand growth scenario, the interest coverage ratio for the large plant is relatively low both during the construction period of the plant[20] and during the period that the system has high reserve margins. Use of a low-high demand scenario[21] narrows the difference. Indeed, the interest coverage ratio trend for the large plant surpasses the small plant trend after the large plant comes on-line in 1997.

Figure 8-5.—Short v. Long Lead-Time Analysis: Impact on Financial Health



SOURCE Office of Technology Assessment

Summay

The new technologies addressed in this assessment have the potential to compete economically with conventional generating technologies, e.g., pulverized coal, combustion turbines. The new technologies which are most likely to provide lower cost power are AFBC, IGCC, geothermal, and wind power. Fuel cells and photovoltaics could compete favorably with peaking technologies such as combustion turbines. Storage technologies could also compete effectively with these peaking technologies. In addition, most of the generating technologies considered in this assessment offer the small-scale modular features many utilities are seeking, although many are subject to significant cost and performance uncertainty.

A more serious impediment to utility investment in these new technologies for the next 10 to 15 years is that most of them are not likely to compete effectively with other generally more cost effective strategic options—life extension and rehabilitation of existing generating facilities, and increased reliance *on* load management. These strategic options are being aggressively pursued by many utilities. OTA analysis of these options indicates that their implementation could provide

[18] A scaled-down Northeast EPRI Regional System was used for this analysis, The initial capacity is 6,600 MW and Initial peak load is 5,500. The first year of the scenario is 1990 and continues until 2000. A 800 MW coal plant is assumed to start-up in 1992. A pulverized coal plant is the technology examined, The only differences between the two types of plants are:

	Small	*Large*
Capacity	100 MW	500 MW
Lead-time	1 year	7 years

[19] Two percent load growth in the first 5 years and O percent in the last 5 years. Edison Electric Institute, *Strategic Implications of Alternative Electric Generating Technologies* (Washington, DC: EEI, April 1984).

[20] The 500 MW plant is assumed to come on-line in 1997.

[21] Two percent load growth in the first 5 years and 6 percent in the last 5 years.

sizable benefits to utilities and enhance utility financial health. As a result, the new technologies may take longer to achieve the low costs projected in this section.

NONUTILITY INVESTMENT IN POWER GENERATION

Overview

Interest in nonutility electric power generation has increased in recent years. In some parts of the country, California being the most notable example, nonutility generation has emerged both as a significant source of power and as a strategic option for utilities. In addition to existing industrial self-generation, power is now being sold by companies operating low-head hydroelectric dams, cogeneration, wind turbines, geothermal powerplants, and, to a much more limited extent, photovoltaic arrays and solar thermal electric facilities.

Non utility generating facilities are owned by industrial and commercial firms, and third-party entrepreneurs. This increase in activity is due, primarily, to a supportive regulatory climate and the availability of tax benefits. And whether a healthy nonutility power generation industry emerges in the 1990s will depend on policy decisions over the next few years. This section examines:

1. characteristics of current nonutility producers,
2. nonutility technology choice decisionmaking,
3. the comparative profitability of these technologies, and
4. the impact of Federal tax policy.

Historical Nonutility Generation

Industry has generated electricity since the earliest days of electric power. This power generation included both onsite production to meet industrial needs and cogeneration. The contribution of this industrial capacity to overall electricity production has declined over time, however. In 1962, capacity at non utility owned generating plants represented 8.5 percent of total installed generating capacity. By 1979, this contribution, while remaining relatively constant in absolute terms, had slipped to 2.8 percent of total generating capacity.[22] In the 197os, industrial self-generation (including cogeneration) of electricity decreased in the face of increasing fossil fuel prices, aging plant, a flattening of demand, and a generally lower rate of increase in the price of purchased electricity[23] Changes in this trend, however, may be emerging in the 1980s–the real price of oil has stabilized, curtailments of natural gas no longer occur, the retail price of utility power has continued to increase, and regulatory changes that make it economically attractive to produce electric power for sale to utilities.

Current Nonutility Electric Power Generation

With the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), the prospects for generation of power outside of electric utility ownership improved markedly. Prior to PURPA, owners of nonutility powerplants did not have guaranteed markets for their power beyond their own use, and were subject to possible public utility regulation. Rates for sales of power to utilities were open to negotiation without a consistent "yardstick" against which negotiated rates could be measured, PURPA changed this situation by providing a 100 percent "avoided cost criterion" for these rates and removing potential for regulation. Chapter 3 discusses PURPA in more detail.

The non utility market for sale of power has increased significantly since the early 1980s. installed nonuti lity generating capacity in 1985 consists primarily of cogeneration applications (mostly from natural gas), biomass-fired genera-

[22]Edison Electric *Institute, Statistic/ Yearbook of the Electric Utility Industry/1982* (Washington, DC: EEI, 1983).

[23]R.C. Marlay, "Trends in Industrial Use of Energy," *Science, vol.* 226, No. 4680, Dec. 14, 1984, pp. 1277-1283. These numbers do not include boilers using nonfossil fuels.

tion, wind, geothermal, AFBC, and hydro. Additional activity is occurring in solar thermal electric and photovoltaics. Table 4-4 shows the installed capacity breakdown for the new tech nologies in 1985. Wind power and AFBC are the subject of the most activity.

Characteristics of Nonutility Producers

Nonutility involvement in new technology development is being initiated by both industrial firms and third-party investors. Industrial investment in new technology projects is primarily undertaken to reduce the cost of meeting electrical and/or process heat needs. Either revenues from power sales to electric utilities or the avoidance of electricity purchases can make a project economic. By contrast, third-party investment in these technologies is organized by entrepreneurs who obtain financing and develop projects as profit-making ventures from sale of the electricity and any byproduct steam. Both types of development have occurred in recent years—with industrial involvement centering on cogeneration and third-party investment principally occurring in cogeneration, low-head hydroelectric dams, and wind power.

In order to gauge the level and type of current nonutility power generation, OTA sponsored a survey[24] conducted by the Investor Responsibility Research Center (1 RRC). The trends and characteristics in the I RRC sample provide insight into the nature of the industry and the direction it appears to be headed.

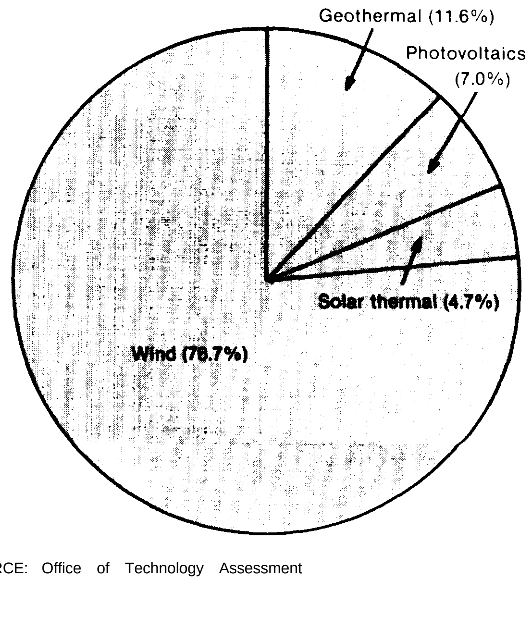
IRRC sent a survey form to current and projected nonutility power producers in the wind, solar thermal electric, geothermal, and photovoltaic industries.[25] It asked questions on the following topics:

- ownership,
- financial structures,
- generating plant characteristics,
- vendor agreements,
- operational data, and
- purchase agreements with utilities

Figure 8-6 shows the breakdown by technology of the survey respondents. Note that wind power companies represented 76.7 percent of the respondents, and geothermal power came in a distant second at 11.6 percent. I n terms of total installed capacity, the disparity is even greater. By the end of 1983, the IRRC sample reports that wind power accounted for over 134 MW of capacity.[26]

The survey results reveal two important industry characteristics which could affect industry health and the impact of Federal policy in the mid 1980s. First, most companies involved in nonutility power projects are relatively young—less than 3 years old. Second, these companies are quite small, typically maintaining generating capacity of less than 6 MW. Any significant changes i n tax and regulatory policy could severely affect the operations and profitability of these young firms.

Figure 8-6.—Survey Responses by Technology



SOURCE: Office of Technology Assessment

[24] Investor Responsibility Research Center, *Survey of Non-Utility Electric Power Producers,* OTA contract 433-7640, July 11, 1984.

[25] A total of 45 companies (25 current and 20 projected producers) responded to the survey. IRRC also surveyed the biomass and hydroelectric small power industries. The remaining technologies highlighted in this report (fuel cells, AFBC, and IGCC) were not sufficiently commercialized or deployed in 1983 to be surveyed.

[26] Comparison of this reported capacity with the 239 MW repot-ted in D. Marier, "Windfarm Update .. .117 Megawatts and Still Growing, "*Alternative Sources of Energy,* No. 63, September/October 1983, suggests that the IRRC sample contains a little over one-half of the industry in 1983.

Figure 8-7 shows the cross-section of ownership of current and projected non utility producers. The majority (78.6 percent) of these producers are privately owned companies, most of which are small in size and were formed strictly to sell power to utilities. Far fewer publicly held companies and subsidiaries, particularly more established, older, and larger firms, have entered the market as yet.

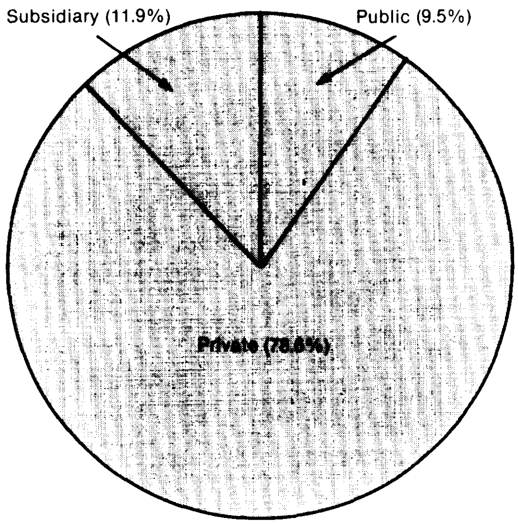
The survey respondents were also asked about the financing methods they have used to capitalize and operate their generating facilities. The responses from the currently producing companies fall generally into four major categories: sole ownership, joint ventures, partnerships, and leasing. Partnerships are the most prevalent, accounting for half of the projects surveyed. Sole ownership ranked second—29.4 percent; joint ventures and leases accounted for 14.7 and 5.9 percent, respectively. This cross-section indicates that most of the current projects, i e., wind farms, are generally financed with private investor capital, although over one-quarter of the respondents noted that they have used a mixture of financing methods such as sole ownership along with partnerships.

The survey indicates that the project location of most of the current and anticipated nonutiiity projects represented in the survey is California (see figure 8-8). California represents an even larger portion of nonutility capacity–over 90 percent of the 1983 reported installed capacity. The primary reasons are the availability of high utility avoided cost rates, tax credits (State and Federal), and California's generally supportive regulatory environment for alternative energy development.

Wind power represents all of the reported 1983 installed capacity of 134 MW in the survey. The average wind farm in the survey had an average capacity of 5,8 MW, Figure 8-9 shows that while small companies dominate the market in terms of total projects, in terms of installed capacity larger companies represent a much greater share of the industry.

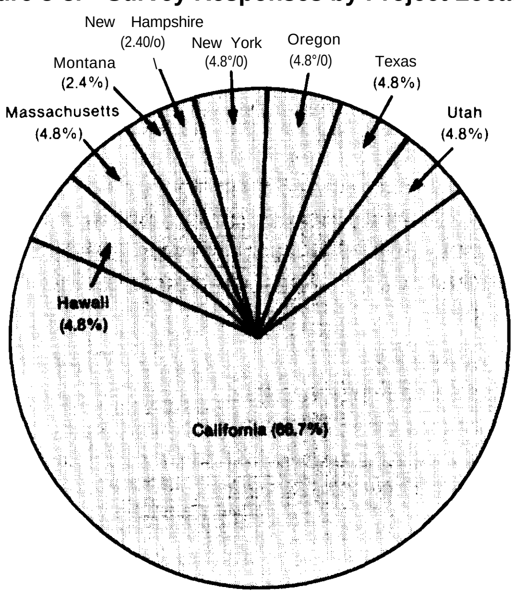
The year of initial generation for most companies has been within the last 3 years. Although PURPA and the business renewable tax credits were first passed in 1978, significant nonutility generation did not occur until 1982 because of court challenges to PURPA and slow implementation by States. As mentioned earlier, most of the companies involved in nonutility production are less than 3 years old; over 60 percent'of the companies in the survey started producing in 1982 and 1983 (see figure 8-10).

Figure 8-7.— Nonutility Ownership: Current and Projected Companies



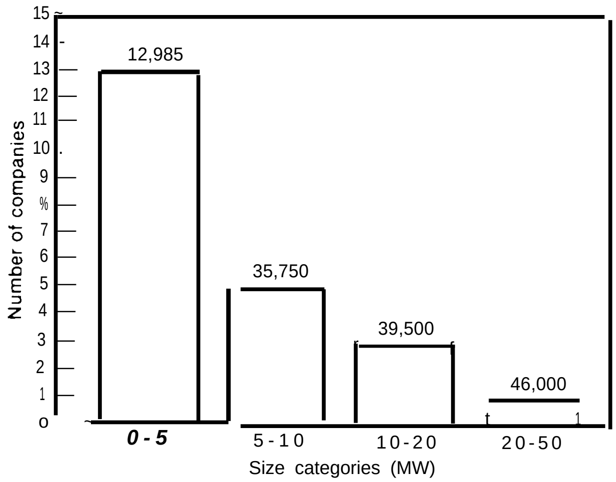
SOURCE: Office of Technology Assessment.

Figure 8-8.—Survey Responses by Project Location



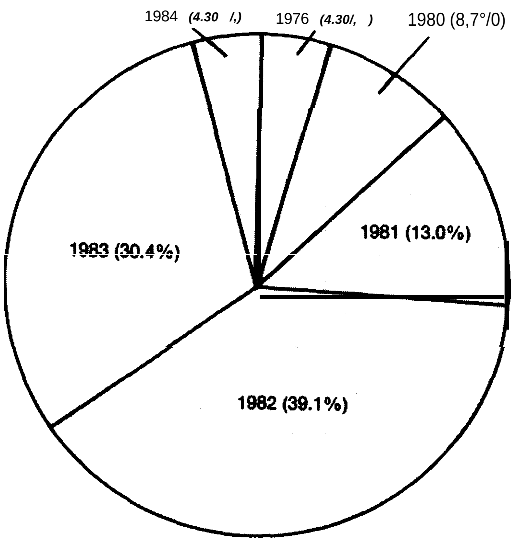
SOURCE: Office of Technology Assessment.

Figure 8-9.—Wind Farm Installed Capacity Distribution (number of companies and total kilowatts)



SOURCE: Off Ice of Technology Assessment

Figure 8-10.— Initial Year of Generation: Currently Producing Companies



SOURCE Off Ice of Technology Assessment.

Nonutility Investment Decisionmaking

Investment in power generation equipment in a nonutility environment is generally not very different than other long-term investment decisions. Investors, either individuals or corporations, are primarily interested in maximizing their risk-adjusted return on their invested capital. Hence, investor interest will increase if nonuti]ity power project investments offer potentially high returns relative to other investment options. But the rationale for the investment will vary according to the types of investors. Additional considerations for investors include tax status, timing of the investment, cash flow patterns, and maintenance of a balanced portfolio of risky and nonrisky investments.

Financing Alternative Technology Projects

Investment in nonutility generation projects can be initiated through a variety of financing structures. For a corporation (industrial or commercial), the two major vehicles are capital investment with internal funds, and project financing (sometimes called "third party financing"). Capital investment by a corporation usually involves the use of retained earnings, equity, or debt issues to finance a generation project. Project financing, on the other hand, looks to the cash flow and assets associated with the project as the basis for financing. Private investors often invest in technology projects through tax shelter syndicates and partnerships. Some nonutility power projects have involved both industrial and private investor participation. The following discussion highlights the major forms of nonutility financing mechanisms.

The likelihood of **sole ownership** by a corporation of a nonutility generation project depends on the size and financial strength of the industrial firm, the rationale for investment, and the riskiness of the technology. A large corporation will be more willing and able to finance a project with retained earnings than a small industrial firm. A large firm usually has more retained earnings available for discretionary investment. If a corporation has a stake in the development of a technology, e.g., the corporation is a vendor of the technology, successful ownership of a project such as a photovoltaic array or wind farm may attract future investment by third parties and lead to increased profits for the corporation. A project directly related to a firm's manufacturing process—e. g., providing process steam or electric power directly to an industrial operation–is also more likely to be financed internally. But a project operated strictly as a small power producer is less likely to be owned solely by a corporation. investments in projects that are more associated with a firm's principal line of business (e.g., sales expenditures or plant expansion) are more likely to receive higher priority. In addition, if the technology under consideration is perceived as risky, an industrial firm may seek partners or guarantees from vendors to share the project risk.

The methods of project finance are particularly appropriate to the financing of distributed electricity generation. As mentioned earlier, project financing looks to the cash flow associated with the project as a source of funds with which to repay the loan, and to the assets of the project as collateral. For successful project financing, a project should be structured with as little recourse as possible to the sponsor, yet with sufficient credit support (through guarantees or undertakings of the sponsor or third party) to satisfy lenders. In addition, a market for the energy output—electrical or thermal—must be assured, preferably through contractual agreements; the property financed must be valuable as collateral; the project must be insured; and all government approvals must be available.z' There are four major forms of project finance applicable to new technology projects: leasing, joint ventures, limited partnership, or small power producer (see box 8C for definitions).

Another ownership structure often used in wind turbine farms is an organized system of individual turbine sales, also known as sole ownership (or "chattel"). Under this structure the private investor owns only one turbine.[28] The project developer organizes the wind farm, sells the wind turbines to prospective investors, and provides maintenance services.

Required Project Characteristics

Every non utility generation technology project, whether it is structured through traditional project financing techniques or third-party entrepreneurs, must meet several requirements before it will be acceptable to investors. These requirements fall into three key areas: risk reduction, firm fuel and power sales contracts, and sufficiently high profitability (before or after taxes depending on the investor),

There are several forms of risk involved in new electric generation technology projects.[29] They include among others:

1. ***Machine** Risk:* Will the technology perform as predicted, i.e., produce the estimated power, meet availability targets, and not suffer catastrophic failure, all within appropriate installation and operational budgets?
2. ***Resource** Risk:* Will the site actually have sufficient fuelstocks (e.g., low-cost coal or geothermal brine) or quality resource (e.g., wind speeds and distribution) for the duration of the project? Will year-to-year fluctuations be great?
3. *Politica/ Risk:* Will the "rules of the game" regarding tax credits and deductions, sales prices to utilities (or others), zoning ordinances, or other permitting regulations change for the worse during the course of operation?
4. *Energy Price Risk:* Will the oil market soften further? Will the utility be allowed to convert to coal or other low-energy cost options?

In order to finance a new nonutility project, these risks must be either mitigated or incorporated in contingency plans. Common risk reduction techniques include vendor guarantees, take-or-pay contracts with utilities, and guarantees on project profitability from the project sponsors. Nevertheless, not all of the risks in projects utilizing new technologies can be eliminated. The higher the level of risk, the higher is the return on investment demanded by investors.

The most critical requirement for nonutility generation projects is the guarantee of stable fuel supply and power sales contracts. Fuel supply, whether it be natural gas, coal, or geothermal brine, must be assured for the duration of the project at reasonable, predictable prices. Even more important than fuel supply contracts are power sales contracts with electric utilities. Without long-term, power sales contracts, project de-

[27] P. K. Nevitt, *Project Financing* (London: Euromoney Publications Limited, 1979).

[28] R. Ceci, "Investing in Windpower: Ownership or Partnership, " *Alternative Sources of Energy, No. 71,* January/February 1985,

[29] M. Lotker, "Making the Most of Federal Tax Laws: A New Way to Look at WECS Development, " *Alternative Sources of Energy, No. 63,* September/October 1983, p. 38.

Box 8C.—Project Financing

There are four major forms of project financing used to develop nonutility projects:

- *Leasing*: Lease financing may be appropriate for projects in which the participants: 1) cannot use currently all the tax benefits associated with ownership of the project, 2) can benefit from off balance sheet financing, or 3) wish to utilize a new source of funds—the lease equity market. Through lease financing, participants may transfer ownership of all or a portion of the project to an equity investor or investors who will receive all or a portion of the tax benefits of ownership. By transferring the benefits to an equity investor who can use the benefits currently, the participants are able to reduce significantly their overall cost of financing the project.[1] Two types of lessors may be involved in project financing: sponsors of a project who lease to the project company, and third-party leasing companies that are in the finance business. The third-party lessors may have more attractive rates because they utilize the tax benefits of owning the equipment.
- *Joint Ventures*: Under the joint venture approach, a corporation undertakes the project with one or more partners. The partners may be investor groups whose primary role is to furnish the required capital, other independent firms that furnish either capital or other services (e.g., operation and maintenance), or equipment vendors. A joint venture can be either a separate corporation or a partnership.[2] A major rationale for joint ventures is the pooling of risks among the partners or participants.
- *Small Power Producer*: A third major form of project financing has been used for many recent nonutility projects, particularly wind farms. In this approach a Small Power Producer (SPP) as defined by PURPA (see chapter 3 discussion), which may be an individual, partnership or corporation, owns the genw+ation project but is not the ultimate Liset of the power. The SPP may sell the electricity produced to the local utility or other users, or may lease the generating equipment itself to a user. The SPP should be able to sell its electricity at high prices and have sufficient tax liability (usually due to income from other sources) to take advantage of the tax credits and deductions.[3] A primary source of capital for these projects are individual private investors, normally in limited partnerships.
- *Limited Partnership*: A limited partnership is an association of one or more general partners who: 1) manage the project, 2) assume the risks, and 3) may make guarantees to limited partners. Limited partners: 1) provide equity funding, 2) may not play an active management role, and 3) assume risk usually limited to the amount invested or a pro rata share of the partnership's debt. A "major reason that limi&i partnerships are attractive ownership options is that tax benefits are distributed to partners who can make most effective use of them.[4] An additional reason is the avoidance of the double taxation of income in corporations (i.e., taxation of corporate income and taxation of dividends). They are widely used in real estate, oil and gas drilling, leased equipment, and other properties.

[1]Merrill Lynch Capital Markets, *Project Financing* (New York: Merrill Lynch Capital Markets, 1984).

[2]Alliance to Save Energy, *Third-Party Financing: Increasing Investment* in *Energy-Efficient Industrial Projects* (Washington, DC: US. Department of Energy, November 1982), DOE/CS/24448—T1.

[3]M. Lotker, "Making the Most of Federal Tax Laws: A New Way to Look at WECS Development," *Alternative Sources of Energy*, No. 63, September/October 1983, p. 38.

[4]Ibid.

velopers will have difficulty obtaining debt and leveraging their investment to reduce capital costs. The guarantee of a sale, at a predetermined price (other acceptable price structures include price floors and schedules of future prices) per kilowatt-hour sold, will allow investors to calculate, with a reasonable degree of certainty, the cash flow associated with a wind turbine installation.[30]

[30]Ibid.

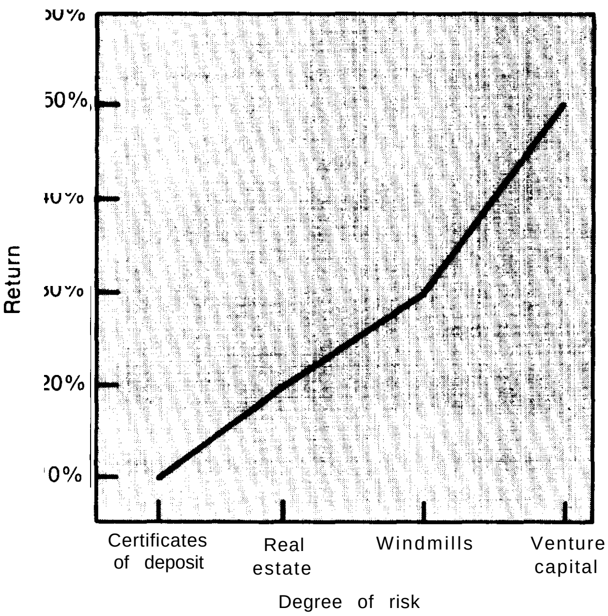
Another requirement for the financing of new technology projects is a sufficiently high rate of return to attract capital. Generally, the nominal internal rate of return (IRR) for a project must be between 20 and 30 percent.[31] For example, as can be seen in figure 8-11, windmills fall between real estate and venture capital on the investment risk continuum. Since the IRR is sensitive to tax and financing, an equally important determinant of profitability is cash return on the capital asset. Cash return on capital assets is obtained by removing tax benefits and debt and concentrating on the straight cash-on-cash return. A minimum required cash-on-cash return of 5 percent after operating expenses is typical.[32] If debt financing is used, the project must show a favorable debt service coverage ratio to obtain debt at reasonable terms. Most suppliers of debt capital require at least a 1.2:1 coverage ratio.[33]

[31]This nominal range translates roughly into a real IRR range of 15 to 25 percent if a 5 percent inflation rate is assumed. Thus, 15 percent will be used as the required rate of return or "hurdle" rate in the following analysis.

[32]R. A. Lyons, "Raising Equity: A Broker-Dealer Guide For the Project Developer," *Alternative Sources of Energy, No. 69,* September/October 1984, p. 20.

[33]Edward Blum, Merrill Lynch Capital Markets, personal communication with OTA staff, Aug. 28, 1984.

Figure 8-11.—Investment Risk Continuum



SOURCE: American Wind Energy Association, briefing for congressional committee staff, Washington, DC, Jan. 18, 1985,

Comparative Profitability

The primary basis for cross-technology comparisons that follow will be the profitability of new technology projects to both institutional and individual investors. The source for the technology cost and performance estimates are the detailed tables included in appendix 8A to this chapter. Cross-technology comparisons based on projected costs and performance will be presented first, followed by a discussion of the sensitivity to these results to key parameters. Alternative Federal policy scenarios, e.g., tax policy, will also be examined.

The technologies examined in this section will be geothermal power, wind power, solar photovoltaics (concentrators[34]), solar thermal electric, fuel cells, and atmospheric fluidized-bed combustion (AFBC). (Integrated coal gasification/combined-cycle (ICCC) plants addressed elsewhere in this assessment will not be included in this analysis because the technology is currently geared toward the utility market, and cogeneration-sized IGCC plants are not expected to be deployed in the 1990s.) All the technologies listed above are assumed to produce just electricity, except fuel cells and AFBC for which cogeneration applications are examined. Neither of these latter two technologies currently qualify as small-power producers under PURPA, and, hence, were configured as cogenerators for the analysis, Combustion turbine-based cogeneration, currently the primary technology used in new cogeneration applications, is used as the conventional alternative against which the new technologies are compared,

Basic Assumptions

Comparisons among technologies will be made primarily by assessing their breakeven cost and performance. Breakeven analysis determines the capital cost and electricity production parameters necessary for a project to cover both costs and required return on investment. A standard discounted cash flow methodology was also used to compare technologies, and check the results

[34]Tracking concentrator systems were chosen for the base case nonutility comparison because initial results indicated that they will penetrate the grid-connected power generation market first with the highest profit.

of the breakeven analysis. This methodology calculates profitability measures and is based on methods used by the financial community. The discounted cash flow methodology is described fully in appendix 8A.

In order to compare the different technologies on a consistent basis in both of these methodologies, several assumptions were made. As discussed earlier, the comparisons are made on a constant dollar (1 983) basis. This allows the comparison of technologies with different reference years, lead-times, and lifetimes. The technologies were examined for three scenarios: worst case, most likely case, and best case. These scenarios were derived from the parameter ranges in the cost and performance projections developed in chapter 4 and listed in appendix A.

Breakeven Analysis

As discussed in chapter 4, each new technology has a unique set of cost and performance parameters, such as capital cost, capacity factor, and expenses. These parameters can be compared to an assumed revenue stream (from electricity sale to utilities or thermal revenues from cogeneration) and required rate of return to determine technology cost effectiveness. The basic concept is to match initial cost and annual electricity production (measured as the capital cost per annual kilowatt-hour) to the sum of net revenues and tax benefits (see box 8D). if a technology's capital cost per annual kilowatt-hour is lower than revenues and benefits, the technology is cost effective. This comparison is called breakeven analysis and is used in financial analysis to provide a relatively simple quide to the profitability of a project.[35] If a technology appears profitable, more detailed analysis and structuring of the project is undertaken.

Figure 8-12 shows breakeven graphs for three groups of technologies: a) wind power, solar photovoltaics, and AFBC; b) geothermal and solar thermal electric (parabolic dish); and c) fuel cells and combustion turbines. Each group represents a different level of annual expenses.[36] For example, technologies with high fuel expenses, such as fuel cells, have much higher expenses than wind turbines and solar photovoltaics, which have no fuel expenses. The three lines in each graph represent breakeven capital cost per kilowatt-hour as a function of the avoided cost buy-back rate. Each line is associated with a particular set of required real rate of return (1 O, 15, and **20** percent).[37] Along side each breakeven graph are the capital cost per kilowatt-hour ranges associated with the new technologies. The high end represents the worse case, the low end represents the best case, and the mark in the middle is associated with the most likely case.

This graph can be used in two ways: 1) to determine the breakeven capital cost per kilowatt-hour associated with a specific avoided cost, and 2) to calculate the required avoided cost rate that each technology needs in order to break even. The top graph in figure 8-12 provides an example of the first type of analysis. The dotted lines trace an avoided cost buy-back rate of 5 cents/kWh[38] and a 15 percent required real rate of return. As can be seen in this figure, wind power could be profitable at this buy-back rate if capacity factors can be increased and initial capital cost can be reduced. While wind power could be cost effective under these conditions, at costs and/or capacity factors associated with the upper portion of wind's capital cost per kilowatt-hour range, profitability will likely be marginal. These graphs also indicate that AFBC, geothermal, and combustion turbines are economic at a wide range of buy-back rates. Conversely, solar thermal, and to a lesser extent, photovoltaics and fuel cells require significantly higher buy-back rates. Both photovoltaics and fuel cells become more economic in the lower portions of their cost ranges.

[35] Edward Blum, Merrill Lynch Capital Markets, personal communication with OTA staff, Mar. 19, 1985.

[36] The expense groups were derived by grouping the technologies according to the percentage of total lifecycle revenue accounted for by the sum of operating, fuel, Insurance, and land rental costs. These percentages were estimated with the discounted cash flow model discussed in this section. The percentages are 20 percent for wind, photovoltaics, and AFBC; 25 percent for solar thermal electric and geothermal; and 60 percent for fuel cells and combustion turbines.

[37] The base set of assumptions are 10 percent Investment Tax Credit (no Renewable Tax Credit), 5 year ACRS depreciation, 50 percent Federal tax rate, 100 percent equity financing, and 2 percent real fuel escalation. The fuel escalation rate serves as the proxy for the rate of increase in avoided cost rates.

[38] This buy-back rate was chosen because it approximates avoided costs for Pacific Gas & Electric and Southern California Edison in 1984.

Box 8D.—Breakeven Analysis

Breakeven analysis, as implemented in this report, is used to determine which parameters equate a project's costs with its revenues and benefits. The focus in this chapter is on which avoided cost buy-back rate is necessary for a new technology project to breakeven.

The equations used to conduct the breakeven analysis are based on the equating capital cost with revenues and tax benefits over the life of the project. This principal can be expressed for a project financed with 100 percent equity as:

$$C = (1 - T)K(1 - E)pR + (TC + f)C$$

where:

- C = Capital cost in $/kWh
- T = Federal tax rate (percent)
- K = Annual production in hours
- E = Expenses as a proportion of total revenue
- p = Present value of an escalating series, i.e., $p = \sum_{i=0}^{N} (1+e)^i/(1+d)^i$
- e = Real fuel escalation rate (percent)
- d = Discount rate (required rate of return) (percent)
- N = Project life
- R = Initial buy-back rate in cents/kWh
- TC = Federal tax credit (combination of investment tax credit and any energy tax credits) (percent)
- f = After tax present value of accelerated depreciation (percent).

The first part of the right side of the equation corresponds to revenue and the second part refers to tax benefits.

A useful measure of the cost of a project is capital cost per annual kilowatt-hour. Capital cost per annual kilowatt-hour is calculated by dividing capital cost by the capacity factor times 8760 hours. Figure 8A-1 performs this calculation for a variety of capacity factors. The above equation can be transformed to equate project revenue and tax benefits per kilowatt-hour to capital cost per annual kilowatt-hour:

$$C/K = \frac{(1 - T)(1 - E)pR}{1 - TC - f}$$

Representative values for each of the equation's parameters can be used to estimate the breakeven capital cost per annual kilowatt-hour. Comparison of this breakeven value to a technology's capital cost per annual kilowatt-hour determines the cost effectiveness of a project. This analysis is shown in figure 8-12.

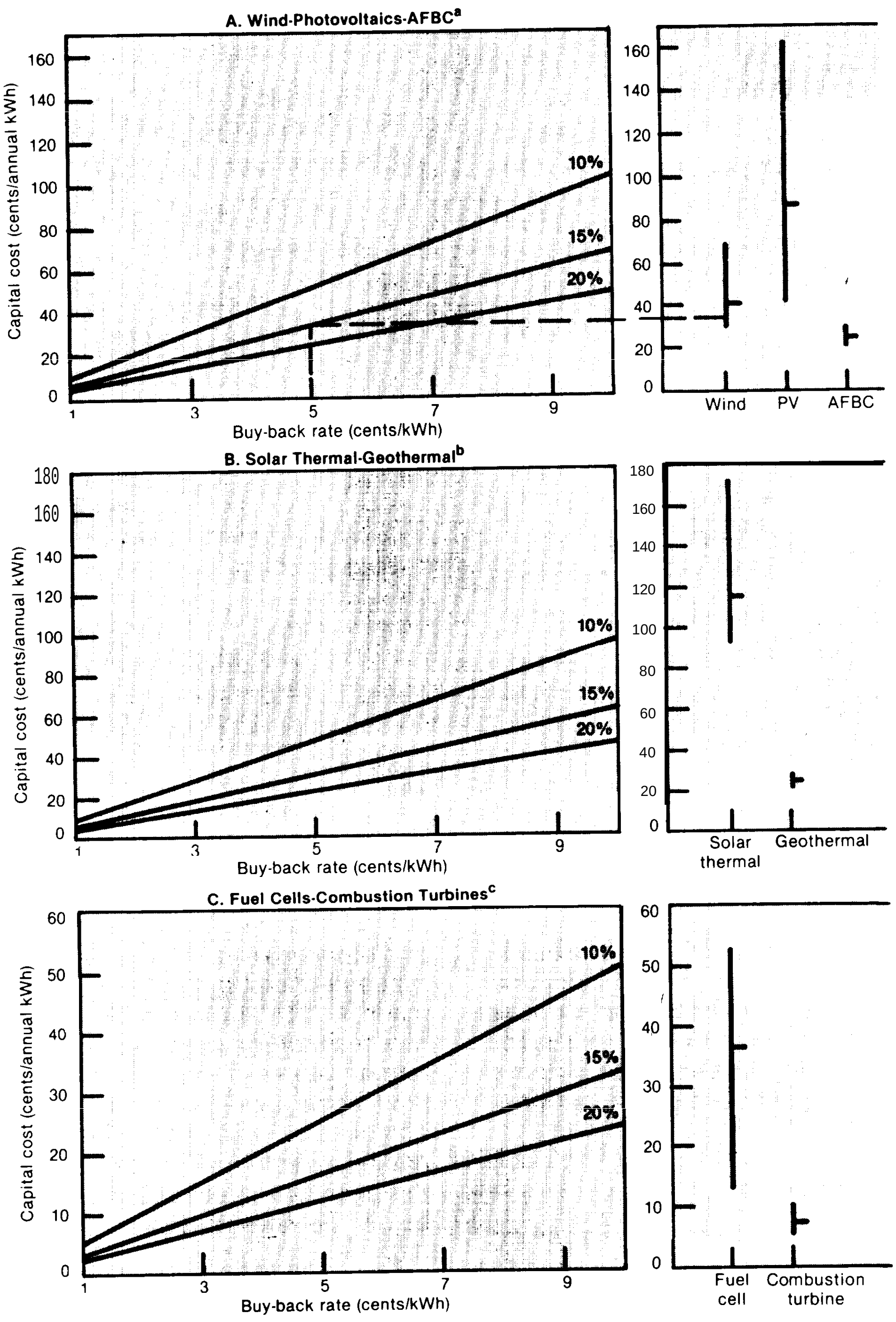
Similarly, a breakeven buy-back rate can be derived by transforming the basic equation to:

$$R = \frac{C \times (1 - TC - f)}{(1-T)K(1-E)p}.$$

This analysis is performed in figure 8-12.

The second analysis approach, calculation of the required avoided cost revenue rate, provides a good basis for comparison of cost effectiveness across the technologies. in addition, the analysis can determine whether a new technology project will be economic with a particular utility or statewide buy-back rate. Figure 8-13 shows the results of this analysis with a 15 percent real required rate of return (or approximately 20 percent nominal) and no Renewable Tax Credit. These results mirror the results listed above. AFBC, geothermal, and combustion turbines are clearly economic throughout their cost ranges at buy-back rates above 4 cents/kWh. At its expected cost and performance levels, wind could be profitable at buy-back rates above 6 cents/kWh. If wind power achieves its most optimistic capital cost and capacity factor ranges, wind

Figure 8-12.—Breakeven Analysis

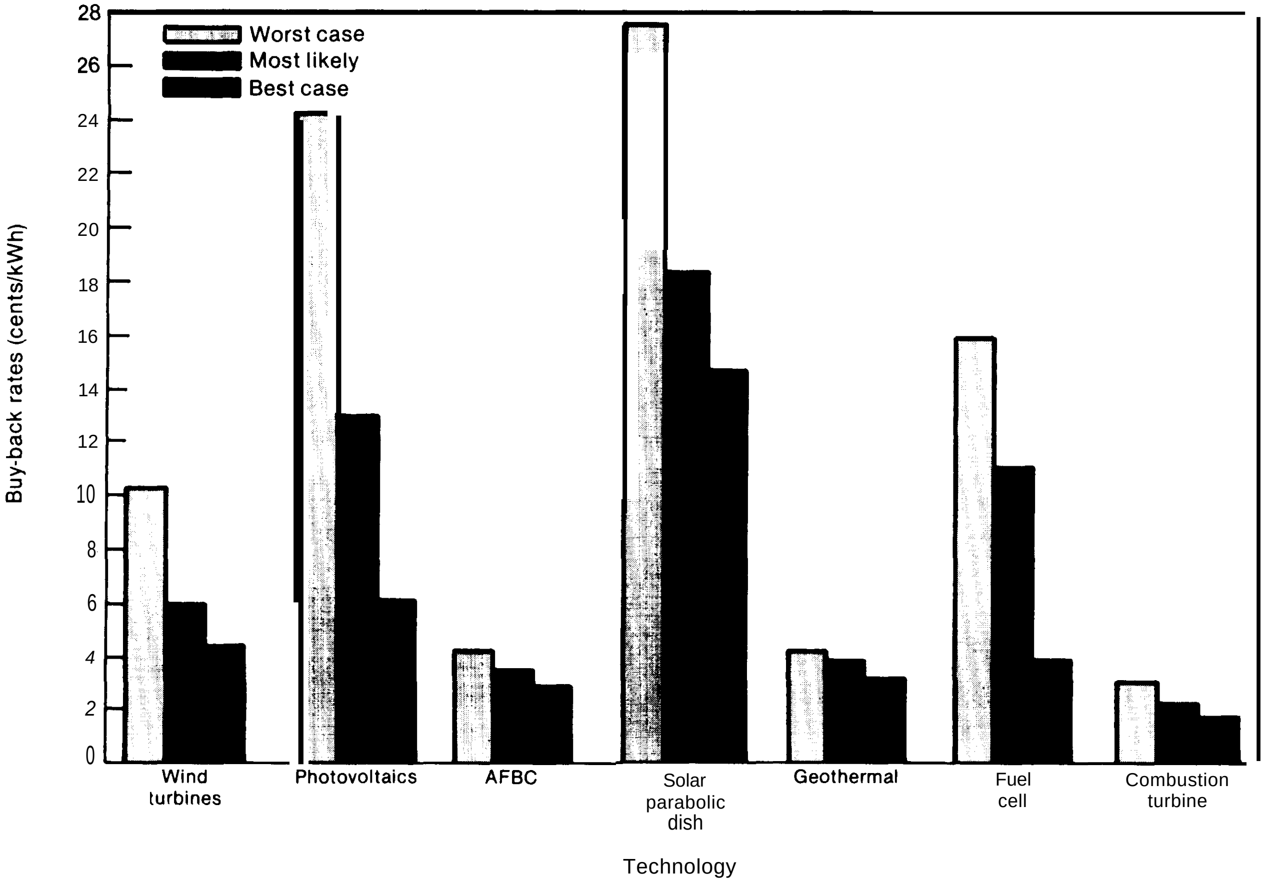


[a]Assumes that expenses equal 20 percent of total revenue.
[b]Assumes that expenses equal 25 percent o total revenue.
[c]Assumes that expenses equal 60 percent of total revenue.

NOTE: All of the graphs assume 2% real fuel escalation, 10% Investment Tax Credit, 5-year ACRS depreciation, and a 50% tax bracket. The three lines in each graph are associated with real rate of return

SOURCE" Office of Technology Assessment

Figure 8-13.—Breakeven Buy-Back Rates



NOTE: Assumes 2°/0 real fuel escalation, 1O°/. Investment Tax Credit, 5-year ACRS depreciation, a 50V0 tax bracket, and 150/. real rate of return
SOURCE: Office of Technology Assessment.

could require only a 4 cents/kWh rate. The breakeven buy-back rate for solar photovoltaics and fuel cells drops below 10 cents/kWh only at their most optimistic cost and performance values. For solar thermal electric, the breakeven rate is above 10 cents/kWh throughout its cost and performance range.

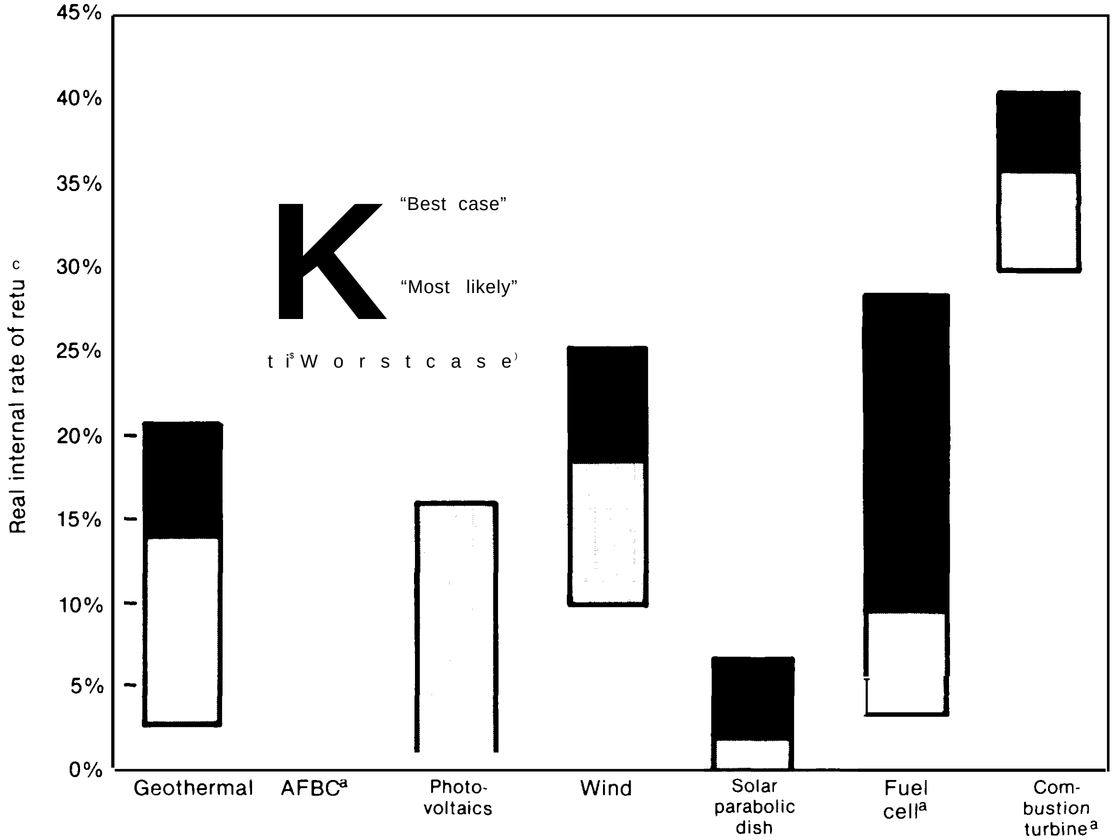
Rate of Return Analysis

In addition to breakeven analysis, a standard discounted cash flow methodology was used to derive profitability, i.e., real internal rate of return. Internal rate of return (I RR) can easily be compared to rates realized by investors, although its calculation and interpretation are not without problems. The most serious problem is the sensitivity of IRR to changes in the debt structure, and other financial parameters (e.g., repayment schedules, leasing, etc.).39 Since no attempt was made by OTA to structure the financing of a given new technology project in order to gain the best rate of return—the basic cross-technology cash flow model assumes established debt and equity portions for the project, no leasing, and a set Federal tax rate[40]—the calculated rates of return in this analysis will be different from and typically below the rates of return actually achievable.

The results of the comparative profitability analysis are included in figure 8-14. Also listed in are the base case assumptions regarding tax rates,

[39] Indeed, many analysts place more weight on payback periods and net present value.
@For the basic comparisons, the tax rate is set at the average Federal tax percentage.

Figure 8-14.—Technology Profitability Range: Nonutility Ownership—West



	Geothermal	AFBC[a]	Photovoltaics	Wind	Solar parabolic dish	Fuel cell[a]	Combustion turbine[a]
Size (MWe)	50	40	10	20	10	11	25
Capital cost ($/kW)[b] .	1450	1420	2633	1050	1750	2240	350
Capacity factor	70%	70%	33%	30%	25%	70%	55%
IRR[c]	13.9%	28.6%	0%	18.6%	1.8%	9.5%	35.8%

NOTE: **Basic economic assumptions**—discount rate: 10% (real); debt interest rate: 5% (real); base year dollars: 1983; Federal tax rate: 50%; Federal depreciation: 5-year ACRS; Federal Renewable Tax Credit: 0%; State tax rate: 9.6%; State Renewable Tax Credit: 25%; insurance rate: 0.25% of capital cost; property tax rate: 2.3% of capital cost; Investment Tax Credit: 10%; debt portion: 40%; gas price escalation: 2% per year; oil price escalation: 2% per year; coal price escalation: 1% per year; avoided capacity credit: $70/kW; capacity credit escalation: 2% per year; avoided energy credit: 5.2 cents/kWh; energy credit escalation: 2% per year.

[a]Cogeneration application.

[b]Represents instantaneous capital cost in 1983 dollars.

[c]Real internal rate of return under most likely cost and performance scenario.

SOURCE: Office of Technology Assessment.

etc. Generally, the values listed, especially State taxes and avoided cost rates, represent conditions in California. (California was chosen because the State's current regulatory environment supports nonutility investment, a large portion of existing nonutility new technology activity is occurring in California, and many new nonutility projects in the near future are expected to be developed in the State.) The regional fuel prices were derived from utility-reported data compiled by the Energy Information Administration .41 The regional aspects of fuel prices are covered in chapter 7. Comparison of the worst and best case scenarios provides a range of profitability; the most likely case results represent OTA's best estimates of future profitability. In general, these results substantiate the relative rankings derived in the breakeven analysis.

This figure shows the attractiveness of AFBC-based cogeneration. Throughout its expected rate of return range, AFBC is clearly the most profitable new technology. These profitability ranges also show the potential for solar photovoltaics

[41]These data were compiled by EIA for OTA on Nov. 27, 1984.

and fuel cells to achieve high rates of return[42] under the best case scenario. The capacity contribution and deployment of these "clean" technologies could be sizable if capital costs are reduced and reliability increased for these two technologies. On the other hand, if they do not occur, these technologies do not compare as favorably with the other technologies and may not be deployed in significant numbers.

Wind power is currently the major source of non utility generation, other than cogeneration. The results shown in figure 8-12 seem to explain this market dominance—wind power compares favorably with the other technologies. Geothermal power is also expected to achieve favorable rates of return.

Sensitivity to Uncertainty

The nonutility profitability values listed above and shown in figure 8-14 were subjected to the same sensitivity analysis framework that was conducted on utility levelized costs presented earlier. The primary purpose of this sensitivity analysis is to examine the cause of the wide rate of return ranges shown in figure 8-14 for each technology.

In general, the results of sensitivity analyses of the key factors—capital cost, O&M cost, capacity factor, heat rates, and electric-thermal ratio[43]—affecting the profitability of the technologies indicate that the most critical are: capital cost, capacity factor, and heat rate. If the nonutility project cogenerates, then the electric-thermal ratio becomes very important. The relative importance of each of these parameters varies according to duty cycle, relative heat rate, and capital intensiveness.

General economic conditions and Federal policies can also significantly affect the profitability of non utility projects. The sensitivity of these economic factors—avoided costs, fuel costs, fuel cost escalations, tax credits, Federal tax rate, debt portion, and debt interest rate–were subjected to sensitivity analysis. The most critical factor was the avoided energy cost rate. This is not surprising since the energy credit is the major source of revenue for nonutility technology projects. Next in importance are the Federal tax credit (both investment and energy credits), the Federal tax rate, and avoided capacity credits. As was indicated by the relatively high sensitivity to heat rates, relative fuel costs are also important for fuel-intensive technologies such as combustion turbines. Sensitivity to tax credits is examined further below.

These results highlight three main factors that affect the development of new generation technologies. First, policies geared toward increasing reliability and availability, lowering initial capital costs, and increasing efficiency (e.g., heat rate) will have the greatest impact on the future market potential in the nonutility sector. Second, locating a project in a region or State with high avoided costs is crucial to project profitability. Finally, Federal tax policy can significantly affect changes in the profitability of non utility projects.

Sensitivity to Federal Tax Policy

The existence of Federal tax benefits for renewable energy projects has been instrumental in the development of the current nonutility industry. Both the nonutility IRRC survey and the previous sensitivity analysis results emphasize the importance of Federal tax credits. Not too surprisingly, the respondents to the IRRC survey advocated their continued existence. AA

Federal tax treatment of non utility investment is currently in flux. The current business energy credits are due to expire on December 31, 1985. Failure to extend these credits will markedly reduce project profitability and probably cause an industry shake-out. In addition, the Treasury Department has proposed a massive "tax simplification." This proposal, among other things, would, if enacted, repeal the 10 percent investment Tax Credit.

[42] A "favorable" or "sufficiently high" rate of return is assumed to be above a 15 percent real (20 percent nominal) "hurdle rate."

[43] The electric-thermal ratio measures the relative production of electricity and steam from a cogeneration unit. A high ratio indicates that the unit produces relatively more electrical energy than thermal energy.

[44] The IRRC survey was discussed in greater detail earlier in this section.

These tax policies were analyzed with the OTA cash flow model. Cross-technology profitability was calculated for five tax policy alternatives:

1. No *Tax Incentives–No* tax credits, and 15 year SOYD[45] depreciation
2. *ACRS Depreciation–No* tax credits, 5-year ACRS depreciation
3. Investment *Tax* Crec/it-Same as (2), with 10 percent ITC
4. *10 percent Renewable Tax Credit—Same* as (3), with 10 percent RTC
5. 15 *percent Renewable Tax Credit—Same* as (3), with 15 percent RTC.

Case 5 represents current policy. Table 8-1 presents the results of this analysis. Figure 8-15 graphically shows the change in profitability (cumulative) upon stepping through the five cases. As can be seen, profitability changes dramatically among the five policy cases. Under the most likely case scenario, if a 15 percent real rate of return (20 percent nominal) is assumed to be the hurdle rate, AFBC and combustion turbine units are likely to be economic under the No Tax Incentive case. Inclusion of a 5-year ACRS allows wind power to become barely profitable. The Renewable Tax Credits cause a dramatic increase in profitability. For example, wind power achieves a real rate of return in excess of 25 percent with a 15 percent tax credit. Geothermal power also is economic with its 10 percent Renewable Tax Credit. The other new renewable technologies–photovoltaics and solar thermal–also benefit from the Renewable Tax Credits, but remain the technologies with the lowest IRR.

[45]Sum of Years Digits.

Summary

Generation of electric power by nonutility entities has become an important alternative to electric utility power generation. The existence of a wide variety of markets and interested investors outside electric utilities increases the likelihood that many of the new technologies considered in this study will be deployed. OTA analysis of technology profitability indicates that wind power and AFBC-based cogeneration compete favorably with conventional technology–combustion turbines—under expected conditions. Because of current and expected profitability, the commercialization of wind power technology has gone forward. And investor interest in AFBC should speed its commercialization as well.

Our analysis shows that the renewable energy tax credit coupled with recovery of full utility avoided costs by non utility power producers have been crucial in both the initial commercial development and the deployment of the new generating technologies. Should avoided cost rates be low or uncertain, their development and application will be retarded. Conversely, high avoided costs, stimulated perhaps by rising oil and gas prices or shrinking reserve margins, might substantially accelerate their deployment. In addition, without continued favorable tax treatment, development of much of the domestic renewable power technology industry will probably be delayed significantly. In particular, without existing tax incentives, many of the small firms involved in development projects will lose access to existing sources of capital. Even large, adequately capitalized firms may lose their distribution networks, leaving the industry struggling to survive.

CROSS-TECHNOLOGY COMPARISON

Overview

This section overviews the critical cross-technology issues involved in the deployment of the technologies covered in this assessment. The emphasis in here will be on the nonquantifiable characteristics of the technologies, i.e., those that cannot be addressed in a cost or profitability analysis. The primary issues covered in this section will be the environmental impacts and the ease of deploying the technologies. Much of the comparisons in this section are based on information contained in chapters 4, 5, 6, and 7, along with previous sections in this chapter.

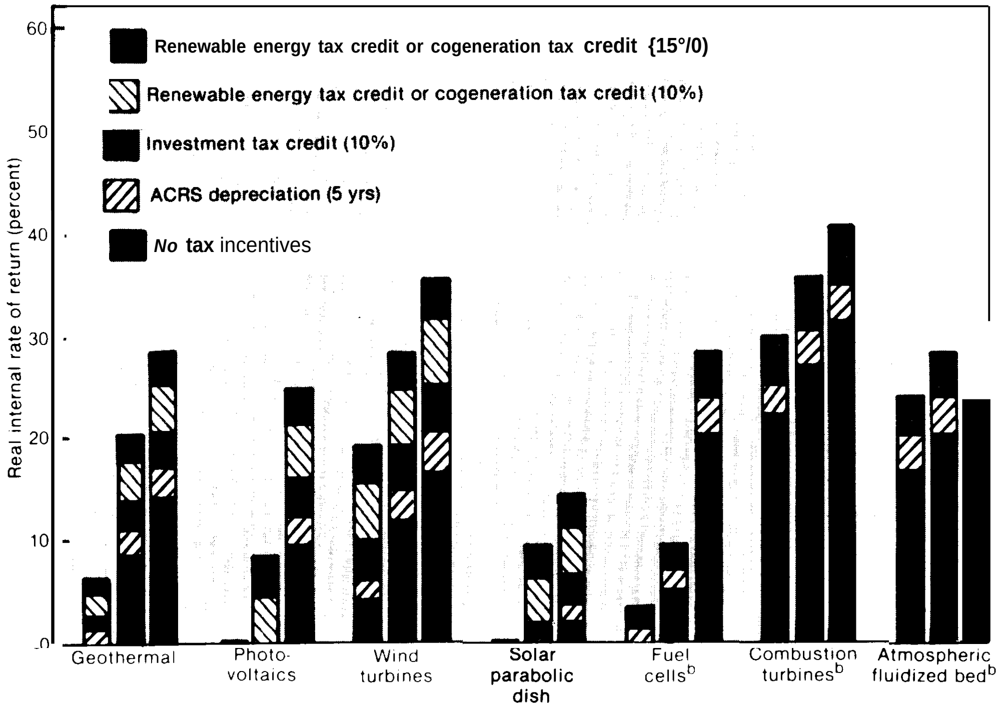
Table 8-2.—Alternative Tax Incentives: Cumulative Effect on Real Internal Rate of Return

	Real internal rate of return (percent)						
Tax incentive	Geothermal	Photo-voltaics	Wind turbines	Solar thermal	Fuel cells	Combustion turbine	Atmospheric fluidized-bed
"Worst case" cost and performance:							
No tax incentives[a]	0.1%	0.0%	4.1%	0.0%	0.0%	22.3%	16.9%
Current tax incentives[b]	4.9	0.0	19.1	0.0	3.4	30.0	24.3
Investment Tax Credit (10%)[c]	2.7	0.0	9.9	0.0	3.4	30.0	24.3
Production Tax Credit: [d]							
$0.01/kWh	6.3	0.0	14.9	0.0	7.7	39.1	29.8
$0.02/kWh	6.7	0.0	16.8	0.1	8.6	40.5	31.7
$0.03/kWh	6.8	0.0	17.9	0.1	9.1	40.5	32.6
$0.05/kWh	7.0	0.0	19.0	0.2	9.5	40.5	33.7
Renewable Tax Credit:[e]							
10% without 5 year ACRS	2.8	0.0	11.6	0.0	3.6	32.0	24.6
10% with 5 year ACRS	4.9	0.0	15.5	0.0	6.6	36.1	29.6
15% without 5 year ACRS	3.8	0.0	14.5	0.0	5.1	35.3	27.3
15% with 5 year ACRS	6.3	0.0	19.1	0.0	8.9	39.7	32.9
ACRS depreciation:[f]							
5 years	1.2	0.0	5.9	0.0	1.3	25.2	20.2
10 years	1.1	0.0	5.1	0.0	1.2	23.2	18.6
"Most likely" cost and performance:							
No tax incentives[a]	8.9%	0.0%	11.7%	0.0%	5.0%	27.2%	20.4%
Current tax incentives[b]	17.8	8.4	28.4	9.5	9.5	35.8	28.6
Investment Tax Credit (10%)[c]	13.9	0.0	18.9	1.8	9.5	35.8	28.6
Production Tax Credit: [d]							
$0.01/kWh	19.2	5.2	24.6	6.1	14.1	46.2	34.9
$0.02/kWh	20.4	6.7	26.8	7.5	15.3	47.0	37.0
$0.03/kWh	20.8	7.5	27.8	8.2	15.9	47.0	37.9
$0.05/kWh	21.2	8.4	28.8	9.1	16.3	47.0	38.8
Renewable Tax Credit:[e]							
10% without 5 year ACRS	13.9	1.5	19.7	2.1	9.5	38.1	29.1
10% with 5 year ACRS	17.8	4.3	24.7	6.2	13.3	42.3	34.4
15% without 5 year ACRS	15.8	4.3	22.7	4.0	11.3	41.7	32.2
15% with 5 year ACRS	20.4	8.4	28.4	9.5	15.8	46.2	37.9
ACRS depreciation:[f]							
5 years	11.2	0.0	14.7	0.0	7.0	30.5	24.1
10 years	10.3	0.0	13.2	0.0	6.4	28.2	22.3
"Best case" cost and performance:							
No tax incentives[a]	14.2%	9.4%	16.6%	1.7%	20.3%	31.5%	24.8
Current tax incentives[b]	25.5	24.8	35.5	14.4	28.4	40.7	33.9
Investment Tax Credit (10%)[c]	20.7	16.0	25.2	6.6	28.4	40.7	33.9
Production Tax Credit: [d]							
$0.01/kWh	27.0	20.6	31.9	10.2	36.4	52.5	41.0
$0.02/kWh	28.4	22.6	34.2	11.8	38.1	52.5	43.2
$0.03/kWh	29.1	23.7	35.2	12.7	38.6	52.5	44.3
$0.05/kWh	29.4	24.7	36.4	13.8	38.6	52.5	44.7
Renewable Tax Credit:[e]							
10% without 5 year ACRS	20.8	16.0	25.6	6.7	28.9	43.3	34.7
10% with 5 year ACRS	25.5	21.3	31.6	11.2	34.2	47.6	40.2
15% without 5 year ACRS	23.3	18.7	28.9	8.7	32.0	47.1	38.1
15% with 5 year ACRS	28.6	24.8	35.5	14.4	37.7	51.6	43.9
ACRS depreciation:[f]							
5 years	17.1	12.3	20.5	3.7	24.0	35.0	28.9
10 years	15.8	11.1	18.6	3.3	22.1	32.4	26.7

[a]Includes Sum of Years Digits depreciation, no Investment Tax Credit (ITC), and no Renewable Tax Credit (RTC).
[b]Includes 5 year ACRS depreciation, 10% ITC, and RTC where applicable.
[c]Includes 5 year ACRS and 10% ITC.
[d]The Production Tax Credit (PTC) is calculated by applying the cents/kWh credit amount to expected yearly electricity production. The credit is applied annually until the cumulative tax credit equals the total tax credit level available with the 15% RTC. The 10% ITC and the 5 year ACRS schedule are also used in computing the PTC.
[e]Includes 10% ITC.
[f]Does not include 10% ITC.

SOURCE: Office of Technology Assessment.

Figure 8-15.—Tax Incentives for New Electric Generating Technologies: Cumulative Effect on Real Internal Rate of Return*



[a]Reported for each technology with "worst case," "most likely," and "best case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8.
[b]In cogeneration applications.

SOURCE: Office of Technology Assessment, U.S. Congress.

Cross-Technology Issues

The previous sections in this chapter focused on the relative costs and profitability of the developing technologies. Usually, most utilities and investors place the greatest emphasis on these monetary values when making investment decisions. Nevertheless, a host of additional issues can affect and, in some cases, determine the choice of electric power technology. These issues include environmental impacts, fuel availability, and modularity, among others. Table 8-3 displays a variety of quantitative and nonquantitative characteristics of the technologies under considerateion.

The most striking aspect of this table is the wide variation in the cost, performance, resource, and environmental attributes evidenced by the different technologies. The new technologies vary from small, short lead-time technologies such as wind power to large, longer lead-time technologies such as IGCC; from capital-intensive, less mature technologies like fuel cells to low cost per unit power, commercial technologies such as geothermal; and from site-specific technologies such as geothermal to more easily sited technologies such as photovoltaics. This variation among the technologies makes easy classification of the technologies difficult. Trade-offs between important characteristics such as cost, environmental impacts, and lead-time must be made prior to selection of a particular technology. Nevertheless, a few insights concerning these cross-technology issues can be made.

First, although the clean coal technologies, i.e., AFBC and IGCC, are low in cost per unit power, and can use a variety of fuels and fuel types, the potential environmental impacts from these technologies are significant. AFBCS and IGCCS require sizable quantities of water and land, produce sig-

Table 8-3.-Cross-Technology Comparison: OTA Reference Systems

Technology chacteristics	Geothermal	Wind power	Photovoltaics	Solar parabolic dish[a]	AFBC	IGCC	Fuel cells	CAES	Battery storage
General:									
Geographic location	Western U.S.	Entire U.S.	Entire U. S., South better	SW & SE	Entire U.S.	Entire U.S.	Entire U.S.	Entire U.S.	Entire U.S.
Plant size[b]	Small-medium	Small	Small	Small	Large	Large	Small	Medium-large	Small
Development status	Demo-commercial	Commercial	Demo-commercial	Demo	Commercial under construction	Demo	Demo planned	No Demo	Pilot
Lead time[c]	Short-medium	Short	Medium	Medium	Long	Long	Medium	Medium-long	Medium
Siting fiexibility[d]	Low	Medium	High	Medium	Medium	Medium	High	Medium	High
Intermittent? [e]	No	Yes	Yes	Yes	No	No	No	No	No
cost:									
Cost[f]	Medium	Medium	High	High	Low	Low	High	Medium	Low
Profitable? [g]	No	Yes	No	No	Yes	N/A	No	N/A	N/A
Resoume reoukements and envhvnmental Inmacts:fl									
Primary fuel Source	Geothermal brine	Wind	Solar insolation	Solar insolation	Coal/solid fuels	Coal/natural gas	Natural gas	Base load electricity plus natural gas or oil	Base load electricity
Fuel availability	Limited	Limited number of quality sites	Region specific	Region specific	Not constrained	Not constrained	Not constrained	Not constrained	Not constrained
Noise	Medium	Medium to high	Low	Low	Medium	Medium	Low	Medium	Low
Solid waste[i]	Medium	Low	Low	Low	Medium to high	Medium to high	Low	Low	Low
Alr quality	Medium to high	Low	Low	Low	Medium to high	Medium to high	Low	ed	Low
Water quality[j]	Medium	Low to medium[k]	Low	Low		Medium	Low	Low	Low
Water consumption:[l]									
Daily amount[m]	Low to high	Low	Low	Low	Medium	Medium to high	Low	Low	Low
Amount per MWe(net)[n]	High	Low	Low	Low	Medium	Medium	Low	Low	Low
Land use:									
Aereal extent[o]	Low	High	High	High	Medium	Medium	Low	Low	Low
Power density[p]	Medium to high	Low	Low	Low		Medium	High	High	High

[a]Engine-mounted solar parabolic dish

[b]Sizes of OTA reference systems, Small = <25 MW, Medium = 25 to 100 MW, Large = >100 MW For size ranges expected in the 1990s, see table 4-2 (Alternate Generating Technologies and Storage Technologies: Typical Sizes and Applications).

[c]Short - <2 years, Medium = 2 to 5 years, Long = >5 years

[d]Refers to the general ease of siting a powerplant. Ranking is based on combination Of geographical location, fuel availability, and environmental characteristics Low = plant can be sited only at specific locations; Medium = plant can be sited at many locations, but is constrained by local resource availability, etc ; High = plant can be sited at most sites with relative ease.

[e]Refers to the overall reliability of the powerplant, primarily daily resource variability

[f]Levelized cost (1983$) under most likely case scenario Low =<7 cents/kWh; *Medium* =7-14 cents/kWh; High = > 14 cents/kWh

[g]Whether technology can achieve a real rate of return over 15 perCent In nonutility applications under most likely case scenario Assumes no Federal Renewable Tax Credit.

[h]These Potential environmental Impacts are based on the reference plant sizes listed above and focus on direct impacts from onsite operation Impacts associated with production of facility components, or disposal of worn components, are not considered

Unless otherwide noted, the following rating system applies:

- High indicates substantial likelihood of large Impacts requiring special measures to bring the facility into compliance with local, State, or Federal environmental protection statutes "High" is also used to Identify a strong potential for conflicting land use objectives and problems resulting from competition for scarce resources (e g., for water in irrigation-dependent areas) In all of these cases, the resulting impacts could be serious enough to constrain full development of a site-specific *energy* resource

  Where air emissions are concerned, a high rating maybe more reflective of local air quality conditions than actual emission rates. For example, location in a nonattainment area can affect development of any combustion unit large enough to fall under Federal standards

- Medium indicates that aome special measures may be requred to bring the facility into compliance with environmental protection statutes, but these conditions are not likely to seriously limit development.
- Low means that environmental impacts are expected to be negligible
- Combination ratings (i.e., low-high) indicate that 1) impacts are likely to vary according to site-specific characteristics, and/or 2) Impacts vary substantially with plant size

[i]From daily plant operation *on/y.* Weetea associated with production and/or periodic replacement of plant components are not considered.

[j]This includes any effluent discharge to surface water (e.g., lakes and streams); impacts on ground. water are not considered

[k]Inadequate erosion Control in steep terrain could lead to increased sedimentation in nearby streams

[l]As explained in the following two footnotes, these ratings reflect the amount of water used rather than the consequent environmental impacts of water use. In areas with limited water resources and/or heavy competition for existing supplies. technologies with a moderate rating under this category may face siting constraints.

[m]Low =<1 million gallons per day; Medium = 1 to 3 gallons per day, High = >3 million gallons per day

[n]Low = < 3,000 gallons par day per MWe(net); High = 3,000 to 20,000 gallons par day per MWe(net); High = >20,000 gallons per day per MWe(net)

[o]These ratings are based on the land requirements for a 25 MWe(net) plant They suggest where potential problems may arise regarding visual impacts, competing land uses, or habitat disruption Low = ≤ 10 acres; Medium = 11 to 100 acres; High > 100 acres While extensive habitat disruption could occur on a small site (i e , ≤ 10 acres), we have assumed that the affected area would be small *enough* that overall Impacts on the resource in question would not be likely to constrain development

[p]Refers to the amount of power produced per acre Low = <0 5 MW per acre, Medium = 0 5 to 5 MW per acre, and High = > 5 MW oer acre

SOURCE: Office of Technology Assessment.

nificant amounts of solid waste, and emit air pollutants. The latter, however, can be controlled below competing, solid fuel technologies. These environmental characteristics will likely limit the deployment of these technologies to remote applications outside of urban areas, possibly to nonattainment areas (u n less emission offsets are available). While these technologies have greater environmental consequences than the other new technologies, the IGCC and AFBC represent two of the most promising ''clean coal" technologies. Therefore, when compared to conventional coal combustion, the IGCC and AFBC offer substantial environmental benefits.

Second, in general, the renewable technologies—geothermal, wind power, solar photovoltaics, and solar thermal electric—have less severe environmental impacts than conventional generation alternatives. This attractive environmental characteristic in combination with the small, modular nature of most of the renewable technologies, should ease siting of these technologies and aid deployment. There are important differences among these technologies, though, in terms of their environmental impacts. Geothermal and, to a lesser extent, wind power create more environment impacts than solar photovoltaics and solar thermal electric. For example, wind power installations are highly visible, noisy, require large amounts of acreage, and can cause erosion problems in environmentally sensitive areas.

Finally, the two technologies which appear to be the most desirable according to the characteristics listed in table 8-3 are fuel cells and solar photovoltaics. These two technologies are small, modular technologies which can be sited in a variety of locations without major environmental impact in relatively short periods of time. Photovoltaic powerplants use a fuel that is inexhaustible (solar insolation), while fuel cells can use a variety of fuel types (natural gas, methanol, synthetic natural gas). In the case of these two technologies, therefore, cost and performance will almost completely determine their market penetration.

Summary

Choice among the new technologies involves more than just comparison of costs or profitability. At the micro level, this decision is based on very detailed analysis of engineering, and cost analyses, site-specific characteristics, and environmental impacts, among others. At the more general level, the approach taken here, the technologies must be compared with each other, both in relation to their quantifiable and their nonquantifiable values.

This section has highlighted the complex issues associated with deployment of the new technologies. Complicated variations exist among the technologies in terms of their cost, lead-time, and environmental impacts. On one hand, AFBC and IGCC are very cost competitive, but their long lead-times and their relatively large impacts on the environment could make AFBC and IGCC hard to site. On the other hand, flexible, relatively benign technologies like fuel cells and photovoltaics are currently too costly to be deployed in large numbers. Actual technology choice will depend on specific utility concerns and circumstances.

CONCLUSIONS

New electricity-generating technologies have the potential of being competitive with traditional technologies, e.g., pulverized coal, combined cycle, combustion turbines, in the 1990s. Several of the new technologies, specifically, small-scale AFBC and wind power, are in later stages of commercialization, and could provide lower cost or more profitable power in the early 1990s. The status and costs of other new technologies such as fuel cells and photovoltaics are uncertain. Although these technologies are potentially competitive, uncertainties surrounding their cost and performance will slow deployment.

A wide variety of cost-effective strategic options are also available to electric utilities. These options include plant betterment and life extension, load management, and interregional power purchases. OTA analysis indicates that these options are extremely competitive with the traditional generating technologies, and are less costly than the new technologies. Consequently, utilities will probably concentrate on these options prior to extensive deployment of the new, developing technologies.

Investment decisions concerning the new technologies will reflect more than just cost comparisons. A variety of nonquantitative characteristics, particularly modularity and the level and type of environmental impact, will influence investment decisions.

APPENDIX 8A: INVESTMENT DECISION CASH FLOW MODELS FOR CROSS-TECHNOLOGY COMPARISONS

Introduction

This appendix describes the analysis methodologies adopted in this assessment for: 1) utility levelized busbar cost calculations, and 2) nonutility profitability measurement. These methodologies are the basis for the cost and profitability estimates provided in chapter 8. The analysis approach in these models is a modified version of the Alternative Generation Technologies model developed by Battelle Columbus Laboratories.[1] The modifications generally allow the model to more accurately calculate electric utility revenue requirements and nonutility profitability measures. The estimates produced by these calculations can be compared with utility-reported costs and nonutility-reported rates of return.

Electric Utility Levelized Busbar Cost

Since electric utilities are regulated, utility shareholders receive a set return on their investment. The revenue necessary to produce this set income, often termed the revenue requirement, includes three major components: capital cost carrying charges, interest charges, and fuel and operating expenses.

Capital Cost Carrying Charges[2]

The charges associated with a capital investment can be split into three basic categories: 1) depreciation, 2) return, and 3) income taxes associated with the investment.

An annual revenue stream is required to recover the initial capital cost of a new electric generation facility. Book depreciation is the mechanism used to generate the funds needed for this carrying charge component. Book depreciation in year i (D_{bi}) is defined as

$$D_{bi} = \frac{I}{n_b} \qquad [1]$$

where I is the total capital cost of the facility (includes Allowance for Funds Used During Construction) and n_b is the book life in years. Accumulated book depreciation in year i (C_{bi}) is the sum of all the previous years' depreciation, i.e.

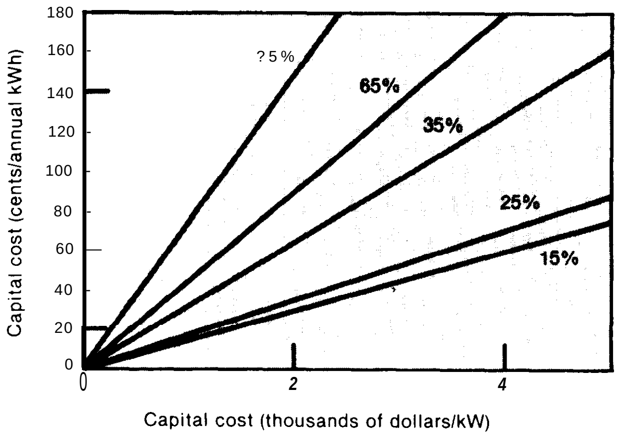
$$C_{bi} = \sum_{j=1}^{i-1} D_{bj} \qquad [2]$$

The electric utility also earns a return on the invested capital. The return on capital in year i (R_i) can be found by multiplying the required rate of return k by the remaining undepreciated book value of the facility. (The required rate of

[1] Battelle Columbus Division, *Final Report on Alternative Generation Technologies, Nov. 18,* 1983 (Columbus, OH: Battelle, 1983).

[2] This section draws heavily on Peter D. Blair, Thomas A.V. Cassel, and Robert H. Edelstein, *Geothermal Energy: Investment Decisions and Commercial Development (New* York: John Wiley & Sons, 1982) and Philadelphia Electric Co., *Engineering Economics Course* (Philadelphia, PA: Philadelphia Electric Co., January 1980).

Figure 8A-1 .—Calculation of Capital Cost per Kilowatt-Houd



aShown for different capacity factors.

SOURCE: Office of Technology Assessment.

return k is assumed to be equal to the discount rate.):

$$R_i = k[I - C_{bi}] \quad [3]$$

The third component of capital cost carrying charge is the income tax liability associated with the project. The total tax liability in year i can be determined by multiplying taxable income by the composite tax rate t. The composite tax rate (t) is a weighted combination of the State tax rate (t_s and Federal tax rate (t_f):

$$t = t_s + t_f(1 - t_s)$$

Total taxable income is found by deducting debt interest (K_i) and tax depreciation (D_{ti}) calculated from the accelerated depreciation schedules,[3] from the revenues received[4]:

$$T_i = t(D_{bi} + R_i + T_i - K_{di} - D_{ti}) \quad [4]$$

The calculation of tax liability is complicated, however, by the use of accelerated depreciation. The use of accelerated depreciation procedures provides additional depreciation in early years and less in the later part of an equipment's lifetime. Hence, income taxes are lower in the early years and higher in the later years, but the same in absolute total at the end of service life. If these tax depreciation benefits were "flowed-through" directly to customer rates, Equation [4] would an accurate representation of tax treatment. The Economic Recovery Tax Act of 1981 stipulates, however, that tax benefits should be "normalized" over the life of the equipment if accelerated depreciation is used. When normalized accounting is used, the income statement is adjusted to show the taxes that would have been paid if the taxes had been based on straight-line depreciation. This adjustment complicates the calculation of both the return and tax components of carry charges.

To accommodate the tax ramifications of accelerated depreciation accounting, equation [4] can be rewritten as:

$$T_i = (t/1 - t)(R_i - K_{di} + D_{bi} - D_{ti}) \quad [5]$$

It is often convenient to express debt interest in terms of return on capital, that is, total return (R) can be expressed as:

$$R = \sum_{i=1}^{n_b} R_i = kI \quad [6]$$

and debt interest can be expressed as:

$$K_{di} = k_d f_d I \quad [7]$$

where k_d is cost of debt and f_d is the fraction of investment funded by debt. Combining Equations [6] and [7] results in:

$$K_{di} = \frac{k_d f_d R}{k} \quad [8]$$

Hence equation [5] can be rewritten as:

$$T_i = (t/1 - t)(R_i - (k_d f_d R_i/k) + D_{bi} - D_{ti}) \quad [9]$$

The use of normalization accounting causes modifications in the return component (equation [3]), principally deferral of income taxes (DT_i):

$$DT_i = t(D_{ti} - D_{bi}) \quad [10]$$

This convention provides utilities with a source of internally generated funds, i.e., accumulated deferred taxes (CD_i), defined by:

$$CD_i = \sum_{j=1}^{i-1} DT_j \quad [11]$$

These funds act to reduce the return on the capital portion of the annual total carrying

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[3]The assumed accelerated depreciation schedule is the Accelerated Cost Recovery System (ACRS). The ACRS schedules specify the fractions of initial capital cost that are depreciated each year. For the analysis of the repeal of the ACRS system, accelerated depreciation is calculated by the sum of years digits formula, i.e.:

$$D_{ti} = I \times \frac{(n_t - i + 1)}{n_t(n_t + 1) \div 2}$$

where n_t is tax life. This formula is included in W.D. Marsh, *Economics of Electric Utility Power Generation* (Oxford, U.K.: Clarendon Press, 1980).

[4]If the investment tax credit is used, the Tax Equity and Fiscal Responsibility Act (TEFRA) stipulates that total investment (I) for accelerated depreciation calculation must be reduced by an amount equal to one-half of the investment tax credit.

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charges of the facility. Hence, the return component originally expressed in Equation [3] becomes:

$$R_i = k(I - C_{bi} - CD_i) \qquad [12]$$

This return value is used in equation [9] to determine total tax liability. Finally, carrying charges must account for the effects of applicable income tax credits which, for our purposes, assumed to be applied only in the first year. Total carrying charge (CC_i) is then calculated by:

$$CC_i = D_{bi} + R_i + T_i + (ITC \times I) + (ETC \times I) \qquad [13]$$

where ITC and ETC are the investment tax credit and energy tax credit applied, where applicable.

Equations [1], [2], and [9] through [13] are implemented in the modified utility model.

Revenue Requirement

Total revenue requirement (RR_i) is calculated by adding yearly debt interest and operating expenses (O_i), i.e.,

$$RR_i = CC_i + K_{di} + O_i \qquad [14]$$

Operating expenses include fuel, operation and maintenance, consumables, insurance, and property taxes. The yearly level of these expenses is dependent on assumptions concerning initial cost levels and expected escalation.

Standard present value and levelization procedures are used to determine required levelized annual revenues and levelized busbar cost per kilowatt-hour from the yearly RR_i.

Comparison With Other Methods

The resultant busbar cost is directly comparable to busbar costs reported by utilities and regulatory commissions. An alternative technique uses fixed charge rates (FCR) instead of calculating the carrying charge directly. EPRI uses this technique in its Technical Assessment Guide[5] (TAG). The TAG includes tables listing FCRs for different equipment lifetimes, recovery periods, and tax preferences. These FCRs are multiplied by installed capital cost to yield levelized carrying charges. Another source is the finance department of an electric utility, which often computes FCRs for internal planning purposes. While there is no fundamental difference between levelized busbar costs calculated by either method, the methodology presented herein more easily captures significant revenue requirement differences on a year-by-year basis. Moreover, this method is more flexible in handling different equipment lifetimes, ACRS categories, and levels of capital intensiveness associated with alternative technologies.

Nonutility Profitability

Consistent cross-technology financial comparison for non utility electricity producers is best achieved with profitability measures. Although levelized cost values are perhaps convenient for comparative purposes, the financial community generally uses profitability measures (rate of return, payback period, and net present value) for investment decision making purposes. Measurements of nonutility profitability can be derived in a more straightforward fashion than utility revenue requirement estimation—since nonutility income and taxation calculations are not complicated by tax normalization and regulated return adjustments.

The analysis technique adopted for the project is the standard discounted cash flow methodology accounting for the three major components of nonutility cash flows: revenue, operating costs, and after tax income. The various profitability measures are calculated based on after tax cash flow.

Revenue

The revenue achievable from a new technology project is assumed to be based primarily on prevailing utility avoided cost rates. Avoided cost revenue in year i (AR_i) is based on both avoided energy and avoided capacity credits:

$$AR_i = 8760 AE_i CF I_c + AC_i I_c \qquad [15]$$

where AE_i (\$/kWh) and AC_i (\$/kW) are the avoided energy value and avoided capacity values, respectively, in year i (determined by applying an assumed escalation to the base year value), CF is the capacity factor, and I_c is the in-

[5]Electric Power Research Institute, *Technical Assessment Guide* (Palo Alto, CA: Electric Power Research Institute, May 1982), EPRI P-2410-SR.

stalled capacity (in kW). In addition, if the facility is a cogenerator, the thermal output is sold at a price equal to what it would cost to produce the steam in a oil-fired boiler. The thermal revenue in year i (TR_i) is calculated by:

$$TR_i = CP_i + OP_i + FP_i \qquad [16]$$

where

$$CP_i = B_{ci}O_t$$
$$OP_i = O_{ci}O_t$$
$$FP_i = F_{pi}O_tE_t$$

are the capital cost, operating cost, and fuel cost portions, respectively. B_{ci}, O_{ci}, and F_{pi} are annualized capital cost, yearly operations expenses, and yearly fuel price. The thermal efficiency of the boiler, assumed to be 88 percent is represented as E_t. Thermal output (O_t) is calculated by multiplying the E/T ratio (ET), the ratio of electrical output to steam and thermal output (expressed in Btu(e)/Btu(t)), to installed capacity:

$$O_t = 3415I_c/ET$$

Total revenue in year i (T_i) is the sum of avoided cost and thermal revenue:

$$T_i = AR_i + TR_i \qquad [17]$$

Operating Costs

Operating costs in year i, O_i, consist of the yearly values of operation and maintenance expenses (OM_i), fuel costs (F_i), insurance (IN_i), property taxes (P_i), interest payments on loans (K_{li}), and accelerated depreciation (D_{ti}):

$$O_i = OM_i + F_i + IN_i + P_i + K_{li} + D_{ti} \qquad [18]$$

Each of these components are based on input parameters and are escalated where applicable. Depreciation is calculated the same as reported earlier (with adjustments for applicable equipment lifetimes in nonutility ventures).

Interest charges are determined with standard loan calculation methods. The initial loan balance (I_o) is determined by:

$$I_o = f_lI$$

where f_l represents the fraction of the project financed by loans. Interest payments are calculated with:

$$K_{li} = k_lI_i$$

where k_l is the interest rate on the loan, and I_i as the remaining loan balance in year i. Loan payments (L) are calculated with the standard annuity equation:

$$L = L_ok_l/(1 - (1 + k_l)^{-N})$$

where N is the length of the loan (assumed to be equal to equipment lifetime and book life). Principal payment (P_i) in year i is calculated by subtracting interest payments from the loan payment, $P_i = L - K_{li}$, and $I_i = I_{i-1} - P_i$.

Income and Profitability

After tax income (AT_i) in year i is determined by applying taxes and tax credits to net income:

$$AT_i = NI_i - T_{fi} \qquad [19]$$

where net income (NI_i) in year i is calculated by subtracting operating costs from revenues, $NI_i = R_i - O_i - D_{ti} - T_{si}$. State tax in year i ($T_{si}$) is calculated by:

$$T_{si} = t_s(R_i - O_i - D_{si}) - (STC \times I)$$

where D_{si} is State depreciation and STC is State energy tax credit. Federal tax (T_{fi}) is calculated by:

$$T_{fi} = tNI_i - (ITC \times I) - (ETC \times I)$$

where ITC and ETC are the applicable tax credits defined earlier.[6]

After tax cash flows (CF_i) are then calculated by:

$$CF_i = AT_i + D_{ti} + (ITC \times I) - (ETC \times I) - P_i \qquad [20]$$

In addition, the investment and energy tax credits are added to the initial year cash flow.

The profitability measures (internal rate of return, payback period, and net present value) can be calculated from this stream of cash flows using standard procedures. The *internal rate of* return is the expected percentage return on invested capital. Firms will often set a required IRR level (i.e., the "hurdle rate") which a project must

[6]An additional form of tax credit has been proposed for renewable technologies, the production tax credit. This tax credit is based on the electricity generated by the facility. For the tax policy analysis conducted in ch. 8, the production tax credit is calculated by multiplying a tax rate in cents/kWh times generation in kWh. The tax policy discussion assumes that the credit stops being applied when the cumulative credit equals the current energy credit value.

meet when making new investment decisions. The length of the project's payback period, the number of years necessary for project revenues to payback the initial outlay, is also used as a screening tool. Net present value provides information on: 1) whether the project will provide positive returns after discounting for the time value of money, and 2) the relative level of income provided by the project. All of these tools can be used to compare alternative investment projects.