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SOLAR THERMAL SMALL POWER SYSTEMS STUDY, PROGRAM
SUMMARY REPORT

Phase II Study Results

By
D. E. Lapedes
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July 12, 1979

Work Performed Under Contract No. ET-78-C-03-2226

Energy and Resources Division
The Aerospace Corporation
Los Angeles, California

U.S. Department of Energy

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Solar Energy

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MASTER

**SOLAR THERMAL
SMALL POWER SYSTEMS STUDY**

PROGRAM SUMMARY REPORT

**PHASE II
STUDY RESULTS**

12 July 1979

Prepared for
DIVISION OF CENTRAL SOLAR TECHNOLOGY
DEPARTMENT OF ENERGY
Washington, D.C. 20545

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FOREWORD

This report documents an analysis of small solar thermal power systems in both utilities and industrial power plants to determine conditions under which these systems can be cost-effective sources of electric power for applications using electrical generators of no more than 10 MW_e rated capacity. The period of study, under U.S. Department of Energy (DOE) Contract ET-78-C-03-2226,* was from 15 July 1978 to 31 August 1979. Technical management of this study has been the responsibility of the Small Power Systems Branch of the DOE Division of Central Solar Technology.

The utility data base is documented in Aerospace Corporation Report No. ATR-78(7693-05)-1, "Small Power Systems Study, Technical Summary Report, Volume II: Inventory of Small Generating Units in U.S. Utility Systems", 31 May 1978, which was prepared in the Phase I DOE-sponsored study. The data base for industrial power plants is documented in a companion report, "Inventory of U.S. Industrial Small Electric Power Generating Systems", Aerospace Corporation Report No. ATR-79(7780)-1, 1 June 1979.

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1.0 SUMMARY

1.1 INTRODUCTION

This Phase II Study of small solar power systems (SSPS) has been structured to determine conditions under which SSPS can be cost-effective sources of electric power in the U.S. in the period 1985 to 2015. An extensive data base, which provides a discrete identification of all utility and industrial electric generating units up to and including 10 MW_e in rated capacity, has been prepared. This data base defines the market for which comparative evaluations are made of SSPS and alternative fossil-fueled power plants. The market penetration of SSPS is determined and the effect of economic incentives on accelerating the penetration is evaluated. The solar electric power system is evaluated as either a complete replacement for existing conventional electric power systems or as a repowering installation for boilers supplying steam to turbine-driven generators. The cost data used in the market penetration analysis are for a central receiver-type of small solar thermal power system. While the market penetration discussed herein is for this type of SSPS, the sensitivity data in the report can be used to determine the market penetration of other types of solar thermal power systems (e.g., point focus distributed receiver) with different system costs.

1.2 UTILITY MARKET

In 1976, there were 3858 small generating units in 716 utilities with a generating capacity of 7930 MW_e. Municipal utility systems are the most important class of owner with respect to small, fossil-fueled generating units. Approximately two-thirds of all these small units, with a generating capacity of slightly over 60 percent of the power produced by small units, are owned by municipal systems. Investor-owned utilities operate about 23 percent of the small, fossil-fueled units and generate

about 29 percent of the power produced by small units. Electrical cooperatives own about 11 percent of the generating units and produce about 9 percent of the power.

In general, the midwestern states have the greatest number of municipal utility systems with the largest number of small generating units; they also generate the greatest amount of power with small, fossil-fueled units. Of the southwestern "sun-belt" states, only Texas ranks in the top ten states in terms of the number of small generating units (9th) and generating capacity (8th). Consequently, the states in which solar thermal power systems may be used first, represent a minor share of the potential market in terms of current generating units or capacity. On the other hand, they may provide sufficient useful operating experience to utilities to open the door to the introduction of solar thermal power systems into larger utilities.

There is a significant number of small units in operation which are over 40 years old; their median age is of the order of 30 years. In general, steam turbine units are about 10 years older than diesel generators. Also, the oldest units in a given utility usually have the lowest generating capacity.

1.3 INDUSTRIAL MARKET

Within the industrial data base, there are 409 companies operating 730 small electric generating systems with a combined rated capacity of 2111 MW_e. Included in these 730 systems are 14 power systems operated by agencies of the federal government. Of the 730 systems, 477 are steam turbine systems with an average rated capacity of 3.70 MW_e. The remainder of these systems consist of 251 diesel generators with an average rated capacity of 1.34 MW_e and two gas turbines with an average rated capacity of 4.50 MW_e.

Both in terms of number of systems and rated capacity, Texas is the leading state in the nation. When system capacity is ranked by state, Ohio

is second, followed by Michigan, Wisconsin, and Louisiana. Other leading states are found clustered about the Great Lakes Region, along the Northern East Coast, and along the West Coast. The majority of small industrial power systems in the ten states with the largest generating capacities are steam power systems and represent about half of the small steam power systems in U.S. industry. Steam power is the largest nationwide segment of industrial generating capacity and constitutes about 84 percent of the total U.S. small power generation in industry.

Texas again leads all states in both the number of diesel generating systems and their total capacity. Indeed, Texas alone has about 40 percent of the industrial diesel generating systems in the U.S.

The total of all types of small industrial systems is distributed fairly uniformly from sizes of less than 0.25 MW_e up to 4.0 MW_e, followed by a peak in the >5.0 MW_e category. Most of the systems less than 1.0 MW_e are diesels. Above this size, diesels constitute a significantly reduced fraction of the systems in any one size category, particularly above 3.0 MW_e.

As a percent of total generating capacity, more than 80 percent of capacity lies above 2.0 MW_e and almost 50 percent is found in sizes greater than 5.0 MW_e. Diesels make up the major part of capacity below 1.0 MW_e and decrease in importance in the larger system sizes.

1.4 MARKET SIMULATION AND SSPS COMPARATIVE ECONOMIC DETERMINATION

A computerized market penetration model was developed to forecast commercialization of SSPS in the U.S. utility and industrial sectors based on the inventory of existing generating units up to 10 MW_e in rated capacity. The market penetration results presented in this Report do not designate the potential penetration for each individual generating unit or system on a pass or fail basis. Instead, the product of unit rated capacity and penetration probability for each unit is aggregated to determine market penetration in a given classification (e.g. replacement or repowering

units). However, the computer runs do rank units by probability so that it would be possible to contact those utilities and industries with the highest penetration probabilities for additional data. Figure 1-1 shows an example of this type of penetration probability information for a number of utilities. The solar power system simulation and optimization model dynamically simulates the interaction of time-varying solar insolation, electric demand for the application selected, and the time-lag effects of thermal storage for different sizes and operational characteristics of solar collectors, steam turbines, and high temperature thermal storage. The model makes use of performance relationships developed through extensive computer simulation and optimization which define SSPS replacement and repowering economics as functions of installation date, plant size, insolation, type of ownership and price of competing fuels and electric power.

The computer program calculates nationwide market penetration for SSPS replacement and repowering modes state-by-state at five-year time intervals from 1985 through 2015. The results are compiled by type of ownership and generating unit and aggregated for each state and for the entire nation. Separate calculations are carried out for utilities and for industrial plants.

The computer models use the concept of ECR, which is the ratio of the annualized SSPS cost to the annualized cost of the conventional energy which it saves. The annualized SSPS cost is determined from the product of the SSPS plant cost and its annualized charge rate. Similarly, the annualized energy cost is determined from the product of SSPS annual energy saving and the annualized unit cost of the competing energy sources.

The annualized charge rate for a given SSPS plant depends upon its type of ownership, operating lifetime, and a number of financial parameters including discount rate, investment tax credit, depreciation, operating and maintenance (O&M) costs, income and property taxes, and insurance. The annualized unit energy cost of a SSPS depends upon its operating time

STATE	CITY	UTILITY	OWN	STATUS	NPLANT	NSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	6600	S	1962	.3136	2069.63
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	10000	S	1957	.0885	884.68
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	10000	S	1957	.0885	884.68
KS	WELLINGTON	WELLINGTON MUNICIPAL UTILITIES	M	0	1	7500	S	1956	.0452	338.72
TX	GARLAND	GARLAND ELECTRIC DEPT.	M	0	2	8500	S	1957	.0419	712.72
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1958	.0308	231.29
NB	SCHUYLER	SCHUYLER DEPARTMENT OF UTILITIES	M	0	1	5000	S	1958	.0167	83.38
TX		TEXAS A-M UNIVERSITY	O	0	1	5000	S	1958	.0153	76.41
MN	HIBBING	HIBBING PUBLIC UTILITIES COMMISSION	M	0	1	10000	S	1965	.0134	133.54
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	2	5000	S	1965A	.0134	133.83
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	4925	S	1974	.0128	62.85
MO	FULTON	FULTON BOARD OF PUBLIC WORKS	M	0	1	6000	S	1959	.0107	64.09
IA	WEBSTER CITY	WEBSTER CITY MUNICIPAL LIGHT & POWER	M	0	1	7500	S	1960	.0094	70.16
IA	SPENCER	SPENCER MUNICIPAL UTILITIES	M	0	1	7500	S	1960	.0094	70.16
IA	MT. PLEASANT	MT. PLEASANT UTILITIES	M	0	1	7500	S	1966	.0094	70.16
IA		CENTRAL IOWA POWER COOPERATIVE	O	0	1	8000	S	1957	.0079	63.18
MN	WILLMAR	WILLMAR MUNICIPAL UTILITIES COMM.	M	0	1	7500	S	1956	.0045	33.80
IA		IOWA STATE UNIVERSITY	O	0	1	6000	S	1961	.0044	26.53
IA	ATLANTIC	ATLANTIC MUNICIPAL UTILITIES	M	0	1	5000	S	1958	.0019	9.52
OH	ST. MARY'S	ST. MARY'S MUNICIPAL LIGHT & POWER	M	0	1	10000	S	1967	.0017	16.68
MN	NEW ULM	NEW ULM PUBLIC UTILITIES COMMISSION	M	0	1	6000	S	1957	.0015	9.01
MI	GRAND HAVEN	GRAND HAVEN BOARD OF LIGHT & POWER	M	0	2	10000	S	1961	.0011	22.34
IL	WINNETKA	WINNETKA WATER & ELECTRIC DEPT.	M	0	1	10000	S	1960	.0011	11.07
OH	SHELLY	SHELLY MUNICIPAL ELECTRIC PLANT	M	0	1	7500	S	1956A	.0010	7.75
OH	PAINESVILLE	PAINESVILLE ELECTRIC DIVISION	M	0	2	7500	S	1956A	.0010	15.50
OH	ORVILLE	ORVILLE MUNICIPAL UTILITIES	M	0	1	7500	S	1956A	.0010	7.75
OH	COLUMBUS	COLUMBUS, DIVISION OF ELECTRICITY	M	0	1	7500	S	1956A	.0010	7.75
WI	MENASHA	MENASHA ELECTRIC & WATER UTILITIES	M	0	1	8975	S	1956	.0009	8.33
OH	COLUMBUS	COLUMBUS, DIVISION OF ELECTRICITY	M	0	1	7000	S	1956A	.0009	6.21
IN	WASHINGTON	WASHINGTON LIGHT & POWER DEPT.	M	0	2	5000	S	1957	.0009	8.97
MD	HAGERSTOWN	HAGERSTOWN MUNICIPAL ELECTRIC LIGHT PLAN	M	0	2	10000	S	1960A	.0007	13.57
OH	SHELLY	SHELLY MUNICIPAL ELECTRIC PLANT	M	0	1	6000	S	1956A	.0006	3.41
OH	ST. MARY'S	ST. MARY'S MUNICIPAL LIGHT & POWER	M	0	1	6000	S	1957	.0006	3.41
MN	SPRINGFIELD	SPRINGFIELD PUBLIC UTILITIES	M	0	1	4000	S	1960	.0006	2.53
IL	PERU	PERU LIGHT DEPT.	M	0	1	8000	S	1960	.0006	5.11
WI	RICHLAND	RICHLAND CENTER MUNICIPAL UTILITIES	M	0	1	7500	S	1966	.0005	3.86
NC		UNIVERSITY OF NORTH CAROLINA	O	0	1	10000	S	1961A	.0005	5.39
LA	MONROE	MONROE UTILITIES COMMISSION	M	0	3	7500	S	1955A	.0005	10.47
FL	KEY WEST	KEY WEST UTILITY BOARD	M	0	2	5000	S	1957A	.0003	2.96
OH	ORVILLE	ORVILLE MUNICIPAL UTILITIES	M	0	1	5000	S	1956A	.0002	1.02
MI		MICHIGAN STATE UNIVERSITY	O	0	1	6000	S	1958	.0002	1.04
LA	NATCHITOCHES	NATCHITOCHES MUNICIPAL ELECTRIC LIGHT &	M	0	1	6250	S	1962	.0001	.66
LA	MORGAN CITY	MORGAN CITY MUNICIPAL ELECTRIC PLANTS	M	0	2	6250	S	1963	.0001	1.32
IL	HIGHLAND	HIGHLAND ELECTRIC LIGHT DEPT.	M	0	1	6000	S	1961	.0001	.40
LA	MONROE	MONROE UTILITIES COMMISSION	M	0	1	6000	S	1955A	0.0000	.16

Figure 1-1. Example of Individual Utility Plant Rankings Based on
SSPS Repowering Mode Adoption Probability

period, expected yearly conventional energy prices, and the discount rate associated with the type of ownership.

The commercialization of SSPS is divided into operational modes of solar replacement and solar repowering. In the replacement mode, a solar power plant would replace a conventional power plant which is ready to be retired unless the annualized costs of the solar power plant are greater than the alternative annualized costs of purchased electric power, including any associated costs for connection to an electric power grid system. In the repowering mode, a solar energy collection and storage system would be used in place of a conventional steam boiler and associated hardware prior to retirement of the remainder of the plant whenever the annualized costs of the solar option are favorable relative to the annualized costs of purchased fossil fuel. In this study, the repowering concept is applicable only to steam turbine power drives and not to diesels or gas turbines.

1.5 ESTIMATED PENETRATION OF THE UTILITY MARKET

The utility market consists of 7930 MW_e of steam turbine, gas turbine, and diesel power drive units operated by investor-owned utilities, municipal utilities, and electrical cooperatives throughout the U.S. At any point in time, the estimated market penetration is a complex function of many variables, either those inherent to known market characteristics (e.g., size, number, and location of generating units) or those selected on the basis of judgement (e.g., system lifetime or economic factors).

Because the larger size SSPS have lower unit costs in dollars per kW_e, these would be expected to contribute to the earliest penetration. However, geographic location, as measured by the level of insolation, is also a factor; for a unit with a fixed capacity in MW_e, higher insolation results in a smaller, lower cost installation for a SSPS.

Geographic location has an additional impact on market penetration in the form of projected costs for fuel and electric power since increases in these cost elements will offset higher solar system capital costs.

Regions with higher fuel and electric power costs result in smaller solar power systems being cost-effective at an earlier installation date. Indeed, the estimated decline in SSPS capital costs with time, together with projected increases in fuel and electric power costs, combine to improve the future competitive economic prospects for SSPS.

One of the competitive economic scenarios selected for use in the market penetration analysis assumes that, if a solar system is not installed, the utility's conventional power unit will be consuming fossil fuels throughout a period of time equal to the lifetime of the solar system that could have been introduced as a repowering unit. Hence, to make a choice, the solar system lifetime cost (including capital cost and present value of operations/maintenance costs, and taxes, if applicable) is compared with the present value of fuel costs summed over an equivalent period of time.

The other scenario relates to the situation when the expected lifetime of a conventional power unit has been exceeded and consideration must be given to the alternatives of replacing the entire unit with SSPS or purchasing electric power from a major utility grid system. To make a choice in this case, the replacement solar power unit lifetime costs must be compared with the present value of purchased electric power costs (aggregated over the solar power unit lifetime). It is emphasized that this form of analysis applies only to utility choices concerning existing power units. If a utility is contemplating facility expansion by adding additional generating capacity, the capital cost, operations costs, and maintenance costs of conventional power units must then be added to the fossil-fuel costs before making a comparison with SSPS.

The type of utility ownership is also a factor in market penetration because of the influence of taxes or relative cost of utility operations and because of the differing costs in acquiring funds for capital equipment projects, e.g., investor-owned utilities are credited with an investment tax credit of 10 percent against the cost of purchasing a SSPS, while municipals and cooperatives are not.

Calculations made with the SSPS computer program result in estimates of the cumulative market penetration by central receiver-type SSPS during the period 1985 to 2015. In Figure 1-2, market penetration has been isolated for each type of power unit and ownership as a percent of the total available market in each category. In terms of type of ownership, municipal and cooperative utilities capture a larger percent of their available market (5485 MW_e) than the investor-owned utilities with an available market of 2445 MW_e. When considering the type of power unit, SSPS capture a much greater share of the available steam turbine market of 2958 MW_e than of the combined available market of 4972 MW_e for diesels and gas turbines.

Under the baseline scenario, the prospects of solar thermal units capturing a significant portion of the total market in 1985 are not encouraging. Indeed, even as late as 2015, only 14 percent of the available market is susceptible to penetration. Obviously, some forms of incentive are required to alter this picture.

Figure 1-2. SSPS Percent Penetration of Utility Market

Steam turbines account for almost all of the displaced capacity when type of power unit is considered. Repowering applications are favored in the early years, but replacement applications become more important beyond the year 2000. There is very little penetration for the repowering category after 2000 because the 40-year lifetime of most of the conventional steam turbine generating units will have been exceeded, which then requires that the balance of this type of generating unit be shifted into the replacement category.

Municipal utilities and cooperatives account for more than 75 percent of market penetration throughout the 30-year period analyzed. Although less than 25 MW_e of capacity is displaced in all categories in 1985, market penetration increases rapidly to 145 MW_e in 1990, to over 400 MW_e in 2000, and to 1140 MW_e in 2015.

The analysis results identify those states expected to have the largest cumulative installed capacity of SSPS during the 30-year period from 1985 to 2015. Those states leading in the utility repowering category are: Hawaii, Iowa, Kansas, Minnesota, Nebraska, New Mexico, and Texas. In the replacement category, leading states are: Arizona, California, Hawaii, Iowa, Kansas, Missouri, and Nebraska. Kansas and New Mexico consistently show the most repowering over this time period while, for replacement, Arizona, Hawaii, Kansas, and Missouri achieve the top positions at different times.

1.6 ESTIMATED PENETRATION OF THE INDUSTRIAL MARKET

The 2111 MW_e of aggregate capacity in the industrial market supplies power for industrial plants, government facilities, and universities. Because the data base did not provide the installation date of the conventional power system, there is no criterion for deciding when a conventional, fossil-fueled power system is to be shifted from the repowering category to the replacement category. Therefore, the penetration analysis first considered all conventional power systems for replacement by SSPS

during the 30-year period from 1985 to 2015 and then considered all systems for repowering by SSPS during this same period.

Figure 1-3 shows cumulative market penetration for the repowering and replacement categories. The capacity displaced for repowering applications commences earlier and is considerably greater than that for replacement applications. Therefore, repowering applications should be favored in subsequent investigations in order to gain earlier access to the industrial market and to capture the largest possible fraction of the available market. Nonetheless, the capture ratio is quite small even at the year 2015 where only five percent of the available market is penetrated.

Figure 1-3. SSPS Capacity Penetration of Industrial Market

The aforementioned results are not additive because steam turbines are found in both categories. However, the diesel and gas turbine systems in the replacement category can be summed with the repowered steam turbine systems. This increment is very small and adds only about 4 MW_e to the cumulative displaced capacity in 2015.

Significant market penetration is expected for repowering applications in Arizona, California, Hawaii, and New Mexico. Although not located in these particular states, a number of federal government power systems also rank relatively high in expected penetration by SSPS when compared with installations at industrial sites.

1.7 RESULTS OF UTILITY MARKET SURVEY

Some insight into utility operations, decision-making processes, and future plans is considered essential before one can formulate a set of strategies designed to promote the commercialization of small power systems by utilities. The basic data base available at the onset of the study proved to be inadequate for this purpose. Hence, telephone interviews were held with a limited number of utilities in the western U.S.

Data were acquired on 48 utilities operating small electric generating units in 16 western states. The survey was not organized to meet some specific level of statistical significance, but rather to provide a general overall view of a broad spectrum of the electric utility market. All three types of small power generating units of different ages and ownership were included in the survey. The ownership of the 48 utilities surveyed was as follows: Investor-owned - 11; Municipal - 26; Cooperatives - 8; Federal, State and District Systems - 3.

While the natural inclination is to present utility characteristics as a basis for consensus, this view is not practical since each utility is unique in its form of operation, decision-making processes, and plans for the future even though group results are summarized. Hence, the prospects for individual utility adoption of alternative energy sources, such as solar

energy, must be based on in-depth personal interviews that can explore the subject in further detail with a broader representation of decision-makers in the utilities' management organizations.

None of the utility characteristics was found to exhibit a geographic influence. A given type of utility ownership was not distinguishable except for its methods of financing capital improvements and the general observation that larger plants were owned and operated by investor-owned utilities.

Most of the utilities served only one community and this was particularly true of municipals where the largest number of communities served was six.

As would be expected, investor-owned companies generally served larger communities than municipals, cooperatives, and federal, state, and district systems (FSDS).

Annual growth in energy demand over the next 30 years is projected to range primarily from about three to five percent, which is significantly less than projections made by the utility industry in earlier years. A few utilities estimated annual growth of 12 percent or more in the next five years followed by reduced growth (e.g., 5-8 percent) in succeeding years. Some of the small municipal utilities and one cooperative projected annual growth at less than two percent.

None of the three options for satisfying utility demand growth held a clear majority. Twenty-nine utilities favor a major grid tie-in, 26 utilities are opting for joint ventures, and 20 utilities are considering installation of new equipment. The majority of utilities indicated that final selection of options to be pursued over the next several years will be made within the next few years; in some dozen cases, option plans are to be completed this year.

Although there were a few exceptions, purchased power, as a fraction of utility demand, was expected to increase over the next 30 years. Of those utilities purchasing power, an average 64 percent of demand is

satisfied by this means. No clear distinction was discernible on the basis of type of ownership, although most of the municipals and cooperatives appeared to use this power source to satisfy the majority of their demand.

The use of oil and natural gas fuels is evenly distributed amongst the utilities and, in about half the cases, both fuels are used at the plant. The use of coal was noted by only five utilities.

Fuel prices vary considerably among the survey group, and even prices within a given state exhibit major variations, but no consistent geographic influence on prices was evident. Of those who responded to the question of fuel availability problems, about two-thirds of the responses indicated no such problem. When availability problems were noted, the supply of natural gas (presently, and in the future) was cited as being the critical fuel.

Sixteen respondents quoted recent annual fuel price increases; a few cases ranged as high as 41 percent for natural gas and 33 percent for purchased power. Some utilities have not experienced any recent price increases. Little substantive information was available on expected price increases for the future.

In more than half of the replies, economy of scale was noted as the purpose of joint ventures. Access to capital and improved financing terms were equally divided in the balance of replies. About one-third of the utilities cited two or more reasons for joint ventures. In one case, the purpose was to reduce risks associated with plant licensing and with ability to meet environmental regulations. In another case, peak load sharing was cited.

Two-thirds of the respondents indicated land available in the vicinity of the plant. Tracts varied from 40 acres to 3000 acres and averaged about 90 acres.

Only one-third of the utilities had environmental restrictions imposed on their current plant operations. A few additional replies noted

that environmental restrictions would be expected in the future because of investments in coal-fired electric generating systems.

In evaluating alternative power sources, 50 percent cited costs, 30 percent cited system availability (or availability of petroleum-based fuels), and 20 percent cited environmental considerations as primary factors.

The attractiveness of a small solar power system was judged in most cases by its ability to compete with other sources of energy on a lifetime cost basis. The second-most important factor mentioned was the possible future unavailability of petroleum-based fuels.

Payback periods for small solar thermal electric systems ranged from a low of seven years to a high of 30 years, averaging about 16 years.

1.8 RESULTS OF INDUSTRIAL MARKET SURVEY

As in the case of utilities, the industrial data base proved to be inadequate for providing guidance in formulating SSPS commercialization strategies. Therefore, a similar series of telephone interviews was planned to acquire more definitive information. Thirty-six companies operating 48 plants in the western U.S. provided sufficient data to constitute a data base that proved useful in supporting the formulation of commercialization strategies for SSPS.

Eighty-seven percent of the plants use steam turbine electric generators either solely or in combination with other types of power plants; 77 percent use only steam turbines. Thirteen percent of the plants rely on two or more different types of power plants. One plant uses a reciprocating piston steam engine. Other engine types utilized to generate electric power are: gas turbines, natural gas engines, diesel engines, and gasoline engines.

The age of electrical generating equipment varies from a two-year old, 12,500 kW_e steam turbine unit to a 59-year old, 940 kW_e steam turbine unit. The average age is about 26 years.

The majority of plants divided their electric power needs between purchased power and self-generated power in proportions that ranged from

about 13/87 percent to 80/20 percent; the average for all plants was about 33/67 percent purchased-to-generated power.

Steam turbine electric generators perform a dual function for a significant number of plants, particularly food processing plants. When low pressure steam is required for process heat, the turbine is used as a throttling device for boiler-generated steam, and electric power is produced as a by-product. Were it not for this highly efficient means of producing electric power, many companies would likely purchase all required power from electric utilities, rather than purchase equipment for self-generation of power.

Almost without exception, plants operated on a 24 hour per day basis, and about 90 percent of these plants operated seven days a week. With the exception of sugar processing plants, all companies conducted production operations during 12 months of the year. Sugar firms, being dependent on harvesting of crops, conducted plant operations from only three to seven months a year, with scheduled downtime for the balance of the year.

Almost all companies used natural gas as either the primary plant fuel or as a backup fuel. Oil was used as a primary backup fuel in about half the cases. Coal was used in only four cases. Because food processing firms have need for a clean-burning fuel, such as natural gas, and because a large number of such firms were included in the survey, the use of natural gas by industrial firms may be overemphasized. Of interest is the use of fossil fuel substitutes such as production waste by-products, wood waste, and bagasse.

Payback period for capital equipment projects covered a range of 1-10 years with an average period between six and seven years. Some companies with low marginal profits require rapid payback of capital equipment projects. Other companies, incurring large operating costs for fuel, are able to consider longer payback periods for capital equipment projects that are designed to reduce energy consumption.

One-third of the plant locations were classified as urban (or semi-urban) and two-thirds as rural. Available land adjacent to the plant ranged from a few acres to more than 10,000 acres. If the extreme cases are removed from the data base, the average available land is almost 500 acres. From very limited responses, the total available roof area was found to vary from 10,000 to 500,000 square feet. The larger roof areas seemed to be available at paper products firms.

Only one respondent foresaw problems with supplies of diesel oil and natural gas. All other replies, interestingly enough, did not envision any serious fuel supply problems.

Competitive system costs and reliability would be primary requirements before solar-powered electric systems would be considered by industry. Tax credits were mentioned most often as the preferred incentive for inducing purchases of solar power equipment.

About 25 percent of the plants noted that energy conservation measures had been implemented. A number of firms indicated more than one modification to equipment and plant operations. Changes to improve plant efficiency included: (1) installation of (a) economizers, (b) waste heat recovery units, and (c) insulation; (2) improvements in power factor; and (3) recycling of heated exhaust.

1.9 POSSIBLE COMMERCIALIZATION STRATEGIES FOR SSPS

The rate of development and manufacture of SSPS intended for supplanting conventional fossil-fueled electric generating systems will be governed by many complex, interacting factors. Clearly, though, since investment economics are usually the leading factor in any decision to purchase and operate capital equipment, utility and industry management must be able to rank projects that compete for limited funds. This involves the assessment of project ranking values such as total capital required, cash flow required, period of investment, and project risk. The last named consideration is likely the most dominant in the decision-making process and

it sets the required earning value or rate of return for each type of investment.

From this early and somewhat limited view of the infant solar energy industry, it appears that the risks, as perceived by potential buyers of solar power equipment, are indeed much higher than for competing conventional power units. Large-scale demonstration of solar power cost-effectiveness has not been in evidence and this energy source can only be viewed presently, at best, as an interesting future consideration. Of course, conventional power will eventually become a riskier venture if the cost of fossil fuels (or purchased electric power) follows a precipitous rise and if the availability of these fuels (and electric power) becomes increasingly limited. At some time in the future, the solar risks can be expected to be offset by the conventional power risks and the solar energy industry will grow in accordance with the risk balance that is assessed by each of the various potential use sectors.

Acceleration of SSPS commercialization basically requires a reduction in the perceived economics risks by use of various strategies. Some of the proposed strategies can be quantified and the effect on market penetration is shown in Section 12. Other strategies are only discussed in a subjective sense, but their impact on SSPS commercialization is expected to be important. Basically, the commercialization strategies are intended to reduce the risk to potential solar power equipment buyers by having the federal government assume all, or part of the perceived risk.

The commercialization strategies to reduce the risk for equipment buyers have been organized into three major categories: (1) direct financial incentives, (2) indirect financial incentives, and (3) non-financial aid. These strategies are concerned with fostering the growth of the market for small solar thermal electric generating systems in competition with fossil-fueled electric generating systems or with purchased electric power. Possible competition with other forms of solar-derived energy or with other renewable forms of energy sources is not considered in this discussion.

Obviously, numerous strategies can be proposed, limited only by the imagination of the proposer. The strategies discussed herein are only offered as examples and require more thorough analysis before being recommended for implementation.

1.9.1 Direct Financial Incentives

Incentives that have a first-order effect on operating revenues are considered to fall in this category. A subsidy in the form of a government cash rebate on a portion of the solar power system cost is one form of incentive; the economic effect is a direct reduction in the cost of equipment.

Another incentive is the availability of low cost loans. This results in less annual payout in interest costs and would also offer the prospect of using cash reserves for other types of investment.

A third form of direct incentive is much more complex, but could be considered as one of the most instrumental policies in reducing the risk for the potential SSPS buyers. Recall that, for applications involving replacement and repowering of existing units, the economic comparison for SSPS must be based on displaced fuel costs (or displaced electric power purchases) for the conventional system evaluated over the SSPS lifetime. But, without substantial increases in these future costs, solar power systems could not compete. It is recognized that the projections of fuel (or electric power) costs have some degree of uncertainty, and the buyer of SSPS may feel that a SSPS could turn out to be a poor choice if fuel (or electric power) costs do not really rise as fast as the projections on which the purchase was based. Therefore, the federal government could rebate to the buyer a portion of any reduction in these costs from an agreed-upon cost schedule projected over the SSPS lifetime. On the other hand, the government might ask the buyer, in turn, to pay a portion of any increase in costs above the schedule, since the buyer of the SSPS has been shielded from such a cost increase and would be paying for a form of "insurance".

1.9.2 Indirect Financial Incentives

Because of the implicit income tax advantages, some of the incentives in this category have application only to investor-owned utilities or industrial firms, rather than to municipal utilities or cooperatives. Increased investment tax credits and accelerated depreciation are two of these types of incentives. But municipal utilities can share in the benefits of government policies that provide bond guarantees or that back unique warranties offered by qualified equipment manufacturers on SSPS operating reliability or maintenance costs. Cooperatives can find assistance through broader application of REA loans and loan guarantees.

Expansion of the presently proposed Solar Energy Development Bank to meet the large capital needs of potential SSPS buyers might also be considered. Certainly, adequate sources of funds for future major capital purchases will continue to be of concern in the utility and industrial markets.

Except for a limited number of "innovators", buyers will undoubtedly defer their purchases as long as they perceive solar power systems to be in a transitional state of development which promises lower unit costs in the future. To overcome this reluctance to purchase a SSPS, one indirect incentive would be a means for financial compensation to early buyers of small solar power systems that may lack the technological improvements introduced into later models. The compensation could be given in the form of an income tax benefit (or as a cash rebate to non-investor-owned utilities).

1.9.3 Non-Financial Aids

Awards for early participants in a SSPS purchase program could carry the same prestige and notoriety as the Navy E.(Excellence) Awards have done. Public perception of a utility or manufacturing firm can be enhanced by methods other than advertising, particularly if fuel savings are translated into more available fuel for space heating and/or automotive applications.

Although not a direct or indirect transfer of funds to potential SSPS buyers, a large expenditure of federal funds for demonstration units could have a significant impact on perceived risk. If a group of different size units, featuring alternative designs, could be located in various regions of the nation, a number of present-day concerns about solar power systems could be relieved. For example, the demonstration units could provide a vast amount of data on SSPS operations and maintenance costs and reliability. In addition, the specific locales would offer a means of evaluating the system availability which is so dependent on daily insolation and the amount of storage designed into the system. The proliferation of demonstration units similar to the 10 MW_e utility plant planned for installation at Daggett, California, would provide an abundance of statistically significant data that would diminish the perceived investment risk. This policy could be a major factor in accelerating SSPS commercialization by normal market forces and could possibly result in far less expenditure of funds in the indirect and direct incentive categories.

1.10 IMPACT OF COMMERCIALIZATION STRATEGIES ON MARKET PENETRATION

The effect of some commercialization strategies can be judged by showing the sensitivity of SSPS market penetration to derived incentives. Factors offering a positive incentive are potential increases in investment tax credits and in annualized fuel (or electric power) costs above values used in this study. Alternatively, potential increases in operations and maintenance costs or in system capital costs above the values used in this study would prove to be disincentives to market penetration. These negative aspects could conceivably arise if a very limited demonstration program did not permit early assessment of SSPS field units so that corrective action could be taken by various equipment manufacturers before significant production levels were achieved.

The sensitivity analysis also provides a means for assessing the effect on market penetration of solar power system design concepts other

than the central receiver-type. This approach to the evaluation of other design concepts is not completely rigorous, however, because it implies that costs as a function of SSPS size (scaling effect) and year of installation vary from the baseline case in a uniform manner. In fact, costs for alternative designs probably do not conform to this assumption, and therefore, a new analysis would be required to establish a precise measure of market penetration. In lieu of such an analysis, the present sensitivity results are considered effective in providing a first-order quantification of how system costs affect market penetration.

1.10.1 Utility Market

The impact of positive incentives has a remarkable impact on market penetration in the near-term. For example, as seen in Figure 1-4, a doubling in investment tax credit from 10 percent to 20 percent doubles the market penetration. A 50 percent increase in fuel costs above the nominal case could produce almost a hundred-fold increase in the 1985 market penetration, and by 2015 about 87 percent of the nearly 8000 MW_e of installed capacity could be penetrated.

Alternatively, unanticipated increases in O&M costs can have a disastrous effect on market penetration, particularly in the near-term. A 50 percent increase in this factor can result in a two-fold decrease in penetration. Solar system cost increases of 50 percent have an even greater negative impact, producing decreases in penetration of more than an order of magnitude.

The aforementioned curves all provide a means of assessing trade-offs between alternative incentives for accelerating market penetration. In addition, there are trade-offs discernable between natural market forces and the various incentives. For example, an installed capacity of 1000 MW_e could be achieved in 1985 by a solar system cost decrease of about 42 percent. The same installed capacity could be achieved in 1995 with about a 48 percent investment tax credit or incentives could be

Figure 1-4. Utility Market Penetration Sensitivity
(Repowering Plus Replacement Units)

ignored and natural market forces could produce this result about the year 2013.

1.10.2 Industrial Market

The effect of the four influence factors (i.e., the costs for the solar system, O&M, and fuel, and investment tax credit) on industrial market penetration is plotted in Figure 1-5. This market is seen to be as much affected by incentives as the utility market. Indeed, a 50 percent decrease in solar system costs, for example, can result in penetration of 10 percent of the market as early as 1985. By 2015, this same incentive results in a penetration of almost 75 percent of the available market. Where normal market forces might cause this SSPS application to be dismissed, it is seen that the introduction of incentives can be instrumental in retaining the industrial market as a viable consideration. Disincentives, of course, are equally as inhibiting to penetration as they were for the utility market.

1.11 PRE-POLICY IMPLEMENTATION CONSIDERATIONS FOR DOE

Under the scenarios used in this study, commercialization of small solar power systems would be expected to take place during a lengthy evolutionary period as natural market forces reduce the relative risks of these systems and costs decline while competing fuel (or purchased electric power) costs continue to climb. Since this rate of solar power market development may be considered too low to have a major impact on the nation's continued and growing dependence on fossil fuels, DOE may desire to initiate policies to accelerate the penetration of utility and industrial markets by SSPS. To be effective, the structure of these policies will have to be decided in the next few years. Many utilities are already engaged in their own process of policy formation for the future (e.g., joint ventures). It is not the purpose of this study to suggest DOE policy, but rather to present policy alternatives and to suggest some important investigative activities before policy formulation and implementation. These activities are discussed in the succeeding paragraphs.

Figure 1-5. Industrial Market Penetration Sensitivity
(Diesel and Gas Turbine Replacement Plus Steam Repowering Systems)

The strategies discussed in Section 1.9 should be subjected to further investigation and analysis. Personal interviews with management personnel at utilities and industrial firms are essential to determining the favorable and unfavorable aspects of such strategies as well as for soliciting additional strategies favored by these potential buyers of SSPS. The extremely diverse nature of the utility and industrial communities makes it essential that as many data sources as possible be contacted. However, the reality of limited time and funding would suggest that the selection of interviewees be made from the most promising market penetration candidates. This is easily possible since, as pointed out in Section 1.4, the computer market penetration model identifies the utilities and industrial plants in order of their penetration probabilities.

Policy alternatives should be discussed with the U.S. Environmental Protection Agency and state environmental agencies to determine the impact of SSPS on air quality and to determine if modifications to existing or forthcoming regulations might result in incentives favorable to SSPS market penetration. Additionally, analyses should be conducted to evaluate the offsets offered by SSPS in regard to atmospheric emissions of fossil-fueled systems and to determine the cost saving associated with elimination of emission control equipment that would have been required for fossil-fueled systems.

Discussion of policy alternatives with the Rural Electrification Administration and other financial arms of the federal government is also essential to selection of favorable strategies and the rate of implementation of such strategies. In fact, the functional role of all federal agencies expected to be involved in SSPS commercialization policies must be clearly understood and then specified by legislation, if necessary. The role of the U.S. Congress in drafting, reviewing, and approving supportive legislation must be especially considered when preparing implementation schedules for policies designed to accelerate SSPS commercialization.

Last, but certainly not least in importance is the need to perform cost-benefit analyses for each policy alternative. The anticipated massive government expenditures that might be required to develop the economic climate leading to a mature SSPS manufacturing industry and a viable market for this product make it essential that cost-effective solutions be selected. As noted earlier, widespread installation of SSPS demonstration systems may prove to be a more effective strategy than simply outright rebates or special tax advantages to select market sectors.

Two further suggestions are in order. The present study of SSPS was restricted to considering repowering or replacement of existing conventional electric generating systems under 10 MW_e rated capacity. The size of this class of solar power systems should be expanded to include systems up to 50 MW_e (or even 100 MW_e) because, (1) the potential market would be several times that of the market associated with the present size range, (2) most of the power generating systems which utilities consider to be large are in excess of 100 MW_e, and (3) the relative probability of market penetration is greater for the larger systems because of scale effects that reduce SSPS unit costs as size increases. Furthermore, if this class of solar power systems is permitted to grow in size, then additional analyses should be conducted to determine the role of SSPS in meeting plant expansion needs for utilities and industrial firms. In regions where environmental regulations are presently restricting utility and industrial expansion of electric generating equipment, or possibly eliminating it in the future, SSPS may prove to be a partial solution that permits the continued growth of local communities and contributes to the economic health of the nation as a whole.

2.0 INTRODUCTION

This Small Power Systems Phase II Study forms part of the U.S. Department of Energy (DOE) Solar Thermal Program for evaluating and enhancing the role of solar thermal power generation systems in meeting the nation's future energy needs. The earlier Aerospace Corporation Phase I Study conducted economic evaluations of the feasibility of small solar thermal electric power systems (less than 10 MW_e in size) replacing small fossil-fueled generating systems that might be operated by utilities in 1985 in the five "sun belt" states of California, Arizona, Nevada, New Mexico and Texas.

The present Phase II effort includes industrial power plants in addition to utility systems and extends the scope of the Phase I Study throughout the nation to determine conditions under which small solar power systems (SSPS) can be cost-effective sources of electric power in the period 1985 to 2015. The study has been structured to provide broad-based technical and economic analyses and comparative evaluations of SSPS and alternative fossil-fueled power plants in order to support decisions by the DOE Division of Central Solar Technology (CST) relative to the development of SSPS. The data base and analytical methodology, which were developed on the preceding study, have been extended so that the market potential for SSPS can be assessed and commercialization strategies can be identified and analyzed.

This study of SSPS is limited to meeting electric power needs only. Except for those few utility systems involved in cogeneration, this situation is the normal mode of power generation at utilities. The industrial sector, however, has need for process heat as well as for electric power, and it is recognized that a solar thermal energy system might prove to be more efficient and cost-effective if it were designed to provide both thermal and electrical energy. On the other hand, this total energy system would be larger and would require a larger capital investment and more land area for installation.

Three types of conventional, fossil-fueled, electric power generating systems are considered for comparison with SSPS: steam turbines, gas turbines, and diesel engines. The expanded data base provides discrete identification of all utility and industrial electric generating systems of less than 10 MW_e rated capacity in each of the 50 states. This data base forms an integral part of the computer programs developed to estimate market penetration by SSPS. The solar electric power system is evaluated as either a complete replacement for existing conventional electric power systems or as a repowering installation for boilers supplying steam to turbine-driven generators.

Strategies are identified and analyzed for expanding the potential rate of commercialization of SSPS, particularly for units installed in the early years between 1985 and 1995. Much of the discussion of these strategies relates to the impact of financial incentives, system costs, and projected fuel oil costs on market penetration by SSPS.

The 12 sections of this report are divided into two major divisions. The first half of the report discusses the two sets of data bases and the computer programs that use these data to estimate utility and industrial power plant market penetration by SSPS. The second half of the report is devoted to a discussion of results from the computer programs and from surveys of utilities and industrial firms which were conducted to clarify operations and investment viewpoints of these potential markets. The report concludes with a review of commercialization strategies and recommendations for future DOE/CST activities related to the SSPS Program.

3.0 MARKET DATA BASE FOR UTILITIES OPERATING SMALL ELECTRICAL POWER UNITS

The data base described in this section basically consists of the data reported in 1978 by The Aerospace Corporation for utilities having electric generating units with capacities no larger than 10 MW_e (Reference 1), incorporating a few minor corrections made to the data after the report was issued, and augmented by information from the Federal Energy Administration (Reference 2) on the installation dates of these generating units. These data have been segregated on basis of the number, type, and age of the units, the type of utility owning the units, their geographical locations, and their generating capacities. The data are presented in this section in the form of various distributions of these variables.

In summary, there were 3858 small units in 716 utilities in 1976 with a generating capacity of 7930 MW_e. Table 3-1 shows the distribution of these units as a function of the type of utility ownership, e.g., investor-owned utility. Table 3-2 shows the distribution of total generating capacity of these small units on the basis of ownership.

Table 3-1. Number of Generating Units as a Function of Ownership

Ownership	Number of Utilities	Number of Units			
		Steam Turbine	Diesel	Gas Turbine	Total
Investor-Owned	109	191	724	17	932
Municipally-Owned	545	328	2146	21	2495
Electrical Cooperative	<u>62</u>	<u>62</u>	<u>363</u>	<u>6</u>	<u>431</u>
Total	716	581	3233	44	3858

Table 3-2. Capacity of Generating Units as a Function of Ownership

Ownership	Capacity of Units, MW _e			
	Steam Turbine	Diesel	Gas Turbine	Total
Investor-Owned	1135	1224	86	2445
Municipally-Owned	1525	3124	114	4763
Electrical Cooperative	<u>298</u>	<u>392</u>	<u>32</u>	<u>722</u>
Total	2958	4740	232	7930

Section 3.1 presents data on small electrical generating units as a function of their rated generating capacity, as well as on the type and number of small generating units in each of the 50 states. In Section 3.2, the data on small power systems in electric utilities are presented as a function of the installation date or age of the unit. Observations related to the data presented in the two preceding sections are given in Section 3.3.

3.1 CAPACITY AND GEOGRAPHICAL DISTRIBUTION OF SMALL GENERATING UNITS

Figures 3-1 and 3-2 depict the total numbers of small steam/gas turbines and diesel generators, respectively, as a function of their rated capacity. Figures 3-3 and 3-4, respectively, give the percentage distribution by state of total generating capacity and of the diesel generating contribution to the total generating capacity for units no larger than 10 MW_e. The data are from Reference 1, as modified. Tables 3-3 and 3-4, respectively, list by state the numbers of small steam/gas turbines and diesel generators as a function of generating capacity. Table 3-5 lists the number and percentage of small generating units by type, e.g., steam turbine, and in total in each state. Table 3-6 rank orders the states on

Figure 3-1. Number of Steam/Gas Turbines as a Function of Rated Capacity

Figure 3-2. Number of Diesel Generators as a Function of Rated Capacity

Figure 3-3. Distribution of Total Generating Capacity by State as a Percent of Total U. S. Generating Capacity

Figure 3-4. Nationwide Distribution of Diesel Generating Capacity as Percent of Total U.S. Generating Capacity

Table 3-3. Number of Small Steam/Gas Turbines as a Function of Generating Capacity

State	Generating Capacity, MW _e										Total No.
	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	
Alabama								2 / 0			2 / 0
Alaska	1 / 2*	1 / 0	4 / 0		2 / 0		0 / 1		0 / 1		8 / 4
Arizona								4 / 0		0 / 1	4 / 1
Arkansas	2 / 0	1 / 0	1 / 0					2 / 0			6 / 0
California		0 / 1	2 / 0		1 / 0					2 / 0	5 / 1
Colorado	0 / 2	3 / 0	3 / 0	2 / 0	4 / 0				2 / 0	2 / 0	16 / 2
Connecticut						2 / 3		3 / 0		3 / 1	8 / 4
Delaware			0 / 1								0 / 1
District of Columbia											0 / 0
Florida				0 / 2	3 / 0		1 / 1	0 / 1	1 / 0		5 / 4
Georgia					0 / 1						0 / 1
Hawaii				1 / 0	3 / 0			3 / 0			7 / 0
Idaho											0 / 0
Illinois	3 / 0	7 / 0	9 / 0	3 / 0	2 / 0	1 / 0		7 / 0		3 / 0	35 / 0
Indiana		3 / 0	3 / 0		5 / 0	1 / 0	1 / 0			2 / 0	15 / 0
Iowa	3 / 0	5 / 0	7 / 0	5 / 0	6 / 0	2 / 0	1 / 0	16 / 0		12 / 0	57 / 0
Kansas	2 / 0	7 / 1	10 / 0	4 / 0	6 / 0	5 / 0		3 / 0	1 / 0	6 / 1	44 / 2
Kentucky					2 / 0			2 / 0			4 / 0
Louisiana					2 / 0	1 / 0	3 / 0	3 / 0	2 / 0	0 / 2	11 / 2
Maine				0 / 1	2 / 0	0 / 1			1 / 0		3 / 2
Maryland					1 / 0					3 / 0	4 / 0
Massachusetts			1 / 0	2 / 0	2 / 0	1 / 0	1 / 0	2 / 0		5 / 1	14 / 1
Michigan		6 / 0	14 / 0	4 / 0	2 / 0	3 / 0		9 / 0		3 / 0	41 / 0
Minnesota	10 / 0	3 / 0	12 / 0	8 / 0	6 / 0	6 / 0	0 / 1	6 / 0	1 / 0	2 / 2	64 / 3
Mississippi			1 / 0	1 / 0	4 / 0		1 / 0	1 / 0	2 / 0		10 / 0
Missouri	1 / 0	3 / 0	3 / 0	2 / 0	3 / 0	4 / 0		7 / 0		3 / 0	26 / 0
Montana	1 / 0	1 / 0			2 / 0			1 / 0			5 / 0
Nebraska	3 / 0	6 / 0	7 / 0	2 / 0	3 / 0	3 / 0	1 / 0	2 / 0	2 / 0		29 / 0
Nevada											0 / 0

* Number of Steam Turbines/Number of Gas Turbines

Table 3-3. Number of Small Steam/Gas Turbines as a Function of Generating Capacity (Cont'd)

State	Generating Capacity, MW _e										Total No.
	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	
New Hampshire			1 / 0		1 / 0	1 / 0		1 / 0			4 / 0
New Jersey				2 / 0	1 / 0		1 / 0				4 / 0
New Mexico				3 / 0	1 / 0	1 / 0	4 / 0	2 / 0	1 / 0		12 / 0
New York	3 / 0	1 / 0	2 / 0		2 / 0	2 / 0		1 / 0		1 / 0	12 / 0
North Carolina			1 / 0							1 / 0	2 / 0
North Dakota		1 / 0	1 / 0	1 / 2	2 / 0		1 / 0				6 / 2
Ohio	2 / 1	3 / 0	7 / 0	2 / 0	13 / 0	4 / 2	1 / 0	8 / 0		5 / 0	45 / 3
Oklahoma	2 / 0	2 / 0		0 / 2	4 / 0			1 / 0		1 / 0	10 / 2
Oregon							3 / 0			1 / 0	4 / 0
Pennsylvania			2 / 0	1 / 0						1 / 0	4 / 0
Rhode Island					3 / 0						3 / 0
South Carolina					1 / 1						1 / 1
South Dakota					3 / 0						3 / 0
Tennessee											0 / 0
Texas	2 / 0	1 / 0	1 / 0	1 / 0	4 / 2	1 / 1		1 / 0	2 / 0	3 / 0	16 / 3
Utah		2 / 0	1 / 0					1 / 0			4 / 0
Vermont				1 / 0		0 / 2				3 / 0	4 / 2
Virginia	1 / 2					1 / 0	0 / 1				2 / 3
Washington											0 / 0
West Virginia											0 / 0
Wisconsin		2 / 0	3 / 0	4 / 0	8 / 0	1 / 0		5 / 0	1 / 0	5 / 0	29 / 0
Wyoming		2 / 0	1 / 0								3 / 0
Total Steam Turbines	36	70	97	49	94	40	19	93	16	67	581
Total Gas Turbines	7	2	1	7	4	9	4	1	1	8	44

Table 3-4. Number of Small Diesel Generators as a Function of Generating Capacity

State	Generating Capacity, MW _e											Total
	0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0	1.0-2.0	2.0-3.0	3.0-4.0	4.0-6.0	6.0-8.0	8.0-10.0	
Alabama												0
Alaska	23	65	16	11	9	22	24	1	2		2	175
Arizona	3		1		1	4		2	1			12
Arkansas	7	4	4	5	3	5	7				1	36
California				3		6	8					17
Colorado	10	9	5	4	5	21	7	1	1			63
Connecticut						2	3	1	1			7
Delaware		4					1		1			6
District of Col.												0
Florida			1	1	10	23	32	3	1		2	73
Georgia						1						1
Hawaii			1		6	1	11		4			23
Idaho		1				4						5
Illinois	3	10	10	7	19	41	21	11	9	1	4	136
Indiana					3	3	17		2			25
Iowa	43	56	40	100	42	85	28	12	5	4		420
Kansas	7	26	37	31	37	96	41	19	9	1		304
Kentucky					2				1	1		4
Louisiana		1	5	7	8	43	8	6	5	5		86
Maine	4	6			15	13	2					40
Maryland	1	1	1	2	1	4	7	2	1	2		22
Massachusetts			2	2	2	16	41		5			67
Michigan	1	15	7	16	25	42	76	9	5	2		199
Minnesota	20	19	30	26	54	90	29	7	11	2		316
Mississippi		1	1		1							3
Missouri	15	33	16	11	28	49	26	1	11	10		200
Montana												0
Nebraska	23	22	29	16	33	57	15	9	1	2		213
Nevada		4	1	1	3	14	14					37

Table 3-4. Number of Small Diesel Generators as a Function of Generating Capacity (Cont'd)

State	Generating Capacity, MW _e											Total
	0-0.2	0.2-0.4	0.4-0.6	0.6-0.8	0.8-1.0	1.0-2.0	2.0-3.0	3.0-4.0	4.0-6.0	6.0-8.0	8.0-10.0	
New Hampshire		2	2	2		1						7
New Jersey						2						2
New Mexico	1	1	1		4	6	7	2	1			23
New York	6	1	1	8	2	13	8	4	4		2	49
North Carolina	2	3	2			1		4				12
North Dakota	1	11	4	7	12	15						50
Ohio	2	1	4	6	4	14	26	2	1			60
Oklahoma		4	11	7	8	34	16	4	3			87
Oregon					1							1
Pennsylvania					2	15	22					39
Rhode Island	2	3	1		2	4	4					16
South Carolina						1						1
South Dakota	13	18	13	6	7	9	1					67
Tennessee												0
Texas	7	12	5	10	17	50	27	5	7		1	141
Utah	1	2	1	4	6	12	4					30
Vermont	1		2		4	11						18
Virginia	1	3	7	1	2	3	6					23
Washington	7	3	2		2		1					15
West Virginia												0
Wisconsin	14	15	9	10	16	18	6	2	1			91
Wyoming	1	3			1	5	1					11
TOTAL	224	389	272	304	397	656	547	107	95	30	12	3232
Percent of Total	6.93	12.03	8.41	9.40	12.28	26.48	16.92	3.31	2.94	0.93	0.37	100.00

Table 3-5. Summary of Small ($\leq 10 \text{ MW}_e$) Power Units in the United States

State	Steam Turbines		Diesel Generators		Gas Turbines		Total Units	Percent of Total
	Number	Percent	Number	Percent	Number	Percent		
Alabama	2	0.35	0	- -	0	- -	2	0.05
Alaska	8	1.38	175 (11)*	5.41	4	9.09	187 (11)	4.85
Arizona	4	0.69	12	0.37	1	2.27	17	0.44
Arkansas	6 (4)	1.03	36	1.11	0	- -	42 (4)	1.09
California	5	0.86	17	0.53	1	2.27	23	0.59
Colorado	16	2.75	63	1.95	2	4.55	81	2.10
Connecticut	8	1.38	7	0.22	4	9.09	19	0.49
Delaware	0	- -	6 (2)	0.19	1	2.27	7 (2)	0.18
District of Col.	0	- -	0	- -	0	- -	0	- -
Florida	5	0.86	73	2.26	4	9.09	82	2.13
Georgia	0	- -	1	0.03	1	2.27	2	0.05
Hawaii	7	1.20	23	0.71	0	- -	30	0.78
Idaho	0	- -	5	0.15	0	- -	5	0.13
Illinois	35	6.02	136 (2)	4.21	0	- -	171 (2)	4.43
Indiana	15	2.58	25 (1)	0.77	0	- -	40 (1)	1.04
Iowa	57	9.81	420 (10)	12.99	0	- -	472 (10)	12.23
Kansas	44	7.60	304	9.40	2	4.55	351	9.10
Kentucky	4	0.69	4	0.12	0	- -	8	0.21
Louisiana	11	1.90	86	2.66	2	4.55	99	2.57
Maine	3	0.52	40	1.24	2	4.55	45	1.17
Maryland	4	0.69	22	0.68	0	- -	26	0.67
Massachusetts	14	2.41	67	2.07	1	2.27	82	2.13
Michigan	41	7.06	199	6.16	0	- -	238	6.17
Minnesota	64 (2)	11.02	316 (10)	9.77	3	6.81	388 (12)	10.05
Mississippi	10	1.72	3	0.09	0	- -	13	0.34
Missouri	26 (1)	4.47	200 (4)	6.19	0	- -	227 (5)	5.88
Montana	5	0.86	0	- -	0	- -	5	0.13
Nebraska	29 (6)	4.99	213 (3)	6.59	0	- -	242 (9)	6.27
Nevada	0	- -	37	1.14	0	- -	37	0.96

* Number of Standby Units.

Table 3-5. Summary of Small ($\leq 10 \text{ MW}_e$) Power Units in the United States (Cont'd)

State	Steam Turbines		Diesel Generators		Gas Turbines		Total Units	Percent of Total
	Number	Percent	Number	Percent	Number	Percent		
New Hampshire	4	0.69	7	0.22	0	- -	11	0.28
New Jersey	4	0.69	2	0.06	0	- -	6	0.16
New Mexico	12	2.07	23	0.71	0	- -	35	0.91
New York	12	2.07	49	1.51	0	- -	61	1.58
North Carolina	2	0.34	12	0.37	0	- -	14	0.36
North Dakota	6	1.03	50 (3)	1.55	2	4.55	58 (3)	1.50
Ohio	35	6.02	60	1.86	3	6.81	98	2.54
Oklahoma	10 (2)	1.72	87 (17)	2.69	2	4.55	99 (19)	2.57
Oregon	4	0.69	1 (1)	0.03	0	- -	5 (1)	0.13
Pennsylvania	4	0.69	39	1.21	0	- -	43	1.11
Rhode Island	3	0.52	16	0.49	0	- -	19	0.49
South Carolina	1	0.17	1 (1)	0.03	1	2.27	3 (1)	0.08
South Dakota	3	0.52	67 (14)	2.07	0	- -	70 (14)	1.81
Tennessee	0	- -	0	- -	0	- -	0	- -
Texas	16	2.75	141 (28)	4.36	3	6.81	160 (28)	4.15
Utah	4	0.69	30 (2)	0.93	0	- -	36 (2)	0.93
Vermont	4	0.69	18	0.56	2	4.55	24	0.62
Virginia	2	0.35	23 (2)	0.71	3	6.81	28 (2)	0.73
Washington	0	- -	15 (15)	0.46	0	- -	15 (15)	0.39
West Virginia	0	- -	0	- -	0	- -	0	- -
Wisconsin	29	4.99	91 (11)	2.81	0	- -	120 (11)	3.11
Wyoming	3	0.52	11 (4)	0.34	0	- -	14 (4)	0.36
TOTAL	581 (15)	100.00	3233	100.00	44	100.00	3858	100.00

Table 3-6. States With Highest Percentages of Small Power Units

State	Percent of Small Units	Percent of Steam Turbines	Percent of Diesel Generators	Capacity, MW _e
Iowa	12.23	9.81	12.99	747.1
Minnesota	10.05	11.02	9.77	672.5
Kansas	9.10	7.60	9.40	665.8
Nebraska	6.27	4.99	6.59	371.7
Michigan	6.17	7.06	6.16	574.1
Missouri	5.88	4.47	6.19	464.4
Alaska	4.85	1.38	5.41	223.3
Illinois	4.43	6.02	4.21	418.2
Texas	4.15	2.75	4.36	334.6
Wisconsin	3.11	4.99	2.81	259.2
Louisiana	2.57	1.90	2.66	269.7
Oklahoma	2.57	1.72	2.69	190.5
Ohio	2.54	6.02	1.86	317.7
Florida	2.13	0.86	2.26	208.0
Massachusetts	2.13	2.41	2.07	270.9
Colorado	2.10	2.75	1.95	153.7
South Dakota	1.81	0.52	2.07	60.3
New York	1.58	2.07	1.51	159.0
North Dakota	1.50	1.03	1.55	76.7
Maine	1.17	0.52	1.24	75.3
Pennsylvania	1.11	0.69	1.21	110.3
Arkansas	1.09	1.03	1.11	64.7
Indiana	1.04	2.58	0.77	140.0
Nevada	0.96	0.00	1.14	67.0
Utah	0.93	0.69	0.93	58.1
New Mexico	0.91	2.07	0.71	111.7
California	0.59	0.86	0.53	59.6
Arizona	0.44	0.69	0.37	61.7

the basis of their percentage of the total number of small generating units. In addition, the state percentages of the small steam turbine and diesel generating populations are also given in Table 3-6. Since the number of diesel generators is approximately six times that of steam turbine units, the correlation between the percentages of total small generating units and small diesel units is excellent for the highest ranking states. The data given in Table 3-6 were shown earlier in Figures 3-3 and 3-4 for steam turbines and diesel generators, respectively. Those states having an average insolation of at least $5.0 \text{ kWh/m}^2/\text{day}$ are included in the region enclosed by the heavy line in Figures 3-3 and 3-4. Figure 3-5 shows the total number of utility systems operating small generating units in each state. Table 3-7 lists the state-by-state distribution of the ownership, i.e., investor-owned, of the small utility systems in the United States.

3.2 DISTRIBUTION OF SMALL GENERATING UNITS BY AGE

Information from the Federal Energy Administration (Reference 2), now part of the Department of Energy, was used to determine the age of the small electrical generating units in utilities. Figure 3-6 shows the distribution of the total generating capacity of the small steam turbine units in electric utilities, the total number of these units, and their average generating capacity as a function of the installation dates of these units. Figure 3-7 shows the same types of information for small diesel generators. Figure 3-8 plots the cumulative percentage of generating capacity and number of small units as a function of the age of the steam turbine and diesel generator units.

3.3 OBSERVATIONS ON THE ELECTRIC UTILITY DATA

3.3.1 Type of Ownership

Municipal utility systems are the most important class of owner with respect to small, fossil-fueled generating units. Approximately two-thirds of all these small units, with a generating capacity of slightly over 60

Figure 3-5. Number of Utility Systems Operating Small Generating Units

Table 3-7. Ownership of Small Utility Systems in the United States

State	Number of Utility Systems			Total
	Investor-Owned	Municipally-Owned	Others	
Alabama	0	0	1	1
Alaska	2	10	12 (1) (a)	24
Arizona	1	1	2	4
Arkansas	1	9 (1)	0	10
California	3	1	1	5
Colorado	2	13	1	16
Connecticut	3	2	0	5
Delaware	1	2 (1)	0	3
District of Col.	0	0	0	0
Florida	1	10	1	12
Georgia	0	0	1	1
Hawaii	1	0	0	1
Idaho	0	2	0	2
Illinois	4	23 (1)	2	29
Indiana	4 (1)	6	0	10
Iowa	5	80 (3)	3	88
Kansas	4	56	3	63
Kentucky	0	3	0	3
Louisiana	1	15	0	16
Maine	3	1	2	6
Maryland	2	3	0	5
Massachusetts	5	8	0	13
Michigan	3	20	5	28
Minnesota	4 (b)	62 (1)	6 (2)	72 (b)
Mississippi	0	4	0	4
Missouri	6	37 (2)	2	45
Montana	2	0	0	2
Nebraska	0	54 (3)	3 (1)	57
Nevada	3	0	0	3
New Hampshire	1	1	0	2
New Jersey	1	2 (1)	0	3

Table 3-7. Ownership of Small Utility Systems in the United States (Cont'd)

State	Number of Utility Systems			Total
	Investor-Owned	Municipally-Owned	Others	
New Mexico	2	4	1	7
New York	5	5	1	11
North Carolina	1	0	3	4
North Dakota	3 (b)	5 (1)	1	9 (b)
Ohio	5	15	0	20
Oklahoma	2	14 (4)	2 (1)	18
Oregon	1	2 (1)	0	3
Pennsylvania	4	1	1	6
Rhode Island	3	0	0	3
South Carolina	2	1 (1)	0	3
South Dakota	4 (b)	16 (5)	0	20 (b)
Tennessee	0	0	0	0
Texas	6 (1) (c)	23 (5)	1	30
Utah	0	5	1 (1)	6
Vermont	3	3	0	6
Virginia	1	3 (1)	2	6
Washington	1 (1)	0	1 (1)	2
West Virginia	0	0	0	0
Wisconsin	7	22 (6)	3	32
Wyoming	2 (b)	1 (1)	0	3 (b)
TOTAL	115 (d)	545	62	722 (e)

- (a) Number in parenthesis indicates number of utility systems on standby.
- (b) Two of the utility companies were counted three times, since they have plants in Minnesota, North Dakota, and South Dakota; one of the utility companies has plants in both North Dakota and South Dakota and counted twice; and one utility has plants in South Dakota and Wyoming and was counted twice.
- (c) Only diesel units are on standby.
- (d) Actual number of investor-owned utility systems with small units is 109.
- (e) Actual number of small utility systems in U. S. is 716.

Figure 3-6. Small Steam Turbine Data as a Function of Installation Date

Figure 3-7. Small Diesel Generator Data as a Function of Installation Date

Figure 3-8. Percentage of Generating Capacity and Number of Units as a Function of Unit Age

percent of the power produced by small units, are owned by municipal systems. Diesel generators comprise almost seven-eighths of the small municipal generating units and produce approximately two-thirds of the municipally-generated electrical power. Steam turbines represent about 13 percent of the municipal generating units and generate almost one-third of the power. Gas turbines account for less than one percent of the municipal units and generate only about two percent of the municipal power.

Investor-owned utilities operate about 23 percent of the small, fossil-fueled units and generate about 29 percent of the power produced by small units. Diesel generators account for roughly three-fourths of the investor-owned units but generate only about 47 percent of the power. Steam turbines comprise only 21 percent of the investor-owned small generating units but produce half of the power. Gas turbines represent only two percent of the generating units in investor-owned utilities and produce about 3.5 percent of the power.

Electrical cooperative own about 11 percent of the generating units and produce about 9 percent of the power. Over 80 percent of the units are diesel generators, which generate over half of the power. About 15 percent of the units are steam turbines which generate approximately 42 percent of the cooperatives' power. Gas turbines comprise a little more than one percent of the units and produce about 4.5 percent of the cooperatives' power.

3.3.2 Geographical Distribution

The geographical location of small, fossil-fueled electrical generating units is of interest for two reasons: insolation level and number of small communities generating their own power. High insolation values provide the most favorable environment for the introduction of small solar thermal power systems. A large number of small communities in a given state or region will normally be associated with a large number of small power systems, leading to a large potential market for solar thermal power systems, as is evident in Figure 3-5 for the Midwest.

If a value of $5.0 \text{ kWh/m}^2/\text{day}$ is selected as a desirable lower bound for insolation, the area of interest is restricted to states west of the Mississippi River, excluding Minnesota, Iowa, Arkansas, Louisiana, Washington, Oregon, and portions of Idaho and Montana. In general, the midwestern states have the greatest number of municipal utility systems with the largest number of small generating units; they also generate the greatest amount of power with small, fossil-fueled units. However, the insolation constraint of $5.0 \text{ kWh/m}^2/\text{day}$ eliminates Iowa and Minnesota, the two states with the greatest number of small generating units and generating capacity. Of the southwestern "sun-belt" states, only Texas ranks in the top ten states in terms of the number of small generating units (9th) and generating capacity (8th). Consequently, the states in which solar thermal power systems may be used first, do not represent a major share of the potential market in terms of current generating units or capacity. On the other hand, they may provide sufficient useful operating experience to utilities to open the door to the introduction of solar thermal power systems into larger utilities.

3.3.3 Age of Small Generating Units

On the basis of the data from the former Federal Energy Administration (Reference 2), it is obvious that there is a significant number of small units in operation which are over 40 years old; their median age is of the order of 30 years. In general, steam turbine units are about 10 years older than diesel generators. Also, the oldest units in a given utility usually have the lowest generating capacity. It would appear, based on age alone, that a number of these small generating units should be candidates for replacement by the time that solar thermal power systems should be starting to penetrate the utility market sector in the late 1980s.

In the previous analysis of small solar thermal power systems which had been carried out by The Aerospace Corporation (Reference 3), it was assumed that when existing units reached the age of 30-35 years, they would

have been worn out and would automatically be candidates for replacement. As Figures 3-6 and 3-7 showed for steam turbines and diesel generators, respectively, this is not the case. Approximately one-eighth of the steam turbines are over 50 years old and about the same percentage of diesel generators is over 40 years old. The actual situation is that the costs of generating units in utility systems will have been amortized in 30 years, regardless of whether the units can continue to operate or not. As is apparent from the data, there are a number of units which have been maintained well enough to remain in service beyond the 30-year point. However, since the demands for power of most utility systems have increased markedly with time, old units may be too small to contribute significantly to the utility's needs and may be decommissioned or even sold to another utility which can utilize the old units effectively.

4.0 MARKET DATA BASE FOR INDUSTRIAL FIRMS OPERATING SMALL ELECTRIC POWER SYSTEMS

4.1 INTRODUCTION

To provide an estimate of the size and nature of the industrial small power systems market, The Aerospace Corporation obtained data on U.S. companies operating small electric generating systems* from the Energy Information Agency (EIA) in the U.S. Department of Energy. These data were compiled originally by the (former) Federal Power Commission (FPC) as part of the Form 4 Industrial Ledger and Form 12-C Ledger for 1976. The Aerospace Corporation screened these data and selected only those companies operating electric generating systems less than or equal to 10 MW_e in rated capacity. The complete Aerospace Corporation inventory of small power systems in industry is given in Reference 4. This report lists system size, type of power system, name of operating company, and plant location.

4.2 DATA BASE SUMMARY

The data base referred to in Section 4.1 was included in the computerized market penetration model discussed in Section 6. Within this data base, there are 409 companies operating 730 small electric generating systems with a combined rated capacity of 2111 MW_e. Included in these 730 systems are 14 power systems operated by agencies of the federal government. Of the 730 systems, 477 are steam turbine systems with an average rated capacity of 3.70 MW_e. The remainder of these systems consist of 251 diesel generators with an average rated capacity of 1.34 MW_e and two gas turbines with an average rated capacity of 4.50 MW_e. Annual fuel consumption of all these systems is estimated at 0.07 to 0.15 quadrillion Btu.

* The term "system" is used herein (rather than "unit" as for utilities in Section 3) because the FPC data sources give the size and type of power generation at each company plant without designating the number of units contributing to the given power level.

4.3 GEOGRAPHIC DISTRIBUTION OF SMALL POWER SYSTEMS

State-by-state distribution of small electric generating systems throughout the U.S. is shown in Figure 4-1 as a percent of the 730 small industrial systems. A similar display in Figure 4-2 shows the U.S. geographic distribution expressed as a percent of the 2111 MW_e total rated capacity of these systems. Both in terms of number of systems and rated capacity, Texas is the leading state in the nation. When system capacity is ranked by state, Ohio is second, followed by Michigan, Wisconsin, and Louisiana. Other leading states are found clustered about the Great Lakes Region, along the Northern East Coast, and along the West Coast. The majority of small industrial power systems in the ten states with the largest generating capacities are steam power systems and represent about half of the small steam power systems in U.S. industry. Steam power is the largest nationwide segment of industrial generating capacity and constitutes about 84 percent of the total U.S. small power generation in industry.

Texas again leads all states in both the number of diesel generating systems and their total capacity. Indeed, Texas alone has about 40 percent of the diesel generating systems in the U.S. Figure 4-3 shows the distribution of these systems as a percent of the 730 total systems of all types. When ranked by number of units, Louisiana is next in order, followed by Oklahoma and New Mexico. These four states contain about 60 percent of the diesel systems.

Figure 4-4 shows the distribution of diesel systems as a percent of the total 2111 MW_e generating capacity for all types of systems. When ranked by capacity, Texas is followed by New Mexico, Louisiana, Illinois and Oklahoma. About two-thirds of the U.S. diesel electric capacity is found in these five states.

4.4 DISTRIBUTION OF SMALL POWER SYSTEMS BY SYSTEM SIZE

Figure 4-5 shows that the total of all types of small industrial systems is distributed fairly uniformly from sizes of less than 0.25 MW_e

Figure 4-1. Percentage Distribution of Industrial Small Power Systems

Figure 4-2. Percentage Distribution of Industrial Small Power System Generating Capacity

Figure 4-3. Percentage Distribution of Industrial Small Diesel Systems

Figure 4-4. Percentage Distribution of Industrial Small Diesel System Generating Capacity

Figure 4-5. Number of Power Generating Units in Industry as a Function of System Size

up to 4.0 MW_e, followed by a peak in the >5.0 MW_e category. Most of the systems less than 1.0 MW_e are diesels. Above this size, diesels constitute a significantly reduced fraction of the systems in any one size category, particularly above 3.0 MW_e.

When displayed as percent of total generating capacity in Figure 4-6, more than 80 percent of capacity lies above 2.0 MW_e and almost 50 percent is found in sizes greater than 5.0 MW_e. As is the case with the number of systems, the diesel capacity forms the major part of each category below 1.0 MW_e and decreases in importance in the larger system sizes.

4.5 DISTRIBUTION OF SMALL POWER SYSTEMS BY INDUSTRIAL CLASSIFICATION AND SYSTEM SIZE

A limitation of the FPC Form 4 Industrial Ledger is that it does not include industrial classifications (Reference 5) in its listings, which account for almost two-thirds of the industrial generating capacity in the U.S. The FPC Form 12-C Ledger does provide this information, which permits segregation of electrical generating systems by discrete industrial groups, but these data are limited because they account for only slightly more than one-third of the total 2111 MW_e of the U.S. industrial generating capacity. However, if the Form 12-C data are assumed to be representative of the entire population, a review of such data can be instructive.

Table 4-1 shows the division of small power systems electric generating capacity for the five largest industrial groups, headed by oil and gas extraction. These industries contain nearly 78 percent of the total 767 MW_e of capacity listed in FPC Form 12-C.

Figures 4-7 through 4-16 show the size distribution of small electric generating systems for each of the five major industry categories designated in Table 4-1. The data are shown in two formats: (1) number of systems as a function of system size and (2) system capacity as a function of system size.

Figure 4-6. Power Generating System Capacity in Industry as a Function of System Size

Table 4-1. Distribution of Electric Power Generating Capacity by Major Industry

Industry Classification	Percent of Total Capacity
Oil and Gas Extraction	26.1
Food and Kindred Products	22.2
Paper and Allied Products	10.6
Chemicals and Allied Products	10.0
Lumber and Wood Products	9.0
Remainder (e.g. Primary Metals, Stone/Clay/Glass)	22.1

The oil and gas extraction industry is depicted in Figures 4-7 and 4-8. The majority of generating systems are diesels smaller than 3 MW_e. Most of the generating capacity lies between 0.75 and 3.0 MW_e and peaks in the 2-3 MW_e size range.

Figures 4-9 and 4-10 present characteristics for the food and kindred products industry. Most of these systems are powered by steam turbines in the 1-4 MW_e size range. Almost all of the system capacity is found in sizes greater than 1.5 MW_e and peaks in the 3-4 MW_e size range.

In the paper and allied products industry, there are very few units smaller than 0.25 MW_e in size (Figure 4-11). Most sizes of generating systems lie in the 1.5 to 5.0 MW_e range. The capacity distribution is even more pronounced, as seen in Figure 4-12, with more than 80 percent of generating capacity falling in this size range.

Figure 4-13 shows that almost three-fourths of the generating systems for the chemicals and allied products industry are clustered into two size groups: 0.50 - 0.75 MW_e and 1.5 to 4.0 MW_e. There are no units smaller than 0.25 MW_e. In terms of generating capacity, Figure 4-14 shows that about 70 percent are in the size range from 1.5 to 4.0 MW_e.

Figure 4-7. Number of Power Generating Systems in Oil and Gas Extraction Industry as a Function of System Size

Figure 4-8. Power Generating System Capacity in Oil and Gas Extraction Industry as a Function of System Size

Figure 4-9. Number of Power Generating Systems in Food and Kindred Products Industry as a Function of System Size

Figure 4-10. Power Generating System Capacity in Food and Kindred Products Industry as a Function of System Size

Figure 4-11. Number of Generating Systems in Paper and Allied Products Industry as a Function of System Size

Figure 4-12. Power Generating System Capacity in Paper and Allied Products Industry as a Function of System Size

Figure 4-13. Number of Generating Systems in Chemicals and Allied Products Industry as a Function of System Size

Figure 4-14. Power Generating System Capacity in Chemicals and Allied Products Industry as a Function of System Size

Two-thirds of the generating systems in the lumber and wood products industry are found in the 1.0 - 4.0 MW_e size range (Figure 4-15). All units are larger than 0.25 MW_e. Figure 4-16 shows that almost 90 percent of generating capacity is in system sizes greater than 1.0 MW_e, with a pronounced peak (almost 30 percent of total capacity) in the 3.0 - 4.0 MW_e size range.

Figure 4-15. Number of Generating Systems in Lumber and Wood Products Industry as a Function of System Size

Figure 4-16. Power Generating System Capacity in Lumber and Wood Products Industry as a Function of System Size

5.0 CAPITAL EQUIPMENT COST MODEL FOR SMALL SOLAR THERMAL ELECTRIC POWER PLANTS

A methodology was established in previous Aerospace Corporation small power systems studies (References 3 and 6) to develop sizing relationships and cost models for central receiver-type solar thermal power plants in the 1-10 MW_e capacity range. These models require information on the physical characteristics of the solar power plants as inputs. The resulting cost estimates provide information for each major subsystem of the power plant.

For this Study, it was desired to develop a simplified cost model for a solar thermal central receiver-type electric power plant which would contain only a few parameters. In addition, the model was to consist of only four cost categories: collectors, receiver-tower, thermal storage, and balance of plant to be compatible with the Small Solar Power Systems (SSPS) simulation model discussed in Section 6. It should be noted that this cost model is for a single-module plant, i.e., it has only a single receiver-tower, thermal storage subsystem, and turbogenerator. Figure 5-1 shows the individual cost elements included in each of the four cost categories. The SSPS simulation model optimizes a specific size (10 MW_e for this Study) solar thermal power plant in terms of minimum cost of service (\$/kW_eh).

The dependent cost variables to be used in the new cost model for this Study were to be related only to plant capacity (kW_e), collector field area (ft²), and thermal storage energy (10⁶ Btu). Also, the cost algorithms were to be extended to 100 kW_e and to 100 MW_e from the original 1-10 MW_e range to provide data on very small plants as well as greater insight into the cost/size scaling relationship for central receiver-type solar thermal power systems. A new set of cost estimating relationships (CERs) was developed to meet these objectives. During the time that these CERs were being developed, DOE was sponsoring studies at Battelle's Pacific Northwest Laboratory (PNL), the Jet Propulsion Laboratory

Figure 5-1. Cost Breakdown Structure for Solar Thermal Electric Power Plant

(JPL), and the Solar Energy Research Institute (SERI) to rank a number of solar thermal electrical power systems concepts on the basis of leveled costs. Unpublished, preliminary data on central receiver systems in the 1-10 MW_e range from these three studies were incorporated, where appropriate, into The Aerospace Corporation cost relationships.

The new CERs for each of the four cost categories, as indicated in Figure 5-1, include costs for direct, indirect, distributables, contingency, and non-recurring tooling elements. The last four cost elements were taken as a fixed percentage of the direct cost element for each of the four cost categories. In keeping with the conservative approach used elsewhere in the cost work, a total of 40 percent of the direct cost was allocated for the remaining four cost elements, based on cost information from other high technology projects.

The cost relationship for collectors (heliostats) is based on a given production run made in a special facility dedicated to producing commercial collectors of the Barstow Pilot Plant type (37 m²) for central receiver power plants. However, the cost algorithm was modified to reflect the average heliostat cost per unit area in order to accommodate different size heliostat panels. It was realized that heliostat production for small solar thermal power systems would probably only represent a small portion of the total heliostat production for all solar thermal applications and that the initial heliostat cost should reflect the overall production rate. However, in keeping with the conservative costing approach used elsewhere, it was decided that future heliostat costs for small solar thermal power systems should be based upon the rate of growth of these small power systems. Unpublished data from another DOE contractor were used to establish both the initial heliostat production volume and the rate of growth of small solar thermal power systems. These data projected the quantity of heliostats which would be required to provide sufficient solar thermal power systems to meet a four percent annual growth rate in the amount of intermediate power provided by utilities in eight western states

in the 1985-2005 time period. For this Study, 1990 was selected as the baseline year for determining heliostat costs. Figure 5-2 shows the contractor projection for the number of heliostats produced between 1985 and 2005 and The Aerospace Corporation estimate of the number of 10 MW_e solar thermal power plants which might enter service during the same time period, assuming that there would be 10 of these small solar thermal plants in existence in 1990. It was also assumed that each 10 MW_e plant would require approximately 2000 heliostats.

The receiver-tower CER used in the earlier Aerospace Corporation Small Power Systems Study was based on concrete tower construction. More recent studies by McDonnell Douglas Astronautic Company (Reference 7) use steel tower construction for solar thermal power plants under 10 MW_e in capacity. Other studies also indicate that steel construction is preferred in this size range. The receiver-tower CER was, therefore, modified for this Study to reflect the lower cost of steel construction compared to concrete.

The thermal storage cost relationship is derived from the same data base as used in Reference 6, and is based on 21 MWh of thermal storage for a 10 MW_e plant and 420 MWh of storage for a 100 MW_e plant. The cost algorithms themselves reflect the cost of high temperature thermal energy stored in tanks prior to conversion into electrical energy, however.

The cost relationship for the balance of plant was based on the data in Reference 6, which covers plant capacities in the 1-10 MW_e range. New relationships were developed from earlier turbogenerator algorithms and a new ratio (Reference 3) for the value of turbogenerator cost to total conventional power plant cost. The product of the ratio and turbogenerator costs was used to develop estimates of the balance of plant costs for plants of 100 kW_e and 1 MW_e generating capacity.

Table 5-1 gives the costs in 1978 dollars for a 10 MW_e baseline solar thermal power plant in Inyokern, California, in 1990 for each of the four major cost categories. The plant has 2.153×10^6 ft² of collector area and 1532×10^6 Btu of thermal storage.

Figure 5-2. Projected Production of Heliostats and 10 MW_e Solar Thermal Power Plants

Table 5-1. Cost Factors for a 10 MW_e Baseline Solar Thermal Power Plant

Cost Category	Cost
Solar Collectors	\$10.773/ft ²
Receiver-Tower	\$2.853/ft ²
Thermal Storage	\$4621.3/10 ⁶ Btu
Balance of Plant	\$935.8/kW _e
Total	\$4578.0/kW _e

If the balance of plant cost category is deleted, a value of \$3642 per kilowatt is obtained for a 10 MW_e solar thermal power plant in the repowering mode. Figure 5-3 compares the new cost relationship in 1978 dollars for a commercial solar thermal power plant in the replacement mode with the replacement costs taken from Reference 3 for 10 to 100 power plants.

Figure 5-3. Central Receiver Costs as a Function of Power Level and Production Quantity (Replacement Mode)

Based upon the heliostat production rates and numbers of 10 MW_e solar thermal power plants shown as a function of time in Figure 5-2, a set of cost characteristics was developed for power plants in the 0.1-100 MW_e capacity range for the 1985-2015 time period. These cost values were normalized to the total plant cost shown above in Table 5-1 for both replacement and repowering, and are given in Tables 5-2 and 5-3, respectively, as a function of solar thermal power plant size and installation date.

Table 5-2. ECR Modifying Matrix for Solar Replacement Mode

		Year of SSPS Installation						
		1985	1990	1995	2000	2005	2010	2015
SSPS Rated Capacity (MW _e)	0.1	3.688	3.068	2.801	2.657	2.565	2.494	2.443
	1.0	2.105	1.751	1.599	1.516	1.464	1.424	1.396
	10.0	1.202	1.000	0.913	0.866	0.836	0.813	0.797
	100.0	0.686	0.571	0.521	0.494	0.477	0.464	0.455

Table 5-3. ECR Modifying Matrix for Solar Repowering Mode

		Year of SSPS Installation						
		1985	1990	1995	2000	2005	2010	2015
SSPS Rated Capacity (MW _e)	0.1	3.301	2.746	2.507	2.378	2.296	2.232	2.189
	1.0	1.992	1.657	1.513	1.435	1.385	1.347	1.321
	10.0	1.202	1.000	0.913	0.866	0.836	0.813	0.797
	100.0	0.725	0.603	0.551	0.522	0.504	0.490	0.481

6.0 COMPUTERIZED MODEL FOR ESTIMATING POTENTIAL MARKET PENETRATION BY SMALL SOLAR POWER SYSTEMS

A computerized market penetration model has been developed to forecast commercialization of small solar power systems (SSPS) in the U.S. utility and industrial sectors. A small power system is assumed to be either an individual generating unit (utility sector) or an entire system (industrial sector) which produces no more than 10 MW_e^{*}. The commercialization of SSPS is divided into operational modes of solar replacement and solar repowering. In the replacement mode, a solar power plant would replace a conventional power plant which is ready to be retired unless the annualized costs^{**} of the solar power plant are greater than the alternative annualized costs of purchased electric power, including any associated costs for connection to an electric power grid system. In the repowering mode, a solar energy collection and storage system would be used in place of a conventional steam boiler and associated hardware prior to retirement of the remainder of the plant whenever the annualized costs of the solar option are favorable relative to the annualized costs of purchased fossil fuel. In this study, the repowering concept is applicable only to steam turbine power drives and not to diesels or gas turbines.

The model makes use of performance relationships developed through extensive computer simulation which defines SSPS replacement and repowering economics as functions of time, plant size, insolation, type of ownership and price of competing fuels and electric power.

The computer program calculates nationwide market penetration for SSPS replacement and repowering modes state-by-state at five-year time intervals from 1985 through 2015. The results are compiled by type of owner-

* The industrial market data base (Section 4) did not indicate the number of units at a given industrial facility.

** Annualized costs are also known as levelized costs.

ship and generating unit and aggregated for each state and for the entire nation. Separate calculations are carried out for utilities and for industrial plants. These market penetration forecasts are given in terms of both incremental penetrations in a given year and cumulative penetrations up to, and including, the given year. The model also rank orders the various plants by solar adoption probability for both the replacement and repowering modes.

6.1 APPROACH TO MARKET PENETRATION SIMULATION

In order to forecast future SSPS markets for the U.S. utility and industrial sectors, relative cost and performance relationships for an optimized base case SSPS were developed for both the replacement and repowering modes at different locations with the help of a SSPS simulation model.

The concept of equivalent cost ratio (ECR), which is the ratio of the annualized cost of the SSPS to the annualized cost of the energy which the SSPS displaces, was introduced. Those applications having an ECR no greater than unity are assumed to be economically viable and, hence, susceptible to penetration by SSPS. In the case of the replacement mode, the annualized cost of SSPS includes the total solar plant costs (viz. collectors, receiver-tower, storage, and balance of plant) while the annualized cost of the energy displaced is the cost of equivalent electric power purchased from the local utility. For the repowering mode, the annualized cost of SSPS includes only the solar energy collection components (viz. collectors, receiver-tower, and storage); here, the annualized cost of energy displaced refers to the cost of purchased fuel.

The performance relationships developed through SSPS simulation were combined with an extensive data base on utility characteristics (Section 3) and industrial plant characteristics (Section 4), along with insolation, and forecasts of electric and fuel prices in a set of computer codes which would permit evaluation of market penetration. Two models, Solar System Utility

Market Model (SSUMM) and Solar System Industry Market Model (SSIMM) were developed to carry out detailed market penetration forecasts for the utility and industrial sectors.

6.2 DESCRIPTION OF INPUT DATA BASE MODELS FOR SSUMM AND SSIMM COMPUTER PROGRAMS

The SSUMM and SSIMM computer models are outgrowths of The Aerospace Corporation's earlier studies on Solar Total Energy Systems (STES) market penetration. These STES market penetration models had certain components which are directly applicable to the present analysis of SSPS. However, other parts of the SSIMM and SSUMM computer models are significantly different from the STES market penetration models. In addition, there are several data base inputs to SSUMM and SSIMM. The data inputs that are common with STES market penetration studies are:

- Insolation Data Base
- Annualized Energy Cost Data Base
- Annualized Charge Rate and Annualized Unit Energy Cost

The input models to SSUMM and SSIMM that are new or significantly modified from the earlier STES market penetration studies are:

- SSPS Utility and Industry Data Base
- SSPS Relative Cost and Performance Relationships
- SSPS Cost Model
- SSPS Monte Carlo Simulation

The SSPS relative cost and performance relationships are determined by use of an optimization model. A brief description of the optimization computer program is given in Section 6.2.5. Results of using this program are documented in Section 7.

The utility and industry data bases are described in Sections 3 and 4, respectively. The organization of these data for use in SSUMM and SSIMM along with a brief description of the other input models is given in the following subsections.

6.2.1 Insolation Data Base

Reference 8 briefly discusses modifications to the earlier Aerospace Insolation Data Base. These modifications are based on an improved data set which became available in 1975. A direct-normal insolation estimating procedure is used which is not restricted to linear relations and includes statistical variations. The revised data also include calibration error corrections provided by the National Climatology Center. In high insolation regions, the new values of average daily direct-normal insolation are approximately 20 percent lower than those previously reported; they are even lower for regions with lower insolations.

A comparison has also been made between the revised Aerospace insolation values and the ones prepared for a DOE Solar Energy Handbook (Reference 9). Since there was good agreement between the two sources, and Reference 9 included contours of average daily direct-normal insolation for the entire United States (Figure 6-1), the latter was used to develop nominal values on a state by state basis as shown in Figure 6-2.

6.2.2 Annualized Energy Cost Data Base

Variations in the price of electricity can have a major impact on values for the ECR. This dictated the development of a data base in which energy prices were specified for each of the states.

Sherman H. Clark Associates, under a subcontract to The Aerospace Corporation, had earlier developed state-dependent fuel and electric energy price forecasts by five-year increments for the 1985-2015 time period, as documented in Reference 10. The prices are given for utilities, industrial, commercial, and residential usage in cents per million Btu (1977 dollars). They were developed for each fuel type, including natural gas, light oil, heavy oil, coal, and nuclear, as shown in Table 6-1 for California.

The energy price forecast was based on a real GNP growth rate of three percent, and assumed an inflation rate of four percent for the 1985 through 2015 period. The price projections for various sources of energy

Figure 6-1. Contours of Average Daily Direct Insolation ($\text{kWh}/\text{m}^2/\text{day}$)

Figure 6-2. Statewide Average Daily Direct Insolation (kWh/m²/day)

Table 6-1. Example of State-Dependent Fuel and Electric Energy Price
Forecasts for California

Use Sector	Cents per Million Btu								
	1974	1975	1985	1990	1995	2000	2005	2010	2015
Residential									
Natural Gas	128	146	334	404	471	510	507	500	500
Electricity	902	979	1201	1289	1406	1494	1553	1670	1787
Light Fuel Oil	272	284	430	475	525	574	576	579	581
Commercial									
Natural Gas	94	121	321	392	460	501	500	496	498
Electricity	809	888	1172	1289	1406	1494	1553	1670	1787
Light Fuel Oil	219	258	403	448	498	547	548	551	553
Heavy Fuel Oil	183	267	352	393	441	490	492	493	495
Coal	--	--	--	--	--	--	--	--	--
Industrial									
Natural Gas	64	103	319	390	459	500	498	494	496
Electricity	527	621	967	1084	1231	1348	1436	1582	1729
Light Fuel Oil	197	237	380	425	474	524	526	528	530
Heavy Fuel Oil	172	198	336	375	422	470	471	473	475
Coal	125	134	145	166	185	204	235	275	319
Power Plants									
Natural Gas	59	103	--	--	--	--	--	--	--
Light Fuel Oil	197	237	380	425	474	524	526	528	530
Heavy Fuel Oil	161	250	336	375	422	470	471	473	475
Coal	--	--	121	138	154	170	196	229	266
Nuclear	21	22	39	45	54	66	82	101	126

were based on the projection for the price of oil. A rise in oil prices on the order of 2 to 4 percent per year to the year 2000 was assumed, leveling off as the price of crude reached \$27 per barrel to become competitive with synthetic oil derived from shale, tar sands, and liquids from coal. Electricity prices, unlike the thermal energy prices, were expected to continue to rise during the 2000 to 2015 period at a rate of approximately two percent per year. The forecasts of energy use indicated a national compound annual growth rate of 1.6 percent. Due to limited availability of natural gas, a continuing reduction in the use of this fuel was forecast for the industrial sector, with plants switching to oil and coal.

Using the above data, yearly energy prices were developed by interpolation. Based on an assumed discount rate, k , and an SSPS lifetime of 30 years, annualized electric energy costs (mills/kWh) were then computed for each state in increments of five years. Similarly, annualized costs of thermal energy ($\$/10^6$ Btu) were obtained for each state in increments of five years. Details of annualized electric and thermal price computations are given in Section 6.2.3.2.

6.2.3 Computation of Annualized Charge Rate and Annualized Unit Energy Costs

The SSUMM and SSIMM computer models use the concept of ECR, which is the ratio of the annualized SSPS cost to the annualized cost of the conventional energy which it saves. The annualized SSPS cost is determined from the product of the SSPS plant cost and its annualized charge rate. Similarly, the annualized energy cost is determined from the product of SSPS annual energy saving and the annualized unit cost of the competing energy sources.

The annualized charge rate for a given SSPS plant depends upon its type of ownership, operating lifetime, and a number of financial parameters including discount rate, investment tax credit, depreciation, operating and maintenance (O&M) costs, income and property taxes, and insurance. The annualized unit energy cost of a SSPS depends upon its operating time

period, expected yearly conventional energy prices, and the discount rate associated with the type of ownership. The computation methodology for annualized charge rate and annualized unit energy cost is described briefly in the following sections. Further details of the methodology can be found in Reference 11.

6.2.3.1 Annualized Charge Rate Computation

The annualized charge rate (ACR) consists of four additive component costs:

$$ACR = ACCR + AOMR + AIR + APTR$$

where:

ACCR = annualized capital cost rate

AOMR = annualized operating and maintenance cost rate

AIR = annualized insurance cost rate

APTR = annualized property tax rate

The four cost components can be calculated by the following expressions:

$$ACCR = CRF (1 - \alpha - \tau \cdot DPF)$$

$$AOMR = (1 - \tau) OM$$

$$AIR = (1 - \tau) INS$$

$$APTR = (1 - \tau) \tau_p \left(1 - \frac{1}{Nk} + \frac{1}{(1 + k)^N - 1} \right)$$

where:

CRF = capital recovery factor

α = investment tax credit rate

τ = marginal income tax rate

DPF = depreciation factor
 OM = operating and maintenance costs, as an annual percentage of original capital costs.
 INS = insurance costs, as an annual percentage of original capital costs
 τ_p = local property tax rate on assessed valuation
 N = SSPS operating and accounting lifetime and loan term
 k = discount rate (after-tax cost of investment capital)

The capital recovery factor (CRF) and depreciation factor are calculated as:

$$CRF = \frac{k}{1 - (1 + k)^{-N}}$$

$$DPF = \frac{2 (N^* - \frac{1}{CRF^*})}{N^* k (N^* + 1)}$$

where:

N^* = 2/3 of the SSPS operating lifetime, N

CRF^* = capital recovery factor corresponding to N^*

Using the above set of equations, the ACRs for utilities and industries were computed for different types of utility ownership, (viz. investor-owned, municipal, cooperatives, and federal-, state- and district-owned) and industry ownership (viz. investor-owned and federal-owned). In addition to the baseline case, the effects of various investment tax credit rates and O&M cost rates were included in the computation of ACRs to evaluate various strategies for promoting commercialization of SSPS (Section 12). Tables 6-2 and 6-3 summarize the resulting ACRs for utilities and industries, respectively.

Table 6-2. Annualized Charge Rate (ACR) for Small Utility Units as a Function of Investment Tax-Credit and Operations and Maintenance Costs

Annualizing Parameter	ACR, Pre-tax, Percent		
	Type of Ownership		
	Investor	Municipal	Cooperative and FSDS*
Baseline Case	9.5	8.0	8.0
<u>Investment Tax-Credit (α) Sensitivity</u>			
α = 0%	10.7	N.A.**	N.A.**
α = 10% (Baseline)	9.5	N.A.	N.A.
α = 20%	7.8	N.A.	N.A.
α = 40%	6.0	N.A.	N.A.
<u>O&M Sensitivity</u>			
O&M = 0%	7.5	6.0	6.0
O&M = 2% (Baseline)	9.5	8.0	8.0
O&M = 4%	11.5	10.0	10.0
O&M = 6%	13.5	12.0	12.0
<u>Inputs</u>			
Discount Rate, k	4.0	2.3	2.3

* Federal, State and District Systems

** Investment Tax-Credit does not apply to municipal utilities and electrical cooperatives or government-owned systems.

Table 6-3. Annualized Charge Rate (ACR) for Small Industrial Systems as a Function of Investment Tax-Credit and Operations and Maintenance Costs

Annualizing Parameter	ACR, Pre-tax, Percent	
	Type of Ownership	
	Investor	Federal Agency
Baseline Case	12.1	8.0
<u>Investment Tax-Credit (α) Sensitivity</u>		
$\alpha = 0\%$	13.6	N.A.*
$\alpha = 10\%$ (Baseline)	12.1	N.A.
$\alpha = 20\%$	10.7	N.A.
$\alpha = 40\%$	7.7	N.A.
<u>O&M Sensitivity</u>		
O&M = 0%	10.1	6.0
O&M = 2% (Baseline)	12.1	8.0
O&M = 4%	14.1	10.0
O&M = 6%	16.1	12.1
<u>Inputs</u>		
Discount Rate, k	6.0	2.3

* Investment Tax-Credit does not apply to government-owned systems.

6.2.3.2 Annualized Unit Energy Costs Computation

Earlier, in Section 6.2.2, electric and thermal energy price forecasts by Sherman H. Clark Associates were discussed. The Sherman H. Clark Associates data base was available for each of the 50 states in five year increments from 1985 to 2015. Using these data, yearly energy prices were developed by interpolation. Annualized unit electric and thermal energy costs were then computed for different types of utility and industrial ownerships. Annualized unit electric energy cost (mills/kWh) is computed in increments of 5 years ($t_1 = 1985, 1990, \dots, 2015$) using the following:

$$L_{V_{t_1}} = PV_{t_1} \cdot \frac{k}{1 - (1 + k)^{-N}} \quad \text{if } k \neq 0$$

$$= \frac{PV_{t_1}}{N} \quad \text{if } k = 0$$

where

$$PV_{t_1} = \sum_{j=t_1}^{t_1 + (N-1)} C_j (1 + k)^{t_1 - j - 1}$$

$L_{V_{t_1}}$ = annualized electric energy cost from t_1 to $t_1 + N$

C_j = electric energy price in year j

N = SSPS lifetime (nominally 30 years)

k = discount rate based upon the application and type of ownership.

Similarly, the annualized unit cost of thermal energy ($\$/10^6$ Btu) was obtained in increments of five years. Tables 6-4 through 6-6 list the annualized electric and thermal energy unit costs for utilities and industries for different types of ownership. Annualized costs for federal agencies operating industrial systems were made equivalent to the costs for federal, state and district utility systems (Table 6-5).

6.2.4 Organization of the Data Base for Small Power System Installations

The utility and industry data bases are used by the SSUMM and SSIMM computer models, respectively, to determine market penetration levels in various regions of the U.S. These data bases only contain power plants no larger than 10 MW_e in generating capacity because, for this study, a small power system is defined to be either an individual generating unit or generating system which produces no more than 10 MW_e . A discussion of the utility and industrial data bases is given in Sections 3 and 4, respectively.

6.2.4.1 Utility Data Base

Reference 1 contains a compilation of small power units in utility systems. It is based on data acquired from the Electrical World Directory, the (former) Federal Energy Administration, and the (former) Federal Power Commission. Installation dates of the individual power plants were included in the data base wherever such data were available. When a power plant lifetime is specified, this information determines whether a power generating unit becomes a potential candidate for solar replacement or for solar repowering. The data base was keypunched to generate a complete data file for the SSUMM computer model, and was organized according to the following available information:

- State
- City
- Utility Name
- Type of Ownership
- Date Installed

Table 6-4. Annualized Unit Electric and Thermal Energy Prices for Investor-owned Utilities

STATE	Annualized Thermal Costs, \$/10 ⁶ Btu							Annualized Electric Costs, \$/10 ⁶ Btu						
	1985	1990	1995	2000	2005	2010	2015	1985	1990	1995	2000	2005	2010	2015
AL	4.12	4.40	4.60	4.68	4.69	4.70	4.70	37.62	42.62	47.27	51.42	54.72	57.04	57.99
AK	4.11	4.37	4.56	4.65	4.66	4.67	4.67	26.32	27.29	28.15	28.88	29.45	29.84	30.00
AZ	4.18	4.44	4.64	4.72	4.73	4.74	4.74	41.79	46.44	51.04	55.27	53.73	61.06	62.01
AR	4.18	4.45	4.64	4.73	4.74	4.75	4.75	37.37	41.74	46.00	49.61	52.63	55.06	56.01
CA	4.19	4.45	4.64	4.73	4.74	4.75	4.75	42.83	46.99	50.67	53.71	56.28	58.22	59.01
CO	4.03	4.29	4.48	4.56	4.57	4.58	4.58	41.35	46.40	51.08	55.42	59.25	62.05	63.00
CT	4.18	4.44	4.64	4.72	4.73	4.74	4.74	45.24	49.97	54.15	57.81	60.87	63.04	63.99
DE	4.29	4.56	4.75	4.83	4.84	4.85	4.85	55.55	61.53	66.73	71.31	75.18	77.90	79.01
FL	4.14	4.41	4.61	4.69	4.70	4.71	4.71	46.10	50.32	54.39	57.97	60.87	63.04	63.99
GA	4.03	4.30	4.49	4.58	4.59	4.60	4.60	40.78	45.79	50.27	54.23	57.63	60.01	60.99
HI	4.17	4.44	4.63	4.71	4.72	4.73	4.73	64.67	70.10	74.92	78.90	81.98	84.11	84.98
ID	4.18	4.44	4.64	4.72	4.73	4.74	4.74	24.67	29.69	34.43	38.98	43.18	45.89	47.00
IL	3.97	4.25	4.44	4.52	4.53	4.54	4.54	44.57	50.07	55.08	59.53	63.33	65.89	67.00
IN	4.32	4.59	4.79	4.87	4.88	4.89	4.89	44.60	49.85	54.42	58.42	61.72	64.04	64.98
IA	4.29	4.57	4.77	4.86	4.87	4.88	4.88	47.03	52.32	57.31	61.89	65.57	68.06	69.01
KS	4.01	4.29	4.49	4.57	4.58	4.59	4.59	44.30	49.35	54.01	58.03	61.56	64.04	64.98
KY	4.12	4.40	4.60	4.68	4.69	4.70	4.70	44.54	50.03	55.15	59.69	63.33	65.89	67.00
LA	4.04	4.31	4.50	4.58	4.59	4.60	4.60	44.24	48.64	52.39	55.98	58.89	61.06	62.01
ME	3.99	4.25	4.45	4.53	4.54	4.55	4.55	38.11	42.63	46.74	50.42	53.72	56.04	57.00
MD	4.14	4.41	4.61	4.69	4.70	4.71	4.71	43.26	48.60	53.53	57.84	61.32	63.87	64.98
MA	4.10	4.37	4.56	4.64	4.65	4.66	4.66	53.89	58.45	62.55	66.16	69.12	71.22	72.01
MI	4.20	4.47	4.66	4.74	4.75	4.76	4.76	41.91	46.93	51.58	55.62	58.96	61.22	62.01
MN	4.27	4.55	4.74	4.82	4.83	4.84	4.84	45.46	50.44	55.04	59.27	62.73	65.06	66.01
MS	4.09	4.37	4.57	4.65	4.66	4.67	4.67	42.67	46.70	50.54	53.97	56.68	59.05	60.00
MO	4.17	4.45	4.64	4.73	4.74	4.75	4.75	45.40	50.77	55.61	59.87	63.56	66.05	67.00
MT	4.18	4.44	4.64	4.72	4.73	4.74	4.74	30.84	35.56	39.58	43.42	46.72	49.05	50.00
NB	4.16	4.43	4.63	4.71	4.72	4.73	4.73	43.37	49.52	54.70	58.85	62.34	64.90	66.01
NV	4.09	4.35	4.54	4.62	4.63	4.64	4.64	34.78	40.11	45.15	49.91	54.01	56.83	57.99
NH	4.05	4.32	4.51	4.59	4.60	4.61	4.61	36.86	43.12	49.37	55.28	60.23	63.56	64.98
NJ	4.21	4.48	4.67	4.75	4.76	4.77	4.77	49.48	55.66	61.19	65.95	69.95	72.73	73.99
NM	4.28	4.54	4.73	4.81	4.82	4.83	4.83	40.35	45.99	51.42	56.52	60.85	63.87	64.98
NY	4.08	4.35	4.54	4.62	4.63	4.64	4.64	46.55	52.56	58.18	63.14	67.17	69.88	70.99
NC	4.06	4.33	4.53	4.61	4.62	4.63	4.63	44.80	49.85	54.42	58.42	61.72	64.04	64.98
ND	4.15	4.43	4.62	4.70	4.71	4.72	4.72	42.82	47.27	51.43	55.24	58.51	60.91	62.01
OH	4.29	4.56	4.76	4.84	4.85	4.86	4.86	45.34	50.47	55.09	59.20	62.57	65.06	66.01
OK	3.96	4.23	4.42	4.50	4.51	4.52	4.52	46.23	50.72	54.23	57.55	60.27	62.21	63.00
OR	4.12	4.39	4.58	4.66	4.67	4.68	4.68	30.52	34.59	38.02	41.13	43.66	45.37	46.01
PA	4.18	4.44	4.64	4.72	4.73	4.74	4.74	44.36	50.11	55.34	60.13	64.17	66.88	67.99
RI	4.02	4.29	4.48	4.56	4.57	4.58	4.58	46.48	51.05	55.16	59.04	62.57	65.06	66.01
SC	3.97	4.24	4.43	4.51	4.52	4.53	4.53	40.10	46.00	51.30	55.88	59.57	62.05	63.00
SD	4.27	4.55	4.74	4.82	4.83	4.84	4.84	38.02	43.72	48.95	53.46	57.17	59.88	60.99
TN	4.12	4.40	4.60	4.68	4.69	4.70	4.70	39.28	43.73	47.89	51.58	54.50	56.36	57.00
TX	4.18	4.45	4.64	4.73	4.74	4.75	4.75	44.35	48.28	51.74	55.00	57.80	59.88	60.99
UT	3.99	4.25	4.45	4.53	4.54	4.55	4.55	42.62	47.14	51.59	55.62	58.96	61.22	62.01
VT	4.15	4.41	4.61	4.69	4.70	4.71	4.71	43.06	50.33	57.04	61.96	65.95	68.73	70.00
VA	4.14	4.41	4.61	4.69	4.70	4.71	4.71	41.25	46.20	50.84	54.81	57.88	60.04	60.99
WA	4.11	4.37	4.56	4.65	4.66	4.67	4.67	26.48	30.95	34.63	37.78	40.43	42.21	43.00
WV	4.16	4.44	4.63	4.71	4.72	4.73	4.73	51.36	57.61	63.45	68.76	73.02	75.89	77.00
WI	3.97	4.25	4.44	4.52	4.53	4.54	4.54	46.60	51.21	55.57	59.39	62.26	64.19	64.98
WY	4.15	4.41	4.61	4.69	4.70	4.71	4.71	36.64	41.32	45.17	48.65	52.34	54.90	56.01

Table 6-5. Annualized Unit Electric and Thermal Energy Prices for Municipal Utilities, Cooperatives, and Federal, State and District Systems

STATE	Annualized Thermal Costs, \$/10 ⁶ Btu							Annualized Electric Costs, \$/10 ⁶ Btu						
	1985	1990	1995	2000	2005	2010	2015	1985	1990	1995	2000	2005	2010	2015
AL	4.19	4.44	4.61	4.68	4.69	4.70	4.70	38.86	43.87	48.36	52.22	55.19	57.20	57.99
AK	4.17	4.41	4.58	4.65	4.66	4.67	4.67	26.56	27.51	28.34	29.01	29.53	29.87	30.00
AZ	4.25	4.48	4.65	4.72	4.73	4.74	4.74	42.96	47.69	52.16	56.10	59.20	61.22	62.01
AR	4.25	4.49	4.66	4.75	4.74	4.75	4.75	38.46	42.88	47.01	50.56	53.33	55.21	56.01
CA	4.25	4.49	4.66	4.73	4.74	4.75	4.75	43.82	47.94	51.49	54.35	56.67	58.35	59.01
CO	4.09	4.33	4.49	4.56	4.57	4.58	4.58	42.58	47.66	52.27	56.35	59.80	62.21	63.00
CT	4.24	4.48	4.65	4.72	4.73	4.74	4.74	46.37	51.06	55.13	58.55	61.32	63.20	63.99
DE	4.35	4.60	4.76	4.83	4.84	4.85	4.85	56.98	62.92	67.96	72.25	75.73	78.08	79.01
FL	4.21	4.45	4.62	4.69	4.70	4.71	4.71	47.14	51.39	55.34	58.69	61.32	63.20	63.99
GA	4.10	4.34	4.51	4.58	4.59	4.60	4.63	41.98	46.99	51.34	55.06	58.11	60.17	60.99
HI	4.23	4.48	4.64	4.71	4.72	4.73	4.73	66.00	71.35	75.95	79.64	82.41	84.26	84.98
ID	4.25	4.48	4.65	4.72	4.73	4.74	4.74	25.90	31.02	35.68	39.97	43.72	46.07	47.00
IL	4.04	4.29	4.45	4.52	4.53	4.54	4.54	45.91	51.41	56.27	60.44	63.85	66.07	67.00
IN	4.39	4.63	4.80	4.87	4.88	4.89	4.89	46.03	51.06	55.48	59.22	62.18	64.19	64.98
IA	4.36	4.61	4.79	4.86	4.87	4.88	4.83	48.36	53.67	58.51	62.76	66.07	68.22	69.01
KS	4.08	4.33	4.50	4.57	4.58	4.59	4.59	45.53	50.59	55.10	58.89	62.05	64.19	64.98
KY	4.19	4.44	4.61	4.68	4.69	4.70	4.73	45.89	51.39	56.34	60.57	63.85	66.07	67.00
LA	4.10	4.35	4.52	4.59	4.59	4.60	4.63	45.28	49.64	53.35	56.70	59.33	61.22	62.01
ME	4.05	4.29	4.46	4.53	4.54	4.55	4.55	39.20	43.74	47.75	51.22	54.19	56.20	57.00
MD	4.21	4.45	4.62	4.69	4.70	4.71	4.71	44.56	49.90	54.67	58.70	61.85	64.06	64.98
MA	4.16	4.41	4.57	4.64	4.65	4.66	4.65	55.00	59.54	63.51	66.88	69.54	71.35	72.01
MI	4.26	4.51	4.67	4.75	4.75	4.76	4.75	43.16	48.21	52.65	56.41	59.40	61.35	62.01
MN	4.34	4.59	4.75	4.83	4.83	4.84	4.84	46.69	51.68	56.15	60.09	63.20	65.21	66.01
MS	4.16	4.41	4.58	4.65	4.66	4.67	4.67	43.65	47.73	51.47	54.69	57.33	59.21	60.00
MO	4.24	4.49	4.66	4.73	4.74	4.75	4.75	46.71	52.07	56.76	60.75	64.06	66.20	67.00
MT	4.25	4.48	4.65	4.72	4.73	4.74	4.74	31.96	36.67	40.62	44.22	47.19	49.21	50.00
NB	4.22	4.47	4.64	4.71	4.72	4.73	4.73	44.81	50.85	55.81	59.71	62.86	65.08	66.01
NV	4.15	4.39	4.56	4.63	4.63	4.64	4.64	36.09	41.50	46.44	50.90	54.58	57.06	57.99
NH	4.11	4.36	4.52	4.60	4.60	4.61	4.61	38.47	44.84	50.94	56.47	60.91	63.80	64.98
NJ	4.27	4.52	4.68	4.75	4.76	4.77	4.77	50.97	57.12	62.46	66.93	70.52	72.94	73.99
NM	4.35	4.58	4.75	4.82	4.82	4.83	4.83	41.75	47.49	52.79	57.56	61.45	64.06	64.98
NY	4.15	4.39	4.56	4.63	4.63	4.64	4.64	48.05	54.06	59.48	64.10	67.72	70.06	70.99
NC	4.13	4.37	4.54	4.61	4.62	4.63	4.63	46.03	51.06	55.48	59.22	62.18	64.19	64.98
ND	4.22	4.47	4.64	4.71	4.71	4.72	4.72	43.89	48.39	52.46	56.05	59.00	61.09	62.01
OH	4.36	4.60	4.77	4.84	4.85	4.86	4.86	46.58	51.71	56.18	60.03	63.07	65.21	66.01
OK	4.02	4.27	4.44	4.51	4.51	4.52	4.52	47.28	51.69	55.15	58.21	60.66	62.34	63.00
OR	4.18	4.43	4.59	4.67	4.67	4.68	4.68	31.50	35.52	38.84	41.73	44.00	45.48	46.01
PA	4.24	4.48	4.65	4.72	4.73	4.74	4.74	45.77	51.53	56.62	61.10	64.71	67.06	67.99
RI	4.08	4.33	4.49	4.56	4.57	4.58	4.58	47.58	52.19	56.23	59.89	63.07	65.21	66.01
SC	4.03	4.28	4.44	4.52	4.52	4.53	4.53	41.55	47.43	52.50	56.76	60.06	62.21	63.00
SD	4.34	4.59	4.75	4.83	4.83	4.84	4.84	39.41	45.10	50.16	54.37	57.72	60.06	60.99
TN	4.19	4.44	4.61	4.69	4.69	4.70	4.70	40.41	44.85	48.85	52.26	54.86	56.47	57.00
TX	4.25	4.49	4.66	4.73	4.74	4.75	4.75	45.26	49.21	52.62	55.71	58.25	60.06	60.99
UT	4.06	4.29	4.46	4.53	4.54	4.55	4.55	43.76	48.34	52.65	56.41	59.40	61.35	62.01
VT	4.21	4.45	4.62	4.69	4.70	4.71	4.71	44.84	52.00	58.33	62.93	66.53	68.94	70.00
VA	4.21	4.45	4.62	4.69	4.70	4.71	4.71	42.47	47.41	51.87	55.56	58.32	60.20	60.99
WA	4.17	4.41	4.58	4.65	4.66	4.67	4.67	27.53	31.92	35.47	38.41	40.79	42.34	43.00
WV	4.23	4.48	4.64	4.71	4.72	4.73	4.73	52.92	59.19	64.84	69.78	73.59	76.07	77.00
WI	4.04	4.29	4.45	4.52	4.53	4.54	4.54	47.76	52.36	56.55	60.07	62.65	64.32	64.98
WY	4.22	4.45	4.62	4.69	4.70	4.71	4.71	37.71	42.39	46.21	49.71	52.86	55.08	56.01

Table 6-6. Annualized Unit Electric and Thermal Energy Prices for
Investor-owned Industries

Annualized Thermal Costs, $\$/10^6$ Btu								Annualized Electric Costs, $\$/10^6$ Btu						
STATE	1985	1990	1995	2000	2005	2010	2015	1985	1990	1995	2000	2005	2010	2015
AL	4.05	4.35	4.58	4.68	4.69	4.70	4.70	36.29	41.27	46.06	50.51	54.16	56.65	57.99
AK	4.03	4.33	4.55	4.65	4.66	4.67	4.67	26.06	27.04	27.93	28.72	29.36	29.81	30.00
AZ	4.11	4.40	4.62	4.72	4.73	4.74	4.74	40.53	45.09	49.80	54.32	58.17	60.87	62.01
AR	4.11	4.41	4.63	4.73	4.74	4.75	4.75	36.20	40.51	44.09	48.95	52.36	54.66	56.01
CA	4.11	4.41	4.63	4.73	4.74	4.75	4.75	41.75	45.95	49.77	52.99	55.81	58.05	59.01
CO	3.96	4.24	4.46	4.56	4.57	4.58	4.59	40.04	45.01	49.77	54.35	58.59	61.66	63.00
CT	4.10	4.40	4.62	4.72	4.73	4.74	4.74	44.01	48.76	53.07	56.95	60.35	62.65	63.99
DE	4.21	4.51	4.73	4.83	4.84	4.85	4.85	53.99	60.02	65.37	70.23	74.53	77.68	79.01
FL	4.07	4.37	4.59	4.69	4.70	4.71	4.71	44.98	49.15	53.33	57.15	60.35	62.65	63.99
GA	3.96	4.26	4.48	4.58	4.59	4.60	4.60	39.47	44.49	49.09	53.29	57.05	59.81	60.99
HI	4.09	4.39	4.61	4.71	4.72	4.73	4.73	63.22	68.73	73.76	78.05	81.47	83.94	84.98
ID	4.11	4.40	4.62	4.72	4.73	4.74	4.74	23.36	28.27	33.04	37.84	42.52	45.66	47.00
IL	3.90	4.20	4.42	4.52	4.53	4.54	4.54	43.13	48.61	53.75	58.48	62.71	65.66	67.00
IN	4.25	4.55	4.77	4.87	4.88	4.89	4.89	43.47	48.53	53.24	57.50	61.16	63.84	64.98
IA	4.21	4.52	4.75	4.86	4.87	4.88	4.88	45.61	50.85	55.97	60.83	64.98	67.87	69.01
KS	3.94	4.24	4.47	4.57	4.58	4.59	4.59	42.97	48.00	52.80	57.06	60.97	63.84	64.98
KY	4.05	4.35	4.58	4.68	4.69	4.70	4.70	43.08	48.55	53.62	58.67	62.71	65.66	67.00
LA	3.96	4.26	4.48	4.58	4.59	4.60	4.60	43.12	47.53	51.34	55.15	58.36	60.87	62.61
ME	3.91	4.21	4.43	4.53	4.54	4.55	4.55	36.95	41.43	45.62	49.50	53.16	55.85	57.00
MD	4.07	4.37	4.59	4.69	4.70	4.71	4.71	41.86	47.19	52.26	56.86	60.71	63.65	64.98
MA	4.02	4.32	4.54	4.64	4.65	4.66	4.66	52.68	57.26	61.48	65.34	68.62	71.06	72.01
MI	4.12	4.42	4.64	4.74	4.75	4.76	4.76	40.56	45.64	50.39	54.70	58.43	61.06	62.01
MI	4.20	4.50	4.72	4.82	4.83	4.84	4.84	44.14	49.08	53.79	58.32	62.17	64.86	66.01
MS	4.02	4.32	4.55	4.65	4.66	4.67	4.67	41.62	45.59	49.52	53.15	56.36	58.05	60.00
MO	4.10	4.40	4.63	4.73	4.74	4.75	4.75	43.98	49.35	54.34	58.86	62.97	65.85	67.00
MT	4.11	4.40	4.62	4.72	4.73	4.74	4.74	29.64	34.36	38.44	42.50	46.16	48.85	50.00
NE	4.08	4.39	4.61	4.71	4.72	4.73	4.73	41.78	48.07	53.46	57.87	61.72	64.67	66.01
NV	4.02	4.31	4.52	4.62	4.63	4.64	4.64	33.38	38.61	43.73	48.77	53.33	56.65	57.99
NE	3.99	4.27	4.49	4.59	4.60	4.61	4.61	35.18	41.27	47.62	53.92	59.43	63.27	64.98
NJ	4.13	4.43	4.65	4.75	4.76	4.77	4.77	47.87	54.08	59.78	64.84	69.27	72.47	73.99
NH	4.21	4.50	4.71	4.81	4.82	4.83	4.83	38.85	44.38	49.89	55.33	60.13	63.65	64.98
NY	4.01	4.30	4.52	4.62	4.63	4.64	4.64	44.95	50.92	56.73	62.03	66.52	69.66	70.99
NC	3.99	4.29	4.51	4.61	4.62	4.63	4.63	43.47	49.53	53.24	57.50	61.16	63.84	64.98
ND	4.08	4.38	4.60	4.70	4.71	4.72	4.72	41.67	46.06	50.29	54.32	57.92	60.68	62.01
OH	4.22	4.52	4.74	4.84	4.85	4.86	4.86	43.99	49.13	53.87	58.26	61.98	64.86	66.01
OK	3.89	4.18	4.40	4.50	4.51	4.52	4.52	45.09	49.68	53.31	56.79	59.80	62.05	63.00
OR	4.05	4.34	4.56	4.66	4.67	4.68	4.68	29.45	33.55	37.10	40.43	43.26	45.25	46.01
PA	4.10	4.40	4.62	4.72	4.73	4.74	4.74	42.85	48.57	53.92	59.03	63.51	66.65	67.99
RI	3.94	4.24	4.46	4.56	4.57	4.58	4.58	45.31	49.63	53.98	58.06	61.98	64.86	66.01
SC	3.89	4.19	4.41	4.51	4.52	4.53	4.53	38.52	44.46	49.55	54.87	58.98	61.66	63.00
SD	4.20	4.50	4.72	4.82	4.83	4.84	4.84	36.52	42.22	47.63	52.42	56.52	59.66	60.99
TN	4.05	4.35	4.58	4.68	4.69	4.70	4.70	33.07	42.51	46.02	50.79	54.06	56.24	57.00
TX	4.11	4.41	4.63	4.73	4.74	4.75	4.75	43.36	47.27	50.76	54.21	57.28	59.66	60.99
UT	3.92	4.21	4.43	4.53	4.54	4.55	4.55	41.39	45.83	50.39	54.70	58.43	61.06	62.01
VT	4.07	4.37	4.59	4.69	4.70	4.71	4.71	41.12	48.49	55.59	60.85	65.27	68.48	70.00
VA	4.07	4.37	4.59	4.69	4.70	4.71	4.71	39.92	44.87	49.69	53.95	57.35	59.65	60.99
WA	4.03	4.33	4.55	4.65	4.66	4.67	4.67	25.33	29.89	33.70	37.05	39.99	42.05	43.00
WV	4.09	4.39	4.61	4.71	4.72	4.73	4.73	49.68	55.89	61.90	67.59	72.34	75.66	77.00
WI	3.90	4.20	4.42	4.52	4.53	4.54	4.54	45.34	49.95	54.48	58.60	61.80	64.03	64.98
WY	4.08	4.37	4.59	4.69	4.70	4.71	4.71	35.50	40.18	44.03	47.87	51.72	54.67	56.01

These data are given alphabetically by state and, within a given state, the data are reported according to the following types of ownership:

- Investor-owned Utilities (I)
- Municipal Utilities (M)
- Electrical Cooperatives and Other Utility Systems (O)

Each of the generating units is given the following operational status:

- Active (O)
- Standby (I)

Each of the generating units is listed in terms of one of the following three types of units:

- Steam Turbine (S)
- Diesel Generator (D)
- Gas Turbine (G)

Finally, the installation dates of the generating units are given. Whenever these installation dates were not known, state-average dates were assigned. An example of the data file is given in Figure 6-3.

6.2.4.2 Industry Data Base

The industry data base was derived from off-line printouts of the (former) Federal Power Commission Form 4 and Form 12-C data bases for 1976. This data base was keypunched for the necessary input to the SSIMM computer model and was organized (Figure 6-4) in the following sequence:

- State
- City
- Industry Name
- Plant Name
- Type of Ownership
- Status

STATE	CITY	UTILITY	TYPE OF OWN	STATUS	NUMBER OF UNITS	SIZE OF UNITS	TYPE OF UNITS	DATE INSTALLED
IL	MASCOUTAH	MASCOUTAH MUNICIPAL LIGHT DEPT.	M	0	1	1500	S	1957
IL	MASCOUTAH	MASCOUTAH MUNICIPAL LIGHT DEPT.	M	0	1	2000	S	1967
IL	MASCOUTAH	MASCOUTAH MUNICIPAL LIGHT DEPT.	M	0	2	560	D	1951
IL	MASCOUTAH	MASCOUTAH MUNICIPAL LIGHT DEPT.	M	0	1	1135	D	1958
IL	MASCOUTAH	MASCOUTAH MUNICIPAL LIGHT DEPT.	M	0	1	2070	D	1969
IL	MASCOUTAH	MASCOUTAH MUNICIPAL LIGHT DEPT.	M	0	1	2280	D	1973
IL	MC LEANSBORO	MC LEANSBORO MUNICIPAL LIGHT ^ POWER PLA	M	0	1	750	S	1959
IL	MC LEANSBORO	MC LEANSBORO MUNICIPAL LIGHT ^ POWER PLA	M	0	1	600	D	1949
IL	MC LEANSBORO	MC LEANSBORO MUNICIPAL LIGHT ^ POWER PLA	M	0	1	600	D	1950
IL	MC LEANSBORO	MC LEANSBORO MUNICIPAL LIGHT ^ POWER PLA	M	0	1	645	D	1952
IL	MC LEANSBORO	MC LEANSBORO MUNICIPAL LIGHT ^ POWER PLA	M	0	1	2300	D	1963
IL	PERU	PERU LIGHT DEPT.	M	0	1	1000	S	1936
IL	PERU	PERU LIGHT DEPT.	M	0	1	3000	S	1938
IL	PERU	PERU LIGHT DEPT.	M	0	1	4000	S	1950
IL	PERU	PERU LIGHT DEPT.	M	0	1	8000	S	1960
IL	PERU	PERU LIGHT DEPT.	M	0	1	6250	D	1973
IL	PRINCETON	PRINCETON MUNICIPAL UTILITIES DEPT	M	0	1	3000	D	1958
IL	PRINCETON	PRINCETON MUNICIPAL UTILITIES DEPT	M	0	1	3000	D	1953
IL	PRINCETON	PRINCETON MUNICIPAL UTILITIES DEPT	M	0	2	4000	D	1965
IL	PRINCETON	PRINCETON MUNICIPAL UTILITIES DEPT	M	0	1	4000	D	1971
IL	PRINCETON	PRINCETON MUNICIPAL UTILITIES DEPT	M	0	1	6000	D	1971
IL	PRINCETON	PRINCETON MUNICIPAL UTILITIES DEPT	M	0	2	9000	D	1976
IL	RANTOUL	RANTOUL LIGHT ^ POWER DEPT.	M	0	2	1230	D	1951
IL	RANTOUL	RANTOUL LIGHT ^ POWER DEPT.	M	0	1	1230	D	1953
IL	RANTOUL	RANTOUL LIGHT ^ POWER DEPT.	M	0	1	1230	D	1954
IL	RANTOUL	RANTOUL LIGHT ^ POWER DEPT.	M	0	2	1350	D	1964
IL	RANTOUL	RANTOUL LIGHT ^ POWER DEPT.	M	0	1	5200	D	1967
IL	RANTOUL	RANTOUL LIGHT ^ POWER DEPT.	M	0	1	4000	D	1964
IL	RED BUD	RED BUD POWER, LIGHT ^ WATER DEPT.	M	0	1	1000	D	1959
IL	RED BUD	RED BUD POWER, LIGHT ^ WATER DEPT.	M	0	1	1000	D	1948
IL	RED BUD	RED BUD POWER, LIGHT ^ WATER DEPT.	M	0	1	1000	D	1953
IL	RED BUD	RED BUD POWER, LIGHT ^ WATER DEPT.	M	0	1	2000	D	1965
IL	RED BUD	RED BUD POWER, LIGHT ^ WATER DEPT.	M	0	1	2000	D	1968
IL	RED BUD	RED BUD POWER, LIGHT ^ WATER DEPT.	M	0	1	4000	D	1973
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	1000	D	1936
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	1000	D	1940
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	1000	D	1946
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	1000	D	1949
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	1000	D	1950
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	2000	D	1953
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	3000	D	1956
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	2	3000	D	1966
IL	ROCHELLE	ROCHELLE MUNICIPAL UTILITIES	M	0	1	4000	D	1960
IL	SPRINGFIELD	SPRINGFIELD WATER, LIGHT ^ POWER DEPT.	M	0	1	10000	S	1939
IL	SPRINGFIELD	SPRINGFIELD WATER, LIGHT ^ POWER DEPT.	M	0	1	10000	S	1940
IL	SULLIVAN	SULLIVAN ELECTRIC DEPT.	M	0	1	230	D	1934
IL	SULLIVAN	SULLIVAN ELECTRIC DEPT.	M	0	1	300	D	1939
IL	SULLIVAN	SULLIVAN ELECTRIC DEPT.	M	0	1	690	D	1946
IL	SULLIVAN	SULLIVAN ELECTRIC DEPT.	M	0	1	1130	D	1948
IL	SULLIVAN	SULLIVAN ELECTRIC DEPT.	M	0	1	1130	D	1951

Figure 6-3. Utility Data File Sample for SSUMM Computer Model

State	Company Name	City	Ownership	Status	No. of Systems	Size	Type	SIC
IL	Columbia Quarry Company	Krause No. 1	I	0	1	1916	D	1421
IL	Deere & Company	Harvester	I	0	1	10000	S	--
IL	Elliott Paint & Varnish Co.	Chicago	I	1	1	700	D	3411
IL	Federal Paper Board Co.	Morris	I	1	1	4600	S	--
IL	General Motors Corporation	Lagrange	I	0	1	9600	D	--
IL	Granite City Steel Co.	Granite	I	1	1	300	D	--
IL	International Harvester	Canton	I	1	1	2000	S	3522
IL	Johns Manville Corp.	Waukegan	I	0	1	6143	S	3292
IL	Laclede Steel Co.	Alton	I	1	1	650	D	3312
IL	Laclede Steel Co.	Madison	I	1	1	100	D	3312
IL	Olin Corporation	East Alton	I	0	1	7000	S	--
IL	Olin Corporation	Joliet	I	1	1	680	D	2819
IL	Page Engineering Co.	McCook	I	1	1	1000	D	3531
IL	Pet Incorporated	Greenville	I	1	1	625	S	2023
IL	Proctor & Gamble Mfg. Co.	Chicago	I	0	1	500	S	2841
IL	Produce Terminal Corp.	Chicago	I	0	1	5000	S	--
IL	Quaker Oats Co.	Pekin	I	0	1	1500	S	2621
IL	U.S. Government	RI Arsenal	M	0	1	955	D	--
IL	U.S. Tobacco Co.	Franklin Park	I	0	1	1240	S	2131
IL	Hiram Walker & Sons Inc.	Peoria	I	0	1	7000	S	--
IN	Beveridge Paper Co.	Indianapolis	I	0	1	1000	S	2621
IN	Central Soya Co.	Decatur	I	0	1	4000	S	2092
IN	Colgate Palmolive Co.	Clarksville	I	0	1	3000	S	2841
IN	Colgate Palmolive Co.	Clarksville	I	0	1	500	D	2841
IN	Container Corp. of America	Wabash Division	I	0	1	4000	S	2621
IN	General Motors Corp.	Allison	I	0	1	2405	D	--
IN	Harrison Steel Castings	Attica	I	1	1	200	S	3323
IN	Indiana Gas Chemical Corp.	Terre Haute	I	0	1	600	S	3312
IN	Eli Lilly & Co.	Indianapolis	I	0	1	2500	S	2834

Figure 6-4. Industrial Data File Sample for SSIMM Computer Model

- Number of Systems (Always 1)
- Size of Systems (kW_e)
- Type of Systems
- 3-digit Standard Industrial Code (SIC), when available

The industry data are given alphabetically by state and reported according to the following types of ownership:

- Investor-owned Industries (I)
- Federal Agency-Operated Facilities (M)

The operational status and type of generating system are listed according to the designations given earlier for the utility data base.

6.2.5 SSPS Simulation Model

The computer simulation program used to determine SSPS relative cost and performance is shown in the block diagram of Figure 6-5. The model can be modified to simulate different sizes and operational characteristics of collectors, turbines, and high temperature storage. The model dynamically simulates the interaction of time-varying solar insolation, electric demand for the application selected, and the time-lag effects of thermal storage. The simulation is based on hourly insolation and demand data for 365-day operation. The thermal input to the generator and the generator electrical output are assumed to be constant during any hourly period of operation. The program is flexible enough to allow hundreds of different SSPS plant configurations to be simulated under a wide variety of conditions. Moreover, with this program, the size of the SSPS components can be adjusted to maximize the return on invested capital for both the solar replacement and repowering modes of conventional small power systems.

The SSPS simulation program outputs several technical and economic parameters on a daily, yearly, and plant life-cycle basis. Some of the important parameters are the equivalent cost ratio (ECR), capacity factor (CF), and system capital cost (SCC). An example of the optimization analysis for the ECR is given in Section 7.

Figure 6-5. SSPS Simulation Block Diagram

6.2.6 SSPS Cost Model and ECR Modifying Matrix

Table 6-7 presents the major subsystem costs for a 1-, 5-, and 10-MW_e central receiver-type SSPS. These major subsystem costs were derived from the new Aerospace Corporation cost model discussed in Section 5. These costs are based on an initial "bottom-up" analysis using cost estimates for each hardware element contained in the major subsystems and assuming a mature solar manufacturing industry that produces its first commercial product line around the year 1990.

Table 6-7. Major Subsystem Cost Breakdown for SSPS

Subsystem Cost	Plant Capacity		
	1 MW _e	5 MW _e	10 MW _e
Collector, \$/ft ² *	10.9	10.8	10.8
Receiver-Tower, \$/ft ²	5.1	3.4	2.8
Storage, \$/10 ⁶ Btu	6030	4633	4620
Balance of Plant, \$/kW _e	2257	1194	936
* All costs (except for storage media replacement costs) include indirect and contingency costs that are equal to 40 percent of their basic cost.			

To avoid lengthy and repetitious calculations of ECR for different size replacement or repowering solar power systems installed at various locations in any given future year, costs of the 10 MW_e solar system for the year 1990 were used in the baseline SSPS optimization model to generate relationships between insolation and the performance/cost factors:

equivalent cost ratio, capacity factor, and system capital cost (Section 7). These relationships were multiplied by values in an ECR modifying matrix to allow the SSUMM and SSIMM computer programs to determine the corresponding ECRs for solar small power systems with rated capacities other than 10 MW_e and for installation of power units in years other than 1990.

The ECR modifying matrices that were generated for both the solar replacement and repowering modes are given in Tables 6-8 and 6-9. As can be seen, the values for various SSPS sizes and years of installation were normalized to the baseline value of a 10 MW_e SSPS installed in the year 1990. The modifying factor for a given size SSPS was then obtained by logarithmic interpolation of these tables. Details of the procedures and the rationale for developing these modifying matrices are given in Section 5.

6.2.7 SSPS Monte Carlo Simulation Model

It was recognized at the onset of the study that projections of fuel and purchased electric power costs can only be considered as reasonable average values. There is some likelihood that the actual costs may be higher or lower than the projected values and, indeed, cost variations can be expected within a given state. The same type of uncertainty can also be ascribed to the baseline values assumed for the annualized cost rate due to variations in operations and maintenance costs or ownership taxes. Insolation levels are expected to be less subject to future variations in a given locale, but within a statewide area, significant changes are noticed.

Because the foregoing factors can have a major influence on SSPS economic competitiveness, it is appropriate to provide a statistical method that accounts for these uncertainties. Hence, a Monte Carlo simulation model was used to estimate the ECR probability distribution (ECRM), which is the product of the following three independent distributions:

- $\left(\frac{\Delta \text{ECR}}{\text{ECR}_m} \right) S$ State insolation variation normalized to the median insolation ECR_m in a given state.

Table 6-8. ECR Modifying Matrix for Solar Replacement Mode

		Year of SSPS Installation						
		1985	1990	1995	2000	2005	2010	2015
SSPS Rated Capacity (MW _e)	0.1	3.688	3.068	2.801	2.657	2.565	2.494	2.443
	1.0	2.105	1.751	1.599	1.516	1.464	1.424	1.396
	10.0	1.202	1.000	0.913	0.866	0.836	0.813	0.797
	100.0	0.686	0.571	0.521	0.494	0.477	0.464	0.455

Table 6-9. ECR Modifying Matrix for Solar Repowering Mode

		Year of SSPS Installation						
		1985	1990	1995	2000	2005	2010	2015
SSPS Rated Capacity (MW _e)	0.1	3.301	2.746	2.507	2.378	2.296	2.232	2.189
	1.0	1.992	1.657	1.513	1.435	1.385	1.347	1.321
	10.0	1.202	1.000	0.913	0.866	0.836	0.813	0.797
	100.0	0.725	0.603	0.551	0.522	0.504	0.490	0.481

- $\left(\frac{\Delta ECR}{ECR_m}\right)_{EP}$ Annualized energy cost variation normalized to median annualized energy price ECR_m in a given state.
- $\left(\frac{\Delta ECR}{ECR_m}\right)_{AC}$ Annualized charge rate variation normalized to the median rate ECR_m of a given SSPS user sector.

The insolation variation within each state and its relationship to the ECR was discussed in Reference 11. The state insolation was assumed to be uniformly distributed with values of its spread calculated from the relationship between the ECR and insolation. Table 6-10 gives the seven state groupings of these distributions along with the size of their uniform spread. The location group of a given state is decided on the basis of its normalized spread of ECR relative to its median value, $\left(\frac{\Delta ECR}{ECR_m}\right)_S$.

Table 6-10. State Groupings of Insolation Distributions and Associated Sizes of Uniform Spread

$\frac{\Delta ECR}{ECR_m}$	State Location Group	Location Group Member States
0	1	RI, DE, AK, HI
0.037	2	VT, MA, CT, NJ, PA, IN, MD, WV, FL, AL
0.055	3	ME, MI, WI, IA, ND, VA, NC, SC, GA, MS, UT
0.075	4	NH, NY, MO, KS, AR, NM, AZ, NV
0.092	5	OH, IL, MN, SD, NB, KY, TN, LA, OK, WY, CO
0.168	6	CA
0.198	7	TX, MT, ID, WA, OR

A second ECR distribution component is the variation in energy price occurring within a state. A review of current energy price data indicates that a normal distribution is appropriate with a standard deviation of ± 12 percent.

The third ECR distribution component is the variation in annualized charge rate (ACR), which was also assumed to be normally distributed. Using the variations in interest rate and O&M charges given in Reference 10 as ± 2 percent, the resulting ACR standard deviation is ± 5.5 percent for investor-owned utilities and ± 3.9 percent for municipal utilities and electric cooperatives. For the industrial sector, the ACR standard deviation is ± 8 percent for private industries and ± 3.9 percent for federal facilities.

A Monte Carlo simulation is used to combine the above three distributions to obtain $7 \times 1 \times 1 = 7$ distributions of the ECRM multiplicative factors. This simulation was carried out separately for utilities and industries with different types of ownership. These distributions are assumed to be independent of time for the years 1985 through 2015. Table 6-11 gives examples of ECRM multiplicative factor distributions for an investor-owned utility in each of the seven state groups, as defined in Table 6-10. ECRM multiplicative factor distributions are listed at eleven equally spaced values between the minimum and maximum sample draws. The corresponding cumulative distribution of the D(ECRM), (i.e., the probability of ECRM) is printed immediately below the ECRM multiplicative factors.

6.3 SSUMM METHODOLOGY AND MODEL DESCRIPTION

Figure 6-6 outlines the basic relationships of the major components of the SSPS market penetration model. For the case of the Small Solar Utility Market Model (SSUMM), the annualized charge rate (ACR) and the annualized unit energy costs are derived for the financial structure corresponding to each type of utility. This data base, along with the generating unit data base, the insolation data base, the SSPS performance relationships, and the SSPS cost models are used to determine individual utility plant ECRs by the following relationships:

Table 6-11. ECRM Multiplicative Factor Distributions and the Associated Probability Values D (ECRM) for Investor-owned Utilities

Type of Ownership = Investor Discount Rate = 4.0 ACR Sigma = 5.5 Energy Price Sigma = 12.0											
State Group Number = 1											
ECRM =	0.548	0.653	0.758	0.862	0.967	1.071	1.176	1.281	1.385	1.490	1.594
D(ECRM) =	0.000	0.003	0.031	0.154	0.413	0.710	0.906	0.980	0.996	1.000	1.000
State Group Number = 2											
ECRM =	0.484	0.586	0.688	0.790	0.892	0.995	1.097	1.199	1.301	1.403	1.505
D(ECRM) =	0.000	0.001	0.007	0.054	0.207	0.496	0.775	0.933	0.986	0.998	1.000
State Group Number = 3											
ECRM =	0.526	0.627	0.728	0.830	0.931	1.032	1.133	1.234	1.335	1.437	1.530
D(ECRM) =	0.000	0.002	0.020	0.103	0.312	0.600	0.840	0.957	0.993	0.999	1.000
State Group Number = 4											
ECRM =	0.471	0.584	0.697	0.810	0.923	1.036	1.149	1.261	1.374	1.487	1.600
D(ECRM) =	0.000	0.001	0.010	0.080	0.297	0.612	0.856	0.964	0.994	0.999	1.000
State Group Number = 5											
ECRM =	0.554	0.662	0.770	0.878	0.986	1.094	1.201	1.309	1.417	1.525	1.633
D(ECRM) =	0.000	0.005	0.044	0.193	0.465	0.747	0.917	0.980	0.997	1.000	1.000
State Group Number = 6											
ECRM =	0.510	0.627	0.744	0.861	0.977	1.094	1.211	1.328	1.444	1.561	1.678
D(ECRM) =	0.000	0.006	0.051	0.201	0.461	0.725	0.895	0.972	0.995	0.999	1.000
State Group Number = 7											
ECRM =	0.499	0.622	0.746	0.869	0.992	1.116	1.239	1.363	1.486	1.609	1.733
D(ECRM) =	0.000	0.008	0.068	0.243	0.515	0.749	0.901	0.974	0.995	1.000	1.000

Figure 6-6. SSPS Market Penetration Model

$$ECR_{M1} = \frac{ECR_{01}(s) C_E}{C_{EF}(s,t,o)} ECIE(t,ig) \frac{ACR(o)}{FCR}$$

$$ECR_{M2} = \frac{ECR_{02}(s) C_T}{C_{TF}(s,t,o)} ECIT(t,ig) \frac{ACR(o)}{FCR}$$

where:

ECR_{M1}, ECR_{M2}

are modified ECRs for replacement and repowering modes corresponding to revised energy prices and capital equipment costs for a given SSPS size, installation year and ACR.

$ECR_{01}(s), ECR_{02}(s)$

are the original ECRs for replacement and repowering modes computed from the polynomial fits of SSPS optimization simulation outputs for an average insolation value, I , corresponding to state s , such that:

$$\begin{aligned} ECR_{01}(s) &= a_1 + b_1 I(s) + c_1 I^2(s); \\ ECR_{02}(s) &= a_2 + b_2 I(s) + c_2 I^2(s) \end{aligned}$$

where

a_1, b_1, c_1 , are the coefficients of polynomial fits for the replacement mode and a_2, b_2, c_2 , are the coefficients of polynomial fits for the repowering mode.

C_E, C_T

are annualized electric and thermal energy costs used in the original SSPS optimization model.

$C_{EF}(s,t,o), C_{TF}(s,t,o)$

are revised annualized electric and thermal energy prices for state, s , 30-year SSPS lifetime starting in the year, t , and type of ownership, o .

$ECIE(t,ig), ECIT(t,ig)$

are replacement and repowering mode capital cost modification factors for the SSPS installation year, t , and the turbine-generator size, ig .

$ACR(o), FCR$

are the SSPS annualized charge rate for type of ownership, o , and the fixed charge rate used in the SSPS optimization model.

Using the above set of equations and the various SSPS data inputs, individual plant ECRs are calculated for seven time periods (from 1985 to 2015 in five year increments). The SSUMM treats the individual plant ECR for each type of ownership and location as a median value around a certain distribution ECRM. The ECR is multiplied by each of the ECRM factors given in Table 6-11 for the particular state group corresponding to the given plant location. These products give the individual plant ECRM distribution, ECRM'. Each ECRM' value is linked to each D(ECRM) that was associated with the ECRM multiplying factor. For example, if the ECR were 1.5 for a utility unit in State Group Number = 1, the first part of this group tabulation would read:

ECRM' 0.822 0.979 1.137 1.293
D(ECRM) 0.000 0.003 0.031 0.154 and so on.

Then, by interpolation, the D(ECRM) corresponding to an ECRM' value of 1.0 gives the probability of that particular SSPS installation. Individual plant ECRM' values and their associated probability distributions are obtained for all seven time periods.

The SSPS Market Penetration Model calculates the market penetration of small power systems in the solar replacement and solar repowering modes. In calculating these separate replacement and repowering market penetrations, steam power plants are considered for commercialization in the repowering mode until their retirement age. Thereafter, they always stay candidates for replacement. Diesel power plants and gas turbine plants become candidates for replacement only after their retirement age, and their repowering probability is always zero. Thus, total replacement market penetration for diesel and gas turbine power plants is calculated by:

$$p_1 s_1 n_1 + p_2 s_2 n_2 + p_3 s_3 n_3 + \dots$$

where:

p_1, p_2, p_n are replacement probabilities at a given time period

s_1, s_2, s_n are plant capacity sizes

n_1, n_2, n_n are the number of power plants with plant capacity sizes s_1 , and s_2 , and s_n

Total repowering market penetration for steam power plants is calculated by:

$$n_1 s_1 p_{1r} + n_2 s_2 p_{2r} + n_3 s_3 p_{3r} + \dots$$

where p_{1r} , p_{2r} and p_{nr} are the associated repowering probabilities at a given time period.

Total replacement market penetration for steam power plants is calculated by:

$$(1-P_{1r}) n_1 s_1 p_1 + (1-P_{2r}) n_2 s_2 p_2 + (1-P_{3r}) n_3 s_3 p_3 + \dots$$

where P_{1r} , P_{2r} , and P_{nr} are the associated repowering probabilities at retirement age.

The computer program prints SSPS market penetration for replacement and repowering applications by state, type of ownership, and type of power plant. Figure 6-7 shows an example of the computer display for cumulative SSPS market penetration in repowering applications up to a given year. The incremental market penetrations for five-year time periods are displayed in a similar format.

The SSUMM also ranks various small power systems by solar adoption probability. This ranking is done individually for both solar replacement and solar repowering modes. Figure 6-8 shows an example of ranking for the repowering mode.

CUMULATIVE REPOWERING MARKET PENETRATION IN KW										
STATE ID	MUNICIPAL STEAM (FUEL OIL #6)	MUNICIPAL DIESEL	MUNICIPAL GAS	INVESTOR STEAM (FUEL OIL #6)	INVESTOR DIESEL	INVESTOR GAS	OTHER STEAM (FUEL OIL #6)	OTHER DIESEL	OTHER GAS	TOTAL
AL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AZ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FL	2.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.96
GA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HI	0.00	0.00	0.00	427.97	0.00	0.00	0.00	0.00	0.00	427.97
ID	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IL	16.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.58
IN	8.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.97
IA	219.99	0.00	0.00	0.00	0.00	0.00	89.71	0.00	0.00	309.70
KS	2108.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2108.08
KY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LA	12.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.62
ME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MD	13.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.57
MA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MI	22.34	0.00	0.00	0.00	0.00	0.00	1.04	0.00	0.00	23.38
MN	178.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	178.87
MS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MO	64.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.09
MT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NE	83.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.38
NV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NM	2069.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2069.63
NY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NC	0.00	0.00	0.00	0.00	0.00	0.00	5.39	0.00	0.00	5.39
ND	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OH	69.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	69.48
OK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RI	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TX	712.72	0.00	0.00	0.00	0.00	0.00	76.41	0.00	0.00	789.13
UT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WI	12.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.19
WY	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	5595.47	0.00	0.00	427.97	0.00	0.00	172.55	0.00	0.00	6196.00

Figure 6-7. Example of SSPS Cumulative Repowering Market Penetration by State

STATE	CITY	UTILITY	OWN	STATUS	NPLANT	NSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	6600	S	1962	.3136	2069.63
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT	M	0	1	10000	S	1957	.0885	884.68
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	10000	S	1957	.0885	884.68
KS	WELLINGTON	WELLINGTON MUNICIPAL UTILITIES	M	0	1	7500	S	1956	.0452	338.72
TX	GARLAND	GARLAND ELECTRIC DEPT.	M	0	2	8500	S	1957	.0419	712.72
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1958	.0308	231.29
NS	SCHUYLER	SCHUYLER DEPARTMENT OF UTILITIES	M	0	1	5000	S	1958	.0167	83.38
TX		TEXAS A&M UNIVERSITY	O	0	1	5000	S	1958	.0153	76.41
MN	HIBBING	HIBBING PUBLIC UTILITIES COMMISSION	M	0	1	10000	S	1965	.0134	133.54
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	2	5000	S	1965A	.0134	133.83
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	4925	S	1974	.0128	62.85
MO	FULTON	FULTON BOARD OF PUBLIC WORKS	M	0	1	6000	S	1959	.0107	64.09
IA	WEBSTER CITY	WEBSTER CITY MUNICIPAL LIGHT & POWER	M	0	1	7500	S	1960	.0094	70.16
IA	SPENCER	SPENCER MUNICIPAL UTILITIES	M	0	1	7500	S	1960	.0094	70.16
IA	MT. PLEASANT	MT. PLEASANT UTILITIES	M	0	1	7500	S	1966	.0094	70.16
IA		CENTRAL IOWA POWER COOPERATIVE	O	0	1	8000	S	1957	.0079	63.18
MN	WILLMAR	WILLMAR MUNICIPAL UTILITIES COMM.	M	0	1	7500	S	1956	.0045	33.80
IA		IOWA STATE UNIVERSITY	O	0	1	6000	S	1961	.0044	26.53
IA	ATLANTIC	ATLANTIC MUNICIPAL UTILITIES	M	0	1	5000	S	1958	.0019	9.52
OH	ST. MARY'S	ST. MARY'S MUNICIPAL LIGHT & POWER	M	0	1	10000	S	1967	.0017	16.68
MN	NEW ULM	NEW ULM PUBLIC UTILITIES COMMISSION	M	0	1	6000	S	1957	.0015	9.01
MI	GRAND HAVEN	GRAND HAVEN BOARD OF LIGHT & POWER	M	0	2	10000	S	1961	.0011	22.34
IL	WINNETKA	WINNETKA WATER & ELECTRIC DEPT.	M	0	1	10000	S	1960	.0011	11.07
OH	SHELLY	SHELLY MUNICIPAL ELECTRIC PLANT	M	0	1	7500	S	1956A	.0010	7.75
OH	PAINESVILLE	PAINESVILLE ELECTRIC DIVISION	M	0	2	7500	S	1956A	.0010	15.50
OH	ORVILLE	ORVILLE MUNICIPAL UTILITIES	M	0	1	7500	S	1956A	.0010	7.75
OH	COLUMBUS	COLUMBUS, DIVISION OF ELECTRICITY	M	0	1	7500	S	1956A	.0010	7.75
WI	MENASHA	MENASHA ELECTRIC & WATER UTILITIES	M	0	1	8975	S	1956	.0009	8.33
OH	COLUMBUS	COLUMBUS, DIVISION OF ELECTRICITY	M	0	1	7000	S	1956A	.0009	6.21
IN	WASHINGTON	WASHINGTON LIGHT & POWER DEPT.	M	0	2	5000	S	1957	.0009	8.97
MD	HAGERSTOWN	HAGERSTOWN MUNICIPAL ELECTRIC LIGHT PLAN	M	0	2	10000	S	1960A	.0007	13.57
OH	SHELLY	SHELLY MUNICIPAL ELECTRIC PLANT	M	0	1	6000	S	1956A	.0006	3.41
OH	ST. MARY'S	ST. MARY'S MUNICIPAL LIGHT & POWER	M	0	1	6000	S	1957	.0006	3.41
MN	SPRINGFIELD	SPRINGFIELD PUBLIC UTILITIES	M	0	1	4000	S	1960	.0006	2.53
IL	PERU	PERU LIGHT DEPT.	M	0	1	8000	S	1960	.0006	5.11
WI	RICHLAND	RICHLAND CENTER MUNICIPAL UTILITIES	M	0	1	7500	S	1966	.0005	3.86
NC		UNIVERSITY OF NORTH CAROLINA	O	0	1	10000	S	1961A	.0005	5.39
LA	MONROE	MONROE UTILITIES COMMISSION	M	0	3	7500	S	1955A	.0005	10.47
FL	KEY WEST	KEY WEST UTILITY BOARD	M	0	2	5000	S	1957A	.0003	2.96
OH	ORVILLE	ORVILLE MUNICIPAL UTILITIES	M	0	1	5000	S	1956A	.0002	1.02
MI		MICHIGAN STATE UNIVERSITY	O	0	1	6000	S	1958	.0002	1.04
LA	NATCHITOCHES	NATCHITOCHES MUNICIPAL ELECTRIC LIGHT &	M	0	1	6250	S	1962	.0001	.66
LA	MORGAN CITY	MORGAN CITY MUNICIPAL ELECTRIC PLANTS	M	0	2	6250	S	1963	.0001	1.32
IL	HIGHLAND	HIGHLAND ELECTRIC LIGHT DEPT.	M	0	1	6000	S	1961	.0001	.40
LA	MONROE	MONROE UTILITIES COMMISSION	M	0	1	6000	S	1955A	0.0000	.16

Figure 6-8. Example of Individual Utility Plant Rankings
Based on SSPS Repowering Mode Adoption Probability

6.4 SSIMM METHODOLOGY AND MODEL DESCRIPTION

The Small Solar Industrial Market Model (SSIMM) follows the general outline of the functional relationships illustrated in Figure 6-6 for SSUMM. The SSIMM uses the industry data base discussed in Section 4, a portion of which was depicted in Figure 6-4. This industrial data base does not have individual plant installation dates and, thus, cannot be used for combined assessment of SSPS replacement and repowering market penetration. Consequently, market penetration was first determined for the replacement mode by assuming, that for each possible SSPS installation year, the lifetime was exhausted for each conventional power system. Conversely, an alternative market penetration assessment for the repowering mode was made by assuming that the lifetime of conventional steam power systems was not completed in any year of potential SSPS installation.

Except for the above variations, the general structure of the SSIMM computer model is very similar to the SSUMM computer model. For example, the SSIMM and SSUMM computer models take into account the effects of different annualized thermal and electric energy costs which are a function of state, SSPS year of installation, and type of ownership. However, the SSIMM model uses the ACR and annualized unit energy prices that correspond to the financial status of the industrial sector and the federally-operated facilities. Effects of various types of ownerships are considered by calculating appropriate ACRs. Effects of varying capital equipment costs for different SSPS sizes and installation times are also considered using the ECR modifying matrices. Similarly, with the help of the Monte Carlo simulation, individual industrial plant ECRM distributions are obtained that are representative of the industrial sector variations of ACR and annualized unit energy prices.

These individual plant ECRM' values and their associated penetration probabilities are calculated in two separate ways, namely, (a) when all industrial plants are candidates for replacement and (b) when all steam plants are candidates for repowering and all non-steam plants are candidates

for replacement. The resulting cumulative and incremental SSPS industrial market penetrations are obtained in a manner similar to that described for SSUMM in Section 6.3.

The SSIMM computer model also ranks various industrial small power plants by solar adoption probability. The computer prints results for SSPS market penetration and adoption probability in formats identical to that for SSUMM as was illustrated in Figures 6-7 and 6-8.

7.0 RESULTS OF THE 10-MW_e SMALL SOLAR POWER SYSTEMS OPTIMIZATION ANALYSIS

The computerized simulation program used to determine SSPS performance (described in Section 6.2.5) also permits modification of the major subsystems of the model to simulate different sizes and operational characteristics of collectors, turbines, and storage subsystems. The SSPS simulation program outputs several technical and economic parameters on a daily, yearly, and plant life-cycle basis. Some of the important parameters are equivalent cost ratio (ECR), capacity factor (CF), and system capital cost (SCC).

7.1 METHODOLOGY

Performance analysis of the alternate SSPS hardware involves parametrically changing the sizes of the collector field and thermal storage. The optimization criterion is to achieve a minimum ECR. In many instances, several different SSPS hardware combinations gave approximately the same minimum ECR. In these cases, the optimum system was selected on the basis of maximum capacity factor or fuel displacement.

The expected cost of the major subsystems for a 10 MW_e central receiver-type solar system installed in the year 1990 was used as the baseline input to the SSPS optimization computer program. These costs along with other major input assumptions used in the simulation model for the base case are given in Table 7-1. All four cost elements, i.e., collector subsystem, receiver-tower subsystem, storage subsystem, and balance of plant, were used in the solar replacement mode. The balance of plant cost was deleted when evaluating the solar repowering mode. The optimization program was used to calculate values of minimum ECR for SSPS installations at the following five geographic locations: Los Angeles, CA; Columbia, MO; Albuquerque, NM; Blue Hill, MA; and Inyokern, CA.

Each minimum ECR was then plotted versus the average daily-direct insolation corresponding to each location. Corresponding values for CF and

SCC were also plotted versus insolation. Correlations were developed which enabled ECR, CF, and SCC to be expressed as mathematical functions of insolation. These relationships permitted the determination of SSPS relative cost and performance factors for an operational 10 MW_e plant at any given location in the year 1990 without resorting to repeated computer optimization runs.

Table 7-1. Baseline Assumptions for 10 MW_e SSPS Simulation

10 MW _e SSPS Replacement or Repowering Unit	
Collector Subsystem Cost	\$10.8/ft ²
Receiver-Tower Subsystem Cost	\$2.8/ft ²
Storage Subsystem Cost	\$4620/MBtu
Balance of Plant Cost	\$936/kW _e
Levelized Electric Energy Rate	70 mills/kWh
Levelized Thermal Energy Rate	\$5/MBtu
Storage Efficiency (hourly)	0.998
Conventional Boiler Efficiency	0.80
Plant Life for SSPS	30 years
Power Generation Efficiency	27.5%
Fixed Charge Rate	8%

7.2 RESULTS OF ANALYSIS

Each of the optimized results for ECR at a given location was obtained by making 100 to 200 changes in the parametric values assigned to each of the subsystems. Figure 7-1 shows a carpet plot of ECR based on

Figure 7-1. Operating Economics as a Function of Subsystem Sizing for a $10 MW_e$ SSPS

combinations of SSPS collector size and high-temperature storage capacity, using the assumptions listed in Table 7-1. It should be noted that optimum SSPS plant configurations for the replacement mode were different from those for the repowering mode.

Optimization results for a 10 MW_e SSPS baseline plant are plotted in Figures 7-2, 7-3, and 7-4 as a function of average daily-direct insolation, I, for the following relationships:

- Replacement equivalent cost ratio
- Replacement capacity factor
- Replacement system capital cost
- Repowering equivalent cost ratio
- Repowering capacity factor
- Repowering system capital cost

Correlations of these results were developed by using a polynomial data fit program that computed the coefficients for a second degree curve. Table 7-2 gives the various polynomial coefficients for the solar replacement and repowering modes that relate to a 10 MW_e SSPS for installation in the year 1990 at any location with average daily direct insolation, I.

Figure 7-2. ECR as a Function of Insolation for SSPS

Figure 7-3. Capacity Factor (CF) as a Function of Insolation for SSPS

Figure 7-4. System Capital Cost (SCC) as a Function of Insolation for SSPS

Table 7-2. Polynomial Coefficients for SSPS Relative Cost and Performance Relationships (Base Case)

Polynomial Coefficients for Replacement Mode

$$X = A + BI + CI^2$$

X	A	B	C
ECR	2.55	-0.39	0.02
CF	15.39	8.50	-0.21
SCC	56.94	-3.03	0.12

Polynomial Coefficients for Repowering Mode

$$Y = A + BI + CI^2$$

Y	A	B	C
ECR	2.43	-0.39	0.02
CF	8.35	5.42	-0.20
SCC	23.57	-1.10	0.01

8.0 RESULTS OF UTILITY MARKET PENETRATION ANALYSIS

8.1 INTRODUCTION

The utility market being analyzed for penetration by small solar power systems (SSPS) has been described previously in Section 3. The 3856 small electric generating units, totalling 7930 MW_e nationwide, range in size up to 10 MW_e. This market consists of steam turbine, gas turbine, and diesel power drive units operated by investor-owned utilities, municipal utilities, and electrical cooperatives throughout the U.S. At any point in time, the estimated market penetration is a complex function of many variables, either those inherent to known market characteristics or those selected on the basis of judgement. The influence of market characteristic variables on penetration is discussed herein, and the baseline values for judgement-type variables are defined.

Because the larger size SSPS have lower unit costs in dollars per kW_e (see Section 5), these would be expected to contribute to the earliest penetration. However, geographic location, as measured by the level of insolation, is also a factor; for a fixed system rated capacity in MW_e, higher insolation results in a smaller, lower cost installation for a SSPS.

Geographic location has an additional impact on market penetration in the form of projected costs for fuel and electric power, since increases in these cost elements will offset higher solar system capital costs. Regions with higher fuel and electric power costs result in smaller solar power systems being cost effective at an earlier installation date. Indeed, the estimated decline in SSPS capital costs with time, as described in Section 5, together with projected increases in fuel and electric power costs combine to improve the future competitive economic prospects for SSPS.

As noted in Section 6, one of the competitive economic scenarios selected for use in the market penetration analysis assumes that, if a solar system is not installed, the utility's conventional power unit will be consuming fossil fuels throughout a period of time equal to the lifetime of

the solar system that could have been introduced as a repowering unit. Hence, to make a choice, the solar system lifetime cost (including capital cost and present value of operations/maintenance costs, and taxes, if applicable) is compared with the present value of fuel costs summed over an equivalent period of time.

The other scenario relates to the situation when the expected lifetime of a conventional power unit has been exceeded and consideration must be given to the alternatives of replacing the entire unit with SSPS or purchasing electric power from a major utility grid system. To make a choice in this case, the replacement solar power unit lifetime costs must be compared with the present value of purchased electric power costs (aggregated over the solar power unit lifetime). It is emphasized that this form of analysis applies only to utility choices concerning existing power units. If a utility is contemplating facility expansion by adding additional generating capacity, the capital cost, operations costs, and maintenance costs of conventional power units must then be added to the fossil-fuel costs before making a comparison with SSPS.

The type of utility ownership is also a factor in market penetration because of the influence of taxes or relative cost of utility operations and because of the differing costs in acquiring funds for capital equipment projects, e.g., investor-owned utilities are credited with an investment tax credit of 10 percent against the cost of purchasing a SSPS, while municipals and cooperatives are not. These considerations have been taken into account in the development of the Annualized Cost Rate (ACR) for each type of utility as described in Section 6.

Those variables subject to some judgement when selecting values are: (1) conventional power unit lifetime, (2) SSPS lifetime, (3) SSPS operations and maintenance costs, (4) SSPS capital costs, and (5) projected costs for utility purchases of fuel or electric power. The lifetime for conventional power units is assumed to be 40 years. This period is based on discussions with a few utilities and the fact that, within the data base, a number of

generating units have been in operation over 40 years. On the basis of previous Aerospace Corporation analyses and analyses carried out by others under government contract, the lifetime for SSPS is assumed to be 30 years. Annual operations and maintenance costs for SSPS are assumed to be equal to two percent of the system installed capital cost, regardless of type of ownership or geographic location. Baseline capital costs for SSPS are those given in Section 5, but modified in accordance with the rules given in Section 6 to account for the influence of system size, installation location, and year of installation. Annual fuel* and purchased electric power costs are based on the costs projected by Sherman H. Clark, as discussed in Section 6. However, it should be noted that these costs, as well as annual operations/maintenance cost and annual taxes, when aggregated over the SSPS lifetime and put in terms of present value, reflect the influence of the different discount rates associated with each type of utility ownership. Values for these discount rates are also included in Section 6.

In the succeeding sections, market penetration is discussed for baseline central receiver-type SSPS installations analyzed at each five-year interval during the period 1985 to 2015. Those regions of the country where penetration is likely to occur are noted, and individual utilities with a high probability of penetration are highlighted. The estimated influence on market penetration of deviations from assumed baseline values is discussed in Section 12.

8.2 NATIONWIDE CUMULATIVE MARKET PENETRATION BY SSPS

Calculations made with the SSUMM computer program result in estimates of the cumulative market penetration by SSPS during the period 1985 to 2015. In Figure 8-1, market penetration has been isolated for each type of power unit and ownership as a percent of the total available market in each category. (The available market by category is given in Section 3,

* No. 6 fuel oil was assumed to be used for all utility power units.

Figure 8-1. SSPS Percent Penetration of Utility Market

Table 3-2.) In terms of type of ownership, municipal and cooperative utilities capture a larger percent of their available market (5485 MW_e) than the investor-owned utilities with an available market of 2445 MW_e. When considering the type of power unit, steam turbines capture a much greater share of their 2958 MW_e available market than diesels and gas turbines with a combined available market of 4972 MW_e.

Under the baseline scenario, the prospects of solar thermal units capturing a significant portion of the total market in 1985 are not encouraging. Indeed, even as late as 2015, only 14 percent of the available market is susceptible to penetration. Obviously, some forms of incentive are required to alter this picture. Suggested forms of incentive and their potential impact on market penetration are discussed in Section 12.

An alternative to the presentation of cumulative market penetration as a percent of the total available market is to show the megawatts of conventional unit capacity displaced by replacement SSPS units and by repowering SSPS units. Each of these categories in turn has been segregated by type of utility ownership and by type of power unit as presented in Figures 8-2 and 8-3, respectively. Repowering applications are favored in the early years, but replacement applications become more important beyond the year 2000. Very little penetration is shown for the repowering category after 2000 because the 40-year lifetime of most of the conventional steam turbine generating units will have been exceeded (Section 3.2), which then requires that the balance of this type of generating unit be shifted into the replacement category.

Municipal utilities and cooperatives account for more than 75 percent of market penetration throughout the 30-year period analyzed. Although less than 25 MW_e of capacity is displaced in all categories in 1985, market penetration increases rapidly to 145 MW_e in 1990, to over 400 MW_e in 2000, and to 1140 MW_e in 2015.

Steam turbines account for almost all of the displaced capacity when type of power unit is considered. Although steam turbine units are the only

Figure 8-2. SSPS Capacity Penetration of Utility Market
(Division by Type of Utility Ownership)

Figure 8-3. SSPS Capacity Penetration of Utility Market
(Division by Type of Power Unit)

available market for repowering applications, they are also the dominant fraction of the market for replacement applications, particularly in the early years. Even out to the year 2015, 60 percent of the replacement applications are expected to be found in steam turbines.

8.3 GEOGRAPHIC DISTRIBUTION OF SSPS MARKET PENETRATION

8.3.1 Inherent Regional Characteristics

Before proceeding to discuss those regions where SSPS market penetration is projected to occur, it is of value to note the geographic distribution of some major influencing factors. The largest penetration of the utility market by solar power systems would be expected to occur in regions with the highest insolation and highest fuel (or electric power) prices, and largest amount of generating capacity. The highest probability of penetration would be expected for large size units in states with the aforementioned characteristics.

Relative levels of mean daily-direct insolation are shown in Figure 8-4. High insolation levels extend from Texas north through the Midwest and West into five states of the Mountain Region. Very high insolation levels are found in five states: Arizona, California, Hawaii, Nevada, and New Mexico.

An example of statewide ranking of 1995 prices for fuel oil is given in Figure 8-5. High fuel oil prices are projected for states scattered throughout the U.S. with little apparent regionality shown. Very high prices are expected for Delaware, Iowa, Minnesota, New Jersey, New Mexico and three states clustered about the Great Lakes.

A similar example of statewide ranking of levelized electric power prices is given for 1995 in Figure 8-6. High electric power prices are projected for Florida, Nebraska, North Carolina, Rhode Island and five states bordering the Great Lakes. Very high prices are shown for Delaware, Iowa, Missouri, West Virginia, and six of the nine Middle Atlantic and New England States.

Figure 8-4. Daily Direct Insolation (kWh/m^2)

Figure 8-5. Annualized Fuel Oil Prices for 1955

Figure 8-6. Annualized Electric Power Prices for 1995

The nationwide distribution of aggregate capacity for small electric generating units in utilities was discussed previously in Section 3.1. Outside of Texas, those states with the highest concentration of power unit capacity generally lie in the East North Central and West North Central Regions.

8.3.2 States Leading in SSPS Market Penetration

The analysis results identify those states expected to have the largest cumulative installed capacity of SSPS during the 30-year period from 1985 to 2015. Those states leading in the repowering category are: Hawaii, Iowa, Kansas, Minnesota, Nebraska, New Mexico, and Texas. In the replacement category, leading states are: Arizona, California, Hawaii, Iowa, Kansas, Missouri, and Nebraska. Kansas and New Mexico consistently show the most repowering over this time period while, for replacement, Arizona, Hawaii, Kansas, and Missouri achieve the top positions at different times.

8.3.3 Regionality of Highly Probable SSPS Installations

Figures 8-7 through 8-13 show the number of SSPS installations and the aggregate size of generating units in those states where the probability of installation is predicted to be greater than 50 percent during the period 1990 to 2015. At this level of probability, there is a reasonable expectation that the identified generating units could be repowered or replaced by SSPS in the early years of market penetration.

Figures 8-7 through 8-10 show results for repowering applications. The first SSPS utility installations are projected to occur in 1990 in Hawaii, Kansas, and New Mexico and total 61 MW_e. By 1995, Nebraska and Texas have been added to the list. By 2000, Iowa and Minnesota have been included in the combined national repowering installations that have doubled to 123 MW_e in the intervening ten years. As noted in Section 8.2, by this time most of the conventional steam turbine generating units have exceeded their 40-year lifetime and have been, therefore, shifted from the

Penetration Probability > 50%

Figure 8-7. Location of Repowering Units in 1990

Figure 8-8. Location of Repowering Units in 1995

Figure 8-9. Location of Repowering Units in 2000

Figure 8-10. Location of Repowering Units in 2015

repowering category to the replacement category. As a result, no further repowering is anticipated for the succeeding 15 years so that the installations in 2015 are the same as in 2000.

Figures 8-11 through 8-13 show results for replacement applications. The first utility installations are not expected until 1995 when four units totalling 30 MW_e are projected for Arizona, and one unit of 8 MW_e is projected for Hawaii. By 2000, 20 MW_e in California is expected along with a small growth in the number of units in Arizona and Hawaii. A major growth in installations is expected in the succeeding 15 years. By 2015, ten states in the West North Central, Mountain, and Pacific Regions could have installations totalling 430 MW_e.

8.4 RANKING OF UTILITY UNITS WITH GREATEST POTENTIAL FOR PENETRATION BY SSPS

As noted in Section 6, the SSUMM computer program determines the probability of penetration for each electric utility generating unit contained in the data base. Subroutines in the computer program permit the ranking of each utility unit in order of decreasing probability for either replacement or repowering modes; this was accomplished for each of the seven installation periods spaced every five years from 1985 to 2015. Primary interest is focussed on identification of utility units with the highest probability of penetration in the near-term, i.e., SSPS installations in 1985, 1990, and 1995. Abbreviated lists of such units are given in Tables 8-1 through 8-6 for probable replacement and repowering installations. A cumulative year-to-year accounting procedure keeps track of all units in a given category (repowering or replacement) as the probability of penetration increases. The accounting procedure tags those units that have been penetrated in a given year and also tracks the transfer from the repowering category to the replacement category when penetration is not predicted within the 40-year lifetime of the conventional, fossil-fueled unit.

Figure 8-11. Location of Replacement Units in 1995

Figure 8-12. Location of Replacement Units in 2000

Figure 8-13. Location of Replacement Units in 2015

Table 8-1 shows only five utilities with potential for penetration by SSPS replacement units in 1985. Because of the assumed 40-year lifetime, only those units installed prior to 1945 could be considered for replacement. The probability levels in each case are very low and, therefore, there is little likelihood of penetration in replacement modes that year. Note that the listed units are quite large, ranging in size from 5 to 10 megawatts. All types of utilities and generating systems are represented. Surprisingly, two generating units in Massachusetts are given in the ranking. The low insolation in that state evidently must be counterbalanced by the projection of very high prices for purchased electric power (the competing alternative for the SSPS replacement mode).

A much more extensive listing of utilities is given in Table 8-2 for SSPS repowering in 1985. These units are, of course, all steam turbines. Municipal utilities are at the head of the list. Penetration probabilities for the first few units are large enough to suggest that these utility units in New Mexico be subjected to further detailed analysis. The leading candidates are found to be large size units in geographic regions with high levels of insolation (See Figure 8-4, Section 8.3). Because the majority of units have very low probabilities and the results are, therefore, of lesser importance, only one-third of the total repowering penetration potential is shown.

For the replacement case, utility units with penetration probability exceeding 0.05 in 1990 are shown in Table 8-3. This accounts for only four utilities being listed; all others have probabilities less than 0.05. The penetration probability has increased markedly from 1985 and some significance can now be attributed to these results. In addition, the ranking order has changed slightly; this change could be attributed to the state-to-state variations in projected costs of purchased electric power.

Table 8-4 shows the repowering probability for possible SSPS installations in 1990. As noted for the replacement case, the penetration probabilities are much higher in 1990 than in 1985. Also, as noted previously, there are a number of changes in order of ranking, but leading

Table 8-1. Individual Utility Plant Rankings for SSPS Replacement Applications in 1985

POWER PLANTS WITH REPLACEMENT PROBABILITY GREATER THAN 0.00 IN 1985.

STATE	CITY	UTILITY	OWN	STATUS	NPLANT	NSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
HI		HAWAIIAN ELECTRIC CO., INC.	I	D	1	7500	S	1938	.0246	184.13
CA	BURBANK	BURBANK PUBLIC SERVICE DEPT.	M	D	1	10000	S	1943	.0077	77.50
CA	BURBANK	BURBANK PUBLIC SERVICE DEPT.	M	D	1	10000	S	1941	.0077	77.50
AZ		SALT RIVER PROJECT AGRICULTURAL DISTRICT	O	D	4	7500	S	1941	.0046	137.24
AZ		ARIZONA ELECTRIC POWER COOPERATIVE, INC.	O	D	1	5000	D	1942A	.0007	3.42
MA	HOLYOKE	HOLYOKE GAS & ELECTRIC DEPT.	M	D	1	10000	G	1941	0.0000	.09
MA	HOLYOKE	HOLYOKE GAS & ELECTRIC DEPT.	M	D	1	10000	S	1934	0.0000	.09

Table 8-2. Individual Utility Plant Rankings for SSPS Repowering Applications in 1985

POWER PLANTS WITH REPOWERING PROBABILITY GREATER THAN 0.00 IN 1985.

STATE	CITY	UTILITY	OWN	STATUS	NPLANT	NSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
NM	FARMINGTON	FARMINGTON ELECTRIC UTILITY	M	0	1	7500	S	1951A	.3740	2805.31
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	6600	S	1962	.3136	2069.63
NM	FARMINGTON	FARMINGTON ELECTRIC UTILITY	M	0	2	4000	S	1951A	.1151	920.43
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	3600	S	1952	.0983	353.77
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	10000	S	1957	.0885	684.68
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	10000	S	1957	.0835	684.68
KS	CHANUTE	CHANUTE MUNICIPAL ELECTRIC DEPT.	M	0	1	10000	S	1947A	.0885	684.68
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1953	.0755	566.15
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1955	.0755	566.15
NM		SOUTHWESTERN PUBLIC SERVICE	I	0	1	7500	S	1946	.0664	498.03
OK	STILLWATER	STILLWATER ELECTRIC DEPT.	M	0	1	10000	S	1950A	.0599	598.76
KS	LARNED	LARNED ELECTRIC LIGHT DEPT.	M	0	1	8260	S	1947A	.0594	490.55
UT	PROVO	PROVO CITY UTILITY DEPT.	M	0	1	7500	S	1950	.0580	434.83
NM		PUBLIC SERVICE OF NEW MEXICO	I	0	1	6500	S	1949	.0514	334.17
NM		PUBLIC SERVICE OF NEW MEXICO	I	0	1	6500	S	1949	.0514	334.17
NM		PUBLIC SERVICE OF NEW MEXICO	I	0	1	6500	S	1951	.0514	334.17
NE		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1955	.0510	433.16
NE		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1952	.0510	433.16
NE	GRAND ISLAND	GRAND ISLAND ELECTRIC DEPT.	M	0	1	7500	S	1950	.0497	372.93
NE	ALLIANCE	ALLIANCE MUNICIPAL UTILITIES	M	0	1	7500	S	1952A	.0497	372.93
KS	WELLINGTON	WELLINGTON MUNICIPAL UTILITIES	M	0	1	7500	S	1956	.0452	338.72
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	7500	S	1950	.0452	338.72
TX	GARLAND	GARLAND ELECTRIC DEPT.	M	0	2	8500	S	1957	.0419	712.72
KS		SUNFLOWER ELECTRIC COOPERATIVE, INC.	O	0	1	8000	S	1954	.0386	308.76
CO	LAMAR	LAMAR UTILITIES BOARD	M	0	1	5000	S	1952	.0350	174.94
NM		PUBLIC SERVICE OF NEW MEXICO	I	0	1	5500	S	1951A	.0345	189.71
MO	HANNIBAL	HANNIBAL BOARD OF PUBLIC WORKS	M	1	1	10000	S	1951	.0324	323.82
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	2	5000	S	1965A	.0233	232.59
NE	HASTINGS	HASTINGS UTILITIES DEPT.	M	1	1	6000	S	1950	.0227	136.29
NE	HASTINGS	HASTINGS UTILITIES DEPT.	M	1	1	6000	S	1948	.0227	136.29
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	4925	S	1974	.0226	111.53
CO		PUBLIC SERVICE CO. OF COLORADO	I	0	1	9375	S	1953	.0209	195.60
CO		CENTRAL TELEPHONE & UTILITIES CORP.	I	0	1	9000	S	1951	.0186	167.32
MO	COLUMBIA	COLUMBIA WATER & LIGHT DEPT.	M	0	1	7500	S	1947	.0177	132.56
NE		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	5600	S	1947	.0174	97.26
CO	TRINIDAD	TRINIDAD MUNICIPAL POWER & LIGHT DEPT.	M	0	2	3750	S	1950	.0173	129.93
NE	SCHUYLER	SCHUYLER DEPARTMENT OF UTILITIES	M	0	1	5000	S	1953	.0167	83.30
NE	FREMONT	FREMONT DEPT. OF UTILITIES	M	0	1	5000	S	1946	.0167	83.33
NE	ALLIANCE	ALLIANCE MUNICIPAL UTILITIES	M	0	1	5000	S	1952A	.0167	83.33
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	5000	S	1952	.0167	83.69

Table 8-3. Individual Utility Plant Rankings for SSPS Replacement Applications in 1990

POWER PLANTS WITH REPLACEMENT PROBABILITY GREATER THAN .05 IN 1990.

STATE	CITY	UTILITY	OWN	STATUS	NPLANT	NSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1938	.3820	2365.18
AZ		SALT RIVER PROJECT AGRICULTURAL DISTRICT	O	0	4	7500	S	1941	.1618	4355.45
CA	BURBANK	BURBANK PUBLIC SERVICE DEPT.	M	0	1	10000	S	1943	.1212	1211.61
CA	BURBANK	BURBANK PUBLIC SERVICE DEPT.	M	0	1	10000	S	1941	.1212	1211.61
AZ		ARIZONA ELECTRIC POWER COOPERATIVE, INC.	O	0	1	5000	D	1942A	.0509	254.31

Table 8-4. Individual Utility Plant Rankings for SSPS Repowering Applications in 1990

POWER PLANTS WITH REPOWERING PROBABILITY GREATER THAN .05 IN 1990.

STATE	CITY	UTILITY	OWN	STATUS	NPLANT	NSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
NM	FARMINGTON	FARMINGTON ELECTRIC UTILITY	M	0	1	7500	S	1951A	.9119	6839.43
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	6600	S	1962	.8833	5829.99
NM	FARMINGTON	FARMINGTON ELECTRIC UTILITY	M	0	2	4000	S	1951A	.6478	5182.09
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	3600	S	1952	.5813	2092.78
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	10000	S	1957	.5609	5609.24
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	10000	S	1957	.5609	5609.24
NE		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1955	.4907	4171.19
NE		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1952	.4907	4171.19
OK	STILLWATER	STILLWATER ELECTRIC DEPT.	M	0	1	10000	S	1950A	.4605	4605.09
KS		SUNFLOWER ELECTRIC COOPERATIVE, INC.	O	0	1	8000	S	1954	.4202	3361.89
ND	ALLIANCE	ALLIANCE MUNICIPAL UTILITIES	M	0	1	7500	S	1952A	.4162	3121.79
KS	WELLINGTON	WELLINGTON MUNICIPAL UTILITIES	M	0	1	7500	S	1956	.3884	2913.07
CO	LAMAR	LAMAR UTILITIES BOARD	M	0	1	5000	S	1952	.3566	1783.12
MO	HANNIBAL	HANNIBAL BOARD OF PUBLIC WORKS	M	1	1	10000	S	1951	.3375	3375.11
TX	GARLAND	GARLAND ELECTRIC DEPT.	M	0	2	8500	S	1957	.3260	5541.22
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1958	.2561	1920.42
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1955	.2561	1920.42
NE	SCHUYLER	SCHUYLER DEPARTMENT OF UTILITIES	M	0	1	5000	S	1958	.2230	1115.10
NE	ALLIANCE	ALLIANCE MUNICIPAL UTILITIES	M	0	1	5000	S	1952A	.2230	1115.10
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	5000	S	1952	.2054	1026.80
NM		PUBLIC SERVICE OF NEW MEXICO	I	0	1	6500	S	1951	.1845	1199.42
MO		NORTHEAST MISSOURI ELECTRIC POWER CCOP.	O	0	1	7500	S	1953	.1815	1361.36
MO		NORTHEAST MISSOURI ELECTRIC POWER CCOP.	O	0	1	7500	S	1952	.1815	1361.36
MN	WORTHINGTON	WORTHINGTON MUNICIPAL PUBLIC UTILITIES	M	0	1	10000	S	1952	.1755	1755.21
MN	HIBBING	HIBBING PUBLIC UTILITIES COMMISSION	M	0	1	10000	S	1955	.1755	1755.21
IA		CENTRAL IOWA POWER COOPERATIVE	O	0	1	8000	S	1957	.1630	1304.24
IA		CENTRAL IOWA POWER COOPERATIVE	O	0	2	8000	S	1951	.1630	2608.48

utilities are still found in areas of high insolation. The aggregate size of units having probabilities greater than 50 percent is about 61 MW_e. This matches the data presented previously in Section 8.3 (See Figure 8-9).

As seen in Table 8-5, replacement probabilities have become quite high for the leading candidates in 1995. The ranking of utilities has changed somewhat because some previous candidates for repowering have exceeded the assigned 40-year lifetime and are now subject to consideration as replacement candidates.

Utility small generating units susceptible to penetration by SSPS repowering units in 1995 are ranked in Table 8-6. Very high penetration probabilities are shown for a large number of utility units. The rank of individual utilities has changed somewhat. Part of this change may be due to state-to-state variations in projected fuel costs. Other alterations in rank are attributable to those utility units that are predicted to have been repowered previously by SSPS and, hence, their probability remains fixed in time thereafter. This is done to avoid multiple counting of kilowatts penetrated (the far right hand column) when cumulative penetration is being calculated. Leading candidates for penetration are still the larger size units located in geographic regions with high insolation, but appearing further down on the list are 10 MW_e units in areas of medium insolation (Iowa and Minnesota) and even low insolation (Ohio).

The reader is cautioned that these results are preliminary in nature. Although the aggregate megawatts of market penetration given in Section 8.2 is a reasonable estimate for the future nationwide potential SSPS market, the penetration probability for each individual generating unit may increase or decrease significantly from the values shown in this section when more detailed operating information for specific utilities is included in the data base. Indeed, the present function of the list is only to identify those utilities to be considered for personal interviews wherein their particular operational and economic factors can be defined and used subsequently in a reassessment of their penetration probabilities.

Table 8-5. Individual Utility Plant Rankings for SSPS Replacement Applications in 1995

POWER PLANTS WITH REPLACEMENT PROBABILITY GREATER THAN .05 IN 1995.

STATE	CITY	UTILITY	OWN	STATUS	PLANT	SIZE (KW)	TYPE	YEAR	PROB	PEN (KW)
AZ		SALT RIVER PROJECT AGRICULTURAL DISTRICT	O	0	4	7500	S	1941	.6003	18009.20
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1938	.4839	3629.55
CA	BURBANK	BURBANK PUBLIC SERVICE DEPT.	M	0	1	10000	S	1943	.3934	3933.59
CA	BURBANK	BURBANK PUBLIC SERVICE DEPT.	M	0	1	10000	S	1941	.3934	3933.59
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1955	.3600	2700.18
AZ		ARIZONA ELECTRIC POWER COOPERATIVE, INC.	O	0	1	5000	D	1942A	.3356	1677.87
AZ		ARIZONA ELECTRIC POWER COOPERATIVE, INC.	O	0	1	4000	D	1942A	.2042	816.80
KS	CHANUTE	CHANUTE MUNICIPAL ELECTRIC DEPT.	M	0	1	10000	S	1947A	.1906	1905.97
KS	LARNED	LARNED ELECTRIC LIGHT DEPT.	M	0	1	8260	S	1947A	.1153	952.78
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	3500	S	1951	.1045	365.67
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	7500	S	1950	.1004	752.71
NB	GRAND ISLAND	GRAND ISLAND ELECTRIC DEPT.	M	0	1	7500	S	1950	.0936	702.04
OK	STILLWATER	STILLWATER ELECTRIC DEPT.	M	0	1	10000	S	1950A	.0927	926.94
UT	PROVO	PROVO CITY UTILITY DEPT.	M	0	1	7500	S	1950	.0808	606.19
KS	LARNED	LARNED ELECTRIC LIGHT DEPT.	M	0	1	6450	D	1947A	.0790	509.49
NM	TUCUMCARI	TUCUMCARI LIGHT & POWER DEPT.	M	0	1	4100	D	1951A	.0755	309.40
NB	LINCOLN	LINCOLN ELECTRIC SYSTEM	M	0	1	6500	S	1929	.0730	474.76
MO	HANNIBAL	HANNIBAL BOARD OF PUBLIC WORKS	M	1	1	10000	S	1951	.0675	674.60
KS		SUNFLOWER ELECTRIC COOPERATIVE, INC.	O	0	1	8000	S	1954	.0669	535.59
NB		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1955	.0661	562.25
ND		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1952	.0661	562.25
NB	HASTINGS	HASTINGS UTILITIES DEPT.	M	1	1	6000	S	1950	.0578	347.01
NB	HASTINGS	HASTINGS UTILITIES DEPT.	M	1	1	6000	S	1948	.0578	347.01
NB	ALLIANCE	ALLIANCE MUNICIPAL UTILITIES	M	0	1	7500	S	1952A	.0575	431.27
MO	HANNIBAL	HANNIBAL BOARD OF PUBLIC WORKS	M	1	1	7500	S	1936	.0530	397.85
MO	COLUMBIA	COLUMBIA WATER & LIGHT DEPT.	M	0	1	7500	S	1947	.0521	390.82

Table 8-6. Individual Utility Plant Rankings for SSPS Repowering Applications in 1995

POWER PLANTS WITH REPOWERING PROBABILITY GREATER THAN .05 IN 1995.

TATE	CITY	UTILITY	OWN	STATUS	NPLANT	NSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	6600	S	1962	.9825	6484.21
NM	FARMINGTON	FARMINGTON ELECTRIC UTILITY	M	0	1	7500	S	1951A	.9119	6839.43
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	10000	S	1957	.8687	8686.77
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	10000	S	1957	.8687	8686.77
KS	WELLINGTON	WELLINGTON MUNICIPAL UTILITIES	M	0	1	7500	S	1956	.7280	5460.19
NM	FARMINGTON	FARMINGTON ELECTRIC UTILITY	M	0	2	4000	S	1951A	.6478	5182.09
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1958	.5993	4494.92
TX	GARLAND	GARLAND ELECTRIC DEPT.	M	0	2	8500	S	1957	.5813	9881.56
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	3600	S	1952	.5813	2092.78
NB	SCHUYLER	SCHUYLER DEPARTMENT OF UTILITIES	M	0	1	5000	S	1958	.5237	2618.42
NB		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1955	.4907	4171.19
NB		NEBRASKA PUBLIC POWER DISTRICT	O	1	1	8500	S	1952	.4907	4171.19
OK	STILLWATER	STILLWATER ELECTRIC DEPT.	M	0	1	10000	S	1950A	.4605	4605.09
MN	HIBBING	HIBBING PUBLIC UTILITIES COMMISSION	M	0	1	10000	S	1965	.4528	4528.39
IA		CENTRAL IOWA POWER COOPERATIVE	O	0	1	8000	S	1957	.4475	3580.16
KS		SUNFLOWER ELECTRIC COOPERATIVE, INC.	O	0	1	8000	S	1954	.4202	3361.89
NB	ALLIANCE	ALLIANCE MUNICIPAL UTILITIES	M	0	1	7500	S	1952A	.4162	3121.79
IA	WEBSTER CITY	WEBSTER CITY MUNICIPAL LIGHT & POWER	M	0	1	7500	S	1960	.4063	3047.39
IA	SPENCER	SPENCER MUNICIPAL UTILITIES	M	0	1	7500	S	1960	.4063	3047.39
IA	MT. PLEASANT	MT. PLEASANT UTILITIES	M	0	1	7500	S	1966	.4063	3047.39
MO	FULTON	FULTON BOARD OF PUBLIC WORKS	M	0	1	6000	S	1959	.3741	2244.37
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	2	5000	S	1965A	.3578	3577.86
CO	LAMAR	LAMAR UTILITIES BOARD	M	0	1	5000	S	1952	.3566	1783.12
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	4925	S	1974	.3500	1723.88
MO	HANNIBAL	HANNIBAL BOARD OF PUBLIC WORKS	M	1	1	10000	S	1951	.3375	3375.11
TX		TEXAS A&M UNIVERSITY	O	0	1	5000	S	1958	.3362	1680.78
MN	WILLMAR	WILLMAR MUNICIPAL UTILITIES COMM.	M	0	1	7500	S	1956	.3014	2260.63
IA		IOWA STATE UNIVERSITY	O	0	1	6000	S	1961	.2751	1650.72
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1955	.2561	1920.42
OH	ST. MARYS	ST. MARYS MUNICIPAL LIGHT & POWER	M	0	1	10000	S	1967	.2345	2344.79
NB	ALLIANCE	ALLIANCE MUNICIPAL UTILITIES	M	0	1	5000	S	1952A	.2230	1115.10
IA	ATLANTIC	ATLANTIC MUNICIPAL UTILITIES	M	0	1	5000	S	1958	.2113	1056.68
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	5000	S	1952	.2054	1026.80
MN	NEW ULM	NEW ULM PUBLIC UTILITIES COMMISSION	M	0	1	6000	S	1957	.2044	1226.68
NM		PUBLIC SERVICE OF NEW MEXICO	I	0	1	6500	S	1951	.1845	1199.42
MO		NORTHEAST MISSOURI ELECTRIC POWER COOP.	O	0	1	7500	S	1953	.1815	1361.36
MO		NORTHEAST MISSOURI ELECTRIC POWER COOP.	O	0	1	7500	S	1952	.1815	1361.36
MN	WORTHINGTON	WORTHINGTON MUNICIPAL PUBLIC UTILITIES	M	0	1	10000	S	1952	.1755	1755.21
IA		CENTRAL IOWA POWER COOPERATIVE	O	0	2	8000	S	1951	.1630	2603.48

9.0 RESULTS OF INDUSTRIAL MARKET PENETRATION ANALYSIS

9.1 INTRODUCTION

The data base that forms the nationwide industrial market for electric generating systems under 10 MW_e rated capacity was described previously in Section 4. The 2111 MW_e of aggregate capacity consists of 730 small generating systems supplying power for industrial plants, government facilities, and universities.

SSPS capital cost, operations and maintenance costs, and applicable system user taxes are determined in the same manner as for utilities; appropriate discount rates, of course, will alter present values of any costs accrued during the 30-year SSPS lifetime. Purchased fuel and electric power cost projections are identical to those used in the analysis of utilities, but the present values for this industrial analysis are calculated by using the appropriate discount rate for each type of user (i.e., industrial firm or federal government agency).

Economic factors pertinent to SSPS penetration of this market sector have been discussed in Section 6 along with the differences that distinguish the SSIMM computer program from the SSUMM computer program. The methodology is much the same except that SSIMM has no criterion for deciding when a conventional, fossil-fueled power system is to be shifted from the repowering category to the replacement category; this is because the data base did not provide the installation date of the conventional power system. Therefore, the penetration analysis first considered all conventional power systems for replacement by SSPS during the 30-year period from 1985 to 2015 and then considered all systems for repowering by SSPS during this same period. As noted in Section 6, the repowering category applies only to steam turbines.

9.2 ANALYSIS RESULTS

The results of the market penetration analysis are described in this section. However, the discussion is relatively short because the baseline

SSPS penetration of the industrial market is very limited, even as late as the year 2015. Additional information is provided in Section 12 where the impact of incentives on industrial market penetration is discussed.

Figure 9-1 shows cumulative market penetration for the repowering and replacement categories. The capacity displaced for repowering applications commences earlier and is considerably greater than that for replacement applications. Therefore, repowering applications should be favored in subsequent investigations in order to gain earlier access to the industrial market and to capture the largest possible fraction of the available market. Nonetheless, the capture ratio is quite small even at the year 2015 where only five percent of the available market is penetrated.

The aforementioned results are not additive because steam turbines are found in both categories. However, the diesel and gas turbine systems in the replacement category can be summed with the repowered steam turbine systems. This increment is very small and adds only about 4 MW_e to the cumulative displaced capacity in 2015.

Initial market penetration in 1985 is expected for repowering applications in Arizona, but the probability levels are far too low to attach significance to this determination. By 1995, the probability for market penetration in Arizona has exceeded 50 percent and it is likely that repowering with SSPS can be considered seriously for industrial applications using power systems greater than 5 MW_e. Beyond the year 2000, SSPS repowering probabilities are large enough for California, Hawaii, and New Mexico to expect measurable market penetration of industrial power systems. Although not located in these particular states, a number of federal government power systems also rank relatively high in expected penetration by SSPS when compared with installations at industrial sites.

In the replacement category, market penetration is expected first in Hawaii. Indeed, this state leads all other states in market penetration during the entire 30-year period from 1985 to 2015. The probability of penetration elsewhere does not become significant until after the year 2000

Figure 9-1. SSPS Capacity Penetration of Industrial Market

when Arizona, California, New Jersey, and New Mexico head the list of other states with power systems susceptible to penetration by SSPS. Again, as was the case for repowering, some federal government power systems are relatively strong candidates for replacement by SSPS when compared to potential industrial systems.

10.0 SUMMARY OF UTILITY DATA SURVEY

10.1 INTRODUCTION

Some insight into utility operations, decision-making processes, and future plans is considered essential before one can formulate a set of strategies designed to promote the commercialization of small power systems by utilities.

The FPC data base discussed in Section 4.0 proved to be inadequate for this purpose and, hence, a limited number of utilities in the West were interviewed.

Data were acquired on 48 utilities operating small electric generating units in 16 western states. Selection of utilities to be interviewed was made from the extensive inventory of utilities available in Reference 1. The survey was not organized to meet some specific level of statistical significance, but rather to provide a general overall view of a broad spectrum of the electric utility market. All three types of small power generating units of different ages and ownership were included in the survey. The ownership of the 48 utilities surveyed was as follows: Investor-owned - 11; Municipal - 26; Cooperatives - 8; Federal, State and District Systems (FSDS)* - 3.

Table 10-1 lists the utilities interviewed by telephone. The form used to record data from the interviews is given in Appendix A. The data are divided into four major categories: (1) Market Demand Characteristics, (2) Power Sources, (3) Financing, and (4) Solar System Investment Decision Factors. Each interviewee was subsequently sent a letter acknowledging his cooperation in providing information and requesting his confirmation of the data as recorded on the accompanying Aerospace Corporation data form.

* Designation used in Reference 12.

Table 10-1. List of Utilities Interviewed

State	Utility Name	Plant Name	Ownership	Type of Unit	No. of Units	Size (kW _e)	Age (Years)
AR	Safford Municipal Utilities	Safford	M*	D	2	70	--
				D	1	135	--
				D	2	420	42
				D	1	590	29
				D	2	1,250	--
				D	1	2,000	--
	Arizona Electric Power Cooperative, Inc.	Apache Station	O*	D	1	2,000	--
				D	1	4,000	--
				D	1	5,000	--
				G	1	10,000	17
CA	San Diego Gas & Electric Co.	Station B	I*	S	1	3,000	--
		Point Loma		G	1	2,000	--
	Burbank Public Service Dept.	Magnolia	M	S	1	10,000	38
				S	1	10,000	36
	Imperial Irrigation District	Brawley	O	D	3	750	--
				D	3	1,750	--
				D	2	2,290	--
	CO	Central Telephone & Utilities Corp.	Pueblo	I	S	1	8,250
S					1	8,250	38
D					5	2,000	28
Rocky Ford			S		1	9,000	28
			D		5	2,000	15
			Colorado Springs Dept. of Public Utilities		Martin Drake	M	S
S		1		2,500			54
S		1		5,000			47
S		1		5,000			34

Table 10-1. List of Utilities Interviewed (Cont'd)

State	Utility Name	Plant Name	Ownership	Type of Unit	No. of Units	Size (kW _e)	Age (Years)
CO	Lamar Utilities Board	Lamar	M	S	1	2,000	50
				S	1	2,000	40
				S	1	5,000	27
				D	2	1,000	33
	Highline Electric Assoc.	Highline	O	D	2	100	--
				D	1	500	--
ID	Bonners Ferry Light & Water Dept.	Moyie Falls	M	D	1	240	--
				D	2	1,100	--
KS	Central Kansas Power Co.	Colby	I	S	2	6,000	--
				S	1	3,500	--
				S	1	6,000	--
				S	1	7,500	--
		Atwood		D	1	500	--
				D	7	600	--
				D	2	2,000	--
		Larned Electric Light Dept.	M	S	1	1,500	--
				S	1	3,000	--
				S	1	8,260	--
				D	1	6,450	--
				G	1	1,250	--
	McPherson Board of Public Utilities	No. 1	M	S	1	3,000	47
				S	1	5,000	39
				S	1	7,500	25
				S	1	10,000	22
				D	1	1,000	--
	Ottawa Utility Dept.	Ottawa	M	S	1	2,500	51
				S	1	4,000	39
				D	1	3,500	--

Table 10-1. List of Utilities Interviewed (Cont'd)

State	Utility Name	Plant Name	Ownership	Type of Unit	No. of Units	Size (kW _e)	Age (Years)
KS	Ottawa Utility Dept.	Ottawa	M	D	1	3,750	--
	Sunflower Electric Cooperative, Inc.	Garden City	O	S	1	8,000	25
MO	Union Electric Co.	Ashley	I	S	1	10,000	58
	Fulton Board of Public Works	Fulton	M	D	2	4,150	12
				D	1	6,250	6
	N.E. Missouri Electric Power Cooperative	South River	O	S	1	7,500	27
				S	1	7,500	26
				D	2	2,480	30
				D	1	2,480	29
MT	Montana Light & Power Co.	Libby	I	S	1	800	--
				S	1	5,000	--
				S	1	7,500	--
NB	Fairbury Light & Water Dept.	Fairbury	M	S	1	2,000	51
				S	1	2,500	41
				S	1	4,000	31
	Lincoln Electric System Pender Municipal Light Plant	"K" Street	M	S	1	6,500	50
			M	D	1	250	40
		Pender	M	D	1	560	26
				D	1	900	18
				D	1	1,550	11
				D	1	2,070	6
				S	2	1,500	--
				S	1	3,000	--
NV	Sierra Pacific Power Co.	(Several)**	I	D	2	950	--
				D	11	2,000	--
				D	2	2,780	--

Table 10-1. List of Utilities Interviewed (Cont'd)

State	Utility Name	Plant Name	Ownership	Type of Unit	No. of Units	Size (kW _e)	Age (Years)
NM	Public Service Co. of New Mexico	Prager Station	I	S	1	5,500	--
				S	2	6,500	30
				S	1	6,500	28
				S	1	8,200	34
	Raton Public Service Co.	Raton	M	S	1	3,600	27
				S	1	6,500	17
	Clayton Municipal Electric System	Clayton	M	D	1	125	--
				D	1	340	--
				D	1	575	--
				D	2	900	--
				D	1	1,200	--
	Tucumcari Light & Power Dept.	Tucumcari	M	D	2	1,000	--
				D	2	1,320	--
				D	2	2,250	--
				D	1	3,000	--
				D	1	4,100	--
	Farmington Electric Utility	Animas	M	S	2	4,000	--
				S	1	7,500	--
	Lea County Electric Cooperative, Inc.	N. Lovington	O	D	3	1,010	28
				D	2	2,250	27
				D	2	2,250	25
				D	2	4,000	22
ND	Montana-Dakota Utilities Co.	Ellendale	I	S	1	2,000	49
				S	1	2,500	60
				S	1	3,500	60
				S	1	7,500	60
				D	2	1,700	32
				G	2	4,000	26

Table 10-1. List of Utilities Interviewed (Cont'd)

State	Utility Name	Plant Name	Ownership	Type of Unit	No. of Units	Size (kW _e)	Age (Years)
ND	Park River Municipal Light Dept.	Park River	M	D	1	200	41
				D	1	300	--
				D	1	475	--
OK	Laverne Municipal Electric Light Plant	Laverne	M	D	1	1,090	--
	Stillwater Electric Dept.	Boomer Lake	M	S	1	10,000	--
	Grand River Dam Authority	Chouteau	FSDS	S	4	5,000	37
SD	Black Hills Power & Light Co.	Kirk	I	S	2	5,000	44
				S	1	5,000	18
	Estelline Municipal Light & Power Dept.	Estelline	M	D	5	2,000	14
				D	1	40	41
				D	1	75	41
				D	1	200	33
				D	1	300	29
	Winner Municipal Light & Power Dept.	Winner	M	D	2	690	32
TX	Central Power & Light Co.	La Palma	I	S	1	10,000	51
	Brownsville Public Utilities Board	Silas Ray	M	S	1	6,000	39
	Garland Electric Dept.	C. E. Newman	M	S	2	8,500	22
				D	2	800	31
				D	1	2,100	26
				D	1	3,400	25
	Hearne Municipal Electric System	Hearne	M	D	1	700	32
				D	1	1,215	29
				D	1	1,360	23
				D	1	2,000	10

Table 10-1. List of Utilities Interviewed (Cont'd)

State	Utility Name	Plant Name	Ownership	Type Of Unit	No. of Units	Size (kW _e)	Age (Years)
TX	Hearne Municipal Electric System	Hearne	M	D	1	2,500	10
		Tulia	M	D	2	360	30
	Tulia Power & Light Co.	Tulia	M	D	1	475	34
				D	1	1,030	27
				D	1	1,135	23
				D	1	1,135	22
				D	1	1,710	7
				D	1	1,815	16
				D	1	1,815	15
				D	1	4,800	5
	Texas A&M University	Univ. Utility	FSDS	S	1	1,000	49
				S	1	3,000	33
				S	1	5,000	21
UT	Calif.-Pacific Utilities Co.	Cedar	I.	S	1	2,500	--
				S	1	5,000	--
				D	3	725	--
				D	3	1,000	--
	Provo City Power, Dept. of Utilities	Provo	M	S	1	2,000	40
				S	1	2,000	39
				S	1	2,500	37
				S	1	7,500	29
WA	Garkane Power Association, Inc.	Boulder	O	D	2	1,200	7
				D	1	50	52
				D	2	75	41
				D	3	250	34
	Orcas Power & Light Co.	Eastsound	O	D	1	50	52

Table 10-1. List of Utilities Interviewed (Cont'd)

State	Utility Name	Plant Name	Ownership	Type of Unit	No. of Units	Size (kW _e)	Age (Years)
WA	Orcas Power & Light Co.	Eastsound Friday Harbor	O	D	2	500	19
				D	7	200	38
				D	2	1,000	14

* I - Investor-owned Utility

M - Municipal Utility

O - Cooperative Utility

FSDS - Federal, State and District Utility Systems

** - Valley Road, Brunswick, Battle Mtn., Fallon, Gabbs, Lahontan

In most cases, responses to the interview proved to be less than desired. Limited time to answer questions or lack of knowledge on the part of the interviewee contributed in large part to an incomplete data base. Complete responses to questions in the first two categories were provided by more than two-thirds of the respondents; when extended to the third category, less than half the responses were complete. Indeed, even the follow-up mailing for data confirmation produced little additional information beyond that acquired during the initial interview. Nonetheless, an extensive amount of information was acquired and proved valuable in forming the basis for the SSPS commercialization strategies discussed in Section 12.

10.2 RESULTS OF UTILITY SURVEY

Each of the four major categories of data noted in Section 10.1 is discussed separately. Rather than cover each utility^{*} individually, the data for the entire group of utilities are summarized by reference to majority opinions or average characteristics and deviations from the average wherever survey results can be quantified. A summary of replies to the supplementary questions is also included.

While the natural inclination is to present utility characteristics as a basis for consensus, this view is not practical since each utility is unique in its form of operation, decision-making processes, and plans for the future even though group results are summarized. Hence, the prospects for individual utility adoption of alternative energy sources, such as solar energy, must be based on in-depth personal interviews that can explore the subject in further detail with a broader representation of decision-makers in the utilities' management organizations.

* The term "utility" as used herein, refers to a utility plant at a given location and not to an entire utility system.

None of the utility characteristics was found to exhibit a geographic influence. A given type of utility ownership was not distinguishable except for its methods of financing capital improvements and the general observation that larger plants were owned and operated by investor-owned utilities.

10.2.1 Market Demand Characteristics

Most of the utilities served only one community and this was particularly true of municipals where the largest number of communities served was six. Investor-owned utilities served as many as 212 communities. Communities served by cooperatives ranged from 2 to 20. FSDS served as few as one community and as many as 12. The average number of communities served by all types of utilities was about six when the 212 community case was excluded.

Population of the largest community served by any one utility ranged primarily between 5000 and 50,000, with a low of 600 and a high of 3,000,000. The average was about 47,000 when utilities serving major metropolitan areas were excluded. As would be expected, investor-owned companies generally served larger communities than municipals, cooperatives, and FSDS.

The area of the region served by a given utility was as large as 50,000 square miles and as small as one square mile. Investor-owned utilities had the largest service areas, although one cooperative utility served 13,000 square miles. The average area was about 2100 square miles when some of the investor-owned utilities serving very large regions were excluded.

The present level of energy demand (sales) also shows a very wide variation amongst the utilities, ranging from 21,000 kWh to 22 billion kWh with an average of about 580 million kWh when utilities serving major metropolitan areas were excluded. Annual growth in energy demand over the next 30 years is projected to range primarily from about three to five percent, which is significantly less than projections made by the utility

industry in earlier years (Reference 13). A few utilities estimated annual growth of 12 percent or more in the next five years followed by reduced growth (e.g., 5-8 percent) in succeeding years. Some of the small municipal utilities and one cooperative projected annual growth at less than two percent.

Peak loads varied from as little as 2.8 MW_e for a very small municipal utility to as much as 5600 MW_e for a large investor-owned utility. The average peak load was about 400 MW_e; if four of the largest utilities are removed from the data base, then the average peak load is reduced to about 150 MW_e. These loads occurred for the most part during the hours of 4-6 p.m. Other peak periods ranged from 9 a.m. to 9 p.m. With the given data base, it was not possible to determine if there was a clear difference between summer and winter peak hours.

Most responses to the question regarding peak-to-baseload ratio varied from about 1.7 to 2.1 with deviations ranging as high as 3.7 (in two cases) and as low as 1.3 (for a winter-peaking case). The average was 2.1. Quite often the load factor (average-to-peak load ratio) was cited, rather than the peak-baseload ratio. This operational figure averaged 58 percent and ranged from 20 percent for a small cooperative utility serving a few communities with large farm irrigation loads to 83 percent for a large investor-owned utility serving a large community.

More than half of the respondents foresaw no change in their future customer mix. Of the 12 utilities that did anticipate a change, there was a 50-50 split between those citing peak loads and those citing peak-baseload ratio. Three respondents expected to see changes in both peak loads and peak-baseload ratio. One respondent expected a change in peak time-of-day.

10.2.2 Power Sources

None of the three options for satisfying utility demand growth held a clear majority. Twenty-nine utilities favor a major grid tie-in, 26 utilities are opting for joint ventures, and 20 utilities are considering

installation of new equipment. Although 20 utilities* selected only one option (generally either grid tie-in or joint venture), 25 selected two or more options and eight selected three or more options. The majority of utilities indicated that final selection of options to be pursued over the next several years will be made within the next few years; in some dozen cases, option plans are to be completed this year.

Lead-time for plant design and installation (including government agency regulatory approvals) could range from 8 to 10 years for coal-fired systems and from 4 to 6 years for oil-fired systems. Diesel and gas-turbine systems would have much shorter installation periods.

Although there were a few exceptions, purchased power, as a fraction of utility demand, was expected to increase over the next 30 years. Thirty-one utilities purchase power, six do not purchase power, and 11 provided no response to this subject. Of those utilities purchasing power, an average 64 percent of demand is satisfied by this means; variations range from 8 to 100 percent. No clear distinction was discernible on the basis of type of ownership, although most of the municipals and cooperatives appeared to use this power source to satisfy the majority of their demand.

Thirty respondents purchase base power, 22 purchase intermediate power, and 22 purchase peak power. Only 15 utilities purchase just one form of power, whereas 24 purchase two or more forms of power and 14 purchase all three forms of power.

More than half the utilities have no restrictions on buying or selling power. About one-third have some form of restriction ranging from transmission limitations to generating capacity limitations and, in one case, a prohibition exists on the import or supply of power across state boundaries.

* The majority of these were municipals.

The equipment inventory was included on the data form as a means of updating the information contained in Reference 1. These data are not essential to development of the utility market profile presented in this section and, therefore, will not be discussed.

The use of oil and natural gas fuels is evenly distributed amongst the utilities and, in about half the cases, both fuels are used at the plant. The use of coal was noted by only five utilities.

Fuel prices vary considerably among the survey group, and even prices within a given state exhibit major variations, but no consistent geographic influence on prices was evident. (These observations are not unique since Reference 14 shows similar results.) Gas prices varied from a low of \$0.78 per MCF to \$2.31 per MCF; oil prices varied from \$0.25 per gallon to \$0.56 per gallon; coal varied from \$22.00 per ton to \$33.60 per ton. Kansas and Nebraska showed the largest statewide price changes. In this region, gas varied from \$0.78 per MCF to \$2.00 per MCF, and oil varied from \$0.28 per gallon to \$0.41 per gallon. One utility cited a coal price of \$22.00 per ton.

Part of the price differences could be attributed to different distribution costs. Additional variations may occur because some utilities make spot purchases or short-term purchases while other utilities benefit from long-term contracts that have restrictions on allowable year-to-year price escalation.

Of those who responded to the question of fuel availability problems, about two-thirds of the responses indicated no such problem. When availability problems were noted, the supply of natural gas (presently, and in the future) was cited as being the critical fuel.

Sixteen respondents quoted recent annual fuel price increases; a few cases ranged as high as 41 percent for natural gas and 33 percent for purchased power. Some utilities have not experienced any recent price increases. Little substantive information was available on expected price increases for the future. Based on very limited data, it appears that in

the next five years, average annual fuel cost increases may be as follows: coal - 4 to 6 percent; oil - 6 to 9 percent; gas - 12 to 20 percent.

10.2.3 Financing

Municipal utilities rely primarily on revenue bonds for financing capital purchases. In a few cases, operating fund reserves were used for this purpose. Bond coupon rates varied from three percent for issues made more than a decade ago to 6.5 percent for a 1978 issue. Those municipal utilities that have relied on earlier financing for capital improvements face major increases in costs due to current (and possibly continuing) increases in financing costs.

Cooperatives obtained funds through loans originating with the Rural Electrification Administration (REA) and/or with the National Rural Utilities Cooperative Finance Corporation (CFC); in one case, retained earnings were used. REA loans are low cost forms of financing; one case cited was a 1967 loan at two percent interest. Presently, REA loans for power distribution systems bear interest at the standard rate of five percent. A two percent interest rate for power distribution systems is still available to borrowers meeting special statutory criteria. However, long-term loans for power generating capital equipment are issued by the Federal Financing Bank at about nine percent with REA guaranteeing the loan. Additionally, working in cooperation with REA, CFC provides lines of credit and other forms of supplemental financial assistance to its member-systems. Interest rates are linked to the prime rate of commercial lending institutions. Recently, long-term, secured loan rates were set as high as 9 1/4 percent and short-term, unsecured loan rates were set at 11 3/4 percent.

Investor-owned utilities relied on three sources of financing: bonds, common stock, and preferred stock. Distribution of funds among these three sources were not totally uniform but appeared to average 50 percent, 14 percent, and 36 percent, respectively. Bond rates averaged 9.8 percent

(varying with year of issue), while rates of return on preferred stock and common stock averaged 9.8 percent and 14 percent, respectively.

Most utilities did not offer an estimate regarding changes in cost or terms of financing. Of the 19 respondents who did reply to this question, a little more than one-third did not foresee a change.

In regard to percent of plant replacement that could be financed without affecting cost of funds, replies ranged from 0 to 100 percent. Although two-thirds of the responses cited two percent or less of unaffected plant replacement, the data were generally too few in number to offer any meaningful appraisal of this subject.

In more than half of the replies, economy of scale was noted as the purpose of joint ventures. Access to capital and improved financing terms were equally divided in the balance of replies. About one-third of the utilities cited two or more reasons for joint ventures. In one case, the purpose was to reduce risks associated with plant licensing and with ability to meet environmental regulations. In another case, peak load sharing was cited.

10.2.4 Solar System Investment Decision Factors

Very few responses were provided for the required discounted cash flow internal rate of return. A best estimate is 18-19 percent (pre-tax). One respondent preferred to express this value as a 15 percent fixed charge rate.

Two-thirds of the respondents indicated land available in the vicinity of the plant. Tracts varied from 40 acres to 3000 acres and averaged about 90 acres. Land costs ranged from \$300 per acre for rural property to \$5000 per acre for property in towns of about 5000 population and as high as \$20,000 per acre for property within a city of about 40,000 population. Average land cost was about \$2600 per acre.

Only one-third of the utilities responding to this question had environmental restrictions imposed on their current plant operations. A few

additional replies noted that environmental restrictions would be expected in the future because of investments in coal-fired electric generating systems.

Of the 25 responses to the question of factors for evaluating alternative power sources, 50 percent cited costs, 30 percent cited system availability (or availability of petroleum-based fuels), and 20 percent cited environmental considerations. Twenty-five percent offered two or more factors that enter into their evaluation.

The attractiveness of small solar power systems was judged in most cases by its ability to compete with other sources of energy on a lifetime cost basis. The second-most important factor mentioned was the possible future unavailability of petroleum-based fuels.

Payback periods for small solar thermal electric systems were specified in only a dozen cases. Responses ranged from a low of seven years to a high of 30 years, averaging about 16 years.

The question of possible lost revenues or additional costs if utilities were to acquire small solar power systems was not answered in most cases, and, therefore, a summary of responses is not presented. It was recognized in advance, that without knowledge of specific SPS performance, capital cost, operations costs and maintenance costs, replies to this question can only be speculative in nature.

11.0 SUMMARY OF INDUSTRIAL FIRM DATA SURVEY

11.1 INTRODUCTION

The (former) Federal Power Commission Form 4 Industrial Ledger and Form 12-C Ledger were the sources for data on industrial firms operating small electric generating systems (See Section 4). As in the case of utilities, this data base proved to be inadequate for providing guidance in formulating SPS commercialization strategies. Therefore, a similar data survey was planned to acquire more definitive information regarding (1) company operations, (2) energy consumption, (3) financing of capital equipment, and (4) perspectives on future energy sources.

Before data survey plans were completed, communication with the Solar Energy Research Institute (SERI) in Golden, Colorado revealed that a number of other organizations with somewhat different goals were also planning to acquire data from industrial firms. Therefore, it was deemed appropriate to convene a meeting of interested parties to reveal similarities and differences in data needs and survey methodologies so that a common format might be formulated that could prove useful to all organizations. Thus, a meeting attended by ten other organizations was hosted by The Aerospace Corporation and chaired by SERI on 29, 30 November 1978. The objectives of the meeting were to establish a credible data base, minimize overlap in data collection efforts, and minimize the number of contacts made with each industrial organization.

The data recording format resulting from the meeting did not necessarily meet all of the detailed needs of each organization, but it did serve as an excellent guide for data gathering as well as a uniform means for recording data in a computer storage bank at SERI. It was agreed that use of the format would be strictly voluntary and that funding and/or time limitations of various study programs would likely not allow the complete acquisition of all data from each industrial firm to be interviewed. A copy of the finalized version of the format is given in Appendix B.

Within the constraints of the present Small Power Systems Study, The Aerospace Corporation acquired data on industrial small electric generating systems by use of telephone interviews. From the inventory of small power systems documented in Reference 4, 42 industrial firms operating 64 plants in the Western Contiguous United States and Hawaii were selected for survey.

Because the selection of firms to be interviewed had to be made prior to availability of results from the market penetration analysis, the early analyses of SPS documented in Reference 3 were used for guidance. These analyses had shown that, within the 10 MW_e limitation, the larger solar powered electric generating systems operating in the "sunbelt" region could in the future compete on a favorable economic basis with fossil-fueled steam turbine generating systems. Hence, companies operating steam turbine electric generators in states with average daily-direct insolation levels greater than 5 kWh per square meter were selectively favored in forming the survey list. This bias, therefore, did not result in any statistically significant list. Indeed, companies in the food industry formed a larger share in the survey list than if the list had been prepared on the basis of annual energy consumption or number of electric generating systems.

Table 11-1 lists company name, plant location, and power system description for each of the plants interviewed. As explained in Reference 4, the data source for the inventory was the files of the former Federal Power Commission (data base currently managed by DOE's Energy Information Agency). System installation dates were not available and, in a number of cases, the Standard Industrial Classification Code was not provided.

11.2 RESULTS OF INDUSTRY SURVEY

By contrast with the utility sector, the industrial group was generally more hesitant to reveal information concerning physical plant operations, financing of capital equipment, and plans for securing future sources of energy. This difference likely stems from the more severe economic stresses of competition and reduced regulation of industrial firms

Table 11-1. List of Industrial Firms Interviewed

State	Company Name	Plant Location	Plant Name	(1) SIC	Type of Unit	Size (kW _e)
AR	Amstar Corp., Spreckels Sugar Div.	Chandler	Chandler	--	S	5,000
	Apache Powder Co.	Benson	Benson	2892	S D	250 400
	Kennecott Mineral Co., Ray Mines Div.	Hayden	Hayden	-- --	S S	10,000 7,500
	American Crystal Sugar Co.	Clarksburg	Clarksburg	2063	S	2,500
	Consolidated Food Corp., Union Sugar Div.	Santa Maria	Betteravia	2063	S	4,000
CA	Kimberly Clark Corp.	Anderson	Anderson	2421	S	3,000
	Pacific Paperboard Products, Inc.	Stockton	Stockton	--	S	8,000
	U.S. Gypsum Company	Southgate	Oakfield	2621	S	3,000
	Adolph Coors Co.	Golden	Golden	--	S	4,000
	Gates Rubber Co.	Denver	Gates Rubber	--	S	5,000
CO	Great Western Sugar Co. ⁽²⁾	Denver	--	--	--	--
	Holly Sugar Corp. ⁽²⁾	Colorado Springs	--	2063	--	--
	Union Carbide Corp.	Uravan	Uravan	1094	S D	500 100 ⁽³⁾
HI	Hawaiian Com'l Sugar Co.	Puuenne	Paia/Puunene	--	S	8,000
ID	Amalgamated Sugar Co.	Rupert	Rupert	--	S	5,500
	Pet Inc.	Buhl	Buhl	2023	S	400 ⁽³⁾
KS	Carey Salt Co.	Hutchinson	Evaporation	2899	S	3,750

Table 11-1. List of Industrial Firms Interviewed (Cont'd)

State	Company Name	Plant Location	Plant Name	SIC	Type of Unit	Size (kW _e)
KS	Cities Service Co.	Satanta	Jayhawk	2813	S	2,000
					D	300
	Page Milk Co.	Coffeyville	Coffeyville	2023	S	100
	Proctor & Gamble Mfg. Co.	Kansas City	Kansas City	2841	S	2,000
	Packaging Corp. of America	Hutchinson	Hutchinson	--	S	2,500
MO	Monsanto Co.	St. Louis	John F. Queeny	--	S	5,000
NM	Anaconda Copper Co.	Grants	NM Operations	1094	D	1,000
	El Paso Natural Gas Co.	San Juan	San Juan	--	S	8,000
	Warren Petroleum Corp.	Eunice	Eunice	1321	S	3,000
		Saunders Monument	Saunders Monument		D	2,180
					S	2,100
ND	American Crystal Sugar Co.	Drayton	Drayton	--	S	6,000
	Aminoil USA, Burmah Oil & Gas Co.	Tioga	Tioga	--	S	300
				--	D	2,775
TX	American Smelting & Refining Co.	El Paso	El Paso	--	S	6,400
	Amoco Production Co.	Corpus Christi	Burnell	1321	S	3,000
		Houston	Luby Gasoline		D	2,000
		Tyler	Edgewood		D	2,400
		Sweeney	Old Ocean		S	750
	International Inc., CPC Corn Products Co.	Corpus Christi	Corpus Christi	--	S	7,500
	Fort Bend Utilities Co.	Sugarland	Imperial Sugar	2062	S	3,000
	Jefferson Lake Sulfur Co.	Needville	Long Point	1477	S	3,000

Table 11-1. List of Industrial Firms Interviewed (Cont'd)

State	Company Name	Plant Location	Plant Name	SIC	Type of Unit	Size (kW _e)
TX	Kirby Lumber Corp.	Silsbee	Silsbee	--	S	7,500
				--	D	350
	Proctor & Gamble Mfg. Co.	Dallas	Dallas	2841	S	3,000
	Union Carbide Chemical Co. Chemicals & Plastic Div.	Port Lavaca	Seadrift	--	S	9,000
UT	U&I Inc.	Salt Lake City	Garland	2063	S	1,250
WY	Amoco Production Co.	Powell	Elk Basin	1321	S	2,500

Note:

- (1) Standard Industrial Classification Code. Data available only for listings from FPC Form 12-C Ledger.
- (2) Corporate Headquarters contacted; plant peculiar generating system size data are not shown.
- (3) No energy generated with these systems in 1976.

when compared to utilities. Nonetheless, 36 companies operating 48 plants provided sufficient data to constitute a data base that proved useful in supporting the formulation of commercialization strategies for SSPS.

The data presentation methodology used for utilities is also employed here for the industrial sector. Rather than identify each company and plant (a prospect shunned by a limited group of companies interviewed), characteristics are summarized for the entire group of companies or are isolated by industrial classification wherever that segregation is appropriate. Additionally, as was noted for utilities, individual characteristics are, at times, widely divergent from stated averages. Therefore, caution must be exercised in applying generalizations derived from group data to characterize any given company (or even any given industry).

Although electrical requirements were emphasized during the telephone interviews because these data were of primary interest to the present study, other data were requested and recorded on the IPE Data sheets. Each group of data is discussed in turn: Electrical Requirements, Process Heat Requirements, Economic Factors, and Institutional Factors. Within each data group, only those topics pertinent to the SPS Study are discussed. Comments are generally restricted to those topic areas where it is judged that sufficient quantities of data were acquired to indicate trends or to offer some indication of range in magnitude of characteristics in that topic area.

11.2.1 Electrical Requirements

Peak power requirements varied considerably, but most plants cited power levels within the range of 1,300 to 11,000 kW_e. A few companies required peak levels as high as 30,000 kW_e. Excluding these data, the average peak power level was about 5,900 kW_e.

The peak-to-average power ratio varied from about 1.1 to 2.9, averaging 1.38.

Supply voltage ranged from 480 volts to 4200 volts, except for one case of 22,000 volts. If the 22 Kv case is removed from the data, the average supply voltage is about 2300 volts.

The fuel use characteristics for on-site electrical generating equipment are included with the fuel use characteristics for the entire plant discussed in Section 11.2.2.

Eighty-seven percent of the plants use steam turbine electric generators either solely or in combination with other types of power plants; 77 percent use only steam turbines. Thirteen percent of the plants rely on two or more different types of power plants. One plant uses a reciprocating piston steam engine. Other engine types utilized to generate electric power are: gas turbines, natural gas engines, diesel engines, and gasoline engines.

The age of electrical generating equipment varies from a two-year old, 12,500 kW_e steam turbine unit to a 59-year old, 940 kW_e steam turbine unit. The average age is about 26 years.

Data on rated capacity (and number) of electrical generating systems were acquired simply to verify the small power system inventory in Reference 4 and are not discussed here.

Inlet temperatures for steam turbine units varied from 360°F to 830°F (averaging 595°F), and pressures varied from 145 psi to 800 psi (averaging 407 psi). Steam for process heat was extracted from one or more intermediate stages of most turbines at temperatures ranging from 240°F to 660°F (averaging 377°F) and at pressures ranging widely from 18 psi to 600 psi (averaging 124 psi).

Flow rates for steam turbines varied from 59,000 lb/hr to 300,000 lb/hr, averaging 132,000 lb/hr. When expressed as a ratio of flow rate to machine rated capacity, almost all units could be placed in the range of 20-50 lb/hr per kW_e.

A few firms purchased almost all of their electric power, as contrasted with a significant number of others that generated all of their

required electric power. The majority of plants, however, divided their electric power needs between purchased power and self-generated power in proportions that ranged from about 13/87 percent to 80/20 percent; the average for all plants was about 33/67 percent purchased-to-generated power.

The unit cost of self-generated power is influenced by many factors among which are cost of fuel, cost of maintenance, equipment efficiency, form of operation (e.g., condensing versus non-condensing steam turbines), and capacity factor. A high value of 93 mills per kW_eh was cited for a very small, 30-year old steam turbine standby unit used to supply power to critical equipment when the main electrical supply fails. Costs of almost 70 mills per kW_eh can be found in geographic regions with high prices for purchased fuel oil. By contrast, costs less than 2 mills per kW_eh are found at some natural gas processing plants that provide all of their required electrical power 24 hours per day. Obviously, in this latter case, electric utilities cannot compete with self-generated power.

Steam turbine electric generators perform a dual function for a significant number of plants, particularly food processing plants. When low pressure steam is required for process heat, the turbine is used as a throttling device for boiler-generated steam, and electric power is produced as a by-product. This highly efficient means of producing electric power results in costs of only about 2-10 mills per kW_eh in some cases. Were it not for this method of operation, many companies would likely purchase all required power from electric utilities, rather than purchase equipment for self-generation of power.

11.2.2 Process Heat Requirement

When boiler-generated steam was used to deliver process heat, temperatures ranged generally from 240°F to 750°F and pressures varied over a wide range from 30 psi to 600 psi. The higher steam temperatures were generally associated with materials processing and chemical firms while the lower temperatures were found with food processing firms. Steam quality

varied from very small moisture percentage (or just saturated) to various degrees of superheat. Hot water delivery systems in milk processing and sugar plants had temperatures that ranged from about 165°F to 210°F. Furnace-generated hot gas temperatures ranged from 1650°F to 2000°F.

Steam flow rates seemed to lie primarily in the range of 60,000 to 250,000 pounds per hour, although one plant cited 400,000 pounds per hour. There were insufficient data to determine how many boilers produced a given flow rate. Hence, boiler average flow rate could not be determined, but individual boiler designs are known to encompass the range just noted.

Almost without exception, plants operated on a 24 hour per day basis, and about 90 percent of these plants operated seven days a week. With the exception of sugar processing plants, all companies conducted production operations during 12 months of the year. Sugar firms, being dependent on harvesting of crops, conducted plant operations from only three to seven months a year, with scheduled downtime for the balance of the year.

Except for a Hawaiian sugar plant, all companies used natural gas as either the primary plant fuel or as a backup fuel. Oil was used as a primary backup fuel in about half the cases. Coal was used in only four cases. Because, food processing firms have need for a clean burning fuel, such as natural gas, and because a large number of such firms were included in the survey, the use of natural gas by industrial firms may be overemphasized. Of interest is the use of fossil fuel substitutes such as production waste by-products by one company, wood waste by another company, and bagasse by a third company.

Annual fuel usage was found to be surprisingly high, and generally ranged from 0.55×10^{12} Btu to 2.2×10^{12} Btu. One plant used as little as 0.003×10^{12} Btu and another as much as 4×10^{12} Btu. Likely, the fuel usage is governed as much by plant size as by type of process.

Fuel prices varied considerably, even for the same fuel used by the same company in plants at different geographical locations. Natural gas generally ranged from \$2.00 to \$2.60 per million Btu, although prices as low

as \$1.30 to \$1.60 per million Btu were cited in a few cases. Based on only two data points, oil was priced between \$1.15 and \$1.50 per million Btu; these oil prices are much lower than were determined for utilities and may not be a reliable indicator of current market prices. Coal was priced in one example at \$1.40 per million Btu. As would be expected, the fuel costs for gas processing firms are so low that they do not constitute part of the data that reveal current prices for transported, refined fuels on the open market.

Utility supply schedules for industrial plants were about equally divided between those plants receiving continuous service and those receiving interruptible service. The data base in this case is very small and may not accurately depict operations for this industrial sector.

11.2.3 Economic Factors

Very few companies quoted discount rates. Where data were available, rates cited ranged from 15-30 percent, averaging about 22 percent.

A greater number of responses were available for payback period which, except for one 20-year case, covered a range of 1-10 years with an average period between six and seven years. About half of the companies gave a range of years rather than quoting a single payback period. Some companies with low marginal profits required rapid payback of capital equipment projects. Other companies, incurring large operating costs for fuel, were able to consider much longer payback periods for capital equipment projects that were designed to reduce energy consumption.

Energy costs, as a percent of operating costs, varied from a low of two percent for a gas processing firm to a high of 45 percent for a chemical processing firm. Overall, these costs averaged about 25 percent of operating costs.

Available land adjacent to the plant ranged from a few acres to more than 10,000 acres. If these extreme cases are removed from the data base, the average available land is almost 500 acres.

From very limited responses, the total available roof area was found to vary from 10,000 to 500,000 square feet. The larger roof areas seemed to be available at paper products firms.

One-third of the plant locations were classified as urban (or semi-urban) and two-thirds as rural. Urban sites were all level and the majority of rural sites were level, but these data are very limited in number of responses and may not be reliable indicators. Only one response quoted land costs: \$2,000 to \$4,000 per acre for level land adjacent to an agricultural community.

Responses to the question of plant environment were few in number. Of these data, the majority cited dust as the major factor. Particulates, salt air, residual gases from production processes, and blowing sand were isolated responses in other cases.

11.2.4 Institutional Factors

About one-third of the plants responded to the question of future fuel availability. Only one respondent foresaw problems with supplies of diesel oil and natural gas. All other replies, interestingly enough, did not envision any serious fuel supply problems.

Of the 18 responses to the question on fuel costs, three-fourths foresaw annual increases in costs ranging from a moderate eight percent for coal to highs of 38 percent to 50 percent for natural gas; one-fourth expected no cost increases. Predicted increases in oil prices ranged from 20 percent to 27 percent. Data were too sparse to consider these figures as reliable indicators of industry viewpoints.

Fifteen plants responded to the topic of environmental impact problems. Less than half the replies indicated any problem. The use of coal was noted in a few cases as being the major problem when there was some impact of plant operations on the local environment.

Competitive system costs and reliability were of major concern in the very few responses to the question regarding prior conditions before solar-powered electric systems would be considered. Tax credits were mentioned most often as the preferred incentive for inducing purchases of solar power equipment.

About 25 percent of the plants noted that energy conservation measures had been implemented. A number of firms indicated more than one modification to equipment and plant operations. Changes to improve plant efficiency included: (1) installation of (a) economizers, (b) waste heat recovery units, and (c) insulation; (2) improvements in power factor; and (3) recycling of heated exhaust.

12.0 STRATEGIES FOR PROMOTING COMMERCIALIZATION OF SMALL SOLAR THERMAL ELECTRIC POWER SYSTEMS

12.1 INTRODUCTION

The rate of development and manufacture of small solar power systems (SSPS) intended for supplanting conventional fossil-fueled electric generating systems will be governed by many complex, interacting factors. Clearly, though, since investment economics is usually the leading factor in any decision to purchase and operate capital equipment, utility and industry management must be able to rank projects that compete for limited funds. This involves the assessment of project ranking values such as total capital required, cash flow required, period of investment, and project risk. The last named consideration is likely the most dominant in the decision-making process and it sets the required earning value or rate of return for each type of investment.

From this early and somewhat limited view of the infant solar energy industry, it appears that the risks, as perceived by potential buyers of solar power equipment, are indeed much higher than for competing conventional power units. Large-scale demonstration of solar power cost-effectiveness has not been in evidence and this energy source can only be viewed presently, at best, as an interesting future energy source consideration. Of course, conventional power will eventually become a riskier venture if the cost of fossil fuels (or purchased electric power) follows a precipitous rise and if the availability of these fuels (and electric power) becomes increasingly limited. At some time in the future, the solar risks can be expected to be offset by the conventional power risks and the solar energy industry will grow in accordance with the risk balance that is assessed by each of the various potential use sectors.

Employment of the equivalent cost ratio (ECR) to compare solar power system lifetime costs to the value of displaced fossil fuel (or purchased electric power) is the method used in this study for measuring relative

risk. The purchase of a solar power system is assumed to occur as soon as the solar power system lifetime costs are less than the conventional power system fuel costs over the solar power system lifetime (i.e., $ECR \leq 1$). Other risk factors of a more subjective nature would likely be considered by a potential purchaser of SSPS and, in some cases the decision might be predicated on $ECR \leq 0.9$, or $ECR \leq 0.8$, etc.

Acceleration of SSPS commercialization basically requires a reduction in the perceived risks by use of various strategies. Some of the proposed strategies can be quantified and the effect on market penetration is shown. Other strategies are only discussed in a subjective sense, but their impact on SSPS commercialization is expected to be important. Basically, the commercialization strategies are intended to reduce the risk to potential solar power equipment buyers by having the federal government assume all, or part of the perceived risk. Indeed, this form of risk sharing could also be assumed in part by state government and/or local government and by the manufacturer of solar power equipment as well as the general public, but these aspects of risk sharing are not addressed in this study. Other strategies could also be conceived for providing incentives to the manufacturers of solar power equipment but, again, this topic lies outside the scope of this study.

12.2 POSSIBLE COMMERCIALIZATION STRATEGIES FOR SSPS

The commercialization strategies to reduce the risk for equipment buyers have been organized into three major categories: (1) direct financial incentives, (2) indirect financial incentives, and (3) non-financial aid. These strategies are concerned with fostering the growth of the market for small solar thermal electric generating systems in competition with fossil-fueled electric generating systems or with purchased electric power. Possible competition with other forms of solar-derived energy or with other renewable forms of energy sources is not considered in this discussion.

Telephone discussions held with members of the management and technical staffs at utilities and industrial firms (Sections 10 and 11) were instrumental in development of the commercialization strategies. Personal interviews with electric power utilities in the Los Angeles area and with agencies that influence utility operations, financing and future plans (viz. Rural Electrification Administration and American Public Power Association) also contributed to shaping the strategies.

The scope and pace with which commercialization strategies are to be carried out is not addressed in the discussion because the supporting information for such decisions is largely lacking. At issue here is the question of national (or parochial or regional) benefits versus the entailed costs. An analysis of these competing factors is beyond the scope of the present study. In addition, other considerations are equally important. These include: (1) the required lead-time for manufacturers of solar power equipment, (2) various institutional factors such as boiler codes or land use codes, (3) adequacy of the financial market for meeting the needs of solar power borrowers, and (4) the derived benefits to environmental quality from proliferation of solar power systems.

Obviously, numerous strategies can be proposed, limited only by the imagination of the proposer. The strategies discussed herein are only offered as examples and require much more thorough analysis before being recommended to DOE for implementation.

12.2.1 Direct Financial Incentives

Incentives that have a first-order effect on operating revenues are considered to fall in this category. A subsidy in the form of a government cash rebate on a portion of the solar power system cost is one form of incentive; the economic effect is a direct reduction in the cost of equipment. The rebate would likely be of most value if it were awarded in the year of equipment purchase rather than distributed as a series of annual payments.

Another incentive is the availability of low cost loans. This results in less annual payout in interest costs and would also offer the prospect of using cash reserves for other types of investment.

A third form of direct incentive is much more complex, but could be considered as one of the most instrumental policies in reducing the risk for the potential SSPS buyers. Recall that, for applications involving replacement and repowering of existing units, the economic comparison for SSPS must be based on displaced fuel costs (or displaced electric power purchases) for the conventional system evaluated over the SSPS lifetime. But, without substantial increases in these future costs, solar power systems could not compete. It is recognized that the projections of fuel (or electric power) costs have some degree of uncertainty, and the buyer of SSPS may feel that a SSPS could turn out to be a poor choice if fuel (or electric power) costs do not really rise as fast as the projections on which the purchase was based. Therefore, the federal government could rebate to the buyer a portion of any reduction in these costs from an agreed-upon cost schedule projected over the SSPS lifetime. On the other hand, the government might ask the buyer, in turn, to pay a portion of any increase in fuel costs above the schedule, since the buyer of the SSPS has been shielded from such a cost increase and would be paying for a form of "insurance".

A fourth form of incentive applicable to utilities would be to allow the utility to pass on the marginal costs of SSPS to the electric power consuming sectors in the form of peak load and/or capacity pricing, rather than imbedding such costs with other capital cost elements in the power plant or power generating grid system. This policy would require the cooperation of state public utility commissions and other regulatory bodies as well as a host of public interest groups.

12.2.2 Indirect Financial Incentives

Because of the implicit income tax advantages, some of the incentives in this category have application only to investor-owned

utilities or industrial firms, rather than to municipal utilities or cooperatives. Increased investment tax credits and accelerated depreciation are two of these types of incentives. But municipal utilities can share in the benefits of government policies that provide bond guarantees or that back unique warranties offered by qualified equipment manufacturers on SSPS operating reliability or maintenance costs. Cooperatives can find assistance through broader application of REA loans and loan guarantees.

Expansion of the presently proposed Solar Energy Development Bank to meet the large capital needs of potential SSPS buyers might also be considered. Certainly, adequate sources of funds for future major capital purchases will continue to be of concern in the utility and industrial markets.

Except for a limited number of "innovators", buyers will undoubtedly defer their purchases as long as they perceive solar power systems to be in a transitional state of development which promises lower unit costs in the future. To overcome this reluctance to purchase a SSPS, one indirect incentive would be a means for financial compensation to early buyers of small solar power systems that may lack the technological improvements introduced into later models. The compensation could be given in the form of an income tax benefit (or as a cash rebate to non-investor-owned utilities).

12.2.3 Non-Financial Aids

Awards for early participants in a SSPS purchase program could carry the same prestige and notoriety as the Navy E (Excellence) Awards have done. Public perception of a utility or manufacturing firm can be enhanced by methods other than advertising, particularly if fuel savings are translated into more available fuel for space heating and/or automotive applications.

Although not a direct or indirect transfer of funds to potential SSPS buyers, a large expenditure of federal funds for demonstration units

could have a significant impact on perceived risk. If a group of different size units, featuring alternative designs, could be located in various regions of the nation, a number of present-day concerns about solar power systems could be relieved. For example, the demonstration units could provide a vast amount of data on SSPS operations and maintenance costs and reliability. In addition, the specific locales would offer a means of evaluating the system availability which is so dependent on daily insolation and the amount of storage designed into the system. The proliferation of demonstration units similar to the 10 MW_e utility plant planned for installation at Daggett, California, would provide an abundance of statistically significant data that would diminish the perceived investment risk. This policy could be a major factor in accelerating SSPS commercialization by normal market forces and could possibly result in far less expenditure of funds in the indirect and direct incentive categories.

12.3 IMPACT OF COMMERCIALIZATION STRATEGIES ON MARKET PENETRATION

The effect of some commercialization strategies can be judged by showing the sensitivity of SSPS market penetration to such strategies. Factors offering a positive incentive are potential increases in investment tax credits and in annualized fuel (or electric power) costs above values assumed in this study. Alternatively, potential increases in operations and maintenance costs or in system capital costs above the values assumed in this study would prove to be disincentives to market penetration. These negative aspects could conceivably arise if a very limited demonstration program did not permit early assessment of SSPS field units so that corrective action could be taken by various equipment manufacturers before significant production levels were achieved.

Market penetration is also sensitive to the annualized charge rate (ACR) which, as a percentage change factor, is comparable to a percentage change in solar system cost, because the product of these factors forms the numerator of the ECR. As discussed in Section 6.2.3, several key economic

factors are included in the ACR; these include the discount rate, SSPS operating and accounting lifetime, depreciation factor, income tax rate, local property taxes, insurance costs, SSPS operating and maintenance costs, and investment tax credit. Changes in any one, or any combination of these terms could have been considered for analysis. However, only the latter two economic factors, in addition to the ACR, have been isolated to show their individual impact on market penetration.

The sensitivity analysis is limited to showing the individual effect of each influencing factor. A more extensive analysis would be required to show combined effects. It is also likely that there could be some synergistic effects on market penetration, but the ability to model such effects would be dependent on a much more extensive, in-depth, survey of the utility and industrial markets.

Using the SSUMM and SSIMM computer programs, a sensitivity analysis was performed to show the impact of several parameters on SSPS market penetration. Because, as noted, changes in the ACR have the same effect as changes in solar costs, the analysis results are presented for four factors: solar system cost, operating and maintenance costs (O&M), fuel cost, and investment tax credit. The results are discussed in the following subsections. Graphs show the effect of percentage changes in these parameters on percentage changes in ECR and then show the effect of altered ECRs on estimates of nationwide installed SSPS capacity in each of the seven 5-year increments between 1985 and 2015.

The sensitivity analysis also provides a means for assessing the effect on market penetration of solar power system design concepts other than the central receiver-type. This approach to the evaluation of other design concepts is not completely rigorous, however, because it implies that costs as a function of SSPS size (scaling effect) and year of installation vary from the baseline case in a uniform manner. In fact, costs for alternative designs probably do not conform to this assumption, and therefore, a new analysis would be required to establish a precise measure

of market penetration. In lieu of such an analysis, the present sensitivity results are considered effective in providing a first-order quantification of how system costs affect market penetration.

12.3.1 Sensitivity of Utility Market Penetration to Cost and Economic Factors

Sensitivity curves for different ownership and SSPS applications in the utility market are given in Figures 12-1 through 12-7. The effect of solar system cost, operating and maintenance costs, fuel costs, and investment tax credit on the combined repowering and replacement market penetration is shown in Figure 12-1. The nominal case designation refers to the market penetration levels discussed in Section 8. The four influence factors are seen to have a linear effect on ECR, but a highly non-linear effect on market penetration because of the logarithmic scale used in the graph.

The impact of positive incentives has a remarkable impact on market penetration in the near-term. For example, a doubling in investment tax credit from 10 percent to 20 percent doubles the market penetration. A 50 percent increase in fuel costs above the nominal case could produce almost a hundred-fold increase in the 1985 market penetration, and by 2015 about 87 percent of the nearly 8000 MW_e of installed capacity could be penetrated.

Alternatively, unanticipated increases in O&M costs can have a disastrous effect on market penetration, particularly in the near-term. A 50 percent increase in this factor can result in a two-fold decrease in penetration. Solar system cost increases of 50 percent have an even greater negative impact, producing decreases in penetration of more than an order of magnitude.

Because the solar system cost forms one part of the product in the ECR numerator and the annualized fuel or purchased electric power cost forms the entire denominator of the ECR, a percentage increase in one is directly equivalent to a percentage decrease in the other. Hence, the

Figure 12-1. Utility Market Penetration Sensitivity (Repowering Plus Replacement Units)

impact on penetration of solar system cost decreases below the nominal can be ascertained by simply translating these decreases to fuel cost increases and reading values off the fuel cost curve. Similarly, effects of decreases in fuel cost can be assessed by reading values from the solar system cost increase curve.

The analysis has shown thus far that small changes in any one of the four influencing factors has a very significant effect on market penetration. This is also demonstrated for specific market segments such as steam turbine systems. Figure 12-2 shows that a 50 percent decrease in solar system costs below the nominal case or a 50 percent increase in fuel cost could result in 1985 penetration of about one-half of the nearly 3000 MW_e of available market in this category; by 2015, 98 percent of the market could be penetrated. In fact, by the year 2015, about two-thirds of the market could be penetrated with just a 25 percent decrease in solar system cost or increase in fuel cost. The implication from these and other curves is that large incentives can create very significant increases in market penetration in the near-term and that natural market forces are quite effective beyond the year 2000, permitting major reductions in the size of incentives.

The diesel and gas turbine market looks very poor in the near-term (Figure 12-3), and it does not appear that incentives can produce any large penetration of this market until about 1995. A 50 percent reduction in solar system costs at that time could result in penetration of about 20 percent of the nearly 5000 MW_e in this category; about 80 percent would be penetrated by the year 2015 under these conditions.

The curves in Figures 12-4 through 12-7 all show similar effects. The non-investor-owned group, however, always shows greater penetration of its available market (nearly 5500 MW_e) than the investor-owned group with an available market of nearly 2500 MW_e . Of interest is the non-linear nature of the investment tax credit curve in Figure 12-4 and the strong influence of this factor on market penetration when, as in this case, its

Figure 12-2. Utility Market Penetration Sensitivity
(Steam Units, Repowering Plus Replacement)

Figure 12-3. Utility Market Penetration Sensitivity (Diesel and Gas Turbine Units)

Figure 12-4. Utility Market Penetration Sensitivity
(Investor-owned, Repowering Plus Replacement Units)

effect has been isolated for the applicable market sector. Since tax credits have no effect on non-investor-owned units, they are not depicted in Figure 12-5.

Also of interest is the manner in which the repowering curves for 1995 through 2015 coalesce, as seen in Figure 12-6. Repowering has been shown earlier in Section 8 to be the prime market category for early penetration. The implication here is that this market is saturated by about 1990 (except for the impact of incentives) and that further growth in market penetration must take place in the replacement category.

One other aspect of the sensitivity analysis was examined, although the results have not been plotted. The assumed 40-year lifetime for conventional power units was varied by ± 10 years to note the effect on market penetration in the year 2015. An increase in this lifetime produced a small (~ 8.5 percent) increase in market penetration. This increase is attributed to the additional time available for power units to be repowered before being transferred into the replacement category; repowering, as noted, produces an earlier and larger market penetration than replacement. The effect of this extended unit lifetime also causes a large increase in the number of repowered units and a nearly equivalent decrease in the number of replacement units. The opposite effect was seen when the lifetime was reduced to 30 years.

The aforementioned curves all provide a means of assessing trade-offs between alternative incentives for accelerating market penetration. In addition, there are trade-offs discernable between natural market forces and the various incentives. For example, referring back to Figure 12-1, an installed capacity of 1000 MW_e could be achieved in 1985 by a solar system cost decrease of about 42 percent. The same installed capacity could be achieved in 1995 with about a 48 percent investment tax credit or incentives could be ignored and natural market forces could produce this result about the year 2013.

Figure 12-5. Utility Market Penetration Sensitivity
 (Non-Investor-owned, Repowering Plus Replacement Units)

Figure 12-6. Utility Market Penetration Sensitivity (Repowering Units)

Figure 12-7. Utility Market Penetration Sensitivity (Replacement Units)

12.3.2 Sensitivity of Industrial Market Penetration to Cost and Economic Factors

The four influence factors, (i.e., the costs for the solar system, O&M, and fuel, and investment tax credit) discussed in Section 12.3.1 for utilities have been plotted in Figures 12-8 through 12-12 for various categories in the industrial market. Impact of these factors on the total market of roughly 2100 MW_e is shown in Figure 12-8. The industrial market is seen to be as much affected by incentives as the utility market. Indeed, a 50 percent decrease in solar system costs, for example, can result in penetration of 10 percent of the market as early as 1985. By 2015, this same incentive results in a penetration of almost 75 percent of the available market. Where normal market forces might cause this SSPS application to be dismissed, it is seen that the introduction of incentives can be instrumental in retaining the industrial market as a viable consideration. Disincentives, of course, are equally as inhibiting to penetration as they were for the utility market.

Figures 12-9 and 12-12 show effects very similar to those in Figure 12-8 because almost all the industrial systems are investor-owned and more than 90 percent of the market penetration is expected to be achieved with repowering systems.

Since there are only 14 government-operated systems (designated non-investor-owned), the curves in Figure 12-10 are not of great interest in terms of total installed capacity, but are included here to complete the presentation. The same remarks apply to Figure 12-11 which displays the very small portion of the market attributable to replacement systems.

12.4 PRE-POLICY IMPLEMENTATION CONSIDERATIONS FOR DOE

Under the scenarios used in this study, commercialization of small solar power systems would be expected to take place during a lengthy evolutionary period as natural market forces reduce the relative risks of these systems and costs decline while competing fuel (or purchased electric

Figure 12-8. Industrial Market Penetration Sensitivity
(Diesel and Gas Turbine Replacement Plus Steam Repowering Systems)

Figure 12-9. Industrial Market Penetration Sensitivity
 (Investor-owned, Diesel and Gas Turbine Replacement Plus Steam Repowering Systems)

Figure 12-10. Industrial Market Penetration Sensitivity (Federally-Operated Systems)

Figure 12-11. Industrial Market Penetration Sensitivity (Replacement Systems)

Figure 12-12. Industrial Market Penetration Sensitivity (Repowering Systems)

power) costs continue to climb. Since this rate of solar power market development may be considered too low to have a major impact on the nation's continued and growing dependence on fossil fuels, DOE may desire to initiate policies to accelerate the penetration of utility and industrial markets by SSPS. To be effective, the structure of these policies will have to be decided in the next few years. Many utilities are already engaged in their own process of policy formation for the future (e.g., joint ventures). It is not the purpose of this study to suggest DOE policy, but rather to present policy alternatives as in Sections 12.2 and 12.3, and to suggest some important investigative activities before policy formulation and implementation. These activities are discussed in the succeeding paragraphs.

The strategies discussed in Sections 12.2 and 12.3 should be subjected to further investigation and analysis. Personal interviews with management personnel at utilities and industrial firms are essential to determining the favorable and unfavorable aspects of such strategies as well as for soliciting additional strategies favored by these potential buyers of SSPS. The extremely diverse nature of the utility and industrial communities makes it essential that as many data sources as possible be contacted. However, the reality of limited time and funding would suggest that the selection of interviewees be made from the most promising market penetration candidates determined by use of the SSUMM and SSIMM computer program.

Policy alternatives should be discussed with the U.S. Environmental Protection Agency and state environmental agencies to determine the impact of SSPS on air quality and to determine if modifications to existing or forthcoming regulations might result in incentives favorable to SSPS market penetration. Additionally, analyses should be conducted to evaluate the offsets offered by SSPS in regard to atmospheric emissions of fossil-fueled systems and to determine the cost saving associated with elimination of emission control equipment that would have been required for fossil-fueled systems.

Discussion of policy alternatives with the Rural Electrification Administration and other financial arms of the federal government is also essential to selection of favorable strategies and the rate of implementation of such strategies. In fact, the functional role of all federal agencies expected to be involved in SSPS commercialization policies must be clearly understood and then specified by legislation, if necessary. The role of the U.S. Congress in drafting, reviewing, and approving supportive legislation must be especially considered when preparing implementation schedules for policies designed to accelerate SSPS commercialization.

Last, but certainly not least in importance is the need to perform cost-benefit analyses for each policy alternative. The anticipated massive government expenditures that might be required to develop the economic climate leading to a mature SSPS manufacturing industry and a viable market for this product make it essential that cost-effective solutions be selected. As noted earlier, widespread installation of SSPS demonstration systems may prove to be a more effective strategy than simply outright rebates or special tax advantages to select market sectors.

Two further suggestions are in order. The present study of SSPS was restricted to considering repowering or replacement of existing conventional electric generating systems under 10 MW_e rated capacity. The size of this class of solar power systems should be expanded to include systems up to 50 MW_e (or even 100 MW_e) because, (1) the potential market would be several times that of the market associated with the present size range, (2) most of the power generating systems which utilities consider to be large are in excess of 100 MW_e, and (3) the relative probability of market penetration is greater for the larger systems because of scale effects that reduce SSPS unit costs as size increases. Furthermore, if this class of solar power systems is permitted to grow in size, then additional analyses should be conducted to determine the role of SSPS in meeting plant expansion needs for utilities and industrial firms. In regions where environmental regulations

are presently restricting utility and industrial expansion of electric generating equipment, or possibly eliminating it in the future, SSPS may prove to be a partial solution that permits the continued growth of local communities and contributes to the economic health of the nation as a whole.

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APPENDIX A

**DATA RECORDING FORMAT FOR TELEPHONE
INTERVIEWS WITH UTILITIES**

SMALL POWER SYSTEMS
TELEPHONE SURVEY

Utility Name _____
Location _____
Contact(s) _____

Phone _____
Number(s) _____

Interviewer _____
Date of Interview _____

A. Market Demand Characteristics

1. Geographical features of market:
 - a) Number of communities served? _____
 - b) Population of largest community served? _____
 - c) Area of region served? _____
2. Present level of demand? _____ KW_e H/year
3. Demand growth rates? 5 years _____ 15 years _____ 30 years _____
4. Peak load(s)? _____
5. Time(s) of day for peak(s)? _____
6. Ratio of peak to base load? _____

B. Power Sources

7. a) How will growth of demand be satisfied:

installation of new equipment? _____ Type? _____

joint venture with other utilities? _____

major grid tie-in? _____ other? _____
- b) When will a decision on equipment purchase or operations changes be required? _____
8. What percent of power purchased? 5 years _____ 15 years _____
30 years _____
9. Type of power purchased? Base _____ Intermediate _____
Peak _____
10. Restrictions on buying or selling power? _____
11. Equipment inventory

	Steam	Diesel	Gas Turbine
Number			
Size MW _e			
Age			
Capacity Factor			
Yrs. to Replacement			
Estimated Replacement Cost			

12. a) Types of fuel used? _____ Current prices? _____
b) Availability problems expected? _____ When? _____
c) Expected rates of price increase? _____

C. Financing

13. Percentage of funds from:

- bonds? _____ Revenue bonds or general obligations? _____
- preferred stock? _____
- common stock? _____
- general tax revenues? _____
- other? _____ type? _____

14. Cost of funds:

- bond coupon rates? _____
- allowed rate of return on preferred? _____
common? _____
- other? _____

15. Any changes expected in types or terms? _____

16. What percent of plant replacement could be financed without affecting cost of funds? _____

D. Solar System Investment Decision Factors

17. Required discounted cash flow internal rate of return on investment? _____

18. a) Adjacent land available? Yes _____ No _____
b) Number of acres? _____
c) Cost (\$/acre)? _____

19. Environmental restrictions:

- on current operations? _____
- expansion? _____

20. Factors for evaluating alternative power sources in order of priority?

May we contact you again by telephone?

Supplementary Questions if Time Available

A. Market Demand Characteristics

21. How will future customer mix change:

- peak loads? _____
- peak time(s) of day? _____
- peak/base ratio? _____

C. Financing

22. If you would consider a joint venture would the purpose be to:

- take advantage of scale economies of larger equipment? _____
- access capital? _____
- improve financing terms? _____

D. Decision Factors

23. What factors would make small solar power systems attractive? _____

24. Required payback period? _____

25. Lost revenues or additional costs if acquire small solar power system? _____

APPENDIX B

DATA RECORDING FORMAT FOR TELEPHONE INTERVIEWS WITH INDUSTRIAL FIRMS

INDUSTRIAL PROCESS ENERGY DATA

1.0 Plant Identifiers ¹

- 1.1 SIC Code
- 1.2 City
- 1.3 State
- 1.4 Zip Code
- 1.5 Company Name
- 1.6 Plant Name
- 1.7 Plant Contact
- 1.8 Phone Number
- 1.9 Interviewer/Firm
- 1.10 Phone Number

2.0 Process Heat Requirements

Units

Individual processes (up to 5):

2.1	Name of process	
2.2	Supply temperature	°F.
	(Temperature at which heat transfer fluid is delivered to the process)	
2.3	Material temperature	°F.
	(Temperature of the material being processed)	
2.4	Flowrate	lb/hr.
2.5	Pressure	psi.
2.6	Steam Quality	%
2.7	Heat Transport Medium	
2.8	Process Medium	

¹ You may choose not to report portions of this information if there are proprietary restrictions.

2.0 Process Heat Requirements (Continued)

Units

2.9	Daily start hour	
2.10	Daily end hour	
2.11	Days per week	
2.12	Scheduled downtime	
2.13	Unscheduled downtime	weeks/year
2.14	Process line condition (Age, relative efficiency, etc. Rate as excellent, good, average, fair, or poor.)	

Plant totals:

2.15	Unscheduled downtime	weeks/year
2.16	Fuel type	
2.17	Annual fuel usage	MMBTU/year
2.18	Cost	\$/MMBTU
2.19	Utility supply schedule (interruptible or continuous)	

Discuss:

2.20	Backup fuel
2.21	Substituability

3.0 Electrical Requirements

Units

Each process (up to 5):

3.1	Peak power	kw
3.2	Peak/average ratio	
3.3	Supply voltage	v

3.0 Electrical Requirements (Continued)

		<u>Units</u>
Each on-site turbine-generator unit (up to 5)		
3.4	Fuel type	
3.5	Turbo-generator Type (e.g., diesel, steam, gas turbine, etc.)	
3.6	Rated capacity	kVA
3.7	Inlet temperature	°F.
Steam systems only:		
3.8	Inlet pressure	psi
3.9	Flowrate	lb./hr.
3.10	Extraction temperature	°F
3.11	Extraction pressure	psi
Plant totals:		
3.12	Utility company	
3.13	Rate schedule (Utility designated rate code, if available)	
3.14	Total annual purchased power	MWh
3.15	Total annual self-generated power	MWh
3.16	Estimated unit cost of self-generated power	mills/kwh

4.0 Economic Factors

		<u>Units</u>
4.1	Discount rate	%
or 4.2	Payback period	years
4.3	Number of employees	

4.0 Economic Factors (Continued)

		<u>Units</u>
4.4	Value of shipments	\$10 ⁶ /year
4.5	Age of plant	years
4.6	Percent of operating cost for energy	%
4.7	Total available adjacent land (own, lease, purchase)	acres
4.8	Total available roof area	10 ³ sq.ft.
4.9	Urban or rural location	

Discuss:

- 4.10 Shape, terrain, and
suitability of available land
- 4.11 Plant environment (dust, air
pollutants, local micro-climate
etc.)
- 4.12 Other considerations (if any)

5.0 Institutional Factors

- 5.1 Perspectives on Fuel Availability
- 5.2 Perspectives on Fuel costs
- 5.3 Environmental impact problems
- 5.4 Prior conditions before solar considered
- 5.5 Does an energy management program/
committee exist?
- 5.6 Preferred incentives (tax credit,
low-interest loans)
- 5.7 Who is responsible for energy-related
investment?

5.0 Institutional Factors (Continued)

5.8 Preferred methods of information dissemination

- Trade journals
- Technical meetings
- Trade associations
- Briefings
- Other

5.9 Energy conservation measures implemented
(since 1974)

5.10 What alternatives have been considered?

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