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Assessment of the Potential of Solar Thermal Small Power Systems in Small Utilities

Final Report

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ASSESSMENT OF THE POTENTIAL OF SOLAR THERMAL SMALL POWER SYSTEMS IN SMALL UTILITIES

FINAL REPORT

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ABSTRACT

This study involved an assessment of the potential economic benefit of small solar thermal electric power systems to small municipal and rural electric utilities.

Five different solar thermal small power system configurations were considered in the study representing three different solar thermal technologies. The configurations included:

- 1-MW, 2-MW, and 10-MW parabolic dish concentrators with a 15-kW heat engine mounted at the focal point of each dish. These systems utilized advanced battery energy storage.
- A 10-MW system with variable slat concentrators and central steam Rankine energy conversion. This system utilized sensible thermal energy storage.
- A 50-MW central receiver system consisting of a field of heliostats concentrating energy on a tower-mounted receiver and a central steam Rankine conversion system. This system also utilized sensible thermal storage.

The approach used in determining the potential for solar thermal small power systems in the small utility market involved a comparison of the economics of power supply expansion plans for seven hypothetical small utilities through the year 2000 both with and without the solar thermal small power systems. Insolation typical of the Southwestern U.S. was assumed.

The study results can be summarized in terms of break-even capital costs. In this study the break-even capital cost was defined as the solar thermal plant capital cost which would have to be achieved in order for the solar thermal plants to penetrate 10 percent of the reference small utility generation mix by the year 2000. The break-even capital costs calculated in the study were:

- $713/kW to $1307/kW for the parabolic dish concentrator systems
- $977/kW to $1720/kW for the variable slat concentrator system
- $1075/kW for the central receiver system

A comparison of the break-even capital costs with the range of plant costs estimated in this study yields the following conclusions:

- The parabolic dish concentrator systems could be economically competitive with conventional generation if the lowest capital costs can be achieved.
- The variable slat concentrator and central receiver systems would have to achieve lower costs than the lowest in the cost ranges generally assumed in the study to become economically competitive.
- All of the solar thermal plant types are potentially more competitive in utilities which are heavily dependent upon oil (represented in the study by a 35-MW Municipal with oil-fired generation) than in utilities which burn coal primarily.

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SUMMARY

This study involved an assessment of the potential economic benefit of small solar thermal power systems to small municipal and rural electric utilities. The objectives of the study were to develop an inexpensive methodology for a preliminary examination of these systems prior to more detailed analysis and to use this methodology to assess various small solar thermal power system configurations.

Five different small power system configurations were considered in the study representing three different solar thermal technologies. The configurations included:

- 1-MW, 2-MW, and 10-MW parabolic dish concentrators with a 15-kW heat engine mounted at the focal point of each dish. These systems utilized advanced battery energy storage.
- A 10-MW system with variable slat concentrators and central steam Rankine energy conversion. This system utilized sensible thermal energy storage.
- A 50-MW system consisting of a field of heliostats concentrating energy on a tower-mounted receiver and a central steam Rankine conversion system. This system also utilized sensible thermal storage.

The characteristics assumed in the study for each solar thermal power system type are summarized in Table S-1. The characteristics shown assume a plant location in the Southwestern United States.

The approach used in determining the potential for the solar thermal power systems in the small utility market involved a comparison of the economics of power supply expansion plans for seven hypothetical small utilities through the year 2000 both with and without the solar thermal power systems. Key characteristics of the reference utilities are summarized in Table S-2. Other key input data to the economic analysis is summarized in Section 3 of this report.

The study results can be summarized in terms of break-even capital costs. In this study the break-even capital cost was defined as the capital cost

Table S-1

SMALL SOLAR THERMAL POWER SYSTEM TYPES AND CHARACTERISTICS

Characteristic	Parabolic Dish Concentrator Systems			Variable Slat Concentrator System	Central Receiver System	Data Provided By JPL	Data Developed By Burns & McDonnell
Plant Size (Rated Capacity, MW)	1	2	10	10	50	X	
Commercial Availability	1985	1985	1985	1985	1985	X	
Cost Characteristics (1975 $)							
Capital Cost ($/kW)[a,b]	638-2,923	578-2,312	508-1,848	1,506-3,806	1,103-2,759	X	X
Operation & Maintenance							
Fixed ($/kW-yr)	2-14	2-14	2-14	2-14	2-14	X	
Variable (mills/kWh)	1-4	1-4	1-4	1-4	1-4	X	
Other Characteristics							
Average Plant Efficiency	.28	.28	.28	.14	.22	X	
Equipment Forced Outage Rate	.01	.01	.01	.07	.07	X	
Annual Maintenance (weeks/yr)[c]	0.1	0.1	0.1	1.0	1.0	X	
Storage							
Capacity Rating (MW)	1	2	10	7	35	X	
Energy Rating (MWh)[b]	2	4	20	14	70		X
Receiver Intensity Rating (kW/m^2)[b]	0.9	0.9	0.9	0.9	0.8		X
Collector Area (km^2)[b]	0.004	0.008	0.040	0.112	0.422		X
Land Area (km^2)[b]	0.013	0.026	0.133	0.373	1.407		X
Solar Multiple[b]	1.0	1.0	1.0	1.5	1.5		X
Lifetime (years)	30	30	30	30	30	X	

[a]*Includes costs of Solar hardware (collector, transport, conversion and storage subsystems), which were provided by JPL, and all other costs except interest during construction (land, site development, water supply, buildings, electrical connections, cooling towers if necessary, and overhead items), which were developed by Burns & McDonnell or provided by JPL. A discussion of the development of the "other" costs is included in Appendix B.*

[b]*Assumes a location in the Southwestern United States.*

[c]*Includes only maintenance which must be performed when the plant would normally by operating (i.e., daytime maintenance). It is assumed that most routine maintenance could be done at night.*

Table S-2

CHARACTERISTICS OF SEVEN REFERENCE UTILITIES

1974 Peak Demand (MW)	System Description	Peak Load Season	Annual Load Factor (%)	1974 Power Resources					
				Total Generation Capacity	Coal Steam	Oil Steam	Combustion Turbine	Diesel	Hydro
1.3	Municipal	Summer	49	1.2 MW	–	–	–	2-.2 MW 1-.3 MW 1-.5 MW	
10	Municipal With Generation	Summer	49	12 MW	–	–	–	2-1 MW 3-2 MW 1-4 MW	–
10	Municipal Without Generation	Summer	49	None	–	–	–	–	–
35	Municipal With Coal-Fired Generation	Summer	45	40 MW	2-5 MW 1-20 MW	–	1-10 MW	–	–
35	Municipal With Oil-Fired Generation	Winter	55	24 MW	–	1-5 MW 1-10 MW	–	3-3 MW –	–
35	Distribution Cooperative	Summer	49	10 MW	–	–	–	3-1 MW 2-2 MW 1-3 MW	– –
200	Generation & Transmission Cooperative	Summer	57	180 MW	2-10 MW 1-60 MW	1-30 MW	1-20 MW	–	50-MW*

** Assumes 20 MW of firm and 30 MW of firm peaking capacity from a U.S. government agency.*

which would have to be achieved by the solar thermal power system in order for it to have the economic potential to penetrate 10 percent of the generation mix of each reference utility by the year 2000. The break-even capital cost can be used as a guideline in determining what combination of subsystem cost reductions and increases in subsystem efficiency would suffice to make a given solar thermal power system type economically competitive.

Table S-3 summarizes the break-even capital costs calculated in the study for each solar thermal power system type. A comparison of these values with the range of study input capital costs yields the following conclusions:

- The parabolic dish concentrator systems could be economically competitive with conventional generation if the low end of the capital cost range can be achieved.
- The variable slat concentrator and central receiver systems would have to achieve lower costs than the lowest in the cost ranges assumed in the study to become economically competitive.

These results are also shown graphically on Figure S-1.

The factors which had the most impact on these results can be divided into two general categories: the characteristics of the host utility and the characteristics of the solar thermal small power systems. The most important utility characteristics as far as the potential penetration of solar thermal power systems is concerned included the type of existing generation, purchased power costs, geographic location and utility type (ownership). Other less important utility characteristics included peak load season and load pattern. Characteristics of the solar thermal power systems which had the greatest impact included storage, plant costs other than solar hardware costs, collector costs, and system efficiency. Operation and maintenance costs had less impact on results.

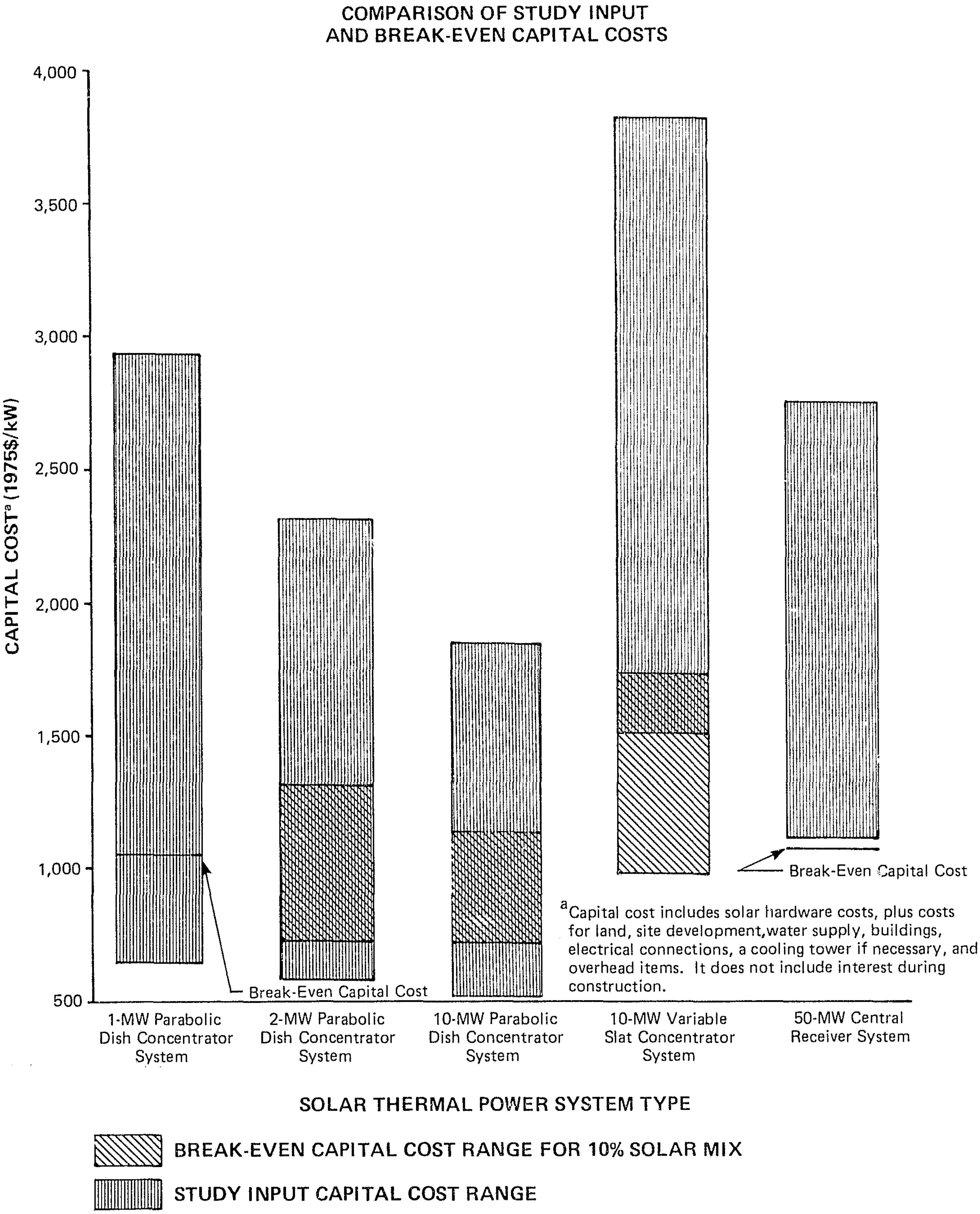
The most important characteristic of the host utility's existing generation mix was the fuel type used by the generating units. It was found that a utility which is heavily dependent on oil-fired generation (represented in the study by the 35-MW municipal with oil-fired generation) is more likely to find solar thermal power systems economically competitive with conventional generation. High purchased energy costs were also found to have a similar impact.

Table S-3

BREAK-EVEN CAPITAL COSTS AT 10% SOLAR MIX VERSUS STUDY INPUT CAPITAL COST RANGES (1975 $/kW)

Reference Utility	Solar Thermal Power System Type: 1 MW Parabolic Dish Concentrator System	2 MW Parabolic Dish Concentrator System	10 MW Parabolic Dish Concentrator System	10 MW Variable Slat Concentrator System	50 MW Central Receiver System
Study Input Capital Cost[a] Range					
All Utilities	638-2,923	578-2,312	508-1,848	1,506-3,806	1,103-2,759
Break-Even Capital Cost[a] At 10% Solar Mix					
1.3-MW Municipal	1,049.8	–	–	–	–
10-MW Municipal With Generation	–	968.6	–	–	–
10-MW Municipal Without Generation	–	1,070.1	–	–	–
35-MW Municipal with Coal-Fired Generation	–	746.4	716.2	1,137.4	–
35-MW Municipal with Oil-Fired Generation	–	1,307.3	1,138.8	1,720.1	–
35-MW Distribution Cooperative	–	720.7	713.0	976.8	–
200-MW Generation & Transmission Cooperative	–	–	771.6	1,069.8	1,075.5

[a] *Capital cost includes solar hardware costs, plus costs for land, site development, water supply, buildings, electrical connections, a cooling tower if necessary, and overhead items. It does not include interest during construction.*



JPL 78-008-4-005

Figure S-1

The impact of geographic location on the competitiveness of solar thermal power systems was primarily a result of regional variations in the intensity of insolation and the amount of cloudiness. These factors affected both the required size of the collector field and the amount of energy which could be obtained from the solar thermal power systems.

Utility type or ownership had an impact on the competitiveness of solar thermal power systems as a result of differences in interest rates or cost of capital. Because solar thermal power systems are more capital intensive than conventional generation, differences in interest rate have a larger impact on solar plant costs than on the costs of conventional generation.

One characteristic of the solar thermal power systems which had a major impact on their competitiveness was the storage subsystem. The type of storage and assumptions made regarding the charging of storage had a significant impact on the required size of the collector field, the amount of energy available from the solar plant and the capacity credit or load carrying capability of the solar plant.

The solar plant costs for all items other than the solar hardware were also a major factor. These costs, which included items such as land, site development (grading, graveling, etc.), water supply, a control room/ maintenance building, electrical connections, a cooling tower if necessary and overhead, were estimated by Burns & McDonnell to range from 27 to 80 percent of the total solar plant costs. With these costs, none of the solar thermal power systems were generally competitive with conventional generation. The only capital costs for which the solar thermal power systems were generally competitive were costs which included low costs for all of these "other" items. These low costs, which were provided by JPL, assumed the development of innovative site preparation and construction techniques. Of the solar hardware costs, the collector costs generally had the largest impact on the competitiveness of the solar thermal power systems. Efficiency also had a relatively large impact on the competitiveness of solar thermal power systems. Improvement in the efficiencies of the lowest efficiency subsystems, which were generally the energy conversion subsystems, would have the largest impact on the system cost and thus would do most to increase the competitiveness of the solar thermal power systems.

In addition to the economic factors discussed above, several non-economic factors may have an impact on the potential role of solar thermal small power systems in small utilities. These include environmental impacts, political climate (including potential governmental subsidies or other economic incentives), and limitations on the availability or legal restrictions on the use of oil for power generation. It was assumed in the study that fuel oil would be available and that the only mechanism for allocation would be price. If fuel oil were not available, solar thermal power systems might be more attractive because of their ability to reduce oil consumption. For the reference utilities considered in the study, oil consumption was projected to be reduced by 16 to 86 percent depending on the scenario by the introduction of solar thermal power systems.

* * * * *

Section 1

INTRODUCTION

There has been increasing interest in recent years in alternative forms of power generation which would help reduce the dependence of the nation's electric utility industry on oil and gas. Solar thermal power systems represent one technology with potential for helping to reduce this dependence. This report presents the results of a study of the potential economic benefits of small solar thermal power systems to small electric utilities. The study, which was sponsored by the Jet Propulsion Laboratory (JPL) of the California Institute of Technology, was conducted as a part of the solar thermal Small Power Systems Applications Project which JPL is managing for the Department of Energy (DOE). The Small Power Systems Applications Project (SPSA) is discussed briefly below.

For the purposes of this study small electric utilities were defined as those with a 1974 peak demand between 0.5 and 500 MW. This study complements a study of fossil-fired advanced power generation technologies which Burns & McDonnell recently completed for the Electric Power Research Institute (1,2).

SMALL POWER SYSTEMS APPLICATIONS PROJECT

The objective of the Small Power Systems Applications Project is to establish technical, operational, and economic readiness of solar thermal small power systems in the 1 to 10 MW_e range. The project will develop systems to the point at which subsequent commercialization activities can lead to successful market penetration. The technologies being considered in this project include distributed systems utilizing Rankine, Brayton and Stirling energy conversion, as well as small central receiver systems. Potential applications for these small power systems include small community electric power, rural electric power, isolated loads, light industrial and military power systems.

The principal issues being considered by the SPSA project include the need for small solar thermal power systems; the solar energy technology which best meets these needs; the economics of small solar thermal power systems; the institutional, societal, and environmental considerations which are important to the commercial success of these small power systems; the desirability of government involvement to accelerate commercialization and the appropriate strategy for commercialization of small solar thermal power systems.

The Small Power Systems Applications Project consists of four functional tasks: Requirements Definition, Systems Definition, Project Analysis and Integration, and Field Test Integration. The primary goals of the Requirements Definition portion of the project, of which the study is a part, include the identification and characterization of potential users of solar thermal small power systems and the establishment of user requirements for these plants.

POTENTIAL ROLE OF SOLAR THERMAL POWER SYSTEMS IN SMALL UTILITIES

The power supply problem of small utilities can be appreciated by considering a typical utility load duration curve shown in Figure 1-1. A load duration curve is simply a distribution of a system's loads during specified intervals over some time period. The area under the load duration curve represents the system's total energy requirement for the period.

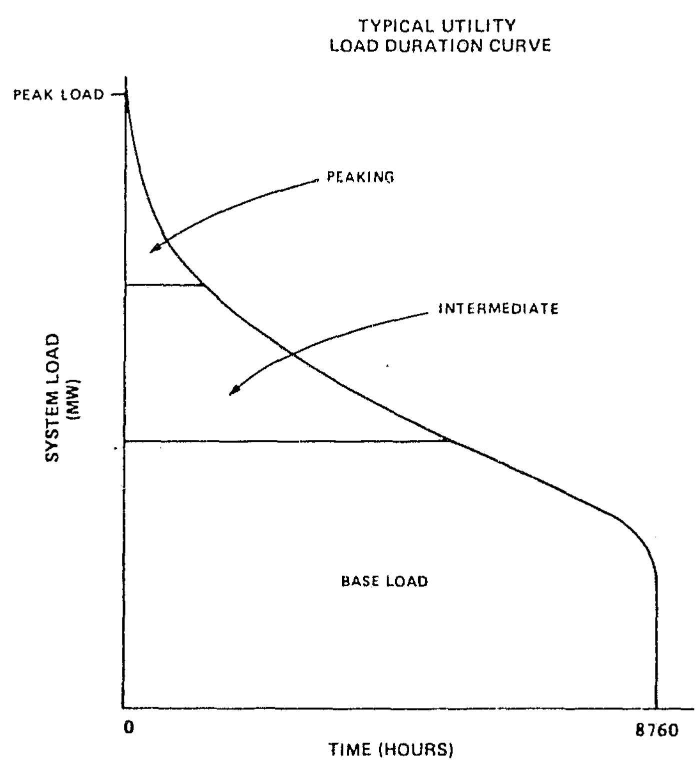


Figure 1-1. Typical Utility Load Duration Curve

For any utility, the fundamental economic problem is to supply the energy requirement of the system (i.e. the area under the load duration curve) at the lowest cost that will ensure reliable service. Electric utilities usually classify their power supply resources into base, intermediate, and peaking capacity types. These resource types supply the energy requirements for a system as illustrated in Figure 1-1. Base load resources, such as coal and nuclear fueled generation, are associated with high fixed costs and low variable costs. Peaking capacity types, such as combustion turbines, usually have low fixed costs and high variable costs. Intermediate power supply resources fall between the extremes of fixed and variable costs. The problem for the utility is to minimize its cost of power generation by optimizing its mixture of these three categories of resources.

Solar power systems cannot be placed into any of these three traditional categories. They have high fixed (capital) costs and low variable (energy) costs like base load resources. However, because the energy from the solar power system is not available at night or during cloudy weather, it cannot be relied on to provide base load power on demand. Rather, one can anticipate solar power systems being operated more like peaking units in order to reduce the peak load which must be met by conventional power supply resources. The inadequacy can be mitigated in varying degrees by energy storage, the effect of dispersed solar power systems in an interconnected system, or a secondary energy source such as oil.

STUDY OBJECTIVES AND SCOPE

The objectives of this study were to develop an inexpensive methodology for use in identifying strengths and weaknesses or potential problem areas of small solar thermal power systems prior to more detailed analyses and use this methodology to assess the potential economic benefits of various small solar thermal power system configurations to small utilities. These objectives were accomplished through the performance of four technical tasks which are described below.

Task 1 - Development of an Additional Reference Utility

This task involved the characterization of small municipal and rural utilities with 1974 peak demands of 0.5 to 2 MW and the development of a hypothetical reference utility to represent these utilities. This reference utility was used in the study, along with six reference utilities which were developed in the EPRI advanced technology study (1,2), to represent utilities with 1974 peak demands of 0.5 to 500 MW. A statistical description of both data bases is included in Appendix A.

Task 2 - Modification of Burns & McDonnell Power Supply Analysis Methodology

This task involved the modification of the Burns & McDonnell power supply analysis methodology to allow the introduction of solar thermal power systems.

The task was accomplished in four parts including:

- Development of a computer program to analyze the solar thermal power systems on an hourly basis considering hourly system loads and insolation patterns.
- Selection of values for solar thermal power system parameters which depend on geographic location for each system type based on the results of preliminary hourly analyses.
- Determination of capacity credit values for each solar thermal power system type considered in the study. Capacity credit indicates the ability of the solar thermal power system to decrease the annual system peak demand which must be met by conventional resources.
- Modification of the existing Burns & McDonnell power supply analysis computer model to accept the results of the hourly analysis of the solar thermal power systems.

Four different solar thermal power system types were considered in the study including a 2-MW and a 10-MW system consisting of modular parabolic dish collectors with a small heat engine mounted at the focal point of each dish, a 10-MW system consisting of variable slat collectors with central steam Rankine energy conversion and a 50-MW central receiver system consisting of a field of heliostats focusing insolation on a tower-mounted receiver and a central steam Rankine energy conversion system.

Task 3 - Development and Analysis of Power Supply Expansion Plans

This task involved the development and analysis of several generation expansion plans for the period 1980-2000 for each of the seven reference utilities with both conventional generation and the applicable solar thermal power system types. The results of these analyses were compared on the basis of the present worth of all future revenue requirements for each expansion plan. In addition, a break-even capital cost was developed at which the solar thermal power system was projected to penetrate 10% of each small utility's generation mix.

Task 4 - Sensitivity Analyses

This task involved the determination of the effect of changes in efficiency, operation and maintenance costs, fuel price escalation rates and geographic location on the results of Task 3.

* * * * *

Section 2

SMALL SOLAR THERMAL POWER SYSTEM TYPES AND CHARACTERISTICS

This section describes the solar thermal power generation technologies considered in this study and summarizes the characteristics assumed for each small power system type.

SOLAR THERMAL POWER SYSTEM TECHNOLOGIES

Three different solar thermal technologies are represented by the small power systems considered in this study. The technologies considered include a two-axis tracking parabolic dish concentrator system, a single-axis tracking variable slat concentrator system and a central receiver system with a field of two-axis steerable heliostats focused on a tower-mounted receiver.

Parabolic Dish Concentrator System

The parabolic dish concentrator systems considered in this study consist of two-axis tracking parabolic dish concentrators with a 15-kW engine-generator mounted at the focal point of each dish. A Brayton cycle gas turbine, Stirling engine, or small Rankine engine could be used as the engine-generator for these systems. Advanced batteries were assumed to provide energy storage for this configuration. A schematic diagram of this system is shown in Figure 2-1.

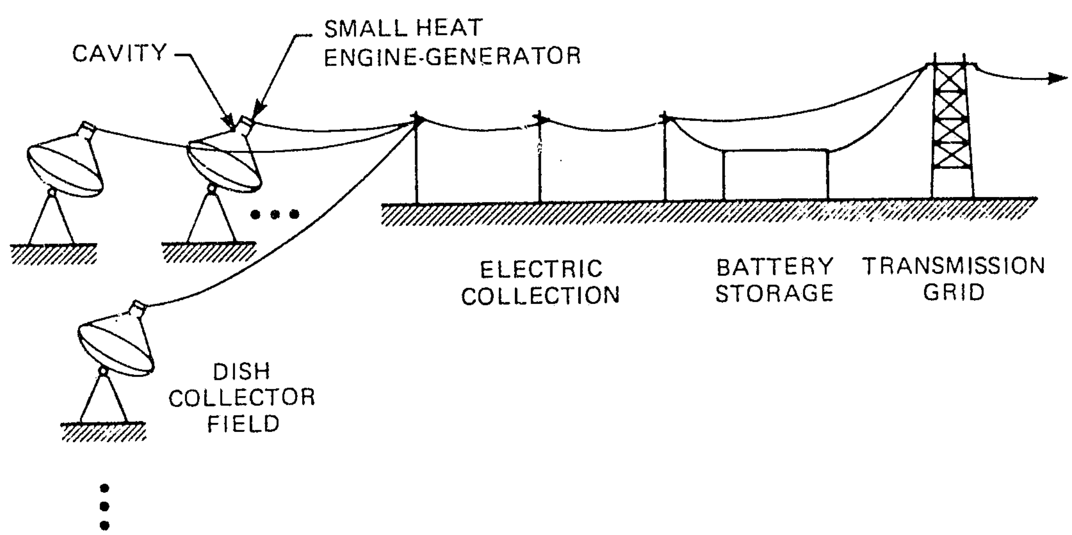


Figure 2-1. Parabolic Dish Concentrator System

There are a variety of possible configurations for the advanced battery storage system associated with the parabolic dish concentrator system. Unlike thermal storage, battery storage need not be located in close proximity to the solar power system. In general, it may be located at any point on the transmission grid and may be charged with power from any of the utility's generating resources. Alternatively, the storage system may be dedicated to the solar power system, so that only power generated by the solar plant can charge the battery system. With a dedicated storage configuration, a portion of the parabolic dish generator modules may be dedicated exclusively to charging the storage system or each module may be capable of delivering power directly to the transmission grid, to storage, or simultaneously to the grid and to storage, up to its rated capacity.

A non-dedicated storage configuration would have the most operational flexibility and would therefore be the most likely configuration to be preferred by the utility. The utility would charge storage with power from the solar generator only if it were most economical to do so. However, with this type of configuration a decision relative to the addition of storage capacity to the utility system might be independent of a decision to install a solar power system. For example, a utility might find it more economical to add storage capacity without any solar capacity than to install both. This type of option was beyond the scope of the current study. Storage was of interest in this study only insofar as it made a given solar thermal power system more attractive economically. Therefore, in this study only dedicated storage was considered.

Of the two dedicated storage configurations mentioned above the second configuration, in which each solar module is capable of delivering power directly to the transmission grid, to storage, or to both up to its rated capacity, has more operational flexibility and is therefore more likely to be implemented. This configuration was selected for use in this study. This choice of storage configuration had implications for both the dispatching strategy used with this system and the selection of system parameters such as collector area. The implications for dispatching strategy are discussed in Section 4 and Appendix D and the implications for parameter selection are discussed in Section 4 and Appendix E.

Variable Slat Concentrator System

The variable slat concentrator system consists of strip reflectors located along a curved surface which concentrate energy on a cavity receiver. In this system, energy is transported as steam from the collectors to a central steam Rankine conversion plant. Energy storage for this system was assumed to be thermal storage, which can only be charged by the solar power system. This system is illustrated schematically in Figure 2-2.

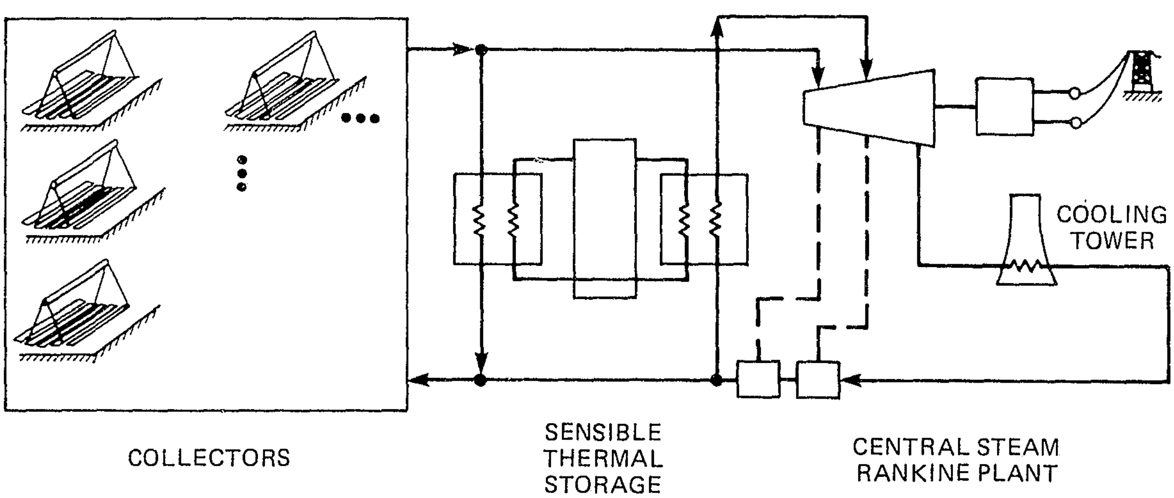


Figure 2-2. Variable Slat Concentrator System

Central Receiver System

The final system considered in the study was a central receiver system consisting of a field of two-axis steerable heliostats concentrating energy on a tower-mounted receiver. Steam is transported from the receiver to a conventional steam Rankine conversion plant. This system also assumed thermal energy storage. A schematic diagram of this system is shown in Figure 2-3.

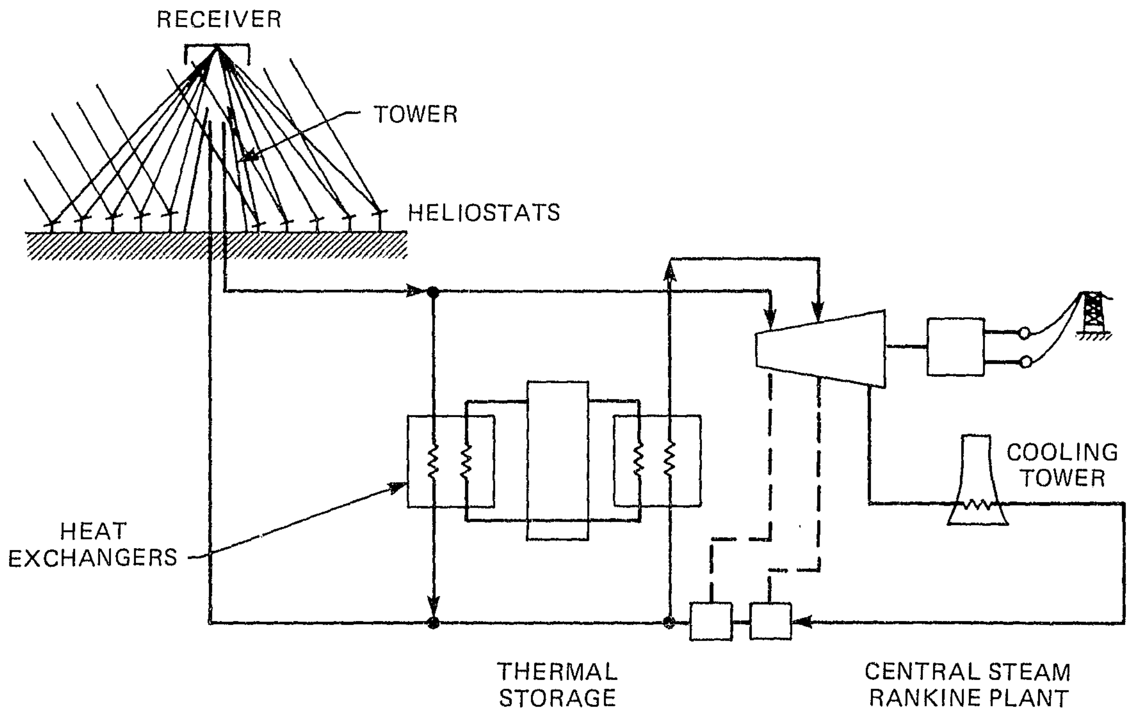


Figure 2-3. Central Receiver System

SMALL SOLAR THERMAL POWER SYSTEM CHARACTERISTICS

The characteristics assumed for each solar thermal power system type considered in this study are summarized in Table 2-1. The first three types are parabolic dish concentrator systems differing from one another primarily in rated capacity. The fourth type is a variable slat concentrator system and the fifth type is a central receiver system. The characteristics shown for each small power system type were provided by JPL or developed by Burns & McDonnell for a southwest location based on data supplied by JPL. A brief discussion of each of these characteristics is provided below.

Table 2-1
SMALL SOLAR THERMAL POWER SYSTEM TYPES AND CHARACTERISTICS

Characteristic	Parabolic Dish Concentrator Systems			Variable Slat Concentrator System	Central Receiver System	Data Provided By JPL	Data Developed By Burns & McDonnell
Plant Size (Rated Capacity, MW)	1	2	10	10	50	X	
Commercial Availability	1985	1985	1985	1985	1985	X	
Cost Characteristics (1975 $)							
Capital Cost ($/kW)[a,b]	638-2,923	578-2,312	508-1,848	1,506-3,806	1,103-2,759	X	X
Operation & Maintenance							
Fixed ($/kW-yr)	2-14	2-14	2-14	2-14	2-14	X	
Variable (mills/kWh)	1-4	1-4	1-4	1-4	1-4	X	
Other Characteristics							
Average Plant Efficiency	.28	.28	.28	.14	.22	X	
Equipment Forced Outage Rate	.01	.01	.01	.07	.07	X	
Annual Maintenance (weeks/yr)[c]	0.1	0.1	0.1	1.0	1.0	X	
Storage							
Capacity Rating (MW)	1	2	10	7	35	X	
Energy Rating (MWh)[b]	2	4	20	14	70		X
Receiver Intensity Rating (kW/m^2)[b]	0.9	0.9	0.9	0.9	0.8		X
Collector Area (km^2)[b]	0.004	0.008	0.040	0.112	0.422		X
Land Area (km^2)[b]	0.013	0.026	0.133	0.373	1.407		X
Solar Multiple[b]	1.0	1.0	1.0	1.5	1.5		X
Lifetime (years)	30	30	30	30	30	X	

[a] *Includes costs of Solar hardware (collector, transport, conversion and storage subsystems), which were provided by JPL, and all other costs except interest during construction (land, site development, water supply, buildings, electrical connections, cooling towers if necessary, and overhead items), which were developed by Burns & McDonnell or provided by JPL. A discussion of the development of the "other" costs is included in Appendix B.*

[b] *Assumes a location in the Southwestern United States.*

[c] *Includes only maintenance which must be performed when the plant would normally by operating (i.e., daytime maintenance). It is assumed that most routine maintenance could be done at night.*

Plant Size

The plant size, or rated capacity, shown for each solar thermal power system type is the capacity which the system is designed to deliver at a specified level (thermal design point) of solar radiation intensity (insolation). At lower levels of insolation, the plant delivers energy at a lower power level. At higher levels of insolation, the excess radiation energy is diverted to thermal storage or dumped for systems with battery storage. Systems with battery storage are incapable of utilizing radiation energy in excess of their thermal design point since all radiation energy must be converted to electrical energy prior to being stored. This limitation is taken into consideration in selecting a thermal design point for these systems.

Commercial Availability

For the purposes of this study, it was assumed that all of the solar thermal power system types would be commercially available in 1985.

Cost Characteristics

The cost characteristics shown in Table 2-1 include capital costs (excluding interest during construction) and operation and maintenance costs. These costs are shown in 1975 dollars. A general inflation rate of six percent per year was assumed for all costs except fuel. Differential fuel price escalation rates of 0, 2 and 4 percent per year were considered in the study.

Capital Cost. As shown in Table 2-1, a range of capital costs was considered for each solar thermal power system type. The capital costs shown assume a location in the Southwestern United States and include the costs of solar hardware (the collector, transport, conversion and storage subsystems) and all other installation costs except interest during construction. All costs are based on the specific system configurations (storage rating, collector area, land area, etc.) shown.

These capital cost ranges were developed using a range of costs provided by JPL for each of the solar power subsystems and a range of "other" costs provided by JPL or developed by Burns & McDonnell. The cost ranges shown in Table 2-2 for the solar thermal subsystems represent values which are potentially achievable by 1985. The cost ranges for the "other" category include land, site development, water supply, maintenance/control room building, electrical connections, a cooling tower if necessary, and overhead items. The high ends of these ranges reflect standard cost estimates (developed in the same manner as steam plant estimates) which were prepared by Burns & McDonnell. The low ends of these ranges are based on figures supplied by JPL which assume the development of innovative site preparation and construction techniques. As an example, the standard estimates developed by Burns & McDonnell assume that the plant site will be graveled for dust suppression, whereas the low estimates might assume aerial spraying or spraying from water trucks for dust suppression.

Table 2-2
SMALL SOLAR THERMAL POWER SYSTEM
SUBSYSTEM COSTS
(1975 $)

Subsystem	Parabolic Dish Concentrator Systems	Variable Slat Concentrator System	Central Receiver System
Solar Hardware			
Collector ($/m^2)	62–192	85–171	65–145
Transport ($/kW)	18–50	75–150	150–300
Conversion ($/kW)	53–200	175–350	175–350
Storage ($/kWh)	45	60	60
Other[a] ($/kW)	100–1820	185–1274	109–764

[a]Includes land, site development, water supply, buildings, electrical connections, cooling tower if necessary, and overhead. Does not include interest during construction. A discussion of the development of "other" costs is included in Appendix B.

To determine the impact of the full range of capital costs three different levels of capital cost were considered for each solar thermal power system, as shown in Table 2-3. The low capital cost assumes both the low end of the solar hardware cost ranges and the low "other" costs which were provided by JPL. The intermediate cost assumes the low end of the solar hardware cost ranges and the standard cost estimates developed by Burns & McDonnell for all other items. The high cost assumes the high end of the solar hardware cost

Table 2-3

SMALL SOLAR THERMAL POWER SYSTEM CAPITAL COST[a] SUMMARY (1975 $/kW)

MUNICIPAL UTILITIES[b]

Solar Thermal Power System Type	Low Cost[c]	Intermediate Cost[d]	High Cost[e]
1-MW Parabolic Dish Concentrator System	637.6	2,043.5	2,895.0
2-MW Parabolic Dish Concentrator System	577.6	1,426.6	2,278.9
10-MW Parabolic Dish Concentrator System	507.6	968.6	1,820.7
10-MW Variable Slat Concentrator System	1,505.5	2,234.5	3,751.0
50-MW Central Receiver System	1,099.9	1,514.7	2,719.1

COOPERATIVE UTILITIES[b]

Solar Thermal Power System Type	Low Cost[c]	Intermediate Cost[d]	High Cost[e]
1-MW Parabolic Dish Concentrator System	641.2	2,063.5	2,923.4
2-MW Parabolic Dish Concentrator System	582.4	1,440.6	2,312.4
10-MW Parabolic Dish Concentrator System	511.3	978.1	1,847.5
10-MW Variable Slat Concentrator System	1,513.9	2,267.9	3,806.2
50-MW Central Receiver System	1,103.0	1,537.0	2,759.1

[a] *Excludes interest during construction.*

[b] *The difference between capital costs for municipal and cooperative utilities is property tax during construction which must be paid by the cooperatives but not by the municipals.*

[c] *The low cost assumes both the low end of the solar hardware cost ranges and low "other" costs which were provided by JPL assuming that these other costs could be reduced through the development of innovative site preparation and construction techniques. "Other" costs are discussed in detail in Appendix B.*

[d] *The intermediate cost assumes the low end of the solar hardware cost ranges and standard cost estimates developed by Burns & McDonnell for all other items. These cost estimates for other items are discussed in Appendix B.*

[e] *The high cost assumes the high end of the solar hardware cost ranges and standard cost estimates developed by Burns & McDonnell for all other items. These cost estimates for other items are discussed in Appendix B.*

ranges and the standard cost estimates developed by Burns & McDonnell for all other items.

These three capital cost levels were further differentiated by the type of reference utility to which they were applicable. This distinction reflects the fact that cooperative utilities must pay property taxes during construction whereas municipal utilities are exempted from such taxes. Additional details of these capital cost estimates are contained in Appendix B.

Operation and Maintenance Cost. The fixed and variable operation and maintenance cost ranges shown in Table 2-1 were provided by JPL. It was assumed in the study that the low fixed operation and maintenance cost ($2/kW-yr) corresponds to high variable operation and maintenance cost (4 mills/kWh) and, conversely, that a high fixed operation and maintenance cost ($14/kW-yr) corresponds to a low variable operation and maintenance cost (1 mill/kWh). The first of these two assumptions ($2/kW-yr and 4 mills/kWh) was included in the initial analyses. The second assumption ($14/kW-yr and 1 mill/kWh) was considered in the sensitivity analysis.

Other Characteristics

Other characteristics shown for each solar thermal power system type in Table 2-1 include operating characteristics and subsystem sizes. Each of these characteristics is discussed separately below.

Average Plant Efficiency. The average plant efficiency assumed for each solar thermal power system type is shown in Table 2-1. Calculated plant efficiencies vary from these values for various scenarios depending upon the proportion of energy which is directly dispatched to the transmission grid from the solar thermal power system versus the amount which passes through energy storage. The subsystem efficiencies for each solar thermal power system type, which were provided by JPL, are shown in Table 2-4. Potential increases in subsystem efficiencies were considered in the sensitivity analysis.

Table 2-4

SMALL SOLAR THERMAL POWER SYSTEM

SUBSYSTEM EFFICIENCIES

Subsystem	Parabolic Dish Concentrator Systems	Variable Slat Concentrator System	Central Receiver System
Collector	.69	.54	.65
Concentrator	.864	-	-
Receiver	.804	-	-
Transport	.95	.92	.95
Conversion	.42	.30	.36
Storage (Round Trip)	.75	.75	.75

Equipment Forced Outage Rate. The equipment forced outage rates provided by JPL were .01 for the parabolic dish concentrator systems and .07 for the variable slat concentrator and central receiver systems, as shown in Table 2-1. The low value assumed for the parabolic dish concentrator systems is based on the fact that these plants consist of a large number of small modules which are unlikely to be forced out simultaneously. The forced outage rate for this plant type is based primarily on the forced outage rate for components such as transmission lines which would cause a forced outage for the entire plant. Forced outages due to cloudiness or other weather conditions were considered separately in the hourly analyses.

Annual Maintenance. The annual maintenance requirements provided by JPL were 0.1 week/year for the parabolic dish concentrator systems and 1 week/year for the variable slat concentrator and central receiver systems. These figures include only maintenance which must be performed when the plant would normally be operating (i.e., daytime maintenance). It was assumed that most routine maintenance could be performed at night when the plants are not operating.

Storage. The storage capacity and energy ratings assumed in the study for each solar thermal power system type are shown in Table 2-1. The energy ratings were developed by Burns & McDonnell in a parameter optimization analysis for the Southwestern United States, as discussed in Section 4 and Appendix E. Basically, the energy storage optimization involved a trade off between increased capacity credit and increased capital cost as the amount of storage was increased.

Receiver Intensity Rating. The receiver intensity rating was defined as the level of direct normal insolation at which the solar thermal power system reaches its rated thermal receiver power. The receiver intensity rating was determined by Burns & McDonnell for each solar thermal power system type in a parameter optimization analysis for the Southwestern United States, as discussed in Section 4 and Appendix E. This optimization involved trade offs between increased capacity factor and increased capital cost as a result of increased collector area as the receiver intensity rating was decreased.

Collector Area. The collector areas shown for each solar thermal power system type in Table 2-1 were developed by Burns & McDonnell in a parameter optimization analysis for the Southwestern United States, as discussed in Section 4 and Appendix E. In general, a larger collector area resulted in a higher capacity credit and capacity factor, but it also resulted in a higher capital cost.

Land Area. The required land area for each solar thermal power system type was calculated by Burns & McDonnell from the required collector area and a factor, provided by JPL, of 3-1/3 square kilometers of land per square kilometer of collector area.

Solar Multiple. The solar multiple was defined as the ratio of the maximum available thermal receiver power to the thermal power corresponding to the rated electrical capacity of the solar thermal power system. The solar multiple was developed by Burns & McDonnell in a parameter optimization analysis for the Southwestern United States, as discussed in Section 4 and Appendix E. The selection of the solar multiple is related to the selection of the amount of thermal storage, since the solar multiple determines the amount of collector area which can be devoted to charging storage. The solar multiple for systems with battery storage is always 1.0 since it was assumed in this study that no collector area would be dedicated exclusively to charging battery storage.

Lifetime. All of the solar thermal power system types considered in the study were assumed to have an average lifetime of 30 years. However, the subsystem lifetimes for the energy conversion and storage subsystems of the parabolic dish concentrator systems were assumed to be only 15 years.

* * * * *

Section 3

GENERAL ECONOMIC ANALYSIS INPUT DATA

The basic approach used in determining the potential for solar thermal small power systems in small utilities involved a comparison of the economics of power supply expansion plans for seven hypothetical small utilities through the year 2000 both with and without the solar thermal small power systems described in the previous section. In this section, the reference utilities used in the study are described and the costs and parameters used to expand the reference utilities through the year 2000 are discussed. Information is provided concerning characteristics of the existing generation of the reference utilities, load growth projections, characteristics of conventional generation types used in the reference system expansions, carrying charge data, fuel prices and purchased power costs.

In conducting this study, the basic scenario outlined in the EPRI advanced technology study (1,2) was followed. Therefore, many of the costs and parameters used in this study were identical to those used in the EPRI study. The primary difference in input data from that study was the use of a 6 percent general inflation rate and 2 percent differential fuel price escalation. No inflation factor was used in the EPRI study. In addition, the interest rate on municipal bonds was changed from 7.25 percent to 6 percent to more closely reflect current market rates.

REFERENCE UTILITIES

Table 3-1 summarizes the key characteristics of the seven hypothetical reference utilities used in the study including their 1974 peak demands, system types, peak load seasons, system load factors, and total power generation capacities in 1974 by generation type. Initially, it was assumed that all of these utilities were located in the Southwestern United States. During the sensitivity analyses, other geographic locations were considered.

Table 3-1
CHARACTERISTICS OF SEVEN REFERENCE UTILITIES

1974 Peak Demand (MW)	System Description	Peak Load Season	Annual Load Factor (%)	1974 Power Resources					
				Total Generation Capacity	Coal Steam	Oil Steam	Combustion Turbine	Diesel	Hydro
1.3	Municipal	Summer	49	1.2 MW	—	—	—	2-.2 MW 1-.3 MW 1-.5 MW	
10	Municipal With Generation	Summer	49	12 MW	—	—	—	2-1 MW 3-2 MW 1-4 MW	—
10	Municipal Without Generation	Summer	49	None	—	—	—	—	—
35	Municipal With Coal-Fired Generation	Summer	45	40 MW	2-5 MW 1-20 MW	—	1-10 MW	—	—
35	Municipal With Oil-Fired Generation	Winter	55	24 MW	—	1-5 MW 1-10 MW	—	3-3 MW —	—
35	Distribution Cooperative	Summer	49	10 MW	—	—	—	3-1 MW 2-2 MW 1-3 MW	— —
200	Generation & Transmission Cooperative	Summer	57	180 MW	2-10 MW 1-60 MW	1-30 MW	1-20 MW	—	50-MW*

** Assumes 20 MW of firm and 30 MW of firm peaking capacity from a U.S. government agency.*

The 1.3-MW municipal reference utility was developed by Burns & McDonnell for this study based on a statistical analysis of over 200 small utilities with 1974 peak demands between 0.5 and 2.0 MW. The other six reference utilities were developed for the EPRI advanced technology study based on a statistical analysis of over 2,000 small utilities with 1974 peak demands between 2 and 500 MW. Statistical characteristics developed from both data bases are summarized in Appendix A.

HOURLY LOAD PATTERNS

The hourly load patterns of each reference utility were modeled with three weeks of hourly load data representing the summer, winter and spring/fall seasons. The three weekly load patterns which were used for the 1.3-MW municipal, the two 10-MW municipals and the 35-MW municipal with coal-fired generation are shown in Figure 3-1. These load patterns represent actual hourly load data of a municipal utility located in the North Central United States. This selection of load data was made during the EPRI advanced technology study (1,2) and was retained for this study even though the utilities were assumed to be located in the Southwestern United States for this study.

The load patterns used for the 35-MW municipal with oil-fired generation were those developed for a synthetic utility with a 56 percent annual load factor by Power Technologies, Inc., in a study for the Electric Power Research Institute (3). These load patterns are shown in Figure 3-2.

Figure 3-3 shows the load patterns used for the 35-MW distribution cooperative and the 200-MW generation and transmission cooperative. These load patterns represent actual hourly load data of a generation and transmission cooperative located in the Southwestern United States.

EXISTING GENERATION CHARACTERISTICS

The characteristics, including fuel type, heat rate, operation and maintenance costs, forced outage rate and annual availability for the existing generating units shown in Table 3-1 were developed by Burns & McDonnell and are shown in Table 3-2. A retirement schedule for these units is shown in Table 3-3.

HOURLY LOAD PATTERNS
FOR 35-MW MUNICIPAL WITH COAL-FIRED GENERATION,
BOTH 10-MW MUNICIPALS, AND 1.3-MW MUNICIPAL

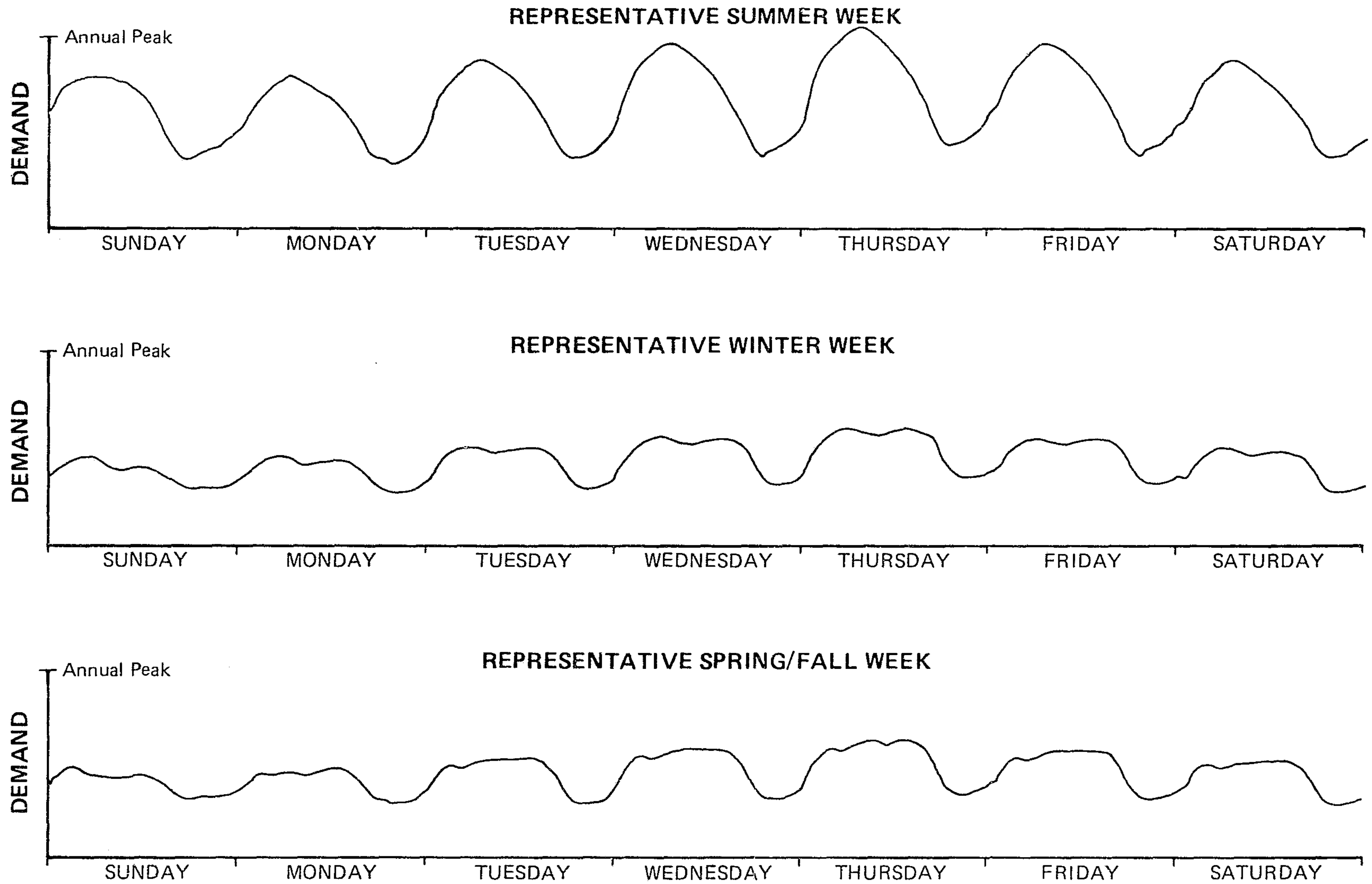


Figure 3-1

HOURLY LOAD PATTERNS
35-MW MUNICIPAL WITH OIL-FIRED GENERATION

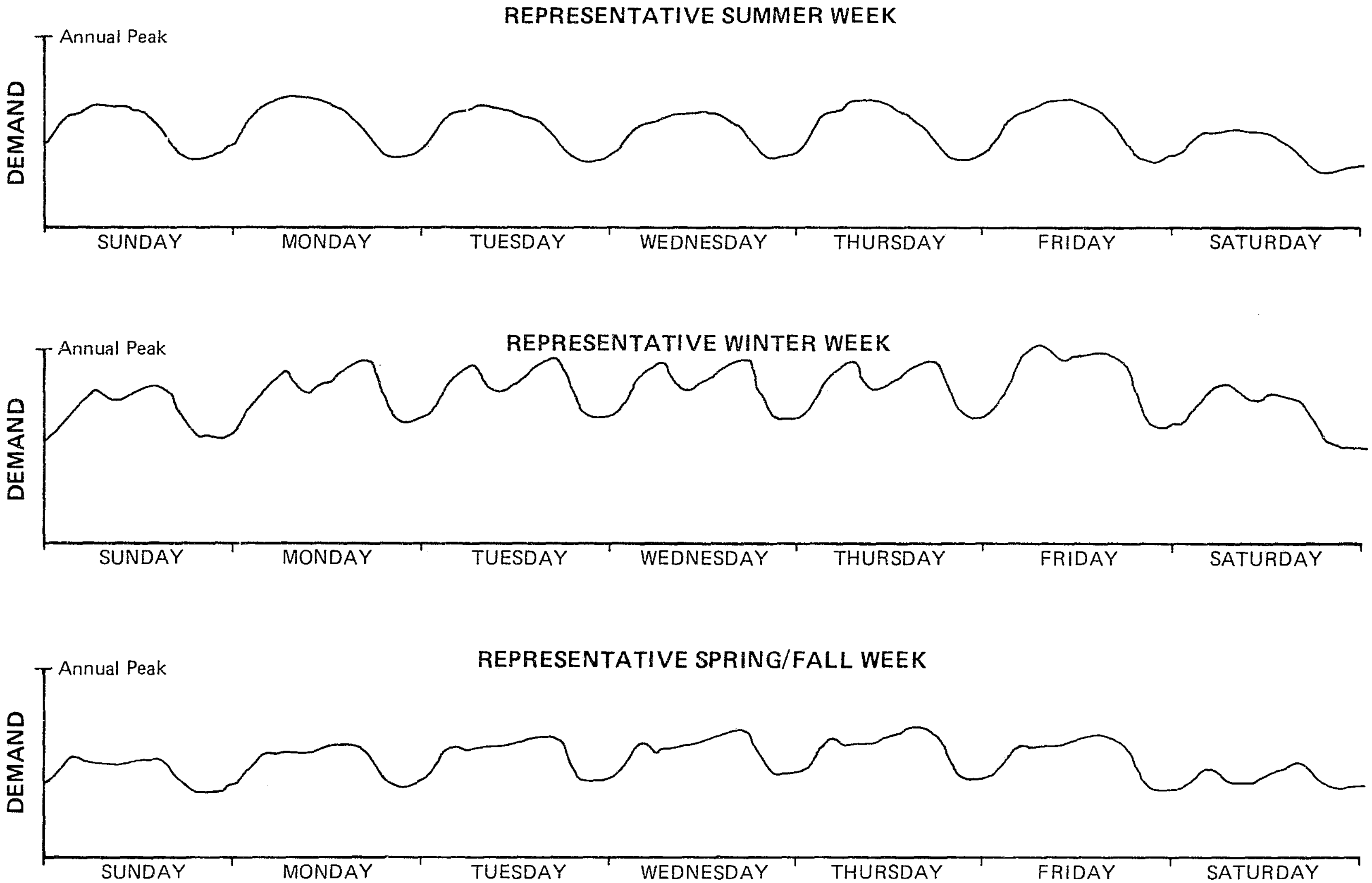


Figure 3-2

HOURLY LOAD PATTERNS
200-MW GENERATION AND TRANSMISSION COOPERATIVE
AND 35-MW DISTRIBUTION COOPERATIVE

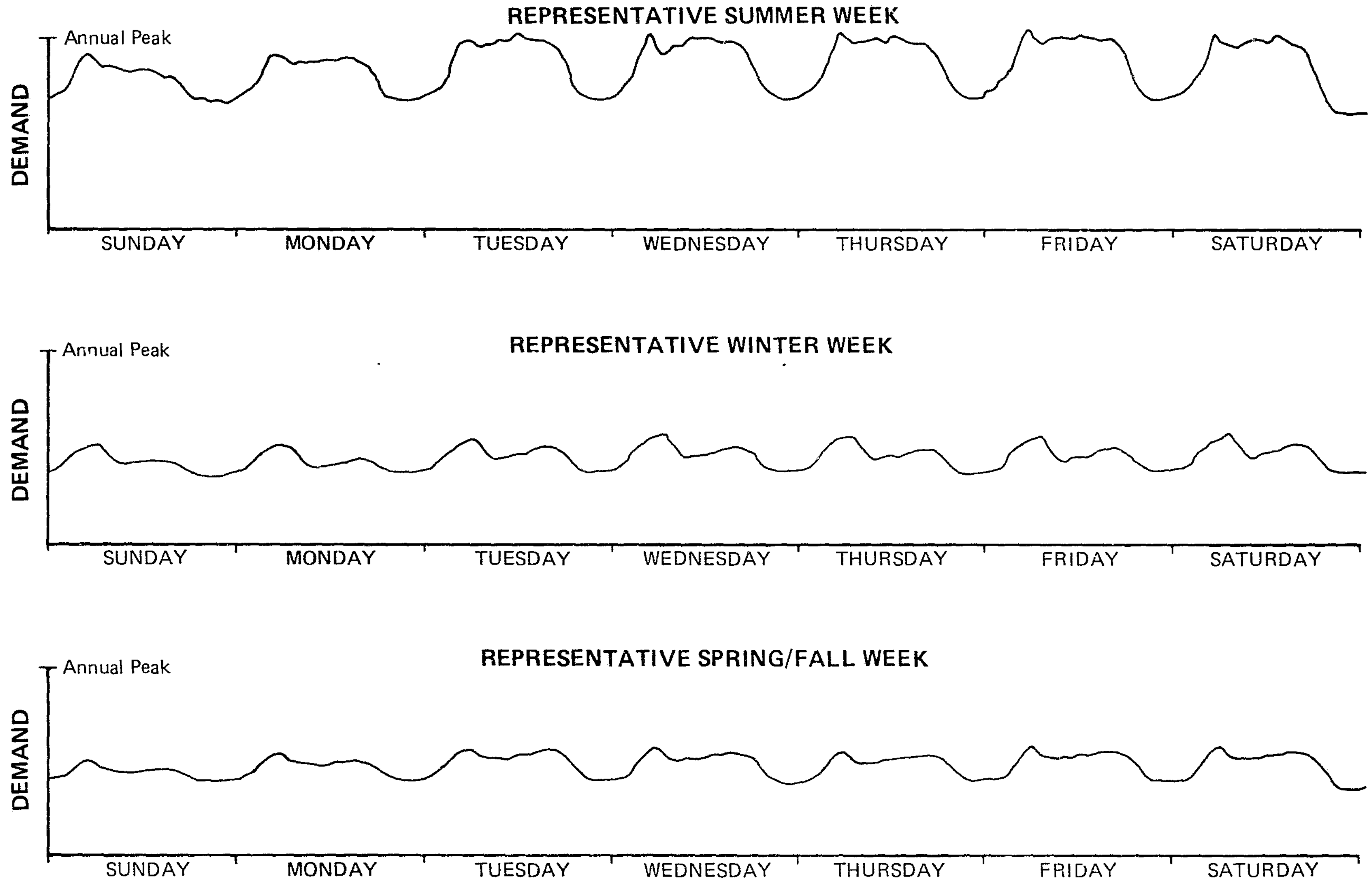


Figure 3-3

Table 3-2
DATA FOR EXISTING UNITS

		Net Heat Rate (Btu/kWh)					Operation & Maintenance (1975$)			
		At % Load								
Generation Type	Fuel Type	25%	50%	80%	100%	Average Annual	Fixed [a] ($/kW)	Variable [b] (Mills/kWh)	Forced Outage Rate (%)	Annual Availability (%) [c]
5-MW Coal Steam	Coal	17,540	16,160	15,540	15,630	16,600	–	1.0	6	87
10-MW Coal Steam	Coal	16,940	15,190	14,810	15,100	15,900	–	1.0	6	87
20-MW Coal Steam	Coal	13,920	12,840	12,380	12,410	13,300	–	1.0	6	87
60-MW Coal Steam	Coal	12,900	11,900	11,470	11,500	11,900	–	1.0	6	87
5-MW Oil Steam	Oil #6	17,540	16,160	15,540	15,630	16,600	–	2.0	6	87
10-MW Oil Steam	Oil #6	16,940	15,190	14,810	15,100	15,900	–	1.0	6	87
30-MW Oil Steam	Oil #6	14,420	13,300	12,820	12,855	13,000	–	1.0	6	87
10-MW Combustion Turbine	Oil #2	30,000	22,830	17,460	14,840	20,000	–	5.0	11	89
20-MW Combustion Turbine	Oil #2	22,300	16,900	14,400	13,600	14,500	–	5.0	11	89
.2-MW Diesel	Oil #2	16,980	12,200	11,800	12,000	12,250	–	2.5	10	90
.3-MW Diesel	Oil #2	16,950	12,190	11,800	12,000	12,250	–	2.5	10	90
.5-MW Diesel	Oil #2	16,900	12,180	11,800	12,000	12,200	–	2.5	10	90
1-MW Diesel	Oil #2	16,750	12,000	11,750	11,890	12,000	–	2.5	10	90
2-MW Diesel	Oil #2	16,050	11,500	11,260	11,390	11,500	–	2.5	10	90
3-MW Diesel	Oil #2	15,100	11,400	10,575	10,625	11,000	–	2.5	10	90
4-MW Diesel	Oil #2	13,960	10,000	9,750	9,910	10,000	–	2.5	10	90

[a] *Since only incremental costs were included in the study (See Appendix C, Page C-7), fixed O&M on existing units was assumed to be zero.*

[b] *Exclusive of fuel.*

[c] *For steam units, Availability = 1-Forced Outage Rate — maintenance outage rate. For intermediate — peaking capacity types, Availability = 1-Forced Outage Rate.*

Table 3-3
RETIREMENT SCHEDULE FOR EXISTING UNITS

Reference Utility	Generation Type	In-Service Year	Retirement Year
1.3-MW Municipal	.2-MW Diesel	1950	1985
	.2-MW Diesel	1956	1991
	.3-MW Diesel	1964	1999
	.5-MW Diesel	1973	2008
10-MW Municipal	1-MW Diesel	1940	1975
	1-MW Diesel	1945	1980
	2-MW Diesel	1950	1985
	2-MW Diesel	1960	1999
	2-MW Diesel	1966	2004
	4-MW Diesel	1970	2008
35-MW Municipal With Coal-Fired Generation	5-MW Coal Steam	1954	1989
	5-MW Coal Steam	1955	1990
	20-MW Coal Steam	1965	2000
	10-MW Combustion Turbine	1970	2005
35-MW Municipal With Oil-Fired Generation	3-MW Diesel	1948	1983
	3-MW Diesel	1950	1985
	5-MW Oil Steam	1955	1990
	3-MW Diesel	1960	1995
	10-MW Oil Steam	1965	2000
35-MW Distribution Cooperative	1-MW Diesel	1940	1975
	1-MW Diesel	1945	1980
	1-MW Diesel	1950	1985
	2-MW Diesel	1955	1990
	2-MW Diesel	1960	1995
	3-MW Diesel	1965	2000
200-MW G&T Cooperative	10-MW Coal Steam	1950	1985
	10-MW Coal Steam	1955	1990
	30-MW Oil Steam	1960	1995
	60-MW Coal Steam	1965	2000
	20-MW Combustion Turbine	1972	2007

PROJECTED POWER REQUIREMENTS

Table 3-4 shows the peak demand growth rates used for the reference utilities in this study. These rates were developed for the EPRI advanced technology study (1,2) based on reviews and analyses of statistical load growth data developed from the small utility data base, information in published articles concerning historic and future load growth rates for the electric utility industry and computer projections based on historic data for actual utilities similar to the reference utilities used in the study. The higher load growth rate shown for cooperative utilities is consistent with historical trends.

TABLE 3-4

PROJECTED PEAK DEMAND GROWTH RATE

	Projected Compound Annual Growth Rate					
System Type	1974-1975	1980-1985	1985-1990	1990-1995	1995-2000	1974-2000
Municipal	6.5	6.0	5.0	4.5	4.0	5.2
Cooperative	10.0	8.0	6.5	5.5	5.0	7.1

INSOLATION DATA

For the initial analysis one set of insolation data was used for the Southwestern United States for all of the reference utilities. The data used was hourly insolation data for Albuquerque, New Mexico for three typical days representing the summer, winter, and spring/fall seasons, as shown in Figure 3-4. The data was developed using a National Bureau of Standards (NBS) program (4). This program provides data based on average conditions for a given location and time of year and day. It requires as input data monthly averages of total daily radiation on a horizontal surface both at the location and outside the earth's atmosphere. During sensitivity analysis, the same program was used to calculate insolation data for other geographic locations.

COMPARISON OF SEASONAL INSOLATION PATTERNS
SOUTHWEST UNITED STATES

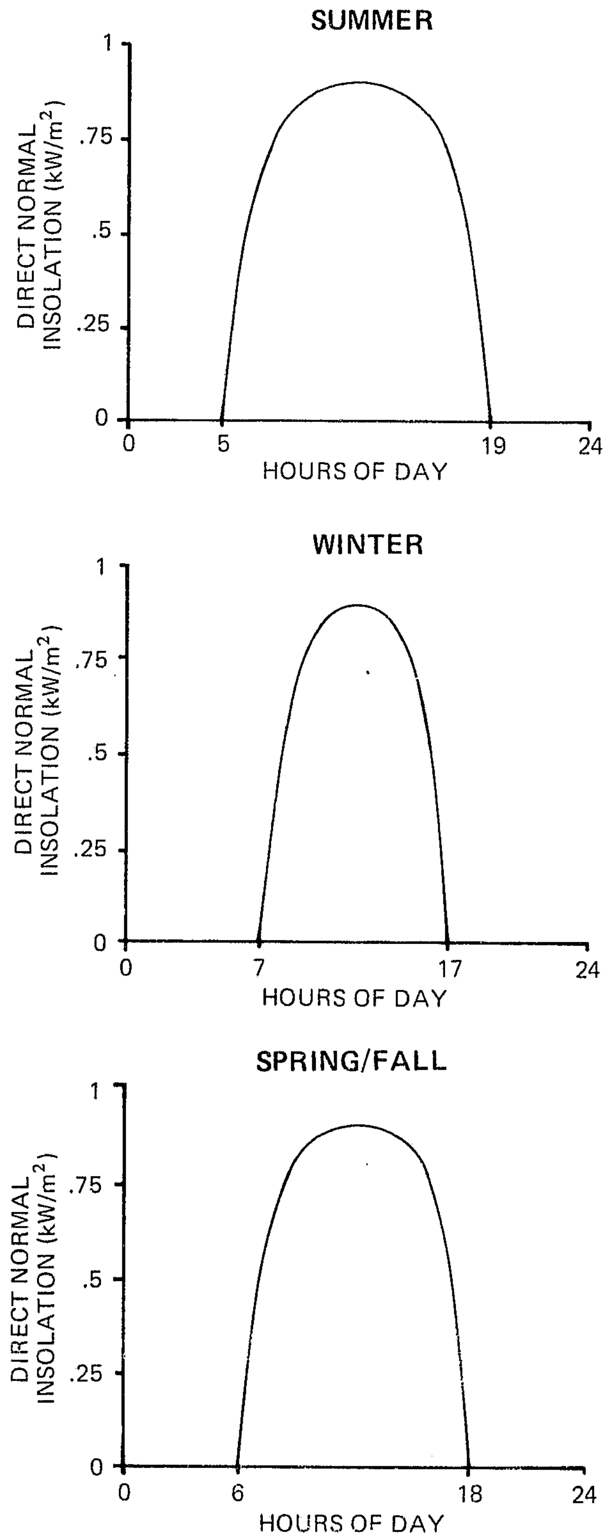


Figure 3-4

CONVENTIONAL POWER RESOURCES

It was assumed in the study that the reference utilities would install their own generation to satisfy their intermediate and peaking capacity requirements and that their base load capacity requirements would be satisfied with purchased power. This assumption was made because all of the reference utilities considered in the study, with the possible exception of the 200 MW generation and transmission cooperative, are too small to independently install large base load units.

Even though small utilities may be incapable of independently installing their own base load generation, they frequently have more than one option for obtaining base load power. One option, which was considered in this study, is the purchase of base load capacity and energy requirements from a neighboring investor-owned utility. Another option which may be available is participation with other utilities in a joint venture to install base load generation. In this case, several small utilities may be able to justify the installation of a large unit which none of them could support individually.

When a joint venture option is available, small utilities may be able to provide for their own base load power requirements at a lower cost than purchased power. Thus, although it was felt that an examination of both purchased power and joint venture participation was beyond the scope of the current study, the potential availability of the joint venture option should be kept in mind in evaluating the economic viability of solar thermal power systems in small utilities.

Intermediate-Peaking Generation Types and Characteristics

The intermediate-peaking generation types assumed to be available to each reference utility are shown in Table 3-5. It should be noted that other than solar only existing technologies were assumed to be available to the utilities and no improvements to existing technologies were considered.

TABLE 3-5

CONVENTIONAL INTERMEDIATE AND PEAKING GENERATION TYPES

Reference Utility	Capacity Types
1.3-MW Municipal	.5-MW High Speed Diesels
10-MW Municipals	3-MW High Speed Diesels and 5-MW Low Speed Diesels
35-MW Municipals and Distribution Cooperative	8-MW Low Speed Diesels and 20-MW Combustion Turbines
200-MW Generation and Transmission Cooperative	50-MW Combustion Turbines and 150-MW Combined Cycle Units

As noted in this table, two types of diesel equipment were assumed to be available to the small utility market. One type is the standard utility diesel generating equipment available in sizes up to about 8,000 kW and capable of operating as both base load and peaking equipment. The speed of these engines is normally in the 360 to 514 rpm range. The diesel generator market also has available for utilities package motor-generator sets complete with foundation and fuel tank in sizes up to approximately 3,000 kW. Although these units are capable of base load operation, they are used primarily for peaking purposes. They typically run at speeds of 720 to 900 rpm and are characterized by a lower capital cost per kW than the slower engines.

Table 3-6 summarizes the characteristics assumed in the study for the conventional peaking and intermediate capacity types. The information provided for each generation type includes capital cost (excluding interest during construction), net heat rate, operation and maintenance costs, forced outage rate and annual availability. The capital costs shown in Table 3-6 are based on manufacturers' estimates and assume the housing of the generating units in all weather structures.

Diesel operation and maintenance costs can vary widely depending on the mode of operation and circumstances. The values shown for diesel operation and maintenance costs were developed in the EPRI advanced technology study based on an extensive review of data from several sources including:

- "1974 Report on Diesel and Gas Engine Power Costs," published by the ASME (5).
- Conversations with manufacturers' representatives.

Table 3-6
DATA FOR CONVENTIONAL INTERMEDIATE AND PEAKING EXPANSION UNITS

Generation Type	Fuel Type	Capital Costs [a] (1975$/kW)	Net Heat Rate (Btu/kWh) At % Load 25%	50%	80%	100%	Net Heat Rate (Btu/kWh) Average Annual	Operation & Maintenance (1975$) Fixed ($/kW)	Variable [b] (Mills/kWh)	Forced Outage Rate (%)	Annual Availability (%)
20-MW Combustion Turbine	Oil #2	200	22,300	16,900	14,400	13,600	16,650	0.26	5.0	11	89
50-MW Combustion Turbine	Oil #2	150	19,680	14,160	12,500	12,000	12,600	0.26	5.0	11	89
.5-MW High-Speed Diesel	Oil #2	439	16,900	12,180	11,800	12,000	12,200	15.00	2.5	10	90
3-MW High-Speed Diesel	Oil #2	238	15,100	11,400	10,575	10,625	11,000	5.00	2.5	10	90
5-MW Low-Speed Diesel	Oil #2	344	13,540	9,700	9,500	9,610	9,950	3.00	2.5	10	90
8-MW Low-Speed Diesel	Oil #2	290	13,540	9,700	9,500	9,610	9,600	1.90	2.5	10	90
150-MW Combined Cycle	Oil #2	210	14,450	10,000	8,700	8,500	9,300	0.90	3.7	22	78

[a] *Figures do not include interest during construction.*

[b] *Exclusive of fuel.*

- Conversations with small utilities having diesel generating plants.
- Responses to a questionnaire sent to some 50 small utilities during the EPRI study.

The ten percent forced outage rate shown for the diesel units, which was developed by Burns & McDonnell, is substantially below that shown in the EEI Report on Equipment Availability for the Period 1965 to 1974 (6). That report shows an equivalent forced outage rate for diesel units of approximately 30 percent. It appears, based on investigations into this matter, that this value substantially understates the reliability of diesel generating units. A ten percent forced outage rate is believed to be more reasonable.

The unit availabilities shown in Table 3-6 are equal to 100 percent minus the forced outage rate. Therefore, only unit forced outages were considered in calculating unit availability. It was assumed that planned outages of intermediate and peaking range units could be scheduled to occur during periods when the services of these units were not required.

It should be noted that the capital cost and operation and maintenance cost figures shown in Table 3-6 are for add-on units at existing sites. Add-on unit costs were used for all conventional peaking and intermediate capacity additions for all reference utilities except the 10 MW municipal without generation. Capital costs and operation and maintenance for the initial generating unit for the 10 MW municipal without generation included additional amounts since this system has no existing generating plant sites or operating staff. A figure of $100,000 per year was used for additional fixed operation and maintenance costs for the first generating unit installed by this utility. A breakdown of the additional capital costs for the first generating unit assumed for this system is shown in Table 3-7.

TABLE 3-7

ADDITIONAL COSTS FOR INITIAL UNIT

(1975$ - Thousands)

Item	3-MW High Speed Diesel	5-MW Low Speed Diesel
Tanks, Piping, Etc.	-	300
Civil	-	40
Structural	25	145
Electrical	125	200
Sub-Total	150	685
10% Contingency	15	68
Construction Cost	165	753
Engineering	8	37
Sales Tax	4	20
Overhead	75	75
Initial Fuel	30	30
Total	282	915
Total ($/kW)	94	183

Purchased Power Cost

It was assumed in the study that the reference utilities would purchase their base load power requirements from a neighboring investor-owned utility at the investor-owned utility's average system cost. The capacity and energy cost used for power purchases are shown in Table 3-8. The purchased energy cost is broken down into two catagories including an energy cost which is representative of the U.S. average and an energy cost which is representative of utilities with mostly oil-fired generation.

TABLE 3-8

PURCHASED POWER COSTS
(1975 $)

	Cost in 1975	Escalation Rate (percent)
Capacity Cost ($/kW-yr)	65	6.0
Energy Cost (mills/kWh)		
U.S. Average	14.3	6.3
Oil-Fired Utility	19.2	5.3

For the utility with oil-fired generation, the 1975 energy cost shown in Table 3-8 is higher than the U.S. average, but this cost is assumed to escalate at a slower rate. The reason for the slower escalation rate is that this utility is assumed to be switching from oil to coal and/or nuclear as a primary fuel. For both the oil-fired utility and the U.S. average, the escalation rate was based on actual purchased energy cost projections. These projections differ from the assumed general inflation rate of 6 percent per year and the differential fuel price escalation rate of 2 percent per year both because of changing fuel mixes and because the purchased energy cost includes both fuel and non-fuel components.

The U.S. average purchased energy cost was used for all of the reference utilities in the study except the 35 MW municipal with oil-fired generation. This utility was assumed to obtain purchased power from an investor-owned utility with oil-fired generation and, thus, the higher purchased energy costs were used.

CONSTRUCTION LEAD TIMES AND COMPOUND INTEREST FACTORS

Table 3-9 shows the construction compound interest factors (to account for interest during construction) and construction lead times used in the study for municipal and cooperative systems. For municipal systems, financing was assumed to be at the rate of six percent for municipal bonds. REA-guaranteed financing at 8.5 percent was assumed to be available for the cooperative systems.

TABLE 3-9

CONSTRUCTION LEAD TIMES AND COMPOUND INTEREST FACTORS (CCIF)

		CCIF Factors[a]		
Unit Type	Lead Time (years)	Investor-Owned	Municipal System	Cooperative System
Nuclear	10	1.52	1.21	1.32
Coal	6	1.30	1.13	1.20
Combined Cycle	3	1.08	1.04	1.06
Gas Turbine	2	1.05	1.02	1.04
Diesel	2	1.05	1.02	1.04
Solar Thermal	2	1.05	1.02	1.04

[a]Assumes financing as follows:
Investor-owned - debt and equity at 10% cost of capital.
Municipal - bonds at 6% interest.
Cooperative - REA-guaranteed loan at 8½% interest.

CARRYING CHARGE RATES AND DISCOUNT RATES

Table 3-10 summarizes the carrying charges used in the study for municipal and cooperative systems. The capital recovery factors shown are based on the six percent and 8.5 percent interest rates assumed to be available, respectively, for the financing of municipal and cooperative systems. The insurance and interim replacement values shown were based on those provided in FPC P-35, "Hydroelectric Power Evaluation, 1968" (7). Discount rates of six percent and 8.5 percent were used in the study to discount future revenue requirements to their present value for municipal and cooperative systems, respectively.

TABLE 3-10

CARRYING CHARGE RATES
(percent)

	Nuclear Units	Other Generating Types
Municipal System		
Capital Recovery Factor	7.26	7.26
Insurance	.80	.20
Interim Replacements	.35	.35
Property Taxes	--	--
	8.41	7.81
Cooperative System		
Capital Recovery Factor	9.31	9.31
Insurance	.80	.20
Interim Replacements	.35	.35
Property Taxes	1.00	1.00
	11.46	10.86

FUEL PRICES

The fuel prices used in the study are shown in Table 3-11. Fuel prices were escalated at eight percent per year in the base case. During sensitivity analyses, escalation rates of 6 and 10 percent per year were considered.

TABLE 3-11

FUEL PRICES[a]
(1975 $/MBtu)

Nuclear	0.60
Coal	1.20
Oil #6	2.05
Oil #2	2.45

[a]Fuel prices were escalated at 8% per year.

* * * * *

Section 4
ECONOMIC ANALYSIS METHODOLOGY

A variety of methodologies and computer models were employed in the study to examine the economics of solar thermal small power systems. The primary methods and models used included a power supply analysis computer model, an hourly dispatching computer model, a methodology for optimizing solar thermal power system parameters which are dependent on geographic location and a methodology for the determination of the capacity credit of the solar thermal power system. Each of the methodologies and models used in the study is described briefly in this section and the major methodologies are described in more detail in Appendices C through H.

BURNS & McDONNELL POWER SUPPLY ANALYSIS MODEL

One of the key methodologies was that used to generate and compare the conventional and solar expansion plans for the period 1980 to 2000. This method is described in Appendix C. Basically a number of alternative expansion plans, both conventional and solar, were generated for each reference utility. Each conventional and solar expansion plan was then analyzed with a Burns & McDonnell computer model which generated information such as annual revenue requirements, the present worth of all future revenue requirements (PWAFRR), annual energy costs and data on fuel consumption. The PWAFRR provided the primary basis for comparing alternative plans.

The Burns & McDonnell power supply computer model allocates energy to a utility's generation resources on an annual basis according to a probabilistic model of the reference utility's loads and resources using an annual load duration curve. Because this method assumes that the outages of the resources are essentially random whereas the outages of solar thermal power systems are strongly influenced by the diurnal cycle, the solar thermal power systems cannot be included in the probabilistic model directly. Thus an hourly analysis model was developed to analyze the solar thermal power systems and the resulting annual capacity and energy contributions of the solar thermal power systems were subtracted from the system load and energy requirements to be met by the reference utility's conventional generation in the power supply computer model.

HOURLY ANALYSIS MODEL

The hourly analysis computer model which was developed by Burns & McDonnell as a part of this study was used to determine the energy contribution and aid in the determination of the capacity contribution of the solar thermal power systems as mentioned above. It was also used to optimize solar thermal power system parameters which depend on geographic location, as discussed in the next part of this section. The basic features of the hourly model are discussed briefly here and in more detail in Appendix D.

The hourly analysis program takes as input data hourly values of insolation and system load as well as the operating characteristics of the solar thermal power system. Using these data, it determines any hourly dispatching schedule for the solar thermal power system as well as the amount by which the dispatch of the solar thermal power system decreases the peak load which must be met by conventional resources, the total energy generated, the annual capacity factor, and the life-cycle levelized busbar energy cost of the solar thermal power system.

The hourly analysis model has available two dispatching strategies, sun-following and peak-shaving. Sun-following dispatching maximizes the energy output of the solar thermal power system by maximizing the direct dispatch of the available receiver power to meet the system load. Energy is sent to the storage device only when the available receiver power exceeds the rated electrical capacity of the solar thermal power system or the system demand. This stored energy is delivered to the transmission grid at up to the storage output rating whenever the available receiver power falls below the storage output rating.

Peak-shaving dispatching, on the other hand, seeks to minimize the system peak demand which must be met with the utility's conventional resources. This strategy involves the development of an hourly unit commitment based on the predicted hourly system load and available insolation at the beginning of the day. Once a commitment schedule has been established the solar thermal power system is dispatched to meet the commitment schedule directly from available receiver power or indirectly through storage if possible. Any receiver power remaining after the commitment schedule has been met is sent to storage at up to the maximum charging rate until the storage device reaches its maximum storage capacity. If receiver power remains, it is used to increase generation up to the rated capacity of the solar thermal power system or the remaining system demand. Receiver power which cannot be directly dispatched or stored is dumped.

Sun-following dispatching has the advantages of simplicity and maximum utilization of the solar thermal power system's inexpensive energy. This type of dispatching was used for the variable slat concentrator system and the central receiver system in the study. However, if applied to a solar power system with dedicated battery storage of the type assumed for the parabolic dish concentrator systems in this study (see Section 2, p. 2-2) the storage device would never be utilized since all receiver power would have to be converted to electricity before being stored. Therefore, peak-shaving dispatching was used in the study for the parabolic dish concentrator systems whenever they were assumed to have storage. Without storage, both dispatching strategies operate in an identical manner.

METHODOLOGY FOR SELECTION OF LOCATION-DEPENDENT PARAMETERS

For each solar thermal power system, the sizing of subsystems and component ratings depends on the amount of insolation available at the plant site. For this study three location-dependent parameters were defined. These were receiver intensity rating, storage time, and solar multiple. The location-dependent parameters selected for each solar thermal power system type for a location in the Southwestern United States are shown in Table 2-1, Section 2.

The receiver intensity rating was defined as the level of direct normal insolation at which the solar thermal power system reaches its rated thermal receiver power. This is a design parameter which influences the size of the collector field (and therefore the system cost) as well as the annual system capacity factor. A system with a higher receiver intensity rating requires a smaller collector area but cannot operate at rated capacity for as large a portion of the year as a system with a lower receiver intensity rating.

Storage time was defined as the length of time for which the energy storage subsystem is designed to deliver its rated capacity. A longer storage time increases the ability of the solar thermal power system to shave the system peak, but it also makes the system more expensive.

The solar multiple was defined as the ratio of the maximum available thermal receiver power to the thermal power corresponding to the rated electrical capacity of the solar thermal power system. Thus the solar multiple is a measure of the amount of collector area which can be dedicated to thermal storage.

The criterion used for selection of location-dependent parameters was the minimum net life-cycle levelized busbar energy cost (BBEC). The net BBEC was defined as the BBEC of the solar thermal power system less the BBEC of purchased capacity assumed to be displaced by the capacity credited to the solar thermal power system. The capacity credited to the solar thermal power system was some fraction of its rated capacity. This fraction was estimated from the expected ability of the solar thermal power system to reduce the system peak demand which must be met with conventional generating capacity and the expected impact of the solar thermal power system on the utility's system reliability.

To determine the minimum net BBEC, hourly analyses were performed for each solar thermal power system type for a range of receiver intensity ratings, storage times and solar multiples. These analyses were performed for several reference utilities and several solar mixes (rated solar capacity as a fraction of the utility's total power requirement). The results of these analyses are discussed in Appendix E.

METHODOLOGY FOR DETERMINATION OF CAPACITY CREDIT

For the purpose of this study, capacity credit of the solar thermal power systems was defined as the expected capability of the solar thermal power systems to decrease the utility's annual peak demand which must be met with conventional generating capacity. The same concept has been called "load carrying capability" in a Southern California Edison Study (8) and in a paper on the reliability of photovoltaic power plants (9). In both of these references, the determination of load carrying capability was based on the difference between total system capacity required to maintain the same level of system reliability (loss-of-load probability or LOLP) with and without solar capacity included in the system's generating resource mix.

For this study, two approaches were combined to determine the capacity credit of each solar thermal power system. The first approach, which was incorporated into the hourly analysis program, simply considered the difference in the system peak demand before and after the hourly dispatch of the solar thermal power system as one measure of capacity credit. The primary advantage of this method was that it took into consideration the coincidence (or lack thereof) between the system load pattern and the available insolation. Its primary disadvantage was that it did not take into consideration system reliability.

The second approach involved using a Federal Power Commission (FPC) program which calculates loss-of-load probability (LOLP) to determine the impact of the solar thermal power system on the utility's system reliability. In this approach a conventional expansion plan was analyzed to determine a baseline level of system reliability. Then, the solar thermal power system was added to the system and conventional capacity was removed until the baseline level of reliability was reached. The amount of conventional capacity replaced by the solar thermal power system was used as another measure of its capacity credit. This approach considered generating unit reliability and the random variability of cloudiness but failed to consider the relationship between a utility's load pattern and the available insolation. Averaging the results of this approach and the previous approach to capacity credit determination led to a result which considered all of these factors.

The capacity credit curves derived for each solar thermal power system type as a function of solar mix are shown in Table 4-1. Additional details concerning the derivation of these capacity credit curves are discussed in Appendix F.

TABLE 4-1

SOLAR THERMAL POWER SYSTEMS' CAPACITY CREDIT[a]

Solar Mix[b] (%)	Capacity Credit (% of Rated Capacity) Parabolic Dish Concentrator Systems	Variable Slat Concentrator System	Central Receiver System
2	75	75	75
5	65	70	70
10	50	50	50
20	35	30	30
40	20	15	15
60	15	10	10
80	10	8	8

[a]Assumes a location in the Southwestern United States.

[b]Rated solar capacity as a percent of the utility's total capacity requirement.

OTHER METHODOLOGIES AND COMPUTER MODELS USED IN THE STUDY

In addition to those described above, a variety of other computer models and calculation methodologies were used in the study. These included two Burns & McDonnell computer programs, a National Bureau of Standards (NBS) computer program and two calculation methodologies. One Burns & McDonnell computer program was used to develop statistical summaries from the data compiled on small utilities in Task 1. Another was used to develop power supply expansion plans for the reference utilities. The NBS program was used to develop insolation data for various geographic locations.

The calculation methodologies included one to determine the break-even capital cost at which the solar thermal power system could potentially achieve 10 percent penetration into the generation mix of each reference utility. This methodology is described in Appendix G. The other calculation methodology was used to determine the impact of changes in the efficiency of the solar thermal power system on its capital cost. This methodology is described in Appendix H.

* * * * *

Section 5

ECONOMIC ANALYSIS OF POWER SUPPLY EXPANSION ALTERNATIVES

This section describes the results of the economic analysis of power supply expansion alternatives for each of the reference utilities both with and without solar thermal power systems. Basically, this involved the development of several expansion plans for each reference utility with each applicable conventional generation and solar thermal power system type. These plans were analyzed with the Burns & McDonnell power supply analysis computer program described in Appendix C and compared on the basis of the present worth of all future revenue requirements (PWAFRR).

For the conventional generation types, expansion plans were developed with varying amounts of purchased capacity and one of the conventional intermediate-peaking capacity types. The optimum conventional generation mix for each reference utility was selected as the expansion plan with the lowest PWAFRR. This expansion plan was then used as the basis for the development of the solar expansion plans.

The solar expansion plans were developed by replacing varying amounts of conventional intermediate-peaking capacity with solar thermal power systems in the optimum conventional expansion plan. This approach was determined to result in the most economical solar expansion plans after initial analyses in which purchased power or some combination of purchased power and conventional intermediate-peaking capacity were replaced with the solar thermal power systems.

CONVENTIONAL EXPANSION PLAN RESULTS

The results of the analysis of the conventional power supply expansion plans are shown in Figures 5-1 through 5-7. The abscissas of these graphs show the penetration of purchased base load capacity into the total power resource mix of the reference utilities over the study period as a percent of the system's total capacity requirement. The ordinates indicate the percent by which the PWAFRR for a particular expansion plan is above or below that of the optimum plan. The dotted line at the zero percent level indicates the optimum conventional plan at its point of tangency with the curve for the optimum conventional generation type.

The significance of the purchased capacity penetrations represented by the abscissas merits additional comment. The purchased capacity penetrations indicate the percentage of the total capacity requirement of the system, including the reserve requirement, that would come from power purchases for a particular expansion plan. The balance of the capacity requirement for a given reference utility and for a particular purchased capacity level would be comprised of the existing generating capacity of the utility (available in 1980) plus new conventional intermediate-peaking capacity additions made to meet load growth and to replace retiring existing units. Since most of the existing units of the reference utilities were assumed to be retired by 2000, the purchased capacity penetrations represent, roughly, the complements of the new intermediate-peaking capacity penetrations by the end of the study period.

Looking at the results for the 1.3-MW municipal (Figure 5-1), it can be seen that the optimum conventional expansion plan for this reference utility includes 80 percent purchased capacity with the remaining 20 percent made up of existing generating units (in service in 1980) and new 0.5-MW diesels added during the study period. The 0.5-MW diesel was the only type of conventional intermediate-peaking expansion unit considered for this utility.

The results for the 10-MW municipal with generation (Figure 5-2) indicate that expansion plans with the 3-MW high-speed diesel are slightly more economical than expansions with the 5-MW low-speed diesel for purchased capacity penetrations in the total power resource mix of 50 percent or more. The optimum expansion plan is shown to involve a 60 percent purchased capacity penetration plus expansion with 3-MW high-speed diesels.

The results for the 10-MW municipal without generation (Figure 5-3) indicate that expansions with the 3-MW high-speed diesel are more economical than expansions with the 5-MW low-speed diesel at all levels of purchased capacity penetration above 40 percent. The high-speed diesel again has only a relatively slight advantage, 1.5 percent at the 60 percent purchased capacity penetration level which is again the optimum.

COMPARISON OF CONVENTIONAL ALTERNATIVES 1980-2000
1.3-MW MUNICIPAL

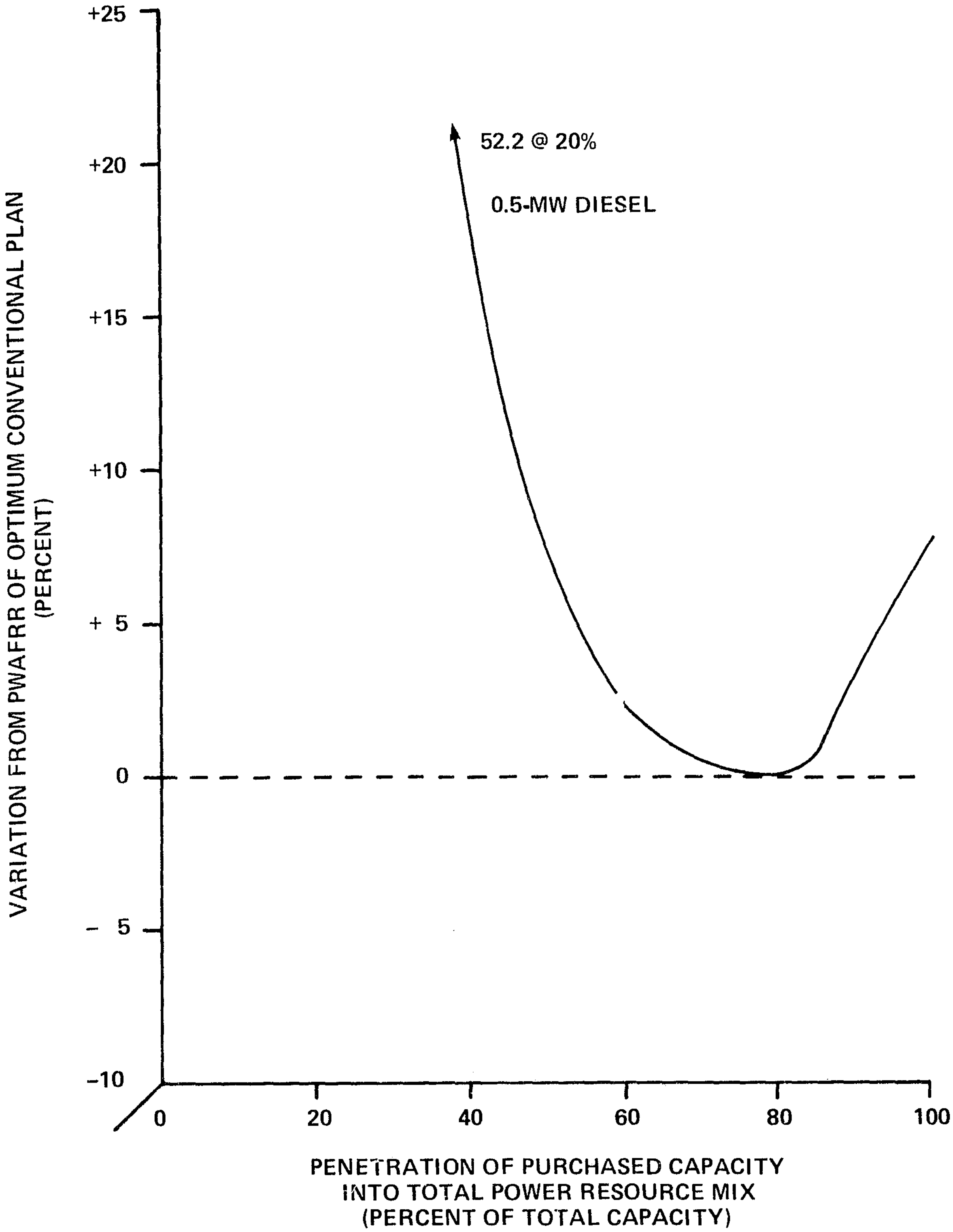


Figure 5-1

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COMPARISON OF CONVENTIONAL ALTERNATIVES
1980-2000
10-MW MUNICIPAL WITH GENERATION

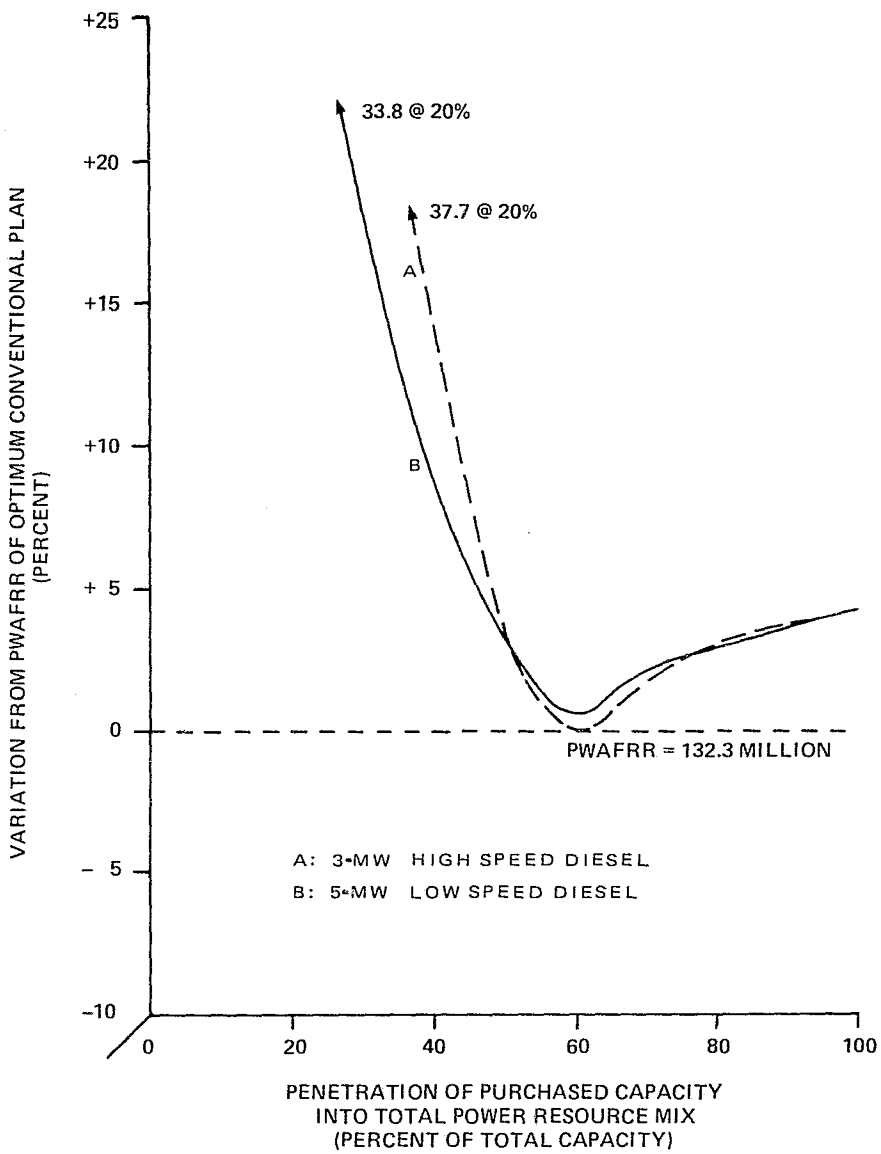

Figure 5-2

COMPARISON OF CONVENTIONAL ALTERNATIVES
1980-2000
10-MW MUNICIPAL WITHOUT GENERATION

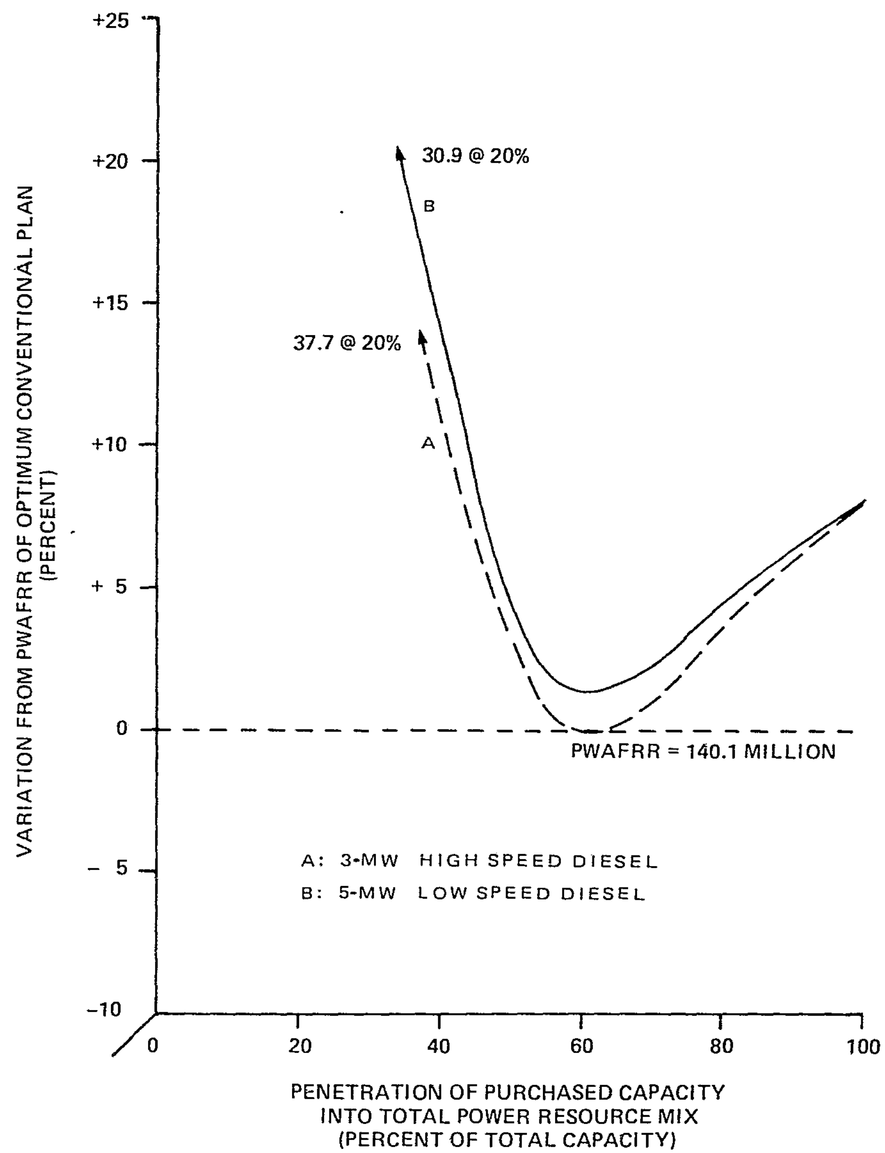

Figure 5-3

Looking at the curves for the 35-MW municipal with coal-fired generation (Figure 5-4), it can be seen that the 8-MW diesel expansion plans are more economical than the 20-MW combustion turbine expansion plans at all levels of penetration of purchased capacity into the total power resource mix. For the 35-MW municipal with oil-fired generation (Figure 5-5) and the 35-MW distribution cooperative (Figure 5-6), expansion with the 8-MW diesel is less expensive than expansion with the 20-MW combustion turbine at purchased capacity penetrations of 70 percent or less. Above this level, the combustion turbine expansion plans are more economical. In general, the difference between the PWAFRR's of the optimum plans for the diesel and combustion turbine expansions was relatively small in all of these cases with the largest difference (2 percent) occurring for the 35-MW municipal with coal-fired generation.

The results for the 200-MW generation and transmission (G&T) cooperative (Figure 5-7) indicate that expansion with a combination of combined-cycle units and combustion turbines is slightly less expensive than expansion with combustion turbines alone at all levels of penetration of purchased capacity into the total power resource mix. At the optimum level, however, the difference in PWAFRR between these two types of expansions is less than 1 percent.

Table 5-1 summarizes the optimum conventional expansion plans in terms of the penetration of capacity existing in 1980, new conventional intermediate-peaking capacity and purchased capacity by the end of the study period. For all of the reference utilities except the 1.3-MW municipal, the optimum generation mix contains 60 percent purchased capacity and 27 to 40 percent new intermediate-peaking capacity. The optimum generation mix for the 1.3-MW municipal contains 80 percent purchased capacity and 12 percent new intermediate-peaking capacity.

SOLAR EXPANSION PLAN RESULTS

As indicated previously, the solar expansion plans were developed by replacing new conventional intermediate-peaking capacity in the optimum conventional expansion plans with capacity from the applicable solar thermal power system types for each reference utility. Solar penetrations of 5, 10, and 20 percent

COMPARISON OF CONVENTIONAL ALTERNATIVES
1980-2000
35-MW MUNICIPAL WITH COAL-FIRED GENERATION

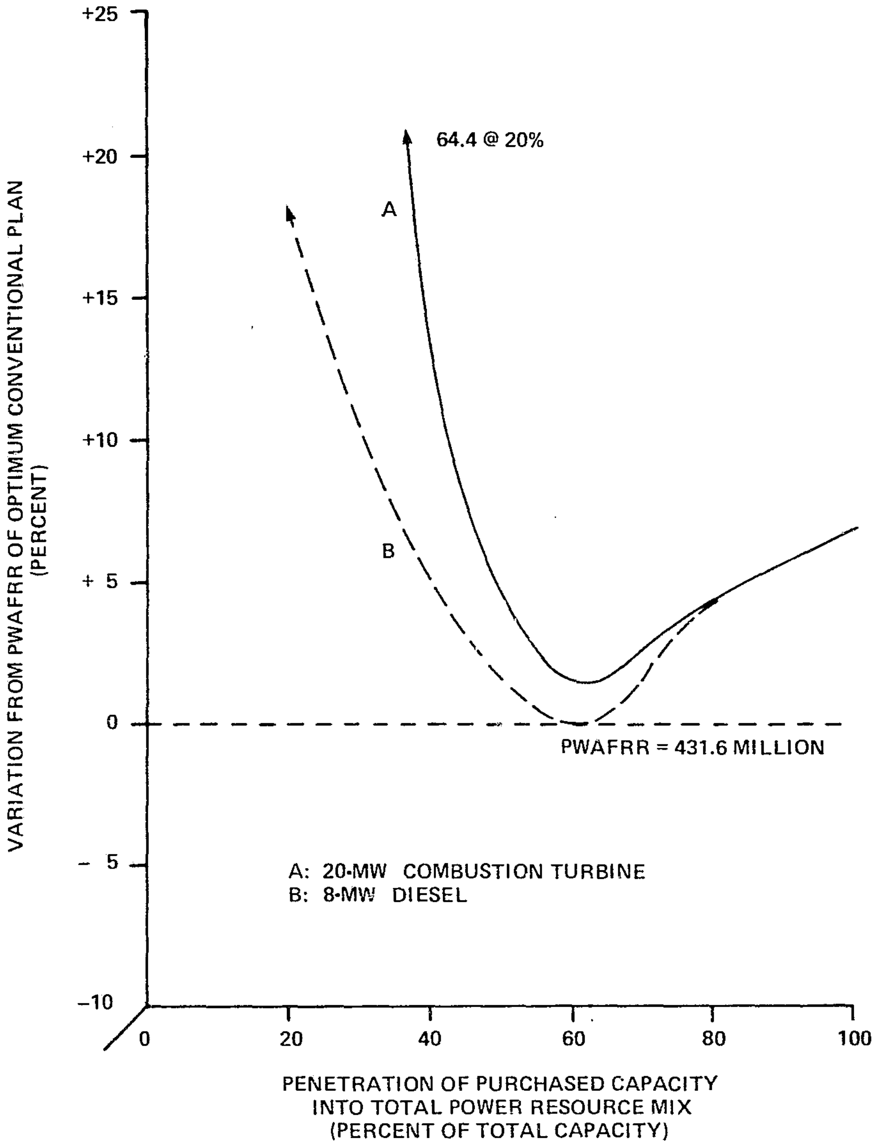

Figure 5-4

COMPARISON OF CONVENTIONAL ALTERNATIVES
1980-2000
35-MW MUNICIPAL WITH OIL-FIRED GENERATION

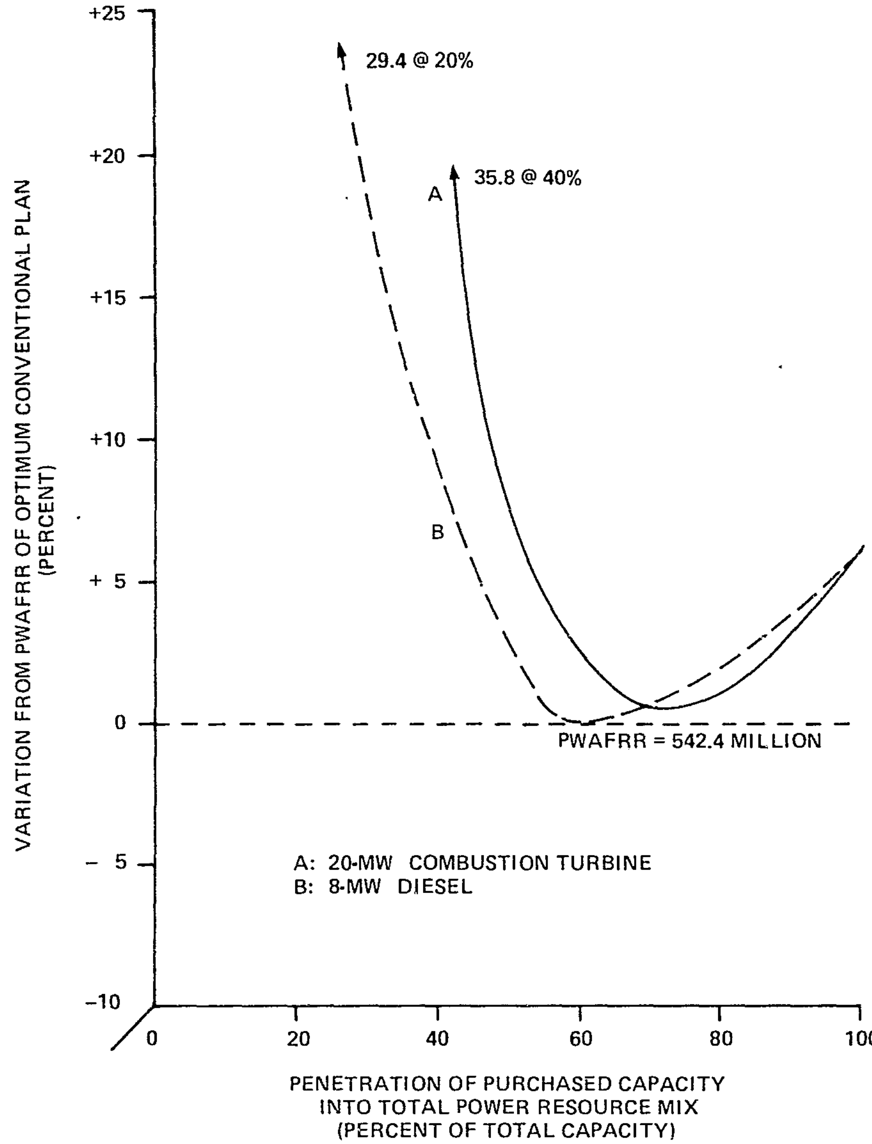

Figure 5-5

COMPARISON OF CONVENTIONAL ALTERNATIVES
1980-2000
35-MW DISTRIBUTION COOPERATIVE

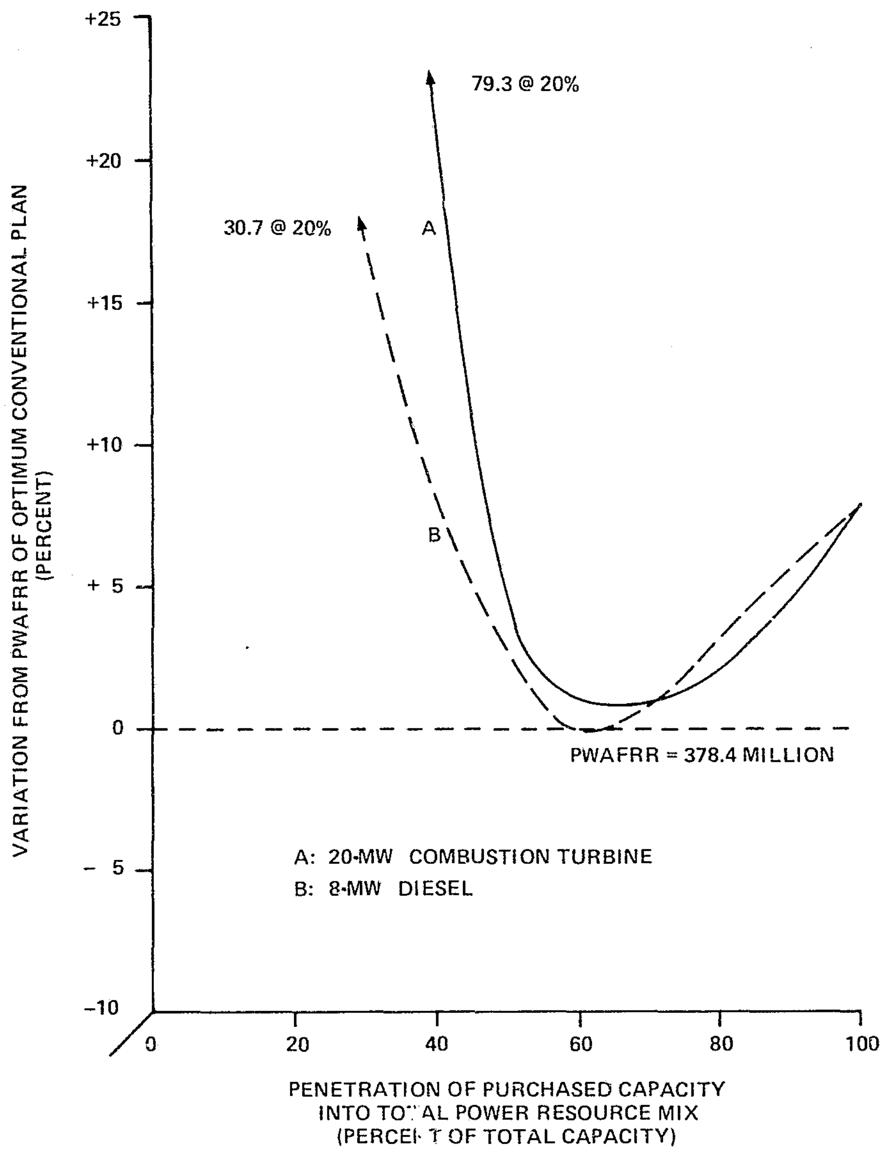

Figure 5-6

COMPARISON OF CONVENTIONAL ALTERNATIVES
1980-2000
200-MW G&T COOPERATIVE

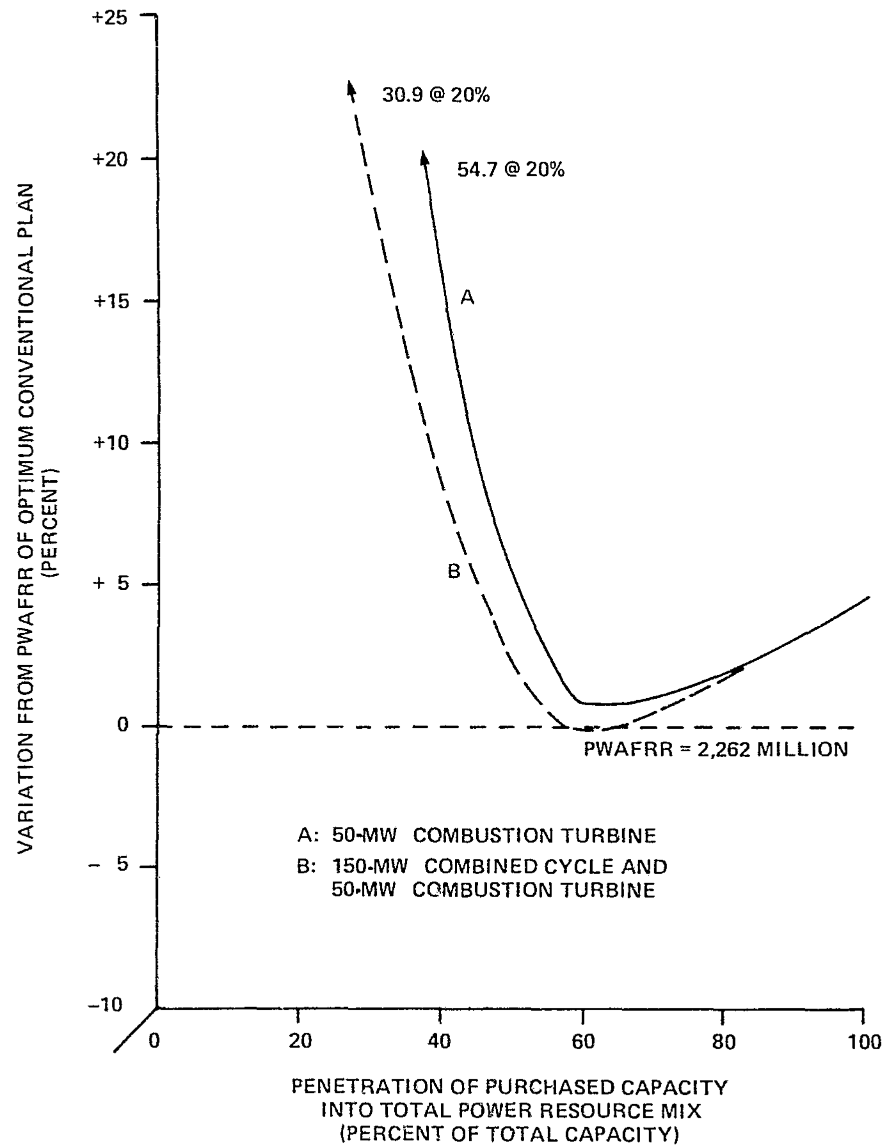

Figure 5-7

Table 5-1

SUMMARY OF OPTIMUM CONVENTIONAL EXPANSION PLANS

Reference Utility	Type of Conventional Intermediate Peaking Expansion Capacity	Capacity Mix in 2000 (Percent of Total Capacity Requirement)		
		Capacity Existing in 1980	New Intermediate Peaking Capacity	Purchased Capacity
1.3-MW Municipal	0.5 MW Diesel	8	12	80
10-MW Municipal With Generation	3-MW Diesel	13	27	60
10-MW Municipal Without Generation	3-MW Diesel	0	40	60
35-MW Municipal With Coal-Fired Generation	8-MW Diesel	6	34	60
35-MW Municipal With Oil-Fired Generation	8-MW Diesel	0	40	60
35-MW Distribution Cooperative	8-MW Diesel	0	40	60
200-MW Generation & Transmission Cooperative	150-MW Combined Cycle & 50-MW Combustion Turbine	5	35	60

were analyzed for each solar thermal power system type. In addition, these expansion plans were analyzed considering a range of potential capital costs for each solar thermal power system type, as discussed in Section 2. The results for each reference utility are discussed below.

1.3-MW Municipal

The 1.3-MW municipal reference utility was expanded initially with the 2-MW parabolic dish concentrator system. It was found that the smallest solar penetration (solar mix) which could be achieved with this unit, because of the size of the unit relative to the utility's peak, was 20 percent of the utility's capacity requirement. At this level of penetration, the PWAFRR of the solar expansion plan ranged from less than 1 percent less expensive to 26 percent more expensive than the PWAFRR of the optimum conventional expansion plan for the range of solar thermal power system capital costs considered.

In order to investigate the economics of the parabolic dish concentrator system at lower levels of penetration into this utility's capacity requirement, characteristics were developed for a 1-MW parabolic dish concentrator system. The results of the analyses of the expansion plans with this 1-MW system are shown in Figure 5-8 for 10 and 20 percent solar mixes and a range of solar thermal power system capital costs. The relatively flat shape of these curves is a result of the fact that the only difference between the 10 and 20 percent solar expansion plans is the timing of the addition of the solar plant. For the 20 percent solar expansion plan, the solar plant was installed in 1985 whereas in the 10 percent plan the solar plant was deferred until 1996. In essence, this is the result of the fact that even a 1-MW solar plant is too large for this utility. No smaller plant size was considered, however, because 1 MW is the smallest plant size being considered in the Small Power Systems Applications Project of which this study is a part.

It can be seen from the results in Figure 5-8 that the PWAFRR's of the solar expansion plans were less than the PWAFRR of the optimum conventional expansion plan only for the low end of the range of solar thermal power system capital costs considered in the study. It can also be seen that, with the low costs, 20 percent solar penetration was more economical than 10 percent penetration. However, at higher capital costs the reverse was true.

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
1.3-MW MUNICIPAL
1-MW PARABOLIC DISH CONCENTRATOR SYSTEM

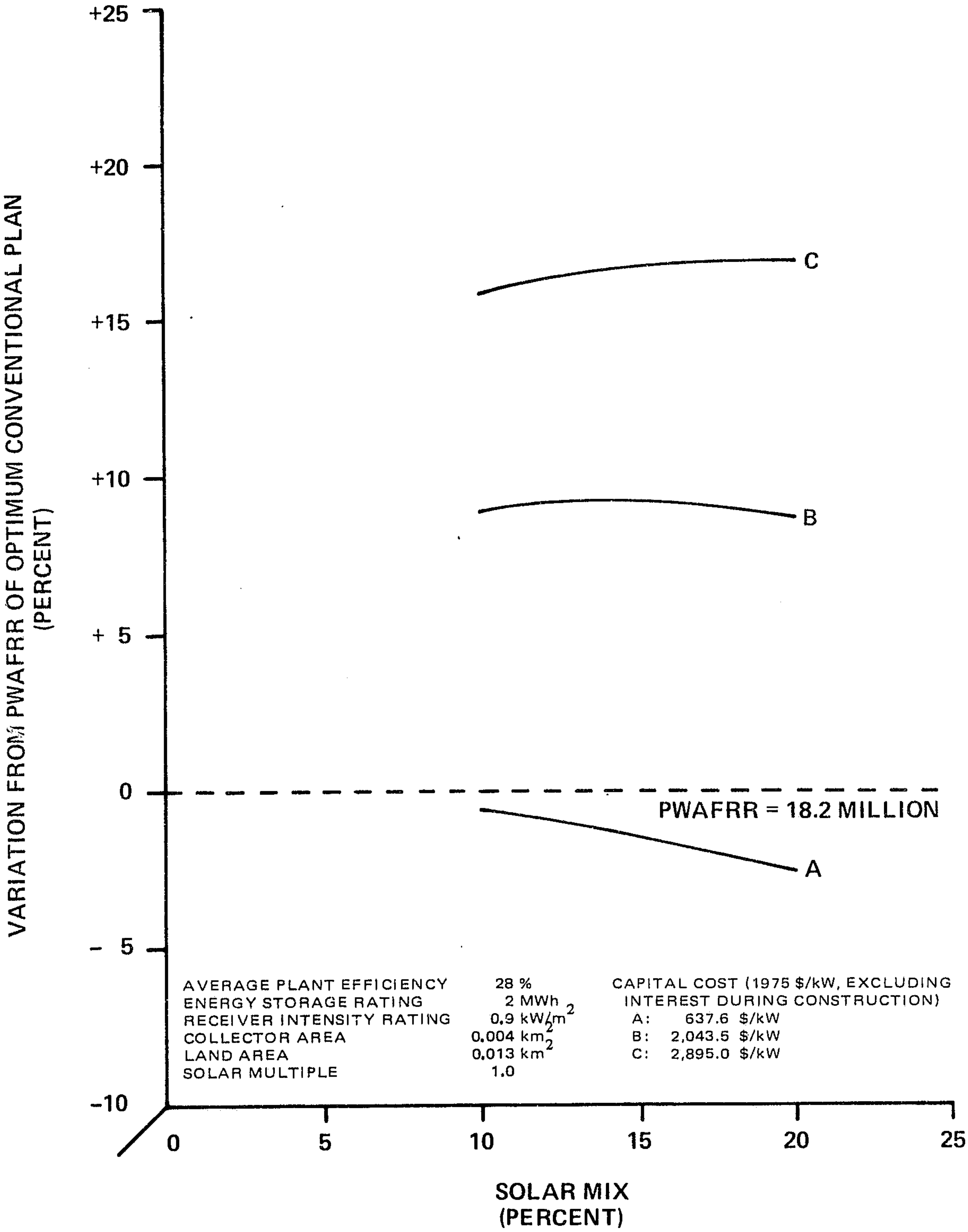

Figure 5-8

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10-MW Municipals

The two 10-MW municipal reference utilities were also expanded with the 2-MW parabolic dish concentrator system with solar mixes of 5, 10 and 20 percent. The results of the analysis of these plans are shown in Figures 5-9 and 5-10 for three different levels of capital cost. For both 10-MW municipal utilities the solar expansion plans were competitive with the conventional expansion plans only for the lowest solar thermal power system capital cost considered in the study. However, for a solar mix of 10 percent the PWAFRR of the solar expansion plans was less than 1 percent higher than that of the conventional expansion plan with the intermediate level of solar thermal power system capital cost.

35-MW Municipals and Distribution Cooperative

The 35-MW reference utilities were expanded with the 2-MW and 10-MW parabolic dish concentrator systems and with the 10-MW variable slat concentrator system. The results of the analysis of these expansion plans are shown in Figures 5-11 through 5-19.

For the 35-MW municipal with coal-fired generation, the 2-MW parabolic dish concentrator system (Figure 5-11) was only slightly competitive with the optimum conventional expansion plan with the lowest capital cost considered for this system up to about a 7 percent solar mix. As might be expected, the 10-MW parabolic dish concentrator system (Figure 5-12) was more competitive with the optimum conventional expansion plan, but it was still competitive only for the lowest capital cost considered. The 10-MW variable slat concentrator system (Figure 5-13) was not competitive with the optimum conventional expansion plan for this reference utility at any of the levels of capital cost considered in the study.

For the 35-MW municipal with oil-fired generation, the 2-MW parabolic dish concentrator system (Figure 5-14) was competitive with the optimum conventional expansion plan with the lowest capital cost considered at all levels of solar

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
10-MW MUNICIPAL WITH GENERATION
2-MW PARABOLIC DISH CONCENTRATOR SYSTEM

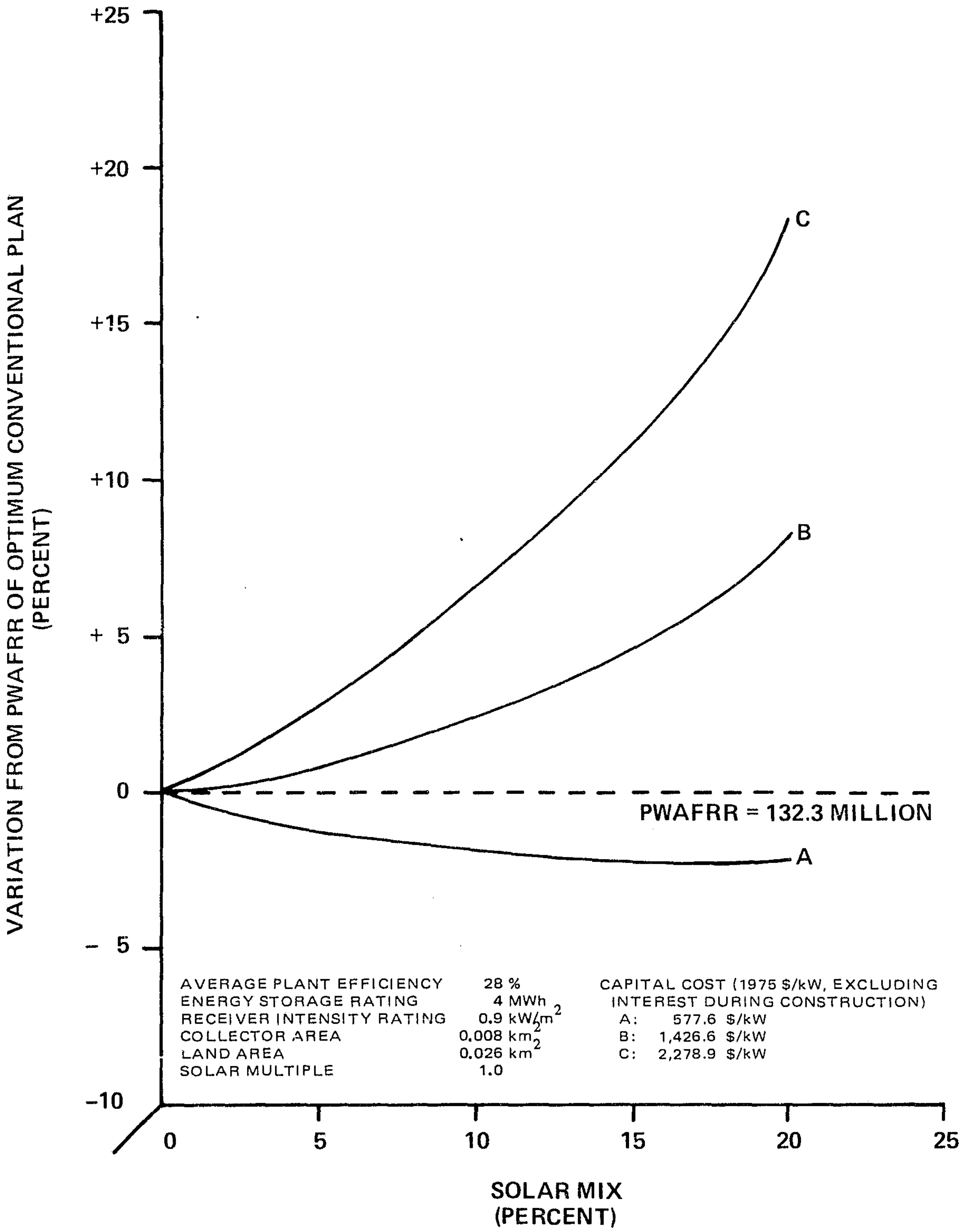

Figure 5-9

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RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
10-MW MUNICIPAL WITHOUT GENERATION
2-MW PARABOLIC DISH CONCENTRATOR SYSTEM

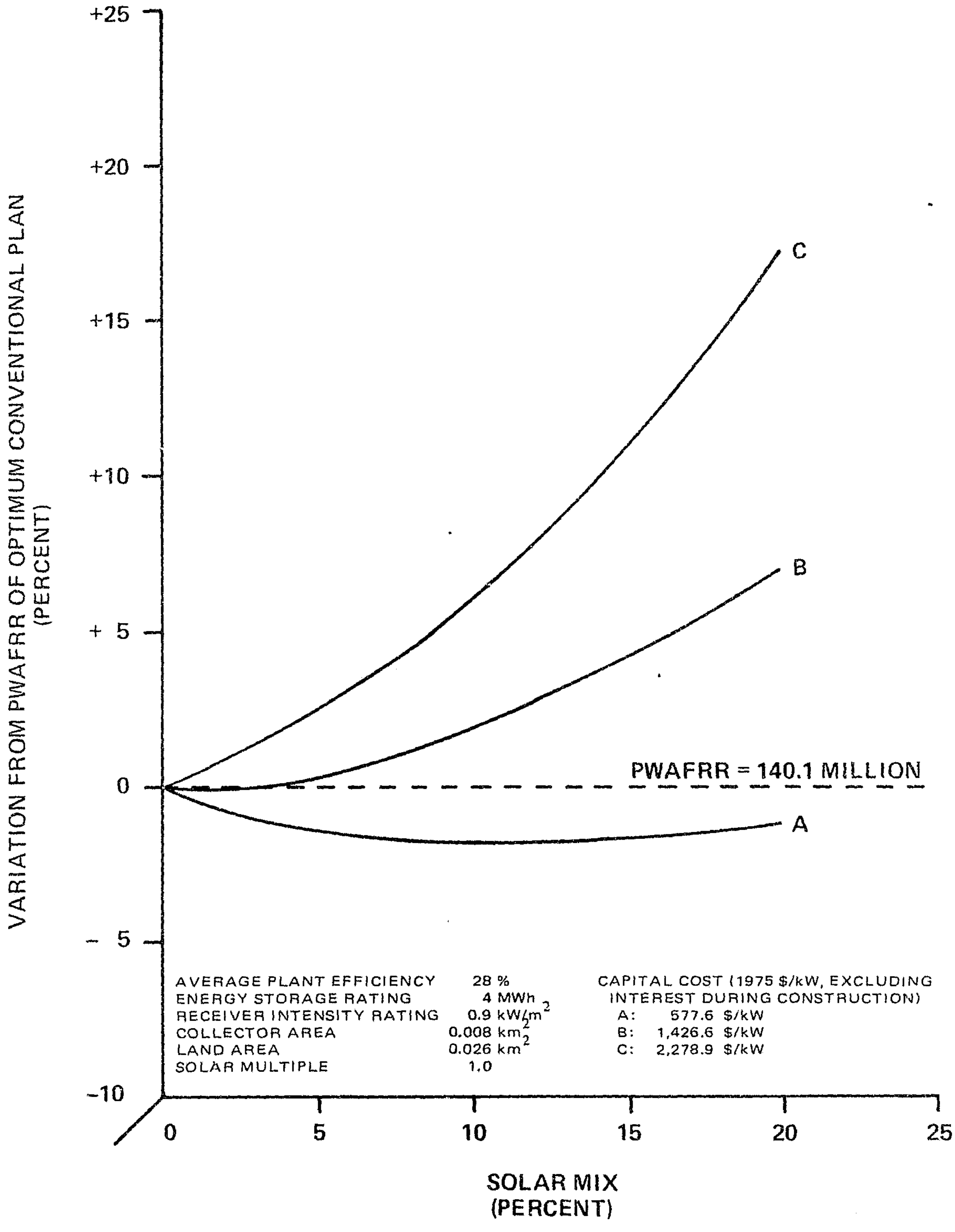

Figure 5-10

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RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
2-MW PARABOLIC DISH CONCENTRATOR SYSTEM

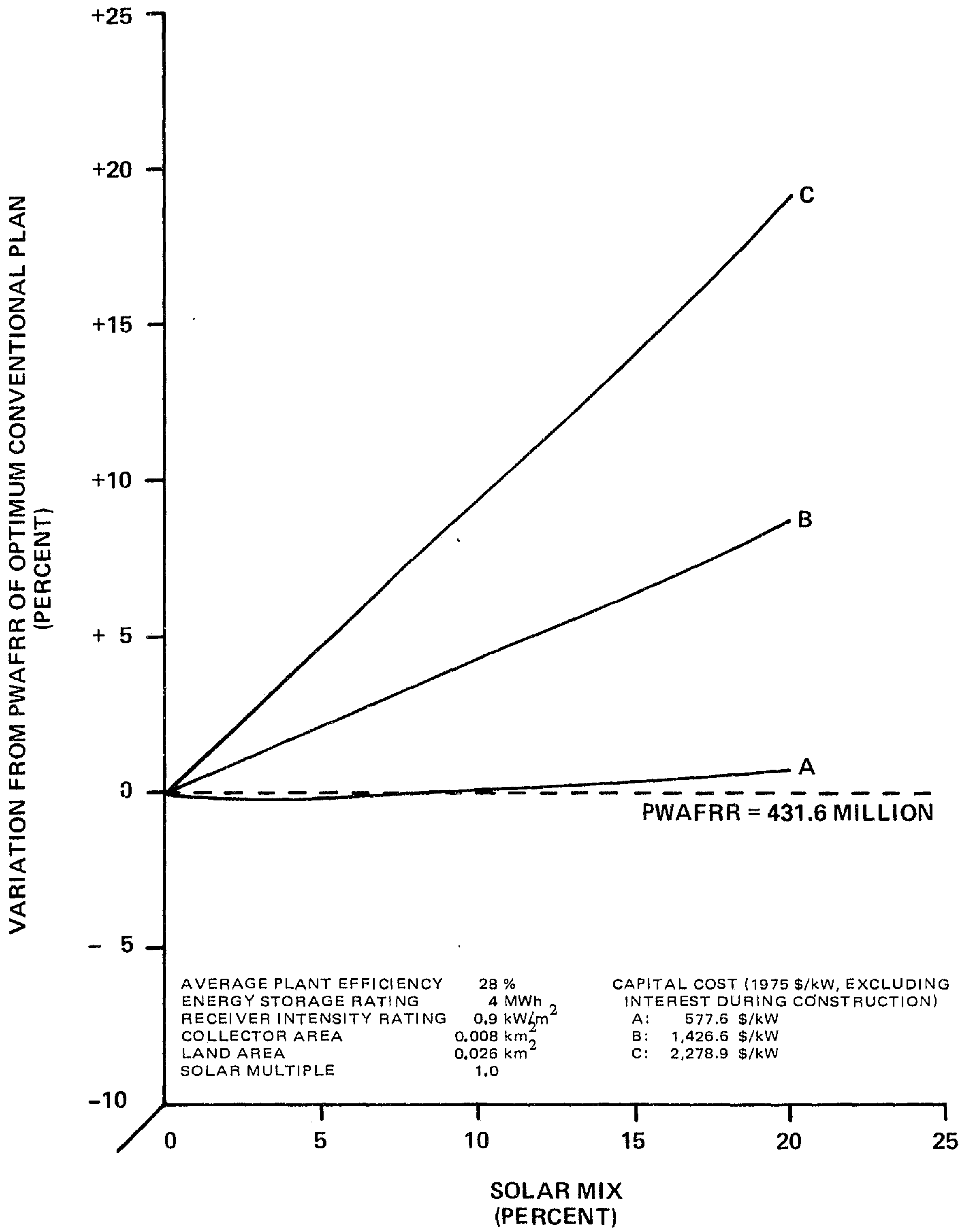

Figure 5-11

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RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM

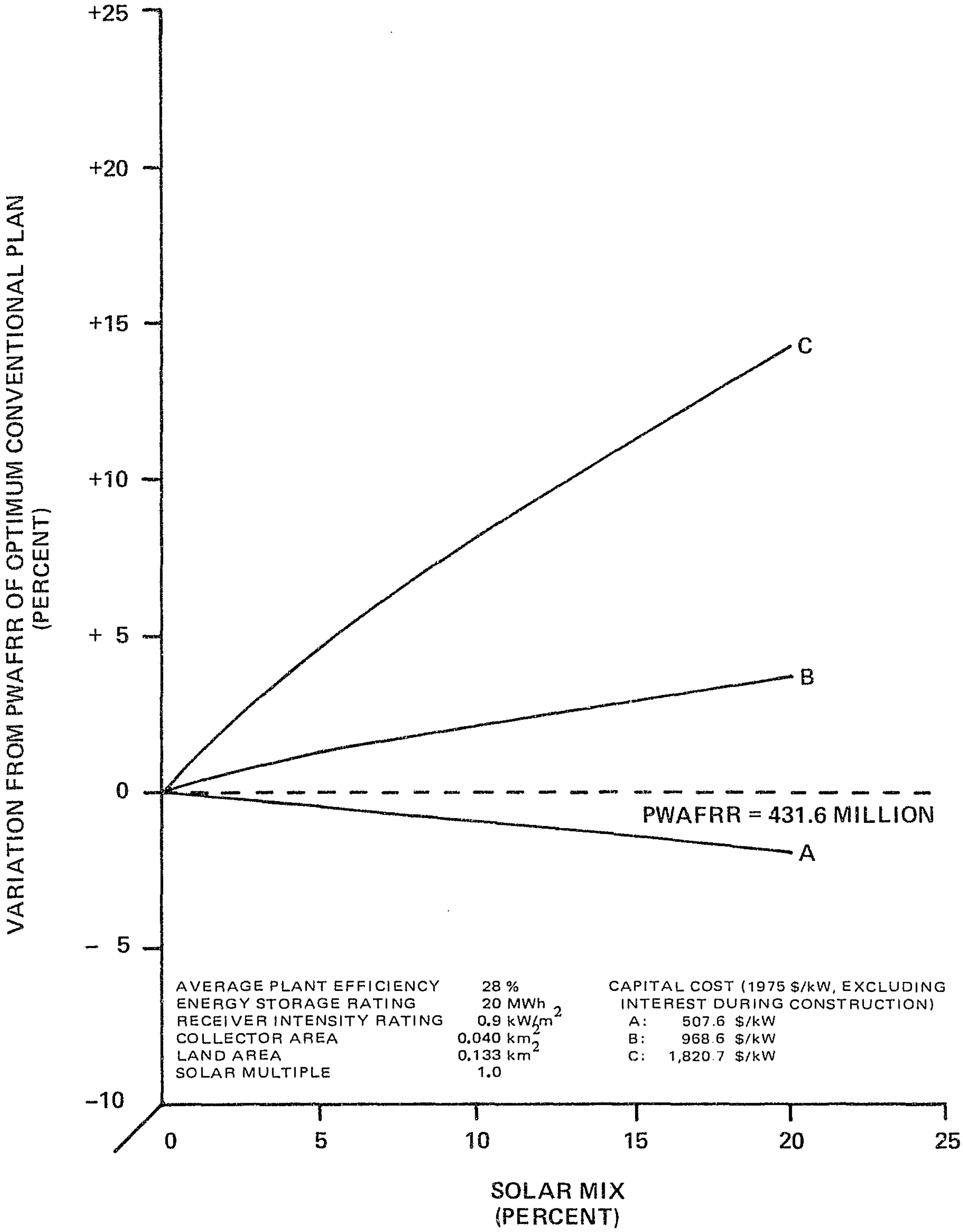

Figure 5-12

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RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
10-MW VARIABLE SLAT CONCENTRATOR SYSTEM

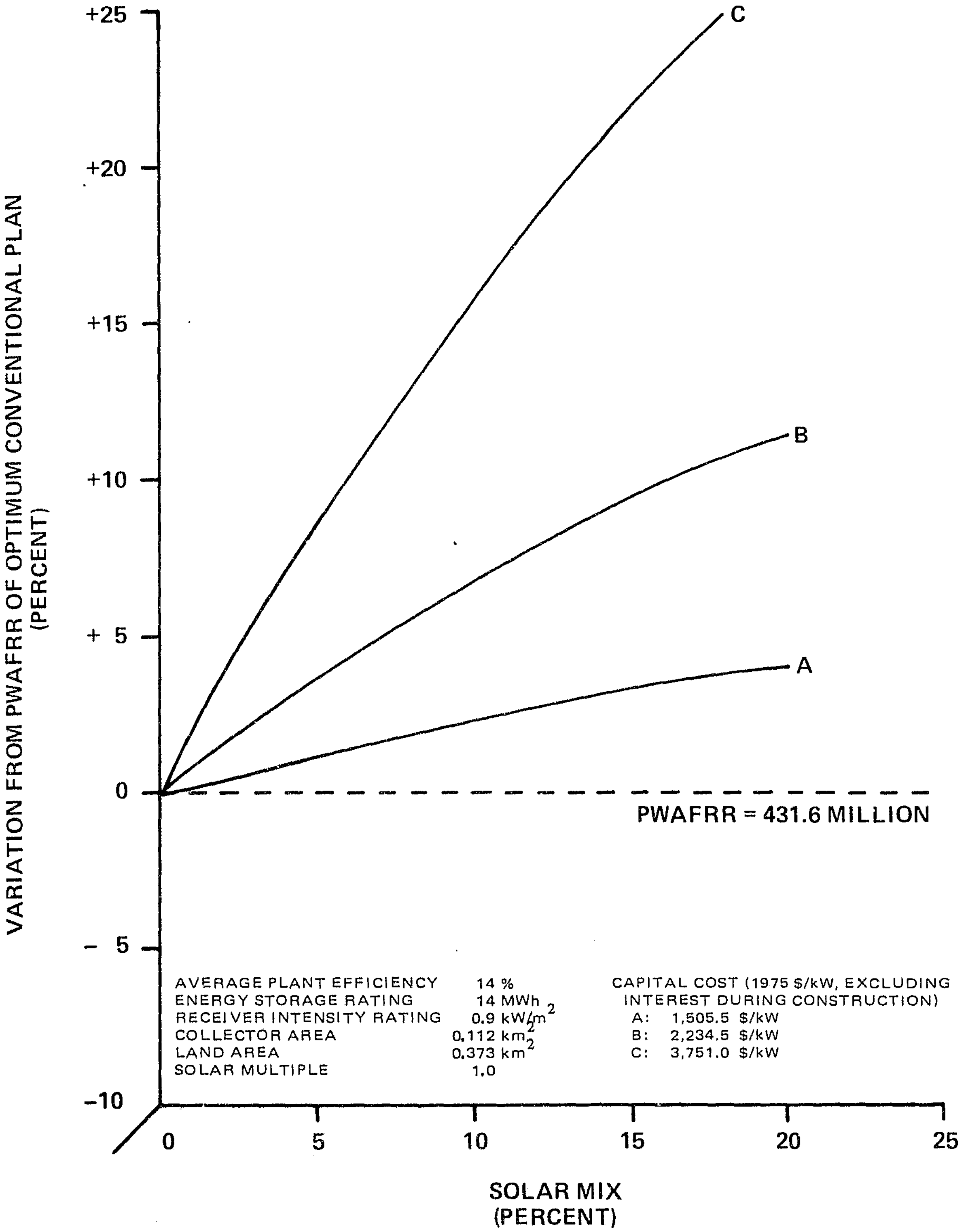

Figure 5-13

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RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
2-MW PARABOLIC DISH CONCENTRATOR SYSTEM

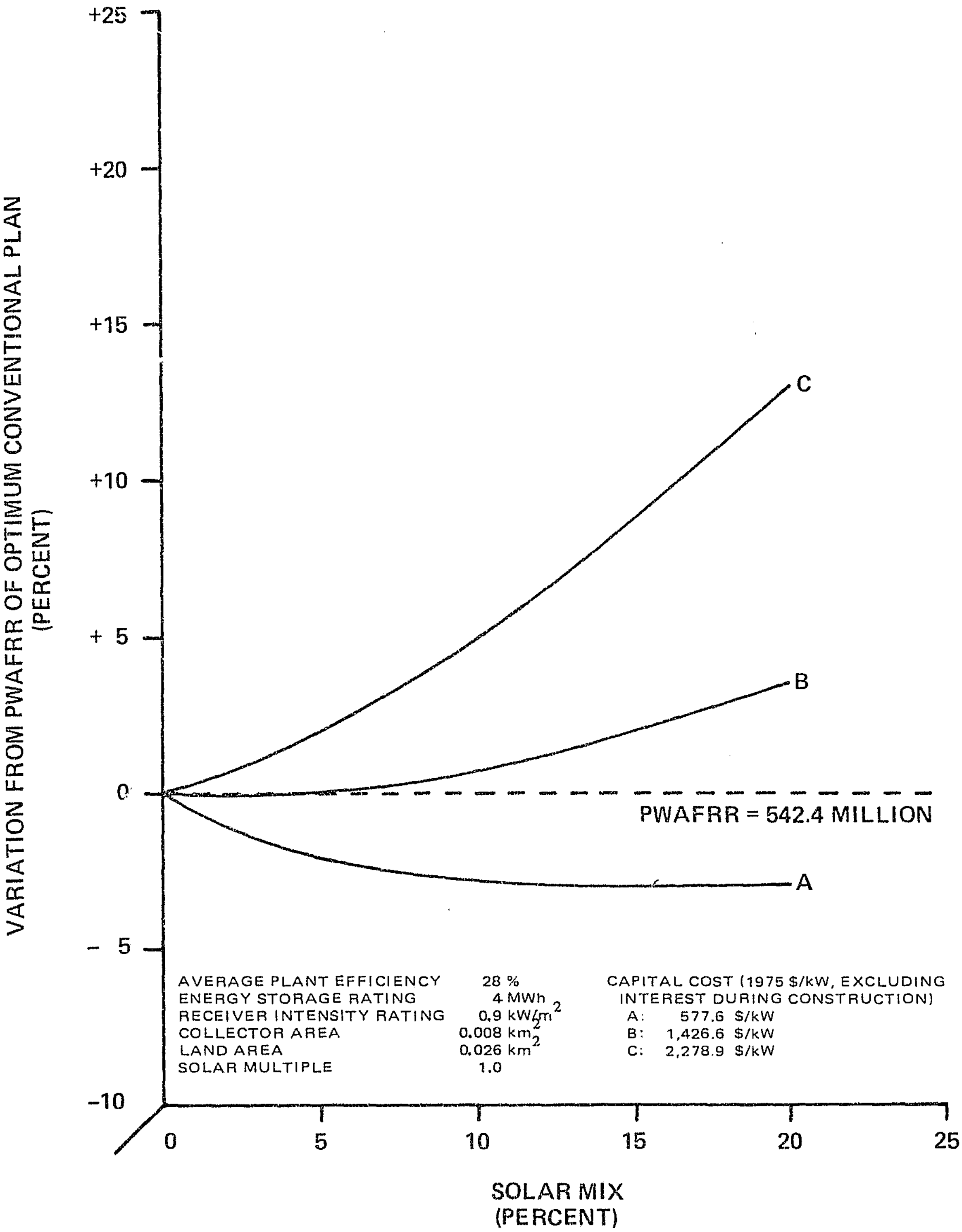


Figure 5-14

penetration shown. With intermediate capital costs it was competitive up to about a 5 percent solar mix. The 10-MW parabolic dish concentrator system (Figure 5-15) was competitive at all levels of solar mix considered with both the low and intermediate capital costs. The 10-MW variable slat concentrator system (F9gure 5-16) was competitive with the optimum conventional expansion plan only with the lowest of the capital costs considered in the study.

The results for the 35-MW distribution cooperative were similar to those for the 35-MW municipal with coal-fired generation. The 2-MW parabolic dish concentrator system (Figure 5-17) was only slightly competitive with the optimum conventional expansion up to a 5 percent solar mix with the lowest capital costs considered. The 10-MW parabolic dish concentrator system (Figure 5-18) was competitive with the optimum conventional plan up to a 20 percent solar mix with the lowest capital costs. The 10-MW variable slat concentrator system (Figure 5-19) was not competitive with the optimum conventional expansion plan at any of the levels of capital cost considered in the study.

There were two primary factors which made these three solar thermal power system types more competitive with conventional generation in the 35-MW municipal with oil-fired generation than in the other two 35-MW reference utilities. First, the oil-fired existing generation of this utility had a higher energy cost than the predominantly coal-fired generation of the 35-MW municipal with coal-fired generation. (The 35-MW distribution cooperative was assumed to have relatively little existing generation.) Second, the 35-MW municipal with oil-fired generation was assumed to buy power from an investor-owned utility with predominantly oil-fired generation whereas the other two 35-MW utilities were assumed to purchase power from an investor-owned utility with mostly coal- and nuclear-fueled generation. Therefore, the purchased energy costs for this utility were higher than those for the two other 35-MW utilities.

Other factors which might have been expected to account for some of the differences in the results for these three reference utilities include the utility's peak load season and load pattern as well as the utility's interest rate. The 35-MW municipal with oil-fired generation was assumed to be winter peaking whereas the other two 35-MW utilities were assumed to be summer

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM

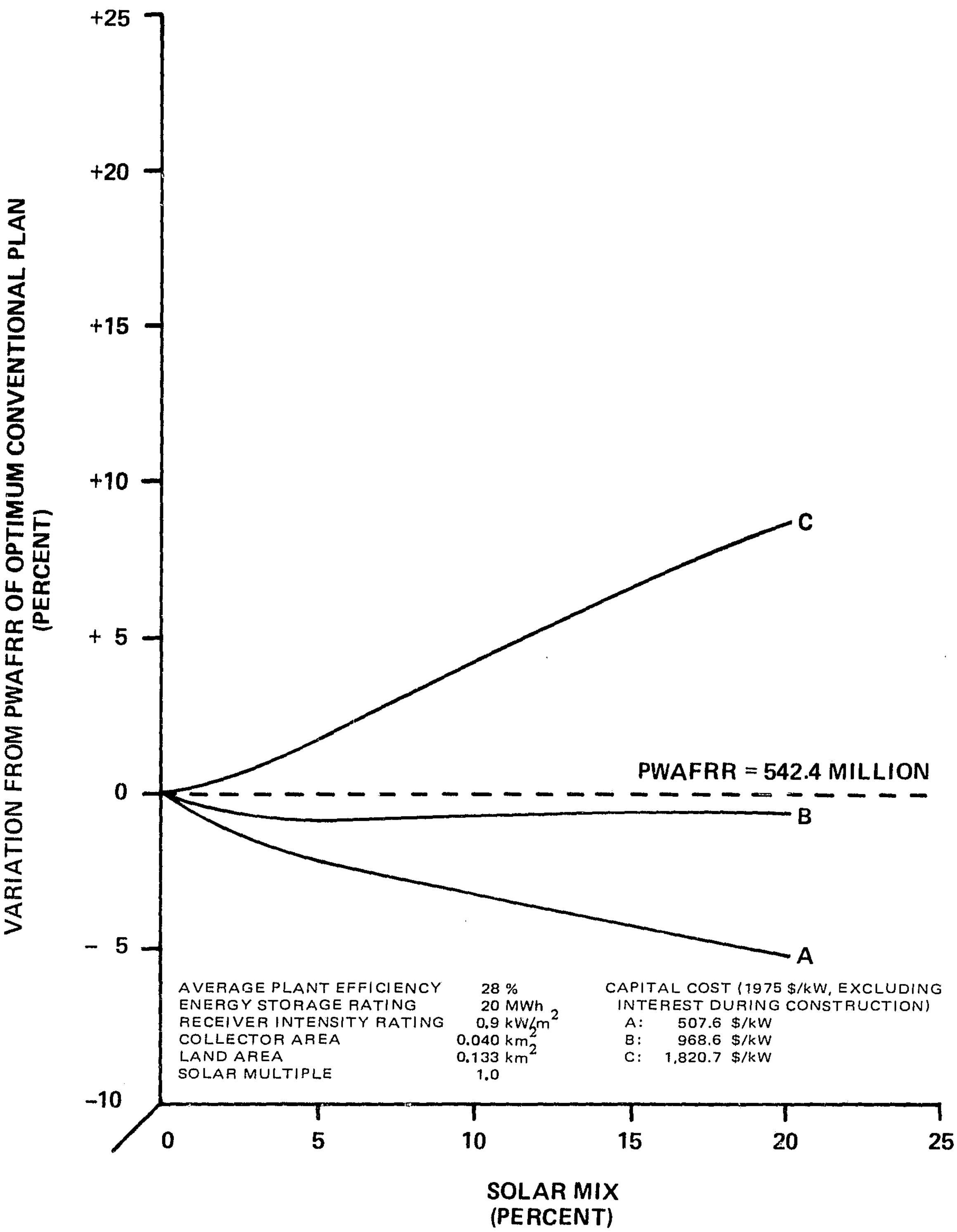


Figure 5-15

JPL 78-008-4-005

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
10-MW VARIABLE SLAT CONCENTRATOR SYSTEM

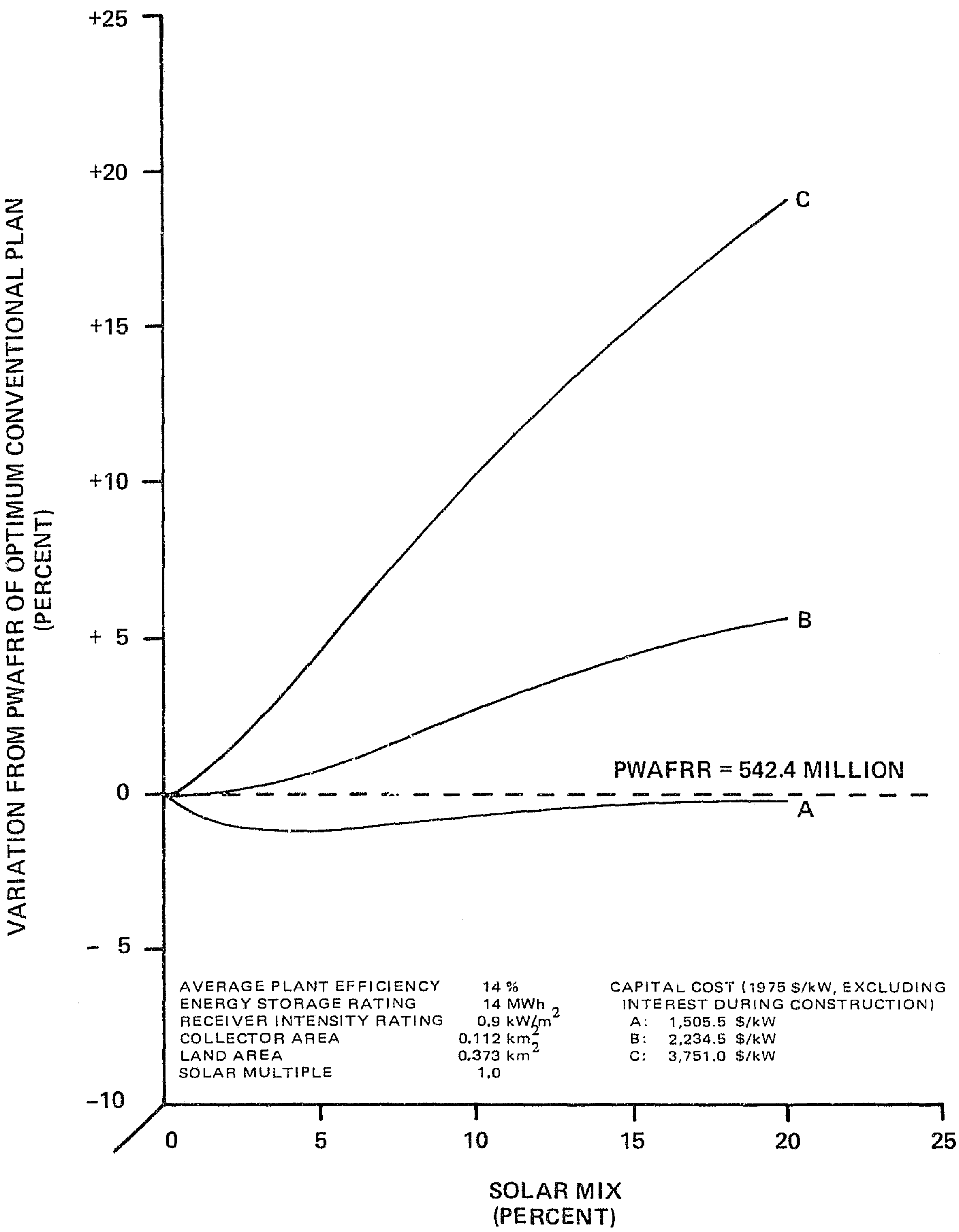


Figure 5-16

JPL 78-008-4-005

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW DISTRIBUTION COOPERATIVE
2-MW PARABOLIC DISH CONCENTRATOR SYSTEM

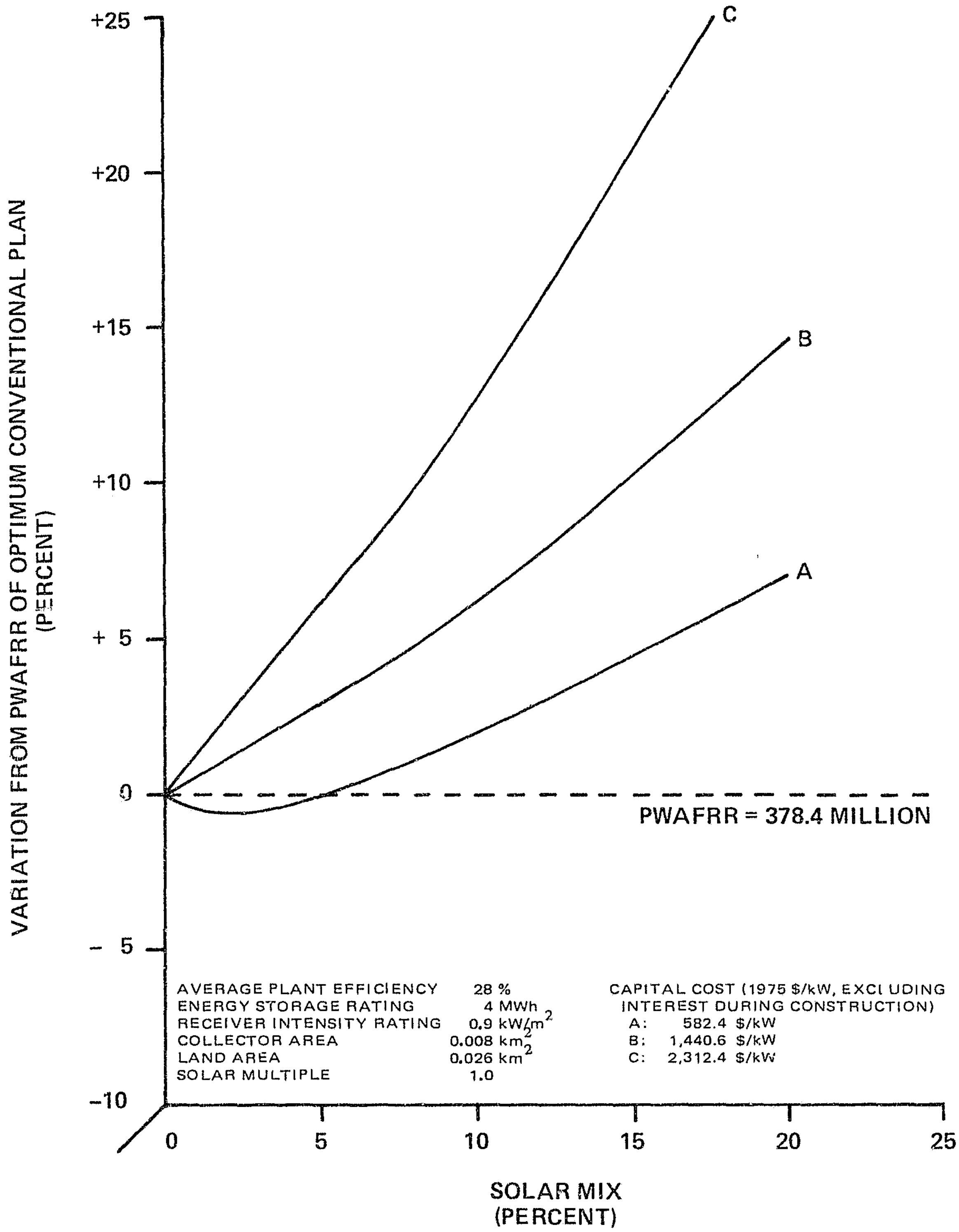


Figure 5-17

JPL 78-008-4-005

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW DISTRIBUTION COOPERATIVE
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM

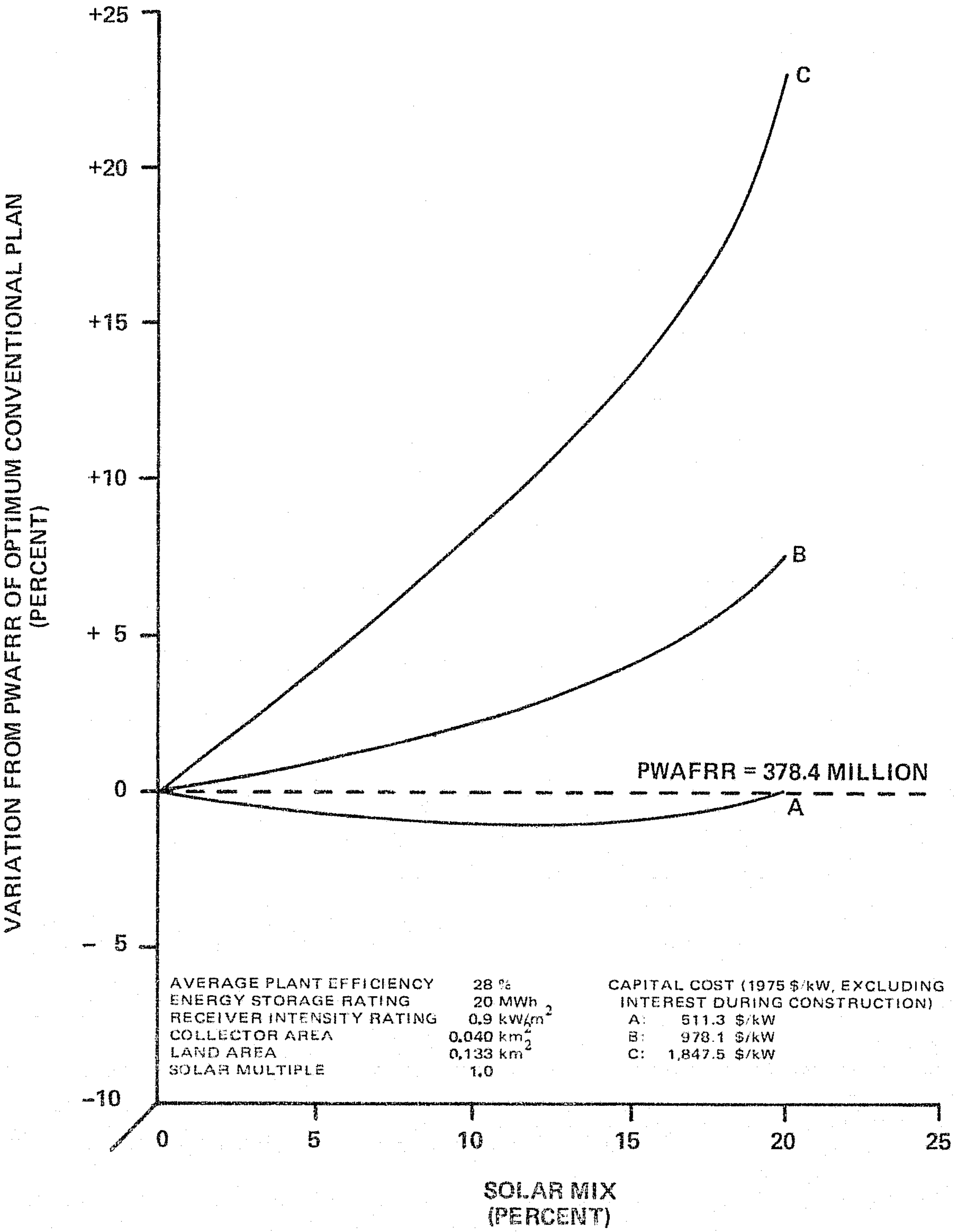


Figure 5-18

JPL 78-008-4-005

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
35-MW DISTRIBUTION COOPERATIVE
10-MW VARIABLE SLAT CONCENTRATOR SYSTEM

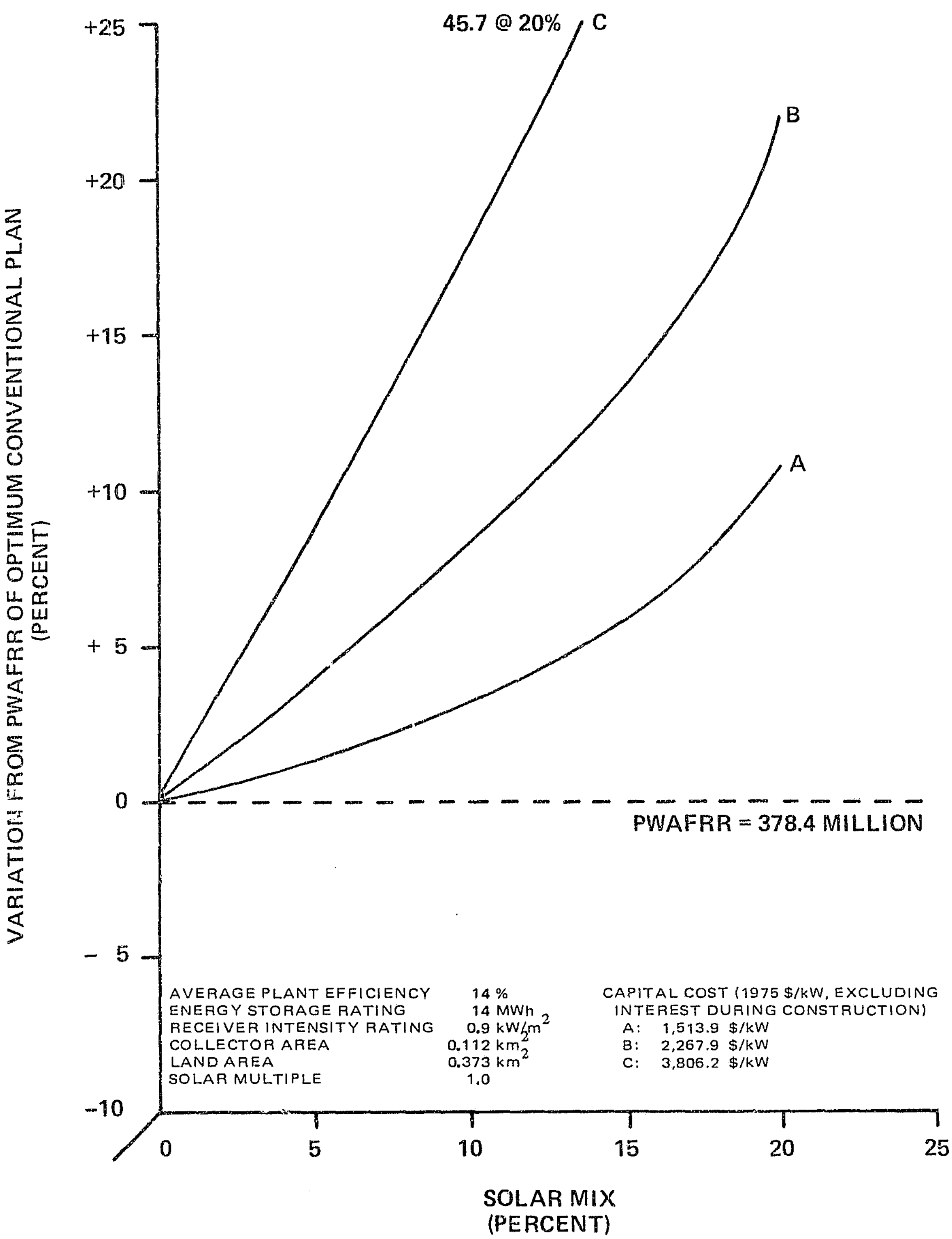


Figure 5-19

JPL 78-008-4-005

peaking. This difference might have been expected to make the solar thermal power systems less competitive rather than more competitive with conventional generation since, in the Southwest, the peak level of insolation is slightly less, the duration of insolation is much shorter and the incidence of cloudiness is much higher in winter than in summer. These factors were taken into consideration in the study during the development of capacity credit and capacity factor curves for each solar thermal power system type (see Appendix F). Perhaps surprisingly, however, the impact of these factors was sufficiently small to justify the use of only one average capacity credit and capacity factor curve for all of the reference utilities for each solar thermal power system type. However, in a more detailed analysis these differences would have to be considered. Similarly, the differences in load pattern, which were also "averaged out" during the capacity credit and capacity factor analysis in this study, would have to be taken into consideration in a more detailed study.

A higher utility interest rate might have been expected to have an adverse impact on the competitiveness of solar thermal power systems with conventional generation since the solar thermal power systems are significantly more capital intensive. This result can in fact be observed by comparing the results for the 35-MW municipal with coal-fired generation (Figures 5-11 through 5-13) to those for the 35-MW distribution cooperative (Figures 5-17 through 5-19). The differences in PWAFRR between the conventional and solar expansion plans was noteably less for the 35-MW municipal with coal-fired generation, which was assumed to finance new generation facilities with 6 percent municipal bonds, than for the 35-MW distribution cooperative, which was assumed to finance its expansion with 8½ percent REA-guaranteed loans. Further, the magnitude of the difference increases more rapidly with increasing solar mix for the 35-MW distribution cooperative than for the 35-MW municipal with coal-fired generation.

Another relevant difference can be noted between the results of the 2-MW parabolic dish concentrator system expansion plans for the 35-MW municipal with coal-fired generation and the two 10-MW municipal utilities. Here the primary factor which made the solar thermal power system more competitive with conventional generation in the 10-MW municipal utilities than in the 35-MW municipal with coal-fired generation was the type of conventional intermediate-peaking generation with which the solar thermal power system was competing.

In the 10-MW municipal utilities, the 2-MW parabolic dish concentrator system was competing with 3-MW diesels in addition to purchased power whereas in the 35 MW municipal with coal-fired generation it was competing with 8-MW diesels in addition to purchased power. The 3-MW diesel actually had a slightly lower capital cost on a dollar per kilowatt basis than the 8-MW diesel. However, the 3 MW diesel was less efficient and had a higher fixed operation and maintenance cost on a per kilowatt basis than the 8-MW diesel so that the total cost per kilowatt (or per kilowatt-hour) of the 3-MW diesel was greater than that of the 8-MW diesel.

The difference in results discussed above were those which affected the application of the same technology to different utilities. Another type of difference which can be explained with reference to the results presented thusfar involved those resulting from the application of different technologies or different plant sizes of the same technology to the same utility. The most easily explainable difference in this category was that between the results for the 2-MW and 10-MW parabolic dish concentrator systems in any of the 35-MW reference utilities. Because of economies of scale primarily in site preparation and plant construction, expansion with the 10-MW parabolic dish concentrator system was always found to be less expensive than expansion with the 2 MW parabolic dish concentrator system provided, of course, that the 10-MW plant size could be justified by the utility's load.

The differences in the results for the expansion plans with the 10-MW parabolic dish concentrator system and the 10-MW variable slat concentrator system were more complex. The basic cause was the higher capital cost of the 10-MW variable slat concentrator system. This higher capital cost, however, was the result of several factors including the nature and costs of the basic system hardware, the plant efficiency, and the type of storage. The costs assumed in the study for the energy transport and energy conversion subsystems (see Table 2-2) were higher for the variable slat concentrator system than for the parabolic dish concentrator system. The costs per square meter for the collector were roughly comparable for both systems but the variable slat concentrator system required a larger collector area both because of a lower system efficiency (.14 compared to .28 for the parabolic dish concentrator system) and because of the difference in storage.

The variable slat concentrator system was assumed to have thermal storage whereas the parabolic dish concentrator system was assumed to have advanced battery storage. The thermal storage caused the variable slat concentrator system to be more expensive both because thermal storage was assumed to be more expensive per kilowatt-hour and because collector area in excess of that necessary to meet the requirements of the electrical conversion system was included for the thermal storage but not for the battery storage system. This was because the thermal storage was capable of utilizing the excess thermal power generated by this extra collector area whereas battery storage was not. The variable slat concentrator system with its thermal storage and larger collector area did have a higher annual capacity factor (i.e., it produced more energy with the same capacity) but this extra energy output was evidently not sufficient to offset the higher capital cost.

<u>200-MW Generation and Transmission Cooperative</u>

The 200-MW generation and transmission cooperative was expanded with the 10 MW parabolic dish concentrator system, the 10-MW variable slat concentrator system and the 50-MW central receiver system. The results of the analysis of these expansion plans are shown in Figures 5-20 through 5-22.

The 10-MW parabolic dish concentrator system (Figure 5-20) was competitive with the optimum conventional expansion plan up to a 15 percent solar mix with the lowest capital cost considered in the study. The 10-MW variable slat concentrator system (Figure 5-21) was also slightly competitive with the optimum conventional plan but only up to about a 3 percent solar mix for the lowest capital cost considered. The 50-MW central receiver system (Figure 5-22) was slightly competitive with the optimum conventional expansion plan with the low capital cost up to a 7 percent solar mix.

These results for the 200-MW generation and transmission cooperative reflect many of the same factors that were discussed above for the 10-MW and 35-MW reference utilities. The results for the 10-MW parabolic dish and variable slat concentrator systems were essentially comparable to the results for the

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
200-MW GENERATION & TRANSMISSION COOPERATIVE
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM

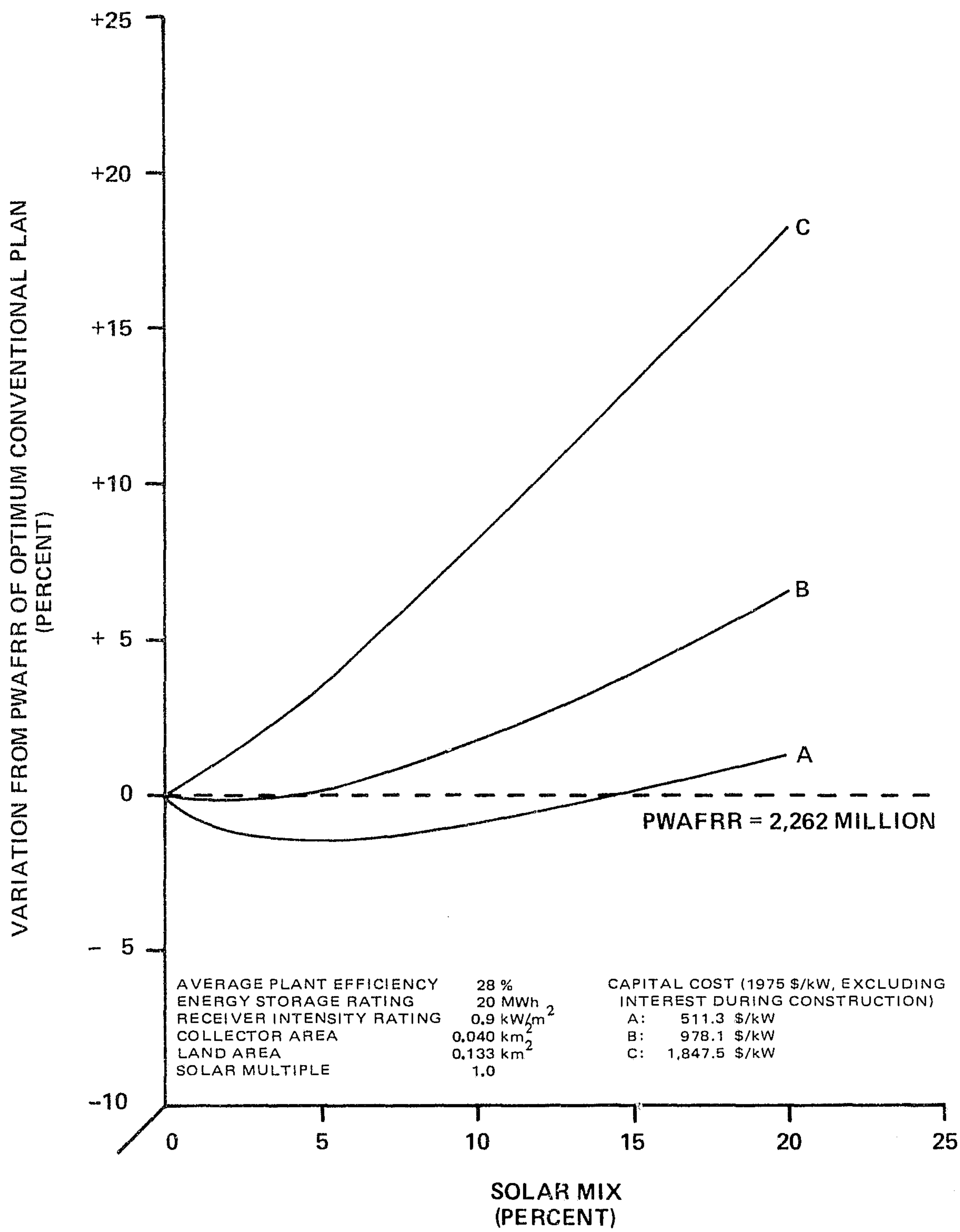


Figure 5-20

JPL 78-008-4-005

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980–2000
200-MW GENERATION & TRANSMISSION COOPERATIVE
10-MW VARIABLE SLAT CONCENTRATOR SYSTEM

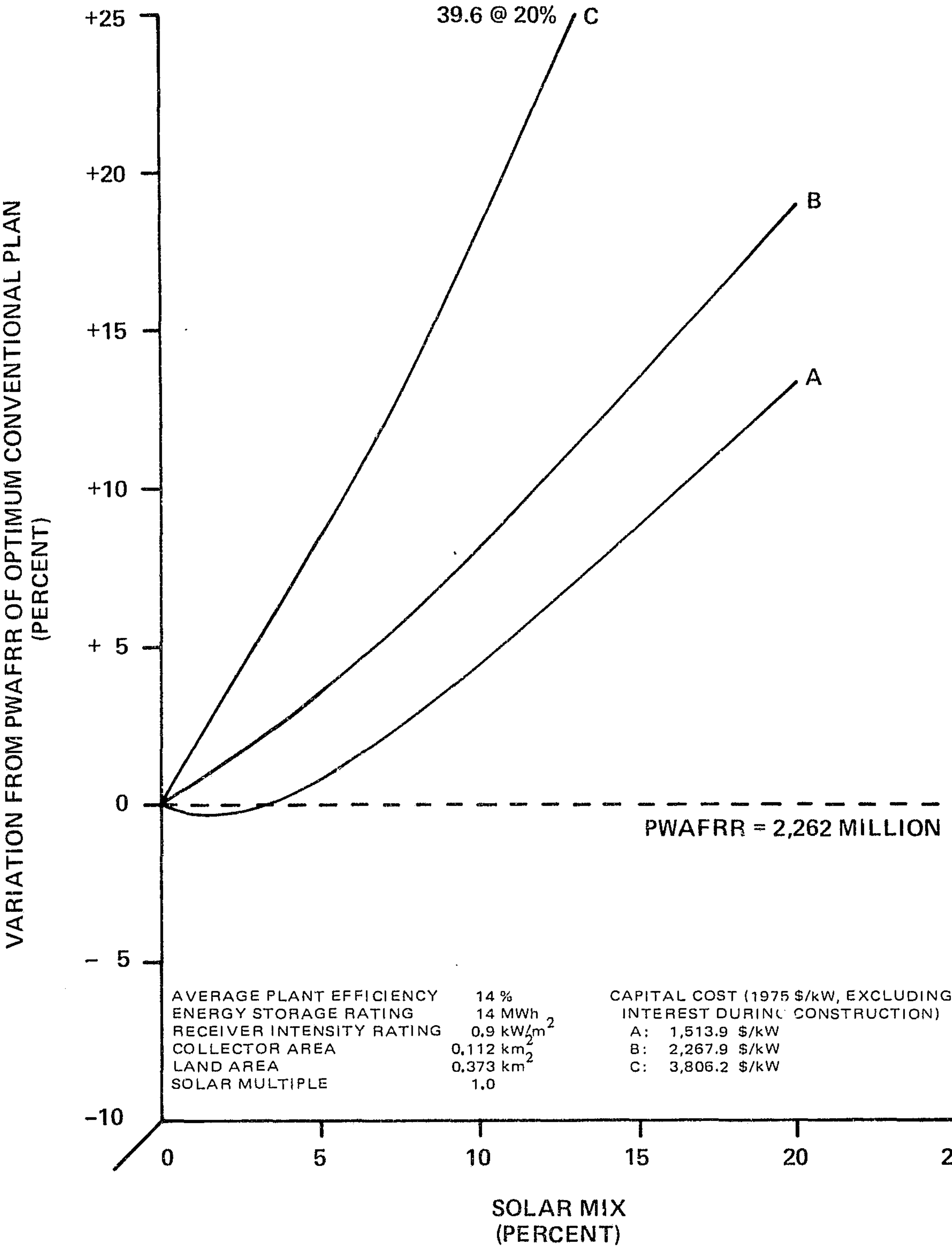


Figure 5-21

RANGE OF SOLAR EXPANSION PLAN COSTS, 1980-2000
200-MW GENERATION & TRANSMISSION COOPERATIVE
50-MW CENTRAL RECEIVER SYSTEM

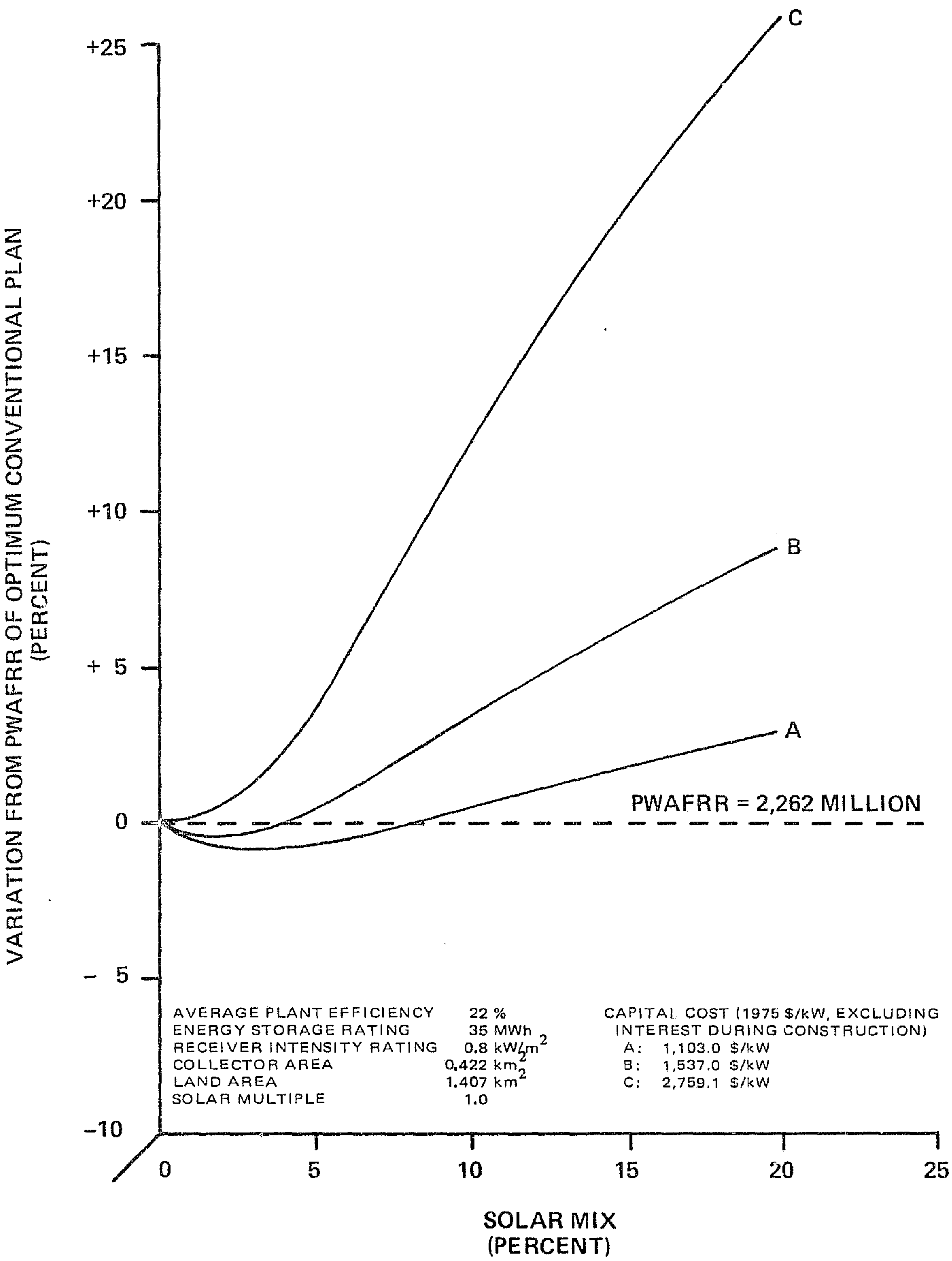


Figure 5-22

35-MW distribution cooperative. The slight differences can be explained primarily by the difference in the conventional intermediate-peaking types with which the solar thermal power systems were competing and differences in existing generation mix. Similarly, the differences in the results for the two 10 MW solar thermal power systems can be explained by the same factors which explained their differences for the 35-MW utilities.

The results for the 50-MW central receiver system can also be explained by many of these same factors. The 50-MW central receiver system was intermediate between the 10-MW parabolic dish concentrator system and the 10-MW variable slat concentrator system in both efficiency and capital cost as well as in results. The major factors which made it more expensive (per kilowatt) than the parabolic dish system were higher costs of solar hardware (see Table 2-2), lower efficiency, and a larger collector area primarily as a result of the use of thermal storage. The major factors which made it less expensive (per kilowatt) than the variable slat concentrator system included a lower cost per square meter of collector area and a higher efficiency.

BREAK-EVEN CAPITAL COSTS

The results presented above gave the relationship of the PWAFRR of the solar expansion plans to that of the optimum conventional expansion plan for a range of potential solar thermal power system capital costs and a fixed set of solar thermal subsystem efficiencies.

In this part break-even capital costs which were developed from these results for each solar thermal power system type and each reference utility are discussed. The break-even capital cost was defined as that capital cost at which the PWAFRR of the solar expansion plan would equal that of the optimum conventional expansion plan for a given solar mix. The methodology used to calculate break-even capital cost is discussed in Appendix G.

The break-even capital cost provides a useful basis for establishing cost goals for the various solar thermal power system types since it represents the cost which would have to be achieved by the solar thermal power system for a given solar mix to be economically viable. The break-even capital cost can be used as a guideline in determining what combination of subsystem cost reductions and increases in subsystem efficiency would be required in order for a given solar thermal power system type to become economically competitive.

The break-even capital costs calculated for each reference utility and each solar thermal power system type for a 10 percent solar mix are summarized in Table 5-2 along with the study input capital cost ranges. These results are also illustrated in a bar chart in Figure 5-23. The break-even capital cost for the 1-MW parabolic dish concentrator system and the 1.3-MW municipal reference utility is $1,049.8/kW. This value falls within the bottom quarter of the study input capital cost range ($638/kW to $2,923/kW).

The break-even capital cost for the 2-MW parabolic dish concentrator system ranged from $720.7/kW for the 35-MW distribution cooperative to $1,307.3/kW for the 35-MW municipal with oil-fired generation. These break-even costs fell within the range of potential capital costs of $578/kW to $2,312/kW which were assumed in the study.

Break-even capital costs calculated for the 10-MW parabolic dish concentrator system ranged from $713/kW for the 35-MW distribution cooperative to $1,138.8/kW for the 35-MW municipal with oil-fired generation. These costs also fell within the range of potential capital costs of $508/kW to $1,848/kW assumed in the study.

For the 10-MW variable slat concentrator system, break-even capital costs ranged from $976.8/kW for the 35-MW distribution cooperative to $1720.1/kW for the 35 MW municipal with oil-fired generation. These costs are less than or in the lower part of the cost range of $1,506/kW to $3,806/kW assumed in the study.

The break-even capital for the 50-MW central receiver system was $1,075.5/kW for the 200-MW generation and transmission cooperative, the only reference utility for which it was considered. This value was $27.5/kW less than the lower limit of the cost range of $1,103/kW to $2,759/kW considered in the study.

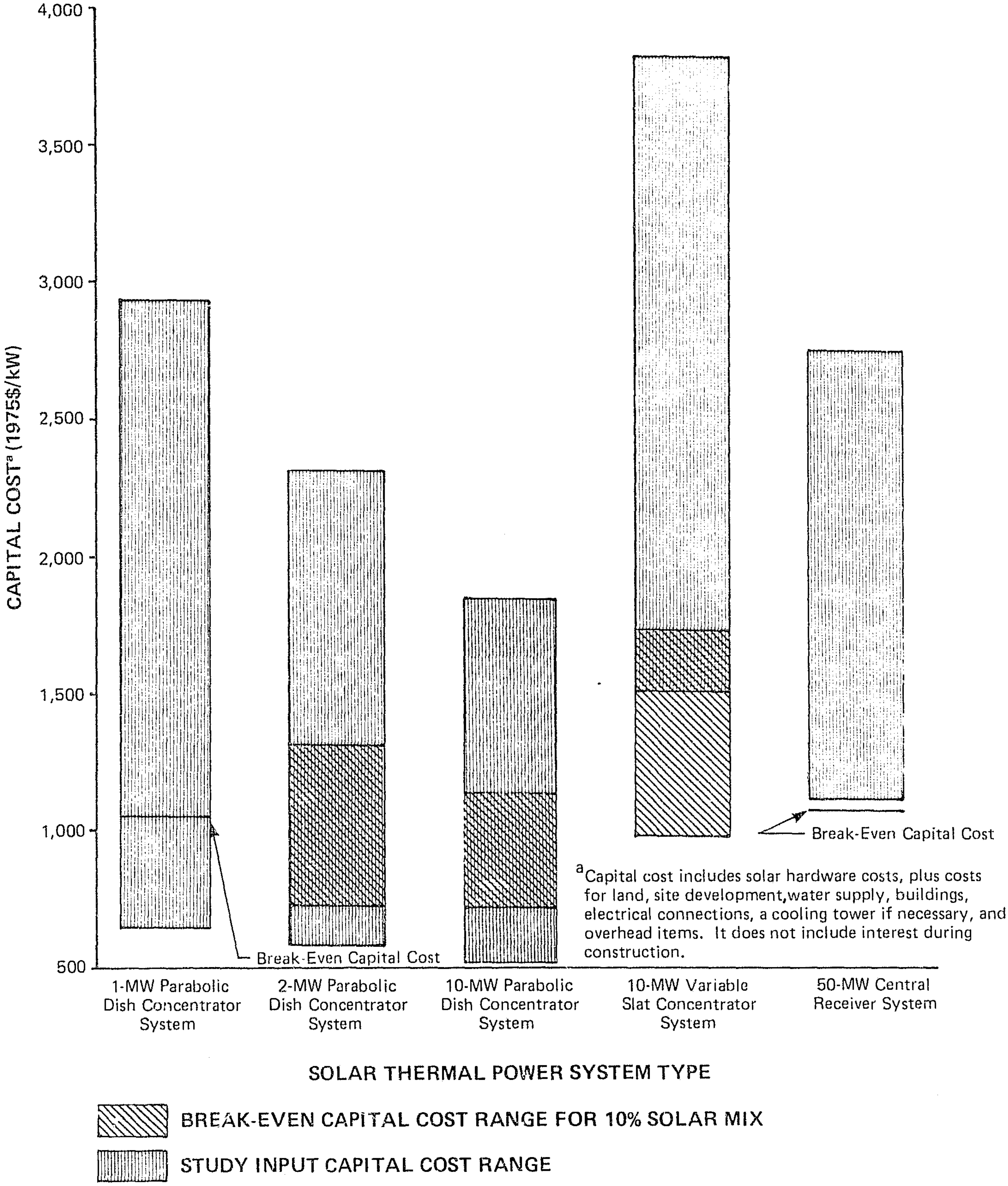
Table 5-2

BREAK-EVEN CAPITAL COSTS AT 10% SOLAR MIX
VERSUS STUDY INPUT CAPITAL COST RANGES
(1975 $/kW)

Reference Utility	Solar Thermal Power System Type: 1-MW Parabolic Dish Concentrator System	2-MW Parabolic Dish Concentrator System	10-MW Parabolic Dish Concentrator System	10-MW Variable Slat Concentrator System	50-MW Central Receiver System
Study Input Capital Cost[a] Range					
All Utilities	638-2,923	578-2,312	508-1,848	1,506-3,806	1,103-2,759
Break-Even Capital Cost[a] At 10% Solar Mix					
1.3-MW Municipal	1,049.8	–	–	–	–
10-MW Municipal With Generation	–	968.6	–	–	–
10-MW Municipal Without Generation	–	1,070.1	–	–	–
35-MW Municipal with Coal-Fired Generation	–	746.4	716.2	1,137.4	–
35-MW Municipal with Oil-Fired Generation	–	1,307.3	1,138.8	1,720.1	–
35-MW Distribution Cooperative	–	720.7	713.0	976.8	–
200-MW Generation & Transmission Cooperative	–	–	771.6	1,069.8	1,075.5

[a]*Capital cost includes solar hardware costs, plus costs for land, site development, water supply, buildings, electrical connections, a cooling tower if necessary, and overhead items. It does not include interest during construction.*

COMPARISON OF STUDY INPUT
AND BREAK-EVEN CAPITAL COSTS



[a]Capital cost includes solar hardware costs, plus costs for land, site development, water supply, buildings, electrical connections, a cooling tower if necessary, and overhead items. It does not include interest during construction.

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Figure 5-23

UTILITIES REPRESENTED BY REFERENCE UTILITIES

The results presented above, including the break-even capital costs, indicated that the small solar thermal power systems considered in the study are potentially more competitive in some utilities than in others. For example, all of the solar thermal power systems were more competitive in utilities with oil-fired generation or utilities that purchase power from utilities with oil-fired generation (represented in the study by the 35 MW municipal with oil-fired generation) than in other utilities. Similarly, because of their lower interest rate, municipal utilities seemed likely to find the solar thermal power systems economically attractive at a higher capital cost than that attractive to rural electric cooperatives.

These observations raised the question of how many small utilities there are that are dependent on oil-fired generation, or that are municipal systems rather than cooperative systems. Exact answers to these questions were not available, but approximations of relative magnitudes were made with reference to the small utility data bases which are described in Appendix A. It should be emphasized that the numbers developed were at best rather broad approximations of the number of utilities represented by each reference utility. This was true, first, because only the utilities included in the data bases were represented in these numbers. However, for many utilities there was insufficient information for their inclusion in the data bases. Second, although seven reference utilities were considered adequate for the purposes of this study, it was impossible to fully represent the diversity of characteristics of the 2000 to 3000 small utilities in the United States with these reference utilities. Thus, a small investor-owned utility may have been grouped with municipal utilities or a utility without generation may have been grouped with utilities with generation. Third, in some cases information was not available in the data bases to make a desired distinction. For example, it was desired to have the 35-MW municipal with oil-fired generation represent utilities which either have predominantly oil-fired generation or purchase power from a utility with predominantly oil-fired generation. However, no information was available in the data bases regarding the generation mixes or fuel types of the utilities supplying purchased power to the small utilities, so the second criterion could not be used. Nonetheless, the numbers developed from the data bases do supply some useful information.

Table 5-3 provides a breakdown of the number of small utilities in the data bases which were assumed to be represented by a particular reference utility, along with the criteria used to define each category. Omitted from these numbers are distribution cooperatives that purchase power from generation and transmission cooperatives and all utilities that purchase power from TVA. This is because such utilities typically have long-term, all-requirements contracts with the generation and transmission cooperative or TVA and therefore would not install their own generation.

Several observations can be made from the figures shown in Table 5-3. By far the largest category of small utilities is that group represented by the two 10-MW municipal reference utilities. The next largest category is distribution cooperatives, followed by the utilities represented by the 35-MW municipal with coal-fired generation. Thus, the study results for these categories should be weighed most heavily when considering the factors most necessary for the success of small solar thermal power systems. On the other hand, the smallest (and hence least important) categories were the utilities with oil-fired generation and the generation and transmission cooperatives.

* * * * *

C-2

Table 5-3

SMALL UTILITIES REPRESENTED BY REFERENCE UTILITIES

Reference Utility	Small Utilities Represented[a]		
	Size Range (MW)	Description	Number Of Utilities
1.3-MW Municipal	0.5-2	All Utilities except Distribution and Generation & Transmission Cooperatives	168
10-MW Municipal With Generation	2-20	All Utilities with Generation except Distribution and Generation & Transmission Cooperatives	297
10-MW Municipal Without Generation	2-20	All Utilities without Generation except Distribution and Generation & Transmission Cooperatives	364
35-MW Municipal With Coal-Fired Generation	20-50	All Utilities except these with Oil-Fired Generation[b]; Distribution and Generation & Transmission Cooperatives	254
35-MW Municipal With Oil-Fired Generation	20-50	All Utilities with Oil-Fired Generation[b] except Distribution and Generation & Transmission Cooperatives	37
35-MW Distribution Cooperative	0.5-500	All Distribution Cooperatives	299
200-MW Generation & Transmission Cooperative	0.5-500	All Generation & Transmission Cooperatives	28
Total			1447

[a] *Includes only those utilities in the data bases described in Appendix A. Does not include distribution cooperatives that purchase power from generation & transmission cooperatives or any utilities tha purchase power from TVA.*

[b] *Utilities with oil-fired generation were defined to be those which supply more than 30 percent of their own capacity requirements and which have at least 90 percent oil or oil and gas fired generation.*

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Section 6
SENSITIVITY ANALYSES

Section 5 described an economic analysis of the solar thermal power systems with a range of potential capital costs but with a fixed set of assumptions concerning the efficiency and operation and maintenance costs of the solar thermal power systems and fuel price escalation rates. In addition, the analysis was performed assuming that all of the reference utilities were located in the Southwestern United States. This section discusses sensitivity analyses to determine the impact of changes to each of these assumptions. It also addresses explicitly the impact of changes to the subsystem costs on the overall system cost.

All of the sensitivity analyses were performed using the intermediate solar thermal power system capital costs (see Table 2-3). It was felt that the relative impact of the changes considered in the sensitivity analyses would be approximately the same for the extremes of the capital cost ranges as for the intermediate costs.

CAPITAL COST

In general, the impact of changes to the costs of individual subsystems on the total capital cost of the solar thermal power systems can be calculated quite directly. For subsystem costs which are measured in terms of dollars per kilowatt the decrease in total capital cost is simply a multiple of the decrease in the subsystem costs. The multiple is determined by the decrease in items such as contingencies, engineering fees, sales taxes and property taxes, which are calculated as a percentage of total construction costs. Subsystem costs which are measured in terms of dollars per square meter of collector or dollars per kilowatt-hour of storage must first be converted to a dollar per kilowatt basis before being increased by the same multiple.

Table 6-1 summarizes the impact of a 10 percent decrease in the cost of each subsystem on the total system cost. The values shown are based on the intermediate capital costs (see Table 2-3) for municipal systems. The values for

Table 6-1

DECREASE IN CAPITAL COST WITH 10% DECREASE IN SUBSYSTEM COSTS (1975 $/kW)

Subsystem	Solar Thermal Power System Type		
	Parabolic Dish Concentrator Systems	Variable Slat Concentrator System	Central Receiver System
Collector	30.3	116.1	65.9
Transport	2.2	9.2	18.0
Conversion	6.4	21.4	21.0
Storage	11.0	14.6	14.4

cooperative systems would be slightly higher because of the impact of property taxes. In general, the results shown on Tables 6-1 indicate that a 10 percent decrease in the collector cost would have the largest impact on the system capital cost.

EFFICIENCY

The costs of each solar thermal power system could be reduced by reducing the costs of the individual subsystems, by increasing the subsystem efficiencies or some combination of the two. The primary impact of increasing subsystem efficiencies is to reduce the required collector area and therefore the required land area for the plant. In this part the impact of increasing the efficiency of the major subsystems both individually and in combination is discussed. The method used to calculate the impact of efficiency on the solar thermal power system capital cost is discussed in Appendix H.

Table 6-2 summarizes the impact on the capital cost of a 1 percentage point increase in the efficiency each of the subsystems individually and of the overall solar thermal power system. It should be noted that the costs shown on the table apply only to municipal utilities. Because of the effect of total land area on property taxes, the values for cooperative utilities would be slightly higher than those shown on Table 6-2.

As can be seen from this table, for the parabolic dish concentrator systems an increase in the concentrator efficency of 1 percentage point from .864 to .874 would result in a decrease in capital cost of $4.4/kW for the intermediate capital costs. An increase of 1 percentage point in the efficiency of the receiver and transport subsystems from .764 to .774 would result in a capital cost reduction of $5.0/kW. An increase in conversion efficiency of 1 percentage point from .42 to .43 would decrease the capital cost by $9.0/kW. A 1 percentage point in the overall system efficiency from .28 to .29 would result in a decrease in capital costs of $13.4/kW.

Table 6-2

DECREASE IN CAPITAL COST[a]
WITH 1 PERCENTAGE POINT INCREASE IN SUBSYSTEM OR SYSTEM EFFICIENCY
(1975 $/kW)

1 Percentage Point Increase in Efficiency Of	Solar Thermal Power System Type		
	Parabolic Dish Concentrator Systems	Variable Slat Concentrator System	Central Receiver System
Concentrator	4.4	—	—
Concentrator & Receiver	—	25.5	12.7
Receiver & Transport	5.0	—	—
Transport	—	15.1	8.7
Conversion	9.0	45.3	22.6
Total System	13.4.	93.5	36.4

[a] *Based on the intermediate capital costs for municipal systems (See Table 2-3). The values for cooperative systems would be slightly higher.*

For the variable slat concentrator system an increase in collector efficiency (which includes both concentrator and receiver) of 1 percentage point from .54 to .55 would result in a decrease in the intermediate capital cost of \$25.5/kW. An increase of 1 percentage point from .92 to .93 in transport efficiency would reduce the capital cost by \$15.1/kW and a similar increase in conversion efficiency from .30 to .31 would result in a capital cost reduction of \$45.3/kW. An increase in the efficiency of the overall system from .14 to .15 would result in a cost reduction of \$98.5/kW.

For the central receiver system and increase in collector efficiency of 1 percentage point from .65 to .66 would result in a decrease in the intermediate capital cost of \$12.7/kW. An increase of 1 percentage point in transport efficiency from .95 to .96 would result in an \$8.7/kW reduction in capital cost and a 1 percentage point increase in conversion efficiency from .36 to .37 would result in a \$22.6/kW capital cost reduction. An increase in the efficiency of the overall system of 1 percentage point from .22 to .23 each each would result in a decrease in capital cost of \$36.4/kW.

The values shown in Table 6-2 are illustrative of the relative magnitudes of changes in capital cost which might be expected as a result of increases in efficiency. The absolute numbers, however, should be treated with some care for two reasons. First, the actual value of the decrease in capital cost is directly dependent on the initial value of the area-related costs which is assumed. Thus, if higher initial costs had been assumed then the calculated decrease in capital cost with the increase in efficiency would also have been higher. Second, the decrease in capital cost is not linearly-related to the increase in efficiency. For example, the first percentage point increase in overall system efficiency from .14 to .15 for the variable slat concentrator system is shown to result in a capital cost reduction of \$93.15/kW. However, the second percentage point increase for this system from .15 to .16 would result in an additional capital cost reduction of only \$81.9/kW. Similar diminishing returns would be observed in all other cases.

Table 6-3 illustrates the impact of efficiency on capital cost from a slightly different perspective. In this table the impact of a 10 percent increase in overall efficiency is shown both in terms of percentage points of increased efficiency and decrease in capital cost. Once again, these results are based on the intermediate level of capital costs for municipal utilities. The cautions discussed above are applicable to these results.

It can be seen that a 10 percent increase in the system efficiency has the greatest impact (in terms of $/kW) on the capital cost of the variable slat concentrator system, followed in order by the central receiver system and the parabolic dish concentrator systems. This order corresponds both to the order of decreasing area-related costs and increasing initial efficiencies.

OPERATION AND MAINTENANCE COSTS

Operation and maintenance (O&M) costs are typically divided into two categories: fixed O&M and variable O&M. Fixed O&M includes all maintenance costs which must be incurred whether or not the unit is operated. Generally, fixed O&M includes items such as the salaries of operators and maintenance personnel and overhead costs. Variable O&M includes all costs which are only incurred when the unit is operated. These normally include the cost of items such as water treatment and waste disposal, lubricants, and spare parts. Inspection and overhaul costs may be either fixed or variable depending upon the way these are scheduled by the individual utility. If they are scheduled at regulartime intervals they would be considered fixed costs whereas if they are scheduled after a certain number of hours of operation then they would be considered variable costs.

Operation and maintenance costs are perhaps one of the most difficult parameters to predict for new technologies. A recent report by EPRI (10) predicted operation and maintenance costs for a central receiver system with 6 hours of storage of $14/kW-year fixed O&M and 1 mill/kWh variable O&M, which are quite different from the values of $2/kW-year fixed O&M and 4 mills/kWh variable O&M which were used in the analysis described in Section 5. The impact of

Table 6-3

IMPACT OF 10% INCREASE IN EFFICIENCY OF SOLAR THERMAL POWER SYSTEMS

Solar Thermal Power System Type	Percentage Points of Increased Efficiency	Decrease In Capital Cost[a] (1975 $/kW)
Parabolic Dish Concentrator Systems	2.8	35.3
Variable Slat Concentrator System	1.4	127.5
Central Receiver System	2.2	76.0

[a] *Based on the intermediate capital costs for municipal systems (see Table 2-3). The values for cooperative systems would be slightly higher.*

these different operation and maintenance costs was determined in two ways. First, the difference in the two sets of O&M values was calculated in terms of equivalent capital cost. Second, selected power supply expansion plans were re-analyzed with the EPRI O&M values to determine the overall impact on the present worth of all future revenue requirements.

A fixed annual payment such as a fixed operation and maintenance cost can be converted into an equivalent lump sum payment (capital cost) by dividing the annual payment by the appropriate carrying charge rate. Thus, using the carrying charge rates shown in Table 3-10, a fixed operation and maintenance cost of $1/kW-year can be converted to an equivalent capital cost of $12.80/kW for municipal utilities and $9.21/kW for cooperative utilities. Similarly, a variable operation and maintenance cost can be converted to a capital cost if an annual capacity factor is assumed. Thus, for the parabolic dish concentrator systems which have an annual capacity factor of 36 percent, a variable O&M of 1 mill/kWh is equivalent to a capital cost of $40.31/kW for municipal utilities and $29.02/kW for cooperative utilities. For the variable slat concentrator and central receiver systems with annual capacity factors of 47 percent, a variable O&M of 1 mill/kWh is equivalent to a capital cost of $52.72/kW for municipal systems and $37.95/kW for cooperative systems.

Using these equivalences, each set of O&M costs was converted to an equivalent capital cost, as shown in Table 6-4. For the parabolic dish concentrator systems the EPRI values are 17½ percent higher when expressed in terms of capital cost than the initial study input values. For the variable slat concentrator and central receiver systems, on the other hand, the EPRI values are almost 2 percent less than the initial study input values when expressed in terms of capital cost. The difference in results for the parabolic dish concentrator systems and the variable slat concentrator and central receiver systems is a result of the difference in annual capacity factors for these systems. A higher annual capacity factor weights the variable O&M more heavily whereas a lower annual capacity factor weights fixed O&M more heavily.

As noted above, selected power supply plans were re-analyzed with the EPRI O&M values to determine the impact of the differences in O&M costs on the

Table 6-4
COMPARISON OF OPERATION AND MAINTENANCE (O&M) COSTS

Solar Thermal Power System Type	Utility Type	Capital Cost Equivalent Of O&M Costs[a] (1975 $/kW)		Percent Difference In Equivalent Capital Cost
		Fixed O&M = $2/kW-yr Variable O&M = 4 mills/kWh	Fixed O&M = $14/kW-yr Variable O&M = 1 mill/kWh	
Parabolic Dish Concentrator Systems	Municipal	186.8	219.5	17.5
	Cooperative	134.5	158.0	17.5
Variable Slat Concentrator System	Municipal	236.5	231.9	−1.9
	Cooperative	170.2	166.9	−1.9
Central Receiver System	Municipal	236.5	231.9	−1.9
	Cooperative	170.2	166.9	−1.9

[a]*Based on the following equivalences:*

Utility Type	*Capital Cost (1975$/kW) Equivalent of*		
		1 mill/kWh Variable O&M	
	$1/kW-yr Fixed O&M	*Parabolic Dish*	*Variable Slat & Central Receiver*
Municipal	*12.80*	*40.31*	*52.72*
Cooperative	*9.21*	*29.02*	*37.95*

total present worth of all future revenue requirements. The plans which were re-analyzed included

- Both 10-MW municipals with a 5 percent penetration of the 2-MW parabolic dish concentrator system.
- Both 35-MW municipals and the 35-MW distribution cooperative with a 5 percent penetration of the 10-MW parabolic dish concentrator system.
- The 200-MW generation and transmission cooperative with 5 percent penetrations of both the 10-MW parabolic dish concentrator system and the 50-MW central receiver system.

Basically, these plans were selected as the most competitive solar expansion plan for each reference utility.

The results of this O&M cost sensitivity analysis are shown in Table 6-5. Basically, these results indicate that the overall impact of the assumed changes in O&M costs is negligible. This is true both because the O&M costs are small compared to the capital costs and to some extent because solar represents a small portion of each utility's total capacity requirement.

FUEL PRICE ESCALATION RATE

In the economic analyses described in Section 5, a differential fuel price escalation rate of 2 percent was assumed. To determine the impact of differential fuel price escalation rates on the study results, the conventional expansion plans and selected solar expansion plans were re-analyzed with differential fuel price escalation rates of zero and 4 percent per year. Since the base inflation rate assumed in the study was 6 percent per year these rates equate to fuel price inflation rates of 6 and 10 percent per year.

Table 6-5

RESULTS OF OPERATION AND MAINTENANCE (O&M) COSTS SENSITIVITY ANALYSIS

Solar Thermal Power System Type	Reference Utility	Present Worth of all Future Revenue Requirements(PWAFRR) (1975 $1000)		Percent Difference In PWAFRR
		Fixed O&M = $2/kW-yr Variable O&M = 4 mills/kWh	Fixed O&M = $14/kW-yr Variable O&M = 1 mill/kWh	
2-MW Parabolic Dish Concentrator System	10-MW Municipal with Generation	133,316	133,485	0.13
	10-MW Municipal without Generation	140,773	140,942	0.12
10-MW Parabolic Dish Concentrator System	35-MW Municipal with Coal-Fired Generation	437,668	438,388	0.16
	35-MW Municipal with Oil-Fired Generation	537,279	537,999	0.13
	35-MW Distribution Cooperative	382,287	382,736	0.12
	200-MW Generation & Transmission Cooperative	2,266,226	2,268,770	0.11
50-MW Central Receiver System	200-MW Generation & Transmission Cooperative	2,267,565	2,267,112	–0.02

The expansion plans which were re-analyzed included

- Both 10-MW municipals with a 5 percent penetration of 2-MW parabolic dish concentrator system.
- Both 35-MW municipals and the 35-MW distribution cooperative with a 5 percent penetration of the 10-MW parabolic dish concentrator system.
- The 200-MW generation and transmission cooperative with 5 percent penetration of both the 10-MW parabolic dish concentrator system and the 50-MW central receiver system.

As mentioned in the discussion of the operation and maintenance cost sensitivity analysis, these plans represent the most competitive solar expansion plan for each reference utility.

The results of this analysis are shown in Figures 6-1 through 6-6. Looking at Figure 6-1, it can be seen that for the 10-MW municipal with generation the optimum conventional expansion plan is more economical than expansion with the 2-MW parabolic dish concentrator system for all levels of differential fuel price escalation considered. The results shown in Figure 6-2 for the 10-MW municipal without generation, on the other hand, show that expansion with the 2-MW parabolic dish concentrator system becomes more economical than the optimum conventional expansion plan at a differential fuel price escalation rate of approximately 3 percent.

Figure 6-3 shows the results of this analysis for the 35-MW municipal with coal-fired generation. For this reference utility the PWAFRR of the optimum conventional plan is less than that of expansion with the 10-MW parabolic dish concentrator system for differential fuel price escalation rates up to 4 percent, although at this level the PWAFRR's are almost equal.

The results for the 35-MW municipal with oil-fired generation are shown in Figure 6-4. In this case the PWAFRR of the optimum conventional expansion plan is less than that of expansion with the 10-MW parabolic dish concentrator system for differential fuel price escalation rates up to about 1 percent. Above this level, the PWAFRR of the solar expansion plan is less.

VARIATION IN EXPANSION PLAN COSTS WITH FUEL PRICE ESCALATION RATE 10-MW MUNICIPAL WITH GENERATION

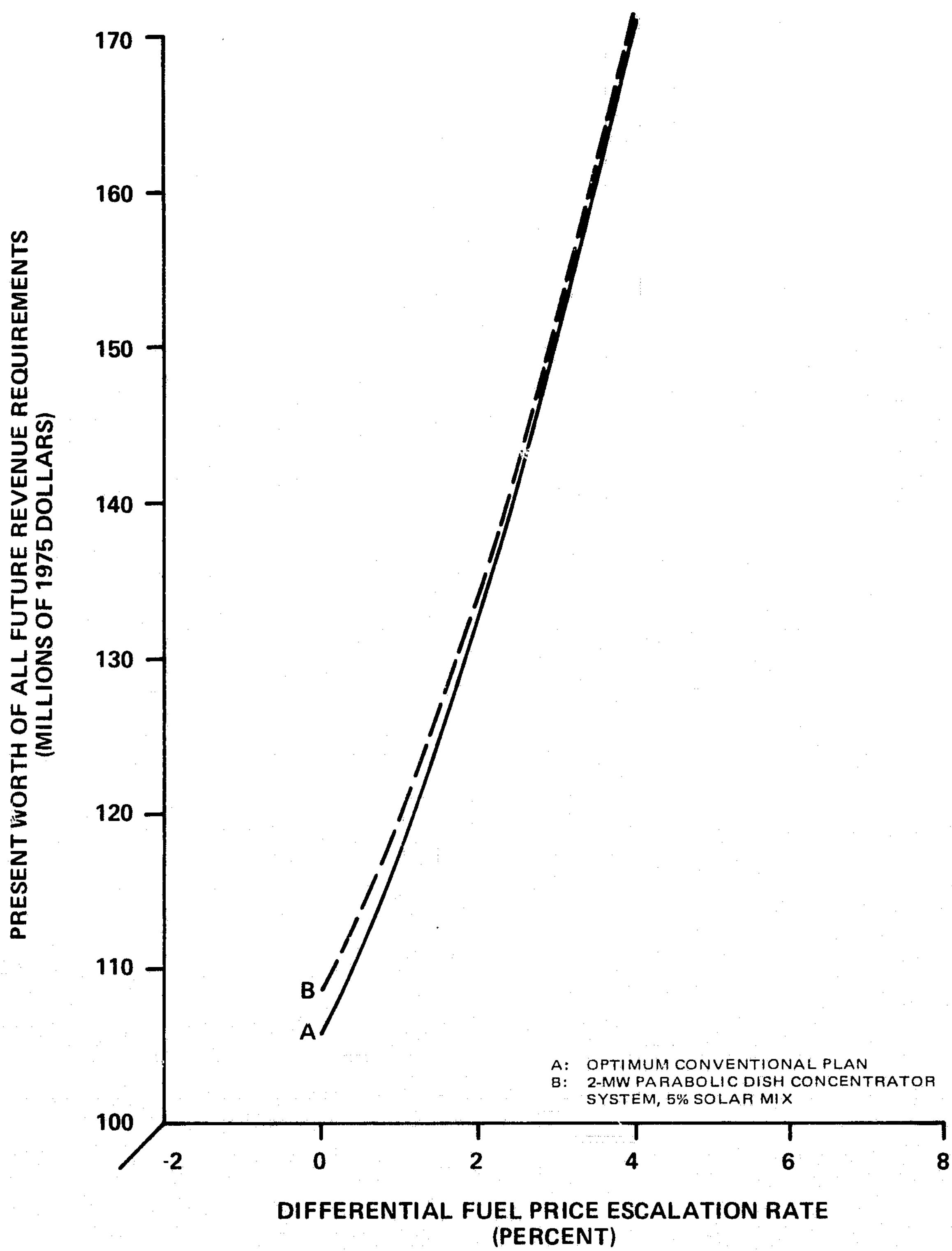


Figure 6-1

JPL 78-008-4-005

VARIATION IN EXPANSION PLAN COSTS WITH FUEL PRICE ESCALATION RATE
10-MW MUNICIPAL WITHOUT GENERATION

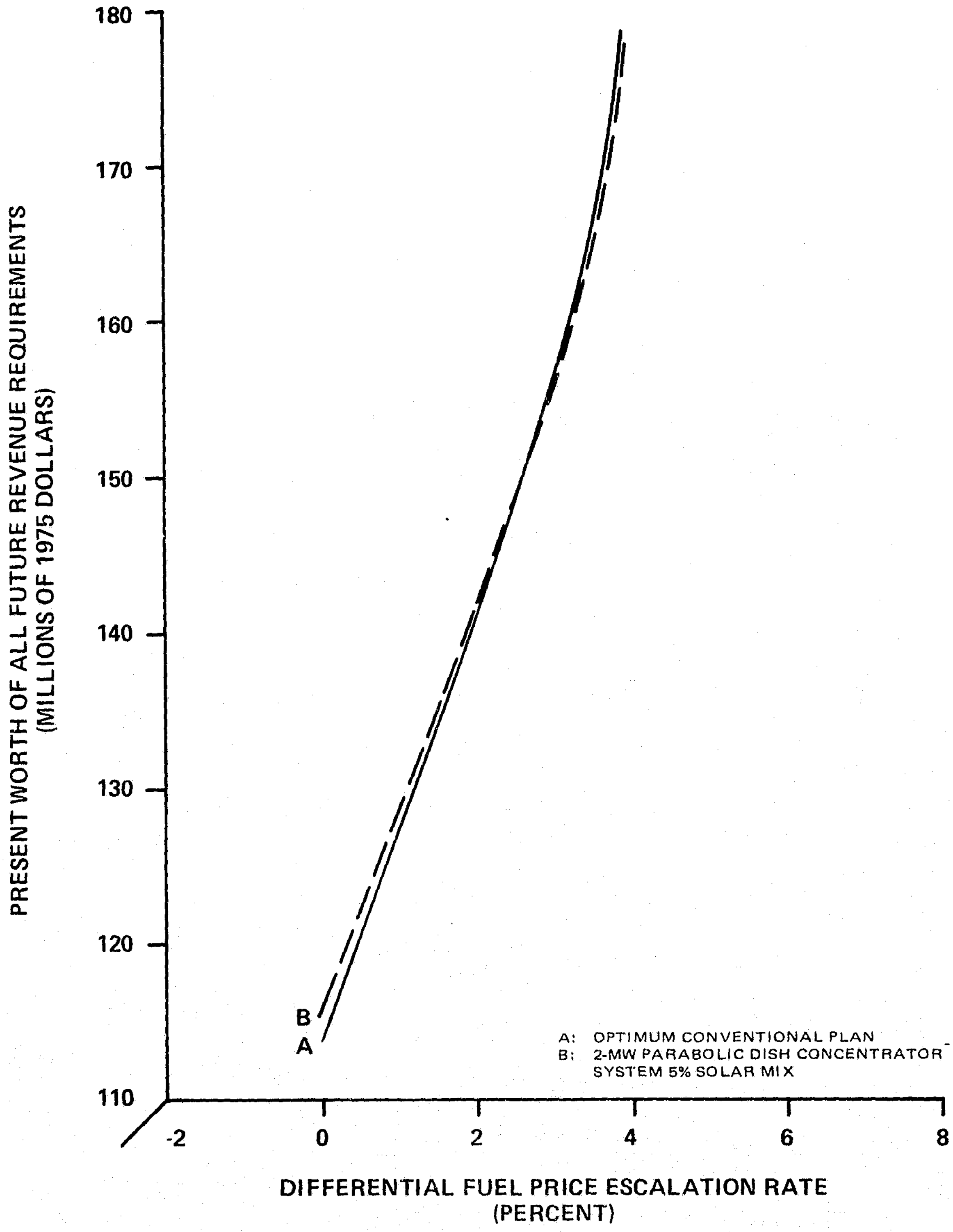


Figure 6-2

VARIATION IN EXPANSION PLAN COSTS WITH FUEL PRICE ESCALATION RATE
35-MW MUNICIPAL WITH COAL-FIRED GENERATION

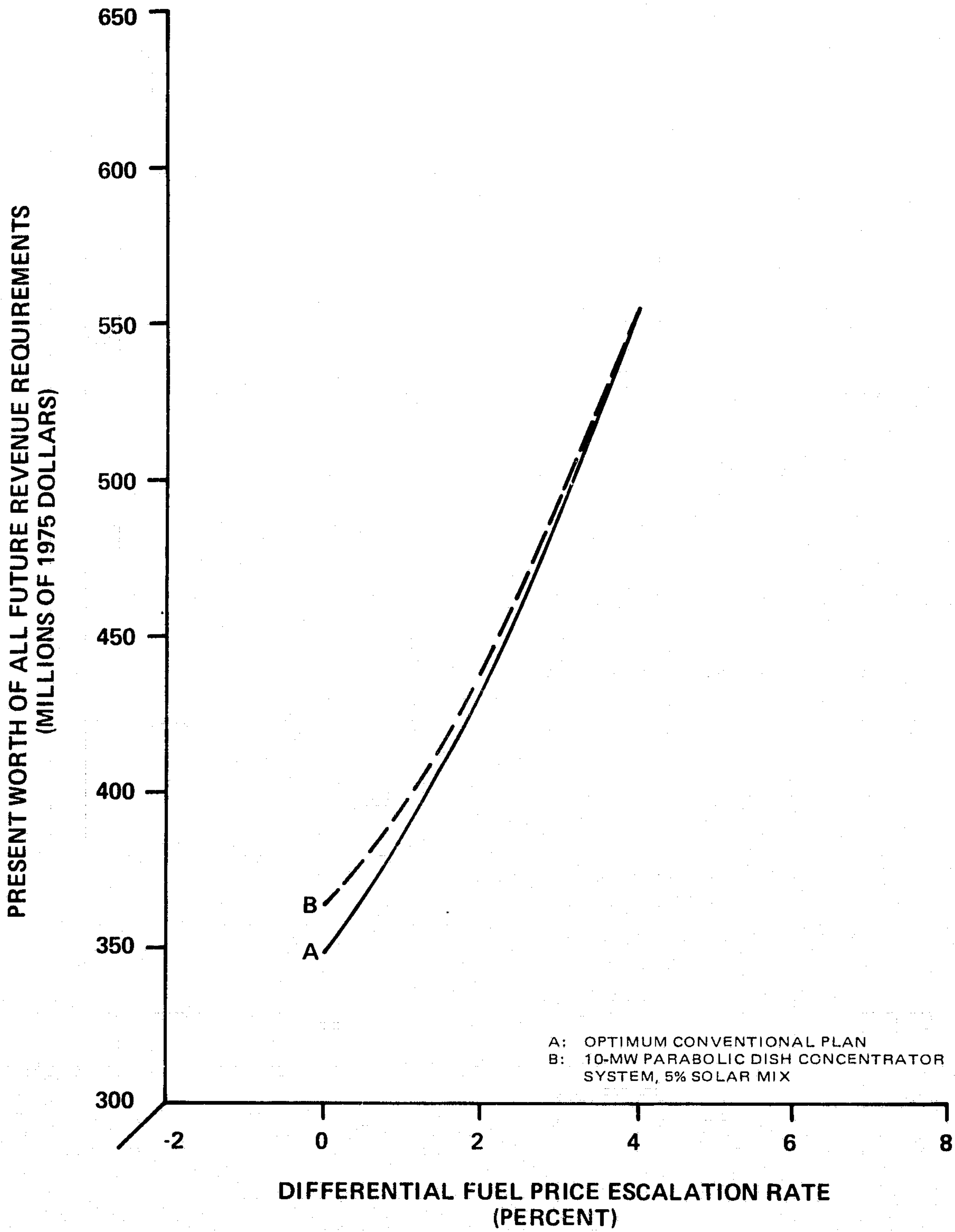


Figure 6-3

VARIATION IN EXPANSION PLAN COSTS WITH FUEL PRICE ESCALATION RATE
35-MW MUNICIPAL WITH OIL-FIRED GENERATION

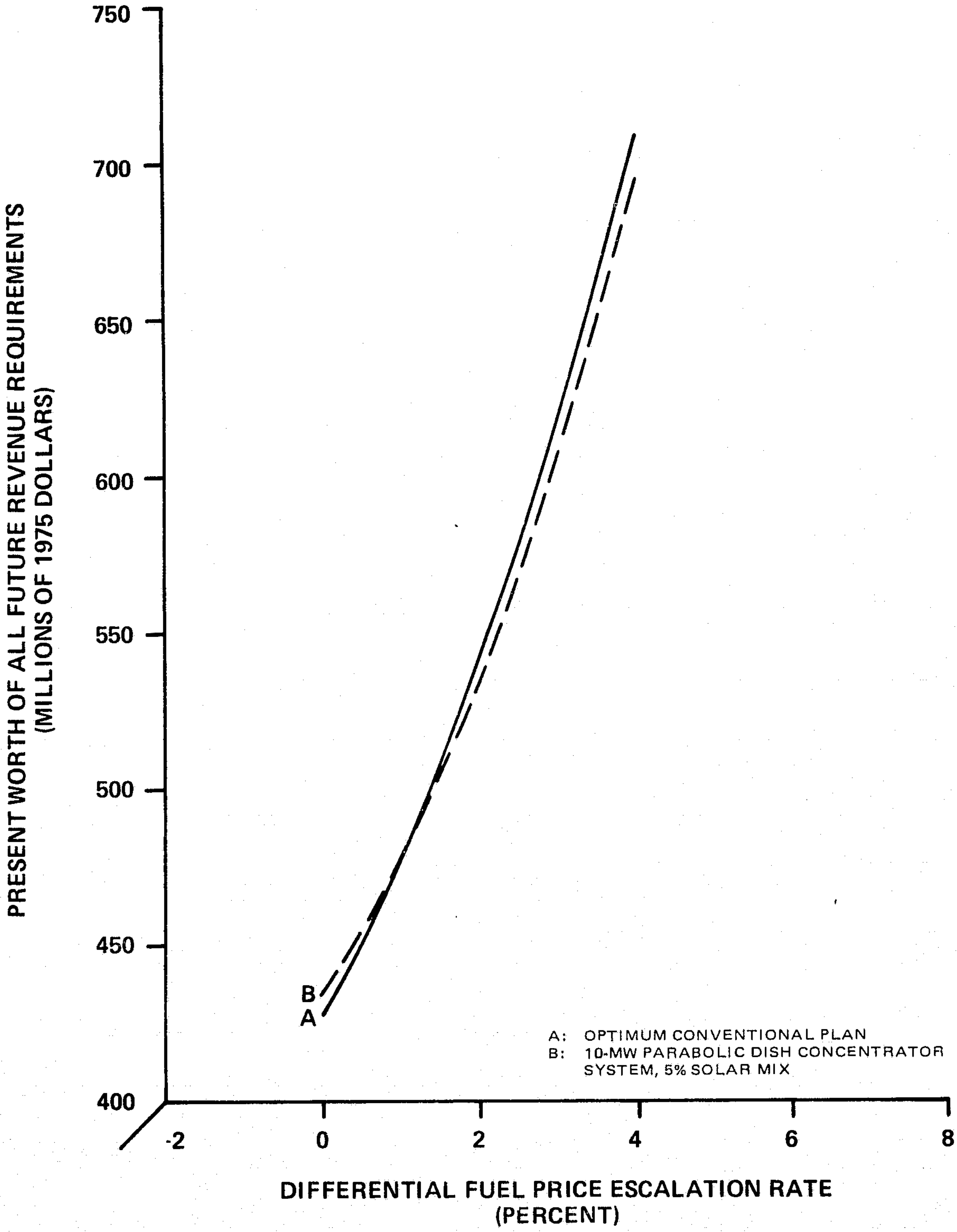


Figure 6-4

The results for the 35-MW distribution cooperative are shown in Figure 6-5. These results indicate that the optimum conventional expansion plan is more economical than expansion with the 10-MW parabolic dish concentrator system for differential fuel price escalation rates of zero to 4 percent.

Figure 6-6 shows the results of the differential fuel price escalation analysis for the 200-MW generation and transmission cooperative with the optimum conventional generation mix and both the 10-MW parabolic dish concentrator system and the 50-MW central receiver system. As indicated in this figure, the PWAFRR of the optimum conventional expansion plan is less than that of both the solar expansion plan up to a differential fuel price escalation rate of two to three percent.

In general, the results of this analysis indicate that if the solar thermal power systems are not competitive with conventional generation when fuel prices are escalating at the same rate as general inflation, then they will not be competitive even with differential fuel price escalation rates up to 3 or 4 percent per year. The one exception involves the 35-MW municipal with oil-fired generation. In this case, a differential fuel price escalation rate in excess of 1 percent would make the 10-MW parabolic dish concentrator system competitive with conventional generation. Although this analysis was only performed for selected combinations of solar thermal power system types and reference utilities and only for a 5 percent solar mix, it is felt that comparable results would be obtained for other scenarios.

GEOGRAPHIC LOCATION

In order to determine the impact of geographic location on the economic analysis of the solar thermal power systems, one reference utility was selected and moved to a new geographic location. The original intention was to continue to change the geographic location of the reference utility, in order of decreasing regional insolation, until the solar thermal power systems were no longer found to be competitive with conventional generation. Since this result was achieved with the first move, to the South Central United States, this was the only region considered in the geographic sensitivity analysis.

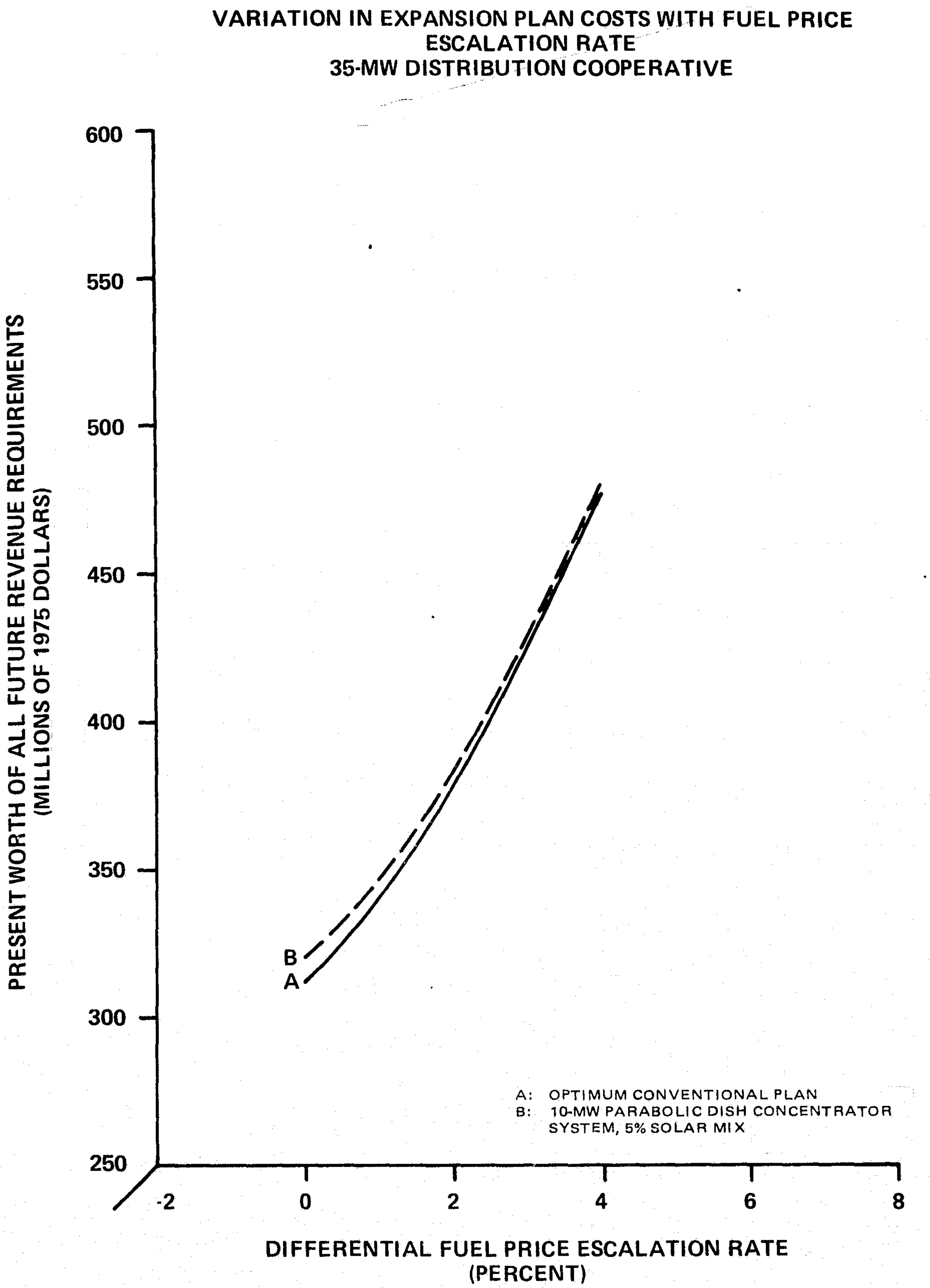

VARIATION IN EXPANSION PLAN COSTS WITH FUEL PRICE ESCALATION RATE
35-MW DISTRIBUTION COOPERATIVE
PRESENT WORTH OF ALL FUTURE REVENUE REQUIREMENTS (MILLIONS OF 1975 DOLLARS)
600
550
500
450
400
350
300
250
B
A
A: OPTIMUM CONVENTIONAL PLAN
B: 10-MW PARABOLIC DISH CONCENTRATOR SYSTEM, 5% SOLAR MIX
-2
0
2
4
6
8
DIFFERENTIAL FUEL PRICE ESCALATION RATE (PERCENT)

Figure 6-5

VARIATION IN EXPANSION PLAN COSTS WITH FUEL PRICE ESCALATION RATE
200-MW GENERATION & TRANSMISSION COOPERATIVE

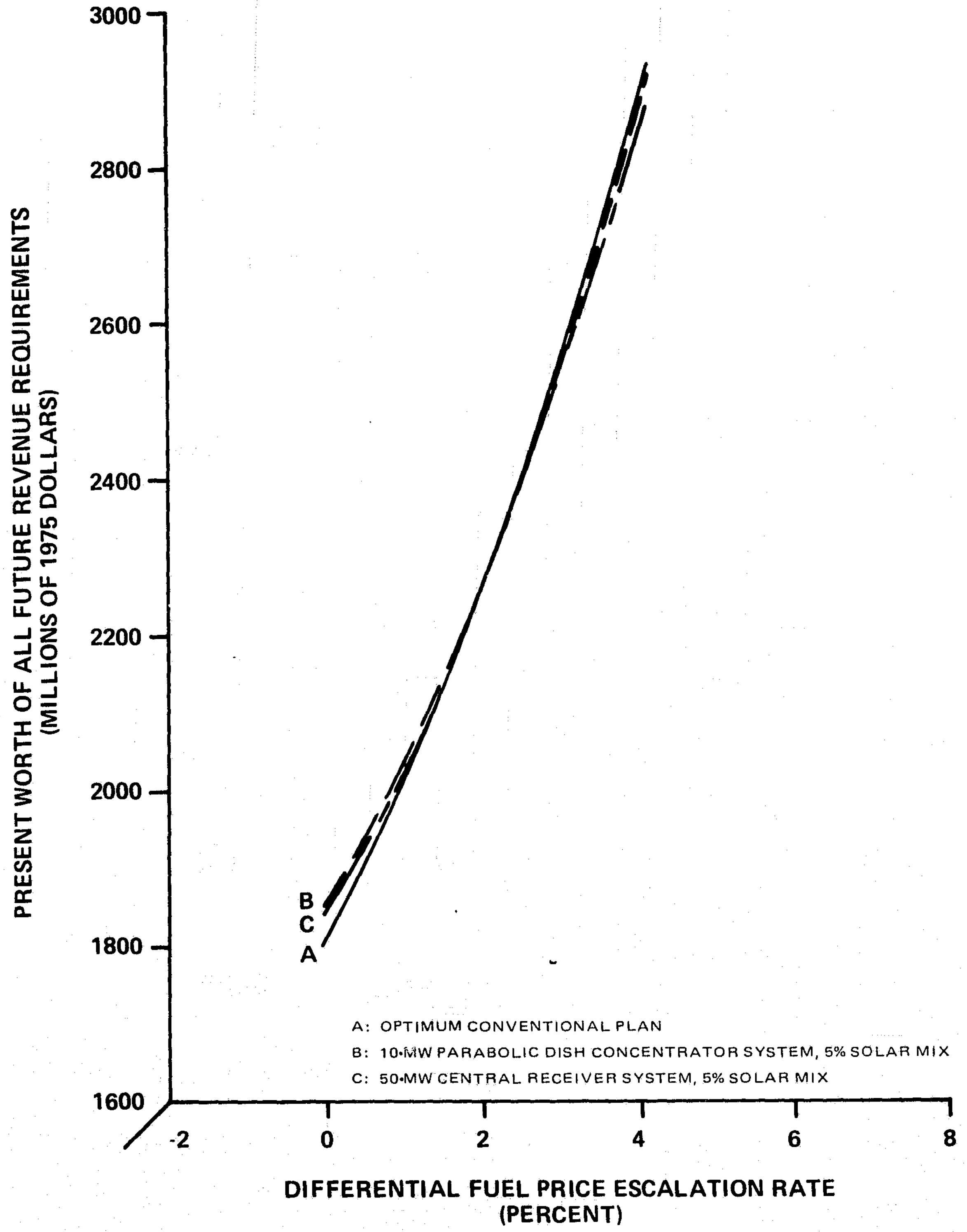


Figure 6-6

JPL 78-008-4-005

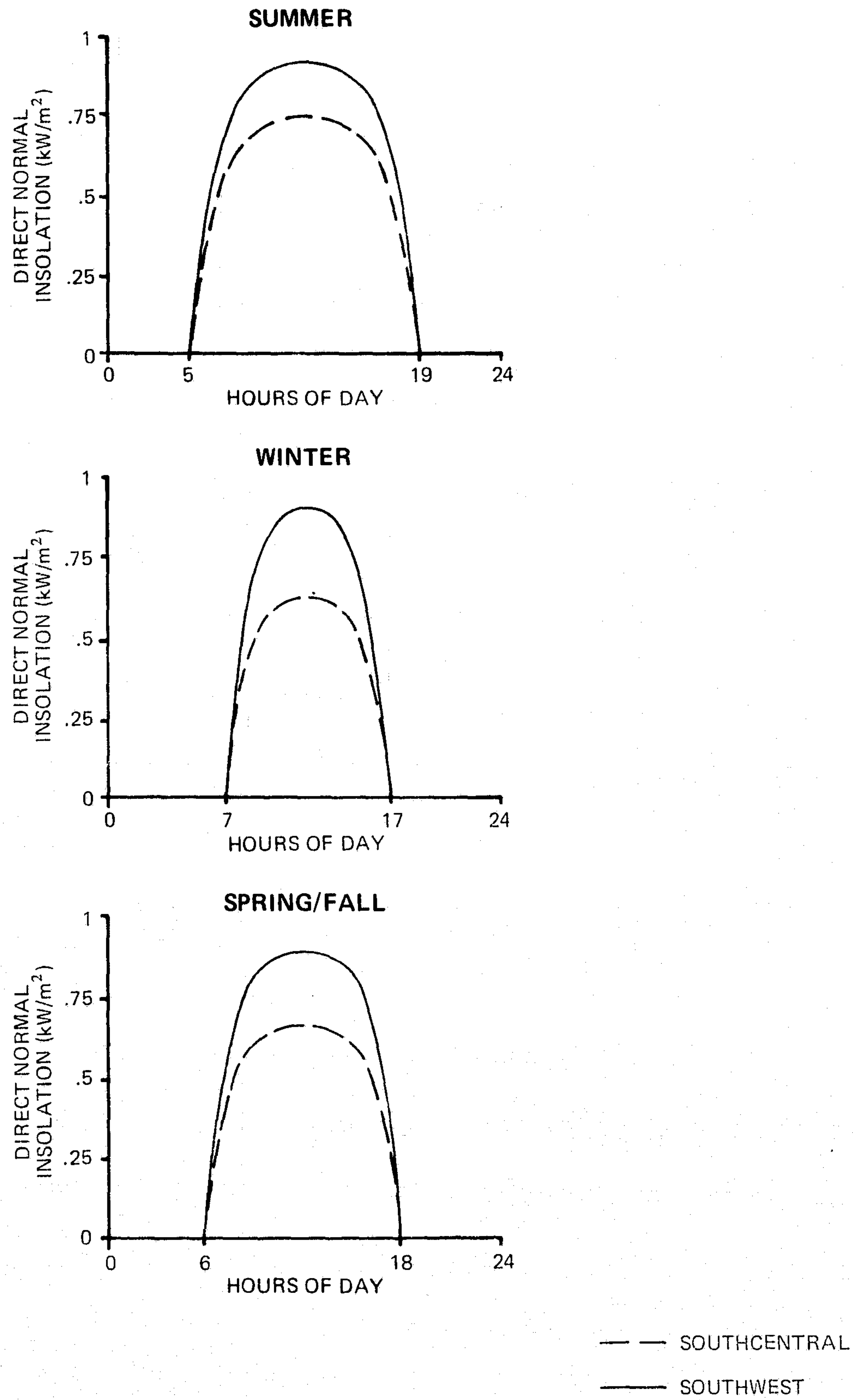
The reference utility selected for the geographic sensitivity analysis was the 35-MW municipal with oil-fired generation. It was selected because it was the reference utility for which the solar thermal power systems considered in the study were most competitive in the Southwestern United States. This reference utility was expanded only with the 2-MW and 10-MW parabolic dish concentrator systems since these were the only solar thermal power system types which were economically competitive in the Southwest for this utility.

The primary study input data which were modified in order to represent the change in geographic location were the insolation values. The insolation values used for the South Central United States were those for Fort Worth, Texas. Fort Worth was chosen because it represented the South Central region in much the same way that Albequerque represented the Southwest. Fort Worth has an average annual daily total radiation value of 6 kWh/m^2 which is approximately 20 percent above the South Central average and Albuquerque has a corresponding value of about 8 kWh/m^2 which is about 20 percent above the Southwest average (11,12). The seasonal insolation patterns used in the study for both the South Central and Southwest regions are compared in Figure 6-7.

The change in insolation data required a new optimization analysis to determine the best location-dependent parameters for the new geographic location. The solar thermal power system characteristics, including location-dependent parameters, are shown in Table 6-6 for both the South Central and the Southwestern United States. The differences in the capital costs shown for the two regions are a result of the differences in the location-dependent parameters and the resulting differences in collector and land area. As noted previously, only the intermediate capital costs (see Table 2-3) were considered in the sensitivity analysis.

The new location-dependent parameters and the new insolation data also affected the values of the capacity factor and capacity credit of the solar thermal power systems. The decrease in average annual daily total radiation primarily affected the capacity factor which decreased by about 5 percent. The capacity credit, on the other hand, was primarily affected by the decrease in the

COMPARISON OF SEASONAL INSOLATION PATTERNS
SOUTHWEST AND SOUTH CENTRAL REGIONS



JPL 78-003-4-005

Figure 6-7

Table 6-6

COMPARISON OF SOLAR THERMAL POWER SYSTEM CHARACTERISTICS FOR SOUTHWEST AND SOUTH CENTRAL REGIONS

Characteristic	Parabolic Dish Concentrator Systems			
	Southwest Region		South Central Region	
Plant Size (Rated Capacity, MW)	2	10	2	10
Commercial Availability	1985	1985	1985	1985
Cost Characteristics (1975 $)				
Capital Cost ($/kW)[a]	1,437	969	1,478	1,017
Operation & Maintenance				
Fixed ($/kW-yr)	2	2	2	2
Variable (mills/kWh)	4	4	4	4
Other Characteristics				
Average Plant Efficiency	.28	.28	.28	.28
Equipment Forced Outage Rate	.01	.01	.01	.01
Annual Maintenance (wks/yr)[b]	0.1	0.1	0.1	0.1
Storage				
Capacity Rating (MWe)	2	10	2	10
Energy Rating (MWh)	4	20	4	20
Receiver Intensity Rating (kW/m^2)	0.9	0.9	0.8	0.8
Collector Area (km^2)	0.008	0.040	0.009	0.045
Land Area (km^2)	0.026	0.133	0.030	0.149
Solar Multiple	1.0	1.0	1.0	1.0
Lifetime (years)	30	30	30	30

[a]*Includes costs of solar hardware, land, site development, water supply, buildings, electrical connections, cooling towers if necessary, and overhead items. Does not include interest during construction.*

[b]*Includes only maintenance which must be performed when the plant would normally be operating (i.e., daytime maintenance). It is assumed that most routine maintenance could be done at night.*

availability of the insolation (as measured by the percent of possible sunshine (13)). The values used for capacity factor and capacity credit for various levels of solar mix are shown in Table 6-7 for both the South Central and the Southwestern United States.

Table 6-7

CAPACITY CREDIT AND CAPACITY FACTOR

VERSUS SOLAR MIX

PARABOLIC DISH CONCENTRATOR SYSTEMS

Solar Mix[a] (%)	Capacity Credit (% of Rated Capacity)		Capacity Factor (% of Rated Capacity)	
	Southwest	South Central	Southwest	South Central
2	75	55	36	30
5	65	45	36	30
10	50	35	36	30
20	35	25	36	30
40	20	15	36	30
60	15	10	35	29
80	10	5	32	28

[a]Rated SPS cpacity as a percentage of total utility capacity requirement.

The results of the economic analysis of the solar expansion plans for the South Central and the Southwest regions are shown in Figures 6-8 and 6-9. The results shown in Figures 6-8 for the 2-MW parabolic dish concentrator system indicate that with intermediate capital costs the PWAFRR's of the solar expansion plans are from 0.5 to 1.5 percent higher in the South Central region than in the Southwest region for solar mixes of 5 to 20 percent. For the 10-MW parabolic dish concentrator system the PWAFRR's of the expansion plans are from 1 to approximately 2 percent higher in the South Central region than in the Southwest region for solar mixes of 5 to 20 percent.

* * * * *

SENSITIVITY OF EXPANSION PLAN COSTS TO GEOGRAPHIC LOCATION 1980–2000
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
2- MW PARABOLIC DISH CONCENTRATOR SYSTEM

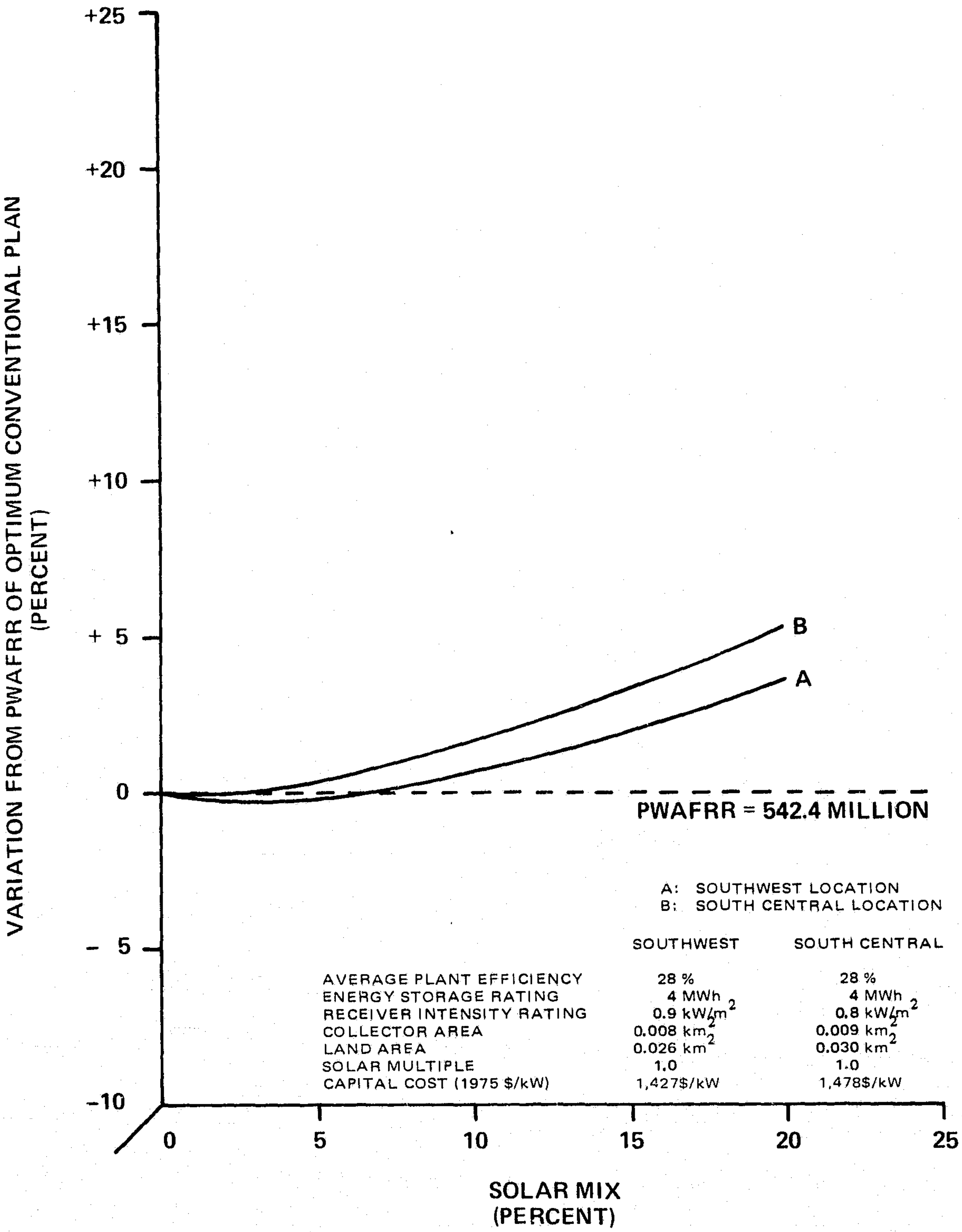


Figure 6-8

JPL 78-008-4-005

SENSITIVITY OF EXPANSION PLAN COSTS TO GEOGRAPHIC LOCATION 1980–2000
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM

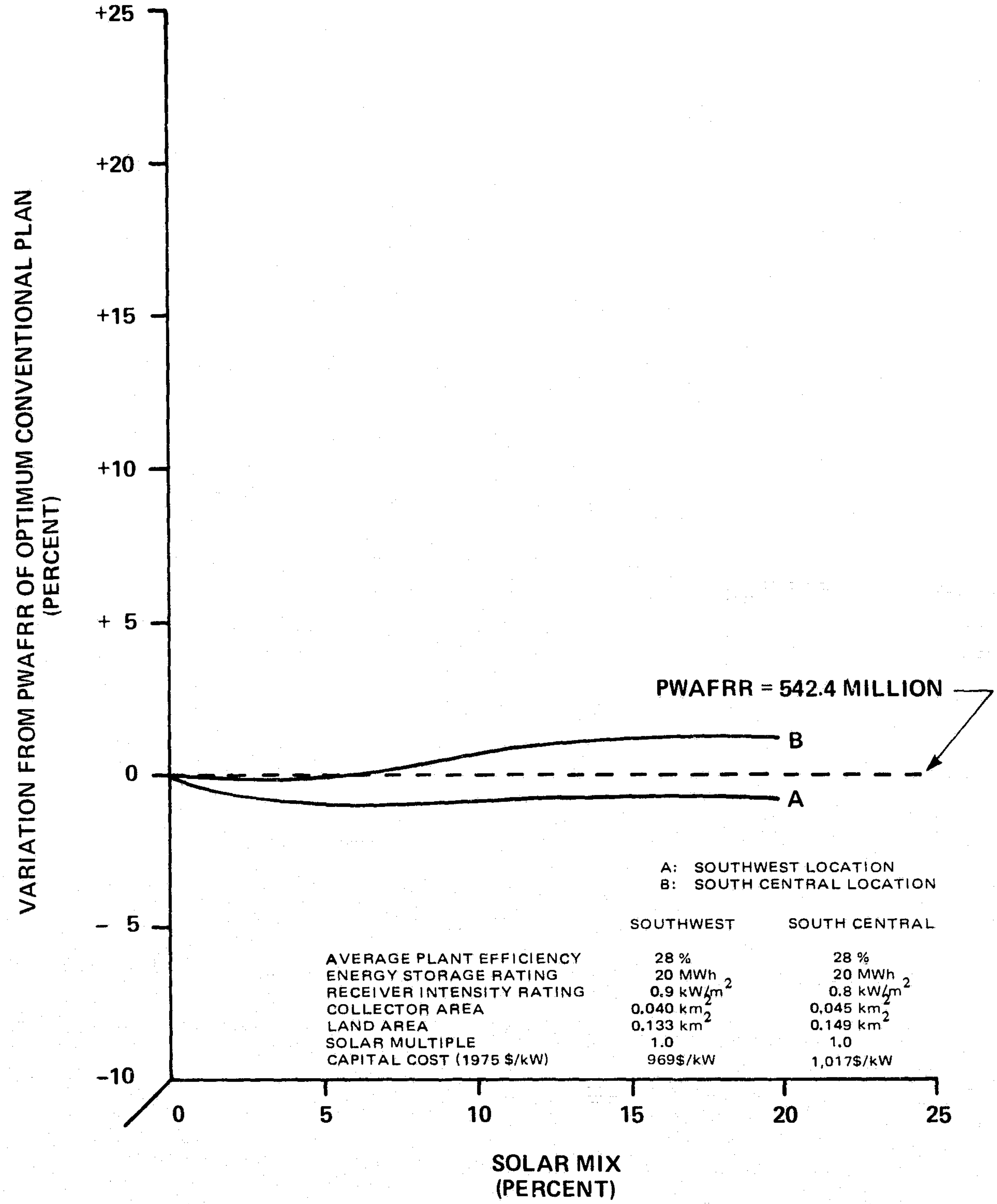


Figure 6-9

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Section 7

CONCLUSIONS AND RECOMMENDATIONS

This section summarizes the results of the study including the characteristics of utilities, of solar thermal power systems and other factors which have the most impact on the economic viability of solar thermal small power systems. In addition, non-economic factors which might influence the potential role of solar thermal power systems in small utilities are discussed. The final part of this section presents recommendations for future work which is indicated by the study results.

CONCLUSIONS

In general, the results of the economic analysis performed in the study indicated that the parabolic dish concentrator systems are potentially competitive if the lowest capital costs considered in the study (which assume the development of low-cost site preparation and construction techniques) can be achieved. The variable slat concentrator and central receiver systems were at best marginally competitive for very low solar penetrations with the lowest capital costs considered in the study.

The factors which had the most impact on these results can be divided into two general categories: the characteristics of the host utility and the characteristics of the solar thermal small power systems. The most important utility characteristics as far as the potential penetration of solar thermal power systems is concerned included the type of existing generation, purchased power costs, geographic location and utility type (ownership). Other less important utility characteristics included peak load season and load pattern. Characteristics of the solar thermal power systems which had the greatest impact included storage, plant costs other than solar hardware costs, collector costs, and system efficiency. Operation and maintenance costs had less impact on results.

The most important characteristic of the host utility's existing generation mix was the fuel type used by the generating units. It was found that a utility which is heavily dependent on oil-fired generation (represented in the study by the 35-MW municipal with oil-fired generation) is more likely to find solar thermal power systems economically competitive with conventional generation. High purchased energy costs were also found to have a similar impact.

The impact of geographic location on the competitiveness of solar thermal power systems was primarily a result of regional variations in the intensity of insolation and the amount of cloudiness. These factors affected both the required size of the collector field and the amount of energy which could be obtained from the solar thermal power systems.

Utility type or ownership had an impact on the competitiveness of solar thermal power systems as a result of differences in interest rates or cost of capital. Because solar thermal power systems are more capital intensive than conventional generation, differences in interest rate have a larger impact on solar plant costs than on the costs of conventional generation.

One characteristic of the solar thermal power systems which had a major impact on their competitiveness was the storage subsystem. The type of storage and assumptions made regarding the charging of storage had a significant impact on the required size of the collector field, the amount of energy available from the solar plant and the capacity credit or load carrying capability of the solar plant.

The solar plant costs for all items other than the solar hardware were also a major factor. These costs, which included items such as land, site development (grading, graveling, etc.), water supply, a control room/ maintenance building, electrical connections, a cooling tower if necessary and overhead, were estimated by Burns & McDonnell to range from 27 to 80 percent of the total solar plant costs. With these costs, none of the solar thermal power systems were generally competitive with conventional generation. The only capital costs for which the solar thermal power systems were generally competitive were costs which included low costs for all of these "other" items. These low costs, which were provided by JPL, assumed the development of innovative site preparation and construction techniques. Of the solar hardware costs, the collector costs generally had the largest impact on the competitiveness of the solar thermal power systems.

Efficiency also had a relatively large impact on the competitiveness of solar thermal power systems. Improvement in the efficiencies of the lowest efficiency subsystems, which were generally the energy conversion subsystems, would have the largest impact on the system cost and thus would do most to increase the competitiveness of the solar thermal power systems.

In addition to the economic factors discussed above, several non-economic factors may have an impact on the potential role of solar thermal small power systems in small utilities. These include environmental impacts, political climate (including potential governmental subsidies or other economic incentives), and limitations on the availability or legal restrictions on the use of oil for power generation. It was assumed in the study that fuel oil would be available and that the only mechanism for allocation would be price. If fuel oil were not available, solar thermal power systems might be more attractive because of their ability to reduce oil consumption. For the reference utilities considered in the study, oil consumption was projected to be reduced by 16 to 86 percent depending on the scenario by the introduction of solar thermal power systems.

RECOMMENDATIONS

A number of recommendations for future studies can be made on the basis of the results of this study. In general, these recommendations fall into two categories: methodology development and verification and investigation of other solar thermal power system configurations and applications.

In the area of methodology, recommendations for additional studies include:

- Verification of the hourly analysis methodology developed in this study, including the use of three weeks of load data and three days of insolation data to represent the summer, winter, and spring/fall seasons, by comparison with results of a more detailed model with more detailed load and insolation data.

- Investigation of the impact of different hourly dispatching strategies on the results of this study.
- Investigation of the impact of time-correlated load and insolation patterns rather than representative load and insolation patterns on the results of the study.
- Verification of the capacity credit methodology used in this study by comparison with more detailed models.
- If the methodologies used in this study can be adequately verified, development of a computer software package utilizing these methodologies which could be made available to utilities as an inexpensive tool for evaluating solar thermal power systems.

In the area of solar thermal power system configurations and applications, recommendations for additional studies include:

- Investigation of alternatives to the storage configurations considered in this study including hybrid systems with oil-fired backup.
- Investigation of solar plant costs other than solar hardware costs, including a detailed determination of the items and costs involved and investigation of less expensive alternatives to standard construction practices.
- Investigation of the impact of the trend toward joint action projects among small utilities both in terms of the impact of potential cost reductions to conventional alternatives and in terms of the potential for joint action solar projects.

* * * * *

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Appendix A
CHARACTERISTICS OF SMALL UTILITIES

This appendix describes the results of a characterization of small municipal and rural utilities according to size, load factor, ratio of purchased to self-generated power, fuel type, distribution system, generation mix, projected load growth rate, type of ownership, and other distinguishable characteristics. The information contained in this appendix was derived from two data bases: an existing data base which was developed for the Electric Power Research Institute (EPRI) Research Project 918 (1,2) and a new data base which was developed for JPL as Task 1 of this study. The EPRI data base includes data on utilities with 1974 peak demands of 2 to 500 MW. The JPL data base expanded on the EPRI data base to include utilities with 1974 peak demands of 0.5 to 2 MW. This appendix provides a general description of these data bases, presents the results of a statistical analysis of both data bases, and compares the results of the two data bases. The information in these two data bases was used to develop the seven reference utilities used in the study.

DEVELOPMENT OF DATA BASES

The first step in attempting to characterize small utilities during the EPRI study involved finding a data base. Since there are a large number of small utility systems in the country, an effort was made to find a comprehensive set of data available in computer retrievable form. However, after contacting various potential sources, it was determined that the available computerized data was not adequate to meet the requirements of the study. Consequently, it was decided to develop a data base as part of the EPRI study effort.

Looking at the available sources of information on small utility systems, it was determined that the single most comprehensive source that would serve the objectives of the EPRI study was the Electrical World Directory of Electric Utilities published by McGraw-Hill of New York. Since the information in this directory was not available in computer retrievable form, it was decided to compile the information about small utilities contained in this publication into a computerized data base.

Although the Electrical World Directory became the primary data source for this effort, the data obtained from this source was augmented with information obtained from Federal Power Commission (FPC) publications, Rural Electrification Administration (REA) publications, electric utility industry periodicals, and Burns & McDonnell in-house information. However, even data from all of these sources was sometimes inadequate so approximately 180 letters were sent to small utility systems around the country requesting additional information. Some 112 responses to these requests were received.

The base year for the data collection effort was calendar year 1974 since this was the most recent year for which Electrical World Directory information was available at the time of the EPRI study. The same base year was used for the JPL data base in order to be consistent with the EPRI data base. The 1974 calendar year data was contained in the 1975-1976 or 84th edition of the Electrical World Directory. Information was also collected for one earlier year (primarily 1968) in order to be able to calculate load growth rates.

DATA COLLECTED

The information collected for each small utility included:

- Name and location.
- System peak demand for 1974 and 1968.
- Total system energy input for 1974 and 1968.
- Energy purchased during 1974 and the sources of purchased energy.
- Generating mix broken down by capacity, unit type and fuel.
- Information concerning the distribution system including:
  - -- Primary distribution voltage.
  - -- Pole-miles of distribution line.
- Description of the transmission system including:
  - -- Primary transmission voltage.
  - -- Circuit-miles of transmission.
- System type:
  - -- Municipal.
  - -- Rural Electric Cooperative.
  - -- Investor-Owned.
  - -- Other.

- Number of customers and types:
  - -- Residential.
  - -- Commercial.
  - -- Industrial.
  - -- Rural.
  - -- Irrigation.
  - -- Other.
- Incoming system substation capacity.

DATA ANALYSIS

The information collected was analyzed using a computer program developed specifically for this purpose. The computer analysis provided statistical distributions of:

- Peak Loads.
- Load Factors.
- Percent of energy purchased.
- Load Growth Rate.
- Pole miles of distribution per customer.
- Circuit miles of transmission per customer.
- Generating Capacity.
- Generating Capacity Types.
- Fuel Types.

These statistical distributions were developed for all small utilities and also broken down into utility types, peak load groupings, and Federal Power Commission (FPC) regions of the U.S., as appropriate.

RESULTS OF THE EPRI DATA BASE

The key results developed in the EPRI study are summarized in Tables A-1 and 2 and Figures A-1 through 8. Table A-1 provides a breakdown of the small utility systems with 1974 peak demands of 2 to 500 MW by geographic region of the United States. The top half of the table provides information for all systems and the bottom half for self-generating systems. Small utilities are further

Table A-1
SMALL UTILITY DATA BASE SUMMARY
(SMALL UTILITIES WITH 1974 PEAK DEMAND OF 2 TO 500 MW)

Classification	FPC Region								
	1 North East	2 Great Lakes	3 North Central	4 North West	5 South West	6 South Central	7 South East	8 Others[a]	Totals
All Systems									
Municipal	130	210	274	34	51	102	205	10	1,016
G&T Coop.	0	7	16	0	3	4	3	0	33
Distribution Coop.	42	160	224	70	46	131	171	5	849
Investor Owned	38	16	13	4	9	3	6	2	91
Other	3	0	32	26	14	2	5	0	82
Total	213	393	559	134	123	242	390	17	2,071
Generating Systems									
Municipal	43	84	208	6	22	51	19	10	443
G&T Coop.	0	7	11	0	3	3	3	0	27
Distribution Coop.	6	3	6	3	3	2	3	5	31
Investor Owned	20	12	11	2	5	2	4	2	58
Other	2	0	3	6	7	2	3	0	23
Total	71	106	239	17	40	60	32	17	582

[a] *FPC Region 8 includes Alaska, Hawaii, Puerto Rico and the Virgin Islands.*

broken down into five system types including municipal, generation and transmission (G&T) cooperative, distribution cooperative, investor-owned and other. The distinction between a G&T cooperative and a distribution cooperative is that the former typically sells power only at wholesale to distribution cooperatives or municipal systems. Distribution cooperatives typically sell power only on a retail level. A G&T cooperative, as the name would imply, usually has a system consisting of significant generation and transmission facilities. Distribution cooperatives, on the other hand, usually have only distribution facilities and no generation or transmission facilities although there are exceptions.

Data on approximately 2,500 small utilities was collected during the EPRI study effort. Only 2,071 of the utilities were included in the EPRI data base. A system was not included in the data base when the data available for that system was insufficient to justify its inclusion. All of the utilities included in the data base were not necessarily used in developing particular sets of information since data was available for some utilities to permit their inclusion for one category of information but not another. For example, data may have been available to calculate the load growth for a utility but not its load factor. It is believed that the elimination of utilities on the basis of the lack of data would have tended to eliminate the smaller utility systems from the analysis since the small utilities tended to be less complete in the amount of data available from the <u>Electrical World Directory</u> and other data sources used in this study. It is felt, however, that the 2,071 small utilities included in the data base was large enough to ensure the validity of the results developed.

In addition, although 2,071 small utilities were included in the data base, those utilities purchasing power from the Tennessee Valley Authority (TVA) or distribution cooperatives that purchased power from a G&T cooperative were not included in developing the statistics which follow. Omitting these systems was considered necessary because they typically have long-term, all requirements, purchased power contracts with the TVA or G&T systems. It was assumed that any generation additions would be made by the TVA or G&T system. In addition, eliminating distribution cooperatives that purchased power from G&T's avoided the double counting of loads for the cooperative systems.

A number of interesting observations can be made by examining the data in Table A-1. One item of significance is that of the 2,071 small utility systems, 582 or 28.1 percent were found to be self-generating systems. Of all the small utility systems, 559 were located in the North Central and 393 in the Great Lakes FPC regions, accounting respectively, for 26.9 and 18.9 percent of all small utility systems. In total these two regions accounted for 45.8 percent of all small utility systems. The North Central and Great Lakes FPC regions become even more significant when only generating utilities are considered. The North Central FPC region was found to have 239 of 582 or 41.0 percent of the generating utilities and the Great Lakes region 106 or 18.2 percent. In total these two regions had 59.2 percent of all the self-generating small utility systems. The next largest region in terms of self-generating small utilities was the Northeast FPC region which had 71 or 12.1 percent of the total.

Table A-2 summarizes mean values based on 1974 data for the small utility systems studied including system peak demands for all utilities and for those utilities with generation, annual system load factors, and annual system compound load growth rates for the period 1968-1974. These categories of information are provided by utility type, in various size groupings and by FPC region of the country.

Figures A-1 through A-8 are graphical summaries of data for the small utility systems with 1974 peak demands of 2 to 500 MW. It should be noted that a total of 121 similar distributions were developed for the small utility categories summarized in Table A-2. The significant results of these distributions are summarized in these figures and the following discussion.

Peak Demands

Figure A-1 provides the distribution of the 1974 peak demands for small utility systems with peak demands between 2 and 500 MW. As can be seen, a total of 1,217 utilities was included in the population for developing this figure. Of the small utilities in the population, 83.5 percent (1,017) had 1974 peak demands between 2 and 50 MW. Approximately 8.3 percent had peak demands between 50 and 100 MW with the number of utilities systems decreasing for additional

Table A-2

SUMMARY OF SMALL UTILITY CHARACTERISTICS (SMALL UTILITIES WITH 1974 PEAK DEMAND OF 2 TO 500 MW)

Small Utility Categories	1974 Mean Peak Demand For All Systems (MW)	1974 Mean Peak Demand For Systems With Generation (MW)	1974 Mean Annual Load Factor (%)	Mean Annual Compound Peak Demand Growth Rate 1968–1974 (%)
All Systems (2-500 MW)	35.2	60.6	49.2	8.0
All Systems (2-100 MW)	18.9	20.2	48.8	8.0
All Systems (2-25 MW)	9.6	9.3	48.4	7.6
Municipals (2-500 MW)	23.8	29.4	48.8	6.9
Municipals (2-100 MW)	15.4	17.5	48.7	–
Municipals (2-25 MW)	8.4	8.9	–	–
Distribution Coops (2-500 MW)	29.9	61.3	48.4	10.5
Distribution Coops (2-100 MW)	24.7	–	48.5	–
Distribution Coops (2-25 MW)	13.3	–	–	–
G&T Coops (2-500 MW)	193.2	227.4	57.4	10.3
Investor Owned (2-500 MW)	147.4	184.7	60.2	5.4
Northeast FPC Region (2-500 MW)	–	–	54.7	6.5
Great Lakes FPC Region (2-500 MW)	–	–	52.4	6.8
North Central FPC Region (2-500 MW)	–	–	44.7	8.0
Northwest FPC Region (2-500 MW)	–	–	48.6	7.2
Southwest FPC Region (2-500 MW)	–	–	54.7	7.9
South Central FPC Region (2-500 MW)	–	–	43.4	9.5
Southeast FPC Region (2-500 MW)	–	–	49.4	10.1

DISTRIBUTION OF PEAK DEMANDS
(ALL UTILITIES WITH 1974 PEAK DEMANDS OF 2-500 MW)*

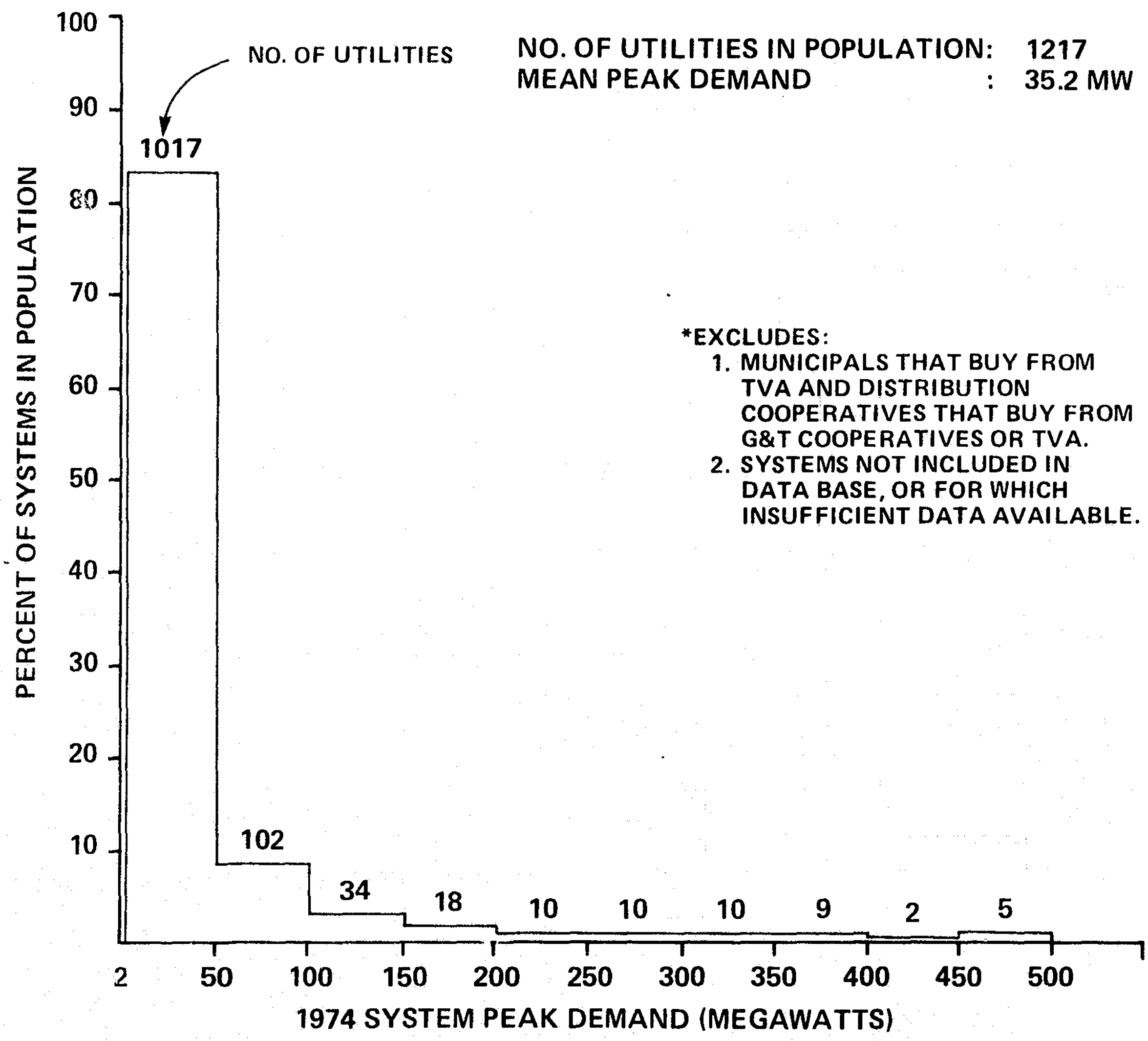

Figure A-1

increments in size range. It was this preponderance of utilities in the smaller size ranges which prompted the expansion of this data base to include utilities with 1974 peak demands of 0.5 to 2 MW for the current study. The average or mean peak demand for all small utilities (with peak demands from 2 to 500 MW) in the sample population was 35.2 MW.

Figure A-2 is a similar distribution for small utilities in the 2-100 MW size category broken down into 10-MW size increments. Again, most of the small utilities are concentrated in the smallest size ranges with 484 or 43.2 percent of the 1119 system population in the 2-10 MW size range and 275 or 24.5 percent in the 10-20 MW range. Of the utilities represented in this distribution, 79.3 percent had 1974 peak demands of less than 30 MW.

Table A-2 shows the mean 1974 peak demands for the various categories of small utility systems for which similar distributions were developed in the EPRI study.

Load Factor

Figure A-3 is a distribution of 1974 load factors for small utility systems with 1974 peak demands of 2 to 500 MW. The mean load factor for the small utilities in the single population of 1,217 was calculated to be 49.2 percent with a standard deviation of 9.2 percent. This means that approximately 2/3 of all small utilities with 1974 peak demands of 2 to 500 MW had a 1974 load factor between 40 and 58.4 percent. Table A-2 shows the average load factor values for various categories of small utility systems. For most categories of small utilities, the annual load factor deviated only slightly from the average for all utilities. The G&T cooperatives, however, had a significantly higher mean load factor of 57.4 percent. The higher load factor of G&T cooperatives relative to the distribution cooperatives is probably due to the diversity achieved by the G&T cooperatives in supplying power to a number of customers, primarily distribution cooperatives, over a relatively large geographic area. The mean annual load factor found for investor-owned utilities was 60.2 percent.

DISTRIBUTION OF PEAK DEMANDS
(ALL UTILITIES WITH 1974 PEAK DEMANDS OF 2-100 MW)*

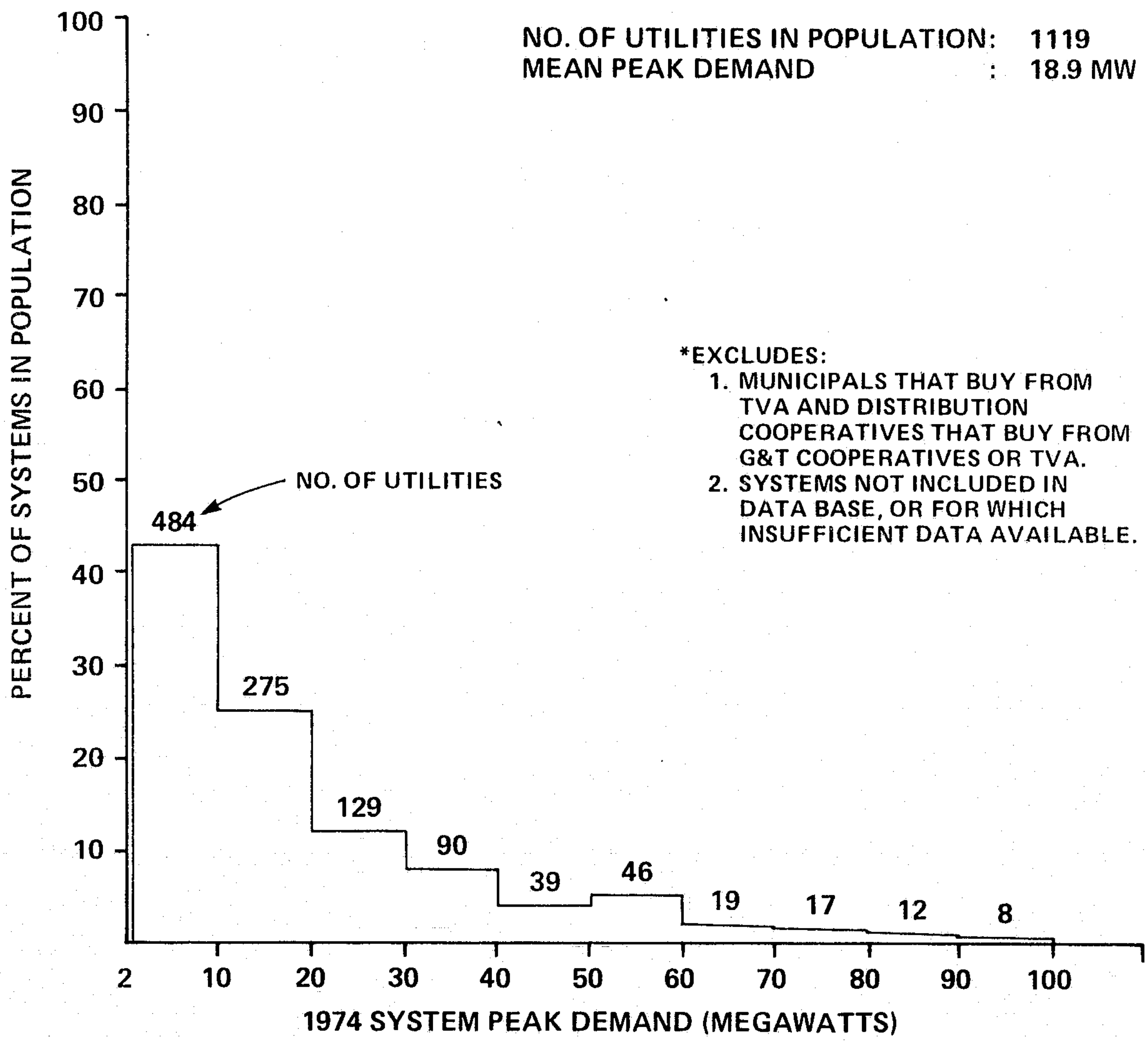

Figure A-2

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DISTRIBUTION OF ANNUAL LOAD FACTORS
(ALL UTILITIES WITH 1974 PEAK DEMANDS OF 2-500 MW)*

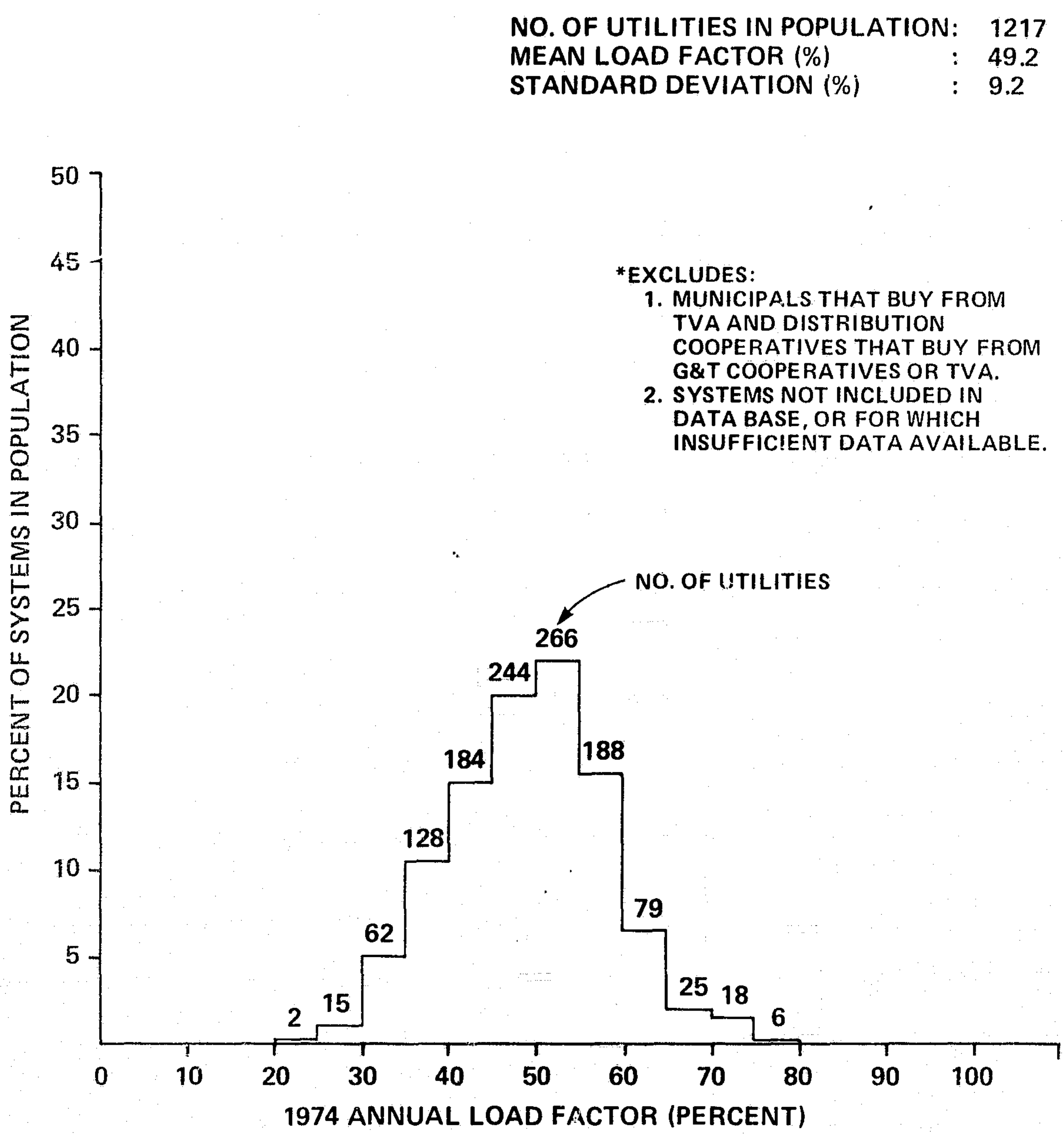

Figure A-3

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It should be noted that the load factor values developed in this study were all simple averages. An analysis of the variation in load factor with system size, suggested there was a trend toward higher load factors for larger systems although the variation within the relevant range of small utility sizes and categories was not observed to be significant. Therefore, simple average load factors were considered to be adequate for this study.

The results of this analysis also indicated some variation in system load factor with geographic area. The highest mean annual load factors were found in the Northeast and Southwest FPC regions (54.7 percent). The lowest mean annual load factor was found for the South Central FPC region (43.4 percent). In general, these variations in regional load factors were consistent with what might be anticipated taking into account the differences in climate and other factors in the various regions of the country.

Load Growth Rates

Figure A-4 is a distribution of the compound annual load growth rates for the small utilities with 1974 peak demands between 2 and 500 MW for the years 1968-1974. The mean annual compound load growth rate was found to be 8.0 percent with a standard deviation of 4.5 percent. Therefore, approximately two-thirds of the utilities included in the distribution had load growth rates between 3.5 and 12.5 percent during period.

Table A-2 summarizes the mean compound annual load growth rates for the 1968-1974 period for various categories of small utilities. As can be seen, the G&T and distribution cooperatives with load growth rates of 10.3 and 10.5 percent, respectively, grew at a more rapid rate than the municipal (6.9 percent) and investor-owned (5.4 percent) systems. Significant regional variations in load growth rates were also found. The slowest growth rate was found for the Northeast FPC region (6.5 percent) and the highest for the Southeast FPC region (10.1 percent).

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DISTRIBUTION OF COMPOUND ANNUAL LOAD GROWTH RATE 1968-1974
(ALL UTILITIES WITH 1974 PEAK DEMANDS OF 2-500 MW)*

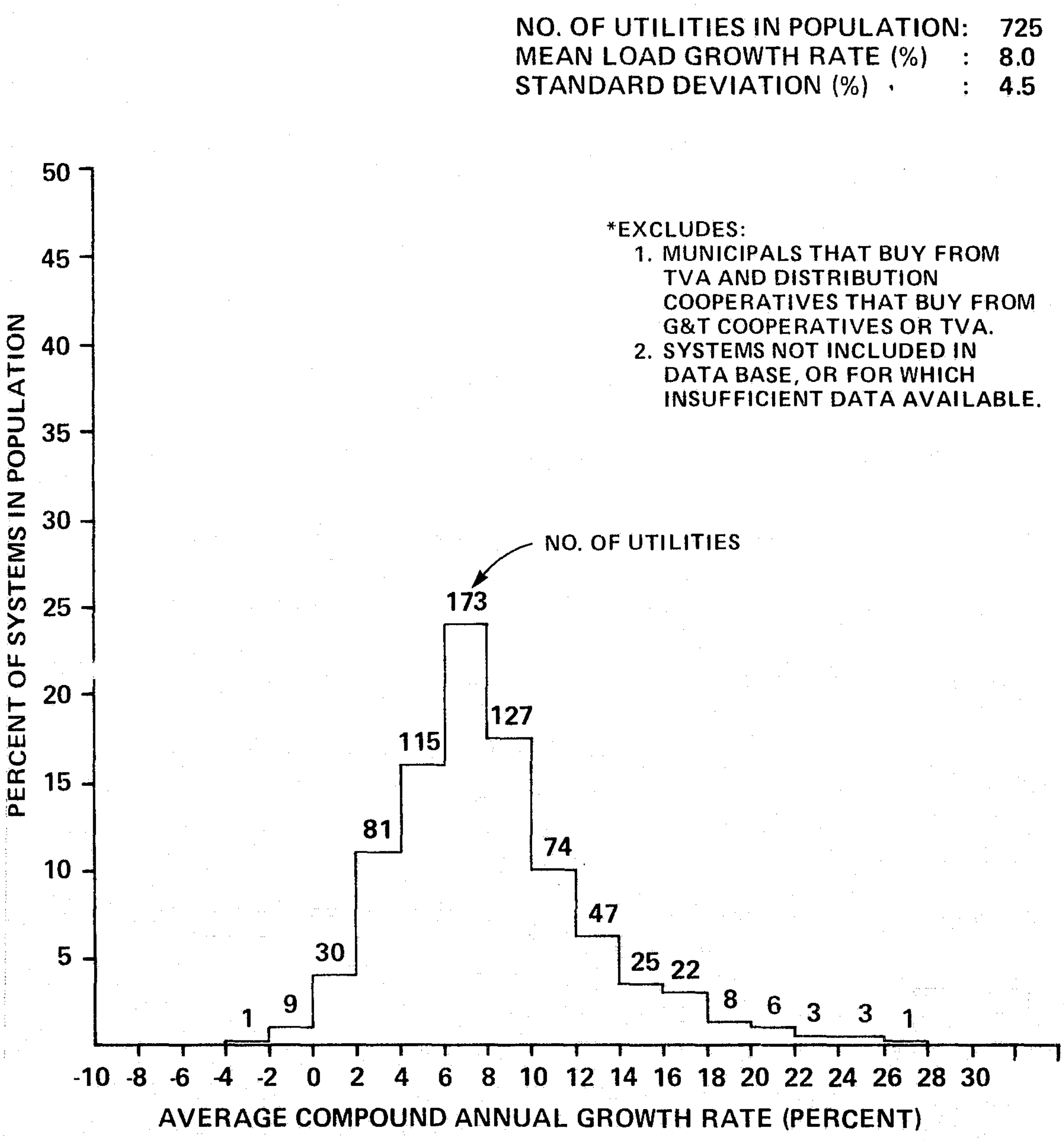

Figure A-4

Generating Mix

Figure A-5 provides information concerning the distribution of generating capacity types for small systems for various ranges of utility size between 2 and 500 MW. As one might expect, the larger the utility, the more significant the role of fossil steam generation in the generating mix. Since this was 1974 data, only a small amount of nuclear capacity is shown and it appears in the largest size category of utilities. Combustion turbine capacity, like fossil steam capacity, also increased as a proportion of total system capacity as the size of the utility increased. The proportion of diesel capacity decreased substantially with utility size. The proportion of hydroelectric (hydro) capacity did not appear to be a function of utility size and varied between 5-10 percent of the total system capacity. The category of capacity labeled "Other" was not significant.

The generating capacity mix information in Figure A-5, it should be noted, represents only average values for the small utilities in the United States with 1974 peak demands between 2 and 500 MW. Significant variations were found in the typical utility capacity mix in various parts of the United States. For example, hydroelectric generation tended to predominate in the Northwest FPC region and was also a major factor in the capacity mixes found in the Southwest FPC region. Either diesel or fossil steam generation tended to predominate in the other FPC regions.

Fuel Types

Figure A-6 shows the distribution of fuel types among the generating capacity of the small utilities with 1974 peak demands of 2 to 500 MW. It can be observed that the proportion of the generating capacity capable of burning coal increases with system size. The percentage of generating capacity capable of burning oil only or oil and gas is highest for the smallest utility systems and tends to decrease toward the larger system sizes. However, the proportion of generating capacity capable of burning gas only tends to increase with utility size, being negligible for the 2 to 10-MW system size range and representing approximately 15 percent of the capacity of the 150 to 500-MW systems.

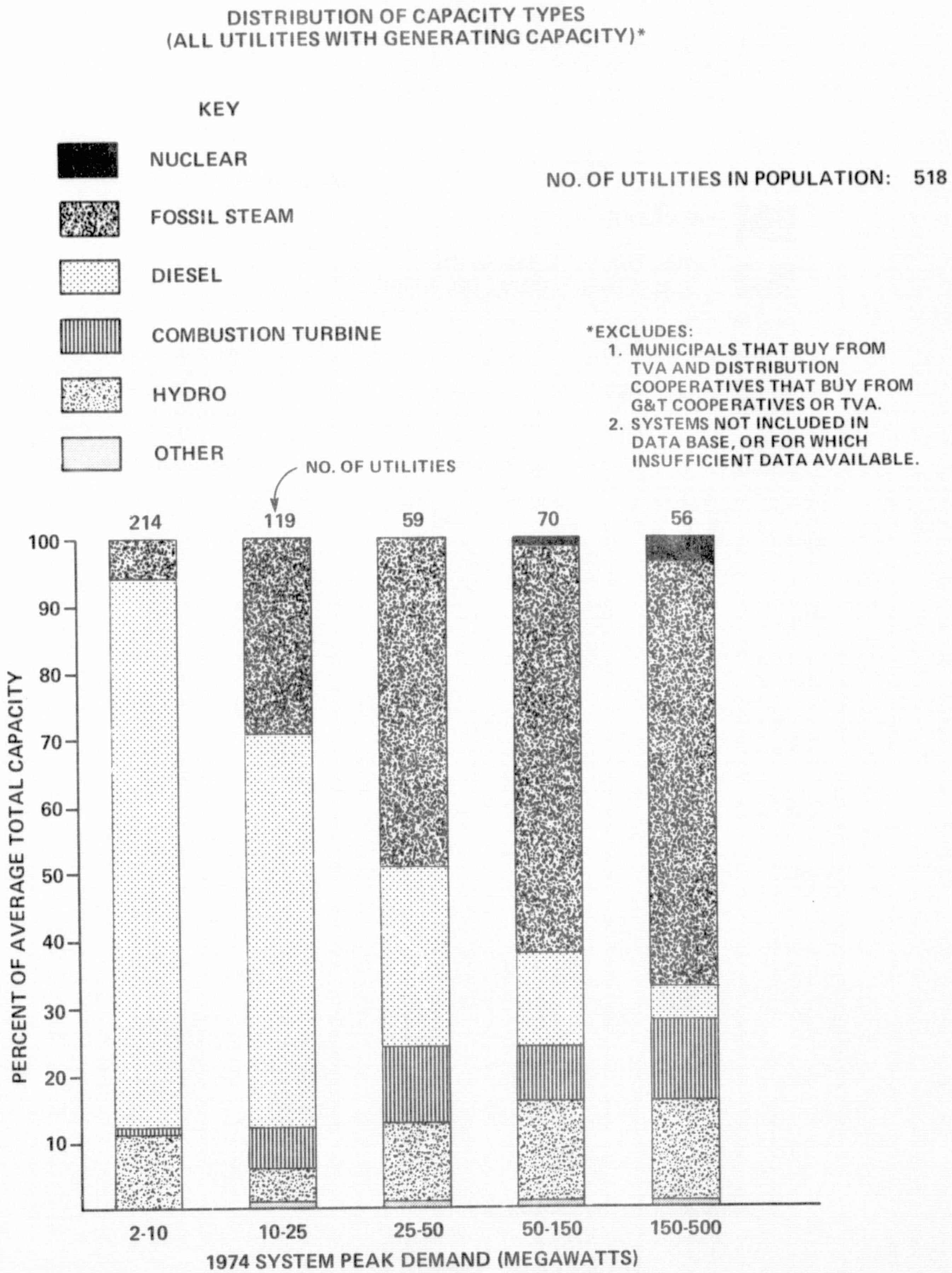

Figure A-5

JPL 78-008-4-005

DISTRIBUTION OF FUEL TYPES
(ALL UTILITIES WITH GENERATING CAPACITY)*

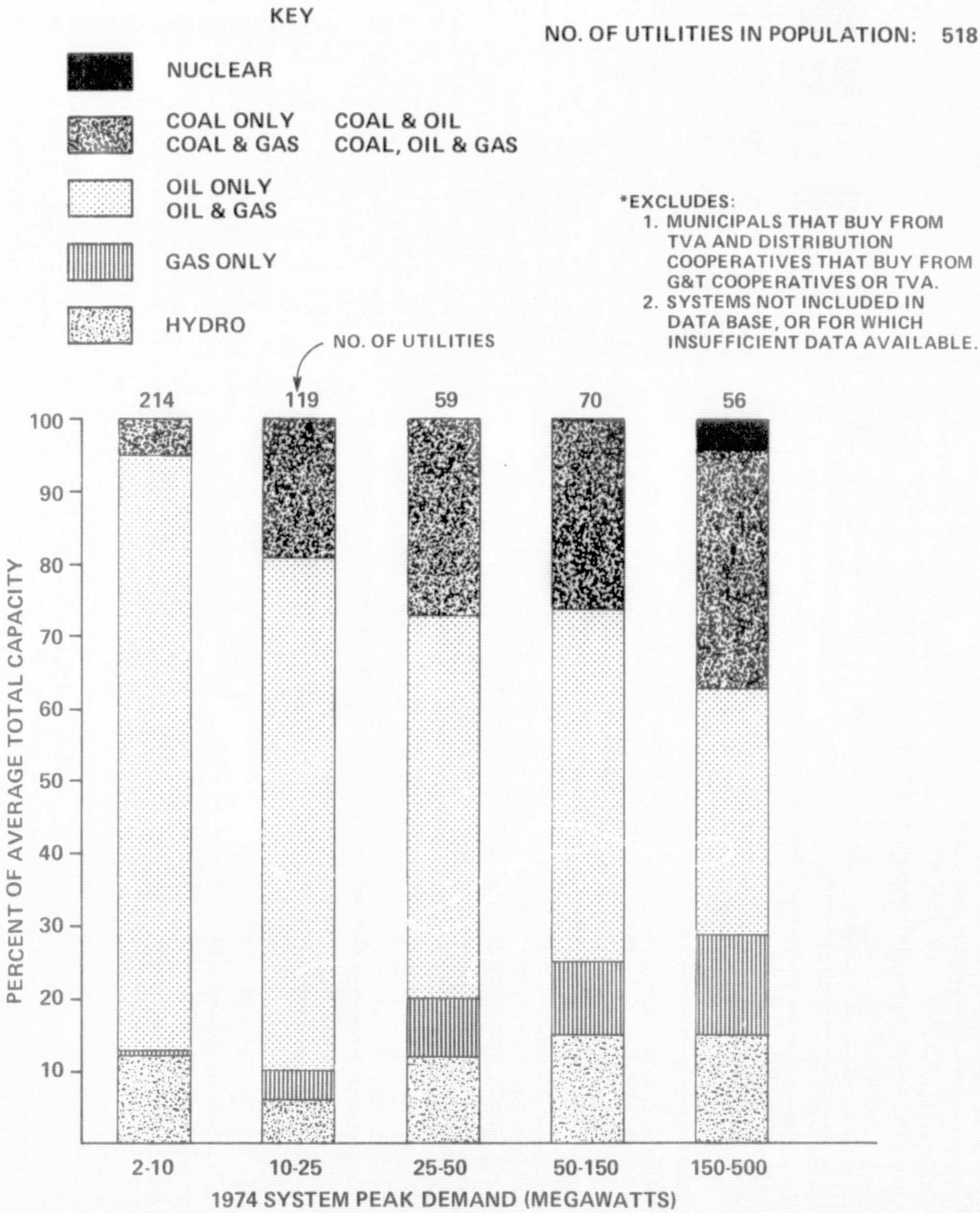

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Figure A-6

As might be expected, significant regional variations were also found for the distribution of fuel types among small utility generating capacity. For example, oil tended to predominate as the alternative fuel to hydro power in the Northwest FPC region. Oil or oil- and gas-fired generation tended to predominate in the Northeast, Southwest, Southeast, and South Central FPC regions. Gas-only generation was found to be most significant in the South Central FPC region. The largest proportions of coal-fired generation were found for the Great Lakes and North Central FPC regions.

Percentage of Energy Generated

Figure A-7 shows a distribution of the percentage of energy generated for small utility systems with 1974 peak demands of 2 to 500 MW. The information in this figure applies only to systems with generation. As indicated by the number of utilities in the population, sufficient data was available to prepare this distribution for only 379 of the 582 small utilities with generation in the EPRI data base. In general, this distribution shows that the larger utilities with generation tend to generate a relatively greater proportion of their total system energy requirement. As shown in the fuel types distribution, however, the smaller utilities are generally more dependent on oil-fired generation than the larger utilities. Consequently, high oil prices would tend to cause the smaller utilities to generate relatively smaller percentages of their own power requirements than has been the case in the past.

Generating Capacity

Figure A-8 provides information concerning the generating capacity available to a small utility relative to its peak demand. In general, for systems with generation, the percent of generating capacity relative to the peak demand varies on the average between 75 and 90 percent. Since small utility systems do not on the average have enough capacity to meet their peak demands, they must look to outside power sources to supplement their own generation.

DISTRIBUTION OF PERCENT OF ENERGY GENERATED
(ALL UTILITIES WITH GENERATING CAPACITY)*

NO. OF UTILITIES IN POPULATION: 379

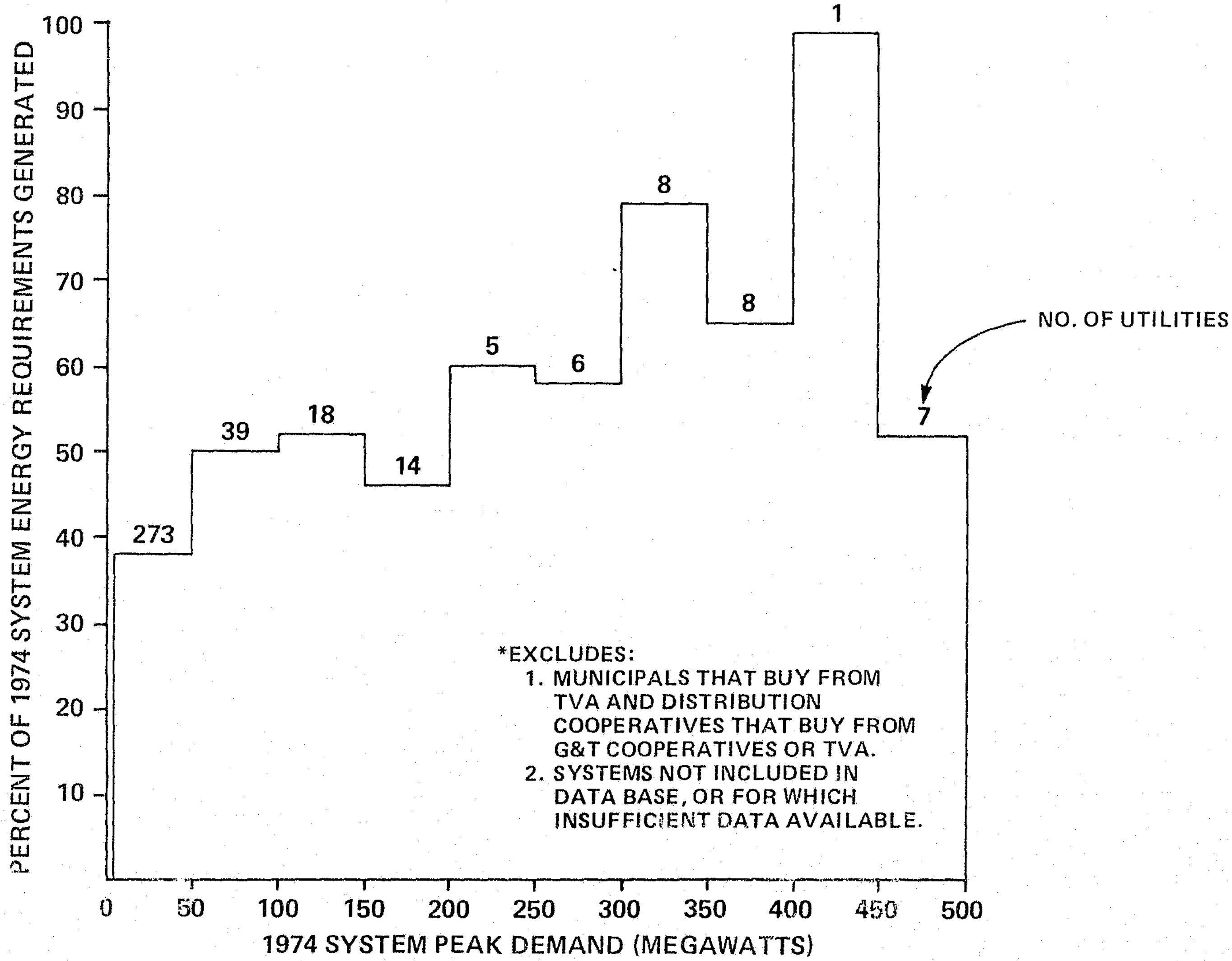


Figure A-7

GENERATING CAPACITY AS A PERCENT OF SYSTEM PEAK DEMAND
(ALL UTILITIES WITH GENERATING CAPACITY)*

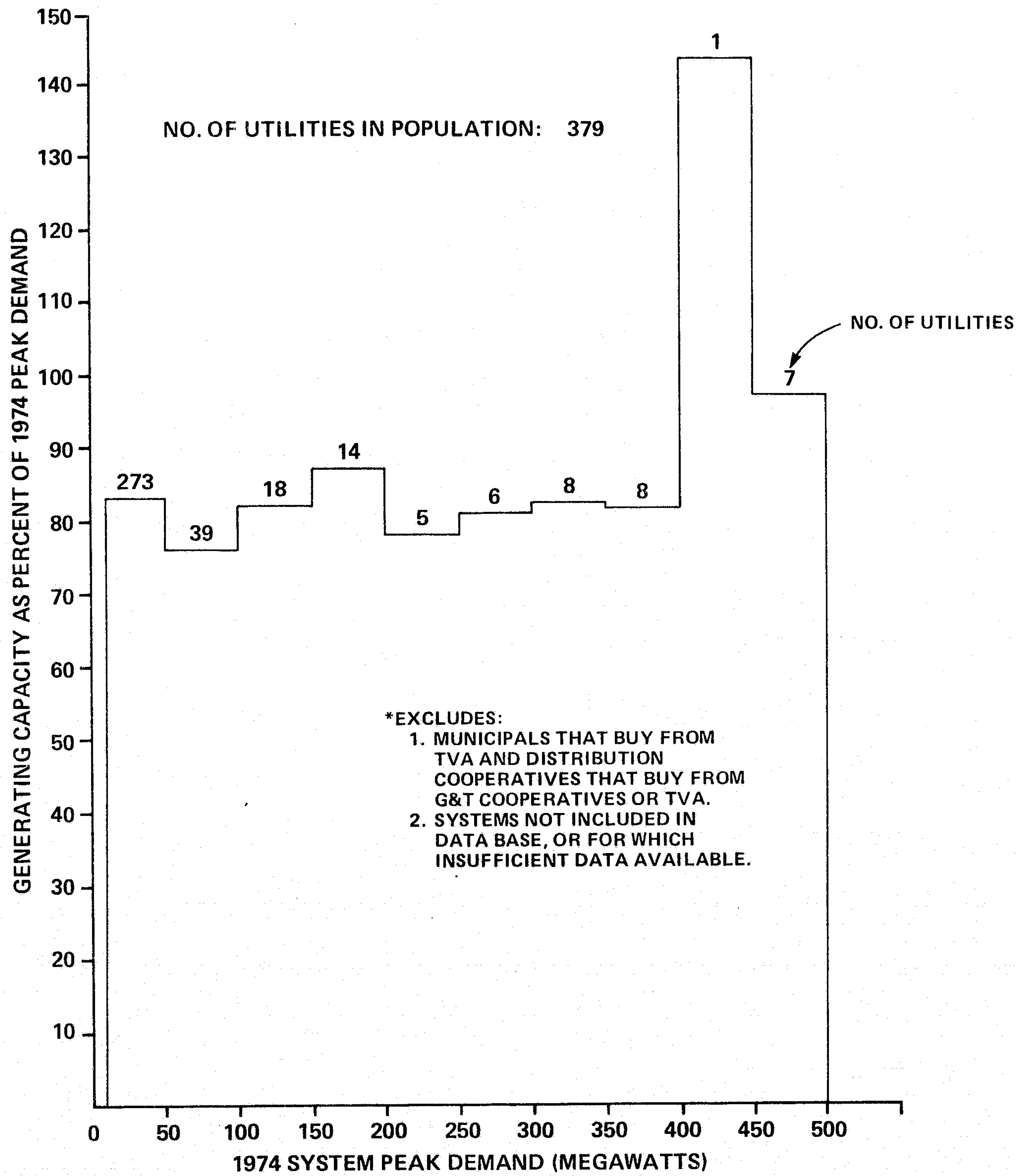


Figure A-8

JPL 78-008-4-005

RESULTS OF THE JPL DATA BASE

A total of 366 utilities were found to have or likely to have a 1974 peak demand of 0.5 to 2 MW. Of these, one system was excluded for lack of information other than peak demand, 15 systems were excluded for inconsistent or unusable data, and 127 systems were excluded for lack of peak demand data although the energy data for these systems indicated that they might have peak demands in the 0.5 to 2 MW range. Data was collected on a total of 223 utilities (61 percent).

Of the 223 utilities included in the JPL data base, from 73 to 175 utilities (32 to 78 percent) were used to calculate each statistic. As with the EPRI data base, all of the utilities included in the base were not necessarily used in developing particular statistics since data was available for some utilities for one category of information but not another. For example, data may have been available to calculate the peak demand growth rate for a utility but not its load factor. It is felt, however, that there were enough utilities represented in each category to assure the validity of the results.

Once again, as was the case for the EPRI data base, in addition to exclusion for lack of data, some of the utilities included in the data base were not used in developing the statistical results. Those systems excluded from the statistical characterization were systems purchasing power from the Tennessee Valley Authority (TVA) and distribution cooperatives purchasing power from generation and transmission (G&T) cooperatives. Exclusion of these systems was considered necessary because they typically have long-term all requirements purchased power contracts with TVA or G&T systems. It was assumed that any generation additions would be made by TVA or the G&T systems. In addition, elimination of distribution cooperatives that purchased power from G&T cooperatives avoided the double counting of loads for cooperative systems already included in the EPRI data base.

The key results developed from the JPL data base are summarized in Table A-3 through A-6 and Figures A-9 and A-10. Table A-3 provides a breakdown of the small utility systems with 1974 peak demands between 0.5 and 2 MW by geographic

Table A-3

SMALL UTILITY DATA BASE SUMMARY
(SMALL UTILITIES WITH 1974 PEAK DEMAND OF .5 TO 2 MW)

Classification	FPC Region: 1 North East	2 Great Lakes	3 North Central	4 North West	5 South West	6 South Central	7 South East	8 Others[a]	Totals
All Systems									
Municipal	10	40	91	3	8	5	5	0	162
Distribution Coop.	1	0	0	2	0	0	0	4	7
Investor Owned	2	1	0	0	0	0	0	2	5
Other	0	0	0	1	0	0	0	0	1
Total	13	41	91	6	8	5	5	6	175
Generating Systems									
Municipal	2	9	62	1	5	0	0	0	79
Distribution Coop.	0	0	0	0	0	0	0	3	3
Investor Owned	1	1	0	0	0	0	0	1	3
Other	0	0	0	0	0	0	0	0	0
Total	3	10	62	1	5	0	0	4	85

[a] *FPC Region 8, which includes Alaska, Hawaii, Puerto Rico, and the Virgin Islands.*

region of the United States. The top half of the table provides information for all utilities and the bottom half for self-generating utilities. Small utilities are further broken down into four system types including municipal, distribution cooperative, investor-owned, and other. There were no generation and transmission cooperatives in this size range.

A number of interesting results can be observed from the figures shown in Table A-3. First, it can be seen that only 49 percent of the systems used to calculate the data base statistics are generating utilities. The remaining 51 percent purchase all of their power requirements. It can also be observed that 93 percent of all systems and 93 percent of the generating systems are municipal utilities. As was the case in the EPRI data base, the dominant geographic regions are the North Central FPC Region, which contains 52 percent of all systems and 73 percent of the generating systems, and the Great Lakes FPC Region, which contains 23 percent of all systems to 12 percent of the generating systems. Together these two regions contain 75 percent of all systems with 1974 peak demands of 0.5 to 2 MW and 85 percent of all systems in this size range with their own generating capacity.

Table A-4 summarizes mean values based on 1974 data for the small utility systems studied including system peak demand, generating capacity, system load factor, percent of energy generated rather than purchased, average annual peak demand growth rate for the period 1968-1974, pole-miles of distribution per customer, and circuit-miles of transmission per customer. These categories of information are provided for all systems and by system type. In addition, load factors are shown geographically by FPC region. The key characteristics are discussed in more detail below.

Peak Demand

The mean peak demand for all systems in the JPL data base was found to be 1.29 MW with a standard deviation of 0.41 MW. The mean peak demand for all systems with generating capacity was somewhat higher at 1.33 MW with a standard deviation of 0.38 MW.

Table A-4

SUMMARY OF SMALL UTILITY CHARACTERISTICS [a]
(SMALL UTILITIES WITH 1974 PEAK DEMAND OF .5 TO 2 MW)

Classification	1974 Mean Peak Demand (All Systems) (MW)	1974 Mean Peak Demand (Gen. Systems) (MW)	1974 Mean Annual System Load Factor (%)	1974 Mean Generating Capacity (Gen. Systems) (MW)	1974 Mean Energy Generated [b] (Gen. Systems) (%)	Avg. Annual Peak Demand Growth Rate 1968 - 1974 (%)	1974 Mean Pole-Miles of Distribution /Customer	1974 Mean Circuit Miles of Transmission /Customer
All Utilities	1.29	1.33	48.8	1.24	23.4	4.7	0.0397	0.0004
System Type								
Municipal	1.29	1.32	48.8	1.26	22.8	4.1	0.0330	0.0004
Distribution Cooperative	1.17	1.05	48.1	1.55	0.0	10.3	0.2061	0.0000
Investor Owned	1.53	1.72	48.7	0.20	50.0	9.6	0.0280	0.0000
Other	1.74	—	53.2	—	—	—	—	—
FPC Region								
Northeast	—	—	50.1	—	—	—	—	—
Great Lakes	—	—	51.6	—	—	—	—	—
North Central	—	—	46.8	—	—	—	—	—
Northeast	—	—	50.4	—	—	—	—	—
Southwest	—	—	53.1	—	—	—	—	—
South Central	—	—	34.2	—	—	—	—	—
Southeast	—	—	58.9	—	—	—	—	—
Other [c]	—	—	49.0	—	—	—	—	—

[a] *All Values shown are Means for the Respective Categories*

[b] *As a percent of Total System Energy*

[c] *FPC Region 8, which includes Alaska, Hawaii, Puerto Rico and the Virgin Islands.*

Load Factor

The mean load factor for all utilities in the JPL data base was found to be 4.8 percent with standard deviations of 9.1 percent. A distribution of annual load factors for all utilities is shown in Figure A-9. Load factors by utility type did not vary significantly from the mean of 48.8 MW. However, regionally, load factors varied from 34.2 percent in the South Central FPC Region to 58.9 in the Southeast FPC Region.

Generating Capacity

The mean generating capacity of all utilities in the JPL data base with generation was found to be 1.24 MW with a standard deviation of 0.56 MW. Since on the average these utilities did not have enough generating capacity to meet their peak demands, they would have to meet the remainder of their capacity requirements through power purchase.

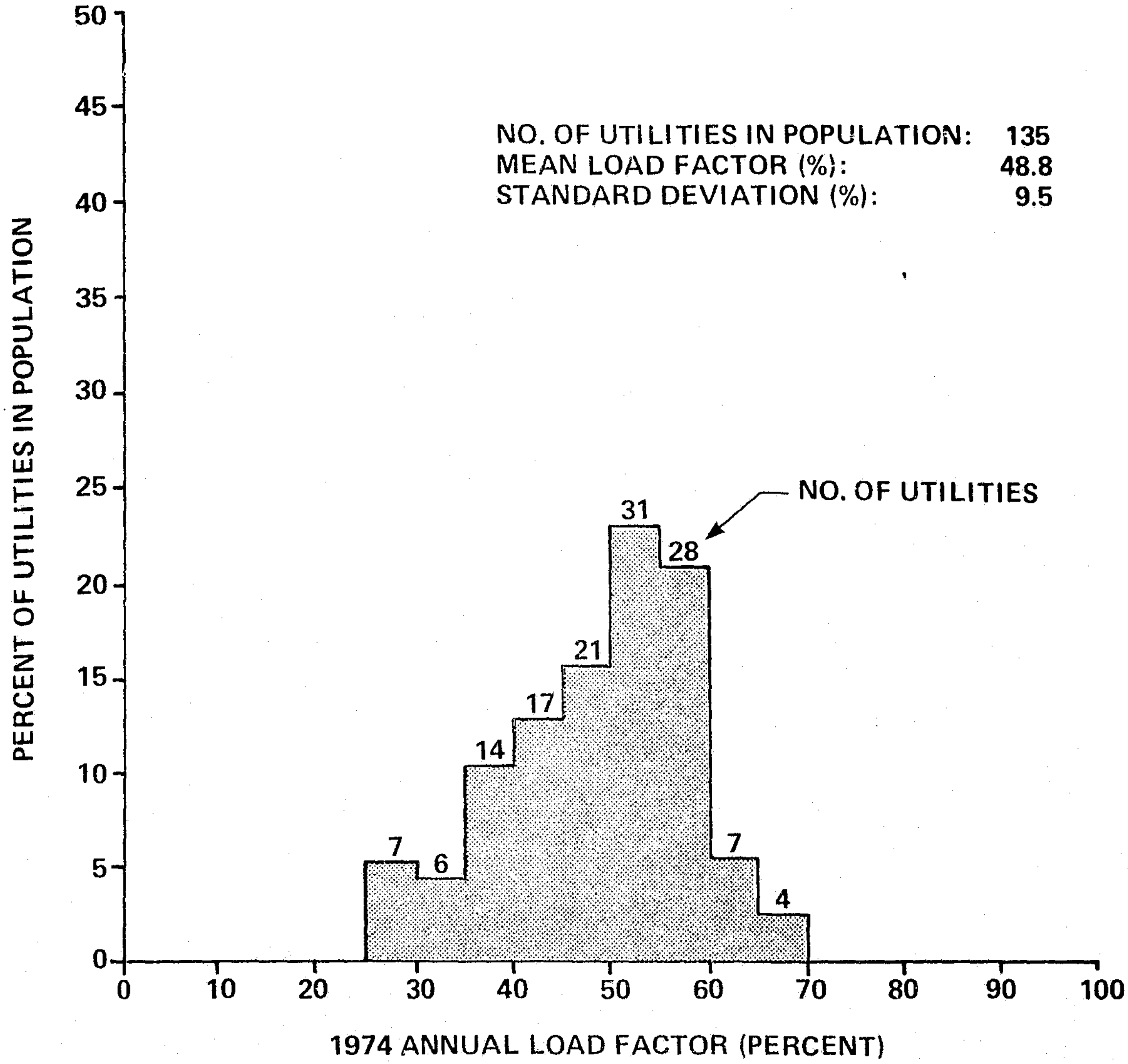
Energy Generated

Whereas utilities with generation were found to have generating capacity equal to about 94 percent of their system's peak demand, these systems generated on the average only 23 percent of their energy requirements. This indicates that the generating capacity available to these small utilities is used primarily as peaking or standby equipment.

Peak Demand Growth Rates

A distribution of the compound annual peak demand growth rates for the small utilities with 1974 peak demands of 0.5 to 2 MW for the years 1968-1974 is shown in Figure A-10. The mean annual compound load growth rate was found to be 4.7 percent with a standard deviation of 4.5 percent. The mean load growth rate was found to vary considerably with system type from 10.3 percent for distribution cooperatives to 4.1 percent for municipal systems.

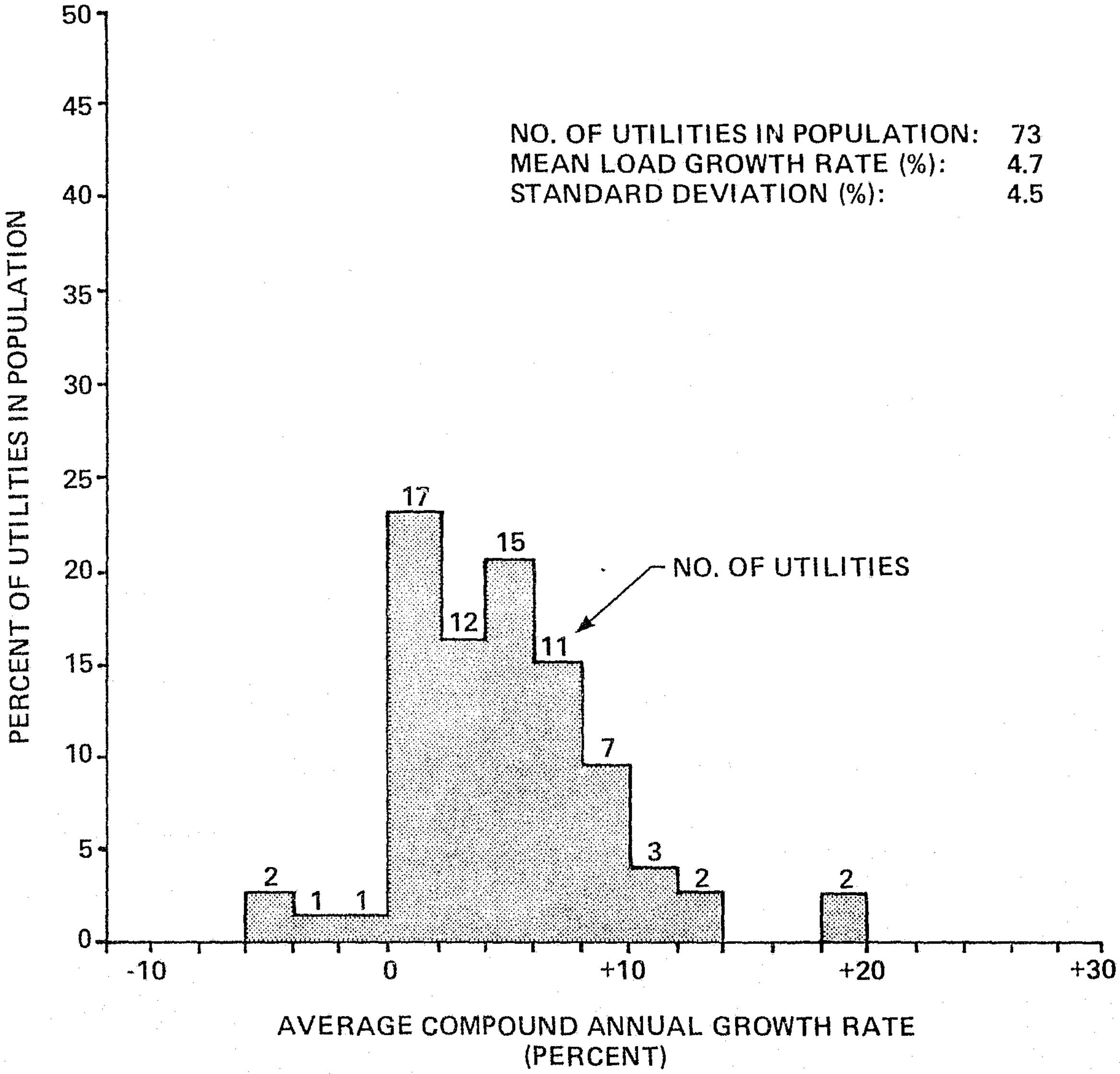
DISTRIBUTION OF ANNUAL LOAD FACTOR
(ALL UTILITIES WITH 1974 PEAK DEMANDS OF .5-2 MW)*



*EXCLUDES MUNICIPALS THAT BUY FROM TVA, DISTRIBUTION COOPERATIVES THAT BUY FROM G&T COOPERATIVES OR TVA, AND SYSTEMS NOT INCLUDED IN DATA BASE OR FOR WHICH INSUFFICIENT DATA AVAILABLE.

Figure A-9

DISTRIBUTION OF COMPOUND
ANNUAL LOAD GROWTH RATE
1968-1974
(ALL UTILITIES WITH 1974 PEAK
DEMANDS OF 0.5-2 MW)*



*EXCLUDES MUNICIPALS THAT BUY FROM TVA, DISTRIBUTION COOPERATIVES THAT BUY FROM G&T COOPERATIVES OR TVA, AND SYSTEMS NOT INCLUDED IN DATA BASE OR FOR WHICH INSUFFICIENT DATA AVAILABLE.

Figure A-10

Generating Mix

Table A-5 provides information concenring the distribution of generating capacity types for the small utilities in the JPL data base with generation. Diesel engines were found to represent 93 percent of the generating capacity of these small systems with combustion turbines representing 2.3 percent and hydro 4.7 percent.

Table A-5

DISTRIBUTION OF CAPACITY TYPES

All Utilities with 1974 Peak Demands of 0.5-2 MW Generating Capacity

Number of Utilities in Population: 44

Capacity Type	Percent of Total Capacity
Diesel	93.0
Combustion Turbine	2.3
Hydro	4.7

Fuel Types

Table A-6 shows the distribution of fuel types for the generating capacity of the small utilities in the JPL data base with generation. As might be expected, oil or oil and gas was the fuel used by 94.4 percent of the generating capacity of these small utilities. The next largest category was hydro with 4.7 percent and 0.9 percent of the generating capacity used gas only.

Table A-6

DISTRIBUTION OF FUEL TYPES

All Utilities with 1974 Peak Demands of 0.5-2 MW Generating Capacity

Number of Utilities in Population: 44

Fuel Type	Percent of Total Capacity
Oil; Oil and Gas	94.4
Gas Only	0.9
Hydro	4.7

COMPARISON OF JPL AND EPRI DATA BASES

Table A-7 shows a comparison of some of the characteristics for the JPL data base, consisting of utilities with 1974 peak demands of 0.5 to 2 MW, with those for the EPRI data base, consisting of utilities with 1974 peak demands of 2 to 500 MW. It can be seen from this table that the small utilities in the JPL data base are able to meet a somewhat larger proportion of their peak demand with their own generating capacity, but generate a much smaller proportion of their own energy requirements. In addition, it can be seen that these smaller systems had a slower peak demand growth rate for the period 1968-1974. On the other hand, the trend of generating capacity and fuel toward oil-fired diesel capacity for the utilities in the JPL data base is consistent with the trends noted in the EPRI data base.

Table A-7

COMPARISON OF JPL AND EPRI DATA BASES

Characteristic	Mean Value of Characteristic: JPL Data Base[a]	Mean Value of Characteristic: EPRI Data Base[b]
Load Factor (%)	48.8	49.2
Generating Capacity as a Percent of Peak Demand[c]	93.2	82.7
Percent of Energy Generated[c]	23.4	42.6
Annual Peak Demand Growth Rate (%)	4.7	8.0

[a] Includes utilities with 1974 peak demands of 0.5-2 MWe

[b] Includes utilities with 1974 peak demands of 2-500 MWe

[c] Generating systems only

* * * * *

Appendix B

CAPITAL COST ESTIMATES FOR SMALL SOLAR THERMAL POWER SYSTEMS

This appendix discusses the capital cost estimates used in the study for the small solar thermal power systems. These estimates consisted of solar hardware costs as well as all other items required for the construction of a solar thermal power plant. A breakdown of the costs for the "other" items (all items except solar hardware costs) for the estimates developed by Burns & McDonnell is given and the alternative low cost estimates provided by JPL are discussed.

ESTIMATES DEVELOPED BY BURNS & McDONNELL

Burns & McDonnell developed Class I estimates for each of the five solar thermal power system types considered in the study based on the solar hardware, (collector, transport, conversion and storage) costs provided by JPL, the subsystem parameters supplied by JPL or developed by Burns & McDonnell during a parameter optimization analysis (see Appendix E), and an assumed location in the Southwestern United States (Albuquerque, New Mexico) using the same estimating techniques which are applied to steam power plant estimates. A Class I estimate is a preliminary estimate which is compiled before a specific site has been selected and is based on past experience rather than on specific bids from manufacturers or subcontractors. The capital cost estimates developed by Burns & McDonnell are summarized in Tables B-1 through B-5. All estimates are in thousands of 1975 dollars.

Each estimate was divided into two major sections: the construction cost, and overhead costs. The construction cost was further subdivided into civil, structural, electrical and mechanical costs. The overhead costs included contingencies, land, engineering fees, legal fees, overhead during construction, sales tax, property tax during construction, and spare parts and supplies.

For each solar thermal power system type, estimates were developed for both the high and low ends of the solar hardware cost ranges which were provided by JPL.

Table B-1
CAPITAL COST ESTIMATES[a]
1-MW PARABOLIC DISH CONCENTRATOR SYSTEM[b]
(Thousands of 1975 Dollars)

Item	High Solar Hardware Cost	Low Solar Hardware Cost
Construction Cost		
Civil		
Site Investigation	11.4	11.4
Site Preparation[c]	325.9	325.9
Railroad[d]	—	—
Water Supply	42.0	42.0
Waste Disposal	3.3	3.3
Quality Control	62.9	62.9
Civil Subtotal	445.5	445.5
Structural		
Building	667.5	667.5
Structural Subtotal	667.5	667.5
Electrical		
Transformers & Electrical Equipment	110.4	110.4
Electrical Subtotal	110.4	110.4
Mechanical		
Collector	763.8	246.6
Transport	50.0	18.0
Conversion	200.0	53.0
Storage	90.0	90.0
Wet Cooling Tower	—	—
Mechanical Subtotal	1,103.8	407.6
Total Construction Cost	2,327.2	1,631.0
Overhead		
Contingencies (10%)	232.7	163.1
Land	3.1	3.1
Engineering Fees (10%)	232.7	163.1
Legal Fees	8.9	8.9
Overhead During Construction[e]	29.4	29.4
Sales Tax	56.8	40.7
Property Tax[f]	28.4	20.0
Parts & Supplies	4.2	4.2
Total Overhead		
Municipals	567.8	412.5
Cooperatives	596.2	432.5
Total Capital Cost[g]		
Municipals	2,895.0	2,043.5
Cooperatives	2,923.4	2,063.5

[a] *All estimates except collector, transport, conversion, and storage costs were developed by Burns & McDonnell. These estimates assume a plant location in the Southwestern United States (Albuquerque, New Mexico)*

[b] *Assumes an energy storage rating of 2-MWh, a collector area of 0.004 km^2 and a land area of 0.013 km^2. For other characteristics see Table 2-1.*

[c] *Includes grading (assuming a basically flat plant site), fencing, site access road construction, application of dust suppressant (3" maximum gravel), construction of site storm drainage and landscaping.*

[d] *No railroad was included for this plant. It was assumed that equipment would be transported to the site by truck.*

[e] *Includes costs of startup and testing, builder's risk insurance, management overhead, and operator training*

[f] *Cooperatives only*

[g] *Does not include interest during construction.*

Table B-2
CAPITAL COST ESTIMATES[a]
2-MW PARABOLIC DISH CONCENTRATOR SYSTEM[b]
(Thousands of 1975 Dollars)

Item	High Solar Hardware Cost	Low Solar Hardware Cost
Construction Cost		
Civil		
Site Investigation	11.5	11.5
Site Preparation[c]	395.0	395.0
Railroad[d]	–	–
Water Supply	42.0	42.0
Waste Disposal	4.2	4.2
Quality Control	62.9	62.9
Civil Subtotal	515.6	515.6
Structural		
Building	839.6	839.6
Structural Subtotal	839.6	839.6
Electrical		
Transformers & Electrical Equipment	110.4	110.4
Electrical Subtotal	110.4	110.4
Mechanical		
Collector	1,527.6	493.3
Transport	100.0	36.0
Conversion	400.0	106.0
Storage	180.0	180.0
Wet Cooling Tower	–	–
Mechanical Subtotal	2,207.6	815.3
Total Construction Cost	3,673.2	2,280.9
Overhead		
Contingencies (10%)	367.3	228.1
Land	5.9	5.9
Engineering Fees (10%)	367.3	228.1
Legal Fees	16.8	16.8
Overhead During Construction[e]	29.4	29.4
Sales Tax	89.4	55.6
Property Tax[f]	67.0	28.0
Parts & Supplies	8.4	8.4
Total Overhead		
Municipals	884.5	572.3
Cooperatives	951.5	600.3
Total Capital Cost[g]		
Municipals	4,557.7	2,853.2
Cooperatives	4,624.7	2,881.2

[a] *All estimates except collector, transport, conversion, and storage costs were developed by Burns & McDonnell. These estimates assume a plant location in the Southwestern United States (Albuquerque, New Mexico).*

[b] *Assumes an energy storage rating of 4 MWh, a collector area of 0.008 km^2 and a land area of 0.026 km^2. For other characteristics see Table 2-1.*

[c] *Includes grading (assuming a basically flat plant site), fencing, site access road construction, application of dust suppressant (3" maximum gravel), construction of site storm drainage and landscaping.*

[d] *No railroad was included for this plant. It was assumed that equipment would be transported to the site by truck.*

[e] *Includes costs of startup and testing, builder's risk insurance, management overhead, and operator training*

[f] *Cooperatives only*

[g] *Does not include interest during construction.*

Table B-3
CAPITAL COST ESTIMATE[a]
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM[b]
(Thousands of 1975 Dollars)

Item	High Solar Hardware Cost	Low Solar Hardware Cost
Construction Cost		
Civil		
Site Investigation	16.8	16.8
Site Preparation[c]	1,028.6	1,029.6
Railroad[d]	633.9	633.9
Water Supply	42.0	42.0
Domestic Waste Disposal	8.4	8.4
Quality Control	104.9	104.9
Civil Subtotal	1,834.6	1,834.6
Structural		
Building	1,259.4	1,259.4
Structural Subtotal	1,259.4	1,259.4
Electrical		
Transformers & Electrical Equipment	586.9	586.9
Electrical Subtotal	586.9	586.9
Mechanical		
Collector	7,638.1	2,466.5
Transport	500.0	180.0
Conversion	2,000.0	530.0
Storage	900.0	900.0
Wet Cooling Tower	—	—
Mechanical Subtotal	11,038.1	4,076.5
Total Construction Cost	14,719.0	7,757.4
Overhead		
Contingencies (10%)	1,471.9	775.7
Land	27.7	27.7
Engineering Fees (10%)	1,471.9	775.7
Legal Fees	84.0	84.0
Overhead During Construction[e]	58.8	58.8
Sales Tax	357.0	189.9
Property Tax[f]	267.7	95.0
Parts & Supplies	16.8	16.8
Total Overhead		
Municipals	3,488.1	1,928.6
Cooperatives	3,755.8	2,023.6
Total Capital Cost[g]		
Municipals	18,207.1	9,686.0
Cooperatives	18,474.8	9,781.0

[a] *All estimates except collector, transport, conversion, and storage costs were developed by Burns & McDonnell. These estimates assume a plant location in the Southwestern United States (Albuquerque, New Mexico).*

[b] *Assumes an energy storage rating of 20 MWh, a collector area of 0.040 km^2 and a land area of 0.133 km^2. For other characteristics see Table 2-1.*

[c] *Includes grading (assuming a basically flat plant site), fencing, site access road construction, application of dust suppressant (3" maximum gravel), construction of site storm drainage and landscaping.*

[d] *A 2-mile railroad spur was included for transportation of equipment to the plant site.*

[e] *Includes costs of startup and testing, builder's risk insurance, management overhead, and operator training.*

[f] *Cooperatives only.*

[g] *Does not include interest during construction.*

Table B-4

CAPITAL COST ESTIMATES[a]

10-MW VARIABLE SLAT CONCENTRATOR SYSTEM[b]

(Thousands of 1975 Dollars)

Item	High Solar Hardware Cost	Low Solar Hardware Cost
Construction Cost		
Civil		
Site Investigation	23.5	23.5
Site Preparation[c]	2,409.5	2,409.5
Railroad[d]	633.9	633.9
Water Supply	100.2	100.2
Waste Disposal	8.4	8.4
Quality Control	104.9	104.9
Civil Subtotal	3,280.5	3,280.5
Structural		
Building	1,259.4	1,259.4
Structural Subtotal	1,259.4	1,259.4
Electrical		
Transformers & Electrical Equipment	425.7	425.7
Electrical Subtotal	425.7	425.7
Mechanical		
Collector	19,122.4	9,505.3
Transport	1,500.0	750.0
Conversion	3,500.0	1,750.0
Storage	1,200.0	1,200.0
Wet Cooling Tower	159.5	159.5
Mechanical Subtotal	25,481.9	13,364.8
Total Construction Cost	30,447.5	18,330.4
Overhead		
Contingencies (10%)	3,044.8	1,833.0
Land	78.1	78.1
Engineering Fees (10%)	3,044.8	1,833.0
Legal Fees	84.0	84.0
Overhead During Construction[e]	58.8	58.8
Sales Tax	735.5	444.7
Property Tax[f]	551.6	333.5
Parts & Supplies	16.8	16.8
Total Overhead		
Municipals	7,062.8	4,348.8
Cooperatives	7,614.4	4,681.9
Total Capital Cost[g]		
Municipals	37,510.3	22,345.3
Cooperatives	38,061.9	22,678.8

[a] *All estimates except collector, transport, conversion, and storage costs were developed by Burns & McDonnell. These estimates assume a plant location in the Southwestern United States (Albuquerque, New Mexico)*

[b] *Assumes an energy storage rating of 14 MWh, a collector area of 0.112 km^2 and a land area of 0.373 km^2. For other characteristics see Table 2-1.*

[c] *Includes grading (assuming a basically flat plant site), fencing, site access road construction, application of dust suppressant (3" maximum gravel), construction of site storm drainage and landscaping.*

[d] *A 2-mile railroad spur was included for transportation of equipment to the plant site.*

[e] *Includes costs of startup and testing, builder's risk insurance, management overhead, and operator training*

[f] *Cooperatives only.*

[g] *Does not include interest during construction.*

Table B-5
CAPITAL COST ESTIMATES[a]
50-MW CENTRAL RECEIVER SYSTEM[b]
(Thousands of 1975 Dollars)

Item	High Solar Hardware Cost	Low Solar Hardware Cost
Construction Cost		
Civil		
Site Investigation	62.9	62.9
Site Preparation[c]	7,728.6	7,728.6
Railroad[d]	633.9	633.9
Water Supply	585.4	585.4
Waste Disposal	21.0	21.0
Quality Control	105.0	105.0
Civil Subtotal	9,136.8	9,136.8
Structural		
Building	1,679.2	1,679.2
Structural Subtotal	1,679.2	1,679.2
Electrical		
Transformers & Electrical Equipment	1,095.7	1,095.7
Electrical Subtotal	1,095.7	1,095.7
Mechanical		
Collector	61,233.0	27,449.0
Transport	15,000.0	7,500.0
Conversion	17,500.0	8,750.0
Storage	6,000.0	6,000.0
Wet Cooling Tower	776.6	776.6
Mechanical Subtotal	100,509.6	50,475.6
Total Construction Cost	112,421.3	62,387.3
Overhead		
Contingencies (10%)	11,242.1	6,238.7
Land	292.2	292.2
Engineering Fees (8%)	8,993.7	4,991.0
Legal Fees	209.9	209.9
Overhead During Construction[e]	88.2	88.2
Sales Tax[f]	2,665.8	1,485.0
Property Tax[f]	1,999.3	1,113.7
Parts & Supplies	42.0	42.0
Total Overhead		
Municipals	23,533.9	13,347.0
Cooperatives	25,533.2	14,459.8
Total Capital Cost[g]		
Municipals	135,955.2	75,734.3
Cooperatives	137,954.5	76,848.0

[a] *All estimates except collector, transport, conversion, and storage costs were developed by Burns & McDonnell. These estimates assume a plant location in the Southwestern United States (Albuquerque, New Mexico)*

[b] *Assumes an energy storage rating of 70 MWh, a collector area of 0.422 km^2 and a land area of 1.407 km^2. For other characteristics see Table 2-1.*

[c] *Includes grading (assuming a basically flat plant site), fencing, site access road construction, application of dust suppressant (3" maximum gravel), construction of site storm drainage and landscaping.*

[d] *A 2-mile railroad spur was included for transportation of equipment to the plant site.*

[e] *Includes costs of startup and testing, builder's risk insurance, management overhead, and operator training.*

[f] *Cooperatives only.*

[g] *Does not include interest during construction.*

The differences in solar hardware costs had an impact on contingencies, engineering fees, sales tax and property tax, all of which were calculated as a percentage of construction costs.

A discussion of the assumptions included in each line item of these estimates is provided below.

Construction Cost

Site Investigation. This category included surveying and subsurface investigation.

Site Preparation. This category included grading, fencing, construction of site access roads, application of dust suppressant (3-inch maximum gravel), construction of site storm drainage and landscaping. A flat plant site was assumed.

Railroad. It was assumed that a 2-mile railroad spur would be constructed for the delivery of equipment to the plant site for the 10-MW and larger plants. For smaller plants it was assumed that equipment would be delivered to the site by truck.

Water Supply. It was assumed that a well field would be developed to supply domestic and plant water requirements.

Waste Disposal. This category included only a domestic waste disposal system.

Quality Control. This category included the cost of a contract for future site and foundation inspections throughout the life of the plant.

Building. It was assumed that a maintenance/control room building would be required at the plant site.

Transformers and Electrical Equipment. This category included 5 miles of transmission line, a transformer and the associated electrical equipment necessary to tie the plant to a nearby substation. It was assumed that all internal wiring and electrical equipment necessary to the plant including wiring to tie together the modules of the parabolic dish concentrator system were included in the solar hardware costs provided by JPL.

Collector, Transport, Conversion and Storage. These estimates were provided by JPL and were assumed to include all of the pumps, piping, electrical connections, controls, foundations and all other equipment not specifically included in any other line item.

Wet Cooling Tower. A wet cooling tower was included in the estimates for the variable slat concentrator and central receiver systems. It was assumed that a cooling tower was unnecessary for the parabolic dish concentrator systems.

Overhead

Contingencies. Allowance for contingencies was assumed to equal 10 percent of the total construction cost.

Land. Land was assumed to cost $840/acre in 1975 dollars.

Engineering Fees. Engineering fees were assumed to be 10 percent of the construction cost for plants of 10 MW or less and 8 percent of the construction cost for the 50-MW plant.

Legal Fees. It was assumed that legal services would be required during the licensing, certification and environmental review processes.

Overhead During Construction. This category includes the costs of startup and testing, builder's risk insurance, management overhead and operator training.

Sales Tax. Sales tax of 4 percent was assumed on approximately half of the plant construction cost.

Property Tax. Property tax of 1 percent on the total plant cost was assumed for cooperative utilities. It was assumed that municipal utilities were not subject to property taxes.

Parts and Supplies. This category was assumed to include an initial inventory of spare parts and supplies.

ESTIMATES SUPPLIED BY JPL

As mentioned earlier, Burns & McDonnell developed Class I estimates of "other" capital costs using standard techniques normally applied to fossil-steam power plant estimates. It was felt that these estimates would probably represent "high" values since they are not optimized for an area-intensive energy source such as solar radiation. To bracket the range of "other" costs, a lower figure was supplied by JPL for use in the study. JPL suggested the use of an "other" cost of $100/kW for the 10-MW parabolic dish concentrator system (versus the $716.0/kW figure for municipal utilities which was developed by Burns & McDonnell in the high solar hardware cost scenario) and proportional "other" costs for the remaining solar thermal power system types. The low "other" costs used in the study are summarized in Table B-6.

* * * * *

Table B-6

CAPITAL COST ESTIMATES INCLUDING LOW "OTHER" COSTS[a]

(Thousands of 1975 Dollars)

Item	Parabolic Dish Concentrator Systems			10-MW Variable Slat Concentrator System	50-MW Central Receiver System
	1-MW	2-MW	10-MW		
Solar Hardware					
Collector	246.6	493.3	2,466.5	9,505.3	27,499.0
Transport	18.0	36.0	180.0	750.0	7,500.0
Conversion	53.0	106.0	530.0	1,750.0	8,750.0
Storage	90.0	180.0	900.0	1,200.0	6,000.0
Other[b]					
Municipals	230.0	340.0	1,000.0	1,850.0	5,295.0
Cooperatives	233.6	349.6	1,037.0	1,934.0	5,450.0
Total					
Municipals	637.6	1,155.3	5,076.5	15,055.3	55,044.0
Cooperatives	641.2	1,164.9	5,113.5	15,139.3	55,199.0

[a] *All costs were based on numbers supplied by JPL. The estimates assume a plant location in the Southwestern United States (Albuquerque, New Mexico) and the plant characteristics shown in Table 2-1.*

[b] *Based on numbers supplied by JPL which assume the development of innovative site preparation and construction techniques. The difference between the costs for municipals and cooperatives is based on the fact that cooperatives must pay property taxes from which municipals are exempt.*

Appendix C

DEVELOPMENT AND ANALYSIS OF GENERATION EXPANSION PLANS

INTRODUCTION

This appendix discusses the approach and methodology utilized in developing and analyzing generation expansion plans for the small utility reference systems. Alternative generation expansion plans were developed and analyzed for each of the reference utilities in order to determine the optimum schedule of capacity additions (conventional or solar) for each utility. The optimum generating capacity expansion plan for an electric utility system is generally the one which minimizes future revenue requirements and environmental impact while maintaining an adequate level of reliable service.

The optimum generation expansion plan was selected from a set of possible expansion plans for each reference utility with the aid of a power supply plan analysis computer model developed by Burns & McDonnell. This program determines the present worth of all future revenue requirements (PWAFRR) associated with a particular generation expansion plan. The PWAFRR was used as the principle basis for comparing alternative generation expansion plans with the optimum plan being the one with the lowest PWAFRR. Since the study was concerned primarily with the economic aspects of the utilization of solar thermal power systems, the environmental impacts associated with alternative generation types were not factored into the selection of optimum expansion plans.

Reliability considerations were handled by assuming a fixed percentage reserve requirement of 20 percent of the annual peak system load for each reference utility. It was assumed that each of the reference utilities was interconnected and required to maintain a 20 percent reserve margin as a result of contractual agreements. In addition, the reliability of the solar thermal power systems was factored into the study by crediting only a fraction of the rated capacity of the solar thermal power system to the capacity available to meet the utility's peak demand. The method used to determine the amount of this capacity credit is discussed in Appendix F.

In determining the optimum generation expansion plans, only generation related costs were considered. Possible transmission system cost variations were not factored into the analysis of alternative generation expansion plans. Essentially, it was assumed that all of the conventional capacity additions for a system would be made at a centralized location and that solar additions would be made at locations near existing substations so that the transmission system would not be affected.

DEVELOPMENT OF GENERATION EXPANSION PLANS

Generation expansion plans were developed for the period 1980-2000 for each reference utility for each of the applicable conventional generation and solar thermal power system types described in Sections 2 and 3. Somewhat different approaches were taken in the development of generation expansion plans for the conventional generation and solar thermal power system types. A brief description of each of these approaches is provided below.

Development of Conventional Expansion Plans

In developing the conventional expansion plans, it was assumed that the reference utilities would expand their intermediate-peaking capacity mix using only one of the conventional generation types (see Table 3-5). That the reference utilities would generally expand with only one of the currently available intermediate-peaking capacity types was considered to be a reasonable assumption since operating problems for a small utility system are greatly simplified if there is a standardization of the installed equipment. Standardized equipment also tends to greatly reduce spare parts costs and maintenance staffing requirements. By making this simplifying assumption, it was possible to greatly reduce the number of alternative expansion plans without detracting from the quality and validity of the results developed. It was also assumed that each reference utility would supply its base load capacity requirements by purchasing power from a neighboring investor-owned utility.

Development of Solar Expansion Plans

Each solar expansion plan was developed as a variation on the corresponding optimum conventional expansion plan. In developing the solar expansion plans it was assumed that the utility would purchase approximately the same amount of capacity as in the optimum conventional expansion plan, but that some of the optimum conventional intermediate peaking capacity would be replaced by capacity from the solar thermal power system. However, the solar capacity was not assumed to replace the conventional intermediate-peaking capacity on a megawatt for megawatt basis. Rather, only the fraction of the capacity of the solar thermal power system which was credited to meeting the utility's peak demand was assumed to replace conventional intermediate-peaking capacity.

Typical Expansion Plans

Generation expansion plans typical of those developed in the study are shown in Tables C-1 and C-2. The expansion plans shown are for the 8-MW diesel and the 2-MW parabolic dish concentrator system for the 35-MW municipal with coal-fired generation. The first four columns in each of these tables list the capacity requirements and existing capacity for the reference utility during the period 1980-2000. The additional capacity required for any year is equal to the system peak demand plus a 20% reserve requirement less the existing capacity resources. The additional capacity requirements were calculated using the system peak demand growth rates and existing capacity resources shown in Section 3. The gradual reduction in existing generating resources that can be observed in the fourth column is due to the assumed retirement of old generating units (See Table 3-3, Section 3).

The remainder of the columns in each table show the timing of proposed generating unit additions for particular levels of penetration of purchased and solar capacity into the system's total power resource mix (total capacity requirement). For example, in Table C-1, which shows several conventional expansions for the 35-MW municipal with coal-fired generation, 8-MW diesels were added to limit the purchased capacity penetration to 40, 60, or 80 percent. In Table C-2, both 2-MW solar and 8-MW diesel additions are shown for 60 percent purchased capacity penetration (the optimum level) and 5, 10 or 20 percent solar penetration. Diesel capacity is added in Table C-2 to meet the remaining system capacity requirements not met by purchased capacity or the capacity credit of the solar thermal power systems.

Table C-1

DIESEL POWER SUPPLY PLANS
35-MW MUNICIPAL WITH COAL-FIRED GENERATION

Calendar Year	Peak Demand (MW)	Total Capacity Required[a] (MW)	Existing Capacity (MW)	Power Supply Plans: Percent of Total Capacity Requirement from Purchased Power		
				40%	60%	80%
1980	51	61	40			
1981	54	65	40			
1982	57	69	40			
1983	61	73	40	8 MW Diesel		
1984	64	77	40			
1985	68	82	40			
1986	72	86	40			
1987	75	90	40	8 MW Diesel		
1988	79	95	40			
1989	83	100	35	8 MW Diesel	8 MW Diesel	
1990	87	105	30	8 MW Diesel	8 MW Diesel	
1991	91	109	30	8 MW Diesel		
1992	95	114	30			
1993	100	119	30			
1994	104	125	30	8 MW Diesel	8 MW Diesel	
1995	109	130	30			
1996	113	136	30	8 MW Diesel		
1997	118	141	30			
1998	122	147	30		8 MW Diesel	
1999	127	153	30	8 MW Diesel		
2000	132	159	10	3-8 MW Diesel	3-8 MW Diesel	3-8 MW Diesel

[a] *120 Percent of Peak Demand*

Table C-2

2-MW PARABOLIC DISH CONCENTRATOR SYSTEM POWER SUPPLY PLANS
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
(60% PURCHASED CAPACITY PENETRATION)

Calendar Year	Peak Demand (MW)	Total Capacity Required[a] (MW)	Existing Capacity (MW)	Power Supply Plans: Percent of Total Capacity Requirement From Solar Power Systems (SPS)					
				5%		10%		20%	
1980	51	61	40						
1981	54	65	40						
1982	57	69	40						
1983	61	73	40						
1984	64	77	40						
1985	68	82	40	2-2 MW SPS		4-2 MW SPS		8-2 MW SPS	
1986	72	86	40					2-MW SPS	
1987	75	90	40			2-MW SPS			
1988	79	95	40						
1989	83	100	35					2-MW SPS	
1990	87	105	30	2-MW SPS	8-MW DSL		8-MW DSL		8-MW DSL
1991	91	109	30					2-MW SPS	
1992	95	114	30			2-MW SPS			
1993	100	119	30		8-MW DSL		8-MW DSL	2-MW SPS	
1994	104	125	30						
1995	109	130	30			2-MW SPS		2-MW SPS	8-MW DSL
1996	113	136	30		8-MW DSL			2-MW SPS	
1997	118	141	30	2-MW SPS					
1998	122	147	30				8-MW DSL	2-MW SPS	
1999	127	153	30			2-MW SPS			
2000	132	159	10		3-8 MW DSL		3-8 MW DSL	2-MW SPS	2-8 MW DSL

[a] *120 Percent of Peak Demand*

Several points need to be clarified with respect to the methodology used to develop these expansion plans. First, the percentages of purchased or solar capacity shown in Tables C-1 and C-2 reflect goals which may not be achieved until there has been sufficient load growth or retirement of existing capacity to justify this amount of capacity. For example, 40% purchased capacity is not achieved in Table C-1 until 1982, and 80% purchased capacity is not achieved until 1999. In the examples shown in Table C-2, the specified percentages of solar capacity are achieved in 1985 as soon as the solar power systems are assumed to become commercially available. However, in some other cases, particularly for the smaller reference utilities, the solar penetration goal may not be achieved until much later in the study period.

A second point regards the priority assigned to capacity additions in the solar expansion plans. Different expansion plans would result if first priority were given to trying to attain 60% purchased power than if first priority were given to trying to attain a 5, 10 or 20% solar penetration. Since the focus of the study was an economic analysis of solar thermal power systems, the solar penetration goals were given first priority in developing the solar expansion plans. Second priority was given to the purchased power penetration goals and conventional intermediate-peaking capacity was added to meet the utility's remaining capacity requirement after both of these goals were met.

A third relevant point involves the exact meaning of the capacity percentages in the solar expansion plans. Five percent solar penetration was assumed to mean that the total rated solar capacity is 5% of the system's total capacity requirement. Further, the capacity requirement was defined to be the utility's peak demand plus 20% reserves. Thus, the utility may have a total available capacity (including purchased capacity) greater than the utility's capacity requirement. This results from the fact that not all of the utility's rated solar capacity is credited toward meeting its capacity requirement because of the uncertainties associated with the availability of the solar plant on peak. For example, in the 20% solar penetration case shown in Table C-2 the 35-MW municipal with coal-fired generation has 32 MW of solar capacity (rated) by the year 2000 (20% of the 159 MW of required capacity), but only 11 MW of this capacity is credited toward meeting the utility's capacity requirement.

ANALYSIS OF GENERATION EXPANSION PLANS

The generation expansion plans developed in this study were analyzed with a power supply plan analysis computer model developed by Burns & McDonnell. This computer program takes as input a variety of data including capital costs, fuel prices, generating unit availability and operating characteristics, purchased power costs, interest rates, plus other information to develop the annual capital-related and production costs (revenue requirements) associated with a particular expansion plan for each year of the study period. The revenue requirements calculated for an expansion plan are totaled and also present valued by the computer model for the entire study period. The computer model also provides other useful information such as fuel consumption data and breakdowns of production costs and capital related charges, both annually and for the entire study period.

The PWAFRR is calculated from the following expression:

$$\text{PWAFRR} = \sum_{K=1980}^{2000} \frac{E(K)}{(1 + D)^{(K-B)}} + \frac{E(2000)}{D\,(1 + D)^{(2000-B)}}$$

where:

- E(K) = Net cash expenditures including production operation and maintenance, fuel, limestone, purchased power costs, principal, interest, insurance, property taxes, and interim replacements less power sold in the year K.
- D = Discount rate (per unit)
- B = Calendar year of present worth (base year)

The first term in this expression is the present worth of the revenue requirements for the period 1980-2000. The second term accounts for the period 2001 - infinity assuming the year 2000 cash expenditures continue indefinitely.

It should be noted that the PWAFRR developed by the Burns & McDonnell computer model is an incremental PWAFRR. That is, it includes only those costs which can be expected to vary with the generation expansion plan. For example, costs such as debt service or fixed operation and maintenance on existing units were not included in developing this figure while fixed charges on new units and variable costs, such as fuel and variable operation or maintenance, for both existing and new generating units were included.

Energy allocation in the Burns & McDonnell computer model is accomplished using a version of the Booth-Baleriaux (14) method for the simulation of the loading of generation resources. This is a probabilistic simulation method for allocating energy to the various power resources of a system using a load duration curve technique. Annual load duration curves are employed in this model. Fuel costs are calculated using average annual net heat rates. Unit loading is variable from year to year and based on the average energy cost with the lowest energy cost power resources loaded first.

The advantage of using the probabilistic simulation approach to the allocation of energy to various power resources is that this type of model is relatively inexpensive to run while also being quite accurate. However, a load duration curve model, unlike a chronological hour-by-hour energy allocation model, cannot calculate the number of start-ups required for a particular generator nor can it accurately take into account the characteristics of the heat rate curve for a generator. But since start-up costs are generally a very small fraction of the total production cost for a system, these are usually ignored or added separately in the form of an allowance when using load duration curve models. In addition, the use of average annual net heat rates is normally sufficiently accurate for long range planning purposes. Chronological production costing models are also cumbersome to handle and very costly to run, especially when a large number of alternative plans need to be analyzed. Therefore, a probabilistic simulation approach is usually preferred for long-range planning purposes.

However, as mentioned in Section 4, the Booth-Baleriaux method of energy allocation assumes that the outages of generating units are random. Since solar outages have a distinct daily cycle, the Booth-Baleriaux method cannot be used to analyze solar thermal power systems. For this reason, an hourly analysis model was developed to analyze the solar thermal power systems and determine their annual capacity and energy contributions for use in the power supply analysis computer model. This hourly analysis model is described in Appendix D.

* * * * *

Appendix D
HOURLY ANALYSIS METHODOLOGY

This appendix discusses the hourly analysis computer model which was developed by Burns & McDonnell as a part of this study to aid in the analysis of the solar thermal power systems. The program takes as input data hourly values of insolation and the utility system's load as well as operating characteristics of the solar thermal power system including receiver intensity rating, storage time and solar multiple. Given these data it calculates other characteristics of the solar thermal power system such as the required collector area and the total capital cost, determines an hourly dispatching schedule for the solar thermal power system and provides annual summaries of the amount of energy generated by the solar thermal power system and the amount by which the dispatch of the solar thermal power system decreases the system peak demand which must be met by conventional resources. Finally, the program calculates the life-cycle levelized busbar energy cost (BBEC) of the solar thermal power system and the net BBEC of the solar thermal power system considering the value of the conventional capacity displaced by the capacity credited to the solar thermal power system.

OPERATING MODEL OF THE SOLAR THERMAL POWER SYSTEMS

A simple linear model, as illustrated in Figures D-1 and D-2, was assumed to represent the operation of the solar thermal power systems. Figure D-1 which shows the operation of the 10 MW variable slat concentrator system is also illustrative of the mode of operation assumed for the central receiver system. Figure D-2 illustrates the operation assumed for the parabolic dish concentrator systems.

The thermal receiver power (P) was determined by the level of direct normal insolation (I_{DN}), the collector area (AREA), and the collector efficiency (η_c):

$$P = \eta_c \, I_{DN} \, \text{AREA} \qquad \text{(D-1)}$$

POWER OUTPUT VS. DIRECT NORMAL INSOLATION
10-MW VARIABLE SLAT CONCENTRATOR SYSTEM

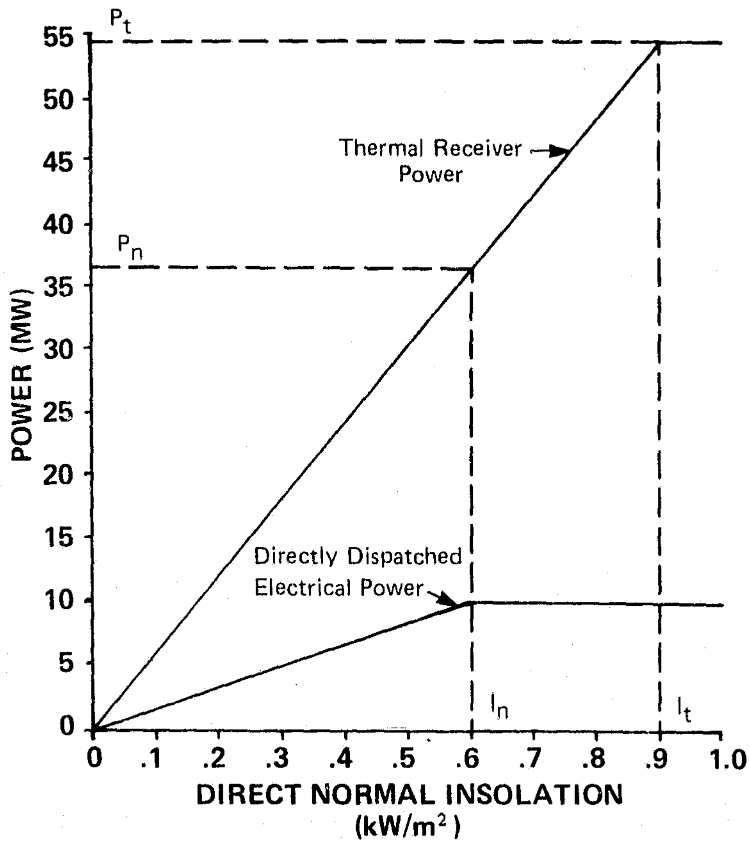


Figure D-1

POWER OUTPUT VS. DIRECT NORMAL INSOLATION
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM

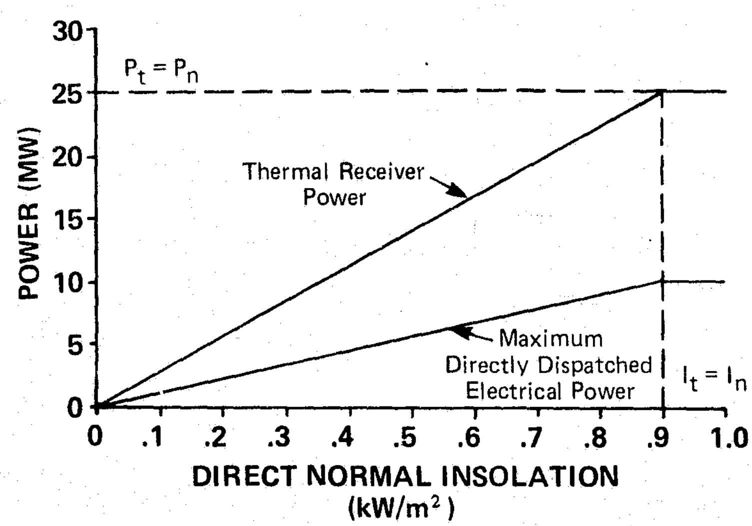


Figure D-2

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The maximum thermal receiver power (P_t) was defined as the level of thermal power produced by the solar thermal power system when the level of direct normal insolation is greater than or equal to the system's receiver intensity rating (I_t). As discussed elsewhere in this report, the receiver intensity rating is a design parameter which affects both the system's annual capacity factor and the required collector area. For this study the value of the receiver intensity rating was selected with the aid of the hourly analysis model during a parameter optimization analysis which is discussed in Appendix E.

Until the solar thermal power system reaches its rated electrical capacity, the maximum directly dispatched electrical power (P_D) was assumed to be a function of the thermal receiver power (P) and the efficiencies of the energy transport and conversion subsystems (η_t and η_x, respectively):

$$P_D = \eta_c \eta_x P \qquad \text{(D-2)}$$

It can be seen in Figure D-2 that for the parabolic dish concentrator systems the rated electrical capacity of the solar thermal power system was reached at the same level of direct normal insolation at which the maximum thermal receiver power was reached. For the variable slat concentration and central receiver systems the maximum thermal receiver power was reached at a higher level of direct normal insolation than the level at which the rated electrical capacity was reached, as shown in Figure D-1. For these systems, the additional thermal power in excess of that necessary for the electrical conversion subsystem was assumed to be diverted to thermal storage.

The ratio of the maximum amount of thermal receiver power (P_t) to the thermal power (P_n) corresponding to the rated electrical capacity of the solar thermal power system was defined as the solar multiple (SM):

$$SM = P_t/P_n \qquad \text{(D-3)}$$

As indicated above, the solar multiple was unity for the parabolic dish concentrator systems because excess thermal power cannot be used by systems with battery storage. For the variable slat concentrator and central receiver systems which have thermal storage the value of the solar multiple was selected with the aid of the hourly analysis model during a parameter optimization analysis which is discussed in Appendix E.

COLLECTOR AREA

Based on the operating model equations derived above, the required collector area for each solar thermal power system was calculated using the expression

$$\text{AREA} = \frac{SM}{I_t} \times \frac{C}{\eta_c \eta_t \eta_x} \tag{D-4}$$

where

SM = solar multiple, which is the ratio of the maximum available thermal receiver power to the thermal power corresponding to the rated electrical capacity of the solar thermal power system.

C = Rated electrical capacity of the solar thermal power system, kW.

I_t = Receiver intensity rating, which is the level of direct normal insolation at which the solar thermal power system reaches its rated thermal receiver power, kW/m^2.

η = Efficiency, per unit. The subscripts indicate subsystem efficiencies: c = collector, t = transport, x = conversion.

From this expression it can be seen that the collector area varies directly with the capacity of the solar thermal power system and the solar multiple, which is a measure of the amount of collector area which may be dedicated to storage, and inversely with the receiver intensity rating and the system efficiency.

DISPATCHING STRATEGIES

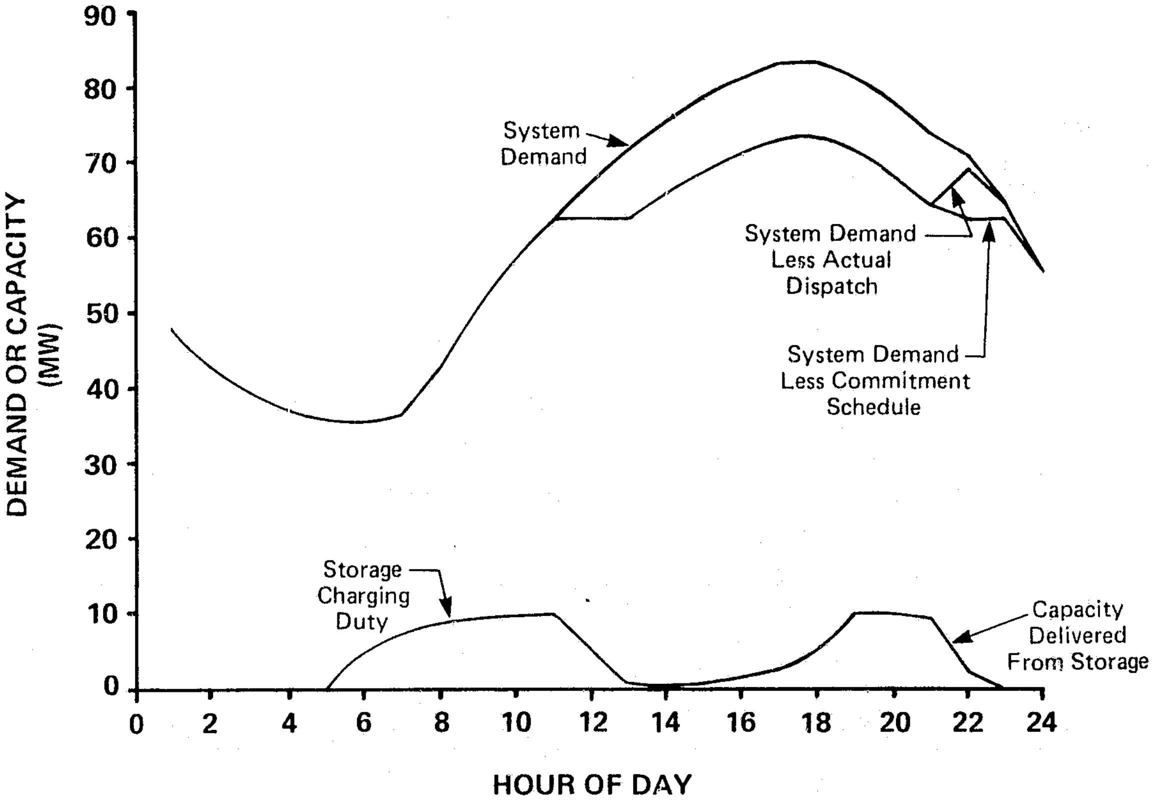
The hourly analysis model has available two different dispatching strategies, peak-shaving and sun-following. Peak-shaving dispatching attempts to minimize the system peak demand which must be met with conventional resources using the energy available from the solar thermal power system. This strategy involves the development of an hourly unit commitment based on the predicted hourly system load and available insolation at the beginning of each day. Once a commitment schedule has been established the solar thermal power system is dispatched to meet the commitment schedule directly from available receiver power or indirectly through storage if possible.

Any receiver power remaining after the commitment schedule is met is sent to storage at up to the maximum charging rate until the storage device reaches its maximum storage capacity. If receiver power remains, it is used to increase generation up to the rate capacity of the solar thermal power system or the remaining system demand. Receiver power which cannot be directly dispatched or stored is dumped, this type of dispatching strategy is necessary whenever the system's thermal energy must be converted into electricity before it is stored. Thus, this dispatching strategy was used for the parabolic dish concentrator systems (which store energy as electricity in advanced batteries) in the study.

Figure D-3 illustrates the peak-shaving dispatch of a reasonably balanced parabolic dish concentrator system configuration (including 60 MWh of storage) that is able to meet the commitment schedule very well for the day shown. Actually, this system probably has excess storage capacity since the storage system is never fully charged. Figure D-4 illustrates the dispatch of the same system with only 20 MWh of storage. In this case, because the storage device is charged to its maximum capacity quickly, the receiver power is used to exceed the commitment schedule early in the day. The storage device is also depleted earlier and the commitment schedule cannot be met late in the day. This results in a higher net system peak demand which must be met by conventional resources. These two examples illustrate that some intermediate amount of storage between 20 and 60 MWh might be optimum. This is an issue which might be explored in a future study.

One method of improving the peak-shaving ability of the parabolic dish concentrator system is to allocate only a fraction of the energy which is expected to be available to it during commitment. This fraction will be referred to as the peak-shaving planning factor, and will be denoted by E_c. The fact that part of the dispatched energy passes through the storage device means

PEAK-SHAVING DISPATCH
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM
WITH 60 MWH OF STORAGE



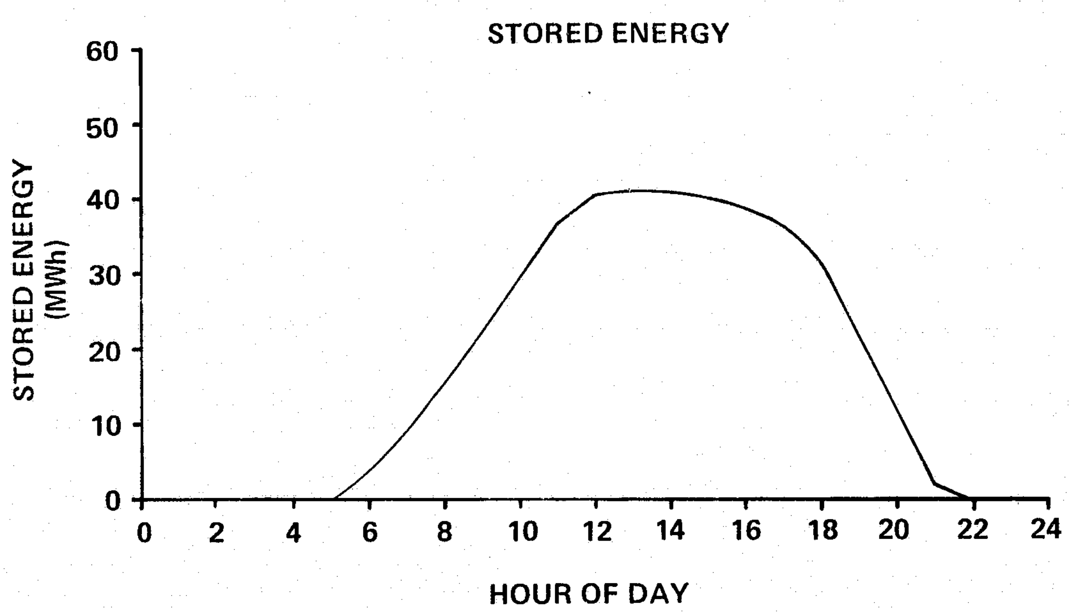


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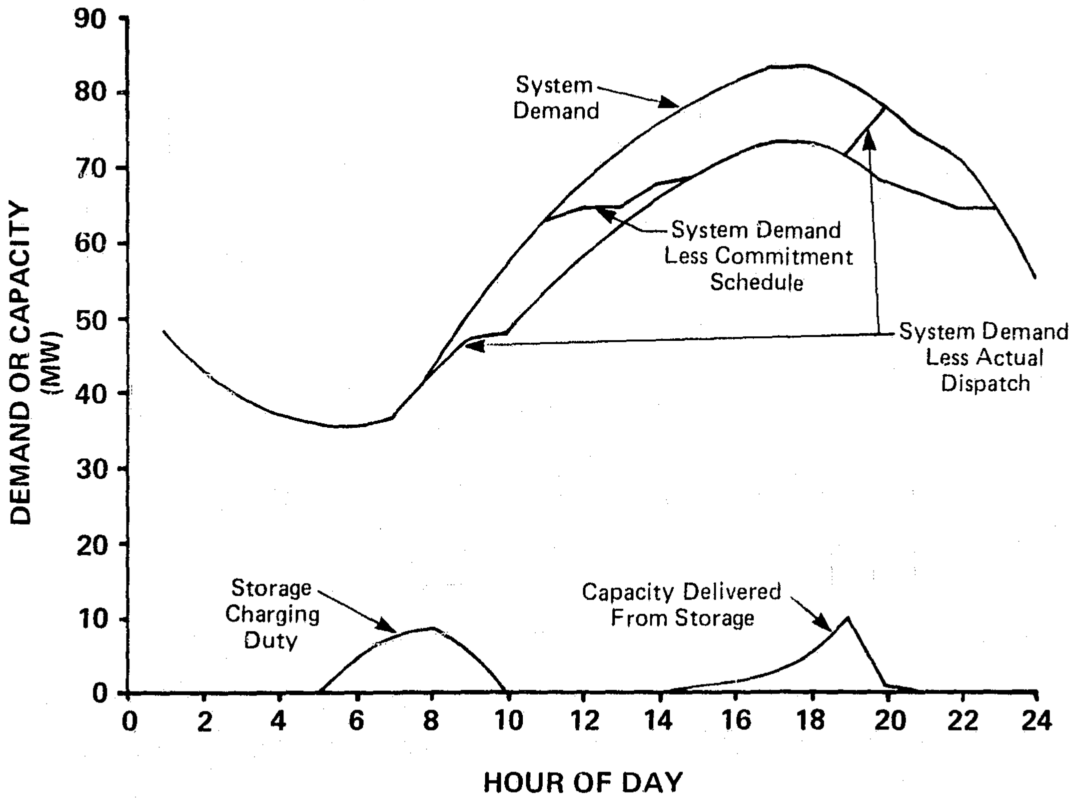
Figure D-3

PEAK-SHAVING DISPATCH
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
10-MW PARABOLIC DISH CONCENTRATOR SYSTEM
WITH 20 MWH OF STORAGE



STORED ENERGY

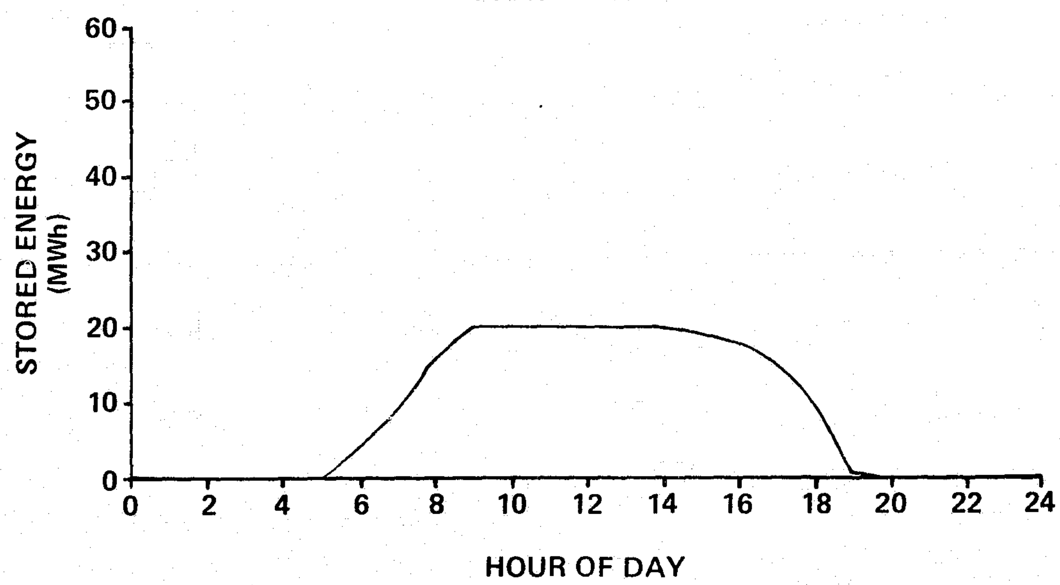


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Figure D-4

that the value of E_c should be between the storage efficiency and 1 if the commitment schedule does not result in a storage-bound situation as illustrated by Figure D-4. For such a situation, however, a lower value can be chosen for E_c to set up a more conservative commitment schedule for the solar thermal power system to meet. Although an optimal value for E_c might be found empirically, the empirical optimum might be approximated by reducing E_c by the fraction of energy that cannot be transferred to peak once the storage device has reached its maximum capacity.

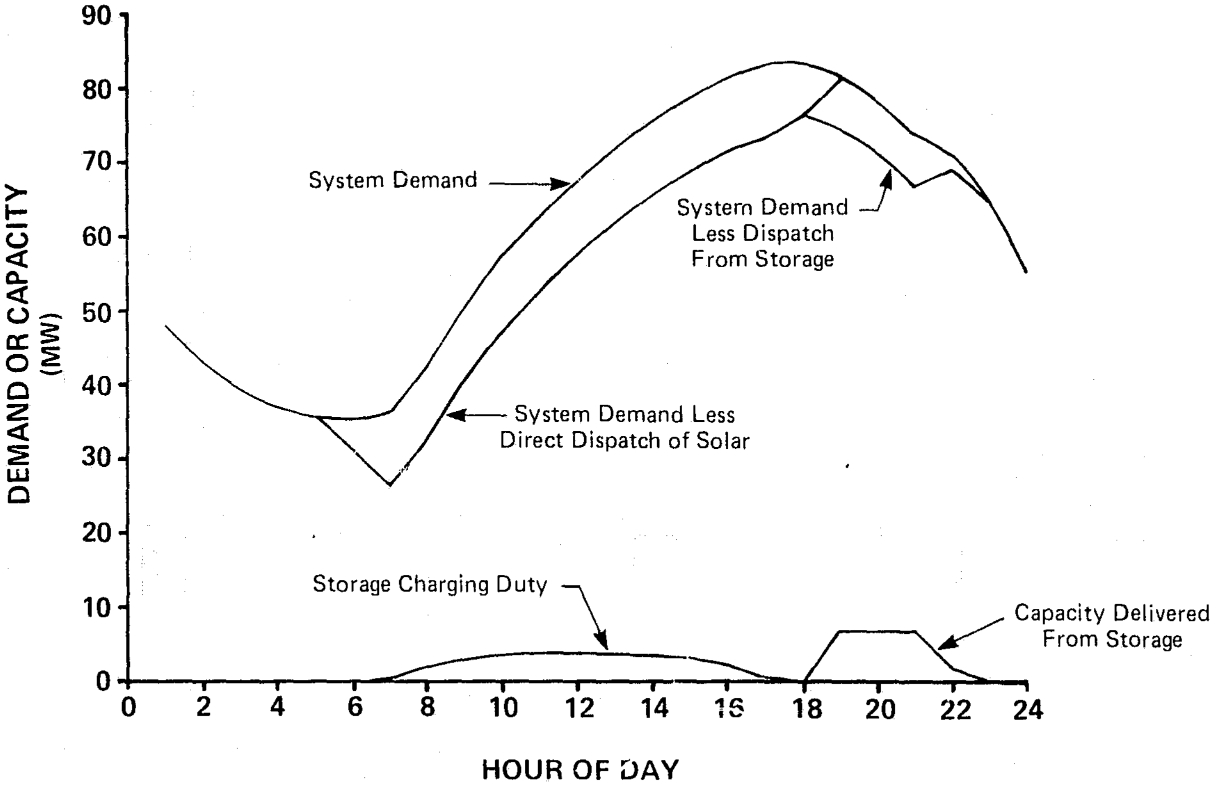
Unlike peak-shaving dispatching, sun-following dispatching maximizes the direct dispatch of the available receiver power to meet the system load. Using this dispatching strategy energy is sent to the storage device of the solar thermal power system only when the available receiver power exceeds the rated electrical capacity of the solar thermal power system or the capacity available from the solar thermal power system exceeds the system demand. This stored energy is delivered at up to the storage output rating whenever the available receiver power falls below the storage output rating provided that additional power is needed to meet system demand. This dispatching strategy was used in the study for the variable slat concentrator and central receiver systems. Figure D-5 illustrates the dispatch of a 10 MW variable slat concentrator system with 60 MWh of storage.

BUSBAR ENERGY COST

As mentioned above, the hourly analysis model also determined the busbar energy cost of the solar thermal power system. The life-cycle levelized busbar energy cost (BBEC) is a price (mills/kWh) in present value dollars per unit of energy generated which would be required to pay for the system over its lifetime. The procedure was to calculate the BBEC in the hourly analysis model is based on a methodology that was developed by J. W. Doane, et al (15) as a part of an effort to establish a consistent basis for comparing alternative and conventional energy systems. BBEC was calculated using the expression

$$BBEC = (\overline{G}_c + \overline{OM}_f) \times \frac{C}{E} + \overline{F} + \overline{OM}_v \qquad \text{(D-5)}$$

SUN-FOLLOWING DISPATCH
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
10-MW VARIABLE SLAT CONCENTRATOR SYSTEM
WITH 60 MWH OF STORAGE



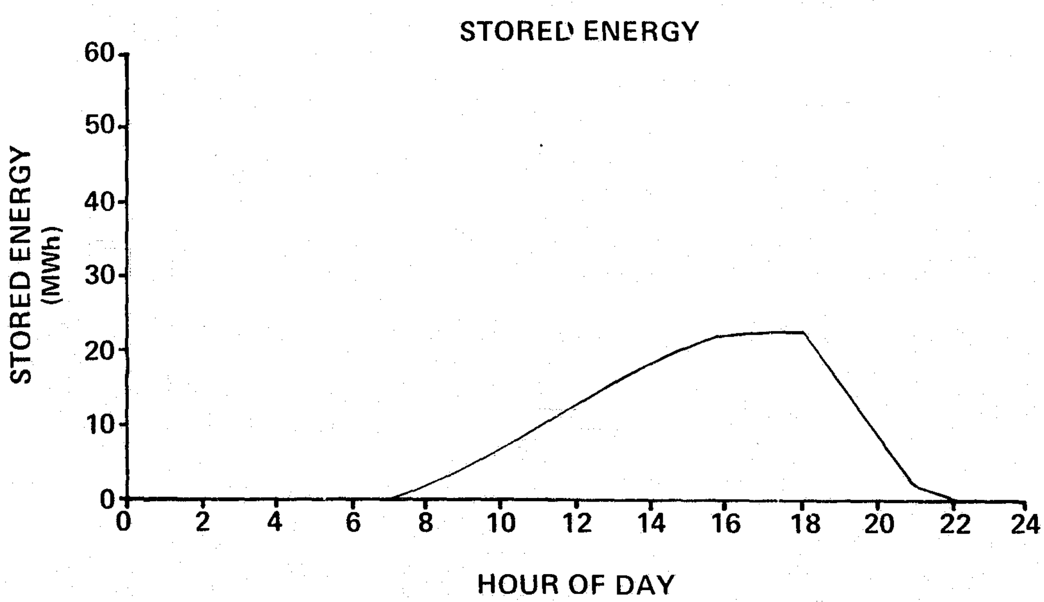


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Figure D-5

where $\overline{G}_c$ = levelized capital charge, \$/kW-yr

$\overline{OM}_f$ = levelized fixed operation and maintenance (O&M), \$/kW-yr

$\overline{F}$ = levelized fuel cost, mills/kWh

$\overline{OM}_v$ = levelized variable operation and maintenance, mills/kWh

C = rated generating capacity of the solar thermal power system, MW

E = annual generated energy of the solar thermal power system, MWh

The levelized capital charge includes debt service payments, interim replacements, property taxes, and insurance. This equation can be rewritten to show the relationship between BBEC and capacity factor, f, by the use of equation

$$f = \frac{E}{8760 \times C} \tag{D-6}$$

These two equations result in the form shown below.

$$BBEC = \frac{\overline{G}_c + \overline{OM}_f}{8760} \times \frac{1}{f} + \overline{F} + \overline{OM}_v \tag{D-7}$$

This equation shows that the sensitivity of BBEC to capacity factor increases as the capital charge and fixed O&M increase relative to fuel cost and variable O&M.

The net BBEC of the solar thermal power system, which was defined as the BBEC of the solar thermal power system, calculated using the equation shown above, less the BBEC of purchased capacity displaced by the capacity credit of the solar thermal power system, was calculated by the hourly analysis program for use in selecting optimum location-dependent parameters as discussed in Section 4 and Appendix E. The BBEC of the displaced purchased capacity ($BBEC_p$) was calculated using the expression

$$BBEC_p = \frac{\overline{G}_p \times C_c}{C x f x 8760} \tag{D-8}$$

where $\overline{G}_p$ = levelized purchased capacity cost, \$/kW-yr, computed as a series of recurrent costs

C_c = capacity credit of the solar thermal power system, MW

C = rated capacity of the solar thermal power system, MW

f = annual capacity factor of the solar thermal power system

The levelized purchased capacity cost was calculated assuming that purchases have a "life" equivalent to the life of the solar thermal power system.

* * * * *

APPENDIX E
SELECTION OF LOCATION-DEPENDENT PARAMETERS

For solar thermal power systems the optimum sizing of the storage subsystem, the collector field, and other components is dependent on the amount of insolation available at the plant site. Three location-dependent parameters which were sufficient to determine all other solar thermal power system characteristics of interest to the economic analysis were defined in this study. These include receiver intensity rating, storage time and solar multiple.

The receiver intensity rating was defined as the level of direct normal insolation at which the solar thermal power system reaches its maximum or rated thermal receiver power. This is a design parameter which influences the size of the collector field (and therefore the system cost) as well as the annual system capacity factor. A system with a higher receiver intensity rating requires a smaller collector area but cannot operate at rated capacity for as large a portion of the year as a system with a lower receiver intensity rating.

Storage time was defined as the length of time for which the energy storage subsystem is designed to deliver its rated capacity. A longer storage time increases the ability of the solar thermal power system to shave the utility's peak demand but it also increases the capital cost. A longer storage time does not directly increase the required collector area. However, a longer storage time is usually associated with a higher solar multiple which does increase the required collector area.

The solar multiple was defined as the ratio of the maximum available thermal receiver power to the thermal power corresponding to the rated electrical capacity of the solar thermal power system. Thus, the solar multiple is a measure of the amount of excess thermal power which may be devoted to charging thermal storage. For systems without thermal storage the solar multiple is one.

The criterion used for selection of location-dependent parameters was the minimum net life-cycle levelized busbar energy cost (BBEC). BBEC includes all capital-related costs (principal, interest, interim replacements, property taxes and insurance), operation and maintenance costs, and fuel costs over the life of the solar thermal power system. A discussion of the calculation of BBEC is included in Appendix D. The net BBEC was defined as the BBEC of the solar thermal power system less the BBEC of purchased capacity assumed to be displaced by the capacity credited to the solar thermal power system. The capacity credited to the solar thermal power system was some fraction of its rated capacity. This fraction was estimated from the expected ability of the solar thermal power system to reduce the system peak demand which must be met with conventional generating capacity and the expected impact of the solar thermal power system on the utility's system reliability.

To determine the minimum net BBEC, hourly analyses were performed for each solar thermal power system type for receiver intensity ratings of 0.7, 0.8, and 0.9 kW/m^2, storage times of 0, 1, 2, and 6 hours and solar multiples of 1.0, 1.5, 2.0 and 2.5, as appropriate. The analyses were also performed for three reference utilities representing the three different sets of hourly load patterns used in the study (see Section 3) and several different solar mixes (penetration of solar capacity into the total utility capacity requirement), as indicated below:

- 35-MW municipal with coal-fired generation with 5, 10 and 20 percent solar mixes.
- 35-MW municipal with oil-fired generation with 10 percent solar mix.
- 200-MW generation and transmission cooperative with 10 percent solar mix.

Several assumptions were made for all of the analyses. First, it was assumed that all of the reference utilities were located in the Southwestern United States and Albuquerque insolation data was used in all of the analyses. During sensitivity analyses (see Section 6) a similar optimization analysis was made for the South Central United States (Ft. Worth insolation). Second, all of the analyses were performed using hourly load patterns for three weeks and hourly insolation patterns for three days to represent the summer, winter, and spring/fall seasons. Third, for all of the analyses a hypothetical capacity requirement (peak demand plus reserves) of 100 MW was assumed since the hourly analysis results depend only on the load shape and not on the absolute load level. Thus, for a 5 percent solar mix the rated solar capacity is 5 MW, for a 10 percent solar mix the rated solar capacity is 10 MW, etc. This assumption made it possible to perform only one set of analyses for the three different parabolic dish concentrator systems.

RESULTS FOR PARABOLIC DISH CONCENTRATOR SYSTEMS

The results of the optimization analyses for the parabolic dish concentrator systems are shown in Tables E-1 through E-5. It should be noted that the results shown in these tables do not necessarily represent all analyses which were performed, but a sufficient number of results is shown to indicate the trends which were found in the analyses.

The first three columns in each table show the location-dependent parameters and the fourth column shows an additional input variable, the peak-shaving planning factor. As discussed in Appendix D the peak-shaving planning factor was multiplied by the predicted daily energy prior to the establishment of a commitment schedule in order to establish a more conservative dispatching plan. The impact of the peak-shaving planning factor as well as that of the location-dependent parameters is discussed below.

The next three columns show the required collector area for the given location-dependent parameters (calculated using equation D-4), the annual capacity factor of the solar thermal power system based on its rated capacity, and the capacity credit which is calculated by the hourly analysis program. This capacity credit is simply the difference in the system peak before and after the dispatch of the solar thermal power system.

Table E-1

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
PARABOLIC DISH CONCENTRATOR SYSTEMS, 10% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Peak-Shaving Planning Factor	Required Collector Area [b] (km^2)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh) Of Solar Thermal Power System [d]	Of Displaced Purchased Capacity [e]	Net [f]
0	1.0	0.7	–	0.05115	0.4296	1.90	1.00	40.21	3.77	36.44
0	1.0	0.8	–	0.04476	0.4136	1.89	1.00	38.73	3.90	34.83
0	1.0	0.9	–	0.03978	0.3894	1.88	0.99	38.36	4.13	34.23
1	1.0	0.7	0.85	0.05115	0.4157	5.25	2.77	43.23	10.78	32.45
1	1.0	0.8	0.85	0.04476	0.3998	5.25	2.77	41.81	11.21	30.60
1	1.0	0.9	0.85	0.03978	0.3710	2.32	1.22	42.04	5.32	36.72
2	1.0	0.7	0.75	0.05115	0.4019	9.38	4.95	46.46	19.92	26.54
2	1.0	0.8	0.75	0.04476	0.3859	9.05	4.77	45.12	19.99	25.13
2	1.0	0.9	0.75	0.03978	0.3571	5.72	3.02	45.63	13.68	31.95
2	1.0	0.7	0.85	0.05115	0.4019	9.38	4.95	46.46	19.92	26.54
2	1.0	0.8	0.85	0.04476	0.3859	9.05	4.77	45.12	19.99	25.13
2	1.0	0.9	0.85	0.03978	0.3571	5.70	3.01	45.63	13.63	32.00
2	1.0	0.7	0.95	0.05115	0.4019	9.38	4.95	46.46	19.92	26.54
2	1.0	0.8	0.95	0.04476	0.3859	9.05	4.77	45.12	19.99	25.13
2	1.0	0.9	0.95	0.03978	0.3571	5.34	2.82	45.63	12.77	32.86
6	1.0	0.7	0.85	0.05115	0.3732	10.00	5.28	58.13	22.88	35.25
6	1.0	0.8	0.85	0.04476	0.3577	10.00	5.28	57.16	23.88	33.28
6	1.0	0.9	0.85	0.03978	0.3295	10.00	5.28	58.67	25.92	32.75
6	1.0	0.7	0.95	0.05115	0.3848	10.00	5.28	56.65	22.19	34.46
6	1.0	0.8	0.95	0.04476	0.3701	10.00	5.28	55.54	23.08	32.46
6	1.0	0.9	0.95	0.03978	0.3434	10.00	5.28	56.64	24.87	31.77

[a] *Assumes a location in the Southwestern United States (Albuquerque insolation).*

[b] *Based on a rated capacity of 10 MW.*

[c] *Adjusted capacity credit = capacity credit x .528. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-2

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
PARABOLIC DISH CONCENTRATOR SYSTEMS, 5% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Peak-Shaving Planning Factor	Required Collector Area [b] (km^2)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh)		
								Of Solar Thermal Power System [d]	Of Displaced Purchased Capacity [e]	Net [f]
0	1.0	0.7	—	0.02557	0.4296	1.87	1.25	40.21	9.41	30.80
0	1.0	0.8	—	0.02238	0.4136	1.87	1.25	38.78	9.78	29.00
0	1.0	0.9	—	0.01989	0.3894	1.87	1.24	38.36	10.30	28.06
1	1.0	0.7	0.85	0.02557	0.4157	4.88	3.25	43.23	25.29	17.94
1	1.0	0.8	0.85	0.02238	0.3998	3.75	2.50	41.81	20.23	21.58
1	1.0	0.9	0.85	0.01989	0.3710	2.07	1.38	42.04	12.03	30.01
2	1.0	0.7	0.85	0.02557	0.4019	5.00	3.33	46.46	26.80	19.66
2	1.0	0.8	0.85	0.02238	0.3859	5.00	3.33	45.12	27.91	17.21
2	1.0	0.9	0.85	0.01989	0.3583	5.00	3.33	45.51	30.07	15.44
6	1.0	0.7	0.95	0.02557	0.3832	5.00	3.33	56.84	28.11	28.73
6	1.0	0.8	0.95	0.02238	0.3683	5.00	3.33	55.76	29.25	26.51
6	1.0	0.9	0.95	0.01989	0.3418	5.00	3.33	56.87	31.52	25.35

[a] *Assumes a location in the Southwestern United States (Albuquerque insolation).*

[b] *Based on a rated capacity of 5 MW.*

[c] *Adjusted capacity credit = capacity credit x .667. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-3

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
PARABOLIC DISH CONCENTRATOR SYSTEMS, 20% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Peak-Shaving Planning Factor	Required Collector Area [b] (km^2)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh)		
								Of Solar Thermal Power System [d]	Of Displaced Purchased Capacity [e]	Net [f]
0	1.0	0.7	—	0.10230	0.4296	1.94	0.87	40.21	1.64	38.51
0	1.0	0.8	—	0.08951	0.4136	1.93	0.87	38.73	1.70	37.03
0	1.0	0.9	—	0.07956	0.3894	1.92	0.86	38.36	1.79	36.57
1	1.0	0.7	0.75	0.10230	0.4157	5.25	2.36	43.23	4.59	38.64
1	1.0	0.8	0.75	0.08951	0.3998	5.25	2.36	41.81	4.77	37.04
1	1.0	0.9	0.75	0.07956	0.3710	5.25	2.36	42.04	5.14	36.89
2	1.0	0.7	0.75	0.10230	0.4019	9.38	4.22	46.46	8.49	37.97
2	1.0	0.8	0.75	0.08951	0.3859	9.38	4.22	45.12	8.84	36.27
2	1.0	0.9	0.75	0.07956	0.3571	9.38	4.22	45.63	9.56	36.07
2	1.0	0.7	0.85	0.10230	0.3670	20.00	9.00	58.97	19.83	39.13
6	1.0	0.8	0.85	0.08951	0.3523	20.00	9.00	57.89	20.66	37.23
6	1.0	0.9	0.85	0.07956	0.3271	20.00	9.00	59.03	22.25	36.73

[a] *Assumes a location in the Southwestern United States (Albuquerque insolation).*

[b] *Based on a rated capacity of 20 MW.*

[c] *Adjusted capacity credit = capacity credit x .450. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-4

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
PARABOLIC DISH CONCENTRATOR SYSTEMS, 10% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m²)	Peak-Shaving Planning Factor	Required Collector Area [b] (km²)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh) Of Solar Thermal Power System [d]	Busbar Energy Cost (mills/kWh) Of Displaced Purchased Capacity [e]	Busbar Energy Cost (mills/kWh) Net [f]
0	1.0	0.7	–	0.05115	0.4296	0	0	40.21	0	40.21
0	1.0	0.8	–	0.04476	0.4136	0	0	38.73	0	38.73
0	1.0	0.9	–	0.03978	0.3894	0	0	38.36	0	38.36
1	1.0	0.7	0.85	0.05115	0.4157	2.43	1.28	43.23	4.98	38.25
1	1.0	0.8	0.85	0.04476	0.3998	2.43	1.28	41.81	5.18	36.63
1	1.0	0.9	0.85	0.03978	0.3753	2.43	1.28	41.66	5.52	36.14
2	1.0	0.7	0.75	0.05115	0.4034	4.38	2.31	46.31	9.26	37.05
2	1.0	0.8	0.75	0.04476	0.3884	4.38	2.31	44.91	9.62	35.29
2	1.0	0.9	0.75	0.03978	0.3644	6.02	3.18	44.89	14.12	30.77
2	1.0	0.7	0.85	0.05115	0.4020	4.38	2.31	46.45	9.29	37.16
2	1.0	0.8	0.85	0.04476	0.3862	4.38	2.31	45.10	9.67	35.43
2	1.0	0.9	0.85	0.03978	0.3623	4.38	2.31	45.10	10.31	34.79
6	1.0	0.7	0.85	0.05115	0.3718	9.88	5.22	58.53	22.71	35.62
6	1.0	0.8	0.85	0.04476	0.3564	9.43	4.98	57.33	22.60	34.73
6	1.0	0.9	0.85	0.03978	0.3294	9.43	4.98	58.68	24.45	34.23
6	1.0	0.7	0.95	0.05115	0.3890	8.77	4.63	56.13	19.25	36.88
6	1.0	0.8	0.95	0.04476	0.3735	8.77	4.63	55.10	20.05	35.05
6	1.0	0.9	0.95	0.03978	0.3476	6.89	3.64	56.06	16.89	39.17

[a] *Assumes a location in the Southwestern United States (Albuquerque insolation).*

[b] *Based on a rated capacity of 10 MW.*

[c] *Adjusted capacity credit = capacity credit x .528. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-5

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
200-MW GENERATION & TRANSMISSION COOPERATIVE
PARABOLIC DISH CONCENTRATOR SYSTEMS, 10% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Peak-Shaving Planning Factor	Required Collector Area [b] (km^2)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh)		
								Of Solar Thermal Power System [d]	Of Displaced Purchased Capacity [e]	Net [f]
0	1.0	0.7	—	0.05115	0.4296	0	0	39.61	0	39.61
0	1.0	0.8	—	0.04476	0.4136	0	0	37.88	0	37.88
0	1.0	0.9	—	0.03978	0.3894	0	0	37.36	0	37.36
1	1.0	0.7	0.85	0.05115	0.4157	0.45	0.24	42.58	0.68	41.90
1	1.0	0.8	0.85	0.04476	0.3998	0	0	40.91	0	40.91
1	1.0	0.9	0.85	0.03978	0.3709	0	0	40.99	0	40.99
2	1.0	0.7	0.75	0.05115	0.4020	8.12	4.28	38.04	12.71	25.33
2	1.0	0.8	0.75	0.04476	0.3860	7.31	3.86	35.55	11.94	23.61
2	1.0	0.9	0.75	0.03978	0.3572	6.69	3.53	33.62	11.80	21.82
2	1.0	0.7	0.85	0.05115	0.4020	8.12	4.28	45.74	12.71	33.03
2	1.0	0.8	0.85	0.04476	0.3860	6.68	3.52	44.15	10.89	33.26
2	1.0	0.9	0.85	0.03978	0.3572	6.69	3.53	44.49	11.80	32.69
6	1.0	0.7	0.85	0.05115	0.3704	8.18	4.32	44.24	13.93	30.31
6	1.0	0.8	0.85	0.04476	0.3546	8.18	4.32	41.76	14.55	27.21
6	1.0	0.9	0.85	0.03978	0.3286	8.18	4.32	39.83	15.70	24.13
6	1.0	0.7	0.95	0.05115	0.3867	8.18	4.32	55.32	13.34	41.98
6	1.0	0.8	0.95	0.04476	0.3719	8.18	4.32	53.92	13.87	40.05
6	1.0	0.9	0.95	0.03978	0.3451	8.18	4.32	54.82	14.95	39.87

[a] *Assumes a location in the Southwestern United States (Albuquerque insolation).*

[b] *Based on a rated capacity of 10 MW.*

[c] *Adjusted capacity credit = capacity credit x .528. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

The adjusted capacity credit shown in the eighth column represents an attempt to approximate the actual capacity credit which would be used in the study after the reliability analysis as well as the hourly analysis had been performed. An approximation was necessary because actual values for capacity credit could not be established until the optimum location-dependent parameters were selected. The procedure used to adjust the capacity credits calculated by the hourly analysis program was to multiply each value by a constant which was chosen so that none of the adjusted capacity credits would exceed the value for the appropriate category shown in Table E-6. The values in Table E-6 reflect the results of a capacity credit analysis performed by Southern California Edison Company (8). The values shown in this table closely approximated the capacity credit values determined in the capacity credit analysis which was performed as a part of this study (see Appendix F).

Table E-6

CAPACITY CREDIT AS A FUNCTION
OF STORAGE TIME AND SOLAR MIX

Storage Time (hours)	Capacity Credit (% of Rated Capacity)		
	5% Solar Mix	10% Solar Mix	20% Solar Mix
0	30	1C	8
1	65	35	20
2	70	50	35
6	80	60	45

The last three columns show the life-cycle levelized busbar energy cost (BBEC) of the solar thermal power system, the busbar energy cost of the purchased capacity displaced by the adjusted capacity credit credit of the solar thermal power system and the net busbar energy cost (BBEC of solar thermal power system less BBEC of displaced purchased capacity). The method used to calculate the busbar energy cost is discussed in Appendix D.

In a sense, the net BBEC is a measure of the cost advantage or penalty of the solar thermal power system relative to purchased power over the life of the solar thermal plant. However, to be a complete measure of such an advantage or penalty the value of the purchased energy displaced as well as the purchased capacity displaced would have to be subtracted from BBEC of the solar thermal power system. This step was omitted for simplicity because the value of the purchased energy displaced is a constant and would have had no impact on the ranking of the various configurations analyzed.

A final comment is in order with regard to the busbar energy costs shown on these tables. The costs for the solar thermal power systems include only solar hardware (collector, transport, conversion and storage subsystems) costs. None of the site preparation, overhead or other costs were included. This was necessary because these other costs were not calculated until an optimum solar thermal power system configuration had been selected. Therefore, these busbar energy costs are useful only as comparative and not as absolute values.

Looking at the results in Table E-1 for the 35-MW municipal with coal-fired generation and a 10 percent penetration of parabolic dish concentrator systems, several trends can be seen. As expected, a longer storage time generally results in a higher capacity credit but a lower annual capacity factor for a given receiver intensity rating. A higher receiver intensity rating results in a smaller required collector area for a given storage time but it also generally results in a lower annual capacity factor and a lower capacity credit.

The impact of the peak-shaving planning factor varies depending upon the amount of storage and the receiver intensity rating. With 2 hours of storage and receiver intensity ratings of 0.7 or 0.8 kW/m^2, the differences in peak-shaving planning factor have no impact on the quantities shown. However, for 2 hours storage and a receiver intensity rating of 0.9 kW/m^2, the capacity credit decreases with increasing values of the peak-shaving planning factor. This indicates that for a relatively small amount of storage and a high receiver intensity rating, a commitment schedule which calls for the dispatch of nearly all of the energy which is expected to be available from the solar thermal power system during the day may result in too little energy remaining for dispatch on peak. For the 6-hour storage cases, on the other hand, the capacity factor increases and the capacity credit remains constant as the

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value of the peak-shaving planning factor increases, for all values of receiver intensity rating. This indicates that with enough storage a higher value of peak-shaving planning factor may increase the amount of energy obtained from the solar thermal power system with reducing its capacity credit.

A comparison of the results in Table E-2 for a 5 percent solar mix to those in Table E-1 for a 10 percent solar mix indicates that the primary impact of the solar mix is on the amount of capacity credit (relative to rated solar capacity). Capacity factor is relatively insensitive to changes in solar mix, and the trends noted in Table E-1 are also evident in Table E-2. Similar observations can be made with regard to the results shown in Table E-3 for a 20 percent solar mix.

Tables E-4 and E-5 show results for a 10 percent penetration of the parabolic dish concentrator system into the generation mix of the 35-MW municipal with oil-fired generation and the 200-MW generation and transmission cooperative, respectively. As far as the hourly analysis model is concerned, the primary difference among these reference utilities is the shape of their hourly load patterns. A comparison of the results in Tables E-4 and E-5 with those in Table E-1 indicates that the annual capacity factor of the parabolic dish concentrator system is relatively insensitive to load pattern, but that capacity credit may be quite sensitive to load pattern. The 35-MW municipal with coal-fired generation was assumed to have a fairly sharp peak relatively early in the day compared to relatively flat peaks which do not decline until late in the day for the 35-MW municipal with oil-fired generation and the 200-MW generation and transmission cooperative (see Figures 3-1 through 3-3 in Section 3 for illustrations of the load patterns assumed for each reference utility).

Table E-7 summarizes the optimum location-dependent parameters for each of the scenarios which were examined and the location-dependent parameters which were selected for use in the study.

Table E-7

SUMMARY OF OPTIMUM LOCATION-DEPENDENT PARAMETERS PARABOLIC DISH CONCENTRATOR SYSTEMS

Scenario	Receiver Intensity Rating (kW/m^2)	Storage Time (Hours)	Solar Multiple
35-MW Municipal with Coal-Fired Generation, 5% Solar Mix	.8	2	1
35-MW Municipal with Coal-Fired Generation, 10% Solar Mix	.9	2	1
35-MW Municipal with Coal-Fired Generation, 20% Solar Mix	.9	2	1
35-MW Municipal with Oil-Fired Generation, 10% Solar Mix	.9	2	1
200-MW Generation & Transmission Cooperative, 10% Solar Mix	.9	2	1
Values Used in Study	.9	2	1

RESULTS FOR VARIABLE SLAT CONCENTRATOR SYSTEM

The results of the optimization analyses for the variable slat concentrator system are shown in Table E-8 through E-12. These tables are similar in format to Table E-1 through E-5 except that the peak-shaving planning factor, which is not relevant for this system, is omitted.

In general, the trends observed for the parabolic dish concentrator systems are also present for the variable slat concentrator system. A higher receiver intensity rating results in a smaller collector area for a given storage time and solar multiple but it generally also results in a lower annual capacity factor and capacity credit. A longer storage time results in a higher capacity credit for a given receiver intensity rating and solar multiple.

Unlike the parabolic dish concentrator systems, however, a longer storage time generally also results in a higher annual capacity factor for a given receiver intensity rating and solar multiple. This difference can be accounted for by the difference in the type of storage available to each system and the resultant dispatching strategies.

The parabolic dish concentrator system has an advanced battery storage system. As discussed in Section 2, it was assumed that none of the parabolic dish modules would be devoted exclusively to charging storage. Therefore, a peak-shaving dispatching strategy, which attempts to allocate the total electricity generated between direct delivery to the transmission grid and storage for later delivery to the grid in order to minimize the system peak demand which must be met by other generating resources, was used for this system. One consequence of this type of dispatching strategy is that a less than perfect prediction of future loads and future insolation will result in the loss of some energy which could have been utilized if a perfect prediction had been made. It is likely this imperfection in the dispatching strategy which results in lower annual capacity factors with longer storage times.

Table E-8

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
VARIABLE SLAT CONCENTRATOR SYSTEM, 10% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Required Collector Area [b] (km^2)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh)		
							Of Solar Thermal Power System [d]	Of Displaced Purchased Capacity [e]	Net [f]
0	1.0	0.7	0.09529	0.4144	1.89	1.00	56.89	3.90	52.99
0	1.0	0.8	0.08387	0.3935	1.89	1.00	54.71	4.11	50.60
0	1.0	0.9	0.07455	0.3827	1.88	1.00	52.21	4.23	47.98
1	1.5	0.7	0.14378	0.4740	5.63	2.98	67.37	10.16	57.21
1	1.5	0.8	0.12581	0.4645	5.58	2.95	62.55	10.27	52.28
1	1.5	0.9	0.11183	0.4569	5.53	2.92	58.69	10.33	48.35
2	1.5	0.7	0.14378	0.5026	8.85	4.68	64.79	15.06	49.73
2	1.5	0.8	0.12581	0.4931	7.86	4.15	60.20	13.61	46.59
2	1.5	0.9	0.11183	0.4730	7.00	3.70	57.79	12.65	45.14
2	2.0	0.7	0.19170	0.5072	8.85	4.68	78.98	14.92	64.06
2	2.0	0.8	0.16774	0.5072	8.85	4.68	71.64	14.92	56.72
2	2.0	0.9	0.14910	0.5040	8.85	4.68	66.28	15.02	51.26
6	1.5	0.7	0.14378	0.5781	8.85	4.68	60.40	13.09	47.02
6	1.5	0.8	0.12581	0.5410	7.86	4.15	58.47	12.40	46.07
6	1.5	0.9	0.11183	0.4943	7.00	3.70	58.77	12.10	45.73
6	2.0	0.7	0.19170	0.6215	8.85	4.68	68.53	12.18	56.35
6	2.0	0.8	0.16774	0.6214	8.85	4.68	62.53	12.18	50.35
6	2.0	0.9	0.14910	0.6016	8.85	4.68	58.52	12.58	45.94
6	2.5	0.7	0.29363	0.6216	8.85	4.68	80.51	12.17	68.34
6	2.5	0.8	0.20968	0.6215	8.85	4.68	73.02	12.18	60.84
6	2.5	0.9	0.18638	0.6214	8.85	4.68	67.20	12.18	55.02

[a] *Assumes a location in the Southwestern Unites States (Albuquerque insolation).*

[b] *Based on a rated capacity of 10 MW.*

[c] *Adjusted capacity credit = capacity credit x .528. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-9

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
VARIABLE SLAT CONCENTRATOR SYSTEM, 5% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Required Collector Area [b] (km^2)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh) Of Solar Thermal Power System [d]	Of Displaced Purchased Capacity [e]	Net [f]
0	1.0	0.7	0.04793	0.4127	1.87	1.22	57.08	9.56	47.52
0	1.0	0.8	0.04194	0.3919	1.87	1.21	54.90	9.98	44.92
0	1.0	0.9	0.03728	0.3827	1.87	1.21	52.21	10.22	41.99
1	1.5	0.7	0.07189	0.4740	4.49	2.92	67.37	19.92	47.45
1	1.5	0.8	0.06290	0.4645	3.93	2.55	62.55	17.76	44.79
1	1.5	0.9	9.95581	0.4569	3.50	2.28	58.68	16.14	42.54
2	1.5	0.7	0.07189	0.5026	4.49	2.92	64.79	18.78	47.01
2	1.5	0.8	0.06290	0.4931	3.93	2.55	60.20	16.72	43.48
2	1.5	0.9	0.05591	0.4730	3.50	2.28	57.79	15.59	42.20
2	2.0	0.7	0.09585	0.5072	5.00	3.25	78.98	20.72	58.26
2	2.0	0.8	0.08387	0.5072	5.00	3.25	71.64	20.72	50.92
2	2.0	0.9	0.07455	0.5040	4.66	3.03	66.28	19.44	46.84
6	1.5	0.7	0.07189	0.5769	4.49	2.92	60.22	16.36	43.86
6	1.5	0.8	0.06290	0.5410	3.93	2.55	58.47	15.25	43.22
6	1.5	0.9	0.05591	0.4943	3.50	2.28	58.77	14.92	43.85
6	2.0	0.7	0.09585	0.6215	5.00	3.25	68.53	16.92	51.61
6	2.0	0.8	0.08387	0.6214	5.00	3.25	62.53	16.92	45.61
6	2.0	0.9	0.07455	0.6016	4.66	3.03	59.49	16.29	43.20
6	2.5	0.7	0.11981	0.6216	5.00	3.25	80.51	16.91	63.60
6	2.5	0.8	0.10484	0.6215	5.00	3.25	73.02	16.92	56.10
6	2.5	0.9	0.09319	0.6214	5.00	3.25	67.20	16.92	50.28

[a] *Assumes a location in the Southwestern Unites States (Albuquerque insolation).*

[b] *Based on a rated capacity of 5 MW.*

[c] *Adjusted capacity credit = capacity credit x .650. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-10

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS[a]
35-MW MUNICIPAL WITH COAL-FIRED GENERATION
VARIABLE SLAT CONCENTRATOR SYSTEM, 20% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Required Collector Area[b] (km^2)	Capacity Factor[b] (Per Unit)	Capacity Credit[b] (MW)	Adjusted Capacity Credit[c] (MW)	Busbar Energy Cost (mills/kWh)		
							Of Solar Thermal Power System[d]	Of Displaced Purchased Capacity[e]	Net[f]
0	1.0	0.7	0.19170	0.4152	1.93	1.10	56.80	2.14	54.66
0	1.0	0.8	0.16774	0.3943	1.92	1.09	54.61	2.24	52.37
0	1.0	0.9	0.14910	0.3827	1.92	1.09	52.21	2.31	49.90
1	1.5	0.7	0.28755	0.4740	6.00	3.41	67.37	5.82	61.55
1	1.5	0.8	0.25161	0.4645	5.91	3.36	62.55	5.85	56.70
1	1.5	0.9	0.22365	0.4569	5.81	3.30	58.68	5.84	52.84
2	1.5	0.7	0.28755	0.5026	10.13	5.75	64.79	9.25	55.54
2	1.5	0.8	0.25161	0.4931	10.04	5.70	60.20	9.35	50.85
2	1.5	0.9	0.22365	0.4730	9.45	5.37	57.79	9.18	48.61
2	2.0	0.7	0.38341	0.5072	10.38	5.89	78.98	9.39	69.59
2	2.0	0.8	0.33548	0.5072	10.26	5.82	71.64	9.28	62.36
2	2.0	0.9	0.29805	0.5040	10.16	5.77	66.28	9.26	57.02
6	1.5	0.7	0.28755	0.5788	15.85	9.00	60.06	12.57	55.57
6	1.5	0.8	0.25161	0.5529	15.72	8.93	57.40	13.06	49.49
6	1.5	0.9	0.22365	0.4943	14.00	7.95	58.77	13.01	45.76
6	2.0	0.7	0.38341	0.6215	15.85	9.00	68.53	11.71	56.82
6	2.0	0.8	0.33548	0.6214	15.85	9.00	62.53	11.71	50.82
6	2.0	0.9	0.29805	0.6016	15.85	9.00	59.49	12.10	47.39
6	2.5	0.7	0.47926	0.6216	15.85	9.00	80.51	11.71	68.80
6	2.5	0.8	0.41935	0.6215	15.85	9.00	73.02	11.71	61.31
6	2.5	0.9	0.37276	0.6214	15.85	9.00	67.20	11.71	55.49

[a] *Assumes a location in the Southwestern Unites States (Albuquerque insolation).*

[b] *Based on a rated capacity of 20 MW.*

[c] *Adjusted capacity credit = capacity credit x .568. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-11

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS [a]
35 MW MUNICIPAL WITH OIL-FIRED GENERATION
VARIABLE SLAT CONCENTRATOR SYSTEM, 10% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Required Collector Area [b] (km^2)	Capacity Factor [b] (Per Unit)	Capacity Credit [b] (MW)	Adjusted Capacity Credit [c] (MW)	Busbar Energy Cost (mills/kWh)		
							Of Solar Thermal Power System [d]	Of Displaced Purchased Capacity [e]	Net [f]
0	1.0	0.7	0.09585	0.4144	0	0	56.89	0	56.89
0	1.0	0.8	0.08387	0.3935	0	0	54.71	0	54.71
0	1.0	0.9	0.07455	0.3827	0	0	52.21	0	52.21
1	1.5	0.7	0.14378	0.4740	0	0	67.37	0	67.37
1	1.5	0.8	0.12581	0.4645	0	0	62.55	0	62.55
1	1.5	0.9	0.11183	0.4569	0	0	58.68	0	58.68
2	1.5	0.7	0.14378	0.5026	2.43	1.28	64.79	4.12	60.67
2	1.5	0.8	0.12581	0.4931	2.43	1.28	60.20	4.20	56.00
2	1.5	0.9	0.11183	0.4730	2.43	1.28	57.79	4.38	53.41
2	2.0	0.7	0.19170	0.5072	2.43	1.28	78.98	4.08	74.90
2	2.0	0.8	0.16774	0.5072	2.43	1.28	71.64	4.08	67.56
2	2.0	0.9	0.14910	0.5040	2.43	1.28	66.28	4.11	62.17
6	1.5	0.7	0.14378	0.5781	7.00	3.70	60.11	10.35	49.76
6	1.5	0.8	0.12581	0.5410	5.62	2.97	58.47	8.88	49.59
6	1.5	0.9	0.11183	0.4943	3.06	1.62	58.77	5.30	53.47
6	2.0	0.7	0.19170	0.6215	7.00	3.70	68.53	9.63	58.90
6	2.0	0.8	0.16774	0.6214	7.00	3.70	62.53	9.63	52.90
6	2.0	0.9	0.14910	0.6016	7.00	3.70	58.52	9.95	48.57
6	2.5	0.7	0.23963	0.6216	7.00	3.70	80.51	9.63	70.88
6	2.5	0.8	0.20968	0.6215	7.00	3.70	73.02	9.63	63.39
6	2.5	0.9	0.18638	0.6214	7.00	3.70	67.20	9.63	57.57

[a] *Assumes a location in the Southwestern Unites States (Albuquerque insolation).*

[b] *Based on a rated capacity of 10 MW.*

[c] *Adjusted capacity credit = capacity credit x .528. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Table E-12

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS[a]
200 MW GENERATION & TRANSMISSION COOPERATIVE
VARIABLE SLAT CONCENTRATOR SYSTEM, 10% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Required Collector Area[b] (km^2)	Capacity Factor[b] (Per Unit)	Capacity Credit[b] (MW)	Adjusted Capacity Credit[c] (MW)	Busbar Energy Cost (mills/kWh)		
							Of Solar Thermal Power System[d]	Of Displaced Purchased Capacity[e]	Net[f]
0	1.0	0.7	0.09585	0.4144	0.21	0.11	59.51	0.31	59.20
0	1.0	0.8	0.08387	0.3935	0.18	0.10	57.06	0.30	56.76
0	1.0	0.9	0.07455	0.3827	0.16	0.09	54.28	0.28	54.00
1	1.5	0.7	0.14378	0.4740	0.38	0.20	71.20	0.51	70.69
1	1.5	0.8	0.12580	0.4645	0.33	0.17	65.84	0.43	65.41
1	1.5	0.9	0.11183	0.4569	0.28	0.15	61.54	0.39	61.15
2	1.5	0.7	0.14378	0.5026	6.24	3.31	68.37	7.86	60.51
2	1.5	0.8	0.12580	0.4931	6.20	3.28	63.26	7.94	55.32
2	1.5	0.9	0.11183	0.4730	5.90	3.12	60.56	7.88	52.68
2	2.0	0.7	0.19170	0.5072	6.37	3.38	84.13	7.96	76.17
2	2.0	0.8	0.16774	0.5072	6.31	3.34	75.98	7.86	68.12
2	2.0	0.9	0.14910	0.5040	6.26	3.32	70.02	7.87	62.15
6	1.5	0.7	0.14378	0.5781	7.00	3.70	63.21	7.63	55.58
6	1.5	0.8	0.12580	0.5410	7.00	3.70	61.66	8.17	53.49
6	1.5	0.9	0.11183	0.4943	7.00	3.70	61.66	8.94	52.72
6	2.0	0.7	0.19170	0.6215	7.00	3.70	72.59	7.10	65.49
6	2.0	0.8	0.16774	0.6214	7.00	3.70	65.93	7.10	58.83
6	2.0	0.9	0.14910	0.6016	7.00	3.70	61.46	7.34	54.12
6	2.5	0.7	0.23963	0.6216	7.00	3.70	85.90	7.09	78.81
6	2.5	0.8	0.20968	0.6215	7.00	3.70	77.58	7.10	70.48
6	2.5	0.9	0.18638	0.6214	7.00	3.70	71.11	7.10	64.01

[a] *Assumes a location in the Southwestern Unites States (Albuquerque insolation).*

[b] *Based on a rated capacity of 10 MW.*

[c] *Adjusted capacity credit = capacity credit x .528. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

The variable slat concentrator system, on the other hand, has a thermal storage system. With thermal storage, energy in excess of that necessary to generate the system's rated electrical power is sent to storage. Further, this system utilizes sun-following dispatching which maximizes the energy output of the solar thermal power system. Therefore, for this system a longer storage time is an advantage in terms of annual capacity factor as long as the system has a large enough collector area to insure the efficient utilization of storage.

The impact of a higher solar multiple is to increase the storage area and, up to a point, to increase the annual capacity factor and capacity credit for a given storage time and receiver intensity rating. It is evident, however, that beyond some point an increase in solar multiple without a corresponding increase in storage time provides no benefit in terms of capacity factor or capacity credit. This is not surprising, since the solar multiple is a measure of the amount of "excess" thermal power available for storage. If there is insufficient storage capacity to utilize this "excess" power then no benefit can accrue.

Looking at Tables E-9 and E-10, it can be seen that the primary impact of lesser or greater solar mixes is relatively greater or lesser capacity credit, respectively. As was the case for the parabolic dish concentrator systems, all other trends are unchanged as the solar mix varies.

Looking at Tables E-11 and E-12, the primary difference in the results for the 35-MW municipal with oil-fired generation and the 200-MW generation and transmission cooperative relative to those for the 35-MW municipal with coal-fired generation is a lower capacity credit as a result of the differences in load patterns.

The optimum location-dependent parameters for the variable slat concentrator system are summarized in Table E-13 for the scenarios discussed above. Also, shown in Table E-13 are the location-dependent parameters selected for use in the study for this system.

Table E-13

SUMMARY OF OPTIMUM LOCATION-DEPENDENT PARAMETERS VARIABLE SLAT CONCENTRATOR SYSTEM

Scenario	Receiver Intensity Rating (kW/m^2)	Storage Time (Hours)	Solar Multiple
35-MW Municipal with Coal-Fired Generation, 5% Solar Mix	.9	2	1.5
35-MW Municipal with Coal-Fired Generation, 10% Solar Mix	.9	2	1.5
35-MW Municipal with Coal-Fired Generation, 20% Solar Mix	.9	6	1.5
35-MW Municipal with Oil-Fired Generation, 10% Solar Mix	.9	6	2.0
200-MW Generation & Transmission Cooperative, 10% Solar Mix	.9	2	1.5
Values Used in Study	.9	2	1.5

RESULTS FOR CENTRAL RECEIVER SYSTEM

Location-dependent parameters for the central receiver system were only examined for the 200-MW generation and transmission cooperative since this was the only reference utility to which this system type was applicable. The results of this analysis are shown in Table E-14.

The trends seen in Table E-14 are similar to the trends observed for the variable slat concentrator system. As the storage time increases both the annual capacity factor and the capacity credit increase for a given receiver intensity rating and storage time. As the solar multiple increases the collector area increases and the capacity credit and annual capacity factor increase and then level off for a given storage time and receiver intensity rating. As the receiver intensity rating increases the collector area, the annual capacity factor and the capacity credit all decrease.

The values used in the study for the location-dependent parameters were the optimum values shown in Table E-14: storage time = 2 hours, solar multiple = 1.5, receiver intensity rating = 0.8 kW/m^2.

* * * * *

Table E-14

ANALYSIS OF LOCATION-DEPENDENT PARAMETERS[a]
200-MW GENERATION & TRANSMISSION COOPERATIVE
CENTRAL RECEIVER SYSTEM, 10% SOLAR MIX
(All Dollar Values in 1975 Dollars)

Storage Time (Hrs.)	Solar Multiple	Receiver Intensity Rating (kW/m^2)	Required Collector Area[b] (km^2)	Capacity Factor[b] (Per Unit)	Capacity Credit[b] (MW)	Adjusted Capacity Credit[c] (MW)	Busbar Energy Cost (mills/kWh)		
							Of Solar Thermal Power System[d]	Of Displaced Purchased Capacity[e]	Net[f]
0	1.0	0.7	0.06426	0.4144	0.21	0.11	45.91	0.31	45.60
0	1.0	0.8	0.05623	0.3935	0.18	0.10	45.01	0.30	44.71
0	1.0	0.9	0.04998	0.3827	0.16	0.09	43.71	0.28	43.43
1	1.5	0.7	0.09640	0.4740	0.38	0.20	51.78	0.51	51.27
1	1.5	0.8	0.08435	0.4645	0.33	0.17	48.91	0.43	48.48
1	1.5	0.9	0.07497	0.4562	0.28	0.15	46.67	0.39	46.28
2	1.5	0.7	0.09640	0.4993	6.24	3.31	50.33	7.92	42.41
2	1.5	0.8	0.08435	0.4729	5.92	3.13	49.05	7.90	41.15
2	1.5	0.9	0.07497	0.4494	2.79	1.48	48.23	3.93	44.30
2	2.0	0.7	0.12853	0.5072	6.37	3.38	58.93	7.96	50.97
2	2.0	0.8	0.11246	0.5072	6.31	3.34	54.30	7.86	46.44
2	2.0	0.9	0.09997	0.5040	6.26	3.32	50.96	7.87	43.09
6	1.5	0.7	0.09640	0.5021	7.00	3.70	53.47	8.80	44.67
6	1.5	0.8	0.08435	0.4856	6.69	3.70	51.43	9.10	42.33
6	1.5	0.9	0.07497	0.4494	2.79	1.48	52.01	3.93	48.08
6	2.0	0.7	0.12853	0.5718	7.00	3.70	55.98	7.73	48.25
6	2.0	0.8	0.11246	0.5584	7.00	3.70	52.95	7.91	45.04
6	2.0	0.9	0.09997	0.5313	7.00	3.70	51.87	8.31	43.55
6	2.5	0.7	0.16066	0.5831	7.00	3.70	63.09	7.58	55.51
6	2.5	0.8	0.14058	0.5777	7.00	3.70	58.53	7.65	50.88
6	2.5	0.9	0.12496	0.5700	7.00	3.70	55.22	7.75	47.47

[a] *Assumes a location in the Southwestern Unites States (Albuquerque insolation).*

[b] *Based on a rated capacity of 10 MW.*

[c] *Adjusted capacity credit = capacity credit x .528. See page E-3 for discussion of reason for adjustment to capacity credit.*

[d] *Calculated using Equation D-7 (see Appendix D).*

[e] *Calculated using Equation D-8 and adjusted capacity credit (see Appendix D).*

[f] *Busbar energy cost of solar thermal power system less busbar energy cost of displaced purchased capacity.*

Appendix F
DETERMINATION OF CAPACITY CREDIT AND CAPACITY FACTOR

Capacity credit was defined for this study as the expected capability of the solar thermal power system to decrease the annual system peak demand that must be met with conventional generating capacity. The same concept has been referred to elsewhere as "load carrying capability" (8,9). A study by Southern California Edison (SCE) defined load carrying capability as "a probabilistic measure of the amount of load the units could carry at a specified reliability" (8). In the SCE study, load carrying capability was calculated based on the difference in installed capacity at a given level of reliability with and without solar capacity. For example, if the utility's total installed capacity were 100 MW without any solar capacity and 101 MW with 5 MW of solar capacity, then the load carrying capability of the solar plant would be 4 MW or 80 percent.

Another useful concept in this regard is the concept of "dependable capacity" as it is applied to hydroelectric plants. "The dependable capacity of an electric system's hydroelectric plants is the capacity which under the most adverse flow conditions of record can be relied upon to carry system load, provide dependable reserve capacity, and meet firm power obligations, taking into account seasonal variations and other characteristics of the load to be supplied... The extent to which capacity limitations may be disregarded depends in large measure on whether the limitations are likely to occur at the time of annual peak load" (7). The availability of storage is another factor which may be taken into consideration in determining the dependable capacity of hydroelectric plants. Similar statements, with "insolation" substituted for "flow conditions" would be applicable to solar power.

A criterion which is frequently applied to small hydroelectric plants is that they must have at least two hours of storage in reserve in order for the hydroelectric capacity to be considered dependable capacity. A similar criterion might be useful for small solar thermal power systems.

Capacity credit (or load carrying capability or dependable capacity) of a solar thermal power system could be expected to decrease (as a percent of rated capacity) as the penetration of solar power systems increases as a percent of the total system power requirement. Similarly, the annual capacity factor of the solar thermal power systems might vary with solar mix. Therefore, both capacity credit and capacity factor were assessed for each solar thermal power system type over a range of solar mixes from 2 to 80 percent.

Two approaches were used in this study to assess capacity credit. The first approach was to determine the amount by which the utility's annual peak demand was projected to be decreased by the operation of the solar thermal power system. This approach was accomplished using the hourly analysis program discussed in Appendix D to determine the difference in the utility's peak demand before and after dispatch of the solar thermal power system. The annual capacity factor of the solar thermal power system was also determined by the hourly analysis program. The hourly analysis approach has the advantage of examining hourly radiation data and utility load data concurrently to allow consideration of the impact of their coincidence on the ability of the solar thermal power system to meet the utility's peak demand. However, it fails to consider the impact of the solar thermal power system on the utility's system reliability.

The second approach used a Federal Power Commission (FPC) program which calculates the loss-of-load probability (LOLP) to determine the impact of the solar thermal power system on system reliability. The loss-of-load probability is defined as the probability that load will exceed the generating capacity of a utility. It is expressed in the FPC program as the hours per week that the capacity is likely to be insufficient to meet the utility's load.

In this approach a conventional expansion plan was analyzed to determine a baseline level of system reliability. Then the solar thermal power system was added to the system and conventional capacity was removed until the baseline level of reliability was reached. The amount of conventional capacity replaced by the solar thermal power system was used as another measure of capacity credit of the solar thermal power system.

To employ this approach it was necessary to develop a forced outage rate for each solar thermal power system type which included the effects of weather outages as well as mechanical outages and to differentiate between the daylight hours when the solar thermal power system was available and the night hours when it was not available.

The forced outage rate (FOR) developed for each solar thermal power system type included a term for mechanical outages and a term for outages due to random cloudiness using the expression:

$$FOR = FOR_c + FOR_m - (FOR_c)(FOR_m)$$

where FOR_c = forced outage rate due to cloudiness

FOR_m = mechanical forced outage rate

The last term in this formula accounts for the joint probability that cloudiness and mechanical outages will occur at the same time. The forced outage rate due to cloudiness was taken to be 100 minus the mean percentage of possible sunshine in peak load season (13). It should be noted that this measure of cloudiness outages does not include a provision for outage at night when sunshine is not possible. The mechanical forced outage rate was supplied by JPL.

Table F-1 summarizes the forced outage rates used for each solar thermal power system type for a location in the Southwestern United States. As shown in this table, two sets of forced outage rates were used, one for summer peaking utilities and one for winter peaking utilities, which were represented in the study by the 35-MW municipal with oil-fired generation.

The equivalent forced outage rate developed above is only valid for the daylight hours. Therefore, the system load curve was divided into a "day" portion and a "night" portion. The "day" portion of the curve was analyzed with all of the system resources including the solar thermal power system. The "night" portion was analyzed with only the conventional resources. The total system reliability (which was measured in terms of insufficient capacity in hours per week) was then determined as the sum of the day reliability and the night reliability.

Table F-1

FORCED OUTAGE RATES (FOR)[a] FOR SOLAR THERMAL POWER SYSTEMS

Utility Classification	Parabolic Dish Concentrator Systems	Variable Slat Concentrator System	Central Receiver System
Summer-Peaking Utilities			
Cloudiness FOR[b]	0.16	0.16	0.16
Mechanical FOR[c]	0.01	0.07	0.07
Total FOR[d]	0.17	0.22	0.22
Winter-Peaking Utilities			
Cloudiness FOR[b]	0.30	0.30	0.30
Mechanical FOR[c]	0.01	0.07	0.07
Total FOR[d]	0.31	0.35	0.35

[a] *Assumes a location in the Southwestern United States.*

[b] *1 – fraction of possible sunshine in the peak load season from "Climatic Atlas of the United States," U.S. Dept. of Commerce, June, 1968.*

[c] *Provided by JPL.*

[d] *Total FOR = Cloudiness FOR + Mechanical FOR – (Cloudiness FOR x Mechanical FOR)*

A comment is in order with regard to the definition of "day" hours. Day hours were defined to be all hours in which power was available from the solar thermal power system as determined by the hourly analysis program. In some cases, hours in which insolation was available were not considered day hours because all power from the solar thermal power system was sent to storage during these hours and none was dispatched to the grid. Conversely, some hours were considered day hours if power was available from storage even though insolation may not have been available. This definition of day hours tended to maximize the capacity credit of the solar thermal power system since it tended to make the solar thermal power system available to meet higher load levels.

The capacity of the solar thermal power system during the day hours was assumed to be its average capacity over these hours as determined by the hourly analysis results. Table F-2 shows the average capacities (as a percentage of rated capacity) assumed for each solar thermal power system type for various reference utilities and the hours which were considered to be day hours. For the variable slat concentrator and central receiver systems the average capacity of the solar thermal power system was slightly less than the rated capacity because the maximum power output of thermal storage was only 70 percent of the unit's rated capacity. For the parabolic dish concentrator systems, on the other hand, the maximum output of the battery storage was equal to the unit's rated capacity. For these systems the cause of the discrepancy between the rated and average capacity was the use of the peak-shaving dispatching strategy (see Appendix D). Using this dispatching strategy, energy was sometimes dispatched at a power level less than rated capacity so that the remaining energy could be stored for use on peak. This had the effect of lengthening the "day" hours during which solar power was available while at the same time reducing the average capacity level.

It is recognized that from the viewpoint of a reliability analysis a capacity of 10 MW for 12 hours followed by a capacity of 7 MW for 2 hours is not the same as a capacity of 9.6 MW (the weighted average of these values) for 14 hours. However, it was felt that the additional cost and complication which would have been required to consider hourly fluctuations in capacity were not justified in a preliminary screening analysis such as the current study.

Table F-2
AVERAGE SOLAR CAPACITY DURING DAY HOURS[a]

Solar Thermal Power System Type	Reference Utility	Average Capacity In Peak Load Season[b] (% of Rated Capacity)	Day Hours[a] (Inclusive)
Parabolic Dish Concentrator Systems	35-MW Municipal with Coal-Fired Generation	86	9-20
	35-MW Municipal with Oil-Fired Generation	51	8-20
	200-MW Generation & Transmission Cooperative	74	8-21
Variable Slat Concentrator System	35-MW Municipal with Coal-Fired Generation	90	6-20
	35-MW Municipal with Oil-Fired Generation	86	8-18
	200-MW Generation & Transmission Cooperative	90	6-20
Central Receiver System	200-MW Generation & Transmission Cooperative	90	6-20

[a] *Assumes a location in the Southwestern United States. "Day Hours" include those hours during which solar capacity is dispatched in the hourly analysis model. This may not include some hours during which insolation is available if no solar power is dispatched during these hours. Further, it may include some hours during which insolation is not available if solar power is available from storage in these hours.*

[b] *Based on the results of the hourly analysis program. Average capacity may be less than rated capacity because a significant portion of the power is dispatched through storage, which has a lower capacity rating, or because the available solar energy is dispatched at less than rated capacity so that some energy may be stored for dispatch on peak.*

Figures F-1 and F-2 show sample results for both of these approaches for the 35-MW municipal with oil-fired generation for the parabolic dish concentrator systems and the variable slat concentrator and central receiver systems, respectively. Also shown on these figures are results from a study by Southern California Edison Company (8) for a solar thermal power system with two hours of storage. The results for the other reference utilities examined were similar to those shown. The results for all reference utilities were averaged to obtain the values used for all reference utilities in the study. These values, which are shown in Table F-3, are remarkably similar to each other and to the results from the Southern California Edison study.

Table F-3 also summarizes the values of annual capacity factor which were used in the study for all reference utilities. As can be seen, the capacity factors are relatively insensitive to solar mix. However, there is a marked difference between the capacity factors of the parabolic dish concentrator systems on the one hand and the variable slat concentrator and central receiver systems on the other hand. This difference can be attributed to the difference in dispatching strategies as a result of differences in storage systems.

As discussed in Appendix D, the variable slat concentrator and central receiver systems are dispatched by sun-following dispatch which maximizes their annual system capacity factors. The parabolic dish concentrator systems, on the other hand, are dispatched with a peak-shaving dispatching strategy which attempts to maximize capacity credit rather than capacity factor. Although this strategy does not significantly increase the capacity credit for these systems over that of the variable slat concentrator and central receiver systems it does significantly decrease the annual capacity factor. However, this dispatching strategy is necessary because of the system's battery storage. See Appendix D for a further discussion of the two dispatching strategies.

* * * * *

CAPACITY CREDIT
VS. SOLAR MIX
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
PARABOLIC DISH CONCENTRATOR SYSTEMS

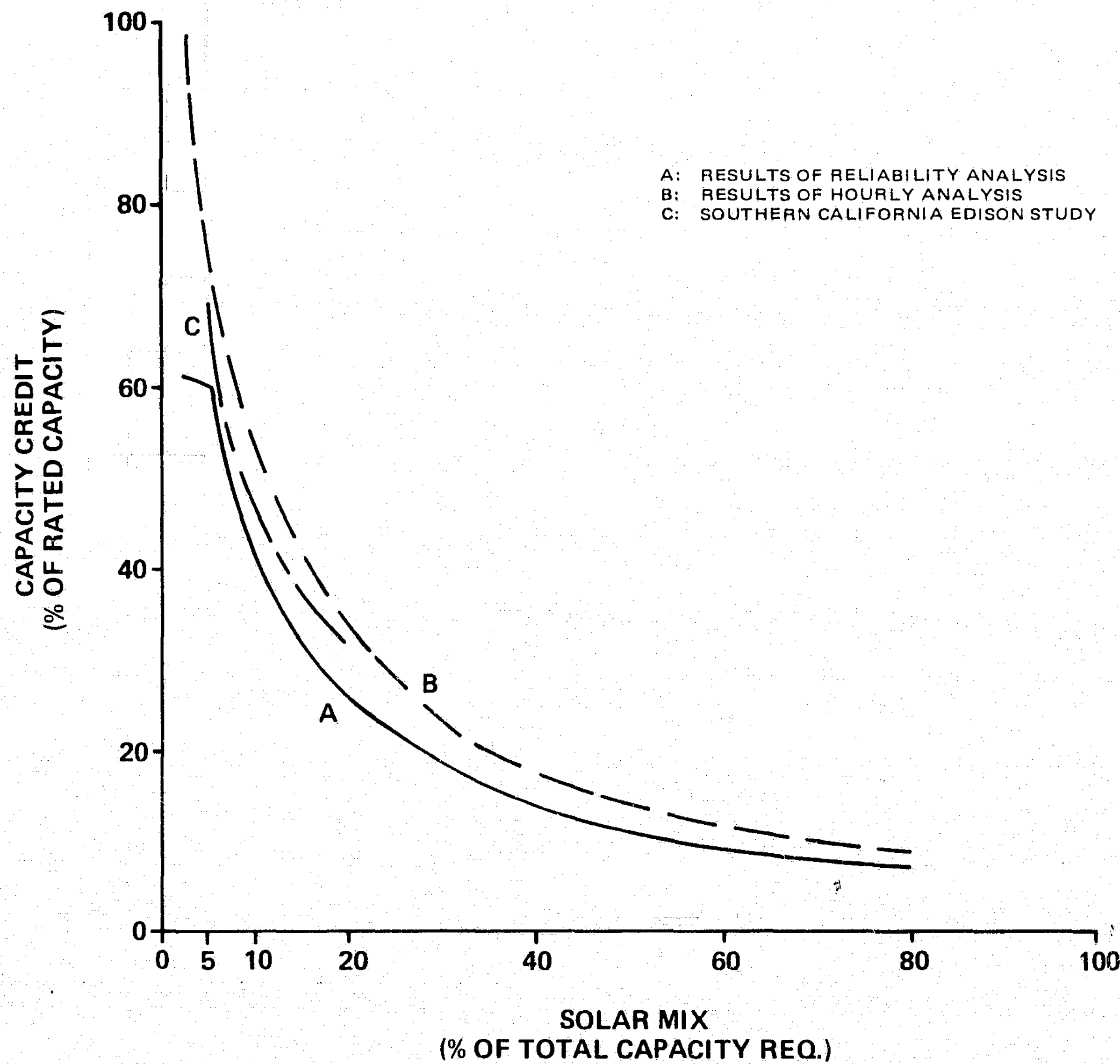

Figure F-1

CAPACITY CREDIT
VS. SOLAR MIX
35-MW MUNICIPAL WITH OIL-FIRED GENERATION
VARIABLE SLAT CONCENTRATOR AND CENTRAL RECEIVER SYSTEMS

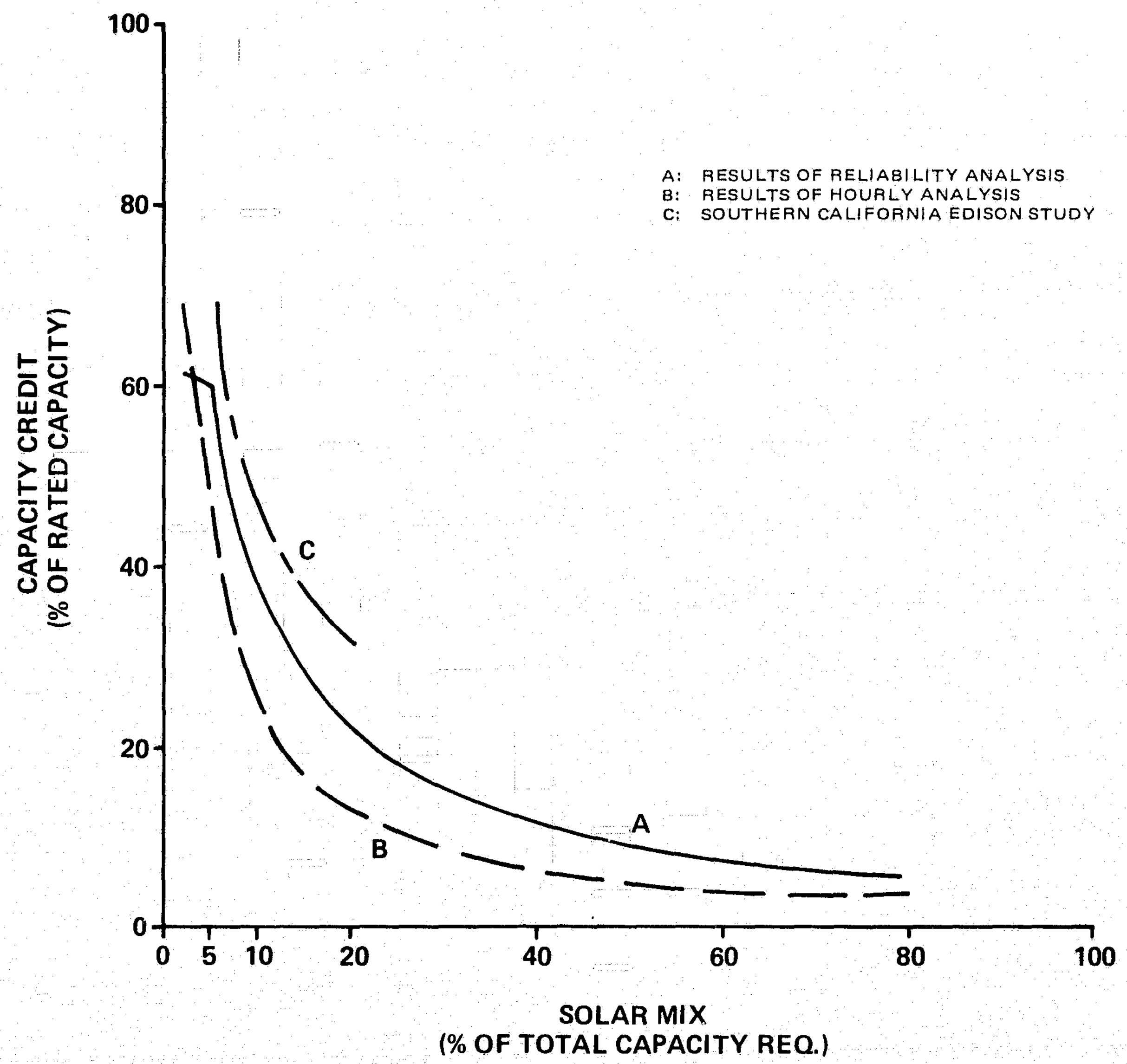

Figure F-2

PL 78-008-4-005

Table F-3

SOLAR THERMAL POWER SYSTEM CAPACITY CREDIT AND CAPACITY FACTOR[a] VERSUS SOLAR MIX

Solar Mix[b] (Percent)	Parabolic Dish Concentrator Systems		Variable Slat Concentrator System		Central Receiver System	
	Capacity Credit (% of Rated)	Capacity Factor (Percent)	Capacity Credit (% of Rated)	Capacity Factor (Percent)	Capacity Credit (% of Rated)	Capacity Factor (Percent)
2	75	36	75	47	75	47
5	65	36	70	47	70	47
10	50	36	50	47	50	47
20	35	36	30	47	30	47
40	20	36	15	46	15	46
60	15	35	10	45	10	45
80	10	32	8	37	8	37

[a] *Assumes a location in the Southwestern United States.*

[b] *Rated solar capacity as a percent of a utility's total capacity requirement.*

Appendix G

BREAK-EVEN CAPITAL COST METHODOLOGY

This appendix describes the methodology used in the study to calculate break-even capital costs. Essentially, the method employed involved the use of linear regression to determine the capital cost of the solar thermal power system at which the the present worth of all future revenue requirements (PWAFRR) of a solar expansion plan with a particular solar mix was equal to the PWAFRR of the corresponding optimum conventional expansion plan. This value was taken to be the break-even capital cost of the solar thermal power system for that solar mix.

* * * * *

Appendix H

CALCULATION OF IMPACT OF EFFICIENCY ON CAPITAL COST OF THE SOLAR THERMAL POWER SYSTEMS

The impact of changes in the subsystem efficiencies on the capital cost of the solar thermal power system can be calculated using an expression for capital cost which is written in terms of subsystem efficiencies:

$$\text{Capital Cost} = C_a \times \text{AREA} + \text{CONSTANT}$$

where C_a = area related costs ($\$/m^2$ of collector area), including collector, site preparation, dust suppressant and land costs expressed in terms of collector area.

AREA = collector area (m^2)

CONSTANT = all non-area-related costs

$$\text{AREA} = \frac{SM}{I_t} \times \frac{C}{\eta_c \eta_t \eta_x}$$

where SM = solar multiple

I_t = receiver intensity rating, kW/m^2

C = rated capacity of the solar thermal power system, kW

η_c = collector efficiency

η_t = transport efficiency

η_x = conversion efficiency

If one efficiency is changed at a time, then the change in the SPS capital cost can be expressed as

$$\Delta \text{ Capital Cost} = C_a \times \text{AREA} \times \frac{\Delta\eta}{\eta + \Delta\eta}$$

If more than one efficiency is changed at a time, the change in capital cost can be calculated as

$$\Delta \text{ Capital Cost} = C_a \times \text{AREA} \times \left(\frac{\eta_c \eta_t \eta_x}{(\eta_c + \Delta\eta_c)(\eta_t + \Delta\eta_t)(\eta_x + \Delta\eta_x)} - 1\right)$$

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GLOSSARY

AVAILABLE RECEIVER POWER - the power at the receiver of the solar thermal power system after collector losses (MW).

CAPACITY, BASE LOAD - generating capacity that is generally characterized by the high fixed costs and low variable costs that are generally associated with coal-fired and nuclear steam generation, resulting in a capacity factor ranging from about 50 percent up to the unit's operating availability. Base load units are usually expected to run at or near their capacity rating when they are not shut down for maintenance or forced outages.

CAPACITY, INTERMEDIATE - generating capacity that normally has lower fixed costs and higher variable costs than base loaded capacity. It is often represented by units that have been moved out of base load operation by newer units with high efficiency, but its operation, by contrast to base load capacity is characterized by a high degree of cycling, which means swinging between its minimum loading and its rated capacity to follow the utility's varying load.

CAPACITY, PEAKING - generating capacity characterized by low fixed costs and high variable costs associated with units such as combustion turbine and diesels. It is loaded after base load and intermediate capacity by an economic dispatch because of its high incremental costs. It generally operates at a capacity factor below about 25 percent, and is designed for frequent, perhaps daily, startups and shutdowns. Peaking units normally have far worse heat rates at partial loading relative to their full load heat rates than intermediate units, which will often be dispatched at partial loading to allow the peaking capacity to operate at full load while it is committed to operation.

CAPACITY CREDIT - the expected capability of the solar thermal power system (MW) to decrease the annual system peak demand that must be met with conventional generating capacity while maintaining the same level of system reliability.

CAPACITY FACTOR - the ratio of the average load on a generating unit over a designated period of time to the capacity rating of the unit.

CAPACITY RATING - the maximum load (MW) that can be supplied by a generating unit under a set of specified operating conditions.

CAPACITY REQUIREMENT - the system peak demand plus the reserve requirement, which is computed as a required fraction of peak demand.

COMMITMENT - the selection in advance of the generating capacity required to meet the expected hourly demand values and the associated reserve margin. Economic commitment is usually made according to a priority order based on full load costs, and is adjusted to satisfy minimum down time constraints imposed by the startup characteristics of the generating units.

DIRECT NORMAL SOLAR INTENSITY - (see Insolation)

DISPATCH, ECONOMIC - the minimization of the cost of energy generated to serve a utility's load. It is generally preceded by a commitment, defined elsewhere. The economic dispatch is implemented by assigning for each hour, the blocks of capacity from the committed units in order of the incremental energy price of the blocks up to the utility's demand level.

DISPATCH, PEAK-SHAVING - a dispatch intended to minimize the utility's peak demand with the energy available from the solar thermal power system. It involves a 24-hour commitment at the beginning of a day that determines the desired interaction of the solar thermal power system and its storage subsystem. The peak-shaving dispatch is identical to the sun-following dispatch for a system with no storage.

DISPATCH, SUN-FOLLOWING - a dispatch intended to maximize the utilization of the available receiver power of the solar thermal power system to deliver capacity to the utility's load. This dispatch is analogous to the dispatch of run-of-river hydro.

FORCES OUTAGE RATE - the probability that a generating unit or major piece of equipment will not be available because of mechanical problems (and cloudiness for the solar thermal power systems) that occur randomly.

HEAT RATE - a measure of a generating unit's thermal efficiency (Btu/kWH), computed by dividing the total heat content of the energy source (fuel) by the generated energy.

INSOLATION - solar radiation intensity, or power density (kW/m^2). In general, this refers to the visible and near-infrared bands of the spectrum emitted by the sun, within which most of its energy lies. In the present study, this term refers to the direct normal component of the total solar radiation, since the diffuse component is of relatively small value for a tracking concentrator, and is ignored in the analysis of the solar thermal power systems.

LEVELIZED BUSBAR ENERGY COST - a price (mills/kWH) in present value dollars per unit of generated energy required to pay for the system over its lifetime, including capital, fuel and O&M.

LOAD FACTOR - the ratio of the average load over a designated period to the peak load occurring in that period.

LOCATION-DEPENDENT PARAMETERS - parameters that cause the levelized busbar energy cost (BBEC) of the solar thermal power system to be sensitive to geographical location. These include storage time, receiver intensity rating, and solar multiple, which are defined elsewhere.

LOSS-OF-LOAD PROBABILITY (LOLP) - the probability that a utility's load will exceed its available generating capacity.

OPERATING AVAILABILITY - the probability that a generating unit or major piece of equipment is available for service, whether or not it is actually in service.

PERCENT POSSIBLE SUNSHINE - the percent of daylight hours during which insolation is not obscured by clouds.

PRESENT WORTH OF ALL FUTURE REVENUE REQUIREMENTS (PWAFRR) - the present value of the series of annual costs over the study period plus a term end effects, which are the present value of the costs for all years following the study period. End effects are included to reduce the effect of the study period's length on the comparison of alternative expansion plans, which can result from differences in the timing of investments. The PWAFRR is the principal economic criterion applied in comparing the costs and benefits of alternative expansion plans, and is computed for this purpose on an incremental basis, meaning that annual costs exclude those components that remain constant over the range of expansion plan alternatives under consideration, such as debt service on the utility's existing generation and transmission facilities.

RATED CAPACITY - (see Capacity Rating)

RECEIVER INTENSITY RATING - the level of direct normal solar intensity (kW/m^2) at which the solar thermal power system reaches its rated thermal receiver power.

RESERVE MARGIN - the required generating capacity in addition to that required to serve the utility's demand to accommodate uncertainty in the load forecast.

SOLAR MIX - the fraction of the utility's capacity requirements represented by the rated capacity of the solar thermal power system.

SOLAR MULTIPLE - the ratio of the rated thermal receiver power to the thermal receiver power corresponding to the rated electrical capacity of the solar thermal power system.

STORAGE TIME - the length of time (hours) for which the energy storage subsystem is designed to deliver power at its output rating.

ABBREVIATIONS

BBEC	- levelized busbar energy cost
DOE	- Department of Energy
EPRI	- Electric Power Research Institute
FOR	- forced outage rate
FPC	- Federal Power Commission (now Federal Energy Regulatory Commission)
G & T	- generation and transmission
JPL	- Jet Propulsion Laboratory
LOLP	- loss-of-load probability
NBS	- National Bureau of Standards
O & M	- operation and maintenance
PWAFRR	- present worth of all future revenue requirements
REA	- Rural Electrification Administration
SCE	- Southern California Edison
SPSA	- Small Power Systems Applications project
TVA	- Tennessee Valley Authority