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SUNBURN: A Computer Code for Evaluating the Economic Viability of Hybrid Solar Central Receiver Electric Power Plants

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Abstract

The computer program SUNBURN simulates the annual performance of solar-only, solar-hybrid, and fuel-only electric power plants. SUNBURN calculates the levelized value of electricity generated by, and the levelized cost of, these plants. Central receiver solar technology is represented, with molten salt as the receiver coolant and thermal storage medium. For each hour of a year, the thermal energy use, or dispatch, strategy of SUNBURN maximizes the value of electricity by operating the turbine when the demand for electricity is greatest and by minimizing overflow of thermal storage. Fuel is burned to augment solar energy if the value of electricity generated by using fuel is greater than the cost of the fuel consumed. SUNBURN was used to determine the optimal power plant configuration, based on value-to-cost ratio, for dates of initial plant operation from 1990 to 1998. The turbine size for all plants was 80 MW*e* net. Before 1994, fuel-only was found to be the preferred plant configuration. After 1994, a solar-only plant was found to have the greatest value-to-cost ratio. A hybrid configuration was never found to be better than both fuel-only and solar-only configurations. The value of electricity was calculated as The Southern California Edison Company's avoided generation costs of electricity. These costs vary with time of day. Utility ownership of the power plants was assumed. The simulation was performed using weather data recorded in Barstow, California, in 1984.

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Contents

List of Figures

List of Tables

Chapter 1

Introduction

The use of energy from fossil fuel to augment solar energy in a power plant is called fossil-fuel hybridization. Fossil-fuel hybridization of a solar-only plant may be beneficial for several reasons. First, the utilization of the non-solar components of the power plant, such as the turbine, can be increased. A hybrid plant can generate electricity when there is no insolation and thermal storage is empty; also, it can generate electricity when only the solar portion of the plant is inoperative. Certainly, for a solar-only plant, it is possible to increase the field size, thereby increasing the overall capacity factor of the plant; however, for solar multiples (ratio of the maximum thermal supply rate of the receiver to the maximum thermal demand rate of the turbine) greater than unity, thermal storage is required. The added cost of storage reduces the benefit of increased non-solar utilization.

Second, for a solar-only plant, to guarantee service during periods of peak demand, a utility may need to have reserve generating capacity unless a large amount of thermal storage is available. It may be more economical to purchase a fuel burner and a small quantity of fuel rather than a large amount of thermal storage. Third, since the heat losses from a solar plant increase with increasing temperature, it may be desirable to use a fuel burner to increase the temperature of the working fluid, thereby allowing operation of the solar portion of the plant at a lower temperature. As an additional benefit, the solar thermal energy could be converted to electricity using advanced gas turbine cycles, which operate at high temperature with high efficiency.

The cost of hybridization consists of the cost of the fuel and the cost of all equipment necessary to make use of the energy from the fuel. If the benefits of hybridizing a solar-only plant exceed the costs, then a solar-hybrid plant will be preferred to a solar-only plant. If the cost of thermal energy from a solar plant is less than the cost of thermal energy from fuel, then a solar-hybrid plant may be preferred to a fuel-only plant. Of course, if fuel is very inexpensive, then fuel-only would be the preferred plant configuration.

The purpose of this study is to assess the potential of solar-hybrid power plants, compared with solar-only and fuel-only power plants. The tool that was developed and used for this purpose is the computer program SUNBURN. The analysis emphasizes optimization based on the value of electricity as well as on plant cost. It is important to consider the value of electricity in evaluating solar plants because value of electricity may vary greatly depending on when the electricity is generated. Variation in value of electricity is a direct consequence of variation in demand for electricity. Solar thermal plants with thermal storage have the ability to shift the period of solar insolation to coincide with the period of maximum demand. Evaluating the full economic potential of solar thermal power plants requires considering the maximum benefit of electricity produced by these plants. In general, previous studies have emphasized cost considerations only or have analyzed specific solar-hybrid plant designs [1,2,3,4,5,6,7,8,9,10].

SUNBURN performs an annual simulation based on calculations for each hour of an entire year. An hourly simulation was necessary because a major goal of the study was to analyze how well the output of the turbine could be shifted to coincide with the period of maximum demand for electricity. The continuous variations in the demand for electricity and insolation were approximated by series of discrete values for each hour of a year.

As a specific application, the optimal system design and preferred power plant configuration were determined for initial operation dates from 1990 to 1998 for Barstow, California, which is within the service area of the Southern California Edison Company (SCE). SCE was chosen because; first, both the peak demand experienced by SCE and the maximum solar insolation occur in the summer; second, through early 1986, SCE was forecasting load growth and therefore required additional generation capacity; and third, the necessary weather data were available for a location within the service area of SCE. The solar-only and hybrid systems that were studied use external cylindrical receivers cooled by molten salt. Molten salt is also the thermal storage medium. The hybrid and fuel-only systems that were studied burn fuel in a gas-fired salt heater. A heat exchanger converts the thermal energy of the salt to steam which then drives a conventional steam turbine. Fuel was used to augment the quantity of thermal energy only; fuel was not used to increase the temperature of the working fluid. A conventional steam turbine was used by all power plants considered in the study. The turbine size was fixed at 80 MW*e* net. This was the largest plant size for which the methodology used to calculate the electricity value was valid. Smaller plants would not have benefitted from economies of scale. Forced outages were assumed to affect the entire plant rather than specific parts of the plant.

Ownership and operation of the plants by SCE was assumed. The value of electricity to SCE, including the capacity value, if any, was equated with SCE's marginal avoided costs of generating electricity [11,12]. These avoided costs vary with time of day. Avoided costs are published by SCE as required by the *Public Utility Regulatory Policies Act of 1978* (PURPA) [13]. PURPA is limited to plants of less than 80 MW*e* net in size. The costs of the solar components of the plant are taken from the *1986-1990 Solar Thermal Five Year Plan* and are estimates of current costs, near-term or five-year cost goals, and long-term cost goals [14]. Value and cost were levelized and expressed in 1984 constant dollars according to the economic methodology of the *Five Year Plan.* All cost and value figures in this report are expressed in 1984 dollars, unless otherwise noted.

A value-maximizing thermal energy dispatch strategy governs the use of thermal energy. This dispatch strategy is applicable to solar-only and hybrid power plants having different heliostat field sizes and different thermal storage capacities. It is also applicable to fuel-only plants. The dispatch strategy maximizes value by attempting to operate the turbine when the value of electricity is greatest and by minimizing overflow of thermal storage. Although the dispatch strategy was designed specifically for plants operating within the service area of SCE, it could be modified to be suitable for other utilities. The simulation was performed using weather data recorded in Barstow, California, in 1984. The insolation for this year was unusually low, as described in Section 2.10.

Section 2 describes the methodology of the study, including the calculation of electricity value and plant cost, levelization of value and cost, subsystem performance, the dispatch strategy, and weather data. Section 3 describes results, and Section 4 presents conclusions. Appendix A is the user's manual for SUNBURN. Appendix B is a detailed description of the procedure used to calculate the value of electricity.

Chapter 2

Methodology

The main effort of this study involved developing a methodology to compare electric power plants that convert thermal energy into electricity from solar, from solar and fuel, and from fuel sources. Since it is only meaningful to compare optimized alternatives, the ability to optimize solar-only, hybrid, and fuel-only power plant configurations was required. Since the value of electricity is often a function of time, and since the power-generation capability of a solar plant depends on the availability of insolation as well as on plant design, a general optimization requires consideration of the value of electricity as well as plant cost. The power output of the plants was not constrained; rather, a thermal energy dispatch strategy was employed to operate the turbine during periods of greater electricity value in preference to periods of lesser electricity value. The nature of the calculations required use of a computer. Optimization of solar-only and hybrid power plant configurations was accomplished by simulating a large number of plant designs spanning the range of values of the independent variables and choosing, as the optimum, the design with the greatest value-to-cost ratio. There were two independent variables, size of the heliostat field (or solar multiple) and thermal storage capacity. Since the turbine size was fixed, the solar multiple is a function of the field size only.

Figure 2.1 is a schematic drawing of power plants analyzed in this study. The solar central receiver technology that was chosen consists of an external cylindrical receiver surrounded by heliostats and cooled by molten salt. Thermal energy is stored in molten salt contained in tanks. Molten salt receivers, molten salt thermal storage, and salt-to-steam heat exchangers have been tested on a small scale [15]. A heat exchanger converts the thermal energy of the salt into steam which then drives a conventional steam turbine. The turbine can be operated at full power using thermal energy from the solar receiver and thermal storage, or from a gas-fired salt heater. For solar-only plants, the heater is omitted. For hybrid plants, since the cost of heater was generally less than 5 percent of the total levelized plant cost, use of a smaller heater was not studied. Fuel-only plants would probably have been more economical had the salt heater been omitted and a gas-fired steam boiler been used instead of the salt-to-steam heat exchanger. However, most of the cost of the fuel-only plants was found to be

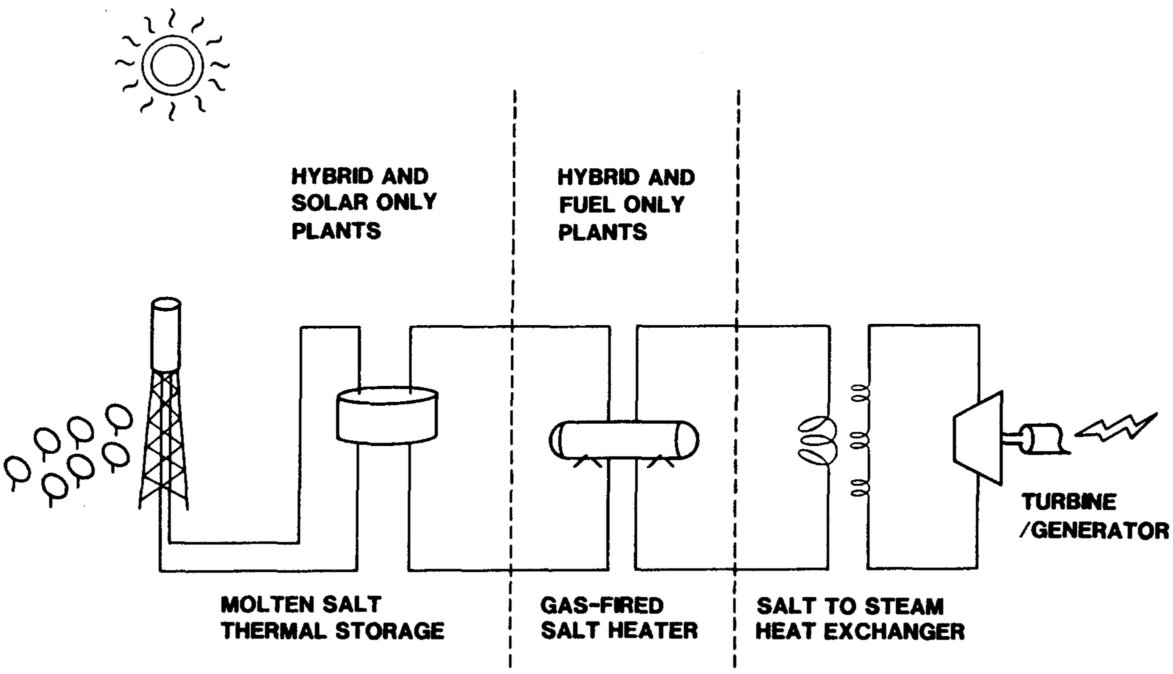

Figure 2.1: Schematic Drawing of Solar-Only, Hybrid, and Fuel-Only Power Plants.

for fuel. Therefore, the fuel-only plants that were studied used the same gas-fired salt heater and salt-to-steam heat exchanger as the hybrid plants. Flows of thermal energy within the power plants is controlled by a thermal energy dispatch strategy.

As a specific application of the methodology, the preferred power plant configuration and the optimum plant design were determined for power plants that will begin operation from 1990 to 1998. Over this range of initial operation dates, the projected decreases in the cost of solar components were expected to shift the preferred power plant configuration from fuel-only to solar-only. Thus, at an intermediate date, an optimized hybrid power plant configuration could be preferred to both optimized solar-only and optimized fuel-only power plants.

2.1 Calculation of Electricity Value

A quantity of electricity generated by a solar plant is equal in worth to that same quantity of electricity generated by any other plant(s). Therefore, if the generation cost of electricity from the solar plant is the same as the generation cost from any other plant(s), a utility will be indifferent to the source of the electricity. Thus, the measure of value of an amount of electricity from a solar plant is the cost of generating that same amount of electricity, using other sources available to the utility. For example, if the cost of generating electricity using other sources is high, then the value of electricity generated by a solar plant will also be high.

The cost of generating electricity varies during a day for utilities that must satisfy a daily varying demand for electricity. Typically, utilities divide days into rate periods: on-peak periods correspond to periods when demand is greatest; mid-peak periods correspond to periods when demand is intermediate; and off-peak periods correspond to periods when demand is least. The difference in cost of electricity during these rate periods reflects the differences in type of plant and type of fuel used to generate electricity during these rate periods. Commonly, baseload plants are run continuously throughout the day and exclusively during off-peak periods. In contrast, peaking plants are operated only during the on-peak periods. The cost of electricity generated by peaking plants is greater than the cost of electricity generated by baseload plants primarily because peaking plants are operated for much less time than baseload plants. Therefore, the capital costs of a peaking plant must be distributed over a much smaller amount of electricity. Also, peaking plants characteristically use more expensive fuels and operate with lower efficiency than baseload plants.

The value of electricity to SCE was equated with SCE's total marginal avoided costs of generating electricity, as described by *Standard Offer No. 2, Capacity Payment Option 2* [11,12]. To qualify for this electricity value, a power plant must satisfy the performance requirement of *Payment Option 2*, which requires that the plant operate with a capacity factor greater than 80 percent during the daily on-peak periods for each month of the summer season (June through September). The value consists of amounts for avoided operating costs (energy payment) and for avoided capacity costs (capacity payment). The energy payment represents avoided operating costs, such as fuel cost, and operation and maintenance costs. It is therefore based on a set of fixed rates, per unit of electricity generated, for each rate period of each season. The capacity payment is a measure of capital equipment costs that a utility may be able to avoid, and is therefore based on the availability, or dependability, of a power plant to generate electricity during each of the demand periods of each of the seasons. If the plant's availability was insufficient, the utility would be forced to purchase reserve generation capacity. The availability is calculated according to *Payment Option 2 of SCE Standard Offer No. 2* [11]. The company has a summer peak load, three daily rate periods, and two seasons. Weekends and holidays are off-peak periods. The rate periods, seasons, and holidays are defined by *SCE Tariff Schedule No. TOU-8* [16].

During the on-peak periods of the summer months, an additional capacity payment, called the capacity bonus payment, is available for electricity generated at monthly on-peak capacity factors greater than 85 percent for a power plant meeting the above performance requirement. During the winter season, as an additional requirement applying to the bonus payment, a power plant must have operated with a capacity factor of at least 85 percent during the on-peak period of each of the summer months.

Figures 2.2 and 2.3 show the value per unit of electric energy as a function of clock time for the summer and winter seasons, respectively. In each Figure, the total payment rate (energy plus capacity payment rate) is shown by the solid curve and the energy payment rate is shown by the dotted curve. The value rates in these Figures

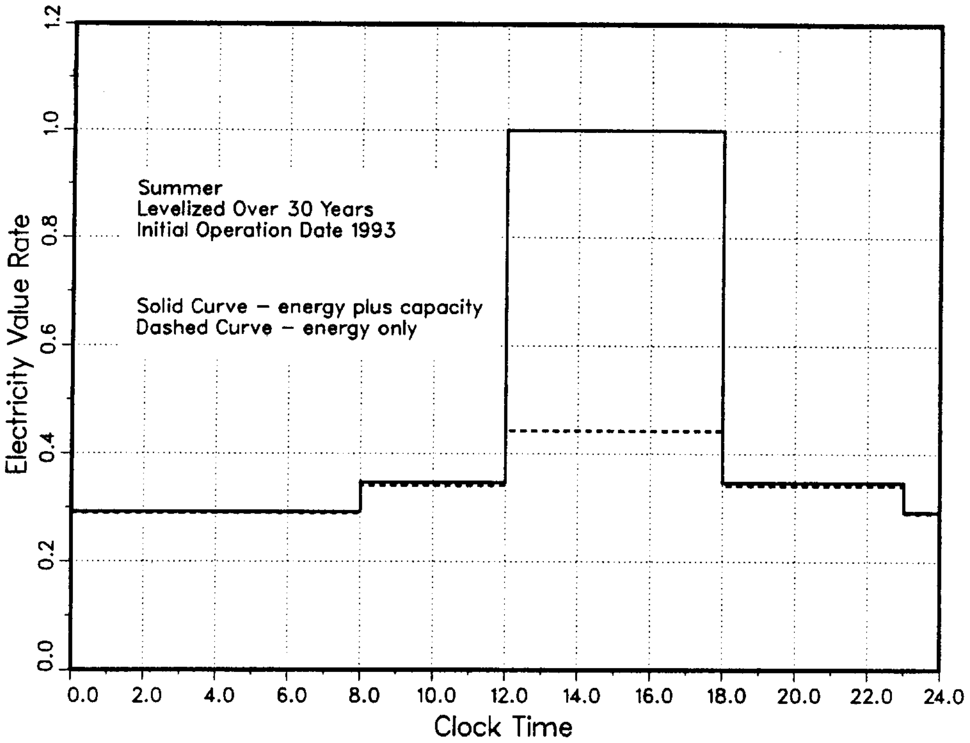

Figure 2.2: Value Rates of SCE vs. Clock Time - Summer.

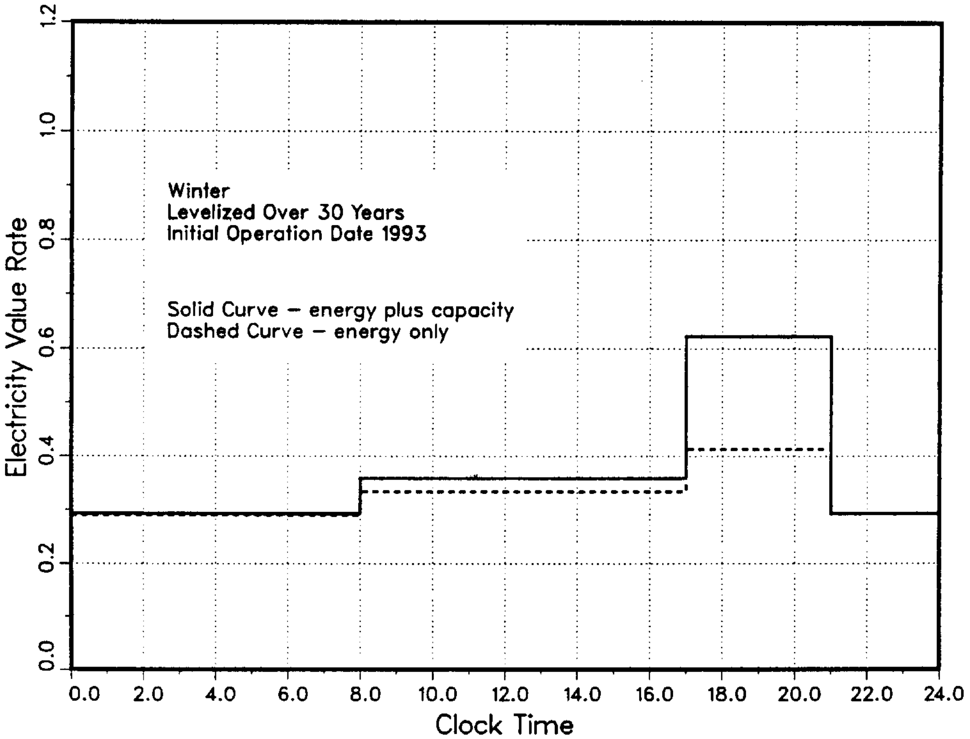

Figure 2.3: Value Rates of SCE vs. Clock Time - Winter.

were calculated in 1984 dollars for a plant beginning operation in 1993 and operating with an annual capacity factor of 100 percent. These value rates are levelized over a plant lifetime of 30 years. Also, the rates are normalized by the maximum total payment rate, which occurs during the on-peak period of the summer months. The energy and capacity value rates for each period and each season were calculated to be the total energy and capacity values obtained during that rate period and season, divided by the total amount of electricity generated during that rate period and season.

During the summer, the on-peak period occurs on weekdays from 12:00 to 6:00 PM. The value of electricity is significantly greater during this period mainly because of the capacity payment. During the winter, the on-peak period occurs on weekdays from 5:00 to 9:00 PM. In the winter, the value of electricity is less than in the summer because the capacity payment rates are less and because the on-peak period is shorter.

Standard Offer No. 2 describes long-term capacity payment rates and short-term energy payment rates. Therefore, it was necessary to assume an escalation rate to levelize the energy payment rates over the lifetime of the plant. In August 1985, the Pacific Gas and Electric Company estimated the escalation rate of the cost of natural gas, not including inflation, to be 2.34 percent per year [17]. This escalation rate was applied both to the energy payment rates and to the cost of fuel used by hybrid and fuel-only power plants. The capacity payment rates specified by *Standard Offer No. 2* are constant in actual dollars over the lifetime of a plant. Therefore, assuming positive inflation, the capacity payment rates de-escalate in real dollars.

The energy payment rates are based on the avoided fuel cost (of natural gas) to SCE in August 1985, which was $4.25 per million Btu [12]. The avoided fuel cost represents fuel expenses that SCE would avoid by obtaining electricity from some other source. As a measure of the uncertainty in forecasts of costs, by the summer of 1986, the cost of gas to SCE had decreased to $2.25 per million BTU. Since then, *Standard Offer No. 2* has been suspended, and new avoided cost estimates have been released.

Estimates of avoided costs are subject to a large degree of uncertainty, since they depend on factors that cannot be controlled by the utility. Among these factors are, most notably, demand, cost of fuel, cost of generating capacity, cost of electricity purchased from third parties, and constraints of the avoided cost methodology itself. Nevertheless, the avoided costs are real because they are actually used to determine the purchase price paid by a utility for electricity supplied by cogenerators and small power producers. The avoided cost methodology is intended to be used by a producer of power external to the utility, such as a cogenerator, to determine the payment for electricity sold to the utility. However, the avoided costs can be interpreted as the value to the utility, given the fact that the utility would incur the same costs by generating the electricity itself. Also, states have generally required that small power producers be paid a utility's full avoided cost. Thus, the avoided costs that utilities regularly publish can be used to calculate the value to a utility of the electricity produced by a power plant owned by that utility. Appendix B describes in detail the calculation of value based on avoided costs.

Table I: Cost Assumptions for Solar Components, 1984 dollars.

Initial Operation Date	1990	1993	1994	1995	1998
Heliostat, $\$/\text{m}^2$	150	80	72	64	40
Receiver, $\$/\text{m}^2$	80	45	42	39	30
Transport, $\$/\text{m}^2$	45	40	37	34	25
Storage, $\$/\text{kWh}t$	25	20	20	20	20
Conversion, $\$/\text{kW}e$	600	400	390	380	350
Balance of Plant, $\$/\text{m}^2$	65	60	54	48	30
O & M, $\$/\text{m}^2/\text{year}$	12	11	10.6	10.2	9

2.2 Calculation of Plant Costs

Costs of the solar components of the power plants are taken from the *1986-1990 Solar Thermal Five Year Plan* [14]. Table I shows the cost data used for power plants that will begin operation from 1990 to 1998. Heliostat costs include the costs for installation, wiring, and controls. Receiver costs include the costs for the tower and controls. Conversion costs include the costs for the steam generator, turbine, and electric generator. Land costs are included in balance-of-plant costs. The costs shown in the Table do not include an expense of 20 percent of the above costs, excluding the operation and maintenance cost, that was added for indirect costs and contingencies, as specified by the *Five Year Plan.* This expense was not added to the cost of the salt heater.

Because the construction period was assumed to be three years, the cost goals must be reached three years before the initial operation date shown in the first row of the Table. For example, the cost data shown in the first column of the Table are estimates to be achieved in 1987, assuming a significant volume of production. These costs are equal to the current technology estimates of the *Five Year Plan.* The cost data for the initial operation dates of 1994 and 1995 were obtained by interpolation between the data for 1993 and 1998, which correspond to the five-year goals and the-long term goals of the *Five Year Plan*, respectively.

For hybrid and fuel-only power plants, the cost of the gas-fired salt heater was assumed to be equal to $100 per kilowatt thermal. Although this cost was not based on an actual salt heater or salt heater design, it is roughly equal to the receiver costs, sized for a solar multiple of 1.08, for the initial operation date of 1993. Since the maximum thermal output of a solar receiver of this size is roughly equal to the maximum thermal output of the salt heater, the assumed cost of the salt heater is reasonable. For fuel-only plants, the operation and maintenance costs were assumed to be included in the cost of fuel to SCE in August 1985. This cost was $4.25 per million BTU [12]. The real annual escalation rate of fuel used in this study was 2.34 percent, as described in Section 2.1.

2.3 Economic Methodology

All cost and value results are expressed in levelized 1984 dollars in accordance with the *Five Year Plan* [14]. The levelized cost methodology is described in detail in *Long Term Goals for Solar Thermal Technology* [18] and is a real dollar analysis, which eliminates the complications and the often confusing or distorting effects of inflation and of assumptions about inflation. The lifetime of the plants was assumed to be 30 years.

The calculation of levelized cost will now be described. Default values of input variables are listed with the variable definitions. These default values are the values used in the present study.

$$\begin{aligned} Levelized\,Cost &= (Capital\ Costs)(FCR)(PVC) \\ &\quad +(Annual\ Fuel\ Cost\ in\ YEAR\ dollars)(PVF)(CRF) \\ &\quad +(Annual\ O\&M\ Cost\ in\ 1984\ dollars)(PVOM)(CRF); \end{aligned} \tag{2.1}$$

$FCR =$ Real fixed charge rate, default value .0615, and

$PVC =$ Present value factor multiplying capital costs to give capital costs plus cost for interest during the construction period, default value 1.0318.

In Equation 2.1, PVF is the present value factor multiplying the annual fuel cost in YEAR dollars to give the present value of the fuel cost over the plant's lifetime. This present value is expressed in 1984 dollars. PVF is calculated as follows:

$$PVF = (\frac{1. + GF}{RATDR - GF})(1. - (\frac{1. + GF}{1. + RATDR})^{TLIFE})(1. + GI)^{(1984.-YEAR)}; \tag{2.2}$$

$GF =$ Annual real escalation rate of fuel, default value .0234,

$RATDR =$ Real after tax discount rate, default value .0315,

$TLIFE =$ Plant lifetime, default value 30 years,

$GI =$ Annual inflation rate, default value .05, and

$YEAR =$ Year of initial operation, an input variable.

In Equation 2.1, $PVOM$ is the present value factor multiplying the annual O & M cost in 1984 dollars to give the present value of the O & M cost over the plant's lifetime in 1984 dollars. $PVOM$ is calculated as follows:

$$PVOM = (\frac{1. + GOM}{RATDR - GOM})(1. - (\frac{1. + GOM}{1. + RATDR})^{TLIFE}); \tag{2.3}$$

$GOM =$ Annual real escalation rate of O & M cost, default value 0.0.

In Equation 2.1, CRF is the capital recovery factor, multiplying a present value or cost to give a level annual series of values or costs. CRF is calculated as follows:

$$CRF = \frac{RATDR(1. + RATDR)^{TLIFE}}{(1. + RATDR)^{TLIFE} - 1.}. \tag{2.4}$$

Levelized value is calculated as the sum of the levelized energy payments and the levelized capacity payments. The levelized energy payment rates are calculated as follows:

$$\begin{aligned} &Levelized\ Energy\ Payment\ Rates = \\ &(Energy\ Payment\ Rates\ in\ YEAR\ dollars) * (PVAE)(CRF). \end{aligned} \tag{2.5}$$

In Equation 2.5, the Energy Payment Rates were obtained from Ref. [12]. $PVAE$ is the present value factor multiplying the Energy Payment Rates in $YEAR$ dollars to give the present value of the rates over the plant's lifetime in 1984 dollars. $PVAE$ is calculated as follows:

$$PVAE = (\frac{1. + GE}{RATDR - GE})(1. - (\frac{1. + GE}{1. + RATDR})^{TLIFE})(1. + GI)^{(1984. - YEAR)}; \tag{2.6}$$

$GE =$ Annual real escalation rate of the energy payment rates, assumed to be equal to GF.

The levelized capacity payment rates are calculated as follows:

$$Levelized\ Capacity\ Payment\ Rates = \tag{2.7}$$

$$(Capacity\ Payment\ Rates\ in\ YEAR\ dollars) * (PVAC)(CRF). \tag{2.8}$$

In Equation 2.7, the Capacity Payment Rates were obtained from Ref. [11]. $PVAC$ is the present value factor multiplying the Capacity Payment Rates in $YEAR$ dollars to give the present value of the rates over the plant's lifetime in 1984 dollars. $PVAC$ is calculated as follows:

$$PVAC = (\frac{1.}{RATDR + GI + RATDR * GI} \tag{2.9}$$

$$- \frac{1.}{(RATDR + GI + RATDR * GI)(1. + RATDR)^{TLIFE}(1. + GI)^{TLIFE}}) \tag{2.10}$$

$$*(1. + GI)^{1984. - YEAR}.$$

Note: The form of this equation is different from that for *PVAE* because the capacity payment rate has a real negative escalation rate of *GI* over the lifetime of the plant [19].

The default values of *FCR, PVC*, and *RATDR* are for utility ownership, and were taken from *Long Term Goals for Solar Thermal Technology* [18]. Calculated values of *PVF, PVOM, CRF, PVAE,* and *PVAC* are printed in the detailed results for each run of SUNBURN. The *Solar Thermal Financing Guidebook* [20] contains more information concerning financing and cost analysis of solar plants.

2.4 Optical Performance

An external cylindrical receiver surrounded by a field of heliostats was used by all of the solar plants considered in the study. The computer program DELSOL3 [21] was used to determine the optimal heliostat spacings or layout, the optimal receiver size, the optimal tower height, and the optical performance of the field. It may be desirable to have a heliostat field layout that is asymmetric about the north-south direction to maximize the energy collected during the afternoon when the demand for electricity is greatest. However, asymmetric field layouts were not considered in this study because field layouts designed by DELSOL3 are always symmetric about the north-south direction. The plant was designed for a latitude of 34.9 degrees north for Barstow, California.

For the turbine size of 80 MW*e* net, solar multiples ranged from .54 to 4.8 for the six DELSOL3 runs incorporated into SUNBURN. The corresponding heliostat areas ranged from 197,000 to 1,800,000 square meters. The heliostats were rectangular, with sides measuring 12.34 and 12.55 meters in length. The reflectivity of the mirrors of the heliostats was .92 and the absorptivity of the receiver was .95. The costs used to perform the optimization were the default costs in DELSOL3. They are similar but not equal to those used in this study. Also, DELSOL3 optimizes field and receiver design based on energy cost alone (ignores time-of-day fluctuations in value of electricity) and uses clear sky insolation for a few days of a year. Nevertheless, use of DELSOL3 was appropriate for this study because the optimal field design and performance are not expected to vary significantly for the different component costs and weather data. The idea was to obtain performance estimates of solar plants that were designed to minimize energy cost for one set of component cost assumptions; the assumption was made that the resulting solar plant designs would be close to optimal for the value and cost criteria of this study, using actual weather data for Barstow. Use of asymmetric fields to maximize collection of solar energy when the value of electricity is greatest is beyond the scope of the study.

A linear interpolation over the three variables, field area (solar multiple), solar azimuth angle, and solar zenith angle, gives the optical efficiency of the field and the receiver for the particular solar field considered and for each instant in time.

2.5 Thermal Energy Loss and Receiver Warmup

Molten salt was used both as the coolant for the receiver and as the storage medium for thermal energy. Heat loss from the receiver was determined according to correlations developed by Stoddard as a function of wind speed, ambient temperature, and aperture area of the receiver [22]. Heat loss from storage, over a 24-hour period, was assumed to be 3 percent. Although the temperature of the salt in storage decreases because of thermal loss, it was assumed that the salt could always provide steam at the temperature and pressure required by the turbine. For this assumption to be true, it may be necessary to heat the salt to a higher temperature, so that steam could always be supplied at the required conditions. Otherwise, the dependence of the turbine efficiency on steam temperature and pressure would have to be modeled to accurately calculate the effect of heat loss from the salt.

When the receiver was operating, the thermal energy loss rate from the piping in the solar plant was assumed to be 5 percent of the receiver heat loss rate at steady state operating conditions. The piping loss was assumed to be zero when the receiver was not operating.

The amount of thermal energy used to heat the receiver to the steady state operating temperature was assumed to be equal to the amount of heat lost by the receiver over a 30-minute period at the steady state operating temperature.

2.6 Turbine Efficiency

The gross efficiency of the turbine, which was sized at 80 MWe net, was calculated as a function of mass flow fraction and ambient wet bulb temperature. The efficiency was obtained from the manual for the STEAEC computer code for a steam turbine of the type used in the Solar One pilot plant at Barstow, California [23]. These gross efficiency values were adjusted upward according to the net annual efficiency estimates contained in the *Five Year Plan* [14] for steam turbines that are currently available. The turbine efficiency is plotted in Figure A.3, in Section A.3.10, of Appendix A. The amount of thermal energy required to bring the turbine to operating condition was assumed to be equal to the amount of thermal energy consumed by the turbine at maximum power over the duration of the start-up period. It was assumed that no electricity could be generated during the start-up period, which was set to be 24 minutes.

2.7 Electric Power Requirements

Electric-power requirements, or electrical parasitics, of the plant were determined differently depending on whether the turbine was running or on standby (off). When the turbine was running, and during the start-up period, the electric-power requirements were assumed to be 8.9 MW*e*, or 10 percent of the gross turbine rating. When the turbine was on standby and during forced outages, the electrical parasitics were assumed to be 1.5 MW*e*, calculated according to a formula described in the manual for the computer program SOLERGY [24]. The electrical parasitics were assumed to be zero during scheduled maintenance periods. The resulting amounts of annual total electrical parasitics are comparable to the amounts calculated by SOLERGY for plants of similar design. When the turbine was on standby and during start-up, the electrical parasitics were termed non-operational and were assumed to be obtained from SCE at avoided cost. It was assumed that the turbine generated no power during start-up. When the turbine was generating power, the electrical parasitics were termed operational and were obtained from the gross electrical output of the turbine.

2.8 Forced and Scheduled Maintenance Outages

It was assumed that a forced outage occurred every 20 days. During forced outages, the entire plant was assumed to be disabled. Scheduled maintenance was performed during the last three weeks of the year. Thus in 1984, the total amount of time for outages due to equipment failure and scheduled maintenance was 912 hours, or 10.4 percent of the total 8784 hours of the leap year.

2.9 Thermal Energy Dispatch Strategy

The thermal energy use, or dispatch, strategy attempts to maximize the value-to-cost ratio of electricity generated by a power plant. The principal tenet that guided the development of the dispatch strategy was that the simulation would be sufficiently general not to favor any particular plant design or configuration. Therefore, the dispatch strategy must be appropriate for solar plants having different field size and different thermal storage capacity. In addition, the dispatch strategy must also be appropriate for solar-only, hybrid, and fuel-only power plant configurations. For the solar portion of the plants, the dispatch strategy operates the turbine during the on-peak period in preference to the mid- and off-peak periods. Also, it operates the turbine during the mid-peak period in preference to the off-peak period.

For the fuel portion of the plants, the dispatch strategy burns fuel whenever the levelized value of the electricity generated by using fuel exceeds the levelized cost of the fuel consumed. Although operating the fuel portion of plants in this manner maximizes value minus cost rather than value divided by cost, the iterative procedure that would have been required to explicity maximize the value-to-cost ratio was considered to be beyond the scope of the study, often unnecessary (the same value-to-cost ratio would have resulted), and impractical for use in the operation of actual power plants. To increase the life of the turbine, the dispatch strategy avoids frequent on-off cycling of the turbine.

Because rates for electricity value escalate at a different rate than the fuel cost rate escalates, optimal dispatching of fuel would require a year-by-year simulation over the lifetime of a power plant, because a hybrid or fuel-only plant might use a different amount of fuel at the beginning of its life than at the end. However, a year-by-year simulation was beyond the scope of this study. Instead, fuel dispatching was based on the value rate of electricity and the fuel cost rate levelized over the lifetime of the plant. For this reason, the value-to-cost ratio of hybrid and fuel-only power plants may possibly be increased by performing a year-by-year analysis, using the electricity value rates and the fuel cost rate as functions of time.

The part of the dispatch strategy that governs use of solar thermal energy controls turbine start-up, operation, and shutdown according to daily and hourly predictions of the thermal energy available from the receiver for the rest of the day, the amount of thermal energy in storage, and three calculated storage energy levels. The predicted energy values from the receiver are calculated based on insolation predictions that are projections of past insolation. The energy levels are called carryover storage energy levels and are calculated at the beginning of each day, based on the predicted receiver output for the day and the rate periods for the day and the following two days. Carryover storage is accumulated during lower demand periods to be used during higher demand periods. The turbine may be operated at less than full power before the on-peak period and may be turned off before storage is empty to shift generation of electricity from lower demand periods to higher demand periods. In addition to maximizing the turbine operation during the on-peak period, the dispatch strategy minimizes waste of solar thermal energy by using the insolation prediction to anticipate, and by operating the turbine to avoid, overflow of thermal storage. This overflow would occur when thermal storage is full and the receiver output would exceed the maximum turbine consumption rate.

There are two ways SUNBURN may be modified that may be beneficial for a specific solar-only plant. First, the weather prediction algorithm used in SUNBURN is simply a projection of past weather. Because the prediction is central to the function of the dispatch strategy, it is likely that a more accurate prediction would increase the value of electricity generated by solar-only plants. Second, the dispatch strategy was designed for solar-only and hybrid plants with different field size and different storage capacity in a general location; it was not designed for a specific plant in a specific location. Therefore, optimizing the dispatch strategy for a particular plant in a particular location may increase the value of solar-only plants. The value-to-cost ratio of hybrid plants may also be increased by using a more accurate weather prediction algorithm or by optimizing the dispatch strategy for a particular application because less fuel may be used to obtain the same value. The dispatch strategy and SUNBURN require modification for utilities other than SCE. Ref. [24] outlines modifications that would be required. The design philosophy and algorithms of the dispatch strategy are described in detail in Section A.2.1 of Appendix A, the user's manual.

2.10 Weather Data

The weather data required by SUNBURN include measurements of direct normal insolation, wind speed, dew point temperature, barometric pressure, and dry bulb temperature. The weather data that were used for each hour of the simulation were averages of data recorded in Barstow, California in 1984, at time intervals of 15 minutes. These data were the most convenient to use and were being used for other annual power simulations. The average daily direct normal insolation was 6.42 kWh per square meter, or only 91 percent of the daily direct normal insolation averaged over a 25-year period. In July of 1984, the direct normal insolation was only 66 percent of the direct normal insolation averaged over the 25-year period for that month [25]. The afternoons were often cloudy, requiring a relatively large amount of thermal storage to allow a solar plant to operate with a high capacity factor during the afternoon on-peak period. July is a month during which it is important to provide electricity during the on-peak period in order to satisfy the performance requirement for the full capacity payments described by *Payment Option 2 of SCE Standard Offer 2.* Consequently, if a solar-only plant satisfied the performance requirement in July, then it was able to satisfy the performance requirement for the other summer months. Had July 1984 been more typical, it is likely that less thermal storage would have been required to generate approximately the same value of electricity.

Chapter 3

Results

For solar-only plants beginning operation in 1993, Figure 3.1 shows the value, Figure 3.2 shows the cost, and Figure 3.3 shows the value-to-cost ratio as functions of solar multiple and thermal storage capacity. Solar multiple is defined as the ratio of maximum thermal supply rate of the receiver to maximum thermal demand rate of the turbine (recall that the turbine size was fixed at 80 MW*e* net). Storage capacity is expressed in units of hours that the turbine can be operated at full power from a fully charged storage system. The value increases with increasing solar multiple because more solar energy is collected as the field size increases. The value also increases with increasing thermal storage capacity because generation of electricity can be shifted to higher demand periods and because less thermal energy is wasted. However, costs also increase with increasing solar multiple and increasing storage capacity. For 1993, the maximum value-to-cost ratio for a solar-only plant was calculated for a plant sized with a solar multiple of 1.62 and 5.5 hours of thermal storage.

For hybrid plants beginning operation in 1993, Figure 3.4 shows the value, Figure 3.5 shows the cost, and Figure 3.6 shows the value-to-cost ratio as functions of the solar multiple and thermal storage capacity. The value of electricity during the on-peak and mid-peak periods of both seasons was great enough to justify use of fuel whenever the turbine could not be operated using solar energy during these periods. The on-peak and mid-peak periods comprised 39.4 percent of the total time during 1984. For hybrid plants with solar portions capable of running the turbine significantly less than 39.4 percent of time, value was roughly constant with respect to solar multiple and storage capacity because fuel was used to run the turbine, during the on-peak and mid-peak periods, whenever solar energy was not available. For hybrid plants with larger solar portions, there was more solar energy available than could be dispatched in the on-peak and mid-peak periods. Thus, for these larger plants, value increases with increasing solar multiple and increasing storage capacity because more electricity is generated, using solar energy, during the off-peak periods. Costs of the solar portion of the plant increase with increasing solar multiple and storage capacity. Fuel costs decrease with increasing solar multiple and storage capacity. For 1993, the maximum value-to-cost

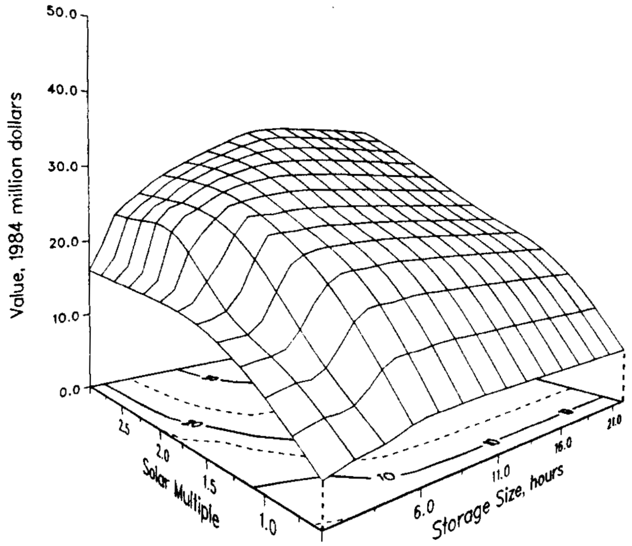

Figure 3.1: Solar-Only 1993, Value vs. Solar Multiple and Storage Capacity.

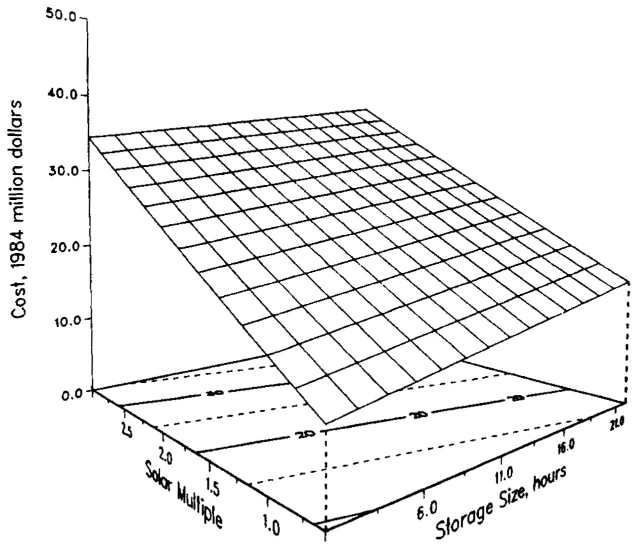

Figure 3.2: Solar-Only 1993, Cost vs. Solar Multiple and Storage Capacity.

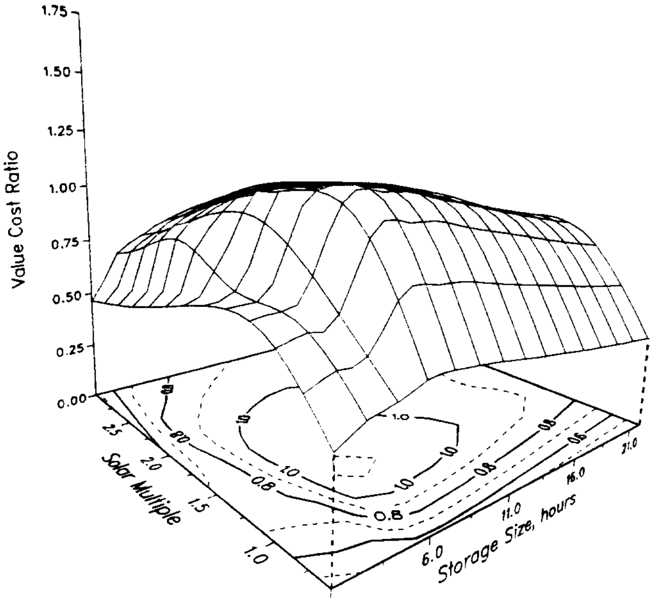

Figure 3.3: Solar-Only 1993, Value to Cost Ratio vs. Solar Multiple and Storage Capacity.

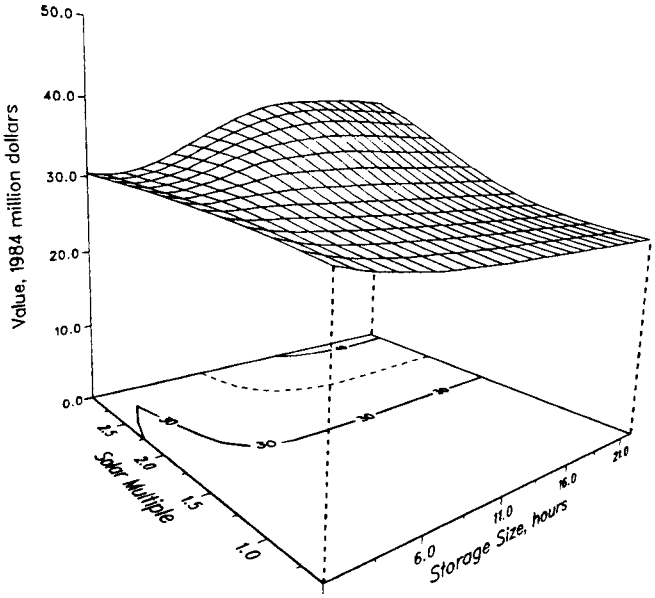

Figure 3.4: Hybrid 1993, Value vs. Solar Multiple and Storage Capacity.

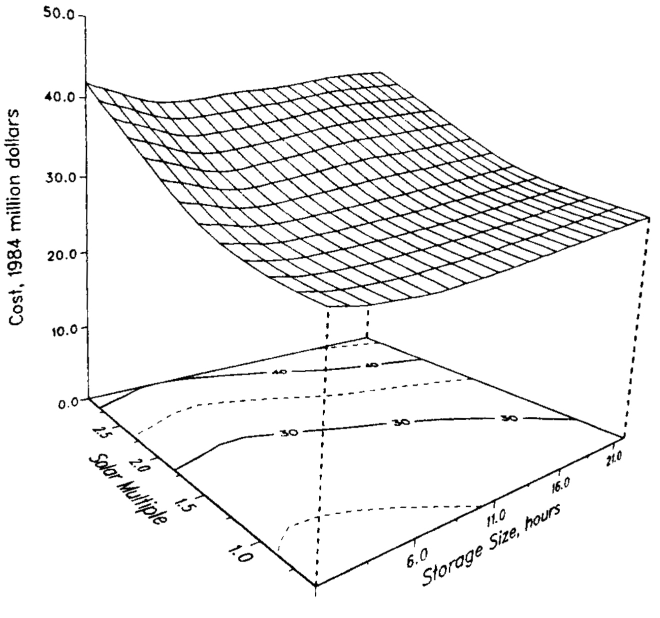

Figure 3.5: Hybrid 1993, Cost vs. Solar Multiple and Storage Capacity.

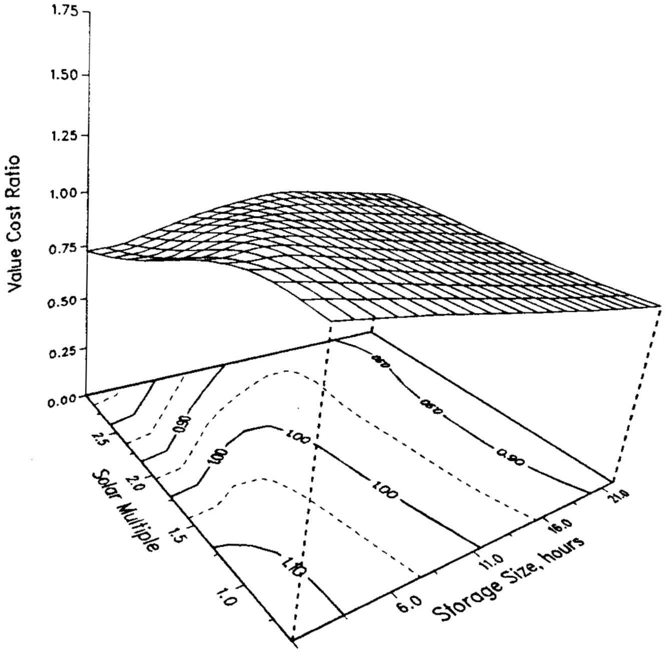

Figure 3.6: Hybrid 1993, Value to Cost Ratio vs. Solar Multiple and Storage Capacity.

Table II: Optimal Power Plant Designs.

Initial Operation Date	1990	1993	1994	1995	1998
Solar-Only					
Solar Multiple	1.08	1.62	1.62	1.62	1.62
Storage Capacity, Hours	6.5	5.5	5.5	5.5	5.5
Annual Capacity Factor	0.20	0.32	0.32	0.32	0.32
Value-to-Cost Ratio	0.752	1.08	1.17	**1.27**	**1.67**
Hybrid					
Solar Multiple	0.54	1.08	1.08	1.08	1.62
Storage Capacity, Hours	0.5	0.5	0.5	0.5	4.0
Fuel Fraction	0.73	0.48	0.48	0.48	0.25
Annual Capacity Factor	0.39	0.42	0.42	0.42	0.43
Value-to-Cost Ratio	0.971	1.13	1.18	1.23	1.46
Fuel-Only					
Annual Capacity Factor	0.33	0.33	0.33	0.33	0.33
Value-to-Cost Ratio	**1.11**	**1.19**	**1.19**	1.20	1.21

ratio for a hybrid plant was calculated for plant sized with a solar multiple of 1.08 and 0.5 hours of thermal storage.

Table II shows the optimal power plant designs for solar-only, hybrid, and fuel-only plants. The system designs shown in this Table were selected from 420 solar-only, 420 solar-hybrid, and 5 fuel- only system designs. For each initial operation date, and for solar-only and hybrid configurations, the solar multiple had six values ranging from .54 to 3.2, and the storage capacity had 14 values ranging from 0 to 22 hours. Results for all plant designs for the initial operation date of 1993 were plotted in Figures 3.1 through 3.6, above. For each date, the greatest value-to-cost ratio is printed in boldface type.

As shown in the Table, the value-to-cost ratio for the optimal solar-only systems exceeds unity for plants beginning operation just before 1993. If the long-term cost goals are reached on schedule, in 1998 a solar-only plant would operate with a value-to-cost ratio of 1.67. For the optimal solar-only systems, the largest value of solar multiple was 1.62 for plants beginning operation after 1993. For SCE in 1984, there were 3465 hours during the on-peak and mid-peak periods of both seasons out of a total of 8784 hours for the entire leap year. As the solar multiple increases, a greater fraction of the electricity must be generated when the value of electricity is less. The value of the additional electricity generated by plants with a larger solar multiple is not great enough to justify the additional cost for more heliostats, a larger receiver, and a larger thermal storage system. For solar-only plants, the optimal thermal storage capacity was found to be between 5.5 and 6.5 hours. Ref. [26] contains additional results and discussions concerning value and cost analyses of solar-only power plants.

As shown in Table II, the value-to-cost ratio for the optimal hybrid systems exceeds unity for plants beginning operation after 1990. In 1998, a hybrid plant is estimated to operate with a value-to-cost ratio of 1.46. For hybrid plants, the fuel fraction is defined as the ratio of of the thermal energy that is obtained from fuel to the total amount of thermal energy used by the turbine. As the solar multiple increases, thermal energy from solar is used instead of thermal energy from fuel, thereby decreasing the fuel fraction. Also for the hybrid plants, a small amount of thermal storage is always found to be better than no storage, even for 1990 when the solar multiple of the optimal hybrid plant is only 0.54.

The value-to-cost ratio of the fuel-only plants was nearly constant at 1.20 except for 1990 when the greater cost of conversion equipment decreased the value-to-cost ratio to 1.11. The cost of conversion equipment was shown in Table I in Section 2.2 above. For the range of initial operation dates considered, the dispatch strategy ran the turbine using fuel during the on-peak and mid-peak periods of both the summer and the winter seasons. Therefore, all the fuel-only plants operate with the same annual capacity factor. The value of electricity during the off-peak periods of both seasons is always less than the cost of fuel used to generate the electricity. Therefore, the fuel-only plants did not generate electricity during off-peak periods.

Chapter 4

Conclusions

The computer program SUNBURN was developed to provide a comparative value-and-cost analysis of solar-only, solar-hybrid, and fuel-only electric power plants. The value of electricity to SCE was equated with SCE's avoided costs of generating electricity. These avoided costs reflect the variation in the value of electricity to SCE as a function of time of day and time of year. The value-maximizing thermal energy dispatch strategy of SUNBURN controls flows of thermal energy within the power plants. The dispatch strategy uses thermal storage to shift generation of electricity from periods of lesser value to periods of greater value and to minimize waste of solar thermal energy. For hybrid plants and fuel-only plants, the turbine was operated using thermal energy from fuel burned in a salt heater if the levelized value of electricity generated by use of the fuel was greater than the levelized cost of the fuel used.

SUNBURN was used to determine the optimal power plant configuration, based on a value-to-cost ratio, for initial operation dates from 1990 through 1998 for plants sized at 80 MW*e* net. Actual weather data for Barstow, California were used. Fuel-only was found to be the preferred configuration from 1990 through 1994, and solar-only was the preferred configuration thereafter. Although an optimized hybrid plant was never found to have a greater value-to-cost ratio than both optimized solar-only and optimized fuel-only plants, a hybrid plant was found to have a value-to-cost ratio greater than unity after 1990.

Possible benefits of hybridization not considered in this study include use of fuel to provide thermal energy at higher temperatures and the ability to operate the turbine when only the solar portion of the plant is experiencing an outage. The value-to-cost ratio of solar-only and hybrid plants could probably be increased by using a more sophisticated weather prediction algorithm and by optimizing the dispatch strategy for a specific plant design, utility, and location. Also, the value-to-cost ratio of hybrid and fuel-only power plants may possibly be increased by performing a year-by-year analysis with dispatching of fuel depending on the electricity value rates and the fuel cost rate as functions of time.

Further studies could relate to the following subject areas:

- The effect of different algorithms for insolation prediction;
- The effect of changes in the avoided costs of SCE, particularly the decrease in avoided fuel costs;
- The effect of optimizing the dispatch strategy for a particular plant and location;
- Simulation over the plant's lifetime to determine the effect of different rates of fuel cost and capacity payment escalation;
- The effect of new cost estimates;
- The benefit of asymmetric fields; and
- The sensitivity to fuel cost.

Appendix A

User's Manual for SUNBURN

A.1 Summary

SUNBURN performs an hour-by-hour performance simulation and calculates the levelized value of electricity generated by, and the levelized cost of, solar-only, solar-hybrid, and fuel-only central receiver electric power plants. SUNBURN uses actual weather data and a value-maximizing thermal energy use, or dispatch, strategy that is designed for plants operating within the service area of the Southern California Edison Company (SCE). The dispatch strategy is suitable for solar-hybrid plants with different heliostat field size and different thermal storage capacity. Although the dispatch strategy was designed for solar-hybrid plants operating within the service area of SCE, its basic logic should be applicable to solar plants in other locations.

For each hour, the dispatch strategy maximizes the value of solar thermal energy by shifting generation of electricity from periods of lesser demand to periods of greater demand. This is accomplished by controlling the solar thermal energy flows into and out of thermal storage and into the turbine. Then, for each hour during which the turbine is not operating at full power using solar thermal energy, the turbine is operated at full power using thermal energy from fuel, if the incremental value of burning fuel is greater than the incremental cost of the fuel. In one run of SUNBURN, *NFLD* times *NSTO* times *NSCF* systems can be simulated. *NFLD* is the number of heliostat field sizes, *NSTO* is the number of thermal storage capacities, and *NSCF* is the number of solar cost factors. The cost factors multiply costs of the plant's solar components. Use of these factors is described below.

SUNBURN assumes that the value of the electricity generated by a hybrid plant is equal to the utility's generation cost of that amount of electricity, using other power sources available to the utility. For SCE, these costs are called avoided costs and are described by *SCE Standard Offer No. 2, Payment Option 2* [11,12]. The three daily rate periods, two seasons, and holidays of SCE are defined by *Tariff Schedule*

No. TOU-8 [16]. Refer to Appendix B for a detailed discussion of the method used to calculate the value of electricity. Since the value calculation and the dispatching of fuel depend on the capacity bonus payment rates, which in turn depend on the on-peak monthly capacity factors, the program must use an iterative procedure to optimize use of fuel. High values of the on-peak monthly capacity factors are guessed; the bonus capacity payment rates are calculated; and the annual simulation is performed. New values of the on-peak monthly capacity factors are then calculated. This procedure is repeated with the new capacity factors used as the guessed capacity factors until the new capacity factors are within 1 percent of the guesses.

The economic methodology levelizes value and cost over the lifetime of the plant. It is a constant dollar analysis with amounts expressed in 1984 dollars. The methodology was described in Section 2.3 above.

The solar technology incorporated in SUNBURN consists of heliostats surrounding an external molten salt receiver and molten salt thermal storage. For hybrid and fuel-only plants, gas is burned in a salt heater sized to provide enough steam to operate the conventional steam turbine at full power. The heater is omitted from solar-only systems. Simple models are used in the program for estimating thermal losses from thermal storage, forced and scheduled outages, time and energy requirements for receiver and turbine start-up, and electrical parasitics. When the turbine is generating electricity, electrical parasitics are termed operational and are obtained from the gross electric generation. When the turbine is off or is in start-up, the electrical parasitics are termed non-operational and are assumed to be obtained from SCE at the same avoided-cost rates used to determine the value of electricity.

The user must provide weather data in file WEATHER and must make certain that the default algorithms for calculating system performance, levelized electricity value, and levelized plant cost are pertinent to the particular problem of interest. Many of the default inputs may be changed by specifying new values in the input file SBNAML, which contains data in a format suitable for the NAMELIST utility. The version of SUNBURN that runs on a microcomputer obtains user input from file USERIN.FOR instead of from the SBNAML file. USERIN.FOR must be compiled and then linked, as a subroutine, with the main program before execution. File PRECIS contains a summary of the results, and file DETAILS contains details of the results.

The general approach used in writing SUNBURN emphasizes simplicity and clarity. Except for the NAMELIST utility used in the VAX version, the program conforms to standard FORTRAN, ANSI X3.9-1978 [27]. All parameters passed from the main program to and from subroutines are included in the CALL and SUBROUTINE statements. The source file consists of about 2600 lines of code, half of which are comments, including an alphabetized list of variables and subroutines.

This user's manual describes the organization and algorithms of the main program and the subprograms, and then presents an example problem. The dispatch strategy is part of the main program. The version of the code that is described is the version that runs on a VAX. Notes are included describing differences between the version of the program that runs on a microcomputer. SUNBURN has also been run, with minor modifications, on Cray machines.

A.2 Main Program - SUNBURN

The main program begins with introductory comments and alphabetized lists of variables and subroutines. Arrays are then dimensioned and the two input files, SBNAML and WEATHER, and the two output files, PRECIS and DETAILS, are opened. SBNAML contains, in NAMELIST format, the problem specification generated by the user. WEATHER contains the weather data. Default values of the input variables are then defined and the file SBNAML is read, changing only the values of input variables that are defined in the SBNAML file. The example problem, presented in Section A.4, lists the default values of the input variables. The file SBNAML is not used by the microcomputer version of SUNBURN. Instead, a file called USERIN.FOR is modified by the user, compiled, and linked as a subroutine of SUNBURN. The file USERIN.FOR defines the same input variables that can be defined using the SBNAML file.

The following segment of the program calculates values of variables based on the variables input in the preceding segment. The start and end times of each of the three daily rate periods are defined in local standard time. Since holidays and weekends are entirely off-peak periods, the start and the end times of the on- and the mid-peak periods are set to a flag value of zero. For those days having mid- or off-peak periods in the morning and in the evening, the start time is defined to be the beginning of the morning period and the end time is defined to be the end of the evening period. For example, for all days, the start time of the off-peak period was zero, and the end time of the off-peak period was 24. Throughout the program, all times are local times, except in subroutine SUNANG, in which local time is converted to solar time. Therefore, the rate periods defined by *Tariff Schedule No. TOU-8* [16] had to be adjusted, since they are given in clock time. The floating point value of the integer variable *IHOUR* is used throughout SUNBURN as the time at the end of the current hour being simulated.

SUNBURN next calculates in hours the total amount of time, the amount of time for scheduled maintenance, and the amount of time for forced outages during each of the three rate periods for each month of the year. A call to subroutine ECON defines the economic factors used to levelize the value and cost figures. The maximum possible capacity payments are calculated for each rate period of each month of the year, assuming plant operation with annual capacity factor of 100 percent. These maximum capacity payments are used later to normalize the actual capacity payments for printing as results. SUNBURN then calculates the levelized cost of the salt heater and the levelized fuel cost rate.

The remainder of the main program is repeated for each of the *NFLD* values of the heliostat field area. A call to subroutine SIZE gives the receiver absorber area and the tower height for each heliostat field size. The tower height is calculated and printed for user information only. The solar multiple is then calculated by simulating the performance of the heliostat field and receiver for each hour of the year. Solar multiple is defined as the ratio of the maximum thermal power from the receiver divided by the maximum thermal energy consumption rate of the turbine. Subroutines SUNANG and FIELD are called when the solar multiple is being calculated. For holidays and weekends, this portion of the code makes the on- and mid-peak periods begin and end at sunset. This was done because the dispatch strategy does not have separate algorithms for holidays and weekends and using sunset shifts the time the turbine operates to days with on- and mid-peak periods from those days without such periods.

The remainder of the main program is repeated for each of the *NSTO* values of the thermal storage capacity. The monthly on-peak capacity factors are guessed to be 100 percent and the contract capacity (See Appendix B for the definition of contract capacity.) is equated with the turbine's net rated output. New values of the monthly on-peak capacity factors are calculated in the following part of the code, which is the annual performance simulation. If any of these capacity factors is more than 1 percent different from the the value guessed, then the annual simulation iterates with the new values of the monthly capacity factors used as the guessed values.

The simulation also repeats if the performance requirement is not satisfied, that is, if any of the on-peak capacity factors for the summer months is less than 80 percent. In this case, the contract capacity is decreased in an attempt to satisfy the performance requirement at a lesser value of the contract capacity. Decreasing the contract capacity decreases the denominator of the quotient that is the capacity factor; however, the numerator is also decreased because the amount of electricity that is allowed to be counted in the calculation of the monthly on-peak capacity factor is only that amount generated at power levels less than the contract capacity. Therefore, it is possible that the performance requirement cannot be satisfied merely by decreasing the contract capacity; in this event, the program will continue to iterate for smaller and smaller values of the contract capacity. To avoid excessive computation, iteration is terminated if the contract capacity becomes less than one-half of the net rated turbine output. For each iteration, subroutine BONUS is called to determine the new bonus capacity payment rates based on the latest guessed values of the monthly on-peak capacity factors. Then, arrays containing sums are set to zero and the weather data file is rewound.

The annual simulation begins by incrementing the value of the forced outage day counter and checking if a forced outage occurs for the present day. If so, the heat losses from storage and the electrical parasitics are calculated for an entire day, and the forced outage day counter is set to zero. Execution then proceeds to the following day. If a forced outage does not occur for the day, calls at the beginning of the day to subroutines WBTEMP, SUNANG, and ALLEN then determine the wet bulb temperatures, sun angles and times of sunrise and sunset, and maximum clear sky insolation, respectively, for each of the 24 hours of the day. The following part of the annual simulation is the dispatch strategy.

A.2.1 Detailed Description of the Dispatch Strategy

The dispatch strategy of SUNBURN is a set of rules, which are designed to run the turbine during the on-peak period in preference to the mid- or off-peak periods, and to run the turbine during the mid-peak period in preference to the off-peak period. Compared to simply running the turbine when the sun is shining, the increase in value of electricity can be substantial and may be obtainable with little or no increase in cost. In addition to maximizing the operation of the turbine during the on-peak period, the dispatch strategy minimizes discard of solar thermal energy by using an insolation prediction to anticipate, and by operating the turbine to avoid, discard of thermal energy. This discard would occur when storage is full and the receiver output is greater than the maximum turbine consumption rate. The dispatch strategy is applicable for solar plants with different field size and different storage capacity.

Thermal energy dispatch is simply defined as the manner in which thermal energy is used in a power plant. There are several possible objectives of thermal energy dispatch strategies for a solar plant. These are listed below:

1. minimize discard of thermal energy - discard occurs when thermal storage is full and the receiver thermal power output exceeds the turbine energy consumption rate,

2. maximize turbine efficiency - run the turbine at full power,

3. maximize turbine life - minimize the number of turbine starts, and

4. maximize value of electricity - operate the turbine during high demand periods in preference to low demand periods.

The principal problem for thermal energy dispatch strategies for solar plants is the variation in insolation. The principal tool used to deal with this problem is thermal storage.

The thermal energy dispatch strategy of SUNBURN attempts to satisfy all four of the objectives listed above. Often, one objective can be satisfied only at the expense of another. For example, to satisfy objective #4, it is desirable to postpone turbine startup, allowing storage to be filled. However, to satisfy objective #1, it is desirable to advance turbine startup to avoid possible overflow of storage. Therefore, compromises must be made. The compromises that are made, corresponding to the four objectives above, are as follows:

1. A prediction of energy flows is used to determine when to start the turbine so that overflow of storage is avoided;
2. The prediction of energy flows is based on running the the turbine at full power;
3. The turbine is run at less than full power, rather than shutdown, if it is possible that the turbine would be re-started later in the day; and
4. A prediction of energy flows is used to determine when to start the turbine so that the maximum amount of energy is stored prior to turbine startup, consistent with #1 above. Before the on-peak period, the turbine may be derated, if it is predicted that insufficient energy will be available to operate the turbine at full power throughout the on-peak period. After the on-peak or mid-peak periods, and on weekends and holidays, the turbine may be shutdown before storage is exhausted, to allow for the possibility that there will be insufficient insolation to run the turbine during the on-peak and mid-peak periods for the next day or the day after the next day.

The dispatch strategy assumes that loss of heat from thermal storage can be neglected, for the purpose of value-maximizing dispatch.

The dispatch strategy controls turbine startup, operation, and shutdown according to the following energy quantities:

PHBT, the predicted amount of thermal energy collected by the receiver from the current time until sunset;

STLE, the amount of energy currently in storage; and

SCO1, SCO2, and SCO3, calculated values of thermal storage, called carryover storage.

PHBT is calculated by subroutine PREDICT. PREDICT uses one of two arrays of predicted insolation values, *SUNP* and *SUNAP*. *SUNP* is updated once at the end of each day, within the main program. *SUNP* is derived exclusively from actual insolation for previous days. *SUNAP* is set equal to *SUNP* at the beginning of each day. Then, for each hour that the sun is above the horizon, subroutine ADJPRE adjusts *SUNAP*, for each hour until sunset, according to the difference between the predicted and the actual insolation value for the current hour. See Section A.3.1 for a description of subroutine ADJPRE.

The dispatch strategy uses thermal storage for the following two objectives:

1. to avoid discard of thermal energy when the receiver collects more power than the turbine can use, and

2. to insure generation of power during the on-peak period, even if there is no incident solar energy at this time.

The effectiveness of the dispatch strategy in accomplishing these goals depends on solar multiple, storage capacity, and insolation. The carryover storage energy levels, *SCO1, SCO2*, and *SCO3* are calculated and used to accomplish the second objective, without precluding the first. They are calculated once at the beginning of each day from the variable *SMAX*, which is the maximum level of thermal energy in storage that is predicted to occur for the day, subject to the following two assumptions:

1. storage is empty at the beginning of the day, and
2. the turbine is started at time T.

$T =$ (time at the end of the on-peak period) - $PHBT/HMAX$,

$HMAX =$ the thermal energy consumption rate of the turbine at full power, and

$PHBT =$ the predicted amount of energy collected by the receiver from the current time until sunset. It is the sum of the receiver hourly thermal outputs, *HBT*, calculated using predicted insolation.

Note: For weekends and holidays (off-peak periods), the start and the end times of the on-peak period are set to the time when sunset occurs.

SMAX is calculated at the beginning of each day using insolation prediction *SUNP*. The calculation is performed by subroutine SCOVER (see Section A.3.8) according to the following procedure:

$$STLE_i = \sum_{j=1}^{i}(HBT_j - ETT_j) \tag{A.1}$$

$$SMAX = Max(STLE_i),\ i = 1,24 \tag{A.2}$$

$STLE_i =$ the energy in storage at the end of the *ith* hour of the day,

$HBT_j =$ the energy collected by the receiver during the *jth* hour of the day, and

$ETT_j =$ the amount of energy used by the turbine during the *jth* hour of the day.

Using Equation A.2, *SMAX* is then calculated as the maximum energy level occurring in storage for the day.

The carryover storage levels are then calculated as follows:

$$\begin{aligned} SCO1 &= (STO(ISTO) - SMAX), with\ today's\ SMAX && \text{(A.3)} \\ SCO2 &= (STO(ISTO) - SMAX), with\ tomorrow's\ SMAX && \text{(A.4)} \\ SCO3 &= SCO2 + (E - PHBT) && \text{(A.5)} \end{aligned}$$

In Equations A.3 and A.4, *STO(ISTO)* is the *ISTO-th* value of the thermal storage capacity. *SCO1* will be equal to *SCO2* if the on-peak period ends at the same time today as it does tomorrow. In Equation A.5, E is defined to be the greater of of E' and E'', where,

E' = the energy required to run the turbine at full power from the beginning of the mid-peak period tomorrow through the end of the on-peak period tomorrow, and

E'' = the energy required to run the turbine at full power from the beginning of the mid-peak period the day after tomorrow through the end of the on-peak period the day after tomorrow.

The carryover storage levels are constrained to be between zero and the storage capacity.

There are three major daily time intervals during which the turbine will be operated using a different procedure:

a. before and during the on-peak period,

b. during the mid-peak period which occurs after the on-peak period (See Figure 2.2), and

c. during the off-peak period which occurs after the on-peak period, and during weekends and holidays.

SCO1 is used to control turbine startup and operation during interval a; *SCO2* is used to control turbine operation during interval b; and *SCO3* is used to control turbine startup and operation during interval c.

The dispatch strategy attempts to reserve *SCO1* in thermal storage before the on-peak period. This is accomplished by delaying turbine startup and, if necessary, by derating the turbine before the on-peak period. Since *SCO2* is *SCO1* calculated for tomorrow (see above), during time interval b the turbine is shutdown when the energy level in storage drops below *SCO2*. Thus, the next day will begin with the next day's value of *SCO1* in storage.

Time interval c is during the off-peak period. It is desirable to shift generation of electricity from the off-peak period to either the on-peak or the mid-peak periods. Thus, in time interval c, if PHBT is less than *SCO3*, then the turbine will be shutdown.

At the beginning of each day, values of *PHBT* and the carryover storage energy levels, *SCO1, SCO2*, and *SCO3* are calculated based on the predicted insolation for the day. The insolation prediction is contained in array *SUNP*. For each hour between the times of sunrise and sunset subroutine ADJPRE is called to modify the weather prediction for the present hour and for each of the hours for the rest of the day. This updated insolation prediction is contained in array *SUNAP*. Then, subroutine PREDICT is called to calculate new values of *PHBT* based on the modified weather prediction. The rules of the dispatch strategy are organized in two groups, depending on whether the turbine is not running or is running.

Turbine Not Running

If the turbine is not running, the dispatch strategy must decide if it should be started. If the present time is before the on-peak period of any day (for holidays and weekends, the main program sets the beginning and the end times of the on-peak period to sunset), and if the following four conditions are satisfied, then the turbine will be started.

1. The energy level in storage, *STLE*, exceeds *SCO1*,
2. The sum of *PHBT* and *(STLE − SCO1)* must be greater than the amount of energy required to start and run the turbine at full power until the end of the on-peak period. (Recall that the energy required to start the turbine is the product of the maximum thermal energy consumption rate of the turbine and the time required to start the turbine),
3. The sum of *HBT* and *(STLE − SCO1)* must be greater than the amount of energy required to start the turbine and run it for the current hour, and
4. *(STLE − SCO1)* must be sufficient to start and run the turbine at full power until 2.0 hours after sunrise. This condition insures that carryover storage will not be used to run the turbine before sunrise.

If the present time is within the turbine startup time, *TSTUR*, of the on-peak period, today is not a holiday or a weekend, and if the following two conditions are satisfied, then start the turbine in anticipation of the on-peak period.

1. *(STLE + PHBT)* is greater than the amount of energy required to start and run the turbine until the end of the on-peak period, and
2. *(STLE + HBT)* is greater than the amount of energy required to start the turbine.

If the present time is during the on-peak period, today is not a holiday or weekend, and if the following condition is satisfied, then start the turbine.

1. *(STLE + HBT)* is sufficient to start the turbine.

The following two additional rules, concerning turbine startup, apply for all times.

1. If *(STLE + HBT)* minus the storage capacity, *STO(ISTO)*, is greater than the energy required to start the turbine, then start the turbine to avoid overflow of thermal storage.
2. If the present day is a holiday or weekend and *(STLE + PHBT)* is less than the sum of *SCO3* and the energy required to start the turbine, then do not start the turbine.

Turbine Running

If the turbine is running, the dispatch strategy must decide at what power level the turbine should be operated, and must consider when to turn off the turbine. The turbine may be turned off before thermal storage is exhausted depending, as described below, on the values of the carryover storage levels *SCO2* and *SCO3*. Thermal to electric conversion efficiency is maximized by operating the turbine at full power. However, running the turbine at less than full power (derated) before the on-peak period may be desirable to conserve thermal energy for use during the on-peak period. In this event, the mass flow fraction of the turbine was determined according to the amount of energy predicted from the receiver for the remainder of the day, the amount of thermal energy in storage, the carryover storage energy levels, and the rate periods of the day. The minimum mass flow fraction of the turbine is equal to .25. Frequent on-off cycling of the turbine was considered to be harmful to the turbine and was avoided.

If today is a holiday or weekend and *(STLE + PHBT)* is less than *SCO3*, then turn the turbine off.

If the present time is before the on-peak period, then derate the turbine if either of the following conditions applies.

1. *STLE* is less than *SCO1*. The idea is to maintain *SCO1* as a reserve energy level in storage for possible use during the on-peak period, should the actual insolation be less than the predicted insolation, or
2. *PHBT + (STLE - SCO1)* is less than the energy required to run the turbine at full power from the present time until the end of the on-peak period. Again, the idea is to maintain *SCO1* as a reserve energy level.

If the present time is during the on-peak period then run the turbine at full power or use as much energy as is available from the receiver and from storage.

If the present time is after the on-peak period but before the end of the mid-peak period (in summer, there is a mid-peak period following the on-peak period; in winter, the mid-peak period and the on-peak period end at the same time), then run the turbine until the energy in storage decreases to *SCO2*. Then, turn the turbine off.

If the present time is after the mid-peak period after the on-peak period, then run the turbine until the energy in storage decreases to *SCO3*. Then, turn the the turbine off.

At the end of each day the daily insolation prediction in array *SUNP* is set equal to the sum, divided by four, of three times the previous daily prediction plus the actual insolation that occurred for the day.

At the end of the annual simulation, SUNBURN calculates new values of the monthly on-peak capacity factors and compares these values with the guessed values. If the difference is greater than one percent for any month or if the performance requirement is not satisfied (any of the monthly on-peak capacity factors for the summer months is less than 80 percent) at the current value of the contract capacity, then the annual simulation repeats, with the resultant capacity factors used as the new guesses. For the annual simulation, new bonus capacity payment rates are calculated based on the latest guesses of the monthly on-peak capacity factors. If iteration is terminated and the performance requirement could not be satisfied, then the capacity payments are set to zero.

The next part of the main program calculates the levelized cost of the solar components of the plant and computes values of the output variables and arrays. The remainder of the main program prints the results and is executed *NSCF* times, once for each value of the solar cost factor. The solar cost factor is a constant factor multiplying all solar component costs, including operation and maintenance costs. Usually, *NSCF* will be set to unity and the first value of the array of solar cost factors will be 1.00. The solar cost factors may be useful for determining the cost reduction required to make the value-to-cost ratio equal to a certain value, most likely unity.

A.3 Subprograms of SUNBURN

A.3.1 Subroutine ADJPRE

ADJPRE is called once for each hour during which the sun is above the horizon. ADJPRE performs an adjustment of the predicted insolation, dry bulb temperature, and wind speed. The adjustment is equal to the difference between the predicted and the actual weather reading for the current hour. It is subtracted from the predicted weather readings for the current hour and all remaining hours of the day. The predicted values of the insolation must be between zero and the maximum clear sky insolation, which is calculated by subroutine ALLEN. The weather prediction is used by subroutine PREDICT to predict the amount of thermal energy that will be collected by the receiver during the time period beginning with the current hour and ending at sunset.

A.3.2 Subroutine ALLEN

ALLEN is called once at the beginning of each day to calculate the maximum clear sky insolation possible for each hour that the sun is above the horizon. Insolation values calculated by ALLEN are used to limit the insolation prediction performed by subroutine ADJPRE. ALLEN was obtained from Reference [21].

A.3.3 Subroutine BONUS

BONUS is called once at the beginning of each iteration of the annual simulation. BONUS calculates the bonus capacity payment rates as the total capacity bonus payment for each month divided by the amount of net electricity generated for that month during the on-peak period. This amount of electricity must be generated at power levels less than the contract capacity. The calculation of the bonus capacity payment is based on the total period hours minus the maintenance hours, as described in Appendix B. There is no bonus capacity payment for mid- or off-peak periods.

A.3.4 Subroutine ECON

ECON is called once to calculate the economic factors used to levelize the cost and value figures over the lifetime of the plant. These economic factors are present value factors multiplying the avoided capacity and avoided energy rates, present value factors multiplying the fuel and operation and maintenance costs, and the capital recovery factor. Equations for and use of these factors were discussed in Section 2.3 above, entitled *Economic Methodology.*

A.3.5 Subroutine FIELD

FIELD is called from two places in the main program and from subroutines PREDICT and SCOVER and simulates the performance of the heliostat field and receiver. In the main program, FIELD is used to determine the solar multiple and to determine the gross amount of thermal energy absorbed by the receiver, receiver heat losses, piping heat losses, heat consumed for start-up of the receiver, and net thermal energy, HBT, collected by the receiver for the current hour using actual weather data. In subroutines PREDICT and SCOVER, FIELD is used to calculate the net thermal output of the receiver for each hour of a day, using predicted weather data.

FIELD performs a linear interpolation over the three variables, field area, solar azimuth angle, and solar zenith angle, to give the optical efficiency of the field and the receiver, for the particular solar field considered and for one sun position. Thermal losses from the receiver are calculated using correlations developed by Stoddard [22]. Heat losses from pipes are estimated to be 5 percent of the receiver thermal losses when the receiver is operating and zero when the receiver is not operating. The thermal energy required to start the receiver is set equal to the steady state receiver thermal losses over a period of 30 minutes. FIELD controls start-up and shutdown of the receiver so that the net thermal energy collected by the receiver is always positive. FIELD counts the number of receiver starts.

For the turbine size of 80 MW*e* net, solar multiples ranged from .54 to 4.8 for the six DELSOL3 runs incorporated into SUNBURN. The corresponding heliostat areas ranged from 197,000 to 1,800,000 square meters. The heliostats were rectangular with sides approximately 12 meters in length. The reflectivity of the mirrors of the heliostats was .92 and the absorptivity of the receiver was .95.

A.3.6 Function HTREFF

HTREFF is called from the main program and calculates the efficiency of the fuel-fired salt heater as a function of load fraction. This efficiency is defined to be the ratio of energy transferred to the salt to the energy contained in the fuel based on the higher heating value of the fuel. The heater efficiency is plotted in Figure A.1.

A.3.7 Subroutine PREDICT

PREDICT calculates the amount of thermal energy to be collected by the receiver, *PHBT*, during the period from the current time until sunset. PREDICT is called twice in the main program and once in subroutine SCOVER. In the main program, at the beginning of each day, PREDICT calculates *PHBT* based on the daily weather prediction. Also in the main program, for each hour that the sun is above the horizon, PREDICT calculates *PHBT* based on the hourly weather prediction. In subroutine SCOVER, at the beginning of each day, PREDICT is called to calculate *PHBT*, which is then used to determine when the turbine will be started.

PREDICT calls subroutine FIELD to determine the net receiver output for each hour from the current time until sunset.

A.3.8 Subroutine SCOVER

SCOVER is called in the main program at the beginning of each day and calculates

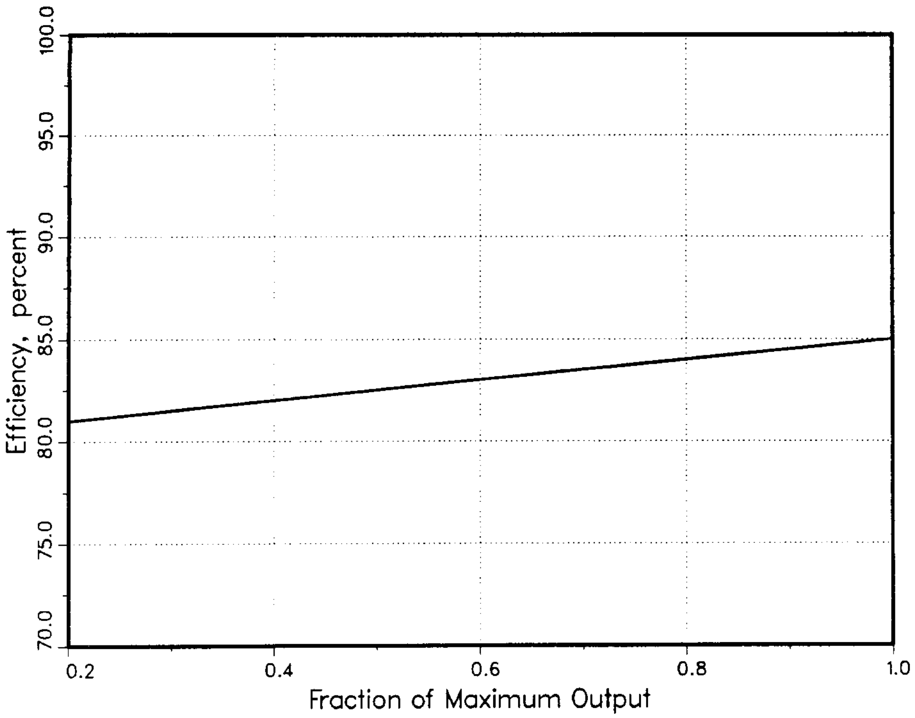

Figure A.1: Heater Efficiency vs. Fraction of Rated Output.

SMAX, the maximum amount of thermal energy in storage for the day, assuming that storage is empty at the beginning of the day and assuming that the turbine is started and run at full power, using exactly the predicted amount of thermal energy from the receiver for the day such that the energy is exhausted at the end of the on-peak period. SCOVER calls subroutine PREDICT to determine the predicted amount of thermal energy collected by the receiver for the day based on the predicted insolation for the day. SCOVER calls subroutine FIELD to obtain values of receiver thermal output for each hour of the day.

Figure A.2 shows the receiver thermal power output, thermal power consumption by the turbine, and energy level in thermal storage calculated by SCOVER for a solar plant with solar multiple of 1.62 operating on a weekday in July. In the figure, thermal energy is expressed as the number of hours that the turbine can be operated at maximum power using that amount of energy. Thermal power is normalized by the maximum thermal power required by the turbine. As was typical of July, the afternoon was cloudy, as shown by the sharp decrease in receiver output after 1 PM. *SMAX* is defined to be the maximum thermal energy level in storage for the day.

The thermal storage capacity minus *SMAX* is the amount of excess, or carryover storage, *SCO1*, that can be filled at the beginning of the day without causing overflow of storage later in the day, provided the actual insolation for the day to come is less than or equal to the predicted insolation that was used to calculate *SMAX*. If the actual insolation is greater than the predicted insolation the turbine may be started before the turbine start-up time calculated in SCOVER. If the actual insolation is less than

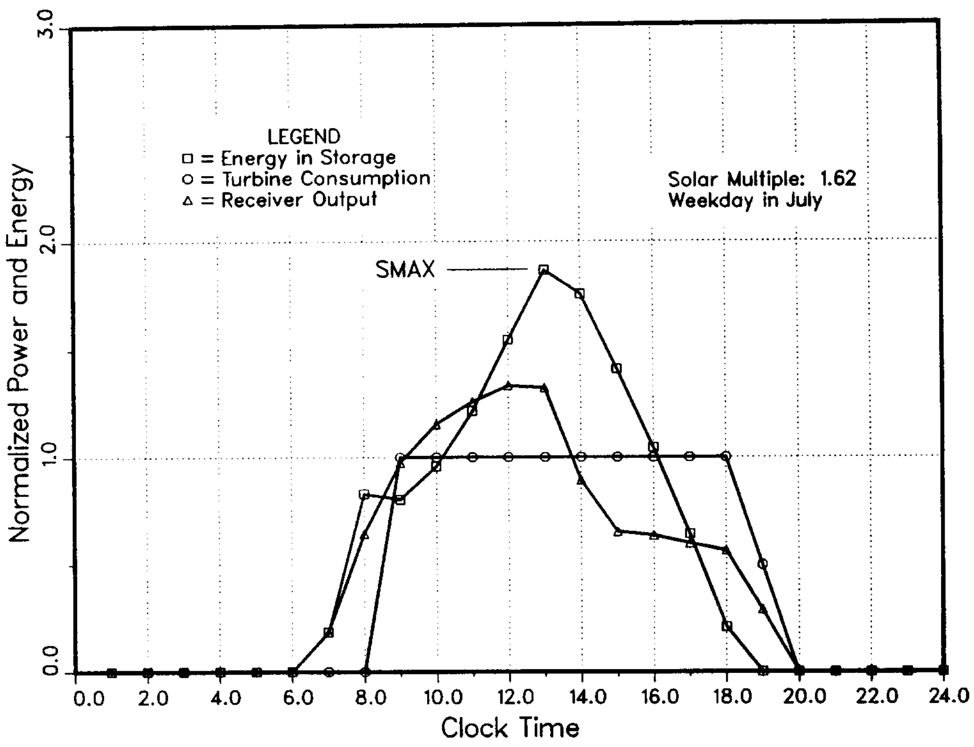

Figure A.2: Calculation of SMAX.

the prediction, then the turbine may be started later than anticipated, the turbine may be derated, or carryover storage may be used during the on-peak period.

With the above definition of *SMAX*, the amount of thermal energy discarded did not go to zero for large thermal storage capacities. Therefore, the value of *SMAX* was increased, within SCOVER, according to the following formula.

$$SMAX = SMAX + (1. - SM) * HMAX * 3.0$$

SM is the solar multiple. The value of 3.0 was determined by comparing results of various SUNBURN runs. For the example of Figure A.2 the value of *SMAX* returned to the main program was 3.71 hours.

A.3.9 Subroutine SIZE

SIZE is called in the main program once for each heliostat field size. SIZE calculates the absorber area of the receiver and the tower height by interpolating receiver areas and tower heights determined by DELSOL3 for the optimized system designs incorporated into SUNBURN. The interpolation is based on area of the heliostat field. Although the tower height is calculated and printed, it is not used in any of the calculations in SUNBURN.

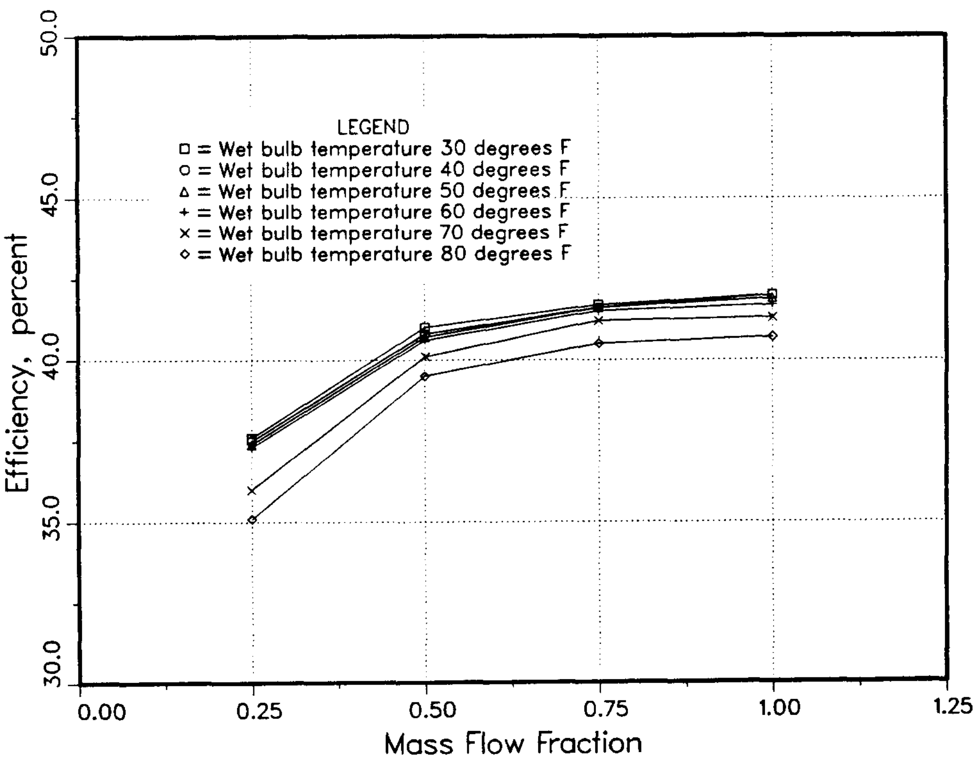

Figure A.3: Turbine Efficiency vs. Mass Flow Fraction.

A.3.10 Subroutine SUNANG

SUNANG is called in the main program each day and calculates the times of sunrise and sunset and 24 values of elevation and azimuth angle of the sun. Unlike the rest of SUNBURN, SUNANG operates in solar time. The solar time used in SUNANG is adjusted according to the equation of time [28]. Also, the time is adjusted to account for the distance of the power plant from the nearest time meridian.

A.3.11 Function TRBEFF

TRBEFF calculates the gross turbine efficiency as a function of ambient wet bulb temperature and mass flow fraction according to data obtained from the manual for the computer code STEAEC [23]. These efficiency values were adjusted upwards to correspond with the conversion efficiencies in the Five Year Plan for steam turbines that are currently available. The turbine modeled by STEAEC was the one used in the Solar One pilot plant. Figure A.3 shows the dependence of gross turbine efficiency on mass flow fraction, with ambient wet bulb temperature as parameter.

A.3.12 Subroutine WBTEMP

WBTEMP is called in the main program at the beginning of each day and calculates a value of wet bulb temperature for each hour of the day as a function of dry bulb temperature, dew point temperature, and atmospheric pressure. The algorithm used by WBTEMP was obtained from the computer code STEAEC [23].

A.3.13 Subroutine WHEN

WHEN is called to determine the season, month, and rate period for the current instant in time. The three variables, *ISEA*, *IMON*, and *IPER* are set by WHEN to designate the season, month, and rate period. Summer is indicated by *ISEA*= 1 and winter by *ISEA*= 2. January is indicated by *IMON*= 1, February by *IMON*= 2, and so on. The on-peak period is indicated by *IPER*= 1, the mid-peak period by *IPER*= 2, and the off-peak period by *IPER*= 3.

A.4 Example Problem

The example problem is the default problem, a hybrid, which is run by using the following, beginning in column 2, as input file SBNAML.

```
Default Case,
$DESIGN
$END
$SYSTMS
$END
$COSTS
$END
$UTLITY
$END
$ECONOM
$END
```

The following is a list of the definitions and the default values of the input variables. These input values can be changed easily by including the variable name and its' new value in the proper namelist of the input file. (For example, to change the net turbine rating to 50 MW*e*, use $DESIGN PSIZE=50.)

Namelist DESIGN

PSIZE = 80. net turbine rating is 80 MW*e*

TSTUR = .4 .4 hours is required to start the turbine TSTUR must be less than 1 hour

NFO = 20 number of days between forced outages

STOHLR = .03 3 percent of the thermal energy in storage is lost over a 24 hour period

NDAYS = 345 the simulation is over the first 345 days of the year the remainder of the year is for scheduled maintenance

Namelist SYSTMS

NFLD = 1 one field size (solar multiple) is simulated

FLD(1) = 395098. the field simulated has total heliostat area of 395098. square meters

NSTO = 1 one thermal storage capacity is simulated

STO(1) = .5 the storage capacity simulated is .5 hours

NSCF = 1 one solar cost factor is used

SCF(1) = 1. the solar cost factor is 1.

Namelist COSTS

BCOSTR = 100. the burner cost rate is \$100 per kilowatt thermal

GASBIL = 4.25 the cost of gas is \$4.25 per million BTU

GASY = 1985.67 year when GASBIL was \$4.25 (August 1985)

CONT = 20. a 20 percent contingency cost is added to the costs of the solar components, including the turbine costs. CONT does not apply to the operation and maintenance costs, nor to the cost of the salt heater.

FLDC = 80. heliostat field costs are \$80. per m^2

RECC = 45. receiver costs are \$45. per m^2 of heliostats

TRANC = 40. transport costs are \$40. per m^2 of heliostats

STOC = 20. thermal storage costs are \$20. per kilowatt hour thermal

EPGSC = 400. conversion costs are \$400. per gross kW*e*

BOPC = 60. balance of plant costs per m^2 of heliostats

OMC = 11. annual operation and maintenance costs per m^2 of heliostats

Namelist UTLITY

CCPAY = 175. contract capacity price in \$/kWe/year

CCPR = .06118 annual escalation rate, including inflation, of CCPAY

CCPY = 1989. year when which CCPAY = 175.

ALF(2,3) = .1643, .0245, .0028, .0123, .0025, .0036, array of factors converting CCPAY to a monthly capacity price for each rate period of each season

CPKWH = 6.1, 5.7, 4.7, 4.6, 4.0, 4.0, period energy value rates

CPKWHY = 1985.67 year when values of CPKWH are obtained (August 1985)

Namelist ECONOM

YEAR = 1993. initial year of operation. The solar component costs in namelist COSTS should be attained three years prior to this date

TLIFE = 30. plant lifetime

RATDR = .0315 real after tax discount rate for the utility

FCR = .0615 fixed charge rate, not including inflation, of the utility

PVC = 1.0318 cost multiplier to account for interest during construction

GE = .0234 real annual escalation rate for the period energy value rates in namelist UTLITY

GF = .0234 real annual escalation rate for fuel cost

GOM = .0 real annual escalation rate for operation and maintenance costs

GI = .05 annual inflation rate

For the version of SUNBURN that runs on a microcomputer, the NAMELIST utility is not used. Instead, the following file USERIN.FOR should be compiled, linked, and executed with SUNBURN. The input variables and their default values are the same as for the file SBNAML. above. To change any of these variables, the user must edit the file USERIN.FOR. This file is listed below:

```
      SUBROUTINE USERIN(PSIZE,TSTUR,NFO,STOHLR,NFLD,FLD,NSTO,STO,
     1                  NSCF,SCF,BCOSTR,GASBIL,GASY,CONT,FLDC,RECC,
     2                  TRANC,STOC,EPGSC,BOPC,OMC,CCPAY,CCPR,CCPY,
     3                  ALF,CPKWH,CPKWHY,YEAR,TLIFE,RATDR,FCR,PVC,
     4                  GE,GF,GOM,GI,NDAYS)
C
```

```
c    This subroutine contains user input data for a SUNBURN run and must
c    be compiled and linked with the main program before execution.
c
      DIMENSION FLD(20),STO(20),SCF(10),ALF(2,3),CPKWH(2,3)
c
      WRITE(*,*)'Default Case: Hybrid 1993 80MWe, Barstow 1984',
     1          ' SM=1.08 Storage=.5 hours'
      WRITE(2,*)'Default Case: Hybrid 1993 80MWe, Barstow 1984',
     1          ' SM=1.08 Storage=.5 hours'
      WRITE(3,*)'Default Case: Hybrid 1993 80MWe, Barstow 1984',
     1          ' SM=1.08 Storage=.5 hours'
c
      PSIZE=80.
      TSTUR=.40
      NFO=20
      STOHLR=.03
c          The default design has a 80 MWe turbine (net), storage
c          heat loss of 3 percent per day, and a forced outage
c          every 20 days.  The avoided costs methods do not apply
c          for PSIZE greater than 80 MWe (PURPA limit).  The same
c          turbine efficiency model in SUNBURN is used for each PSIZE.
c
      NFLD=1
      FLD(1)=395098.
      NSTO=1
      STO(1)=.5
      NSCF=1
      SCF(1)=1.
c          One default system is run with 395098 sq. meters of
c          heliostats, 0.5 hours of storage, and solar cost factor
c          of unity.  The heliostat areas may range from 197549 to
c          1799984 square meters.  The user may choose to simulate
c          NFLD*NSTO system designs in one SUNBURN run.  SCF* is a
c          fudge factor multiplier applied to all solar costs.
c
      BCOSTR=100.
      GASBIL=4.25
      GASY=1985.67
c          The default burner cost is $100/kWt and the default
c          gas cost is $4.25/MBTU in August 1985.  Since BCOSTR
c          is not zero and GASBIL is not very large, the system
c          being simulated is either fuel-only or hybrid.  For a
c          solar-only case, BCOSTR should be zero and GASBIL should
c          be large (>100.).  For a fuel-only case NFLD and NSTO
```

```
c           should be 1 and FLD(1) and STO(1) should be zero.

c      There are 5 possible cost scenarios corresponding to
c      initial operation dates 1990, 1993, 1994, 1995, and
c      1998.  The default is 1993.  These costs are taken
c      from the 1986-1990 Solar Thermal Five Year Plan.
c      Plant construction requires three years.
c
c      Five Year Plan current costs (1987)
c
c       CONT=20.
c       FLDC=150.
c       RECC=80.
c       TRANC=45.
c       STOC=25.
c       EPGSC=600.
c       BOPC=65.
c       OMC=12.
c
c      Five Year Plan five year goals (1990)
c
       CONT=20.
       FLDC=80.
       RECC=45.
       TRANC=40.
       STOC=20.
       EPGSC=400.
       BOPC=60.
       OMC=11.
c
c      Five Year Plan six year goals (interpolated for 1991)
c
c       CONT=20.
c       FLDC=72.
c       RECC=42.
c       TRANC=37.
c       STOC=20.
c       EPGSC=390.
c       BOPC=54.
c       OMC=10.6
c
c      Five Year Plan seven year goals (interpolated for 1992)
c
c       CONT=20.
```

```
c        FLDC=64.
c        RECC=39.
c        TRANC=34.
c        STOC=20.
c        EPGSC=380.
c        BOPC=48.
c        OMC=10.2

c       Five Year Plan long term goals (1995)
c
c        CONT=20.
c        FLDC=40.
c        RECC=30.
c        TRANC=25.
c        STOC=20.
c        EPGSC=350.
c        BOPC=30.
c        OMC=9.
c
        CCPAY=175.
        CCPR=.06118
        CCPY=1989.
        ALF(1,1)=.1643
        ALF(2,1)=.0245
        ALF(1,2)=.0028
        ALF(2,2)=.0123
        ALF(1,3)=.0025
        ALF(2,3)=.0036
        CPKWH(1,1)=6.1
        CPKWH(2,1)=5.7
        CPKWH(1,2)=4.7
        CPKWH(2,2)=4.6
        CPKWH(1,3)=4.0
        CPKWH(2,3)=4.0
        CPKWHY=1985.67
c             For a plant that begins operation in 1989., the default
c             value of the contract capacity price ($/kWe/yr) is 175.
c             The escalation rate on this capacity price is 6.118
c             percent per year as derived from SCE "Avoided Cost Pricing
c             Update for Cogeneration and Small Power Producers", 8/85.
c             The default values of the allocation factors and the
c             energy payment rates in 1985.67 were also obtained from
c             this document.
c
```

```
      YEAR=1993.
      TLIFE=30.
      RATDR=.0315
      FCR=.0615
      PVC=1.0318
      GE=.0234
      GF=.0234
      GOM=0.
      GI=.05
c           The default year of initial operation is 1993 and the
c           default plant lifetime is 30 years.  The default real
c           after tax discount rate is 3.15 percent per year, the
c           real escalation rate on the energy payment rate is 2.34
c           percent, the real escalation rate on the fuel cost is
c           2.34 percent, and the real escalation rate on the
c           operation and maintenance costs is 0.  The default
c           value of the inflation rate, which affects the levelized
c           capacity payments, is 5.0 percent.  The default values
c           of fixed charge rate and present value factor during
c           construction of 6.15 percent and 1.0318 respectively,
c           are taken from the Five Year Plan for utility ownership
c           and thirty year plant life.

      NDAYS=345
c           days for simulation (366-days for scheduled maintenance)
      RETURN
      END
```

The default case is a hybrid plant. To simulate a solar-only plant, set the burner cost rate *BCOSTR* to zero and set the fuel cost *GASBIL* to a high value. To simulate a fuel-only plant, set *NFLD* and *NSTO* to 1 and set *FLD(1)* and *STO(1)* to zero.

The contents of the input weather data file WEATHER. are as follows:

Record 1. latitude and longitude in radians, FORMAT(2F8.4)
Records 2 to 8785. direct normal insolation, kW/m^2
wind speed, m/sec
dew point temperature, *degrees F*,
barometric pressure, *inches of mercury*,
dry bulb temperature, *degrees F*,

FORMAT(4X,F7.4,5X,F5.1,F6.1,F5.1,F6.1)

SUNBURN prints detailed results in the output file DETAILS and a summary of results in the output file PRECIS. The output file DETAILS for the default case is listed below.

First, results are presented by month and by period. Then, results are summarized in the individual categories of system, performance, cost, and value. The on-peak period is designated by number 1, the mid-peak period by number 2, and the off-peak period by number 3. Weighted averages are printed for the capacity factor and the fraction of maximum possible capacity payment.

SUNBURN RESULTS	JAN	FEB	MAR	APR	MAY	•JUN	*JUL	*AUG	*SEP	OCT	NOV	DEC	SUM/WEIGHTED AVERAGE
Total 1	84.0	80.0	88.0	84.0	88.0	124.0	126.0	138.0	114.0	102.0	80.0	80.0	1188.0
Hours 2	189.0	180.0	198.0	189.0	198.0	189.0	189.0	207.0	171.0	207.0	180.0	180.0	2277.0
3	471.0	436.0	458.0	447.0	458.0	407.0	429.0	399.0	435.0	435.0	460.0	484.0	5319.0
Sum	744.0	696.0	744.0	720.0	744.0	720.0	744.0	744.0	720.0	744.0	720.0	744.0	8784.0
Maintenance 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.0	56.0
Hours 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.0	126.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	322.0	322.0
Sum	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0	504.0
Forced Outage 1	4.0	8.0	4.0	4.0	0.0	12.0	6.0	12.0	0.0	4.0	4.0	4.0	62.0
Hours 2	9.0	18.0	9.0	9.0	0.0	18.0	9.0	18.0	0.0	9.0	9.0	9.0	117.0
3	11.0	22.0	11.0	35.0	24.0	18.0	9.0	18.0	24.0	35.0	11.0	11.0	229.0
Sum	24.0	48.0	24.0	48.0	24.0	48.0	24.0	48.0	24.0	48.0	24.0	24.0	408.0
Solar, GWhe 1	0.05	0.19	0.26	0.36	1.26	6.37	4.58	6.51	5.57	1.84	0.06	0.02	27.07
After Operational 2	7.19	6.46	9.82	8.68	12.64	5.39	4.21	4.75	4.34	7.88	6.27	0.89	78.53
Parasitics 3	3.74	3.62	3.18	5.39	5.59	5.90	3.09	3.07	4.87	3.14	3.00	0.83	45.42
Sum	10.99	10.27	13.26	14.43	19.49	17.66	11.88	14.32	14.78	12.87	9.33	1.74	151.02
Fuel, GWhe 1	6.44	5.66	6.54	6.09	5.74	2.50	4.90	3.50	3.46	6.06	6.11	1.60	58.60
After Operational 2	6.80	6.13	5.19	5.50	2.90	8.10	9.68	9.74	8.73	7.44	7.04	2.60	79.85
Parasitics 3	1.36	1.19	2.23	1.37	1.18	1.13	1.02	0.66	0.73	0.96	1.18	0.64	13.66
Sum	14.60	12.98	13.96	12.96	9.81	11.73	15.61	13.90	12.93	14.46	14.33	4.85	152.11
Operational 1	0.711	0.640	0.747	0.711	0.782	0.996	1.067	1.120	1.013	0.871	0.676	0.178	9.511
Parasitics 2	1.532	1.380	1.648	1.572	1.732	1.502	1.554	1.612	1.456	1.685	1.460	0.382	17.515
GWhe 3	0.595	0.553	0.631	0.782	0.864	0.864	0.603	0.517	0.785	0.487	0.482	0.164	7.327
Sum	2.838	2.573	3.026	3.065	3.378	3.362	3.223	3.250	3.254	3.044	2.617	0.724	34.352
Non Operational 1	0.006	0.012	0.006	0.006	0.000	0.018	0.009	0.018	0.000	0.006	0.006	0.006	0.094
Parasitics 2	0.081	0.088	0.046	0.042	0.028	0.045	0.060	0.095	0.064	0.088	0.074	0.031	0.742
GWhe 3	0.645	0.588	0.649	0.601	0.610	0.533	0.598	0.550	0.559	0.598	0.648	0.229	6.807
Sum	0.733	0.688	0.701	0.649	0.638	0.596	0.667	0.663	0.623	0.692	0.728	0.266	7.643
Total Parasitics 1	0.717	0.652	0.753	0.717	0.782	1.014	1.076	1.138	1.013	0.877	0.682	0.184	9.605
GWhe 2	1.614	1.467	1.694	1.614	1.760	1.547	1.614	1.707	1.520	1.774	1.534	0.414	18.257
3	1.240	1.141	1.280	1.383	1.474	1.397	1.201	1.067	1.344	1.085	1.130	0.392	14.134
Sum	3.571	3.260	3.726	3.714	4.016	3.957	3.890	3.913	3.877	3.735	3.345	0.990	41.995
Net Electric 1	6.49	5.83	6.79	6.44	7.00	8.85	9.48	9.99	9.04	7.90	6.16	1.62	85.58
Generation 2	13.91	12.51	14.96	14.14	15.51	13.44	13.83	14.39	13.00	15.23	13.24	3.46	157.64
GWhe 3	4.46	4.22	4.76	6.16	6.15	6.50	3.51	3.18	5.05	3.50	3.53	1.24	52.27
Sum	24.86	22.56	26.51	26.75	28.67	28.79	26.82	27.56	27.09	26.64	22.93	6.32	295.49
Capacity Factor 1	96.54	91.11	96.52	95.81	99.45	89.20	94.03	90.47	99.08	96.82	96.25	25.29	90.05
Based on Net 2	92.01	86.85	94.44	93.55	97.93	88.90	91.46	86.92	95.05	91.99	91.96	24.03	86.54
Generation 3	11.83	12.10	12.99	17.24	16.79	19.96	10.24	9.96	14.50	10.07	9.58	3.21	12.28
Weighted Average	41.76	40.52	44.55	46.44	48.16	49.98	45.06	46.30	47.02	44.75	39.81	10.62	42.05
On peak	95.24	90.00	95.44	95.03	99.16	89.26	93.91	90.26	98.83	96.05	95.00	83.33	93.93

SUNBURN RESULTS		JAN	FEB	MAR	APR	MAY	*JUN	*JUL	*AUG	*SEP	OCT	NOV	DEC	SUM/WEIGHTED AVERAGE
Solar Capacity	1	0.001	0.006	0.008	0.011	0.047	0.807	0.588	0.712	0.688	0.295	0.002	0.002	3.168
Payment, 1984 M$	2	0.043	0.041	0.049	0.048	0.069	0.011	0.005	0.006	0.006	0.037	0.038	0.020	0.375
	3	0.003	0.003	0.003	0.004	0.004	0.004	0.002	0.002	0.003	0.003	0.002	0.002	0.035
	Sum	0.047	0.050	0.060	0.064	0.120	0.822	0.595	0.720	0.697	0.335	0.043	0.025	3.577
Solar Energy	1	0.004	0.016	0.022	0.031	0.109	0.587	0.423	0.600	0.514	0.169	0.005	0.002	2.481
Payment, 1984 M$	2	0.500	0.449	0.683	0.604	0.879	0.382	0.299	0.337	0.308	0.550	0.436	0.062	5.489
	3	0.226	0.219	0.192	0.326	0.338	0.357	0.187	0.185	0.295	0.190	0.181	0.050	2.746
	Sum	0.731	0.684	0.897	0.961	1.326	1.326	0.908	1.123	1.117	0.909	0.622	0.114	10.717
Solar Value	1	0.006	0.022	0.030	0.042	0.155	1.394	1.010	1.312	1.202	0.464	0.007	0.004	5.650
1984 M$	2	0.543	0.490	0.732	0.652	0.948	0.393	0.304	0.343	0.314	0.587	0.475	0.082	5.864
	3	0.229	0.222	0.195	0.330	0.342	0.360	0.189	0.187	0.298	0.193	0.184	0.052	2.781
	Sum	0.778	0.734	0.957	1.025	1.446	2.147	1.504	1.843	1.813	1.244	0.665	0.138	14.294
Fuel Capacity	1	0.225	0.186	0.219	0.214	0.205	0.254	0.540	0.392	0.472	0.271	0.222	0.157	3.358
Payment, 1984 M$	2	0.037	0.039	0.031	0.032	0.011	0.011	0.013	0.012	0.012	0.027	0.042	0.059	0.326
	3	0.001	0.001	0.002	0.001	0.001	0.001	0.001	0.000	0.000	0.001	0.001	0.001	0.011
	Sum	0.263	0.226	0.252	0.247	0.217	0.266	0.553	0.405	0.485	0.299	0.265	0.218	3.695
Fuel Energy	1	0.555	0.487	0.564	0.524	0.494	0.229	0.452	0.323	0.319	0.527	0.526	0.138	5.139
Payment, 1984 M$	2	0.473	0.426	0.361	0.383	0.201	0.575	0.688	0.692	0.620	0.521	0.490	0.181	5.610
	3	0.082	0.072	0.135	0.083	0.071	0.069	0.062	0.040	0.044	0.058	0.071	0.039	0.826
	Sum	1.110	0.986	1.059	0.990	0.767	0.872	1.202	1.055	0.984	1.105	1.087	0.358	11.575
Fuel Value	1	0.780	0.674	0.783	0.738	0.700	0.483	0.992	0.715	0.791	0.797	0.749	0.295	8.497
1984 M$	2	0.510	0.466	0.391	0.414	0.212	0.586	0.701	0.704	0.633	0.548	0.531	0.240	5.937
	3	0.083	0.073	0.136	0.084	0.072	0.069	0.062	0.040	0.045	0.059	0.072	0.040	0.837
	Sum	1.373	1.212	1.311	1.237	0.984	1.139	1.755	1.459	1.468	1.404	1.352	0.576	15.270
Payment for	1	0.001	0.001	0.001	0.001	0.000	0.004	0.002	0.004	0.000	0.001	0.001	0.001	0.017
Parasitics	2	0.006	0.007	0.003	0.003	0.002	0.003	0.004	0.007	0.005	0.007	0.006	0.003	0.056
1984 M$	3	0.040	0.036	0.040	0.037	0.037	0.033	0.037	0.034	0.034	0.037	0.040	0.014	0.417
	Sum	0.046	0.044	0.044	0.041	0.040	0.040	0.043	0.044	0.039	0.044	0.046	0.018	0.490
Total Net Value	1	0.785	0.694	0.813	0.779	0.855	1.873	2.000	2.023	1.993	1.261	0.755	0.298	14.130
1984 M$	2	1.047	0.949	1.120	1.063	1.158	0.976	1.001	1.041	0.942	1.128	1.000	0.320	11.744
	3	0.273	0.259	0.292	0.378	0.377	0.397	0.215	0.194	0.308	0.215	0.216	0.078	3.201
	Sum	2.105	1.902	2.224	2.220	2.390	3.246	3.216	3.258	3.243	2.604	1.972	0.696	29.075
Capacity Payment	1	0.257	0.257	0.257	0.257	0.257	1.167	1.167	1.167	1.167	0.592	0.257	0.257	7.062
Maximum Possible	2	0.080	0.080	0.080	0.080	0.080	0.022	0.018	0.018	0.018	0.079	0.080	0.080	0.716
1984 M$	3	0.023	0.023	0.023	0.023	0.023	0.017	0.016	0.016	0.016	0.023	0.023	0.023	0.253
	Sum	0.361	0.361	0.361	0.361	0.361	1.206	1.202	1.202	1.202	0.694	0.361	0.361	8.032
Capacity Payment	1	0.88	0.75	0.88	0.87	0.98	0.91	0.97	0.95	0.99	0.96	0.87	0.62	0.92
Fraction	2	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.81	1.00	1.00	0.98
	3	0.17	0.17	0.18	0.23	0.23	0.27	0.15	0.15	0.20	0.15	0.14	0.14	0.18
Weighted Average		0.86	0.77	0.86	0.86	0.93	0.90	0.96	0.94	0.98	0.91	0.85	0.67	0.91

```
──────── SYSTEM ─────────────────────────────────────────────────────────────────────
 Field Area, sq. meters:   395098.        Solar Multiple  1.08                 Design Day  129
 Storage Size, hours:     0.50            Turbine Rating, MWe net:   80.00     Tower Height, meters:  104.4
─────────────────────────────────────────────────────────────────────────────────────
──────── PERFORMANCE ────────────────────────────────────────────────────────────────
 Solar Fraction:  0.525                                          Annual Efficiency:  20.93 %
 Fuel Fraction:  0.475                                           Total Insolation, kWh/sq. m:  2373.
 Number of Receiver Starts:   352                                Number of Turbine Starts:   331
 Average Target Carryover Storage, hours:  0.00                  Average Actual Carryover Storage, hours:  0.08
 Magnitude of Insolation Prediction Error, kWh/sq. m/day:  1.04  Total Operation Days:  328
 Cumulative Insolation Prediction Error, kWh/sq. m/day:   0.17
─────────────────────────────────────────────────────────────────────────────────────
 Total Insolation, GWht:                             937.388    100.00 %
 Heat Absorbed by Receiver, GWht:                    483.439     51.57 %
 Heat Used to Start Receiver, GWht:        1.957     481.481     99.60 %
 Heat Loss from Receiver, GWht:           37.442     444.039     92.22 %
 Heat Loss from Pipes, GWht:               1.872     442.167     99.58 %
 Heat Discarded, GWht:                     0.269     441.898     99.94 %
 Heat Loss from Storage, GWht:             0.249     441.649     99.94 %
─────────────────────────────────────────────────────────────────────────────────────
 Solar Heat to Turbine, GWht:                        441.653     47.12 %

 Fuel Burned, GWht:                                  474.338    100.00 %
 Burner Heat Loss, GWht:                  74.314     400.024     84.33 %
─────────────────────────────────────────────────────────────────────────────────────
 Fuel Heat to Turbine, GWht:                         400.030     84.33 %

 Total Heat to Turbine, GWht:                        841.682    100.00 %
 Heat Used to Start Turbine, GWht:        28.427     813.255     96.62 %
 Gross Turbine Generation, GWhe:                     337.487     41.50 %
 Electrical Parasitics, GWhe:             41.995     295.491     87.56 %
─────────────────────────────────────────────────────────────────────────────────────
 Net Electric Generation, GWhe:                      295.491     35.11 %
─────────────────────────────────────────────────────────────────────────────────────
──────── COST ───────────────────────────────────────────────────────────────────────
 Total Plant Costs, 1984 M$/yr:  25.75           Initial Operation Year: 1993.0       Lifetime, years:  30.0
 Total Solar Costs, 1984 M$/yr:  13.99  54.3 %   Total Fuel Costs, 1984 M$/yr:  11.76  45.7 %
         Solar cost factor   1.00                          burner  1.36
         Field   2.41                                      fuel  10.40
         Receiver   1.35                         Fuel Use, GWht:  474.34
         Transport   1.20                        Fuel Escalation:  2.34 %
         Storage   0.16
         EPGS   2.71                             BBEC, mills/kWhe:   87.14
         BOP   1.81                              Capital Costs, 1984 PV$/kWe: 2236.3
         O & M   4.35
 PVAC =  7.0513  PVAE = 17.1538  CRF =  0.0520  FCR =  0.0615  PVC =  1.0318  PVF = 17.1538  PVOM = 19.2258
─────────────────────────────────────────────────────────────────────────────────────
──────── VALUE ──────────────────────────────────────────────────────────────────────
 The contract capacity is:   80.0  Both Capacity and Energy Payments Are Obtained
 Gross Value of Electricity, 1984 M$:  29.56
         from solar  14.29   energy payment  10.72   capacity payment   3.58
         from fuel  15.27    energy payment  11.58   capacity payment   3.69
 Payment to SCE for Non Operational Parasitics, 1984 M$:   0.49
 Net Value of Electricity, 1984 M$:  29.07
 Value Cost Difference, 1984 M$:   3.326
 Value Cost Ratio:  1.129                                            Iterations:  2
──────── THATS ALL FOLKS ! ──────────────────────────────────────────────────────────
─────────────────────────────────────────────────────────────────────────────────────
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A.5 Time Requirements of SUNBURN

Table III shows the times spent at the terminal for compiling and executing SUNBURN to run the default case on various machines. These times depend on the number of other users sharing the machine.

Table III: Time Requirements of SUNBURN, minutes.

Machine	Compilation Time	Execution Time
VAX 11/780	2.0	6.0
VAX 8650	0.5	2.0
IBM PC-XT	20.	45.

Appendix B

Detailed Description of Value Calculation

The following is a description of the method used to calculate value of electricity to SCE according to the avoided costs described by SCE's *Standard Offer No. 2, Capacity Payment Option 2* for firm power purchase [11]. Updates to this *Standard Offer*, including the most recent estimates of avoided costs are described in the *Avoided Cost Pricing Updates*, which are published quarterly by SCE [12]. The rate periods, seasons, and holidays are defined by *Tariff Schedule TOU-8* [16]. To qualify for this *Standard Offer*, a power producer must meet the Performance Requirement of SCE. This Performance Requirement specifies that the power producer must operate with a capacity factor of at least 80 percent during the on-peak periods of each of the summer months, June through September, of the year. The monthly on-peak capacity factors are calculated as follows:

$$On - peak\ Capacity\ Factor = \frac{E_{net}}{(Contract\ Capacity)(Period\ hours - scheduled\ maintenance\ hours)} \tag{B.1}$$

E_{net} = the net energy generated during the on-peak period at power levels less than the Contract Capacity.

Reasonable efforts must be made to perform regular maintenance outside the months of the summer season. The total value of electricity is divided into amounts for energy and for capacity.

The Monthly Energy Value is calculated as the sum of the Period Energy Values for the month.

$$Period\ Energy\ Value = (Period\ Energy\ Value\ Rate) * E_{per} \qquad (B.2)$$

E_{per} = the net electricity generated during the period.

Table IV: Period Energy Value Rates, cents/kWh*e*.

	Summer	Winter
On-peak	6.1	5.7
Mid-peak	4.7	4.6
Off-peak	4.0	4.0

Table V: Contract Capacity Price, dollars/kW*e*/year, (30-year contract term).

Year of Initial Delivery	Contract Capacity Price
1985	138
1986	146
1987	155
1988	165
1989	175

The Period Energy Value Rate is differentiated by rate period and season. Table IV shows the numbers used in the study for the Period Energy Value Rates. These rates were effective in August 1985 [12]. These rates are for fuel costs and operating costs of SCE. For this study, they were assumed to escalate at a real rate (over inflation) of 2.34 percent per year. This escalation rate was derived from *Standard Offer No. 4* of the Pacific Gas and Electric Company [17].

Calculation of the capacity value of electricity was based on *Capacity Payment Option 2 of Standard Offer No. 2*, as follows:

$$\begin{aligned} Monthly\ Capacity\ Period\ Payment = {} & (Contract\ Capacity\ Price) \\ & *(Conversion\ From\ Annual\ to\ Monthly\ Payment) \\ & *(Contract\ Capacity) \\ & *(Period\ Performance\ Factor) \end{aligned} \tag{B.3}$$

The Contract Capacity Price is determined by SCE for plants that begin operation at different times and operate for different lengths of time. Table V shows the values of Contract Capacity Price, taken from *Standard Offer No. 2* [12], that were used for this study. The escalation rate of the Contract Capacity Price over the period beginning 1985 and ending 1989 was 6.118 percent per year. This escalation rate was used to determine the Contract Capacity Price for plants that begin operation after 1989.

Table VI: Conversion to Monthly Payment.

	Summer	Winter
On-peak	.1643	.0245
Mid-peak	.0028	.0123
Off-peak	.0025	.0036

The conversion factors of Equation B.3 multiplying annual payment to give monthly payment are shown in Table VI. These factors increase the capacity payment during the on-peak period of the summer season relative to the capacity payment during other periods.

The Contract Capacity was initially set equal to the net rated output of the turbine, which was 80 MWe. In the event that the Performance Requirement was not satisfied, SUNBURN decreases the Contract Capacity and iterates the annual simulation in an attempt to meet the Performance Requirement at a lower value of the Contract Capacity. If the Performance Requirement cannot be satisfied and the Contract Capacity has been decreased to less than one-half of the net rated output of the turbine, then iteration is terminated and the total capacity value is set to zero. Actually *Standard Offer No. 1*, for as-available capacity and energy should be used in this case. The energy value rates of *Standard Offer No. 1* are the same as for *Standard Offer No. 2*, but the capacity payment is less. *Standard Offer No. 1* does not have a Performance Requirement.

The Period Performance Factor of Equation B.3 is a capacity factor based on the net generation at power levels less than the Contract Capacity, and the duration of the period minus the time during the period allocated for scheduled maintenance.

$$Period\ Performance\ Factor = \frac{Period\ net\ electricity\ generated}{(.8)(Contract\ Capacity)(Period\ hours - Maintenance\ hours)} \tag{B.4}$$

The factor of .8 allows for a 20 percent forced outage rate in any month. The Period Performance Factor cannot exceed unity.

In addition to the Monthly Capacity Period Payment, a Bonus Payment may be earned during the summer months provided that the Performance Requirment is satified and the on-peak capacity factor exceeds 85 percent for that month. During the winter months, as an additional requirement applying to the Bonus Payment, the on-peak capacity factor for each of the summer months must have exceeded 85 percent.

$$\begin{aligned} Monthly\ Bonus\ Payment &= (1.2 * (on - peak\ capacity\ factor) - 1.02) \\ &\quad *(Contract\ Capacity\ Price) \\ &\quad *(1/12) \\ &\quad *(Contract\ Capacity) \end{aligned} \tag{B.5}$$

The calculation of the on-peak capacity factor was described above.

Fuel dispatching in SUNBURN requires that the avoided costs described above be expressed as constants per unit net electricity generated. Although the Period Energy Value and the Monthly Capacity Period Payment can be expressed as constants per unit of the amount of net electricity generated, the Monthly Bonus Payment cannot. Therefore, equivalent constant rates for the Monthly Bonus Payment were calculated by guessing values for the monthly on-peak capacity factors, calculating the Monthly Bonus Payment and dividing by the guessed amounts of electricity generated. Thus, the Bonus Payment was spread over all the net electricity generated during the on-peak period. Actually, the Bonus Payment is paid only for that portion of the net electricity generated during the on-peak period at on-peak capacity factors greater than 85 percent, as mentioned earlier. The annual simulation was then performed, resulting in new values of the monthly on-peak capacity factors. These new capacity factors were then used to calculate new Bonus Payment rates for a subsequent iteration of the annual simulation. This iterative procedure was terminated when the resultant values of the on-peak capacity factors were within 1 percent of the guessed values of the on-peak capacity factors.

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