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SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEM, PHASE I

Final Technical Report for October 1978—August 1979
Volume 1: Executive Summary

September 1979

Work Performed Under Contract No. ET-78-C-03-2234

Martin Marietta Corporation
Denver, Colorado

U.S. Department of Energy

Solar Energy

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Volume I

Final Technical Report

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EXECUTIVE SUMMARY

SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEM, PHASE I

MARTIN MARIETTA CORPORATION
P. O. Box 179
Denver, Colorado 80201

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FOREWORD

This report is submitted by Martin Marietta Corporation to the Department of Energy in accordance with provisions of contract DE-AC03-78ET21038. This final technical report summarizes the work related to the conceptual design, cost and performance of the Solar Central Receiver Hybrid Power System, Phase I, which was performed during the period of October 1978 through August 1979. The report consists of the following volumes:

Volume I - Executive Summary;

Volume II - Conceptual Design;

Volume III - Appendices.

The contract was under the direction of Dr. S. Douglass Elliott, Jr. of the Department of Energy, San Francisco Operations Office, Oakland, California. Mr. Kirk Battleson of Sandia Laboratories, Livermore, California was the Technical Manager.

The efforts performed by the Martin Marietta team are as follows:

1) Martin Marietta	Program Management; System Design and Optimization, Interface Definition; Conceptual Design, Analysis and Optimization of the Heliostat Field and Receiver; System Economic Analysis
2) Badger Energy, Inc.	Conceptual Design, Analysis and Optimization of the High-Temperature Salt Subsystems
3) Gibbs & Hill, Inc.	Conceptual Design, Analysis and Optimization of the Electric Power Generation System (EPGS), Tower, and Nonsolar Support Facilities
4) Foster Wheller Development Corporation	Conceptual Design, Analysis and Optimization of the Nonsolar Energy Source
5) Arizona Public Service	Utility Engineering Review of System Design, Utilization and Economics; and Development of the Market Analysis

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1. INTRODUCTION

Hybrid power system concepts involving the use of an alternate solar central receiver facility combined with a nonsolar energy source (e.g., fossil-fired, geothermal, hydroelectric) are being considered by the Department of Energy (DOE) for near-term applications. In response to these considerations, the Martin Marietta team has conducted system analyses and conceptual designs of hybrid systems employing molten salt (60% $NaNO_3$, 40% KNO_3) heat transfer/storage media using a solar central receiver and a fossil-fired nonsolar energy source (coal, oil or gas). System- and subsystem-level analyses were performed to develop preferred system configurations using various amounts of solar storage capacities and fossil fuels. The various systems contained in this report are based on a technical approach that promotes higher conversion efficiencies, greater operational flexibility, and lower net energy costs than "first generation" water/steam receiver technology. In fact, the analysis shows that in the 1990 time frame, hybrid and solar standalone power systems based on molten salt technology are competitive with peaking, intermediate and baseload conventional power technology.

The hybrid plant consists of solar and nonsolar portions of the plant that operate in parallel. For the solar portion of the plant, molten salt is heated in cavity receivers and delivered to salt storage tanks. The hot salt is used to generate steam for the turbine in salt heat exchangers. For the nonsolar portion of the plant, molten salt is heated in a fossil-fired salt heater and delivered to the salt storage tanks. The large quantities of storage and associated heliostats result in large plant capacity factors (0.75) from the solar portion of the plant, minimize the busbar energy costs, permit nonsolar subsystems less than the plant rating and minimize the amount of fossil fuel burned. This hybrid configuration provides a plant for the utilities that has design and operational flexibility and is an economically viable power alternative to intermediate/baseload power systems using nuclear or fossil fuels.

The salient features of the hybrid configuration are the cost effective use of large quantities of salt storage, simple solar-to-nonsolar equipment and operational interface, and a modular design that facilitates design simplicity and flexibility for plant size scaling. The large amounts of storage capacity promote maximum displacement of fossil fuel and permit a reduction in the nonsolar unit size. Thus the salt heater coupled with the large storage capacity permits a high degree of operational and design flexibility to meet varied utility requirements. Since all thermal energy, whether solar- or nonsolar-derived, passes through storage to a single salt/steam generator, the turbine uses only one source of steam. Thus the solar-to-nonsolar interface is essentially the blending of two sources of salt (solar and nonsolar) at the thermal storage tank, which can be achieved with minimum expense and plant control. The conceptual design of the nonsolar unit was developed using an oil fuel. However the design could be easily modified to handle gas or coal fuels. The modular solar collector/receiver design (two collector/receiver modules for the 100-MWe 18-hour storage system) allows scaling from 50-MWe to 500-MWe plants simply by using one to 10 collector/receiver modules of the same size as the conceptual design. Multiple-module plants also enhance plant reliability and at the same time minimize plant capital costs.

Several types of economic analyses were performed to assess the solar hybrid plant costs and value to a utility. For the 500-MWe commercial plant size installed for the year 1990, capital costs of \$1680/kWe were derived. Based on this cost, the levelized cost of energy is 37 mills/kWhe 1979\$ at a plant capacity of 0.75 using typical utility economics and financial incentives that are available. This plant will save the equivalent of nearly 5×10^6 barrels of oil/year or an annual cost savings in imported oil of \$100 million (1979\$) based on post-Iranian oil prices of \$3.45/MBtu (1979\$).

Several tradeoffs of hybrid plant concepts with conventional power systems showed that our molten salt hybrid concepts can compete for the utility market. A cost/benefit analysis was performed for the Arizona Public Service (APS) Company's system to evaluate the competitiveness of the molten salt solar hybrid with peaking combustion turbine and intermediate/baseload coal capacity displacement. A cost/benefit ratio of 0.98 was computed based on the capital cost estimate of \$1680/kWe (1979\$) and displacement of a 500-MWe coal plant planned for a 1990 installation. The results of this analysis are significant since the APS system in the year 1990 is nearly 70% coal and nuclear capacity--a formidable market for solar power system penetration. Busbar energy costs for solar hybrid and conventional power systems, using baseline economics provided in the systems requirements definition document, are shown in Figure 1-1. Again these results show that the solar hybrid concept is an economically viable power alternative to intermediate/baseload power using nuclear or fossil fuels.

Development of production facilities for the manufacture of low-cost heliostats [\$72/m^2 (\$6.70/ft^2), 1979\$] by 1990 is required for full-scale commercialization of this solar concept. Programs being conducted by DOE will ensure that molten salt technology in large central receiver plants is demonstrated in the 1980's.

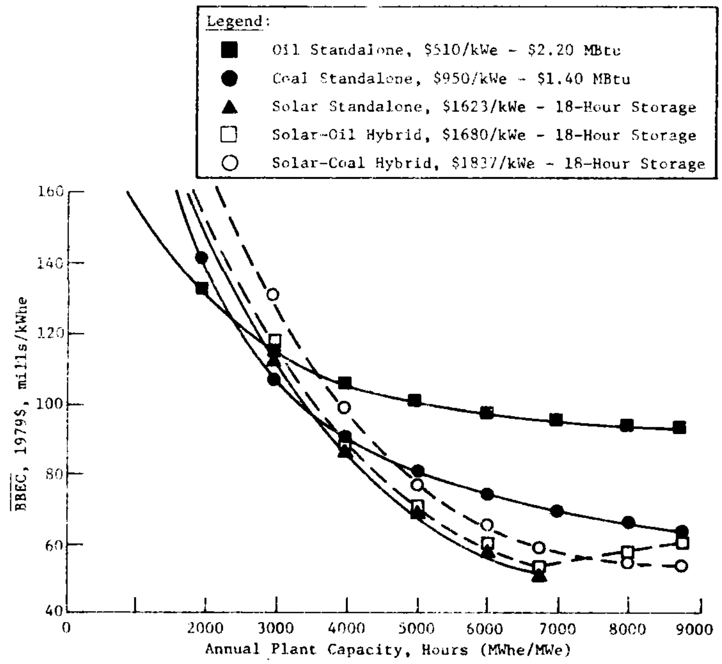


Figure 1-1
Energy Costs for New Plants, 1990 Year of Commercial Operation, 500 MWe

The objectives of this study were to develop a hybrid power system design that (1) produces minimum-cost electric power, (2) minimizes the capital investment and operating cost, (3) permits capacity displacement, and (4) achieves utility acceptance for market penetration. We have met the first three of these objectives and therefore believe that the fourth, utility acceptance, will become a reality.

Table 1-1 shows the team members and their primary areas of responsibility. Martin Marietta provides the program management, the overall system design and optimization of the solar, nonsolar and conventional portions of the plant, the design of the collector and receiver subsystems and the system economic analysis. The nonsolar subsystem consists of the nonsolar energy source, which is a fossil-fired salt heater developed by Foster Wheeler Development Corporation, and the nonsolar support equipment consisting of the fuel delivery and storage and the air quality control facilities developed by Gibbs and Hill, Inc. Gibbs and Hill also developed the electric power generation subsystem, receiver support tower and the balance of the plant. The high-temperature salt systems, which include the piping and process equipment to transport the salt, the salt heat exchanger steam generators and the salt thermal storage were developed by Badger Energy, Inc. The overall review of the system from the utility perspective and the market analysis was developed by Arizona Public Service. This combined team, utilizing each member's areas of expertise, developed and performed the analysis and designs discussed in this report.

Table 1-1 Team Members and Responsibilities

ORGANIZATION	RESPONSIBILITY
Martin Marietta	Program Management; System Design and Optimization, Interface Definition; Conceptual Design, Analysis and Optimization of the Heliostat Field and Receiver; and System Economic Analysis
Badger Energy, Inc.	Conceptual Design, Analysis and Optimization of the High-Temperature Salt Subsystems
Gibbs & HIll, Inc.	Conceptual Design, Analysis and Optimzation of the EPGS, Tower, and Nonsolar Support Facilities
Foster Wheeler Development Corp.	Conceptual Design, Analysis and Optimization of the Nonsolar Energy Source
Arizona Public Service	Utility Engineering Review of System Design, Utilization and Economics; and Development of the Market Analysis

The selected system configuration chosen for the conceptual design is a storage-coupled (18-hour capacity at turbine maximum output power) hybrid plant that burns residual oil in a salt heater (Fig. 2-1). The salt heater has a rated thermal output equivalent to one-half the plant electrical output.

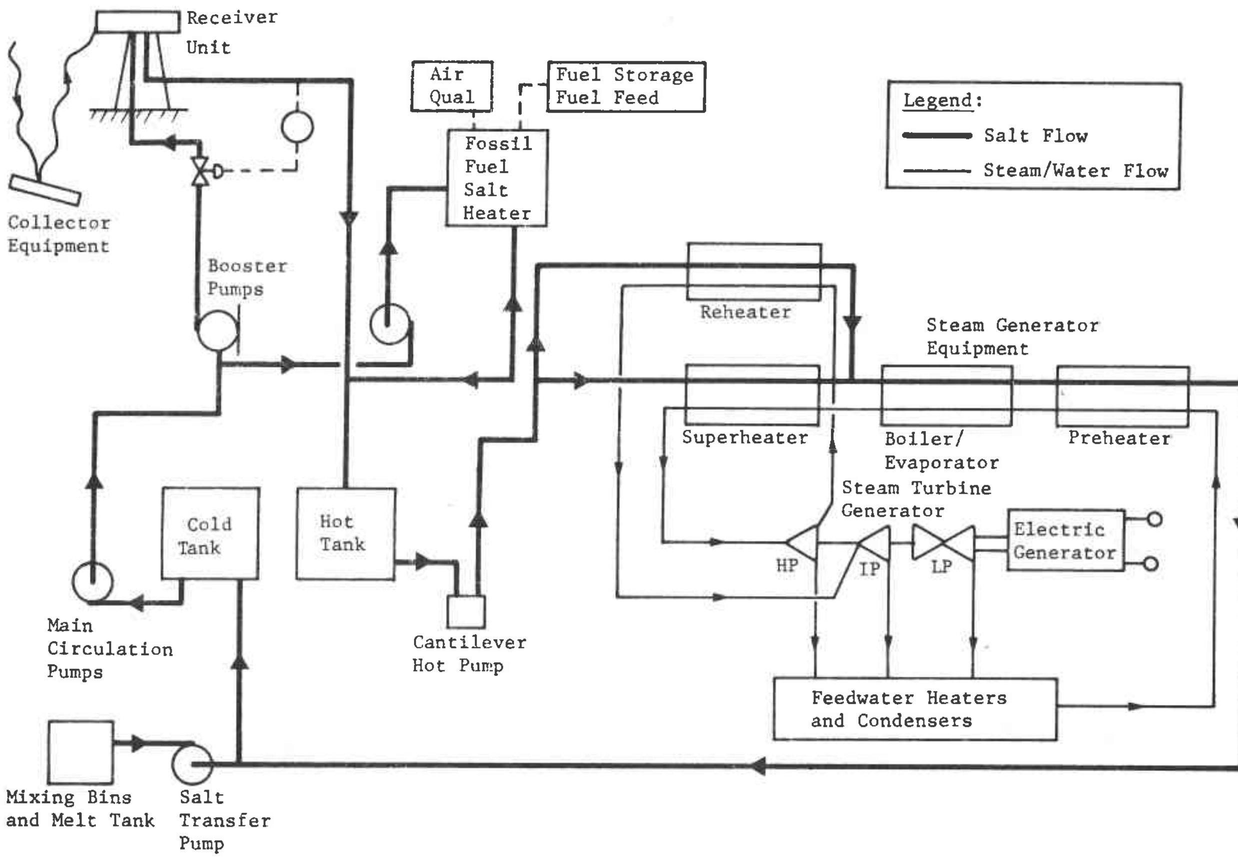


Figure 2-1 Hybrid System Schematic

This configuration provides annual solar power generation equivalent to a plant capacity factor of 0.75. Therefore the nonsolar unit, burning oil fuel, will operate at the maximum 25% of the year (in addition to solar) but will probably operate less than 10%. The salt heater has the capability to charge the large storage capacity, operate in parallel with receiver(s) or thermal storage output, or develop energy independently to directly produce steam for the electric power generation subsystem (EPGS). The optimum size of the hybrid plant, based on the minimization of energy production costs, has been determined to be 500 MWe. Such a commercial system would employ 10 individual receiver field modules piped together to supply thermal energy to a centralized storage and EPGS location.

Some of the more important studies that led to our selected configuration are discussed in this section. The remaining parametric analyses and tradeoff studies are discussed in Volume II.

An artist's concept of the 100-MWe conceptual design, looking from the south, is shown in Figure 2-2. The main plant is located between two collector/receiver modules. A typical heliostat and a receiver and support tower is shown in detail. The exploded view of the main plant area shows the relative locations of the major system components. The turbine building is in the foreground, along with the salt melters that activate the salt systems to the left, and the fuel oil storage tanks. The hot and cold salt storage tanks are located to the rear, with the cold tanks being furthest back. The nonsolar subsystem is shown in the central portion of the plant with the salt heater, electrostatic precipitator and flue gas stack. The salt heat exchangers for generation of the plant's rated steam are located just behind the salt heater and between the hot salt tanks.

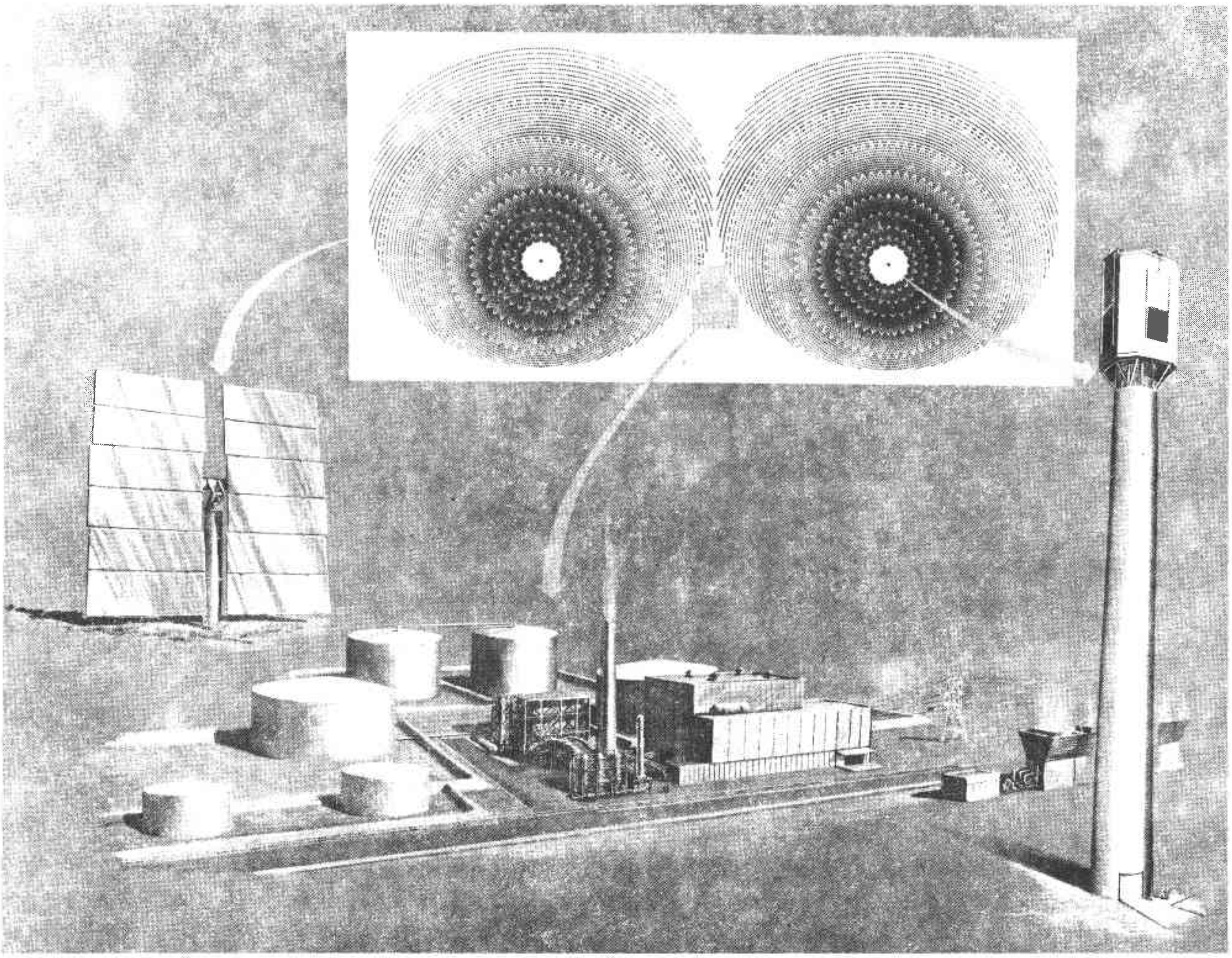


Figure 2-2 Artist's Concept of Hybrid Plant

2.1 PLANT SIZE SELECTION

For the optimum plant size, cost economies of scale in both solar and nonsolar subsystems were considered. Trends in costs and performance of the EPGS were also evaluated. The results from these analyses show that a minimum cost of energy occurs near 500 MWe for a hybrid plant with 18 hours of storage and a salt heater sized at 250 MWe.

Potential cost economies of scale and performance improvements in larger size plants were evaluated for solar standalone and hybrid plants in the 100- to 1000-MWe range. Figure 2.1-1 shows the changes in total plant capital cost and major cost accounts for solar standalone plants with increasing plant turbine sizes. This particular analysis was done for a solar plant with 18 hours of storage and costs estimated with fixed solar field module sizes of 400 MWt. The results depicted in Figure 2.1-1 show an actual reduction of costs to 500 MWe in the field, EPGS, and balance-of-plant due mainly to performance improvements in the EPGS and cost economies of scale over this 100- to 500-MWe range. Piping costs increase as a result of the additional interconnecting module piping required with larger plant sizes are reflected in Figure 2.1-2. The change in total plant costs shows some increase in plant costs ($/kWe between 500 to 800 MWe). In this range the increased piping costs have begun to offset any cost economies of scale in nonpiping items.

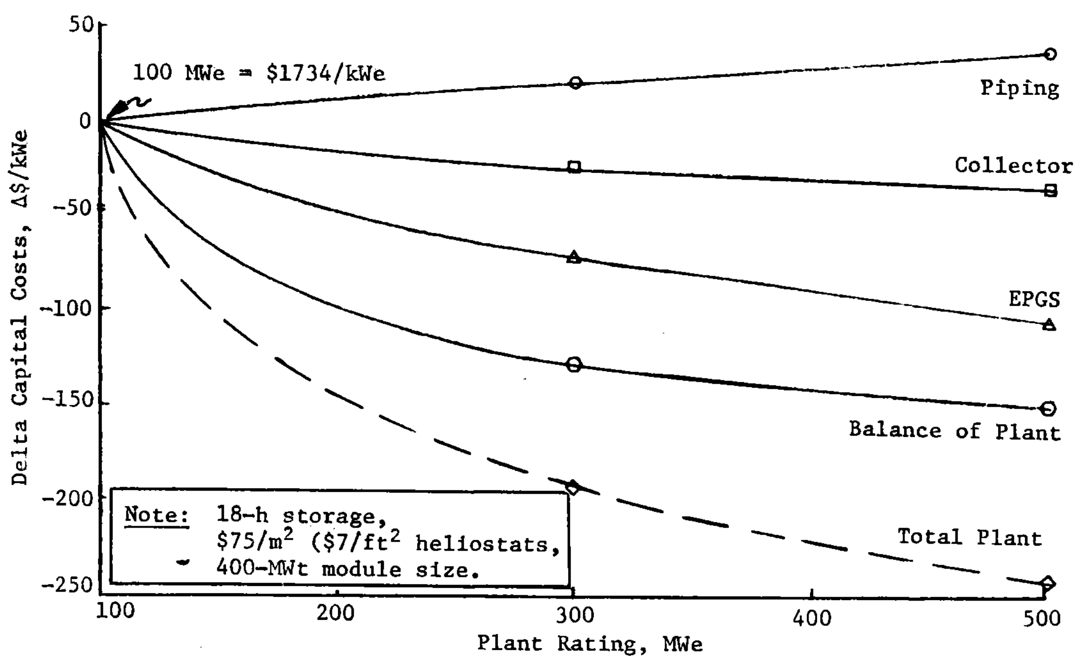


Figure 2.1-1 Solar Standalone Plant Optimization

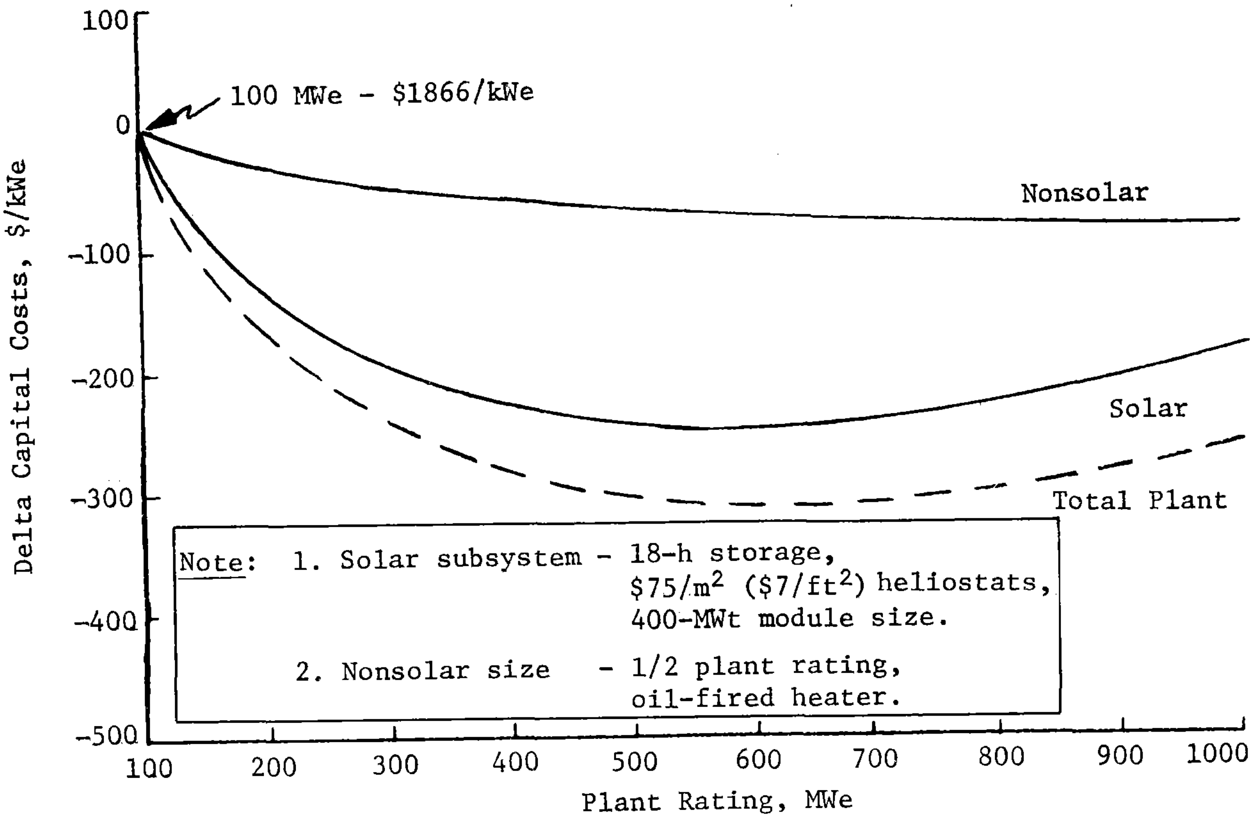


Figure 2.1-2 Hybrid Plant Size Optimization

Hybrid plant capital costs were calculated as a function of plant size with a nonsolar size at one-half plant rating. Figure 2.1-2 shows the capital cost curves generated by adding the solar standalone total plant costs and the oil-fired nonsolar energy source and support equipment costs. Significant economies of scale were projected out to 1000 MWe for the nonsolar system. Therefore, the hybrid plant shows a significant cost reduction out to 500 MWe, and thereafter a slight economy of scale to 650 MWe. Hybrid systems with higher nonsolar capital cost ($/kWe), such as those with the nonsolar energy generator at the full turbine rating or coal-fired steam generators, show trends in lower capital costs on a $/kWe basis from 500 to 1000 MWe. All hybrid configurations, including coal-, oil-, and gas-fired nonsolar energy generators, show a reduction in capital costs per unit power output to 500 MWe. Most utilities prefer units no greater than 500 MWe due to the greater forced and scheduled outage durations above this size. Therefore our conclusion is that the preferred commercial system should be near 500 MWe.

2.2 STORAGE CAPACITY SELECTION

Various storage capacity sizes were considered to determine the amount of storage that would minimize the hybrid plant cost of energy. The optimum storage capacity for a given hybrid plant depends on a number of cost and performance parameters. Capital costs for hybrid plants with various amounts of storage capacity were estimated and annual solar performances were established. Optimum storage capacities were appraised for both solar standalone plants and hybrid plants. Solar standalone plants were assessed by driving toward an optimum storage capacity that would result in minimum levelized busbar energy costs. Hybrid plants were optimized by considering both the minimum cost of energy from the solar portion of the plant and also by comparing the annualized cost of storage versus the cost of burning coal, oil, or gaseous fuels. Results show that an optimum storage capacity for solar standalone plants with salt receiver/storage technology is about 18 hours. For hybrid plants, capacity depends on both the 18-hour storage and cost of fuel being burned.

Levelized busbar energy costs for these 100- and 300-MWe solar standalone plants were calculated at the maximum annual hours of operation value. The levelized busbar energy costs were then plotted versus hours of storage as shown in Figure 2.2-1. The results from these plots show that a minimum in the cost of energy (levelized busbar energy costs, $\overline{\text{BBEC}}$) occurs near 18 hours for both single-module 100-MWe plants and multiple-module 300-MWe plants. These results indicate 18 hours of storage is near optimum for single- and multiple-module solar plants for the heliostat cost assumption of $\$75/m^2$ ($\$7/ft^2$).

Hybrid solar storage capacity tradeoffs not only involve cost comparisons with storage capacity in the solar subsystems but also capital investment in storage versus operating costs in burning fuel. The cost of storage versus the cost of burning coal, oil, and gaseous fuels was calculated based on life-cycle annual costs. Results of the annualized cost ($\overline{\text{AC}}$) calculations are shown in Figure 2.2-2.

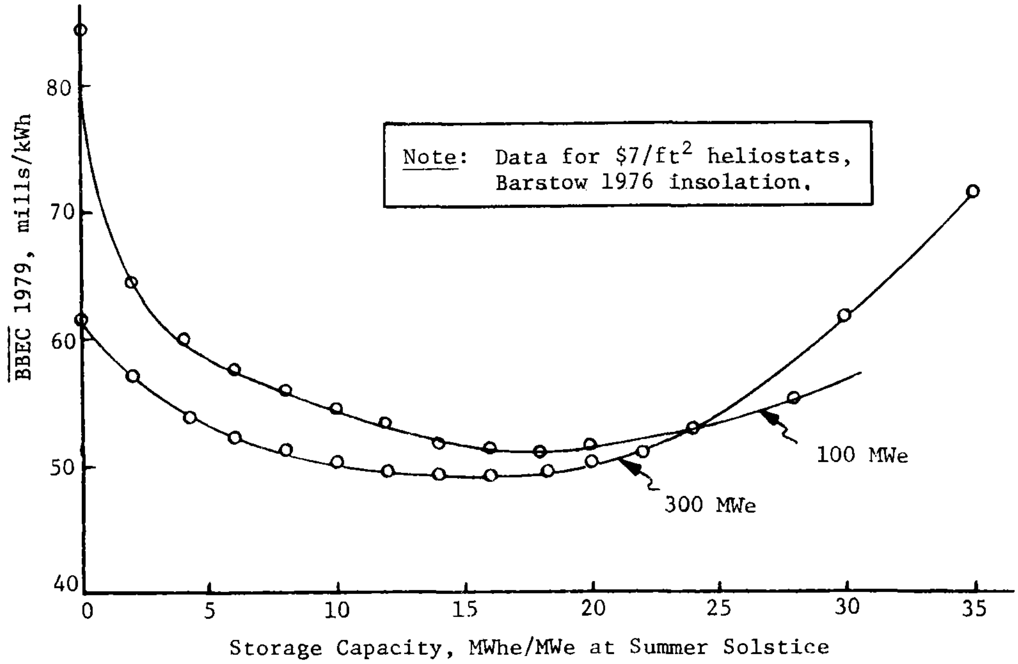


Figure 2.2-1 Solar Storage Optimization

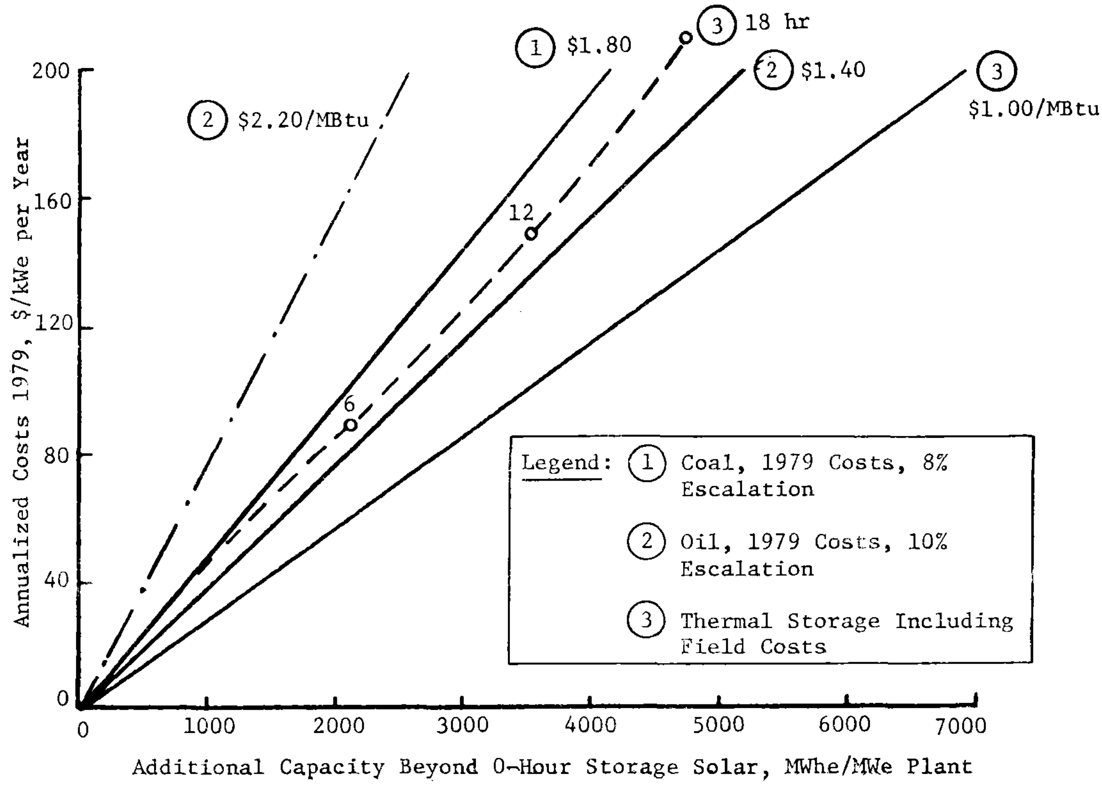


Figure 2.2-2 Fuel Burning vs Capital Investment in Storage

These costs show that oil or gas fuel annualized costs (for fuel only) are higher than the thermal storage investment, which includes heliostats, receiver, and tower costs. Coal burning exhibits higher AC costs than storage investment if the price of coal is greater than $1.60/MBtu (1979$). For coal prices less than $1.60/MBtu, burning coal over 30 years is cheaper than an investment in thermal storage capacity under the economic scenario assumptions used in this study. The thermal storage costs in this comparison includes all collector field and balance-of-plant cost in addition to cost of thermal storage units (tanks, media, storage piping). This cost comparison includes solar capital investment versus cost of fuel only and does not include the nonsolar capital investment to burn these fuels. This approach was used due to the requirement to compare capital investment in solar capacity to the costs obtained with burning fossil fuel in a nonsolar energy source already installed in the hybrid plant.

2.3 NONSOLAR SUBSYSTEM SELECTION

Two nonsolar energy source configurations were evaluated based on the issues of capital cost, performance, and operational flexibility. The two configurations were a boiler and a salt heater. The boiler configuration requires steam blending from solar and nonsolar sources at the turbine throttle and hot reheat points. The EPGS must also be oversized to accommodate the additional steam flow during the solar or nonsolar startup. This oversizing is mandatory to accommodate the other systems' (nonsolar or solar) steam while one unit is producing rated steam. On the other hand, the salt heater system does not require steam blending or EPGS overcapacity considerations. The salt heater can also charge storage when the solar collectors cannot, thus achieving a higher storage capacity utilization.

Cost comparisons of the boiler and the heater were made. The cost comparison clearly indicates that the total cost of the boiler system, including the capital requirements for steam blending and additional EPGS capacity, is higher than the salt heater.

Table 2.3-1 lists all attributes considered in the salt heater-steam boiler tradeoffs. The salt heater has the highest number of attributes, which resulted in its selection over the boiler. The development risks of a salt heater are considered to be relatively minor since salt heaters have been designed in the past but usually in a smaller capacity than that required for our hybrid configuration. Building a salt heater for utility service lifetimes of 30 years would require salt-cooled wall construction techniques similar to boiler construction requirements.

Table 2.3-1 Nonsolar Energy Source Comparison

Attribute	Boiler	Salt Heater
Capital Costs		
Lower unit capital costs	X	X
Lower blending system costs		X
No auxiliary startup system		X
Operation		
Simpler solar/nonsolar transition		X
No performance penalty in blending		X
Ability to charge storage with fossil energy generator		X
Faster startup		X
Simple warm standby operation		X
No heat tracing required	X	
Lower auxiliary loads	X	
Risk		
Lower development risk in blending system		X
Lower unit development risk	X	

Selection of the size for the nonsolar energy generator (salt heater) depends on the plant's storage capacity and other considerations. If the hybrid configuration has a large storage capacity and thus a high solar fraction, a reduction in the nonsolar subsystem size in relation to the turbine output may be in order. The actual size is a function of the plant site's insolation availability, the utility's generation mix, and the thermal storage capacity. With a salt heater, which has the ability to charge the thermal storage units, full plant capacity credit may be obtained when the heater's maximum thermal output is less than the turbine's full-load requirement. The effect of large amounts of storage, say 18 hours at turbine full-load, is to reduce the capital requirements in the nonsolar energy generator and thereby increase the value of storage.

In evaluating the demand requirements of a nonsolar energy source in a hybrid configuration, it is helpful to calculate the annual probability of various insolation outages. These isolation outage probabilities were derived from the 1976 Barstow insolation tape. Barstow received direct normal insolation free of outages 36% of the time. For an additional 6% of that year, Barstow experienced outages in the range from 0 to 10 hours. Outage durations from 10 to 20 hours represented an additional 50% of the year. This high percentage is expected since this range includes nightfall. An additional 8% of the outages was greater than 20 hours.

These analyses provided some insight into the availability or reliability of a solar plant with various amounts of thermal storage. Although a 10-hour storage capacity will increase the solar fraction, the solar plant cannot handle the majority of the insolation outages. That is, 58% of the outages are greater than a 10-hour duration.

Full plant capacity credit and thus high availability can be achieved by designing the hybrid plant to provide fully rated output during a large percentage of yearly operation. The nonsolar energy source can be sized at the thermal duty required for a full EPGS output or, if the thermal storage capacity is large, the nonsolar energy source size can be reduced and the nonsolar energy source can be operated in parallel with storage to achieve a full plant output. For example, if the size of the nonsolar energy source is reduced to one-half the plant full-load output and, during a lengthy insolation outage the nonsolar energy source is operating at a full load (one-half the plant rating) with supplemental energy derived from 18 hours of charged storage capacity, a full 36 hours of power at the turbine rating can be achieved. Only 5% of the outages during a year are attributible to durations greater than 36 hours. So, during only a maximum of 5% of the year, the plant produces power at half the turbine rating. This leads to the conclusion that with the large storage capacity (i.e., solar fraction), a smaller nonsolar fraction or size may provide full capacity credit. In addition since all nonsolar heated salt goes to storage, rated plant operation can be achieved independent of the nonsolar size. Therefore full plant output can be obtained completely independent of solar operation.

The configuration selected for our preferred system takes advantage of reducing the nonsolar size and still obtains full capacity credit. It should be noted that this can only be done with a relatively high hybrid solar fraction, i.e., a thermal storage capacity greater than 10 hours of storage. The salt heater chosen for our selected configuration enhances the possibility of having fully charged storage in preparation for a long-duration outage.

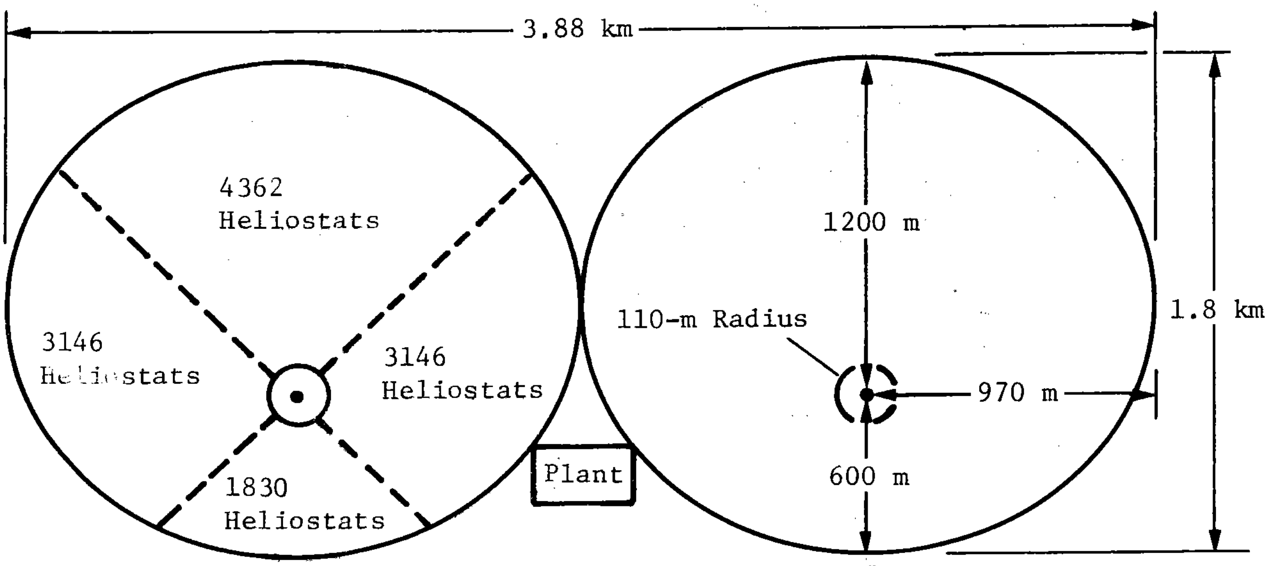
3. CONCEPTUAL DESIGN

The hybrid power plant design concept is based on a steam-Rankine cycle with a parallel configuration of the solar and nonsolar subsystems as shown in Figure 2-1. The steam-Rankine cycle is a high-efficiency reheat cycle using regenerative feedwater heating. The solar portion of the plant utilizes surrounding fields of heliostats. The heliostats reflect energy onto receivers located on top of the towers. Heliostats, tower and receiver modules are used with common thermal storage and EPGS. A high-temperature salt is used as the heat transport fluid in the receiver, steam generator and the nonsolar subsystem, and as the thermal storage media. The steam generator is a series of heat exchangers that heat feedwater from the steam cycle with the hot salt to generate superheated steam and also reheats steam from the high-pressure stage of the turbine. The fossil fuel salt heater heats salt and furnishes this, in parallel with the salt heated in the receiver, to the storage subsystem to be used in generation of steam in the salt heat exchangers.

The system can be operated from solar alone, solar plus storage, storage alone, fossil-fired alone, fossil-fired plus storage or fossil-fired plus solar. The salt temperatures and steam conditions are the same for any of the operational modes, whether operating from solar or nonsolar subsystems. The salt temperature at the outlet of the receiver or the fossil-fired salt heater is 566°C (1050°F) and enters these units at 288°C (550°F). The main steam conditions to the turbine are 538°C (1000°F), 12.41 MPa (1800 psig) with 538°C (1000°F) reheat. The optimum size of the hybrid plant is 500 MWe with 18 hours of storage and a nonsolar unit rated at 250 MWe. In this study the size selected for conceptual design, cost and performance is 100 MWe.

3.1 COLLECTOR SUBSYSTEM DESIGN

The collector subsystem is designed to provide energy to charge 18 hours of storage while the plant is producing 100 MWe net at summer solstice. This collector subsystem size is based on the most cost effective system as discussed earlier. To select the optimum design, a combined analysis was performed with the receiver subsystem. This analysis evaluated the cost of thermal power at the base of the tower in terms of dollars/MWh of annual energy produced for a range of collector-receiver module sizes. This analysis showed that the most cost effective module size is near the 350-MWt peak output. As the power requirements increase, the cost of the thermal power produced increases. The peak power requirements for the 100-MWe plant with 18 hours of storage is near 740 MW thermal. For this requirement it was shown that either a single module or double module is cost effective. For double modules, the plant is located between the two modules. For two modules, the less expensive smaller modules, as compared to the larger single module, tend to offset the additional cost of interconnecting piping between modules. The additional advantage of modularity, including flexibility, reliability, and scalability, favored the selection of two modules. The resultant collector subsystem configuration is shown in Figure 3.1-1.



Note: Number of heliostats per module = 12,484,
heliostat area per module = 612,340 m^2,
land area per module = 2.75 km^2,
total plant land area = 7.0 km^2.

Figure 3.1-1
Hybrid 100-MWe 18-Hour Storage Collector Configuration

The two surrounding radial-stagger fields of heliostats each contain 14,484 heliostats. The heliostat is designed as a 12-facet, glass/steel system with inverted stowage and a 49.05-m^2 (528-ft^2) reflective area. The overall dimensions used for minimum spacing in the collector field are 7.416 m (24.33 ft) x 7.378 m (24.20 ft). The average reflectivity is 90%. The minimum spacing between any two adjacent heliostat foundations in the field is 10.77 m (35.33 ft), allowing a 0.3-m (1.0-ft) clearance between the reflective surfaces in any orientation. As can be seen from Figure 3.1-1, each collector field is divided into four segments that direct power into the north, south, east and west cavities of the receiver.

3.2 RECEIVER AND SUPPORT TOWER DESIGN

A receiver and support tower is located in each of the two collector fields shown in Figure 3.1-1. Energy is collected in the cavity receivers mounted on top of 156.7-m concrete towers as shown in Figure 3.2-1, which is a view looking south and into the north aperture. Each receiver has four separate cavities facing north, south, east and west. Each cavity has three walls that contain salt (tube) panels for collecting solar energy, two side walls and a back wall. The side walls are common between adjacent cavities so solar energy impinges both sides of the tube panels. Molten salt is heated in the receivers from 288°C (550°F) to 566°C (1050°F) and delivered to the thermal storage hot tanks. Each receiver is sized to collect 421 MWt at noon on summer solstice. The receiver is 26.7 m (87 ft 7 in.) wide and 30.02 m (98 ft 6 in.) high from the bottom of the receiver floor to the top structural member.

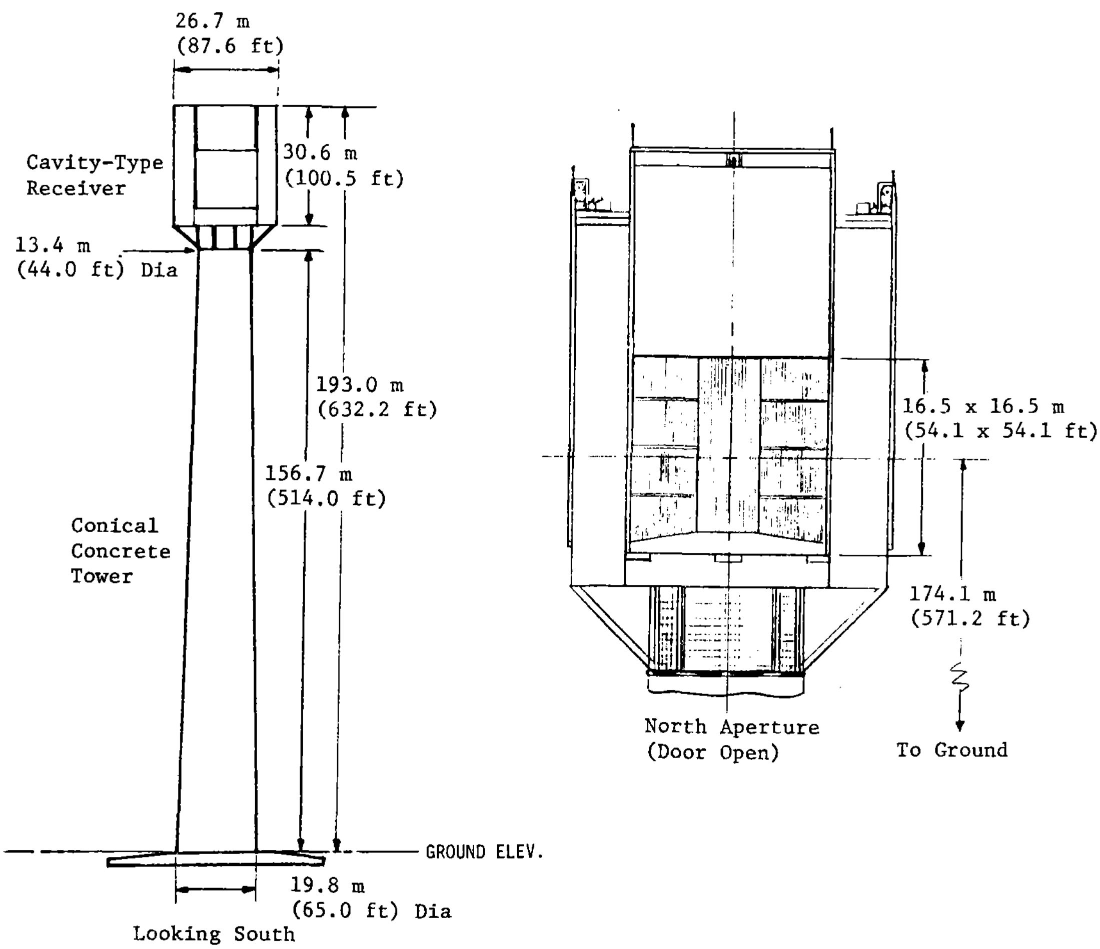


Figure 3.2-1 Receiver and Support Tower

The roof joist extends above the top structure 0.60 m (1 ft 1½ in.) to the roof ridge. As shown in Figure 3.2-2, overall height from the top of the support tower to the roof ridge is 37.27 m (122 ft 3½ in.). The receiver and its superstructure support is a beam column-type construction utilizing standard AISC structural shapes.

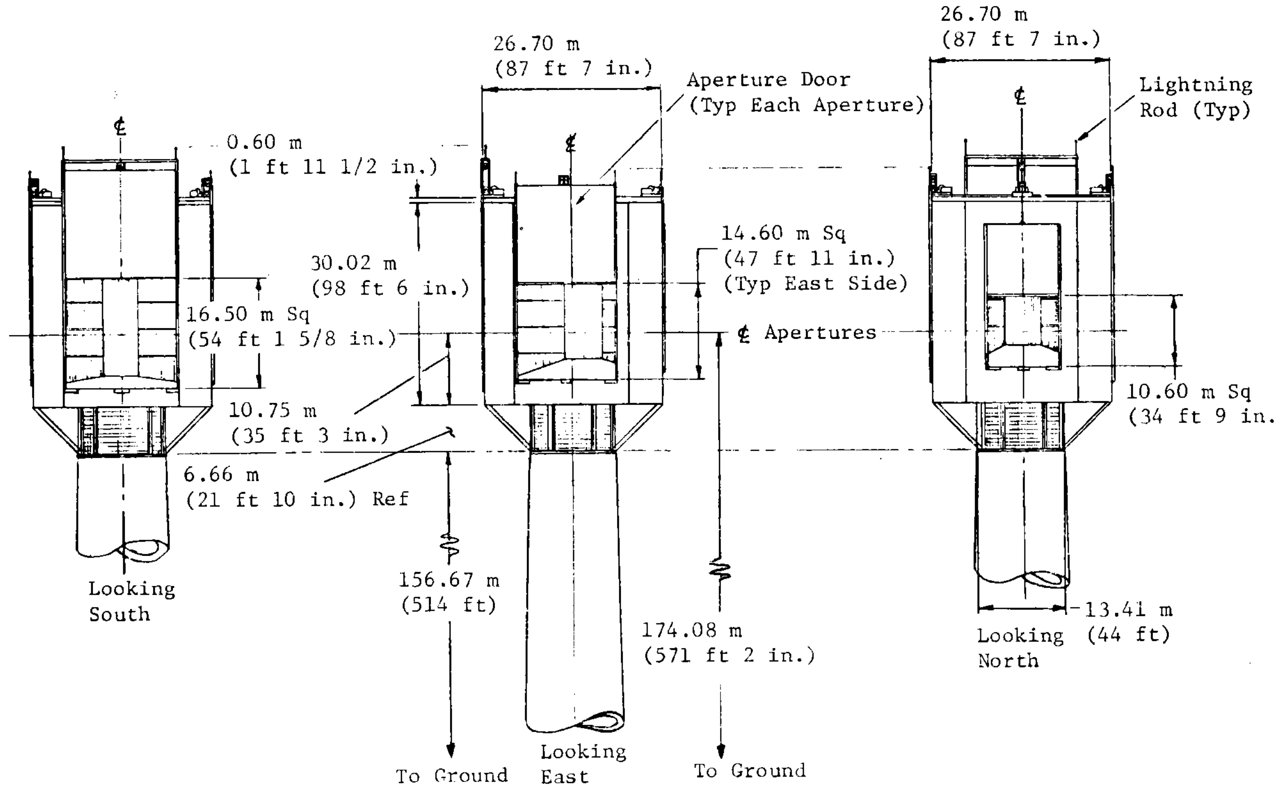


Figure 3.2-2 Receiver General Configuration

The centerline location of all apertures is 174.08 m (571 ft 2 in.) above ground level. The north aperture is 16.5 m (54 ft 1 5/8 in.) square, the east and west apertures are each 14.6 m (47 ft 11 in.) square and the south aperture is 10.6 m (34 ft 9 in.) square. The size and shape of each aperture was determined by the amount of solar flux directed from the collector field.

Most of the piping and valves are located in the east, west and south cavities below the lower shields. These cavities are smaller than the north cavity and allow more working room between the floor and the lower radiation shield. Provisions are made for a crane to be installed on top of the receiver structure for raising and lowering complete absorber panels and equipment, piping, valves, etc. This crane can be installed early in the construction phase to support structural assembly of the receiver.

All platforms and openings are protected by rails or safety chains. The area under the receiver floor above the tower top is enclosed with heavy wire mesh. This provides a safe well-ventilated and day-lighted work area for receiver maintenance operations. Lightning protection is provided by lightning rods installed at the high points on each door guide frame.

3.3 NONSOLAR SUBSYSTEM

The nonsolar subsystem selected for the conceptual design is an oil-fired salt heater. Support equipment includes the fuel storage and supply equipment and air quality control equipment. The heater is fired with No. 6 fuel oil. As previously discussed, the cost of electricity is reduced with increased storage up to 18 hours for molten salt systems. This amount of storage achieves a plant capacity factor of 0.75 and therefore plants are near baseload ratings on solar alone. This permits a reduction in the rating of the nonsolar subsystem. For the 100-MWe plant, the oil-fired heater absorbed duty is therefore 130 MW thermal.

Salt is heated in the oil-fired heater and delivered to storage for the subsequent generation of steam. The salt heater, shown in Figure 3.3-1, is similar in configuration to oil-fired boilers used in the utility industry and has been redesigned to accommodate the salt requirements. Salt enters the heater at 288°C (550°F) and is heated in tubes located in the convective and radiative sections of the heater and exits at 566°C (1050°F).

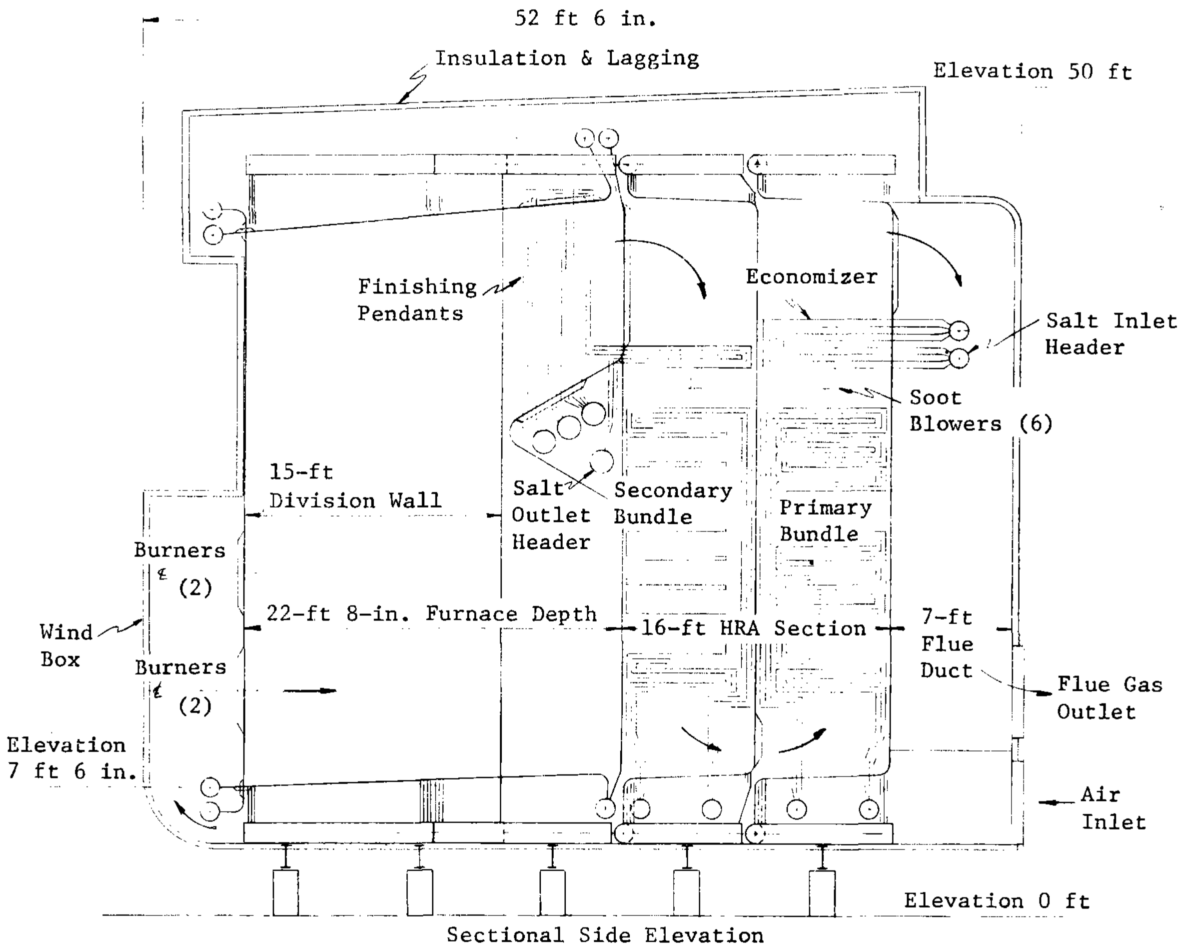


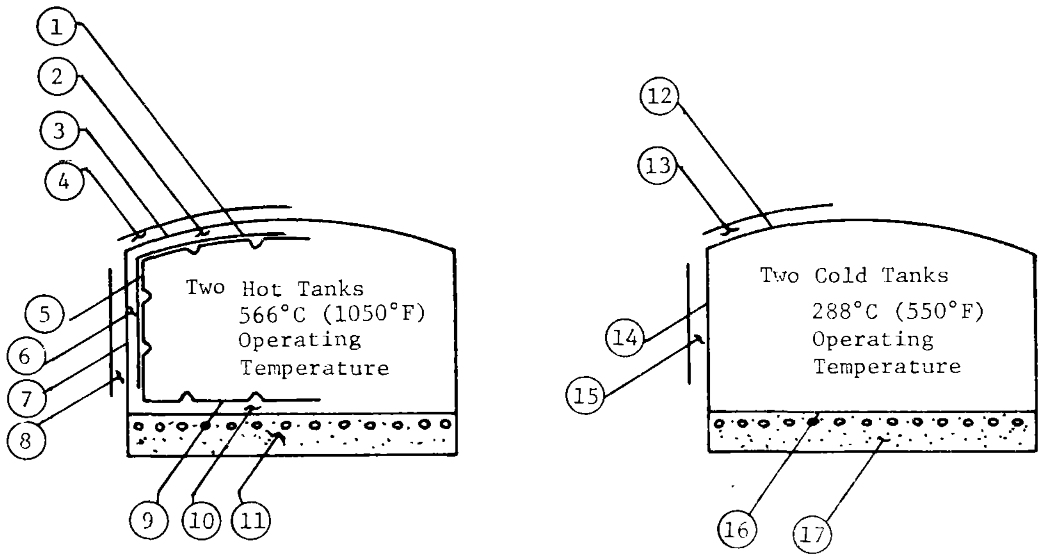
Figure 3.3-1 Salt Heater Subsystem Configuration

3.4 STORAGE SUBSYSTEM

The thermal storage subsystem has separate tanks for storage of hot and cold salt. All of the heated molten salt from either the receiver or the nonsolar subsystem is delivered to the hot salt tanks for storage at 576°C (1050°F). Hot salt is used for the generation of steam in the heat exchangers where it is cooled and returned to the cold tanks for storage at 288°C (550°F). The storage is in the form of sensible heat and the salt remains molten throughout the process. For 18 hours of storage in the 100-MWe plant, it was shown by analysis that two hot and two cold tanks were the most cost effective. These analyses considered soil-bearing capacity, design stresses in the tanks, cost of the tanks, insulation and foundation, tank heat losses and the cost of heliostats to replace the heat losses.

The hot and cold tanks are shown schematically in Figure 3.4-1. The hot tanks are insulated internally and externally. The internal insulation is used to maintain the tank wall temperatures below 316°C (600°F) so carbon steel rather than the more expensive stainless steel can be used for fabrication. The internal insulation is load-bearing and is separated from the hot salt with a unique-design stainless steel liner that takes thermal expansion in two directions. The thickness of both internal and external insulation is established on the basis of cost. The cost of insulation is traded against the cost of heliostats required to make up the heat loss from the tanks as less insulation is used. The cold tanks are also constructed of carbon steel and use only external insulation.

Volume = 11,688 m^3 4.13 x 10^5 ft^3) Each   Volume = 10,362 m^3 (3.66 x 10^5 ft^3) Each



Hot Tank 29.3-m (96-ft dia x 17.4-m (57-ft) high

Top	1	Stainless Steel Liner
	2	15.24-cm (6-in.) Fiberglass
	3	Carbon Steel Shell
	4	15.24-cm (6-in.) Fiber Board
Sides	5	Stainless Steel Liner
	6	22.86-cm (9-in.) Insulating Brick
	7	Carbon Steel Shell
	8	20.32-cm (8-in.) Fiberglass
Bottom	9	Stainless Steel Liner
	10	22.80-cm (9-in.) Insulating Brick
	11	Cooled Foundation

Cold Tank 26.2-m (86-ft) dia x 19.2-m (63-ft) high

Top	12	Carbon Steel Shell
	13	15.24-cm (6-in.) Fiber Board
Sides	14	Carbon Steel Shell
	15	15.24-cm (6-in.) Fiberglass
Bottom	16	Carbon Steel Shell
	17	Cooled Foundation

Figure 3.4-1 Thermal Storage Tanks

The tanks are mounted on insulating concrete foundations that contain active cooling loops that prevent shifting of the soil beneath the tanks caused by the ground water temperature rising above the boiling point. This type of foundation was determined to be more cost effective than raising the tanks off the ground and providing natural cooling with air.

3.5 SALT HEAT EXCHANGERS

Conventional heat exchangers generate rated steam for the high-pressure section of the turbine as well as reheat steam for the intermediate-pressure section of the turbine in the EPGS as shown in Figure 2-1. There are four salt to water/steam heat exchangers, a preheater, boiler, superheater and reheater. The boiler section is natural circulation. A steam drum is provided to separate out the steam that goes to the superheater. Salt from the hot storage tanks enters the superheater and reheater at 566°C (1050°F) and exits the preheater at 288°C (550°F). The salt is then returned to the cold salt tank for recirculation to either the receiver or nonsolar subsystem.

3.6 ELECTRIC POWER GENERATION SUBSYSTEM (EPGS)

The EPGS uses a conventional tandem, compound double flow reheat turbine. Seven feedwater heaters are used, including a deaerator and one for gland steam. Turbine backpressure is maintained with wet cooling. The steam cycle conditions are 12.4 MPa (1800 psig), 538°C (1000°F) high-pressure steam, with reheat steam resuperheated to 538°C (1000°F) and a backpressure of 8.5 kPa (2.5 in. Hga). These cycle conditions were selected based on tradeoff studies that investigated a range of cycle conditions for the 100-MWe plant configuration. The study evaluated the cost and performance of all subsystems within the plant, including the solar as well as the nonsolar subsystems. The results of this analysis (Fig. 3.6-1) shows the selected cycle conditions to be the most cost effective for the 100-MWe plant when considering the total plant cost including heliostats.

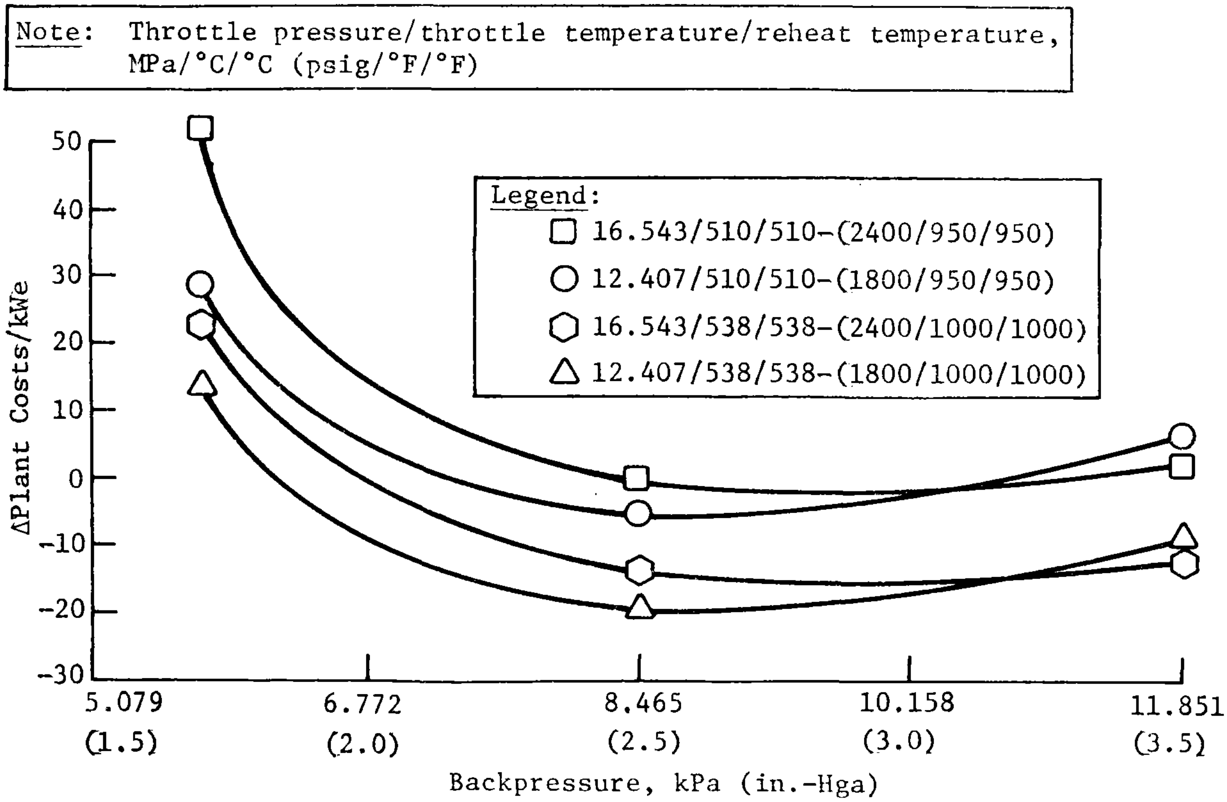


Figure 3.6-1 EPGS Optimization, 100 MWe

4. ASSESSMENT OF THE COMMERCIAL PLANT

Analyses performed throughout the program have shown that, using the molten salt technology, hybrid power plants become even more cost effective as the plant size in increased from 100 to 500 MWe. This is an important consideration since it provides flexibility in selection of a particular plant for each utility system through modularity of the collector and receiver subsystems. In addition to plant size, modularity provides the utility a convenient building block with respect to the amount of storage for a particular size of plant, the ability to add to a plant to meet future needs, the confidence needed for scaling designs to larger sizes and the added reliability afforded by redundancy of the collector/receiver module. For these reasons the plant design was assessed at both the 100- and 500-MWe commercial sizes.

4.1 PLANT PERFORMANCE - 100 MWe

Conceptual design of the 100-MWe solar hybrid plant with 18 hours of storage was modeled for annual performance using three computer models--STEAEC, MIRVAL and TRASYS. Using the performance parameters developed from the subsystem designs, performance losses were determined on an annual basis and at the design point (insolation of 950 W/m^2 at noon summer solstice) for a location at Barstow, California. Figures 4.1-1 and 4.1-2 are the annual energy and design point energy stairsteps, respectively, derived from STEAEC results. The annual energy derived from the solar portion of the plant results in a plant capacity factor of 0.752. The net power output from the system at the design point, with 12,484 heliostats in each of two modules, is 100 MWe net with 479 MWt going to the storage system. The number of heliostats in the two-module 100-MWe system is sufficient to charge the full 18-hour storage capacity on day 176 near summer solstice at Barstow, California based on the 1976 insolation data tapes.

A comparison of the yearly energy to the working fluid and in the working fluid, from the STEAEC computer program, reveals an energy loss of 2.93%, which is the result of piping thermal losses and heliostat turndown. The yearly surplus energy to receiver and storage totals 46,318 MWht, or 2.67% of the yearly energy to the working fluid, and represents the annual energy lost due to heliostat turndown because of fully charged storage. This low value indicates that, with 18 hours of storage, all heliostats are utilized over 97% of the time insolation is available.

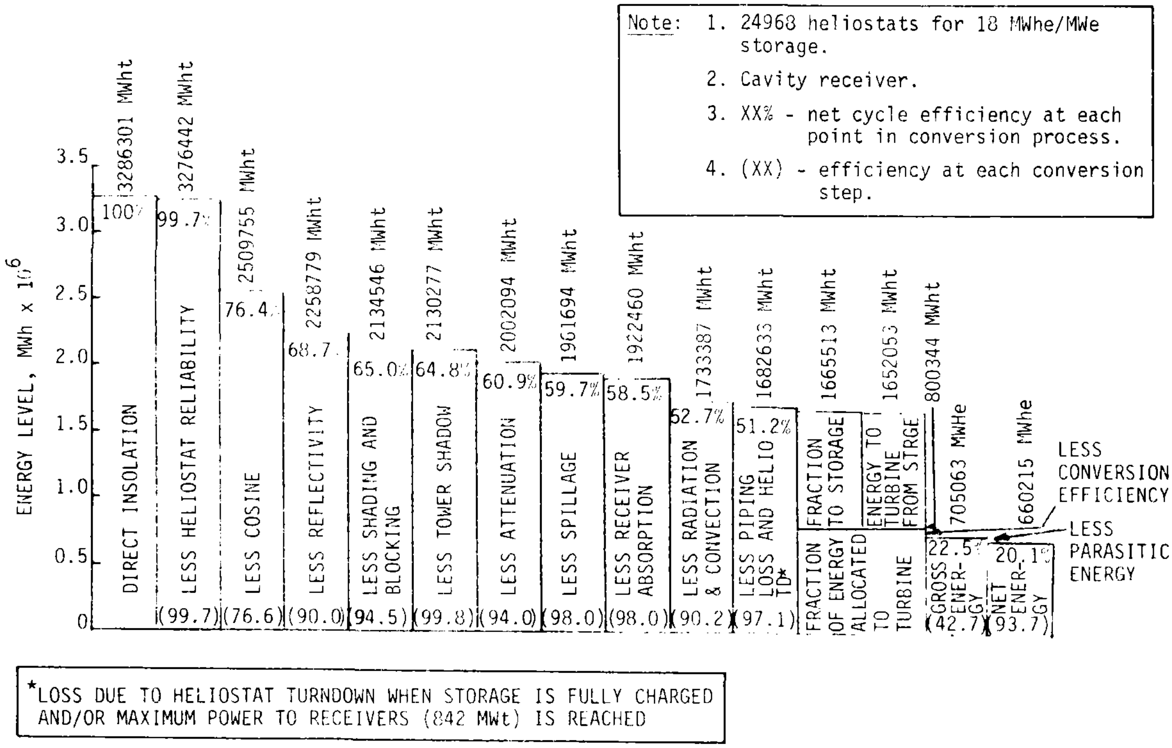


Figure 4.1-1 Annual Efficiency for 100-MWe Plant

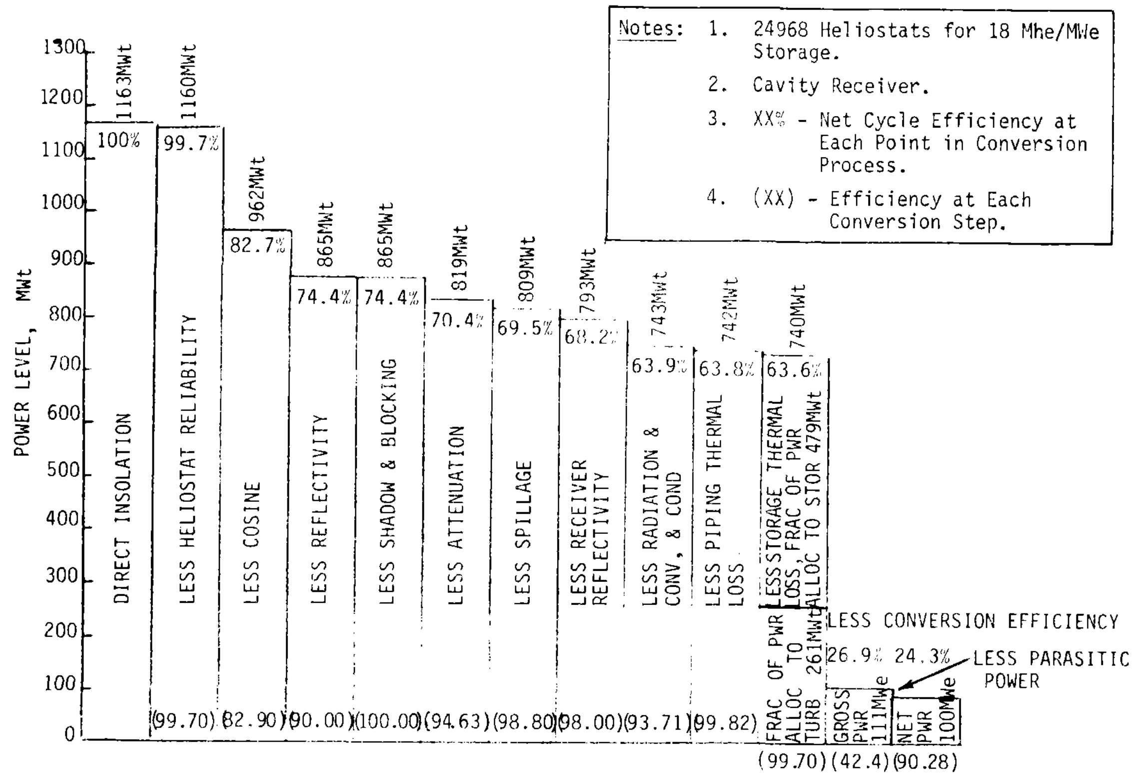


Figure 4.1-2 Design Point Efficiency for 100-MWe Plant

4.2 CAPITAL COST - 100 MWe

The capital cost for the 100-MWe molten salt, 18-hour storage hybrid plant using an oil-fired nonsolar subsystem was determined. Collector field costs, excluding land and site preparation, were provided by Sandia Laboratories-Livermore at $\$144/m^2$ and $\$72/m^2$ of reflective surface with 90% reflectivity. The pie chart, Figure 4.2-1 shows the breakdown of the first commercial 100-MWe plant assuming heliostat cost of $\$144/m^2$ with 90% reflectivity. As can be seen the largest percentage of plant cost is associated with the collector subsystem. This collector cost results from 18 hours of storage that, as discussed earlier, is cost effective when considering the total cost of electrical energy output from the plant. Figure 4.2-2 shows the breakdown of the first plant cost assuming a heliostat cost of $\$72/m^2$ with 90% reflectivity.

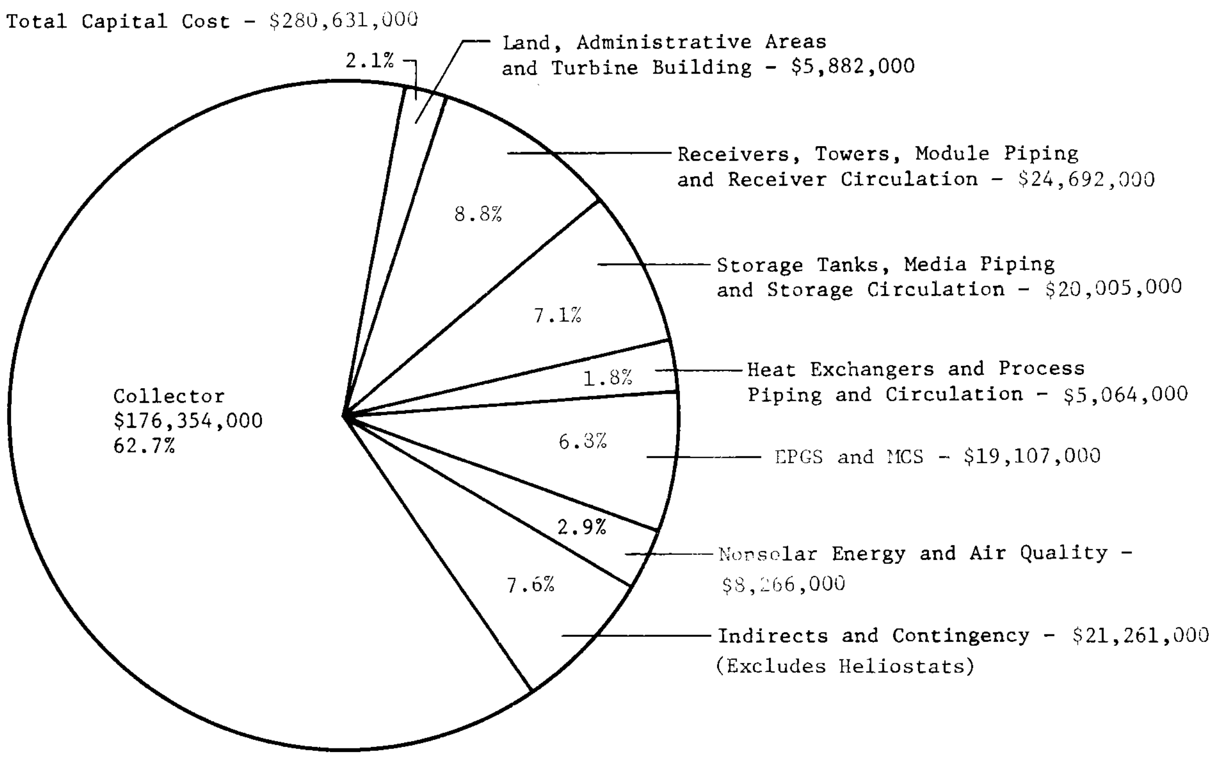


Figure 4.2-1
100-MWe 18-Hour Storage Solar Hybrid Capital Cost
(First Plant, $\$144/m^2$ Heliostats)

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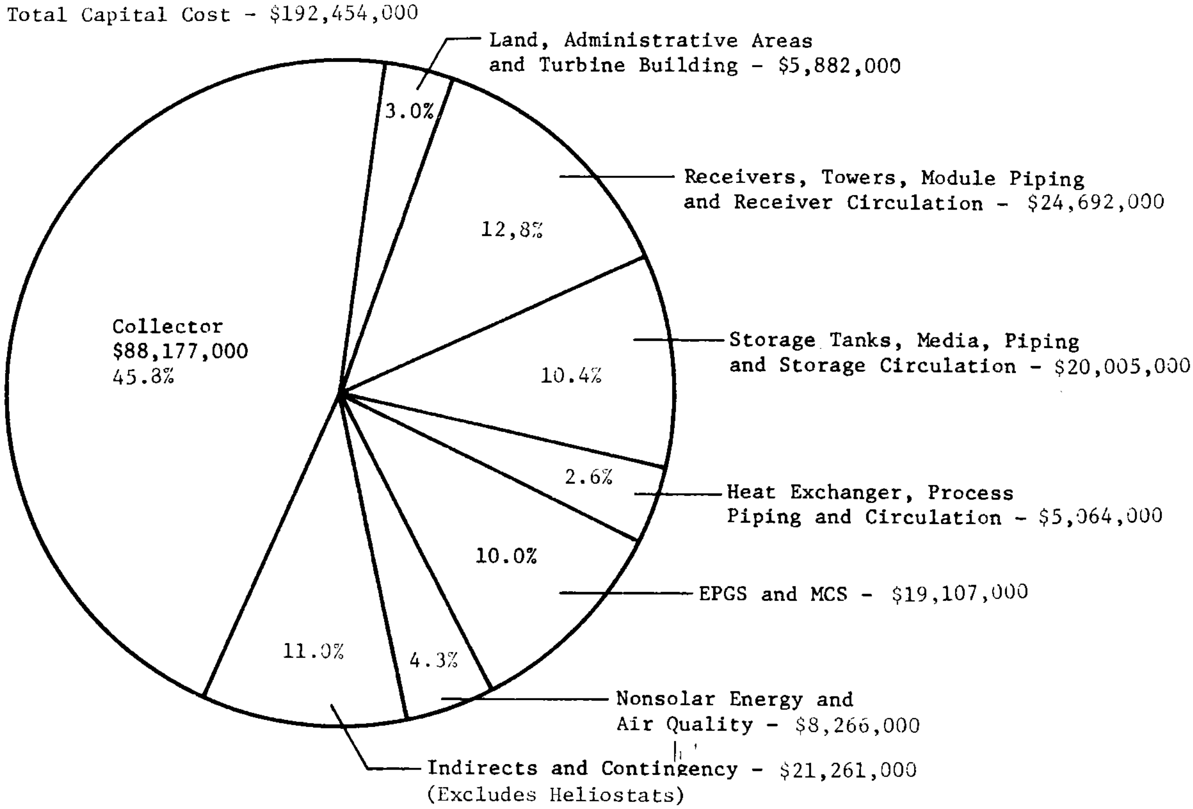

Figure 4.2-2
100-MWe 18-Hour Storage Solar Hybrid Capital Cost
(First Plant, $72/m^2$ Heliostats)

4.3 ASSESSMENT OF PLANT COST AND FINANCIAL INCENTIVES

Using the plant capital and operations and maintenance cost developed for the study and the baseline economic parameters developed in conjunction with Sandia Laboratories-Livermore, the levelized busbar energy costs (BBEC) were developed for the 100-MWe and 500-MWe hybrid plants. The levelized cost account for all costs incurred during construction and operation of the system is a constant value over the life of the system. The BBEC was calculated using the Sandia Laboratories-Livermore BUCKS program for solar-only operation in 1979$ and is shown in Table 4.3-1.

These economic assessments have been predicated on a constant set of assumed economic parameters. These parameters were defined in the solar central receiver hybrid power system requirements definition document as those of a "typical" utility and reflect recommendations by EPRI. However, several subtle commonly utilized financial incentives, which are not considered when using the given baseline economic parameters, significantly affect the cost effectiveness of a solar thermal hybrid plant in the utility environment. These economic parameters involve the cost of capital, depreciation method and investment tax credits. Analyses were performed to assess each of these independently and were then combined to show the total effect. Each of the items result in a bias against solar hybrid in relationship to less capital-intensive conventional power generation plants. As can be seen in Table 4.3-1, there can be a significant reduction in $\overline{\text{BBEC}}$ (30%) for the solar hybrid plants if realistic financial incentives, available to most utilities in the U.S. today, are used.

Table 4.3-1 Summary of Solar Hybrid Economic Assessment

	$\overline{\text{BBEC}}$, mills/kW-h (1979$, 1990 Year of Commercial Operation)	
	Baseline Economics	Available Financial Incentive* Economics
100 MWe - 18-Hour Storage		
(First Plant)		
$72/m^2 Heliostats	64.9	49.3
$144/m^2 Heliostats	91.9	69.8
500 MWe - 18-Hour Storage		
(Nth Plant)	53.2	37.0

*10% investment tax credit, SOYD depreciation method, tax-adjusted cost of capital method.

4.4 COST-TO-BENEFIT ANALYSIS

To evaluate the worth of a molten salt hybrid plant to the utilities, the cost-to-benefit ratio for this concept in an actual utility environment was analyzed. Several types of economic analyses were performed to assess the solar hybrid plant cost and value to a utility for the 500-MWe commercial plant size installed for the year 1990. These analyses showed that hybrid plants using large amounts of salt storage can compete with conventional power systems for the utility market. To determine the value of the selected configuration in an actual utility environment, the cost-to-benefit ratio was assessed. The utility selected was Arizona Public Service. The analysis was performed using the methodology developed by EPRI-Westinghouse.* This methodology consists of

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**A Methodology for Solar-Thermal Power Plant Evaluation.* EPRI-869, Westinghouse Electric Corporation, East Pittsburgh, Pennsylvania.

several computer models that simulate solar plant performance, establish loss of load reliability criteria, and determine costs of running the solar plant. Costs of operating and capital investment in the solar plant are then compared with the value of the conventional plants displaced. The cost and performance of a 500-MWe plant with 18 hours of storage were developed and used in the analysis to evaluate the competitiveness of solar hybrid with peak combustion turbines and intermediate/baseload coal capacity displacement. The analysis was approached parametrically with respect to plant cost and capacity credit. As can be seen in Figure 4.4-1, the cost/benefit ratio of 0.98 was computed based on a capital cost estimate of 1680 $/kWe (1979$) and a displacement of a 500-MWe coal plant planned for 1990 installation. The results of this analysis are significant since the APS system in the year 1990 is nearly 70% coal and nuclear capacity--a formidable market for solar power system penetration.

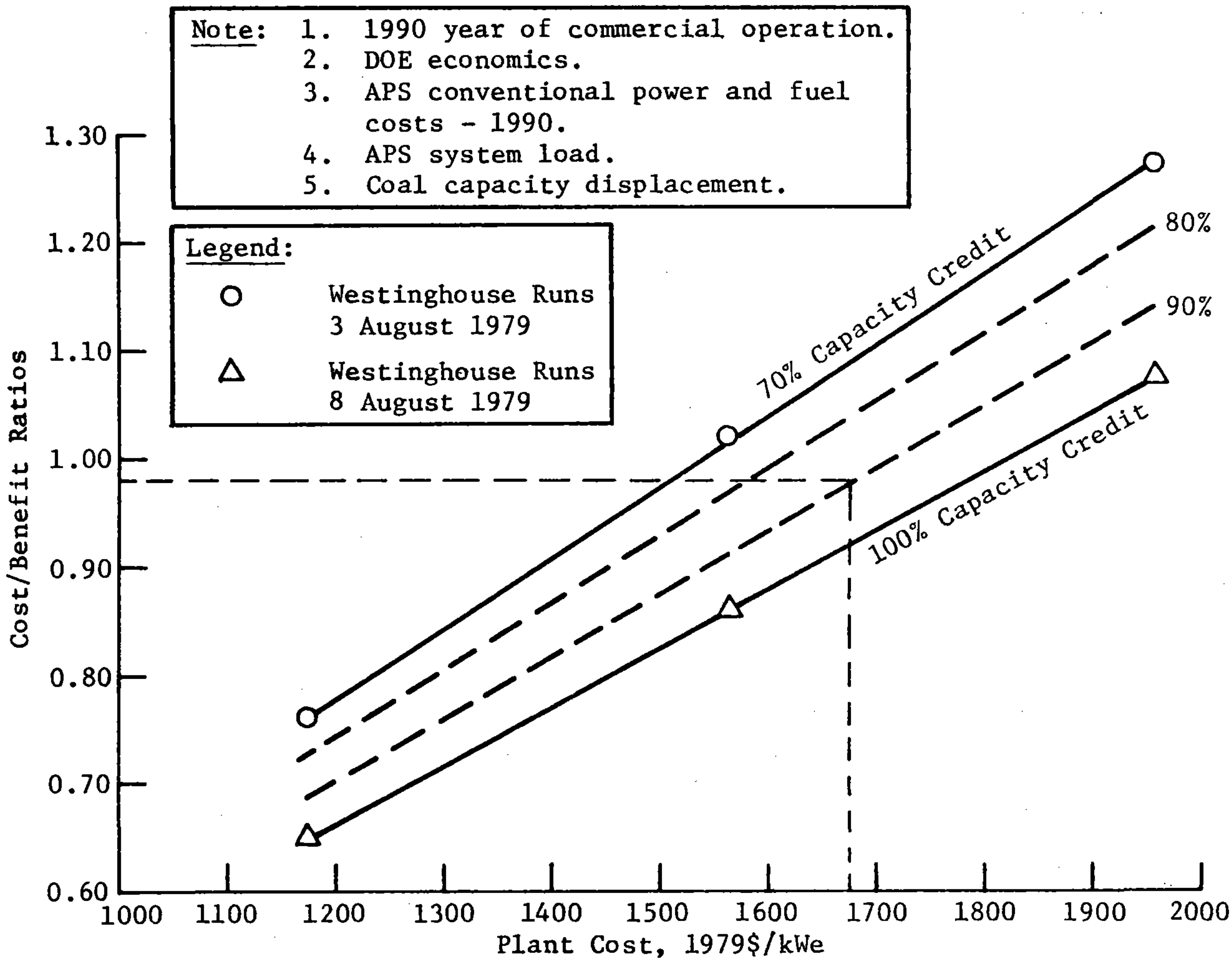

Figure 4.4-1 Hybrid Cost/Benefit Analysis

5. DEVELOPMENT PLAN

In a broad sense, a solar central receiver hybrid power system development plan would normally include all activities in the process from this conceptual study to the completion of first unit operational experience. These activities would include analysis, test, preliminary design, procurement, fabrication, assembly, checkout, and an operations phase. However, only the near-term development activities that will impede commercialization of solar hybrid plants are addressed here.

The general approach to the development plan was to carefully examine the hybrid concept design to identify candidate uncertainties. This examination was done by each of the team members in their area of expertise. Each of the candidates was then assessed to determine if it was appropriate for near-term work. We found that, based on our level of confidence, most of the candidate uncertainties could be properly worked in the detail design phase without any development activity between now and then. Other candidates, such as the collector subsystem, are the subject of extensive DOE-sponsored activity and thus need no additional development. The result of this screening activity is a list of near-term development activities (Table 5-1).

These near-term development activities are listed in descending priority groups that are categorized as to the urgency or need of the activity. The cost and schedule span times for these activities are estimated in Volume II. A plan for the assessment of hybrid industrial process applications is also discussed in Volume II.

Table 5-1
Recommended Near-Term Development Activities

Mandatory Thermal Energy Storage
Development of Necessary Design Data Nonstructural Materials (Seal Development) Receiver Creep Fatigue
Development of Extended Data for Design Confidence Effect of Salt Impurities on Metal Corrosion Effect of Metal Composition Tolerance on Corrosion Corrosion Stress Fatigue Salt Conditioning High-Pressure Flow Test
Development of Designs and Analyses Directly Applicable to Repowering Startup/Shutdown and Partial Loads Effects Control System Logic Oxygen Partial Pressure As a Function of Salt Temperature Effect of Salt Creep and Vapor Pressure Instrumentation Requirements and Availability
Analysis of Solar Central Receiver Applications Commercial Power System Definition Update

6. SUMMARY

In summary, the concept using molten salt has been shown to be a cost effective solution for hybrid power plant applications. It permits flexibility in design of collector/receiver modules, in application of large quantities of thermal storage, in sizing of plants, and in plant operating requirements. It has been shown that large amounts of storage are cost effective and that fossil fuel usage can be minimized. The cost effective salt storage also permits lower nonsolar subsystem ratings than the turbine rating to further reduce the plant capital costs. The selected concept design is compatible with all types of fossil fuels (gas, oil, coal), which provides additional flexibility to the utility. The concept provides a simple solar-to-nonsolar interface that decouples the power sources from electric power generation and actually minimizes control requirements. The nonsolar subsystem's oil-fired salt heater can be used to charge the large amounts of storage, which provides additional design flexibility to meet the varied utility needs. A large plant size, 500 MWe, has been shown to be the economic optimum. The design concept utilizes collector/receiver modularity to provide added flexibility, reliability and ease of scaling commercial plants between 100 and 500 MWe. It has also been shown that the selected concept is competitive with conventional intermediate and baseload plants in an actual utility environment with cost/benefit ratios less than 1.0.

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