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SOLAR CENTRAL RECEIVER HYBRID POWER SYSTEMS SODIUM-COOLED RECEIVER CONCEPT. FINAL REPORT

Volume 1. Executive Summary

January 1980

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Rockwell International
Energy Systems Group
Canoga Park, California

U.S. Department of Energy

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VOLUME I
EXECUTIVE SUMMARY

JANUARY 1980

PREPARED FOR THE
U.S. DEPARTMENT OF ENERGY
AS PART OF
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Rockwell International
Energy Systems Group

University of Houston Founded 1927

MCDONNELL DOUGLAS CORPORATION

Salt River Project
WATER ◆ POWER

Stearns-Roger

Babcock & Wilcox

SRI International

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I. INTRODUCTION

THE HYBRID SOLAR CENTRAL RECEIVER POWER PLANT

As part of the world's search for supplementary, renewable energy sources for, among other applications, the generation of electrical power, studies are being conducted by the Department of Energy and other organizations on evaluating the use of the endless supply of energy from the sun. For electric utility applications, one of the most promising methods for generating power economically from solar sources is the solar central receiver concept. This concept consists of a tower, at the top of which is placed a fluid-cooled receiver device and around which are located a large number of heliostats. Each heliostat tracks the sun and directs sunlight onto the receiver. One version of a solar power plant of this type is shown in Figure 1. The sunlight is converted to heat energy by absorption on the receiver surface, and this heat energy is carried away by a fluid which is pumped through the receiver. Fluids that have been considered in some detail to date are water (which is converted to steam in the receiver), gases (such as air and helium), molten salts, and molten metals (liquid sodium). The steam and gas fluids are used as working fluids in conventional prime movers such as steam turbines (Rankine cycles) or gas turbines (Brayton cycles). Molten salts and sodium carry heat energy to steam generators located at ground level where steam is produced to drive conventional steam turbines in a Rankine cycle.

The central receiver concept has been the subject of intensive study by DOE over the last few years and several versions have been conceptually designed and assessed in terms of their economic competitiveness relative to conventional energy sources.[1,2,3,4] A 10-MWe, water/steam-cooled concept is to be constructed at Barstow in the near future. These initial studies were directed principally toward the storage-coupled or stand-alone application. The stand-alone plant is a solar central receiver that does not incorporate any fossil energy source in its design. One such plant, employing liquid sodium as a coolant, was conceptually designed by the Energy Systems Group of Rockwell International over the period from 1976 to 1978[5,6] and was projected to be economically viable relative to a new coal plant in the 1990's time frame in sizes from 100 to 500 MWe and at capacity factors up to about 80%.

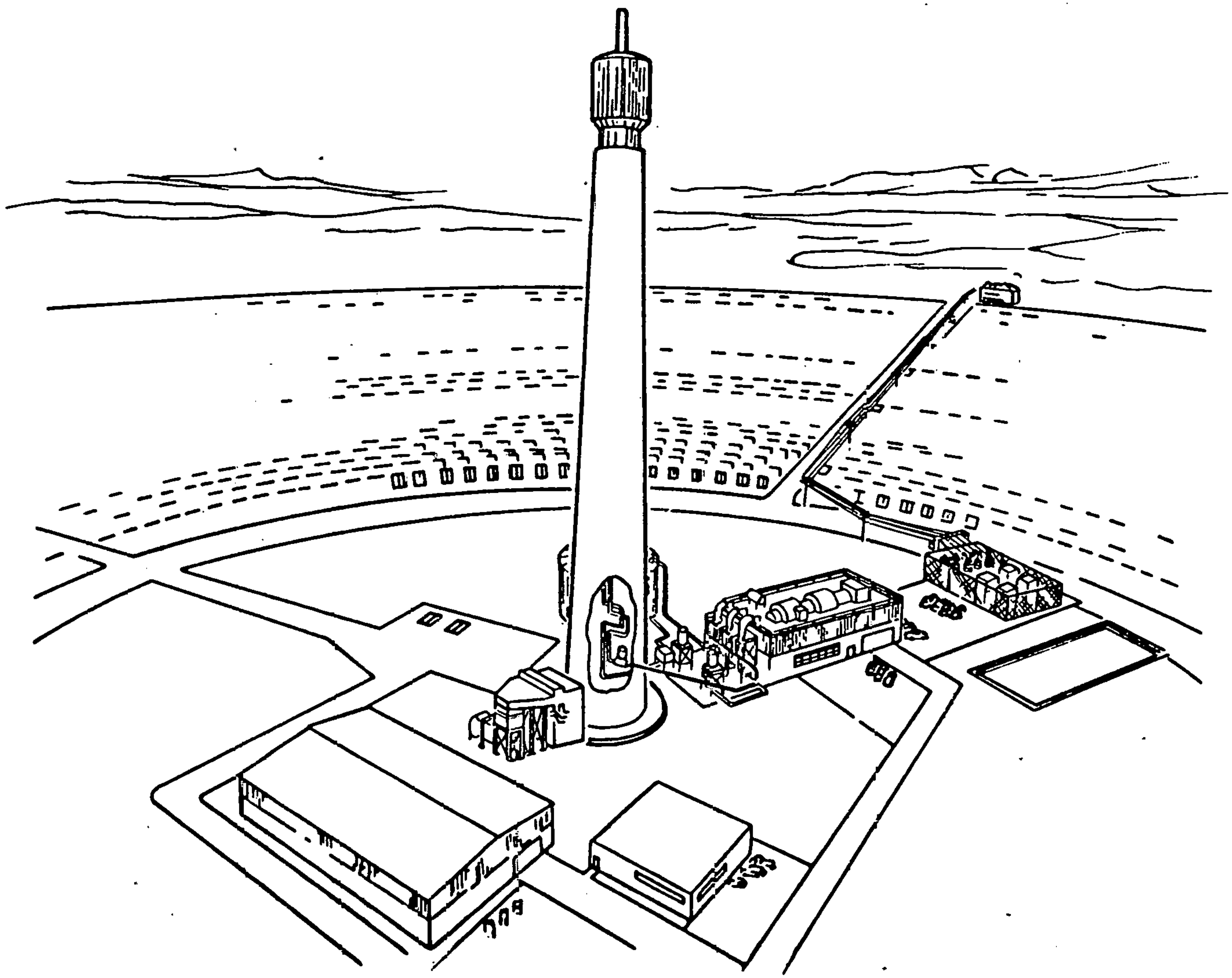

Figure 1. Solar Central Receiver Hybrid Power System

In most of the stand-alone plants, a certain amount of storage of the heat energy absorbed in the receiver has generally been found to be desirable from a cost-effectiveness standpoint, and necessary, if one wishes to operate the plant at night or during cloudy weather and if one wishes to match the solar-cycle power availability more closely with the power demand. In the sodium-cooled concept, storage of energy in quantities that will allow full-power operation for up to 12 or 14 h at equinox is calculated to be economically advantageous.(6) However, full weather coverage requires large amounts of stored energy, amounts that are not always cost effective, especially, in the case of water/steam systems, if the performance of the plant is degraded during operation from storage. At least one way of circumventing this situation by means of an air/rock storage concept has been identified and evaluated by ESG under a company-funded effort,(6) but, generally speaking, stand-alone plants cannot be counted upon to deliver energy with the same degree of availability as a fossil plant and therefore will not be able to penetrate into the utility grid beyond 10 to 20%(7) without improvements in the currently demonstrated storage concepts.

Another way to circumvent the storage problem is to combine the solar central receiver plant with a conventional fossil-fired unit in such a way that the overall cost of energy from the plant is minimized and the plant can produce energy at its rated output independently of the availability of sunshine. This approach greatly reduces, or perhaps eliminates, the need for storage of thermal energy. Thus, the plant has high availability as an energy source and can have constant output 24 h per day and 365 days per year (neglecting planned maintenance and forced outages). The fossil fuel serves essentially as "stored energy" which can be drawn upon whenever the sun is not shining, or can be used to augment a thermal energy storage system, if one is economically viable. From a utility's viewpoint, a solar plant combined with a fossil unit can be given the same capacity credit as any conventional power plant and therefore does not require additional backup capacity. This type of plant is called a hybrid solar plant and is the type depicted in Figure 1. Two basic types, one with storage and one without storage, each employing sodium as the heat transport fluid, have been conceptually designed and evaluated under contract to DOE and are described in this report.

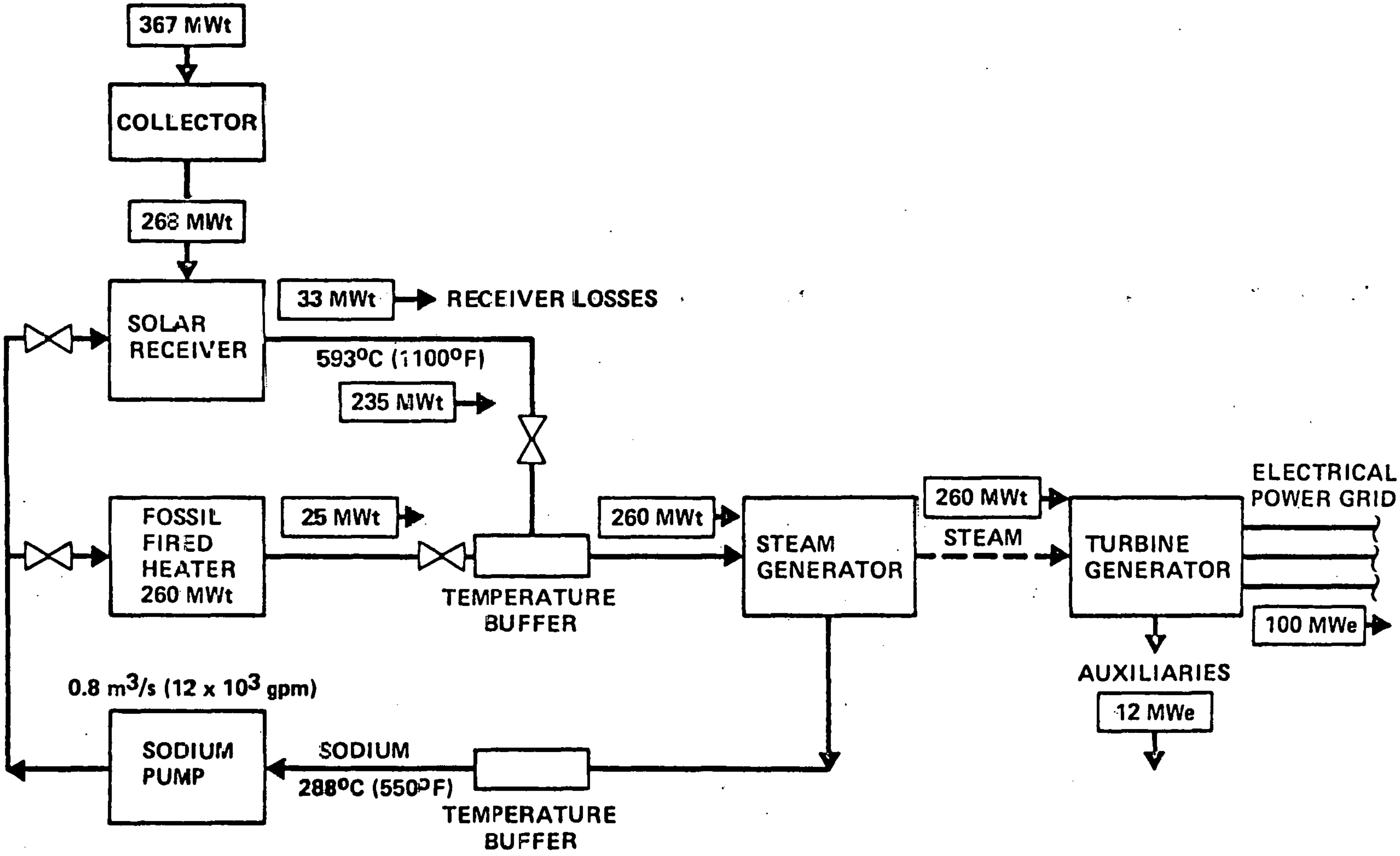

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Figure 2. Hybrid Plant Power Flow

HYBRID PLANT CONFIGURATION

There are several ways in which a fossil energy source can be incorporated into the central receiver system. One such way, and the one that has been selected as a result of this study, is shown in Figure 2. A fossil-fired heater is placed in parallel with the solar receiver and is used to heat the sodium, rather than being placed on the water side of the plant to heat water to produce steam as a conventional boiler would. There are two basic reasons for selecting this design, both of which result in lowering the cost of the energy produced. One of these is that, with the fossil-fired unit on the sodium side, the plant control is greatly simplified since only a single-phase fluid is involved. The second is that ramp rates in the fossil-fired sodium sector may be faster and therefore the amount of thermal energy storage can be minimized. Only enough storage is required to buffer the steam side of the plant from the solar side and thereby allow a smooth transition from operation from the solar receiver heat source to operation from the fossil unit without disturbing the plant output.

MODE OF OPERATION

Solar central receiver hybrid power plants can be operated in a large number of ways, depending upon the type of fuel and the operations planning of the utility dispatcher. For example, in the reference plant shown in Figure 2, the receiver is designed to accept 268 MW of thermal energy from the collector (heliostat) field. Approximately 33 MWt are lost as a result of reflection, re-radiation, and convection from the receiver surface and from piping. A net power of 235 MWt is delivered to the buffer tank. The assumed turndown limit on the fossil-fired sodium heater (rated at 260 MWt) is 90%; therefore, the heater is providing, at its minimum power level, 25 MWt which, when combined with the solar receiver, provides the required 260 MWt to the steam generators. This amount of thermal energy will provide sufficient steam to yield 112 MWe gross output. If heat energy from the receiver decreases, the heater power is increased in order to maintain a constant 260 MWt for the steam generators.

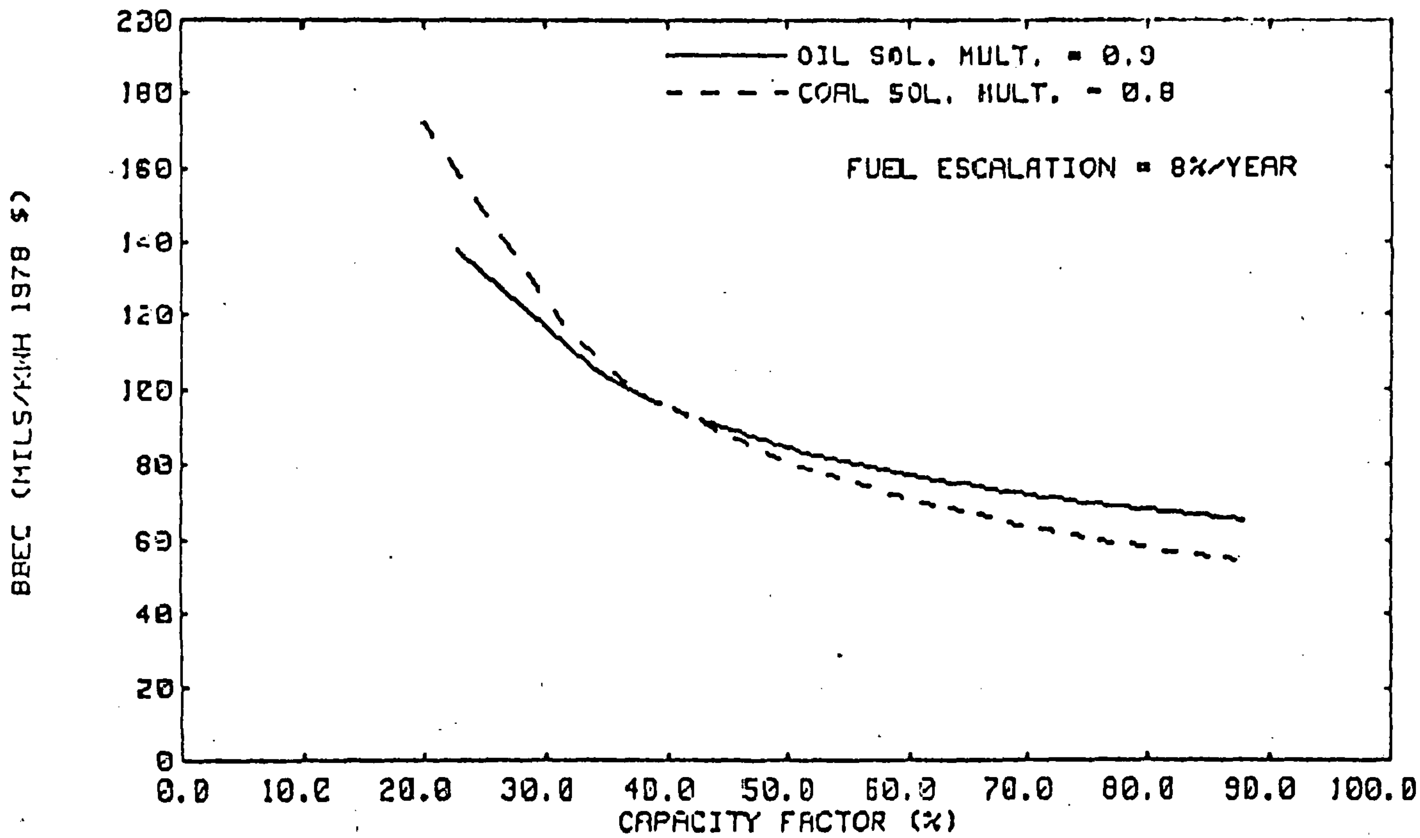

Figure 3. Oil and Coal Hybrid Busbar Energy Costs
(First Plant — Fixed O&M)

FUEL SELECTION

One major decision to be made in the design of a hybrid solar plant is the selection of the type of fuel to be used in the sodium heater. Because of anticipated government restriction on the use of natural gas, only oil and coal were considered viable candidates. In order to determine which of the latter two fuels was most cost effective, the capital, operating, and maintenance costs of complete solar hybrid plants were estimated, and, from these and other inputs, the levelized busbar energy cost, $\overline{\text{BBEC}}$, was calculated as a function of plant capacity factor. To achieve a capacity factor greater than that provided by solar alone (as augmented by the minimum turndown on the heater), it was assumed that either oil or coal would be burned. The results of these calculations are shown in Figure 3 and indicate that the $\overline{\text{BBEC}}$ decreases with increasing capacity factor for both fuels. However, it can be seen that the cost of energy is less if coal is used rather than oil at capacity factors greater than about 35 to 40%. Included in the capital cost of the coal-fired plant were a coal handling system, flue gas cleanup equipment that meets EPA requirements, and an ash handling system. The price of coal and oil were assumed to be \$1.00/MBtu and \$2.00/MBtu, respectively. In view of these results, the reference design for the solar hybrid plant incorporated coal as a fuel even though the initial capital investment is substantially greater.

TYPES OF HYBRID PLANTS

During this program, two basic types of sodium-cooled, solar, central-receiver, coal-fired hybrid plants were conceptually designed. One type incorporated only enough stored energy (buffering) to permit a smooth transition from solar operation to fossil operation and back. Two versions of this buffered plant were studied, one providing 100-MWe net output, and a second, a size optimized concept, providing 615-MWe net output from a single tower and single, surround, collector field. The 615-MWe plant had the lowest capital cost per unit energy output and the lowest $\overline{\text{BBEC}}$ of all the plants investigated.

A second type of plant that was designed and evaluated had a nominal 3 h of solar storage at full output. Again, two versions were studied and assessed from the standpoint of economic viability. One had a 100-MWe net output and the other

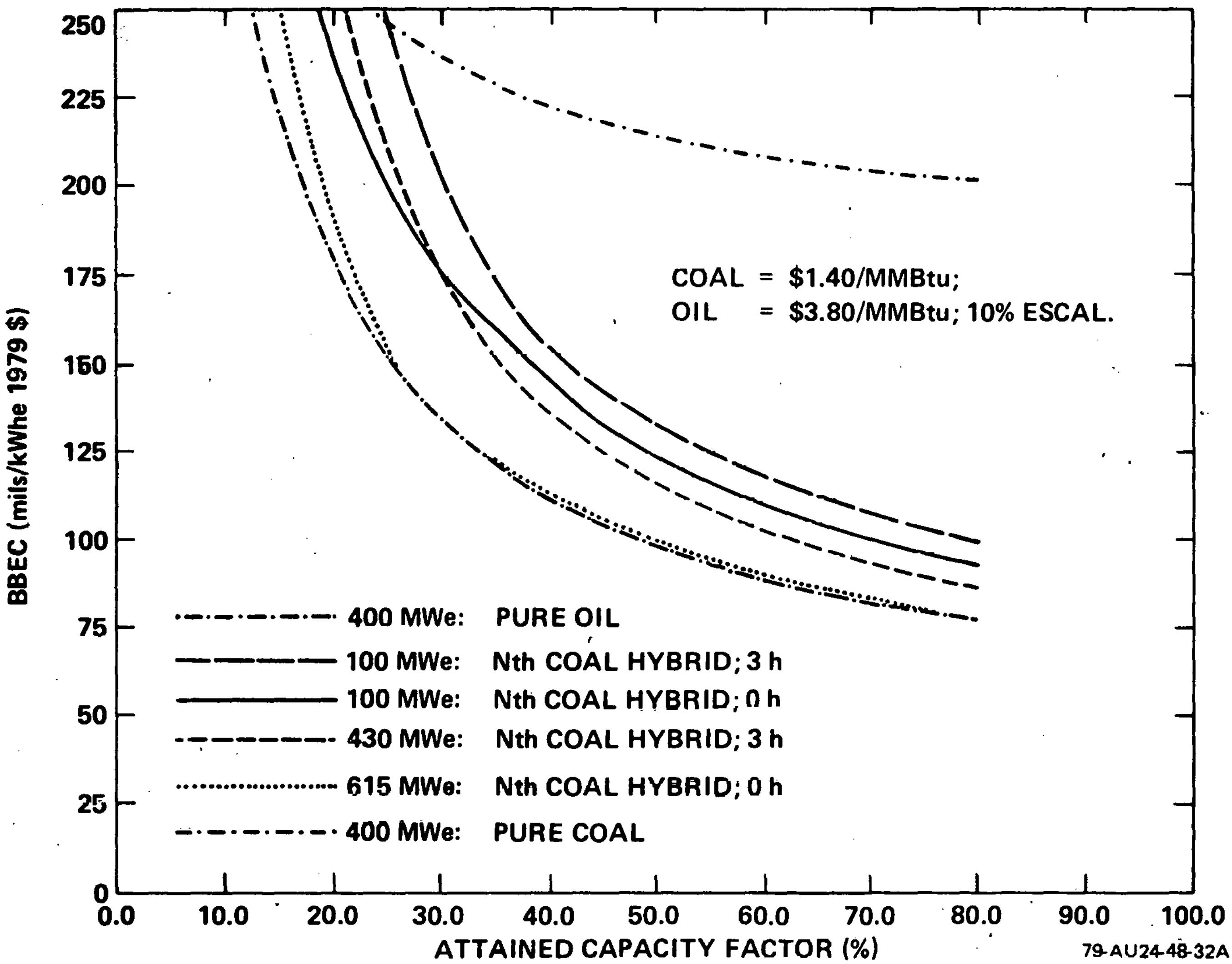

Figure 4. Baseload Candidate Comparisons — 1990 Start

had 430 MWe net output. The latter plant was approximately optimum in size for a single tower and single field. The 615-MWe and 430-MWe plants were basically the same concept except that storage was provided in the 430-MWe system. One variation of the 430-MWe plant that was considered during the program consisted of a heater designed to use coal but initially using oil as a fuel. This procedure allowed the coal handling system to be purchased and installed at a later time and therefore minimized the initial capital investment.

An intercomparison of these various solar hybrid plants is shown in Figure 4 in terms of $\overline{\text{BBEC}}$ versus attained capacity factor. Also shown are the $\overline{\text{BBEC}}$'s for new oil and new coal plants. It is particularly noteworthy that the 615-MWe solar hybrid is cost competitive with a new coal plant for a 1990 date for the start of operation and for an assumed cost of coal of $1.40/MBtu. The capital costs are $1792/kWe, $1400/kWe, $1400/kWe, $992/kWe, $770/kWe, and $590/kWe for the 100-MWe (3-h storage), 100-MWe (0 h of storage (buffered)), 430-MWe, 615-MWe, pure coal and pure oil plants, respectively. It can be seen that the coal-fired solar, hybrid plants produce power at a cost substantially lower than that from a new oil plant, where the cost of oil has been assumed to be $3.80/MBtu and to escalate at 2% above general inflation. The cost of coal is assumed to rise at the same rate as general inflation.

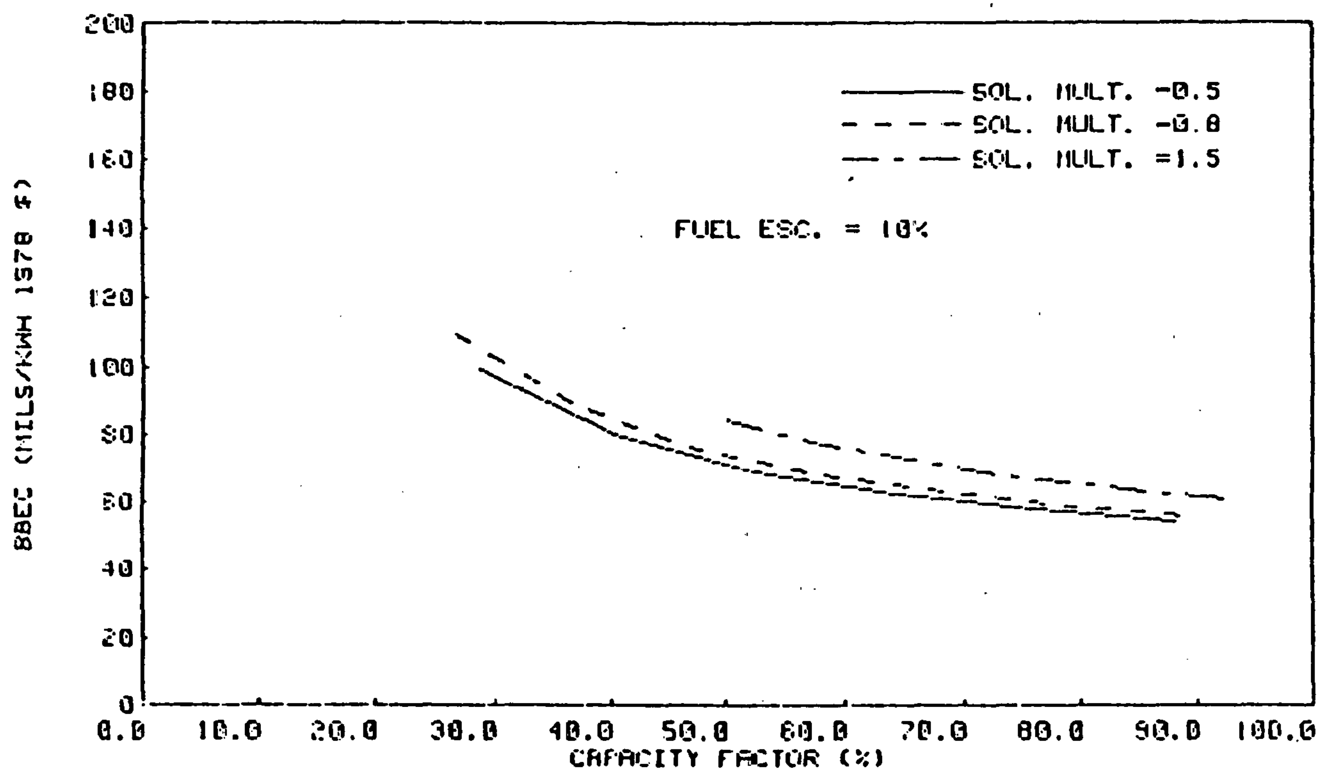

Figure 5. Coal Solar Multiple Trade Study

II. 0.8 SOLAR MULTIPLE TRADE STUDY

SELECTION

A trade study, completed early in the program, using preliminary capital, fuel, and O&M costs, resulted in the calculation of the levelized busbar energy cost ($\overline{\text{BBEC}}$) as a function of solar multiple and capacity factor for coal-fired, 100-MWe hybrid power systems. The results of this study, shown in Figure 5, formed the basis for selection of the solar multiple and, consequently, configuration of the 100-MWe plant design initially mandated by the contract.

The original primary selection criteria included minimal $\overline{\text{BBEC}}$ coupled to maximum solar fraction. As can be seen when coupled to low-cost fuels, such as coal, these two criteria are in opposition. Consequently, a compromise solar multiple appears to offer the best solution. Furthermore, the margins of advantage of the 0.5 solar multiple over the 0.8 solar multiple is not large. In fact, it can be shown that the incremental fuel cost savings of the 0.8 solar multiple plant over the 0.5 solar multiple plant would result in a larger attained capacity factor for the former plant such that it would actually enjoy a small cost advantage. Therefore, the 0.8 solar multiple configuration appears to be the best choice for this application.

PLANT DESCRIPTION

A layout of the plant showing component locations is illustrated in Figure 6. A key plan with collector field layout is shown in Figure 7. This plant consists of a 495 acre field containing 8,496 heliostats surrounding a roughly circular central exclusion area with a major diameter of 226 meters. The central area contains the turbine generator building, control room, steam generator building, coal-fired sodium heater, pulverizers, receiver tower, heater stack, flue gas cleanup, and ash handling equipment as well as auxiliary equipment and maintenance buildings. The plant cooling tower and coal handling equipment are located outside the collector field.

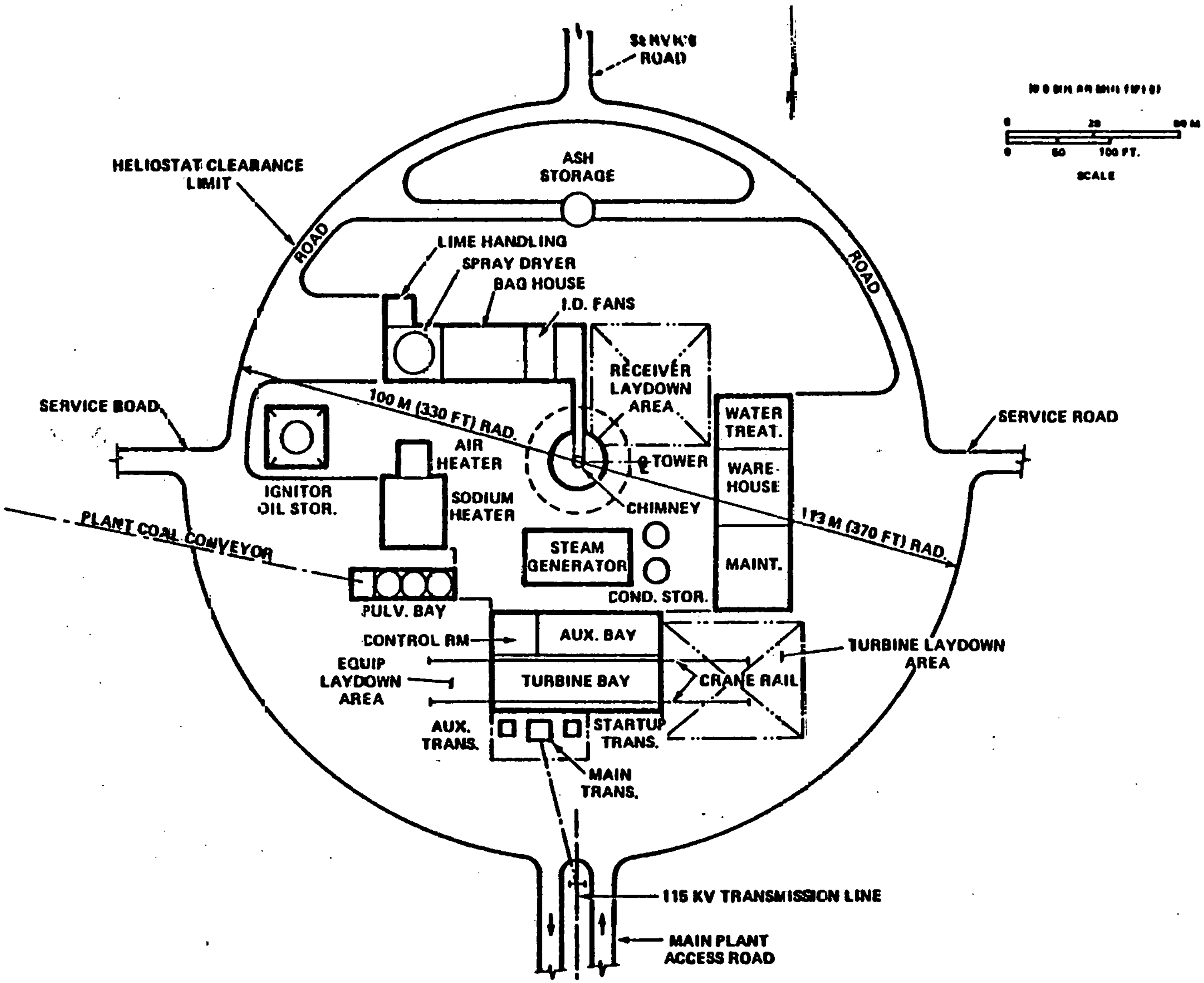

Figure 6. 100-MWe (0.8-SM) Plant Layout

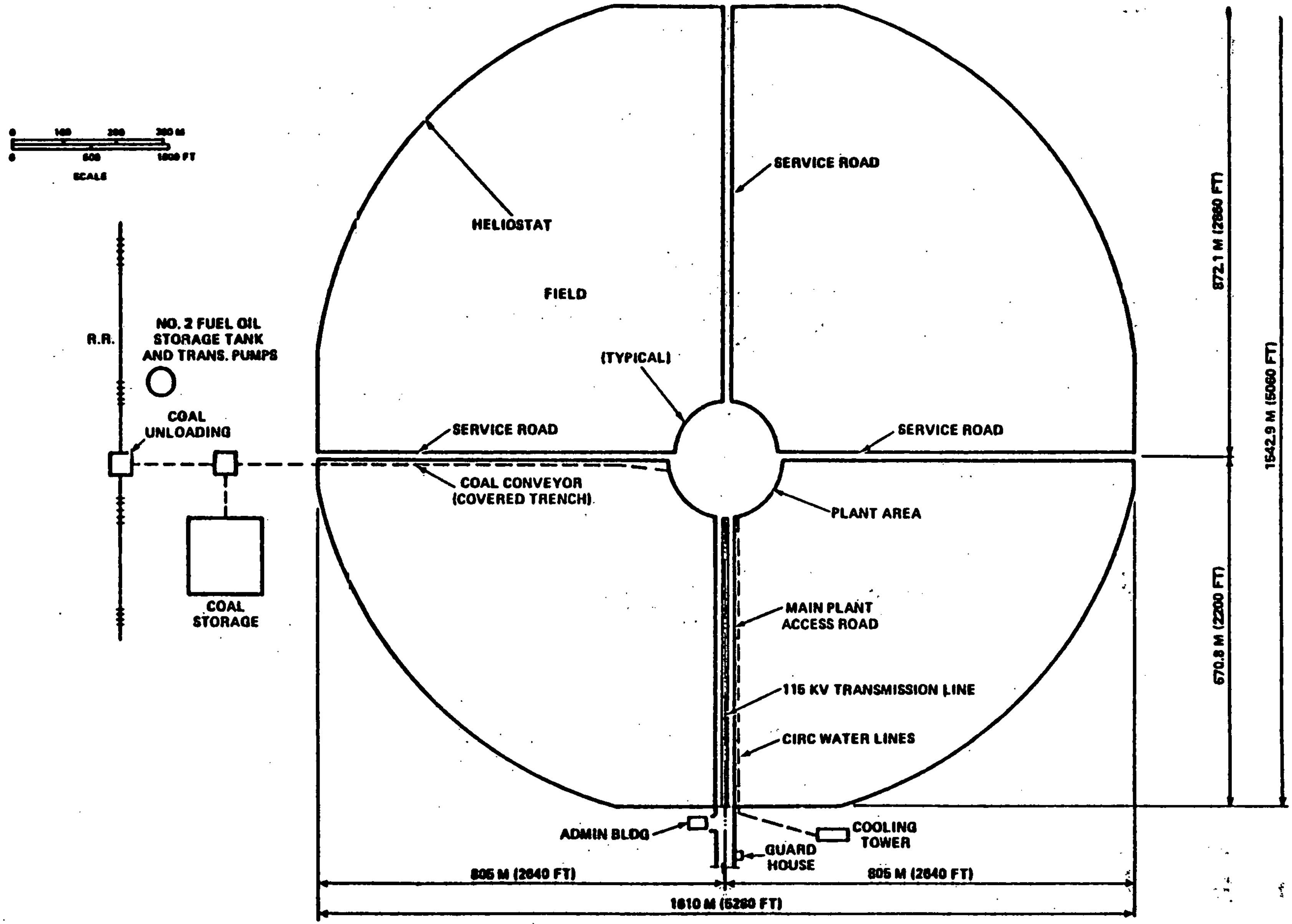

Figure 7. 100-MWe (0.8-SM) Field Layout

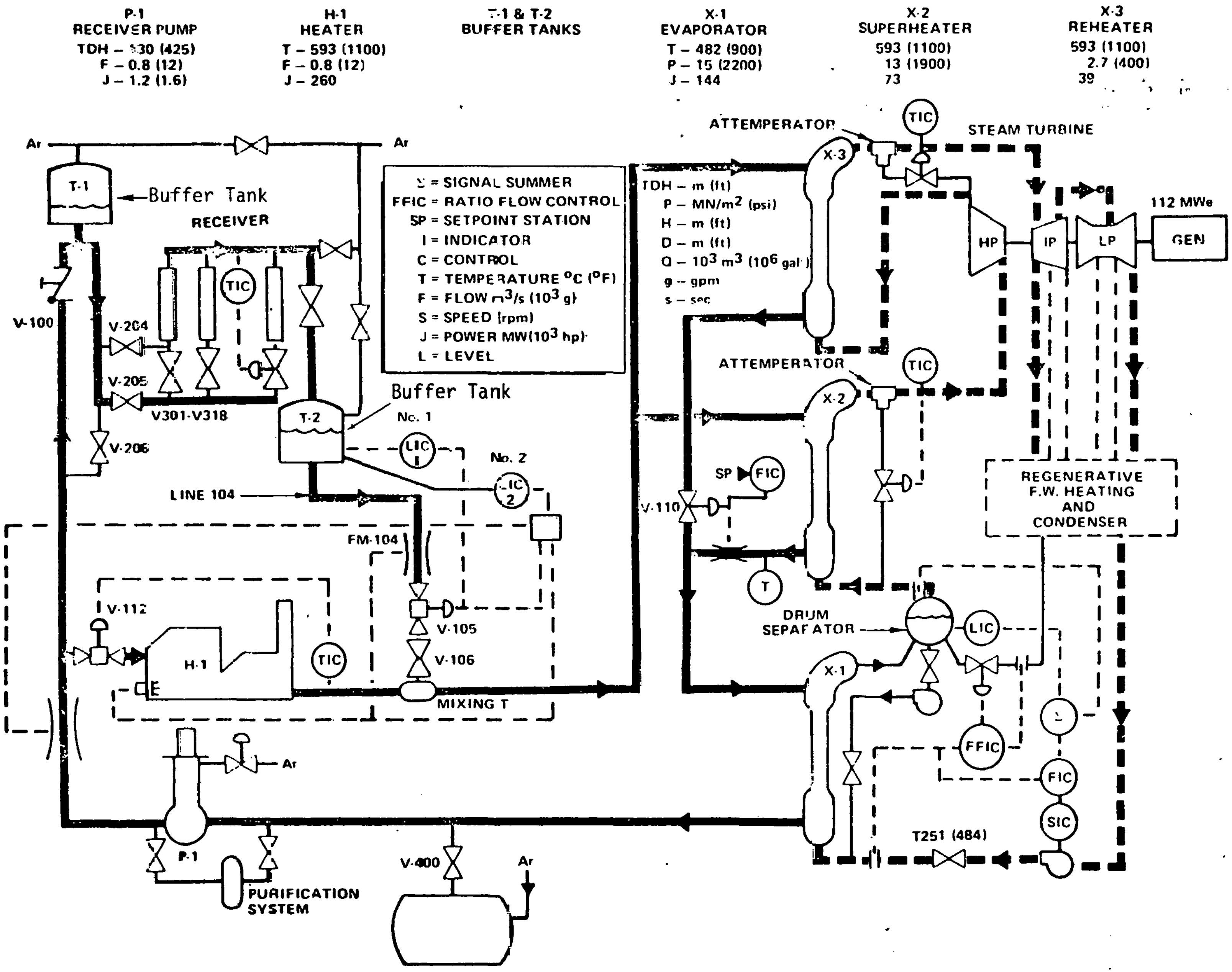

Figure 8. 100-MWe (0.8-SM/No Storage) Plant Flow Diagram

A conceptual process flow diagram of this plant configuration is shown in Figure 8. A special feature of this design is the elimination of ground level storage tanks in favor of hot and cold buffering tanks located in the tower. These tanks provide passive receiver protection during a loss of pump transient and maintain hot sodium flow during periods of rapid cloud cover.

PERFORMANCE

A summary of the performance of this plant is given in Table 1.

TABLE 1

CHARACTERISTICS OF THE 0.8 SM PLANT

	Plant
	Buffered
EPGS*	
Net Power (MWE)	100
Turbine Pressure [MN/m^2 (psia)]	12.5 (1,815)
Capacity Factor (%)	80
FSPA† (%)	25
Heater	
Thermal Power Rated MWt (min %)	260 (20)
Fuel - Coal	
Receiver	
Solar Multiple	0.8
FRPR§	1.1
Thermal Power (MWt)	208
Midpoint Elevation [m (ft)]	124 (407)
Height [m (ft)]	13.5 (44.3)
Diameter [m (ft)]	10.4 (34.1)
Storage Energy (MWe/h)	4.2
Collector	
Mirror Area [km^2(ft^2 x 10^6)]	0.417 (4.6)
Number Heliostats (x 10^3)	8.5
Average Field Diameter (x 10^3) [m (ft)]	1.6 (5)

*Electric power generation system — gross cycle efficiency percent 43.5

†Fraction solar power annual

§Field receiver power ratio [sodium Temperature °C (°F) 288/593 (550/1100) superheater/reheater °C (°F) 538/538 (100/100)]

III. 1.4 SOLAR MULTIPLE PLANT

Hybrid plants do not require storage for post sundown operation. With the standard economic model given in Table 2, plants with storage have a higher BBEC than those without storage. This is shown in Figure 9 for five different storage capacities. This study shows BBEC cost difference of only 10 mills between a plant with 3 h storage and one with no storage. Thus, the two plants are competitive if one considers the operational flexibility afforded by the 3 h of storage, i.e., the solar heat transfer equipment, with the exception of the receiver, can be operated continuously at low power overnight, thus avoiding the startup and shutdown cycling of this equipment. Additionally, with 3 h of storage, the solar contribution will be a little more than 50%, and thus a plant with 3 h storage should be more readily accepted as a solar plant. It is also noted that a relatively modest increase in the price of fuel makes the solar contribution more attractive. Thus, even though these studies show the BBEC to be slightly greater for plants with storage, the added operating flexibility and the uncertainty on the future cost of fossil fuel make these plants an attractive alternative to the zero storage plant which appears to have a slightly lower BBEC.

TABLE 2

ECONOMIC ASSUMPTIONS

Discount Rate = 10%
Economic Life = 30 years
Fixed Charge Rate = 18%
Annual Capital Escalation Rate = 10%
Startup Year = 1990
Annual Fuel Escalation Rates = 6, 8, 10, and 15%
Oil Cost = \$2.00/MMBtu (1978 \$)
Coal Cost = \$1.00/MMBtu (1978 \$)
Natural Gas Cost = \$2.10/MMBtu (1978 \$)
Syngas Cost = \$3.75/MMBtu (1978 \$)

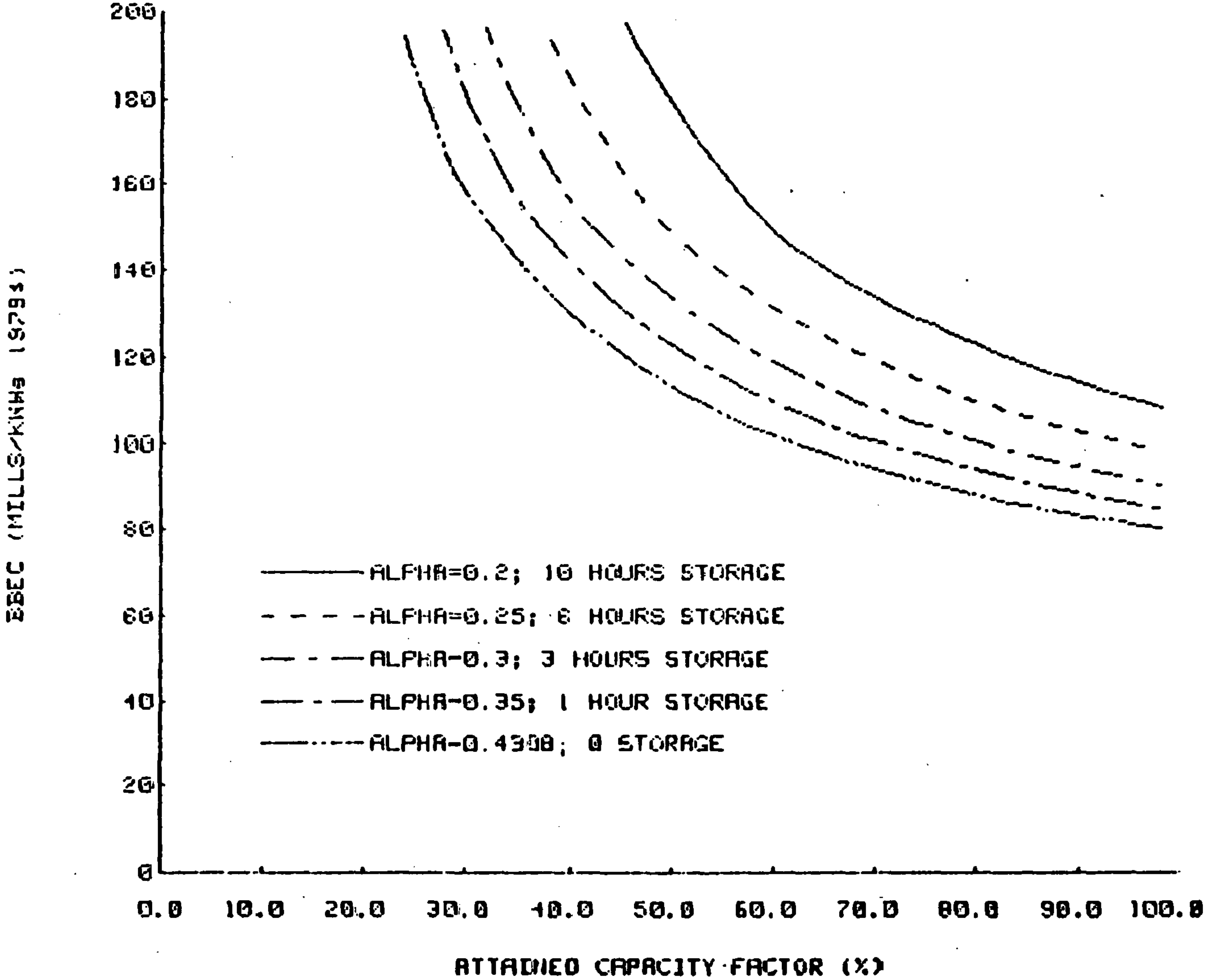

Figure 9. Nth Coal Hybrid Busbar Costs - 364 MWt Receiver

DESIGN OF THE 1.4 SOLAR MULTIPLE (SM) PLANT

This plant is similar in design to the 0.8 SM plant with the exception that it is provided with 3 h of storage based on summer solstice. This requires that the systems and/or components supporting the solar energy collection system be increased in size and the coal conveyor increased in length. The system layouts and major component values are given in Figures 7, 10, 11, and Table 3. For economic reasons, the larger-sized sodium storage tanks are located at ground level and are unpressurized, thus requiring the addition of a pump to circulate the sodium through the steam generator.

TABLE 3

DESIGN CHARACTERISTICS OF THE 100 MWe (1.4 SM) PLANT

Collector Systems	
Heliostats	
Number of Heliostats	13.5 x 10^3
Mirror Area (at 49 m^2/Heliostat) [m^2 x 10^3 (ft^2 x 10^6)]	659.6 (7.1)
Total Land Area [km^2 (acres)]	3.15 (780)
Field Dimension (see Figure 7) [m (ft)]	N-S1970(6465); E-W2012(6603)
Receiver System	
Receiver H x D [m (ft)]	15 x 13 (50 x 43)
Midpoint Elevation [m (ft)]	154 (505)
Tower (Taper = 1^o) H, Base Diameter [m (ft)]	139, 15.2 (457, 50)
Riser Pipe Diameter [cm (in.)]	60 (24)
Downcomer Pipe Diameter [cm (in.)]	30 (12)
For other components see Figure 11	

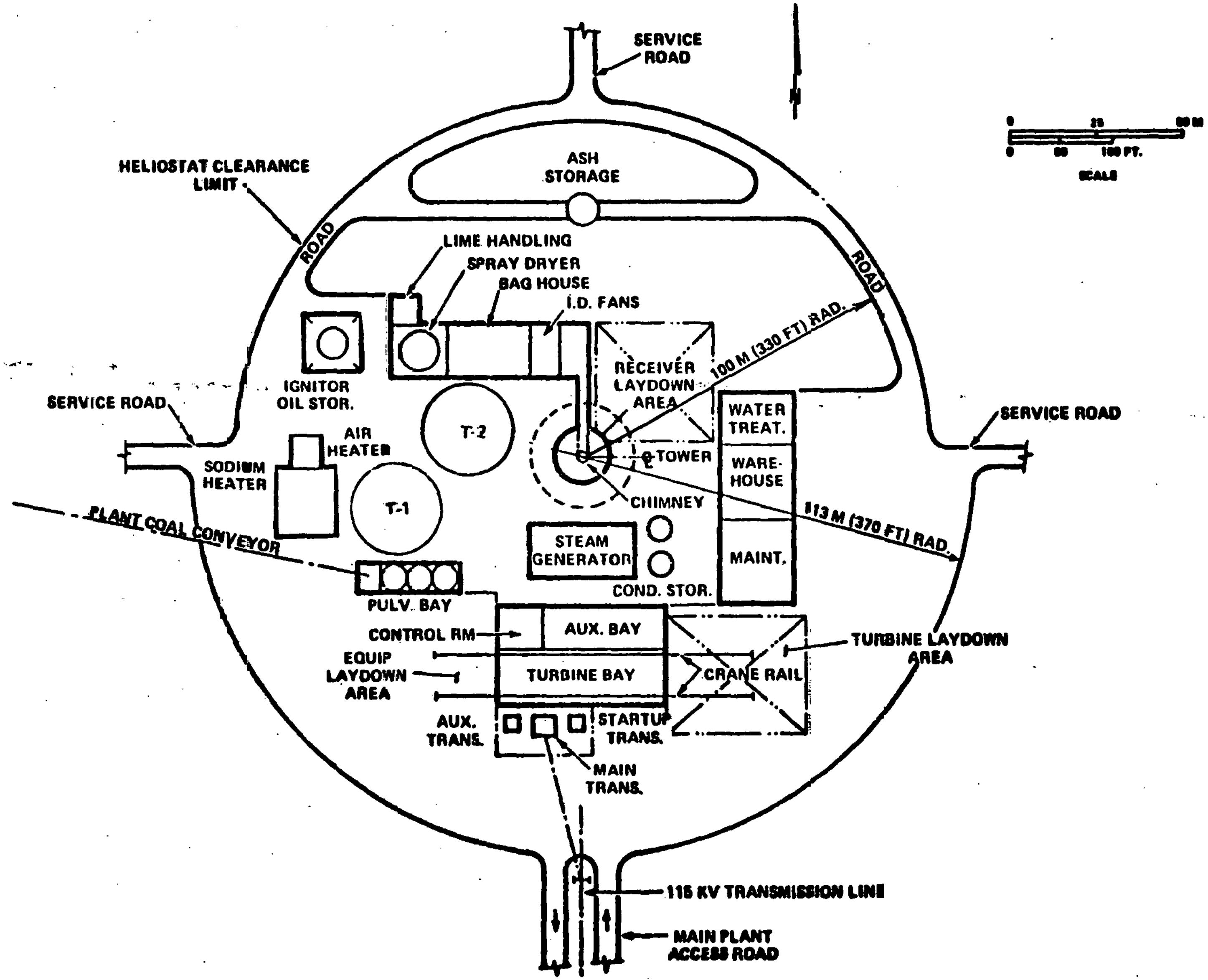

Figure 10. 100-MWe (1.4-SM) Plant Layout

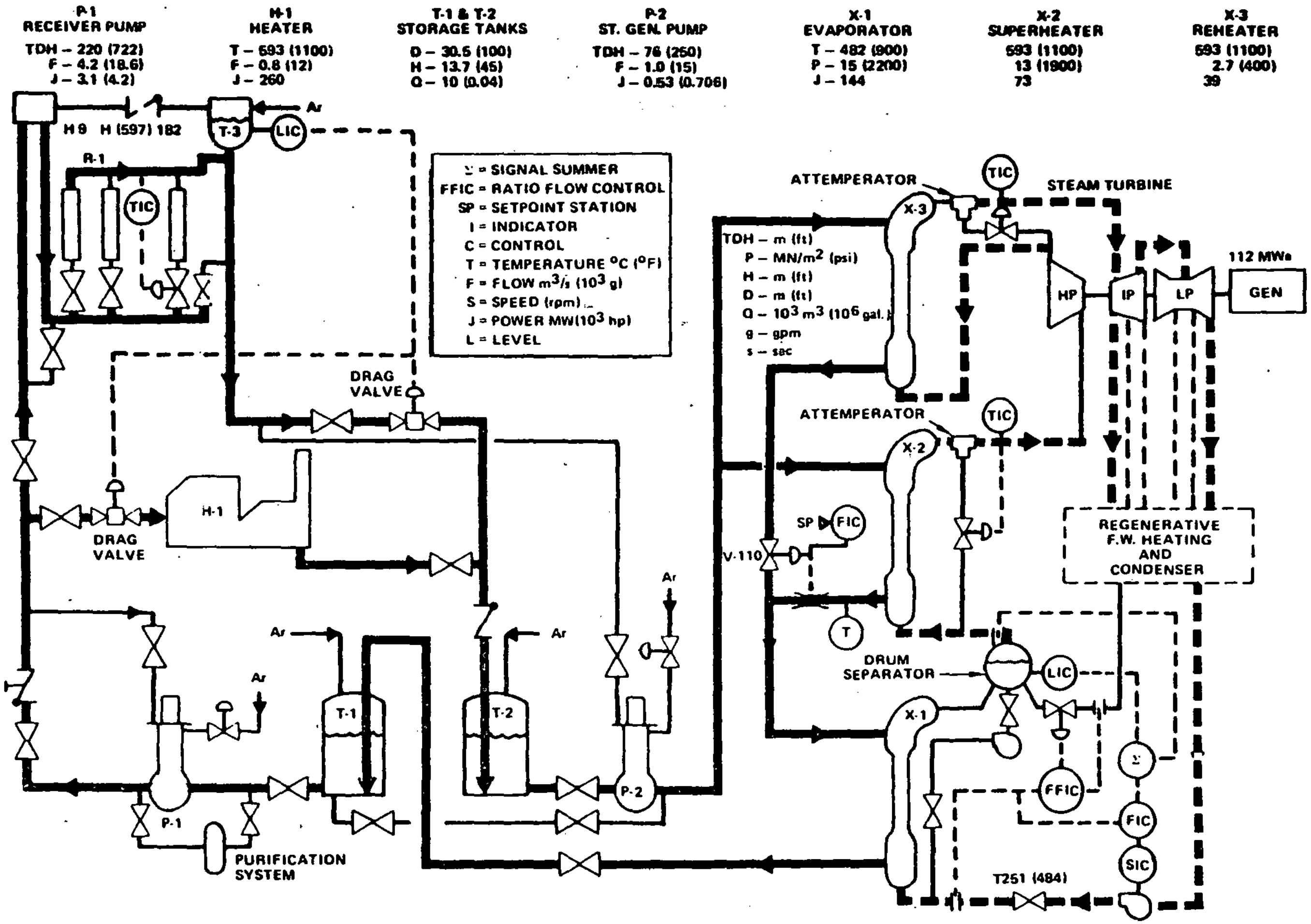

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Figure 11. 100-MWe (1.4-SM) Plant Flow Diagram

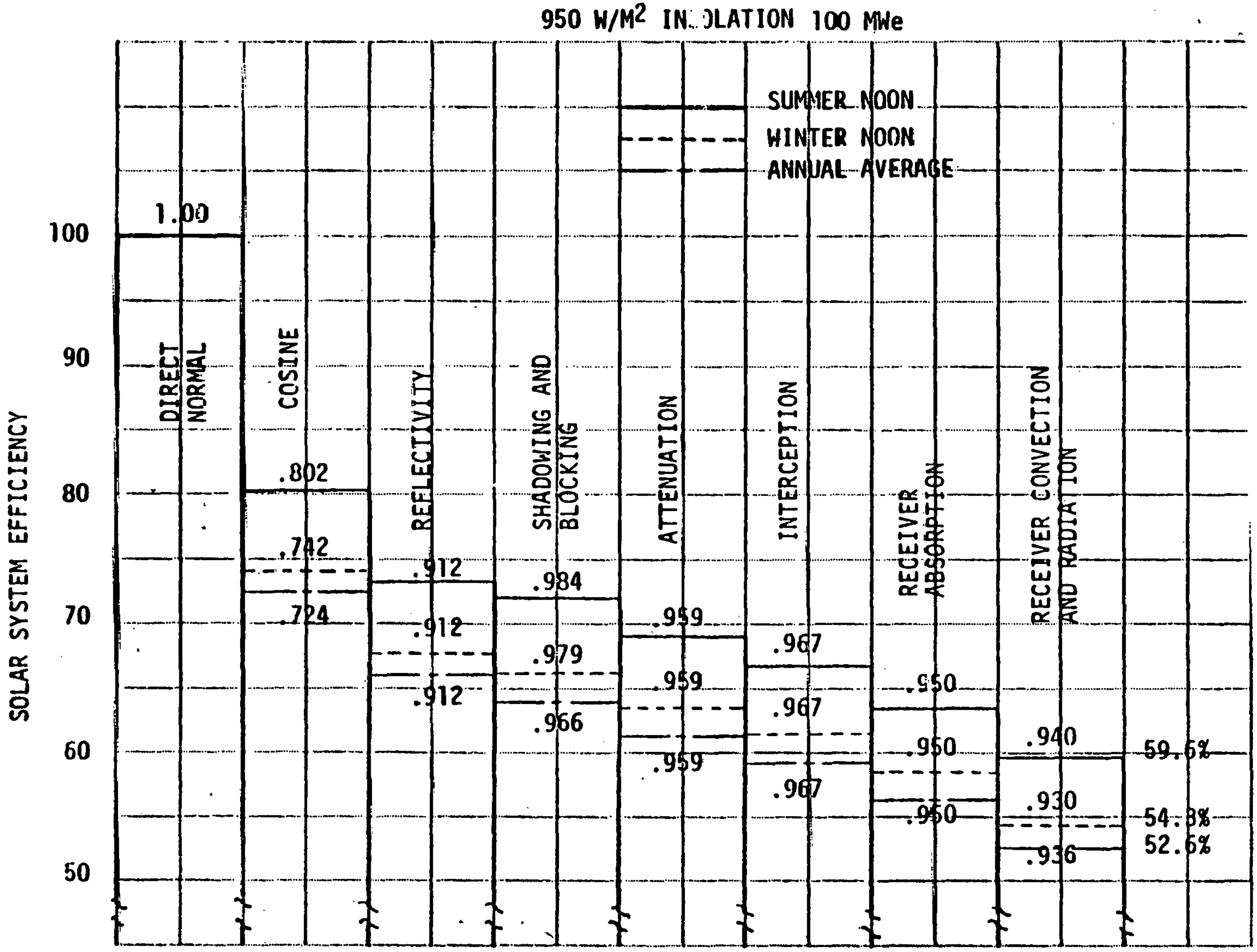

Figure 12. 100-MWe (1.4-SM) Plant Field Efficiency

PERFORMANCE

To obtain good control characteristics, the fossil heater is not operated below about 10% of full power. The plant is assumed to attain a capacity factor of 80%. This leads to a solar contribution of 50% of total plant output. The overall performance of the solar energy collection system is given in Figure 12. The key performance characteristics of the remaining systems and components are given in Table 4.

TABLE 4

PERFORMANCE CHARACTERISTICS OF THE 1.4 SM PLANT*

EPGS†	
Net Power (MWe)	100
Gross Cycle Efficiency (%)	43.5
Net Cycle Efficiency	38.5
Turbine Pressure (psia)	1,815
Capacity Factor (%)	80
Annual Solar Energy (%)	50
Fossil Heater	
Thermal Power (MW)	260
Fuel - Coal	
Receiver	
Solar Multiple	1.40
Thermal Power (MWt)	364
Storage	
See Figure 5	

*Sodium temperature - 550/1100°F; superheater/reheater - 1000/1000°F
†Electric power generation system

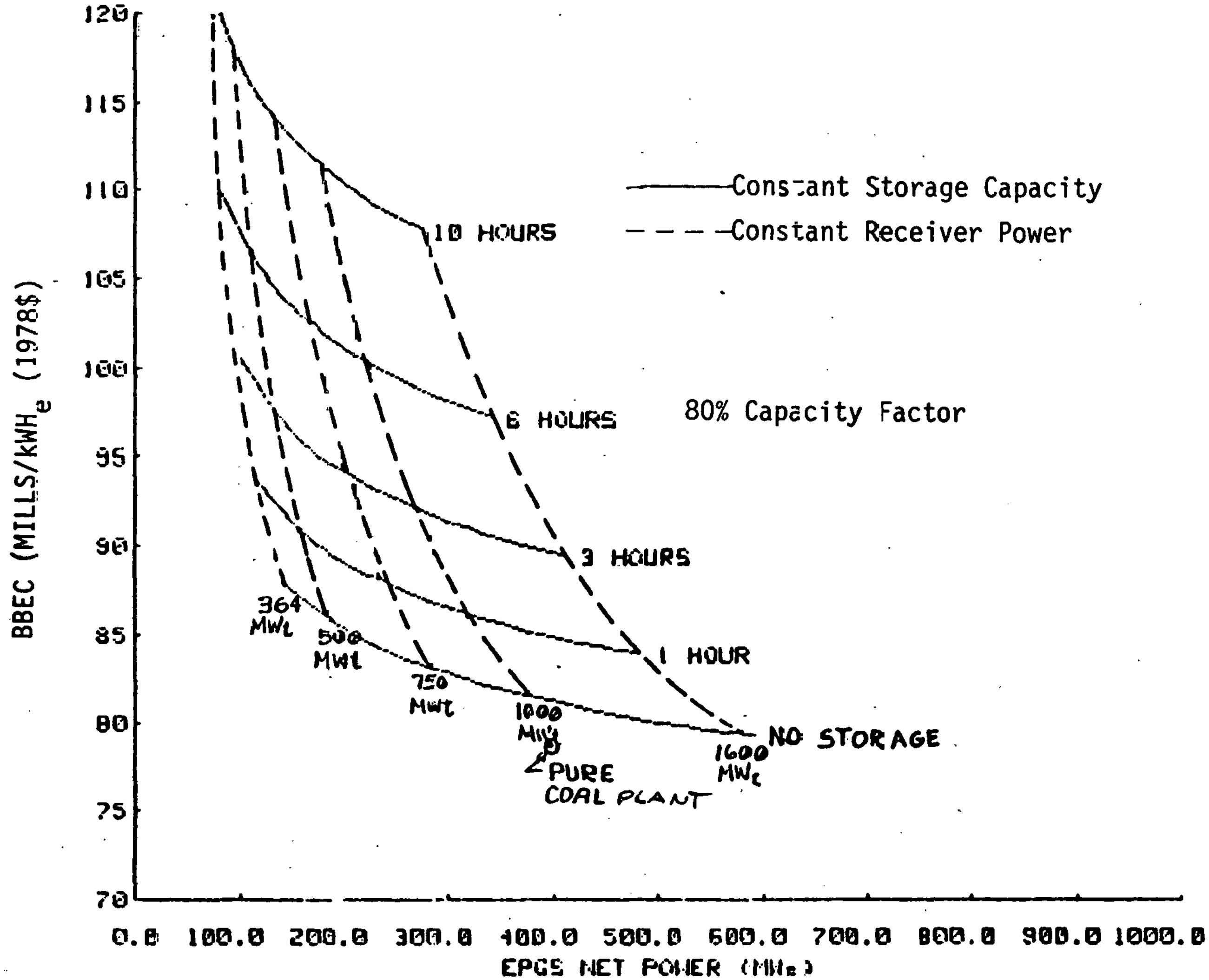

Figure 13. Busbar Cost Versus Receiver and Plant Size and Storage

IV. PREFERRED COMMERCIAL PLANT

SELECTION

Trade studies and engineering and business judgments were employed to develop the 1.4 Solar Multiple Plant as the preferred configuration in the 100 MWe size. This plant was then increased in size to gain the economy of scale. The busbar energy cost, as a function of plant size, is given in Figure 13. The lines tending to the horizontal represent plants with the same amount of storage. The lines tending toward the vertical are lines of constant receiver power. The constant receiver powerline on the far right represents the power limit on size as determined by the availability of proven sodium components. It also represents a limit on tower heights based on previous construction experience. Although larger components and taller towers are feasible, it is felt that good early market penetration can best be achieved by offering only proven components and technology and avoiding scaleup problems and particularly "in-plant" development of systems and components. Previous studies have shown that the use of parallel components to achieve larger plant output is not cost effective. It should be noted that it requires a large increase in plant size to achieve a small potential cost benefit, above 400 MWe.

Based on the component size limit and the requirement for a 50% solar contribution (3 hr of solar energy storage), the intercept of the far right constant receiver power curve with the 3 hr constant storage capacity curve sets the power level at 430 MWe net for the preferred commercial size.

DESIGN

This plant has the same configuration as the 100-MWe, 1.4-SM Plant. The system layout is the same as the 100 MWe plant except for size. The component sizes are given in Table 5 and Figure 14.

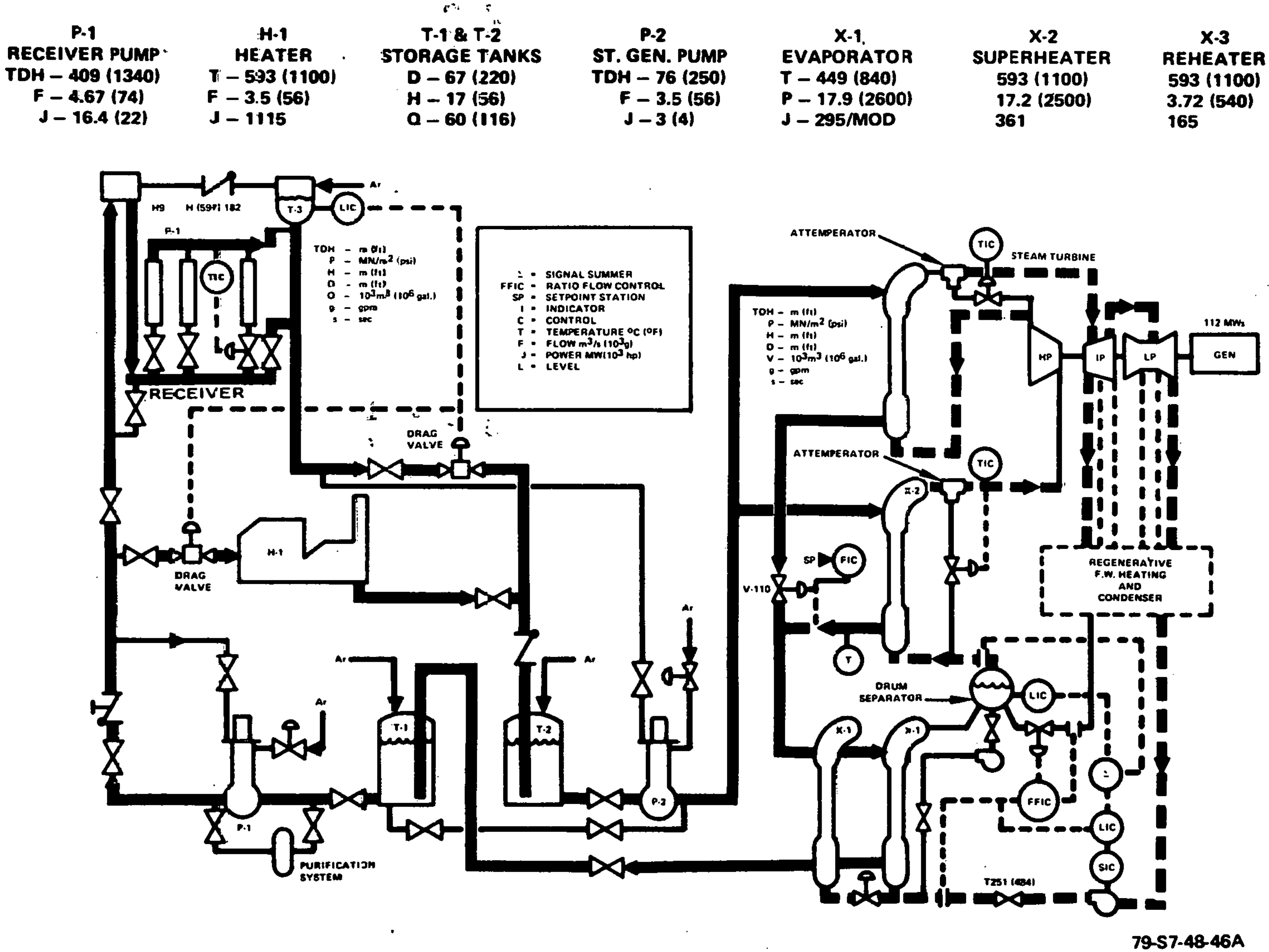

Figure 14. 430-MWe (1.44 SM) Plant Flow Diagram

TABLE 5

DESIGN CHARACTERISTICS OF THE
430 MWe (1.44 SM) PLANT

Collector System	
Number Heliostats ($x\ 10^3$)	61
Mirror Area using 49 m^2/Heliostats ($ft^2\ x\ 10^6$)	32
Total Land Area (acres)	3,200
Field Dimensions (see Figure 7), (ft)	N-S, 13,000 E-W, 13,300
Receiver System	
Receiver H x D, m (ft)	28.5 x 25 (94 x 82)
Midpoint Elevation, m (ft)	334 (1096)
Tower (Taper = 1^o) H; D_{base}, m (ft)	316 (1037); 29 (95)
Riser Pipe Diam, cm (in.)	122 (48)
Downcomer Pipe Diam, cm (in.)	76.2 (30)
For other components see Figure 14	

PERFORMANCE CHARACTERISTICS

This plant will operate on coal at 80% capacity factor and be designed to operate down to 5 to 10% power on the sodium heater. With the exception of the receiver, it is planned to operate the heat transfer equipment on a continuous basis. To accomplish this, 2 hr of storage has been provided to store the energy from the turned down fossil-fired sodium heater while it is operated during the day. This is used during the night operation of the plant. The key performance characteristics of this plant are given in Table 6.

PREFERRED COMMERCIAL PLANT (PCP) OPTIONS

The initially selected preferred commercial plant (PCP) configuration is most effective in a baseload application, due to the use of inexpensive coal. A brief investigation showed that a modified design of this configuration also has potential application in an intermediate load capacity.

TABLE 6

PERFORMANCE CHARACTERISTICS OF
THE 430-MWe (1.44-SM) PLANT

EPGS*	
Net Power (MWe)	430
Gross Cycle Efficiency (%)	43.7
Net Cycle Efficiency (%)	38.7
Turbine Pressure (psia)	2,415
Capacity Factor (%)	40
Annual Solar Energy (%)	85
Fossil Heater	
Thermal Power (min), MW (%)	1,115 (5)
Fuel — Oil/Coal	
Receiver	
Solar Multiple	1.44
Thermal Power (MWt)	1,600
Thermal Storage	
Solar (h)	3
Fossil (h)	2
Collector	
See Figure 16	

*Electric Power Generation System: Sodium temperature - 550/1100°F; superheater/reheater - 1000/1000°F

The PCP initial configuration includes a coal-fired sodium heater. This heater is also specifically designed such that it is also capable of firing oil if the burners and fuel supply system are changed out. By initially constructing the PCP plant with oil-fired fuel delivery and omitting the flue gas cleanup system, the PCP can be utilized as a cost-effective intermediate load plant operating at capacity factor of 40% on low-sulfur oil. Figure 15 shows that such a plant with between 1 and 3 hr of storage is cost competitive with a pure coal plant operating at the same capacity factor. This plant would essentially operate as a stand-alone solar plant with oil firing less than 800 hr per year.

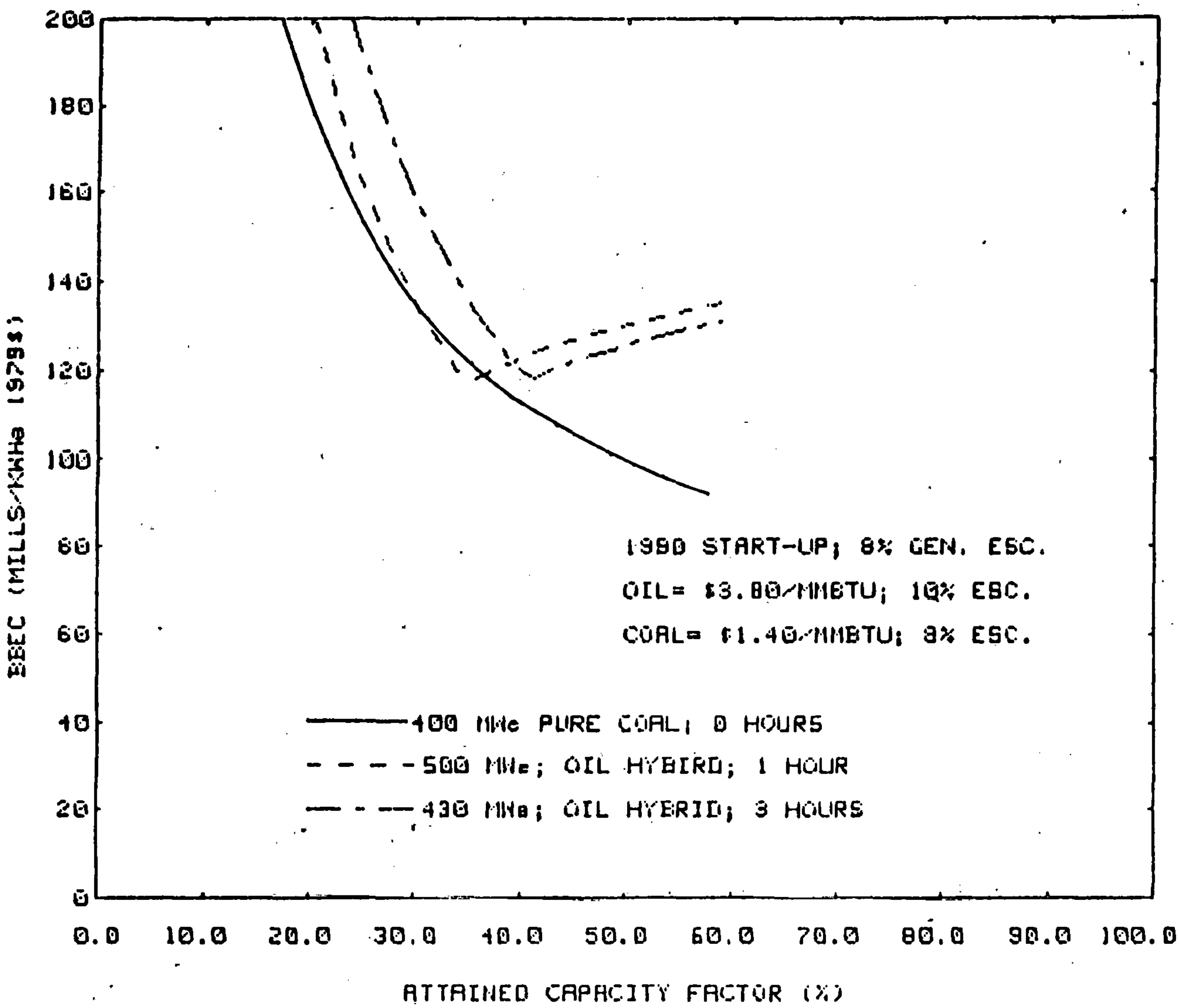

Figure 15. Intermediate Load Candidate Comparisons

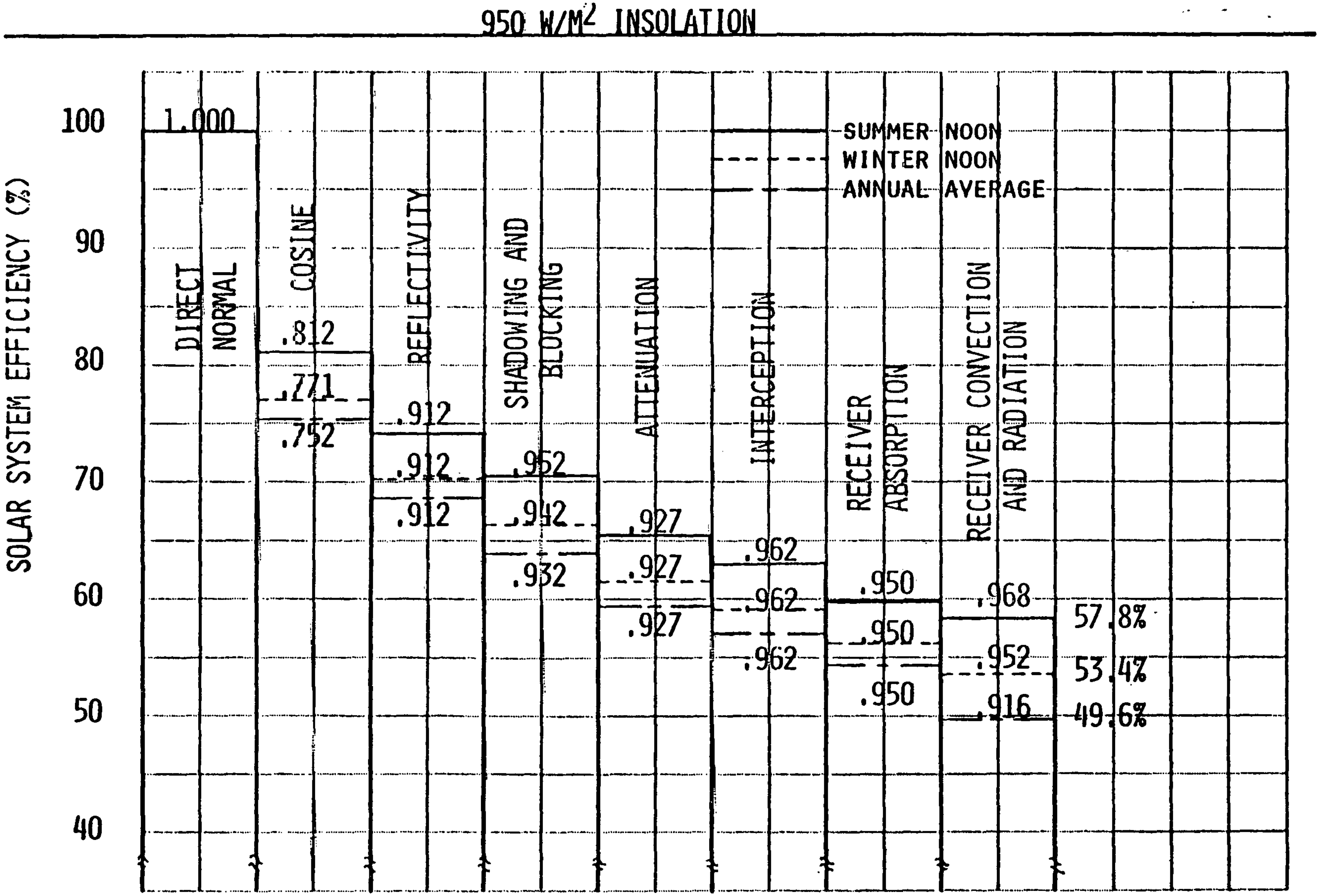

Figure 16. Solar System Efficiency Preferred Commercial System

Still another option for the PCP exists. If the steam generator and EPGS are oversized, the plant can be operated in a peak-load-following (programmed) mode. The size of the storage capacity over and above that required to store excess solar energy would depend upon the utilities' load-duration curve and peak-power requirements. An integration of the load-duration curve for the Salt River Project indicated that the 2-hr storage provided for low-power heater output absorption in the PCP is more than adequate to support such a plant operating scenario.

It should be evident that the flexibility of the PCP has not been completely exploited and that many other operating modes or applications are as yet unidentified.

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V. SPECIAL FEATURES AND STUDIES

HELIOSTAT PARAMETRIC ANALYSIS

Early in the study, an analysis was made to estimate the optimum size of a heliostat, considering only the minimum capital cost for the heliostat. It was found that a good compromise between strength considerations and stiffness considerations resulted in an optimum close to the selected size, 49 m^2. A subsequent analysis, which included O&M costs found a shallow optimum at about 63 m^2. The cost penalty between 63 and 49 m^2 was $0.60/$m^2$. Consequently, the 49 m^2 design was retained as baseline.

SODIUM HEATER

As integral part of the system analyses done in support of configuration selection, considerable effort was expended on the design and analysis of the non-solar subsystem. This system consists generically of a fossil-fired sodium heater in parallel with the receiver. As a result of fuels selection studies, the heater was designed to fire coal, oil, or gas by modification of the fuel supply system. Specific design selection criteria included materials selection, transient operating capabilities (the 0.8 SM model is required and designed to ramp from 20 to 100% power in 5 min), minimum operating conditions, sodium circulation, thermal performance, and new source emissions requirements. Included with the non-solar subsystem, for coal-fired configurations, is a flue-gas cleanup system consisting of an aqueous alkaline spray dryer in series with a fabric filter baghouse. The stack of the heater is designed to be co-axial with the receiver tower. The receiver design was modified to accommodate the stack.

0.8 SOLAR MULTIPLE BUFFER TANKS

Due to the minimal buffering requirements of the 0.8 solar multiple, a trade study was completed which selected the most cost-effective location for the required storage tanks. The location which results in the best compromise between tank and receiver tower cost and sodium circulating equipment and emergency power

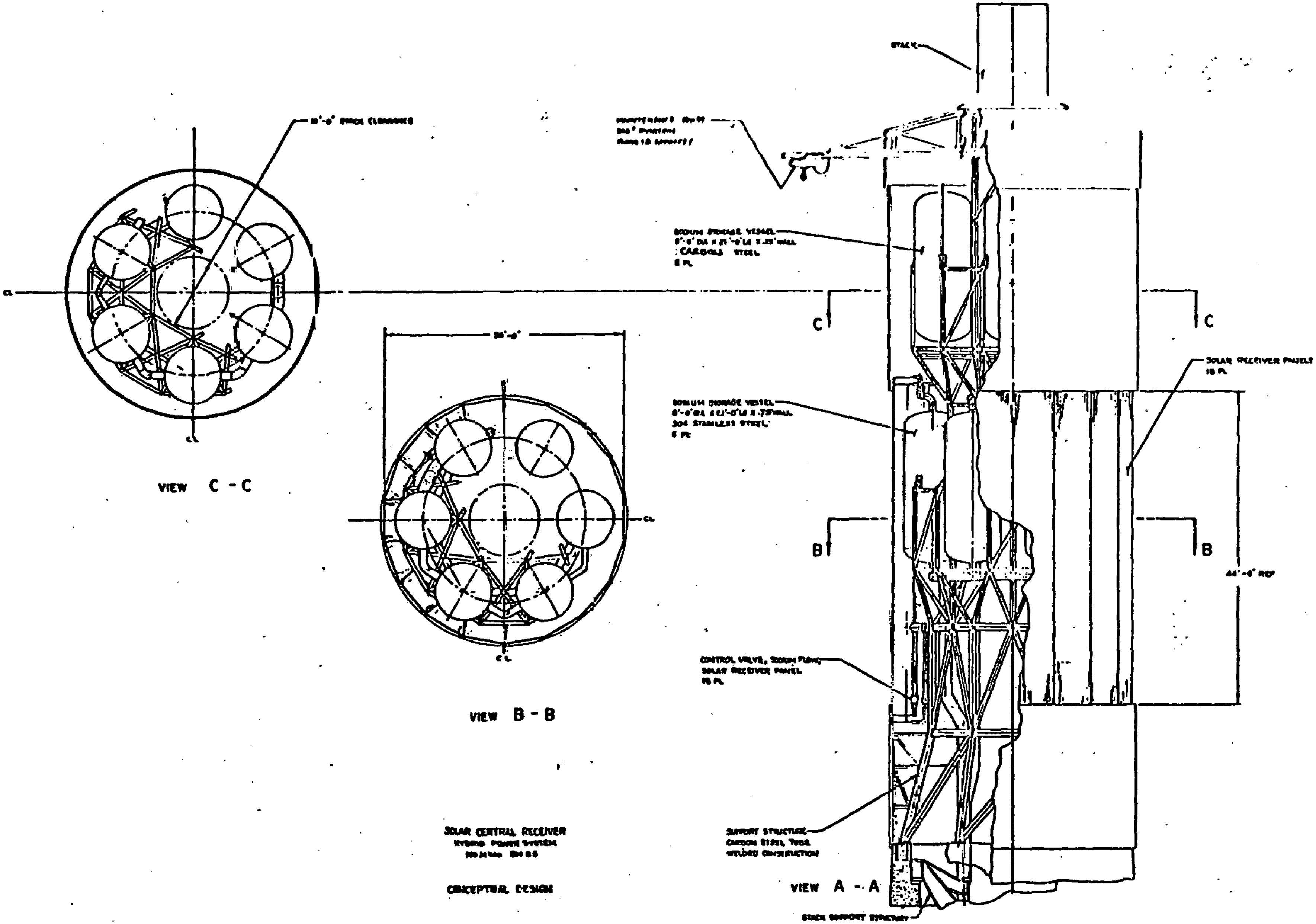

Figure 17. 100-MWe (0.8 SM) Receiver and Buffer Tank Configuration

supply requirements was in the tower at or above the receiver. The hot tanks are located between the heater stack and the receiver, and the cold tanks are located above the receiver as shown in Figure 17. An additional feature of this design is the inherent, passive protection of the receiver in the event of a loss of receiver pump event. The volume of the cold tank, ullage pressure, and elevation are all selected to provide the required inventory and head of cold sodium to cool the receiver in the event that the receiver pump trips. It is assumed that the heliostat system would be interlocked to the receiver pump such that the heliostats would freeze and the receiver flux allowed to decay as a result of the earth's rotation.

TOWER STUDIES

Detailed structural analysis studies were completed on the 0.8 solar multiple plant tower configurations. These studies simulated the effects of wind and seismic loads as well as other environmental constraints and assured that adequate margins exist in the tower designs.

STACK PLUME INSOLATION INTERACTION STUDY

A brief study was completed which determined the spectral flux degradation of incoming and reflected insolation due to optical interaction with the predicted flue gas plume of the heater. It was assumed that effluent conditions, for this study, were the same as those existing when the heater operates at full power. Consequently, the observed degradation was a "worst case" observation. Under these conditions, the insolation degradation was negligible, primarily due to the similarity of plume effluent and ambient air composition.

SERIES PARALLEL COMBINATION OF HEAT SOURCES

A study was made, early in the program, which compared the cost and performance of operating the heater and receiver in parallel or series. It was found that series configuration was inferior due to higher capital cost of extra piping and poorer performance in addition to the requirement of low-temperature operation of one of the components.

TRANSIENT ANALYSES

Brief transient analyses were considered for two cases which could occur in the 0.8 solar multiple configuration. The first case considered the cloud cover of the field and the subsequent shift from a receiver following to heater following operating mode. It was found that the hot tank sodium inventory was entirely adequate to buffer this transition and that, consequently, no degradation in steam generator performance is anticipated during this transient.

The second case involves the aforementioned loss of receiver pump transient. This transient is also buffered by sodium storage and again unacceptable temperature excursion or thermal stresses are not anticipated.

VI. COST SUMMARY

The capital cost estimate for the Nth commercial nonstorage 100-MWe solar central receiver hybrid power plant is shown in Table 7.

Table 8 shows the capital cost estimates for the Nth commercial, 100-MWe, 3-h storage system. The Nth preferred commercial plant, rated at 430 MWe, 5-h storage, plant cost estimate is shown in Table 9.

The estimates are subdivided by account and subsystem as required by the Requirements Definition Document and subsequent cost accounting guidance provided by Sandia Livermore Laboratories. The total capital cost estimate for the Nth commercial, 100-MWe, 0.8 solar multiple plant is 140.3 million dollars. An Nth commercial plant, configured for 100 MWe net output, with 3 h storage would have an estimated capital cost of 179.3 million dollars. A preferred commercial plant configured for 430 MWe output with 5 h of storage (3 filled by solar energy) has an Nth plant capital cost estimate of 610.6 million dollars. All cost estimates are in 1979 dollars.

Estimated operating and maintenance costs (O&M) for the first commercial, 100-MWe, 1.4 solar multiple plant are shown for various operating years in Appendix T, Volume 3. These costs are broken down by account. The first year O&M costs for this plant are estimated to be 3.0 million dollars.

The busbar cost of electricity, as calculated from estimates of capital, O&M, and fuel costs are discussed in detail in Section I of this summary.

TABLE 7

100 MWe, 0.8 SOLAR MULTIPLE
NTH PLANT CAPITAL COST ESTIMATE
1979 "000" DOLLARS

Cost Category	5100 Land & Site	5200 Admin.	5300 Coll.	5400 Rec.	5500 Master Control	5600 Non-Solar	5700 Energy Stor.	5800 EPGS
A. Excav. & Civil	2,932	14	420	18	1	53	0	71
B. Concrete	89	86	3,618	1,852	10	996	0	1,306
C. Struc. Steel	0	0	0	841	0	521	0	0
D. Buildings	0	300	0	535	54	1,760	0	490
E. Mach. & Equip.	53	1,287	21,782	8,013	972	24,330	1,049	28,293
F. Piping	96	38	0	8,983	0	45	0	3,165
G. Electrical	0	99	1,387	77	5	425	0	4,085
H. Instruments	0	0	111	682	141	0	0	500
J. Painting	0	8	0	0	2	35	0	250
K. Insulation	0	0	0	0	0	0	0	500
Direct Fld. Costs	3,170	1,832	27,319	21,001	1,185	28,165	1,049	38,660
L. Temp. Cons. Fac.	0	19	57	91	0	0	0	425
M. Cons. Serv.	0	50	43	261	0	0	0	300
N. Subs. & Expense	0	46	364	930	7	0	0	1,100
P. Benefits & Burdens	0	34	483	81	14	0	0	900
Q. Equip. Rental	0	0	743	197	0	0	0	1,000
Indir. Fld. Costs	0	149	1,691	1,560	21	0	0	3,725
Total Fld. Costs	3,170	1,981	29,010	22,561	1,206	28,165	1,049	42,385
R. Engineering	0	0	0	0	0	0	0	0
S. Procurement	0	0	34	0	0	0	0	15
T. Management	95	59	870	677	36	282	31	1,272
Tot. Fld. & Engr.	3,265	2,040	29,914	23,238	1,242	28,447	1,080	43,672
U. Productivity	0	0	708	0	13	0	0	0
V. Contingency	0	0	0	0	0	0	0	0
W. Fee	163	102	1,531	1,162	63	1,415	54	2,184
Subtotal Cons.	3,428	2,142	32,153	24,400	1,318	29,862	1,134	45,856
Total Construction Cost — 140,293								

TABLE 8

100 MWe, 1.4 SOLAR MULTIPLE
NTH PLANT CAPITAL COST ESTIMATE
1979 "000" DOLLARS

Cost Category	5100 Land & Site	5200 Admin.	5300 Coll.	5400 Rec.	5500 Master Control	5600 Non-Solar	5700 Energy Stor.	5800 EPGS
A. Excav. & Civil	3,718	14	669	20	1	53	0	71
B. Concrete	126	86	5,758	2,110	10	996	280	1,306
C. Struc. Steel	0	0	0	1,169	0	521	0	0
D. Buildings	0	300	0	535	54	1,760	0	490
E. Mach. & Equip.	0	1,377	34,665	8,647	972	24,300	13,176	28,293
F. Piping	53	38	0	13,070	0	45	0	3,165
G. Electrical	96	99	2,207	77	5	425	0	4,085
H. Instruments	0	0	118	702	141	0	0	500
J. Painting	0	8	0	0	2	35	0	250
K. Insulation	0	0	0	0	0	0	0	500
Direct Fld. Costs	3,993	1,922	43,417	26,330	1,186	28,165	13,456	38,660
L. Temp. Cons. Fac.	0	19	91	49	0	0	0	425
M. Cons. Serv.	0	50	69	132	0	0	0	300
N. Subs. & Expense	0	46	580	970	7	0	0	1,100
P. Benefits & Burdens	0	34	769	88	14	0	0	900
Q. Equip. Rental	0	0	1,182	197	0	0	0	1,000
Indir. Fld. Costs	0	149	2,691	1,436	21	0	0	3,725
Total Fld. Costs	3,993	2,071	46,108	27,760	1,206	28,165	13,456	42,385
R. Engineering	0	0	0	0	0	0	0	0
S. Procurement	0	0	59	0	0	0	0	15
T. Management	120	62	1,383	833	36	282	404	1,272
Tot. Fld. & Engr.	4,113	2,133	47,550	28,599	1,242	28,447	13,860	43,672
U. Productivity	0	0	1,127	0	13	0	0	0
V. Contingency	0	0	0	0	0	0	0	0
W. Fee	206	107	2,434	1,430	63	1,415	693	2,184
Subtotal Cons.	4,319	2,240	51,111	30,029	1,318	29,862	14,553	45,856
Total Construction Cost — 179,288								

TABLE 9

100 MWe, 1.44 SOLAR MULTIPLE
NTH PLANT CAPITAL COST ESTIMATE
1979 "000" DOLLARS

Cost Category	5100 Land & Site	5200 Admin.	5300 Coll.	5400 Rec.	5500 Master Control	5600 Non-Solar	5700 Energy Stor.	5800 EPGS
A. Excav. & Civil	14,838	34	3,002	56	1	149	0	170
B. Concrete	187	209	25,841	5,948	10	2,805	0	3,127
C. Struc. Steel	0	0	0	338	0	1,469	0	0
D. Buildings	0	729	0	550	54	4,962	0	1,173
E. Mach. & Equip.	0	3,348	155,557	34,568	1,323	68,175	49,592	67,747
F. Piping	106	92	0	37,723	0	127	16,775	7,579
G. Electrical	192	241	8,555	217	5	1,198	635	9,782
H. Instruments	0	0	275	1,979	277	0	0	1,197
J. Painting	0	19	0	2,723	0	99	0	599
K. Insulation	0	0	0	3,377	0	0	0	1,197
Direct Fld. Costs	15,323	4,673	193,230	87,480	1,670	78,983	67,002	92,571
L. Temp. Cons. Fac.	0	46	410	138	0	0	0	1,018
M. Cons. Serv.	0	122	312	372	0	0	0	718
N. Subs. & Expense	0	112	2,609	3,101	7	0	0	2,634
P. Benefits & Burdens	0	83	3,462	257	13	0	0	2,155
Q. Equip. Rental	0	0	5,323	0	0	0	0	2,394
Indir. Fld. Costs	0	362	12,116	3,868	20	0	0	8,919
Total Fld. Costs	15,323	5,035	205,346	91,348	1,690	78,983	67,002	101,490
R. Engineering	919	0	0	0	0	0	0	0
S. Procurement	0	0	115	0	0	0	0	0
T. Management	460	151	0	2,740	0	790	2,010	3,045
Tot. Fld. & Engr.	16,702	5,186	205,461	94,088	1,690	79,773	69,012	104,535
U. Productivity	0	0	5,018	0	5	0	0	0
V. Contingency	0	0	0	0	0	0	0	0
W. Fee	835	259	10,524	4,704	85	3,989	3,451	5,227
Subtotal Cons.	17,537	5,445	221,003	98,792	1,780	83,765	72,463	109,762
Total Construction Cost — 610,547								

VII. MARKETING SUMMARY

This section includes an analysis for potential markets for electric generating units in the western United States. It compares the costs of solar-hybrid units with their potential competitors; solar only, fossil, and nuclear units under a variety of conditions and assesses the market penetration to the year 2010 for solar hybrid units.

The insolation conditions under which solar-hybrid units might prove competitive was established. This information guided the designer and enabled him to select unit designs with greater commercial potential.

The rate of market penetration was also estimated. This quantity provides a basis for manufacturing requirements, costs of production, and business risks.

The regional demand projections were based on previous SRI projections of regional markets for electricity. The nationwide electricity growth was projected at 5.3% for the period 1975-1985, 3.8% for the period 1985-2000 and 2.0 to 2.5% for the period 2000-2022. A summary of demand for new generating capacity is given in Table 10. The projected equilibrium market shares for solar hybrid is given in Table 11. Under favorable conditions (high insolation, high coal price inflation, 10%) as many as 19 units would be placed in service by the year 2000 and 114 units by the year 2010. This is shown in Table 12.

The several potential impacts of the use of the fossil-solar hybrid central power station on the environment are mild. Land is definitely available. Water requirements are no greater than other types of power producing units. Disturbance of semi-arid ecosystems may cause small effects. Many of the effects will be smaller than those for coal-only units. Thus, the environmental impacts, including land and water requirements, are not likely to prove impediments to the selection of fossil-solar hybrid units by electric utilities.

TABLE 10

SUMMARY OF DEMAND FOR NEW ELECTRIC GENERATING CAPACITY FOR ENTIRE WESTERN UNITED STATES*
[1990-2001 (GW)]

	Base Load	Intermediate Load	Total
Normal retirement	46-58	67-69	113-127
Normal retirement with 1986-89 needs added	48-61	82-85	130-146
Forced retirement with 1990-2001 needs only	67-80	82-83	149-163

*Data rounded to nearest GW.

TABLE 11

PROJECTED EQUILIBRIUM MARKET SHARES FOR FOSSIL-SOLAR HYBRIDS
(No "Behavioral Lag" is Considered; 1990 Startup)

Intermediate Load (40% Capacity Factor)	Plant Capacity (MWe)	Equilibrium Market Share (% Captured in 1990)							
		8%/Yr Coal Price Escalation				10%/Yr Coal Price Escalation			
Solar Insolation (kWh/m^2 day) →		4.5	5.5	6.5	7.5	4.5	5.5	6.5	7.5
Solar-Oil Hybrid, 1st plant cost	430	0.0	0.0	0.3	0.3	0.0	0.4	2.6	2.6
Solar-Oil Hybrid, Nth plant cost	430	0.3	3.7	29.9	29.9	2.3	23.0	76.9	76.9
Base Load (70% Capacity Factor)*									
Solar-Coal Hybrid, 1st plant cost	615	0.1	0.1	0.2	0.3	0.6	1.3	2.6	5.3
Solar-Coal Hybrid, Nth plant cost	615	1.4	2.7	5.4	10.6	9.0	17.9	33.2	54.1

*Nuclear power plants are not considered among the competing plant types.

TABLE 12

SUMMARY OF SOLAR HYBRID UNIT MARKETS
(Coal at $1.40/MMBtu, 10% Escalation)

	2000	2010
Oil Solar	9	53
Coal Solar (Large plant completion)	1	8
Coal Solar (Small plant completion)	9	53

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