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CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM, PHASE 1: PRELIMINARY DESIGN REPORT

Volume 6. Electrical Power Generation/Master Control Subsystems and Balance of Plant

April 1977

Work Performed Under Contract No. EY-77-C-03-1110

Martin Marietta Corporation
Denver, Colorado

U.S. Department of Energy

Solar Energy

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FOREWARD

This document comprises Volume VI of the seven-volume Central Receiver Solar Thermal Power System Pilot Plant Preliminary Design Report. The complete Report consists of the following volumes.

- I. Executive Overview
- II. System Description and System Analysis
- III. Collector Subsystem
- IV. Receiver Subsystem
- V. Thermal Storage Subsystem
- VI. Electrical Power Generation/Master Control Subsystems and Balance of Plant
- VII. Pilot Plant Cost and Commercial Plant Cost and Performance.

The work described herein was performed during the period of July 1975 through April 1977 in accordance with ERDA contract EY 76-C-03-1110 to the Martin Marietta Corporation, Denver, Colorado. Technical direction of this contract was administered by the Sandia Laboratories - Livermore California. The Bechtel Corporation of San Francisco, California performed the analysis and design for the electrical power generation subsystem and the balance of plant systems (Martin Marietta Contract RC5-330001). The balance of plant for the collector foundation and field wiring is reported in Volume III and for the receiver tower is reported in Volume IV. The master control subsystem was performed by Martin Marietta.

The prime contract was under the overall direction of George Kaplan, ERDA Division of Solar Energy. Robert Hughey of the ERDA San Francisco field office was the contract administrator. Sandia Laboratories, Livermore, technical direction was provided by Clifford Selvage, Allan Skinrood and William Moore.

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REA

VOLUME VI OUTLINE

ELECTRIC POWER GENERATION SUBSYSTEM, BALANCE OF PLANT, AND MASTER CONTROL SYSTEM

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TABLES

I. INTRODUCTION

This volume presents design information covering the Electric Power Generation Subsystem (EPGS), the Balance of Plant (BOP), and the Master Control Subsystem (MCS) for both commercial scale and Pilot Plant scale solar-thermal electric generating stations. Design efforts for the EPGS and BOP portions were conducted by Bechtel Corporation. Design of the MCS was performed by Martin Marietta.

The EPGS serves to convert, by way of a conventional steam turbine-generator, the thermal energy delivered from the receiver into electrical power useful in an electric power distribution grid. For the commercial scale EPGS, a conceptual design covering major design features has been conducted to assure the feasibility of the concept and the availability of required components. This design is reported in Section III.B-3 of this volume. For the Pilot Plant EPGS, a preliminary design which covers equipment design and selection in greater depth has been prepared. This material is presented in Section IV of this volume.

For purposes of this study, the BOP includes the equipment and structures required to support the power generating functions and to integrate the solar subsystems into a total plant. Included in this category are such items as overall plant arrangement, design of buildings and structures, and numerous coordination details normally associated with architects and engineers. As with the EPGS design, the commercial BOP has been explored to a conceptual level, giving confidence that the plant can be built using available techniques and technology. Information regarding the commercial BOP is given in Section III of this volume. The Pilot Plant BOP has been considered in greater detail and is discussed in Section V of this volume.

The levels of design detail provided in the EPGS and BOP sections have been established by Bechtel as those adequate to support the conceptual or preliminary design purposes. In the case of Commercial Plant conceptual design, the purposes were to support the cost estimate and to provide the performance data presented in Volume VII of this report. For some plant features, more detail is available from Pilot Plant preliminary design as noted above, due to the modular concept.

The preliminary design of the Pilot Plant has moved forward from the conceptual design and design criteria to develop the more definitive design and cost estimates necessary to increase the reliability of the capital cost estimates. Activities include: site specific design, preparation of sketches and drawings, and preparation of descriptions required to define equipment or subsystems in sufficient detail to reveal special features or design controls which are necessary during the final design. The preliminary design was guided by requirements, codes, and standards necessary to meet both the Martin Marietta needs and the Bechtel standard practice. Cost and schedule estimates were prepared for design, procurement and construction. Purchased equipment, long lead time items, and equipment costs and quantities were determined with greater reliability than was available from the conceptual estimates. Alternate sources for critical equipment were identified and verified. The following levels of detail are provided:

- Design drawings developed in the preliminary design include: plot plans and plant arrangements, systems, equipment, and buildings. A topographic map of the Barstow site was used to determine natural drainage and identify site features. Building sizes and types, foundation sketches and architectural and structural drawings were prepared. General arrangement drawings, P&ID's, and electrical single line drawings were prepared as necessary to define unique or special design features.

- System descriptions were produced in as much detail as necessary to ensure that conceptual and preliminary design requirements are met in the preliminary system design or in the equipment purchased. Preliminary equipment definition includes detail sufficient to insure compatibility with the pertinent system descriptions, provide for adequate reliability, low technical risk, and safety.

- Preliminary design has included sufficient consideration of the methods and sequence of construction to permit evaluation of time phasing for major equipment purchases and cash flow demands versus time after initiation of construction contract.

- For cost and scheduling use, an EPGS equipment list has been developed for major equipment with estimates for major items.

- Preliminary design work has been weighed with physical and chemical, biological, and cultural/aesthetic environmental considerations. These factors have been considered in site plot plan, and plant arrangement.

- All preliminary design features are in sufficient detail to permit a cost estimate of significantly greater reliability than was obtained from the conceptual design.

The MCS acts as the overall control system for the Commercial and Pilot Plants. Its function is to coordinate the actions of the various subsystems (Collector, Receiver, EPGS, etc.), and maintain data records useful in analyzing plant operations. The design of the MCS is discussed in Section VI of this volume.

II. REQUESTED PERFORMANCE SUMMARY TABULATIONS

The performance data covered in this section is in direct response to ERDA requests covered in a Sandia letter, A. C. Skinrood to F. A. Blake et al, dated 2/11/77, listing Preliminary Design Report data requirements and design information desired for each volume of the report. The design information requested is identified in the same order as the Sandia request in the tabulations below where locations for the information is shown. Tables II-1 and II-2 provide the data requested:

Item	Appropriate Section/Table Commercial Plant	 Pilot Plant
A. Design Characteristics		
1. Turbine-generator type and size	III.B-3a	IV.B-2
2. Turbine inlet steam conditions	III.B-3a	IV.B-3a
3. Admission steam conditions	III.B-3a	IV.B-3b
4. Feedwater heating extractions	III.B-3a	IV.B-3d
5. Condenser type and configuration	Table III.B-2	IV.B-3c
6. Feedwater pump stages	Table III.B-3	IV.B-3e
7. Auxiliary steam supply		Section 12 of System Description SD-3, Appendix A.
8. Sealing steam requirements		Section 12 of System Description SD-3, Appendix A.
9. Startup and shutdown characteristics	III.B-3c	IV.B-1

Item	Appropriate Section/Table Commercial Plant	Pilot Plant
B. Design Discussion		
1. Rationale/trade-offs for turbine selection	III.B-3b	IV.B-2
2. Rationale/trade-offs for inlet/admission steam selection	IV.B-3a,b	IV.B-3a,b
3. Rationale/trade-offs for feedwater stages, condenser type, feedwater pumping stages	III.B-3a	IV.B-3c,d,e
4. Principal parasitic losses during each mode of operation	III.B-3d	IV.B-1
5. Startup/shutdown methods and times for the turbine	III.B-3c	IV.B-1
6. Rationale/trade-offs for master control concept	VI	VI

Table II-1 EPGS Performance Data

	COMMERCIAL EPGS				PILOT PLANT EPGS			
	Receiver Steam (a)		Storage Steam (b)		Receiver Steam (a)		Storage Steam (b)	
	ERDA Design Point (c)	Turbine Design Point (d,e)	ERDA Design Point (c)	Turbine Design Point (d,f)	ERDA Design Point (c)	Turbine Design Point (d,g)	ERDA Design Point (c)	Turbine Design Point (d,h)
Gross Generation	157.362 MWe	160.000 MWe	114.169 MWe	116.609 MWe	10.955 MWe	12.500 MWe	7.770 MWe	9.091 MWe
Thermal Input to Cycle	426.949 MWt	426.949 MWt	380.287 MWt	380.287 MWt	32.411 MWt	36.338 MWt	27.825 MWt	31.947 MWt
Gross Turbine Cycle Efficiency	36.86%	37.48%	30.02%	30.66%	33.80%	34.40%	27.92%	28.46%
Gross Turbine Cycle Heat Rate	9 767 kJ/kWh (9258 BTU/kWh)	9 606 kJ/kWh (9105 BTU/kWh)	11 992 kJ/kWh (11366 BTU/kWh)	11 740 kJ/kWh (11128 BTU/kWh)	10 651 kJ/kWh (10095 BTU/kWh)	10 465 kJ/kWh (9919 BTU/kWh)	12 892 kJ/kWh (12219 BTU/kWh)	12 651 kJ/kWh (11991 BTU/kWh)
Net Turbine Cycle Generation (i)	153.068 MWe	155.706 MWe	112.881 MWe	115.321 MWe	10.560 MWe	12.105 MWe	7.670 MWe	8.991 MWe
Net Turbine Cycle Efficiency	35.85%	36.47%	29.68%	30.32%	32.58%	33.31%	27.57%	28.14%
Net Turbine Cycle Heat Rate	10 041 kJ/kWh (9517 BTU/kWh)	9 871 kJ/kWh (9356 BTU/kWh)	12 129 kJ/kWh (11496 BTU/kWh)	11 871 kJ/kWh (11252 BTU/kWh)	11 049 kJ/kWh (10473 BTU/kWh)	10 807 kJ/kWh (10243 BTU/kWh)	13 060 kJ/kWh (12378 BTU/kWh)	12 792 kJ/kWh (12124 BTU/kWh)
Net Plant (j) Electrical Generation	149.397 MWe	152.035 MWe	106.360 MWe	108.800 MWe	10.000 MWe	11.545 MWe	7.000 MWe	8.321 MWe
Thermal Input into Receiver (k)	460.139 MWt	460.139 MWt	—	—	34.761 MWt	38.973 MWt	—	—
Net Plant Efficiency	32.47%	33.04%	27.97%	28.61%	28.77%	29.62%	25.16%	26.05%
Net Plant Heat Rate	11 088 kJ/kWh (10509 BTU/kWh)	10 896 kJ/kWh (10381 BTU/kWh)	12 871 kJ/kWh (l) (12199 BTU/kWh)	12 583 kJ/kWh (l) (11926 BTU/kWh)	12 514 kJ/kWh (11861 BTU/kWh)	12 153 kJ/kWh (11519 BTU/kWh)	14 310 kJ/kWh (l) (13563 BTU/kWh)	13 822 kJ/kWh (l) (13100 BTU/kWh)
Turbine Exhaust Pressure	13.27 kPa (3.92 in. HgA)	8.47 kPa (2.5 in. HgA)	12.67 kPa (3.74 in. HgA)	8.47 kPa (2.5 in. HgA)	10.36 kPa (3.06 in. HgA)	8.47 kPa (2.5 in. HgA)	9.72 kPa (2.87 in. HgA)	8.47 kPa (2.5 in. HgA)
Feedwater Temperature	214.6 C (418.4 F)	214.6 C (418.4 F)	212.9 C (415.2 F)	212.9 C (415.2 F)	216.5 C (421.8 F)	223.5 C (434.3 F)	211.8 C (413.2 F)	220.2 C (428.4 F)
Steam Flow to Turbine	617 413 kg/h (1,361,162 lb/h)	617 413 kg/h (1,361,162 lb/h)	537 099 kg/h (1,263,465 lb/h)	537 099 kg/h (1,263,465 lb/h)	47 145 kg/h (103,936 lb/h)	53 526 kg/h (118,005 lb/h)	41 954 kg/h (92492 lb/h)	48 958 kg/h (107,934 lb/h)

(a) Receiver Steam conditions are 9 411 kPa at 510 C (1365 psia at 950 F).

(b) Storage Steam conditions are 2 859 kPa at 427 C (414.7 psia at 800 F).

(c) ERDA Design Point performance is calculated for 23.2 C (74 F) wet bulb Temperature.

(d) Turbine Design Point is 8.47 kPa (2.5 in. HgA) turbine exhaust Pressure.

(e) Corresponds to ambient wet bulb temperature of 15.3 C (59.6 F).

(f) Corresponds to ambient wet bulb temperature of 15.1 C (59.2 F).

(g) Coresponds to ambient wet bulb temperature of 19.4 C (67.0 F).

(h) Corresponds to ambient wet bulb temperature of 20.6 C (69.0 F).

(i) Gross generation less feedwater pumping power.

(j) Gross generation less all plant auxiliary power.

(k) Thermal input at receiver cavity opening.

(l) Based on TSS thermal input to cycle.

Table II-2 EPGS Auxiliary Loads in kW

Type of Auxiliary Power Requirements \ Mode of Operation	COMMERCIAL PLANT: Receiver Steam Operation (Full Turbine Load)	COMMERCIAL PLANT: TSS Operating (Full Turbine Load)	PILOT PLANT: Receiver Steam Operation (10 MWe Net)	PILOT PLANT: Receiver & TSS Charge (10 MWe Net)	PILOT PLANT: TSS Operation (7 MWe Net)	PILOT PLANT: Uncoupled TSS/Receiver Operation (7 MWe Net)	PILOT PLANT: Turbine Operating on both TSS & Receiver Steam (8.5 MWe Net)	PILOT PLANT: TSS Charge only, Turbine not Running	PILOT PLANT: Overnight Shutdown
Fixed									
Air Compressor	80	80	11	11	11	11	11	11	11
Potable Water Pump	9	9	2	2	2	2	2	2	2
Sanitary Water Pump	6	6	1	1	1	1	1	1	1
HVAC	140	140	20	20	20	20	20	20	20
Lighting	9	9	4	4	4	4	4	4	4
Control Power	150	150	10	10	10	10	10	10	10
Airplane Beacon	60	60	4	4	4	4	4	4	4
Fire Jockey Pump	18	18	2	2	2	2	2	2	2
Component Cooling Water Pump	110	110	22	22	22	22	22	22	8
Seal Steam Exhauster	7	7	2	2	2	2	2	2	2
Vacuum Pump	20	20	17	17	17	17	17	17	17
Misc.	140	140	10	10	10	10	10	10	10
SUBTOTAL	749	749	105	105	105	105	105	105	91
Variable									
Turbine Lube and Turning Gear	192	192	22	22	22	22	22	10	10
Chemical Injection	7	7	1	1	1	1	1	1	0
Circulating Water Pumps	1192	1192	75	75	75	75	75	38	15
Makeup Water Pump	55	55	38	38	38	38	38	0	0
Cooling Tower Fans	671	671	150	150	75	75	150	75	0
SUBTOTAL	2117	2117	286	286	211	211	286	124	25
Pumps									
Condensate Pump	130	116	16	16	16	16	16	16	0
Booster Pump	1335	1172	84	84	84	84	84	84	0
Low Pressure Feedwater Pump	(a)	(a)	86	86	0	0	86	86	0
High Pressure Feedwater Pump	2829	0	209	259	0	259	259	259	0
SUBTOTAL	4294	1288	395	445	100	359	445	445	0
TOTAL EPGS	7160	4154	786	836	416	675	836	674	116

(a) Low Pressure feed pumps not incorporated in commercial plant EPGS design.

III. COMMERCIAL PLANT EPGS AND BOP

A. INTRODUCTION

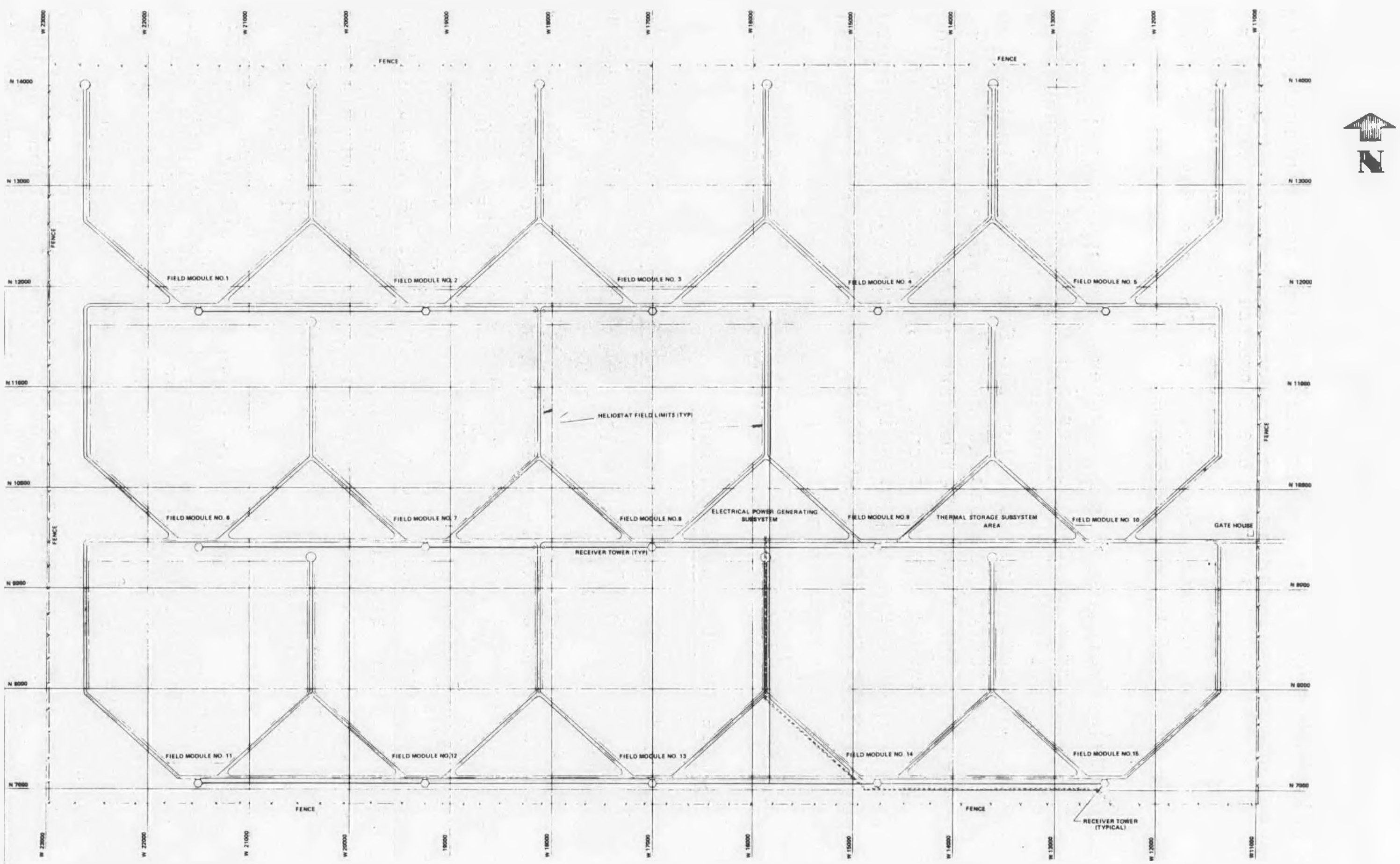
This section describes the Commercial Plant conceptual design for the EPGS and BOP. Features of the Commercial Plant related to the collectors, receiver, and TSS are described in Volumes III, IV, and V, respectively.

Certain features of some systems are applicable to the Pilot Plant as well as the Commercial Plant due to the modular nature of the Martin Marietta concept. In these cases the level of design detail available for the Commercial Plant is much greater than the conceptual design detail required, and references are made to Pilot Plant preliminary design subsections where such greater detail may be found. Cost estimates for the modular Commercial Plant features in this category are therefore expected to be more reliable than would otherwise have been the case.

B. DESIGN DESCRIPTIONS

1. Architectural Considerations

The modular layout of the Commercial Plant is shown in Figure III.B-1. This geometrically symmetrical plan was primarily selected to minimize land use and reduce pipe lengths. The large area required for the Commercial Plant will not be readily visible from a single viewpoint except from overflying aircraft. It is doubtful therefore whether any public considerations will be major factors in the design of the plant buildings and equipment which will be located in areas well within the periphery of the plant. The receiver towers will be visible from all sides of the plant and these towers will incorporate all of the architectural considerations included in the Pilot Plant receiver tower design. The Commercial Plant receiver towers will be identical to the Pilot Plant perliminary design tower described in Vol. IV, Section IV.D of this report. This tower utilizes Fluropan - Citation Gold colored metal siding to provide structural protection while enhancing the distant appearance of the tower. The Citation Gold color is a light sand color which is highly reflective, requiring minimum cleaning, and will attractively blend with the probable color of the plant's surrounding topography. In addition to the color and paneling selection the octagonal plan shape of the tower and the top truncations have been chosen to improve the architectural appearance as well as to provide the most cost effective design solution.



NOTE:
EACH SQUARE IS 1000FT x 1000FT

COOLING TOWERS

FIGURE III.B–1 PLOT PLAN

Heliostat foundations for the 23,310 heliostats required for a commercial plant are identical to those foundations designed for the Pilot Plant. A preliminary design description of these foundations is included in this report as Volume IV Section IV.D-1h.

2. Plant Arrangement

Figure III.B-2 shows the triangular layouts planned for the TSS and EPGS equipment areas in the Commercial Plant arrangement.

All of the EPGS equipment will be located in the triangular area south of modules number 8 and 9 in the plot plan shown in Figure III.B-1. This location will permit most manned operations to be performed in a central area removed from the TSS oil storage area. An EPGS building 40.8 x 25.0 m (134 x 82 ft) is shown in Figure III.B-2 near the east side of the area. This building location was selected to minimize pipe run lengths to the TSS area. The EPGS location between receiver towers 8 and 9 was selected to minimize pipe runs to the 15 module's receiver towers.

Each triangular area is approximately 23 acres in area. In the TSS area, containment dikes have been shown around each of the seven 23.2 m (76 ft) dia. spherical oil tanks. In the event of a tank failure the maximum single tank oil volume of 5 818 m^3 (1,537,000 gal) would fill the diked oil containment basin to a depth of 1.22 m (4 ft). Three fire water tanks are located in the TSS area and spray monitors are to be located around the oil containment basins to control an oil fire in any basin so as to avoid damage to equipment in adjacent basins. This TSS equipment area has been located in the triangular area immediately south of modules 9 and 10 shown in Figure III.B-1 and east of EPGS area. The location provides a minimum pipe run of 366 m (1200 ft) between the EPGS and TSS subsystems. TSS pumps will be located along the road running just north of the line of four tanks on the south edge of the TSS area. Access to the pumps, oil fill and drain stations, fire protection equipment, and piping bellows expansion joints will be from the roads shown in the arrangement.

An administration and control building 22.9 x 30.5 m (75 x 100 ft) has been located west of the EPGS building. This facility combines the administration and control functions at the EPGS equipment area in a single building. At the time of final design the user utility may choose to locate the administrative fuctions remote from the plant equipment areas either at the plant entrance or off-site completely. The control room

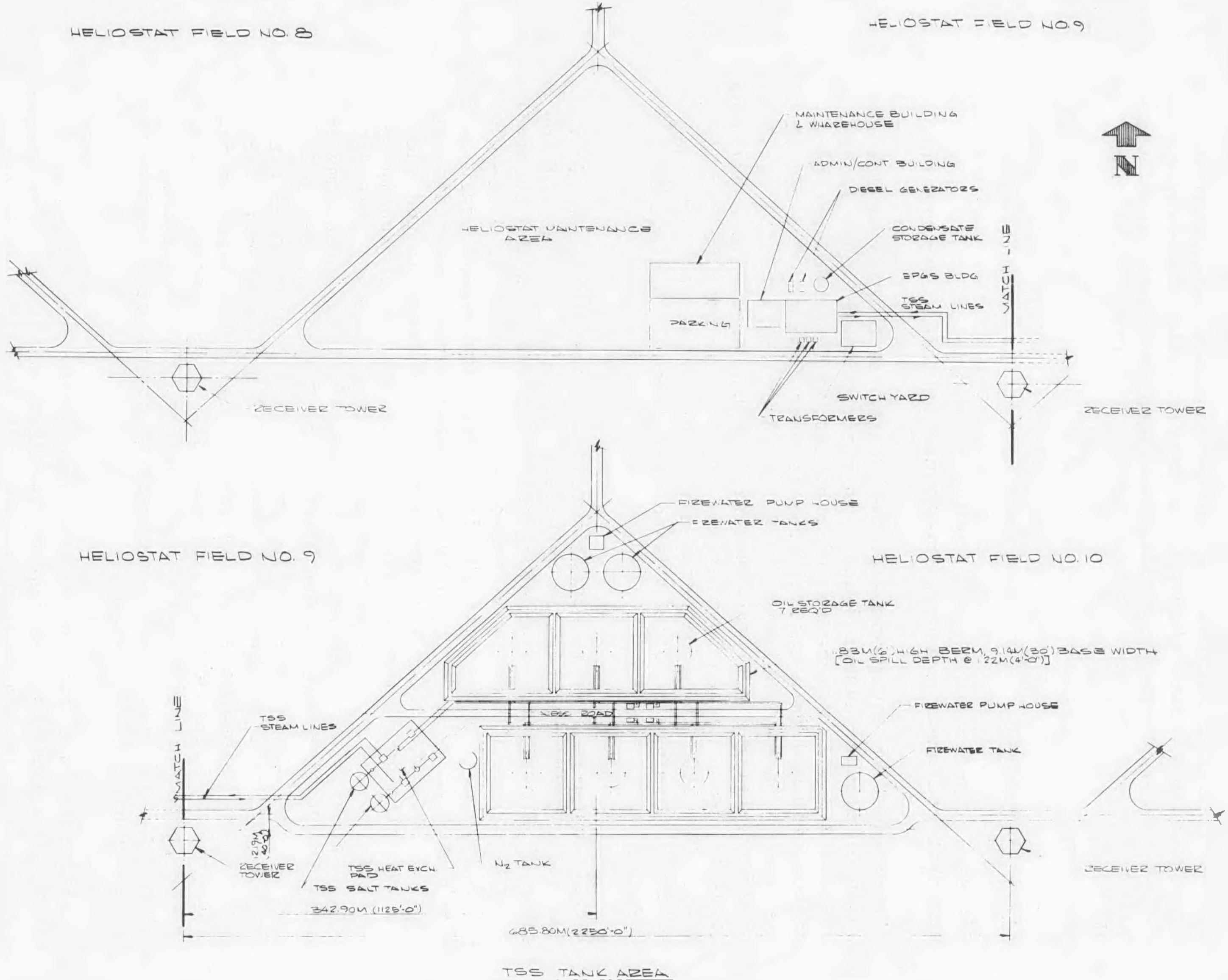


FIGURE III.B–2 PLANT ARRANGEMENT

size of 15.2 x 22.9 m (50 x 75 ft) is generous for a 150 MWe plant and this facility will also require closer scrutiny by the user during final design when control system details have been defined.

Maintenance headquarters will be a 30.5 x 76.2 m (100 x 250 ft) building located west of the EPGS building. Other local maintenance stations for mirror washing or receiver maintenance may be desired at remote modules to minimize personnel transit time.

The unused triangular areas in the central modules of the commercial plant may be utilized as evaporation ponds where rainfall runoff can be collected. Such use would require only minor grading on a flat site and would allow the natural runoff from ungraded collector fields to be contained without deleterious erosion in the plant.

3. EPGS

The commercial scale Electric Power Generation Subsystem (EPGS) serves to convert the thermal energy (steam) from the receiver or thermal storage into electrical power usable by the utility grid. The bulk of the equipment is located in the EPGS structure described in Section III.B-5 of this volume. This section describes equipment, design characteristics, and performance determined during a conceptual design study.

a. Subsystem Characteristics - The Commercial Plant EPGS conceptual design is based a 3 600 rpm 160 MWe (gross) admission type turbine design provided by the General Electric Company, Lynn, Massachussetts. The general arrangement of a similar but larger version of the tandem compound four flow turbine configuration proposed by GE for the Commercial Plant is shown in cross section in Figure III.B-3. Figure III.B-4 shows a cross section of a typical non-condensing automatic extraction turbine of the type which would be used as the high pressure turbine element in the GE design. GE has stated that the commercial turbine can be built using existing component designs. No special development programs will be required to put the turbine into production. The electrical generator included in the conceptual design is a standard GE 180 MVA, hydrogen cooled unit.

The turbine cycle chosen for the Commercial Plant conceptual design (see Figures III.B-5 and III.B-6) incorporates five stages of feedwater heating. Two parallel 50% capacity pump trains were chosen as representative of a typical power plant design.

The heat balance data provided in Figures III.B-5 and III.B-6 also permit preliminary sizing of the feedwater heaters, the main condenser, and the circulating water system. These data are shown in Tables III.B-1 through III. B-3. The equipment noted in the tables can be purchased using normal procurement methods from any of several power plant equipment manufacturers. No research or development costs are required by the design.

Figure III.B-5 present full load (160 MWe gross) operating condition data for the turbine cycle while operating with receiver steam. Steam is introduced to the turbine high pressure control valves at 9 411 kPa(1,365 psia), 510 C (950 F) and expands through the turbine high pressure section to the internal admission control valves which maintain pressure at that intermediate position in the turbine at 2 859 kPa (414.7 psia). After passing trough the admission control valves, the steam further expands through the remaining stages of the high pressure turbine section, turbine low pressure sections and exhausts to condenser vacuum conditions. For purposes of conceptual design, a turbine

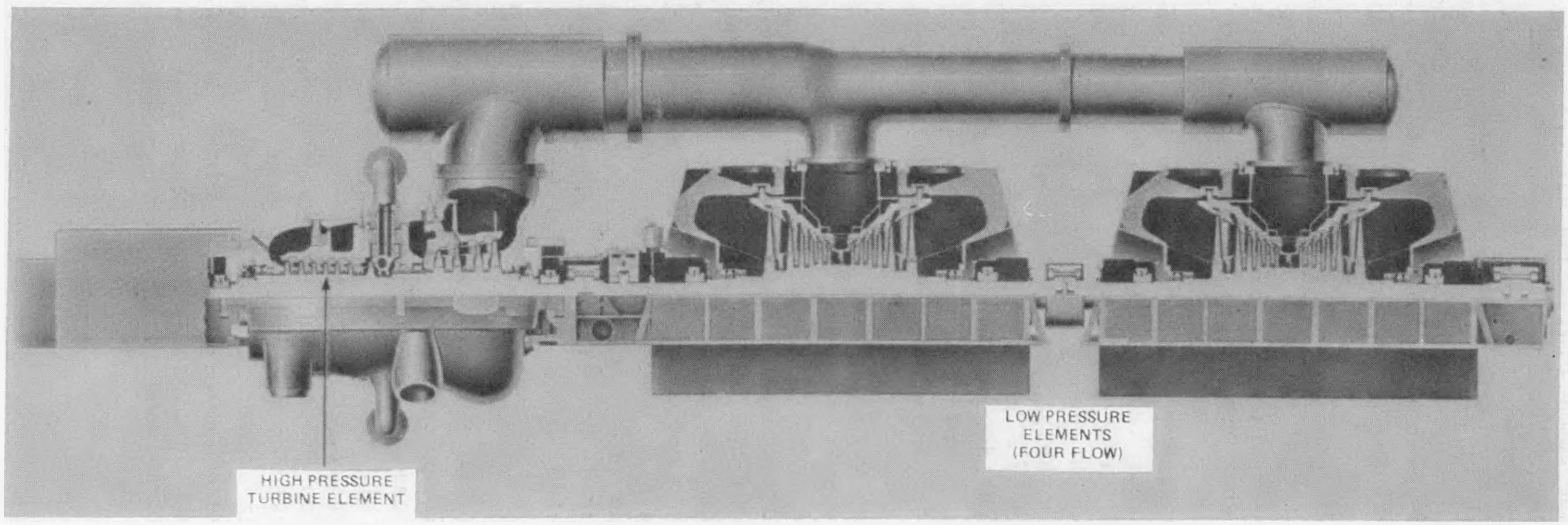


Figure III.B-3 Commercial Turbine Cross Section

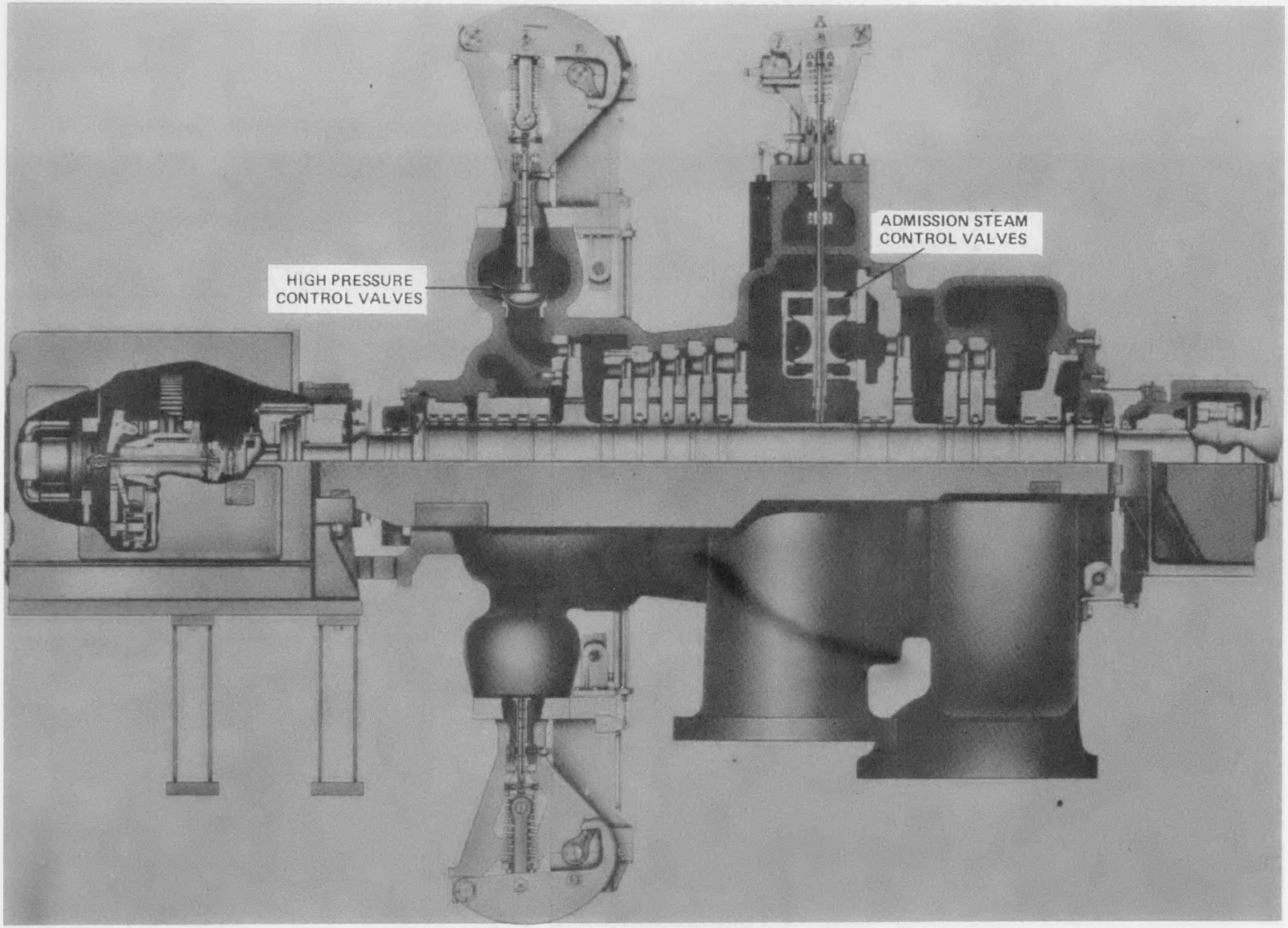


Figure III.B-4 Commercial Turbine High Pressure Element

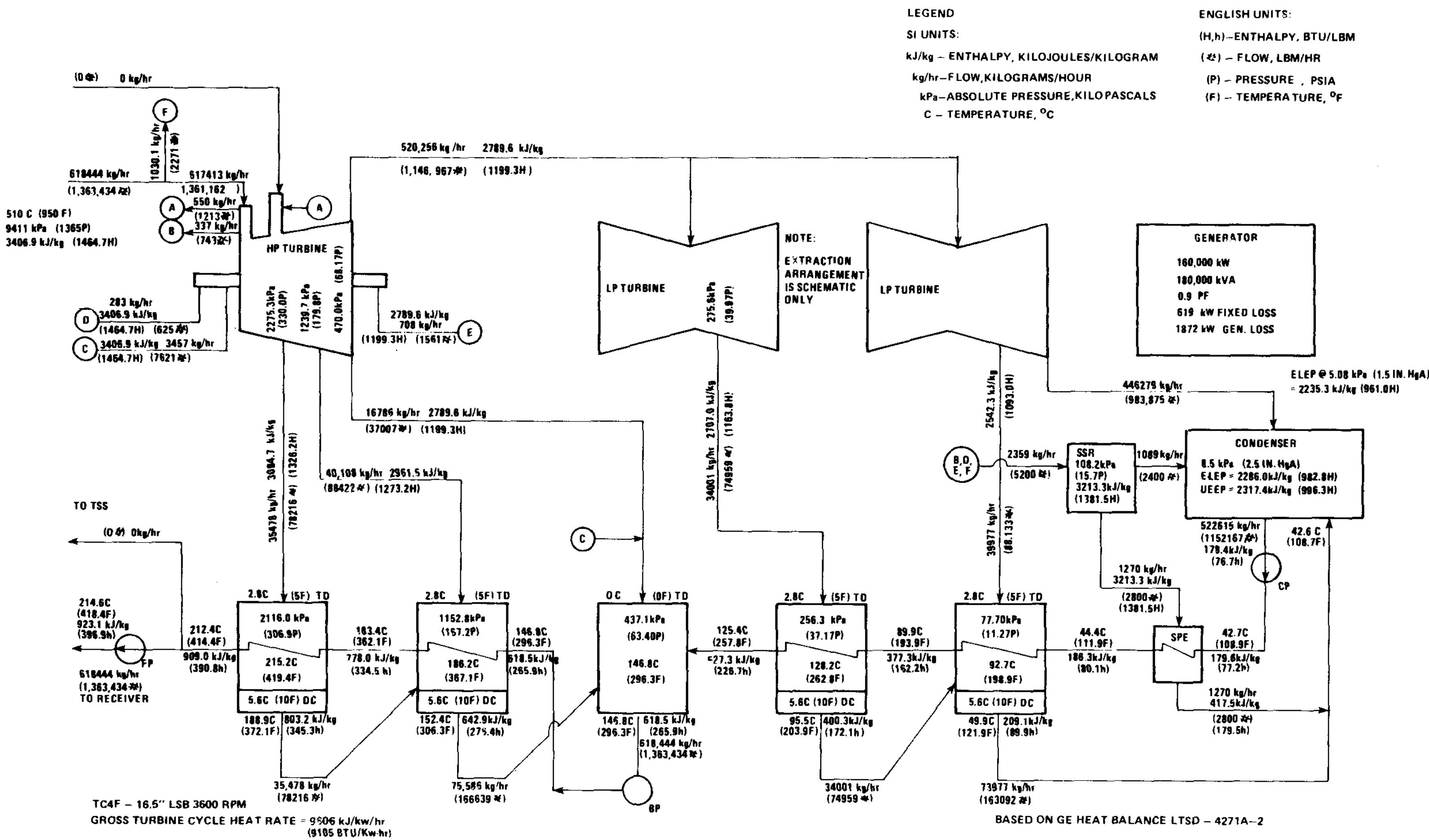
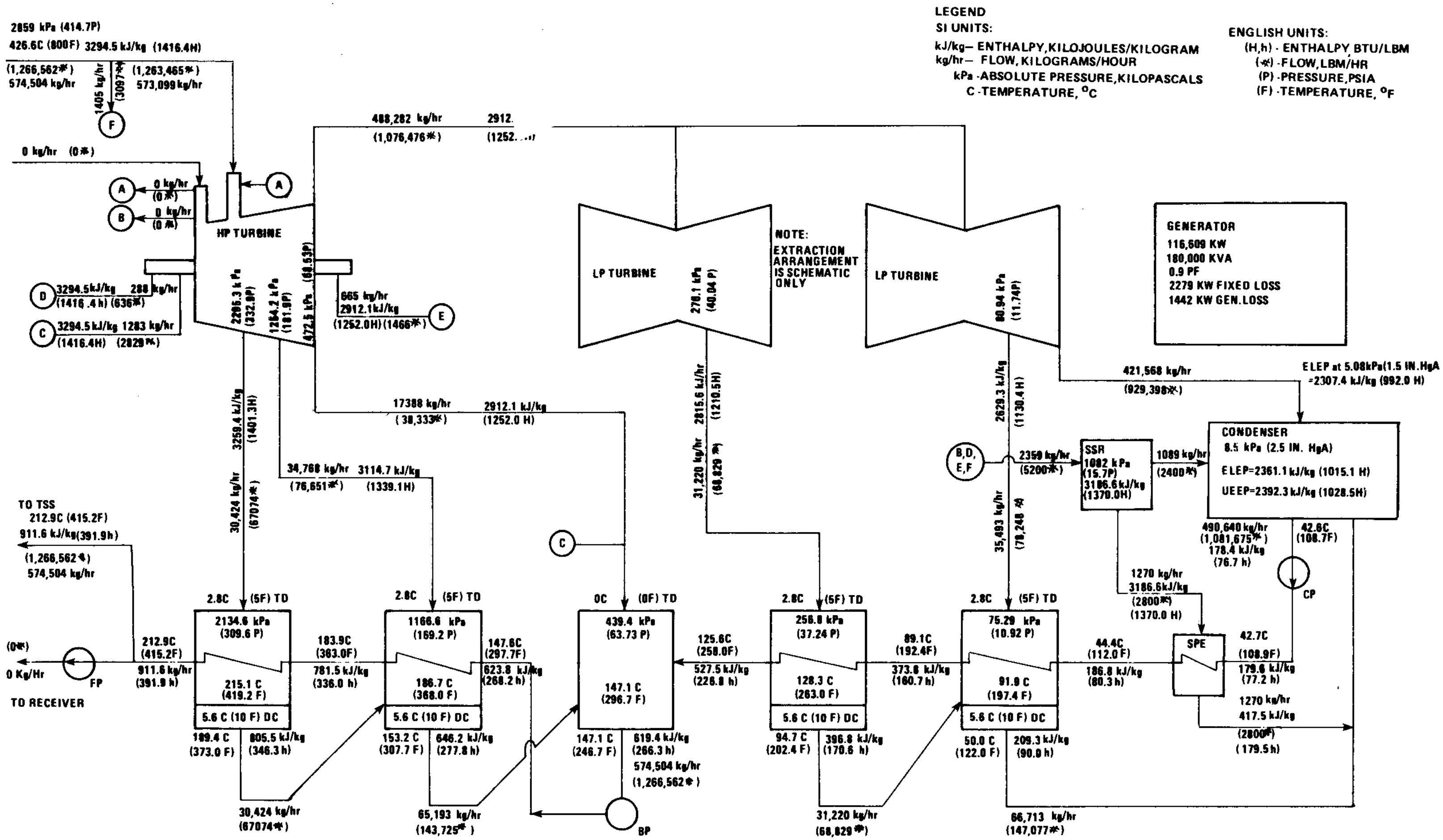


Figure III.B-5 Commercial Plant Turbine Heat Balance Diagram - Receiver Operation



TC4F-16.5" LSB 3600 RPM
GROSS TURBINE CYCLE HEAT RATE = 11740 kJ/kw-hr (11128 Btu/kw-hr)

BASED ON GE HEAT BALANCE LTSD-4271A-4.
FIXED LOSS INCLUDES 1660 KW WINDAGE LOSS FOR TURBINE HIGH PRESSURE SECTION

Figure III.B-6 Commercial Plant Turbine Heat Balance Diagram - TSS Operation

TABLE III.B-1 Commercial Plant

FEEDWATER HEATER PARAMETERS

Heater No.	1	2	3	4	5
Shell Pressure	2 116 kPa (306.9 psia)	1 153 kPa (167.2 psia)	437 kPa (63.4 psia)	256 kPa (63.4 psia)	78 kPa (11.3 psia)
Tube Pressure	5 026 kPa (729 psia)	5 281 kPa (766 psia)		586 kPa (85 psia)	669 kPa (97 psia)
Surface Area (Approx.)	490 m^2 (5,300 ft^2)	680 m^2 (7,300 ft^2)		500 m^2 (5,350 ft^2)	630 m^2 (6,730 ft^2)
Duty	80.9 x 10^6 kJ/hr (76.7 x 10^6 BTU/hr)	98.6 x 10^6 kJ/hr (93.5 x 10^6 BTU/hr)	46.1 x 10^6 kJ/hr (43.7 x 10^6 BTU/hr)	78.5 x 10^6 kJ/hr (74.4 x 10^6 BTU/hr)	(100 x 10^6 kJ/hr) (94.5 x 10^6 BTU/hr)

TABLE III.B-2 Circulating Water System Parameters

CONDENSER

Tube Size	7/8" (2.22 cm) Dia x 18 Gauge
Tube Quantity	5166
Tube Sheet	4.15 m (44.63 ft)
Effective Tube Length	7.58 m (24'-10.5")
Tube layout	Two parallel, two pass units, each pass 2583 tubes and 2.075 m (22.32 ft) tube
Size (approx.)	2 units, each 7.62 m (25 ft) long, 4.27 m (14 ft) wide and turbine pedestal height is 7.32 m (24 ft)

CIRCULATING WATER PIPING

Volume flow	In condenser 3.369 m^3/s (53 400 gpm) Plus approx. 8%, for aux. cooling is 3 628 m^3/s (57,500 gpm)
Concrete pipe size	168. cm (66 in.) O.D. x 147 cm (58 in.) I.D.
Pipe Length	Assumed 2 x 0.8 km (0.5 mi.)

COOLING TOWER

Type	Mechanical draft cooling tower
Construction Material	Wood
Quant. units	6
Unit size	10.97 m (36 ft) long, 18.29 m (60 ft) wide, 15.24 m (50 ft) high
Tower size	65.84 m (216 ft) long, 18.29 m (60 ft) wide, 15.24 m (50 ft) high
Tower duty	1 061 x 10^6 kJ/hr (1 006 x 10^6 BTU/hr)
Fan motor	112 kW

Table III.B-3 Commercial Plant Pump Parameters

Name	Receiver Feedwater Pump	Booster Feedwater Pump	Condensate	Circ. Water Pump	Circ. Water Pony Pump
Type	Opposed Impeller Centrifugal Pump	Opposed Impeller Centrifugal Pump	Vert. Centrifugal Pump	Vert. Centrifugal Turbine Pump	Vert. Centrifugal Turbine Pump
Quantity	2 @ 50% Cap.	2 @ 50% Cap.	2 @ 50% Cap.	2 @ 50% Cap.	1
No. Stages	8	5	3	1	2
Volume Flow (Ea. pump)	0.104 m^3/sec (1 645 gpm)	0.096 m^3/sec (1 524 gpm)	0.076 m^3/sec (1 202 gpm)	1.814 m^3/sec (28 750 gpm)	0.379 m^3/sec (6000 gpm)
Pump Head	1 161 m 3 810 ft	580 m (1,904 ft)	70 m (230 ft)	27 m (90 ft)	27 m (90 ft)
Motor	1 457 kW	688 kW	65 kW	580 kW	123 kW

rating exhaust pressure of 8.5 kPa (2.5 inches HgA) has been chosen as typical for operation with water cooled condensers. To increase turbine cycle efficiency, steam is extracted for feedwater heating at several locations in the high and low pressure sections. Feedwater is heated to 212.4 C (418.4 F) before being returned to the receiver.

Operating conditions using admission (storage) steam are shown in Figure III.B-6. Steam from the TSS at 2 859 kPa (414.7 psia), 427 C (800 F) is introduced to the high pressure turbine at the admission controls valves and expands through the low pressure sections to the condenser. Although not shown on the diagram, some steam is bypassed from the admission opening to the high pressure control valves in order to cool the rotating but non power producing high pressure section of the turbine. The energy the cooling steam receives in the form of windage losses is then partially recovered as the steam mixes with the incoming storage steam, and expands through the low pressure section. As in the receiver steam operating mode, feedwater heating is used to increase cycle efficiency. Under these conditions, feedwater is returned to the TSS at 212.9 C (415.2F).

Inlet steam conditions used for commercial and pilot plant turbines were determined based on studies conducted by Martin Marietta, those studies are summarized in another volume of this report.

b. <u>Selection of the Commercial Turbine</u> - The selection of the admission type turbine for Commercial and Pilot Plant applications followed a survey of available turbine designs. In making the selection, the desirable characteristics of the Commercial and Pilot Plant turbines were compiled, and then the various turbine manufacturers were contacted to determine the characteristics of their commercially produced units.

The criteria which were used for the selection of the turbine type are the following:

- The turbine should be a standard design type normally offered by the manufacturer.
- The turbine must be efficient using both direct receiver steam and steam produced by the TSS.
- The turbine type must be available in sizes suitable for commercial applications.
- The turbine must be tolerant of the daily cyclic operations characteristic of a solar power plant.

The GE admission turbine was selected as providing the best match for these criteria. Also, GE was the most responsive of the manufacturers contacted in providing design and performance data.

The types of turbine proposed by the various turbine manufacturers are shown in Figure III.B-7. The principal differences among the types lies in the steam valving arrangements for the high pressure turbine section. All alternates would employ the tandem compound arrangement shown in Figure III.B-3. The first type shown in Figure III.B-7, the mixed pressure turbine, relies on two sets of external control valves to separately introduce steam to the first stage of the turbine. In this type of turbine, severe receiver steam throttling losses and large temperature differences between steam sources could limit the efficiency and life expectancy of the turbine. For these reasons this type of turbine was excluded from further consideration. The second turbine configuration, the admission turbine, uses two separate sets of valve gear internal to the turbine steam path to control steam flow. This type of turbine is commonly used as an automatic extraction turbine in industrial plants where process steam at controlled pressures are required. As discussed in Section III.B-3c below, the use of internal control valves leads to efficient storage steam operation, especially at partial loads. The third type of turbine, the induction turbine, is similar to the admission turbine, except that storage steam is introduced via an external control valve to an intermediate pressure opening in the turbine cowling. This type of turbine is generally less expensive and has some efficiency advantages for receiver steam operation, but has poorer part load performance when operating with storage steam. In addition the induction turbine undergoes higher internal thermal stresses when transitions between receiver and storage steam are required. This indicates that a thorough evaluation of the life expectancy of the induction turbine in solar commercial applications is warranted before the complete applicability of this type of turbine is confirmed.

GE states that, if desired, they are capable of producing induction type turbines from existing designs, but in general they favor the admission turbine approach for solar applications.

Besides GE, other turbine manufacturers, Westinghouse and Siemens, expressed an interest in supplying commercial scale turbine generators suitable for Commercial Solar Plants. These designs would not necessarily employ the admission turbine approach advocated by GE. Westinghouse states that their configuration would consist of existing double flow low pressure turbine elements and generator designs coupled with a new, high pressure turbine element

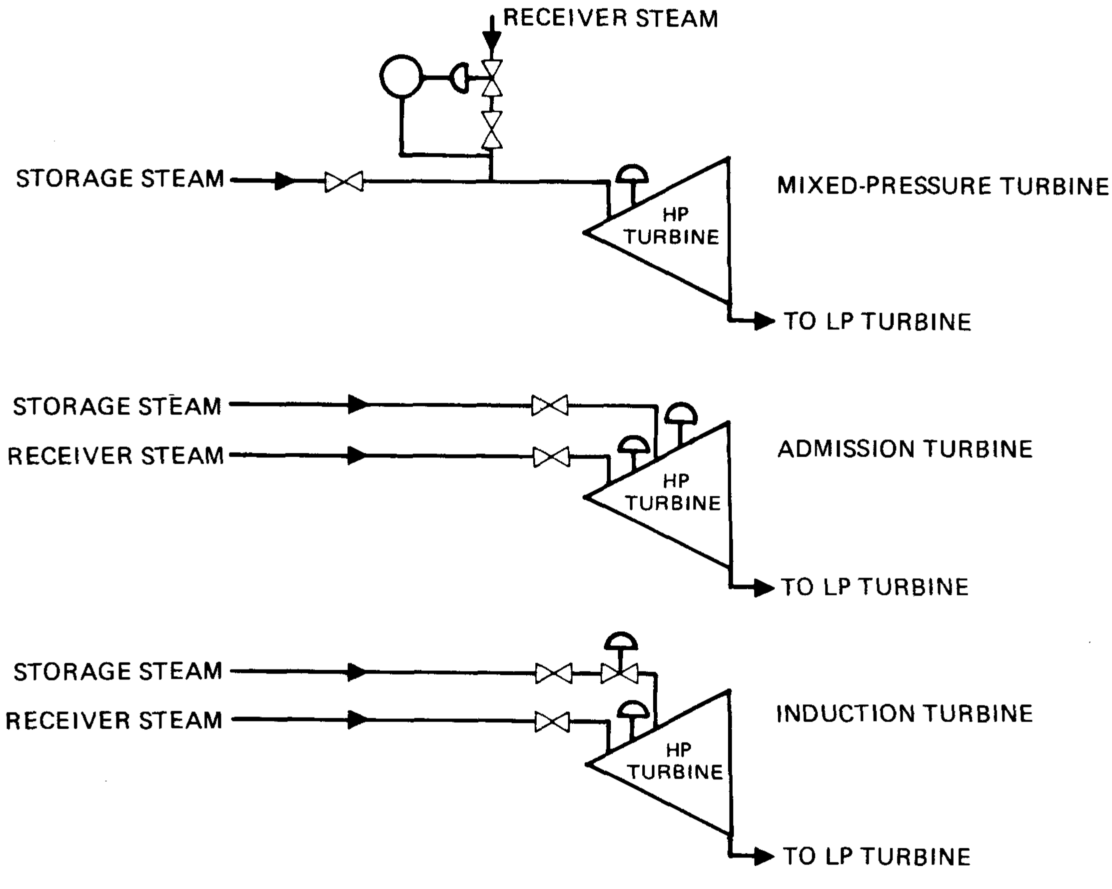


Figure III.B - 7 PROPOSED COMMERCIAL TURBINE TYPES

specially designed for solar applications. Siemens states that they could produce a commercial turbine of the induction type from existing designs. While Siemens favors the induction turbine approach, they state that, if desired, they could also follow the admission turbine approach, but at an increased cost.

Determination of the size of the commercial turbine-generator was found to the based primarily on factors outside of the EPGS. As shown in Figure III.B-8, heat rates and costs per kilowatt for turbines larger than 100 MWe show only slight improvement with increasing unit size. One major reason for this is that at approximately 100 MWe, turbine manufacturers begin to split steam flows into paths through parallel turbine sections rather than using larger components to achieve larger capacities. Because parallel turbine sections are used, turbine efficiency and cost per kilowatt do not significantly change as unit rating is increased. This means that plant sizing becomes realtively insensitive to EPGS considerations in the 100 - 300 MWe range, and other factors must be considered in selecting the optimum Commercial Plant size.

The upturn of the heat rate curve at lower unit ratings shown in Figure III.B-8 is primarily due to the physical characteristics of steam turbines. At the smaller sizes, the internal friction and other fluid-mechanical effects prevent full utilization of the available energy in the steam.

c. <u>Commercial Turbine Operational Characteristics</u> - Operational characteristics of the GE admission turbine were examined relative to solar plant requirements and found to be acceptable. Three areas examined were startup, transient response, and control valve operation.

During normal morning startups, the Commercial Plant turbine will follow startup curves similar to those illustrated in Figure III.B-9. Without prewarming the turbine, approximately an hour and 20 minutes will be required to reach full turbine-generator load. If desired, the turbine startup time can be shortened by prewarming the turbine using small quantities of TSS or receiver steam prior to startup. A startup curve assuming 83 C (150 F) of prewarming is also shown in Figure III.B-9. With this amount of prewarming, turbine startup time is shortened to approximately 50 minutes. If additional prewarming is undertaken, the startup time can be shortened even further.

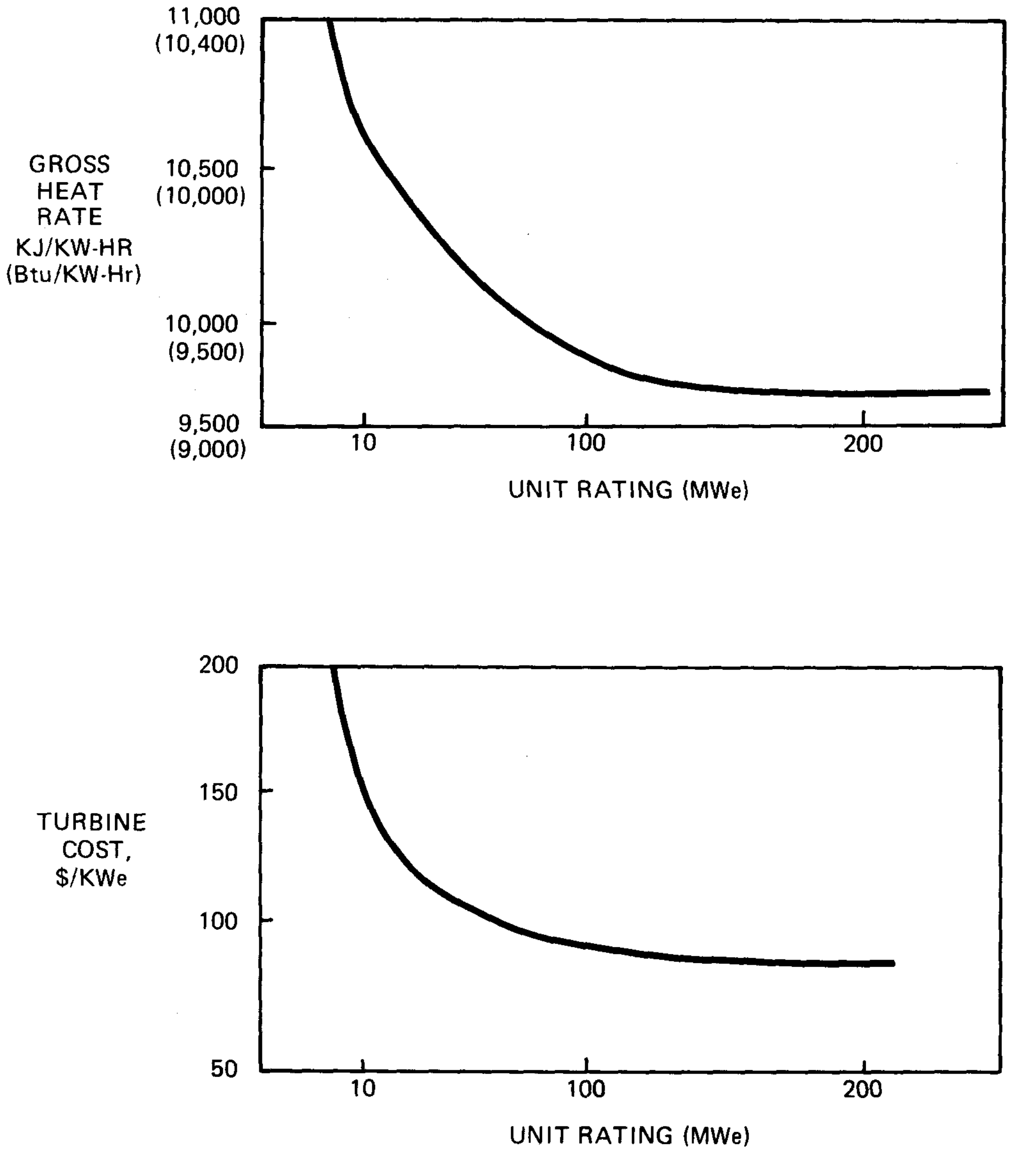


Figure III.B - 8 COMMERCIAL TURBINE SIZING CONSIDERATIONS

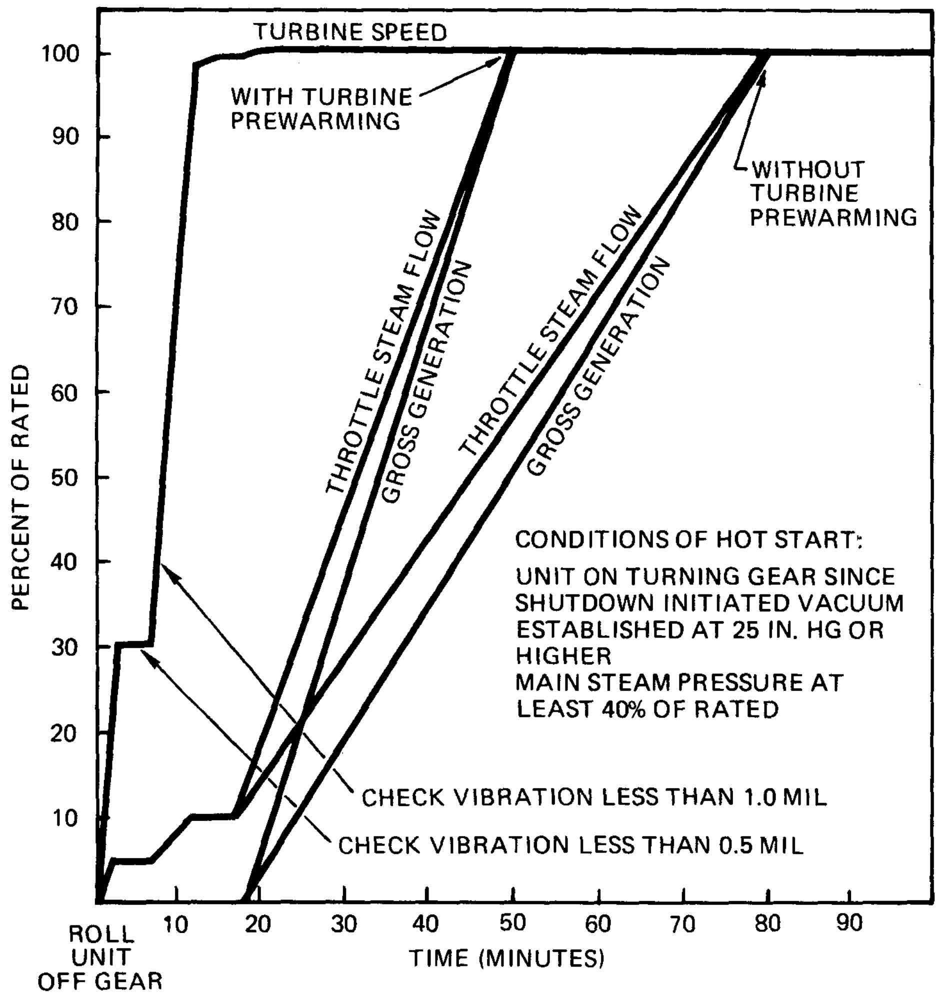


Figure III.B - 9 PREDICTED TURBINE STARTING AND LOADING CURVES; COMMERCIAL TURBINE HOT START

Both overall startup times were calculated using as a basis Figure III.B-10, a life cycle curve supplied by GE as typical for the commercial turbine under consideration. An overnight cooldown of 167 C (300 F), and a warmup rate of 167 C (300 F) per hour following synchronization were assumed, giving a turbine life expenditure of 0.003% per diurnal cycle. Assuming approximately 10,000 starts over the 30 year life cycle of the plant, one-third of the turbine life would be expended in meeting the daily cycle requirements including evening admission steam operation. The remaining turbine life can the be allocated to load maneuvering during the day and to transients.

Through its hydraulically activated high pressure and admission control valves the turbine is capable of rapidly responding to transients such as cloud passage. However, a rapid transition (step change) from receiver steam to admission steam and back, with a correspondingly rapid 78 C (140 F) temperature change at the admission steam opening, causes a turbine life expenditure of approximately 0.01% according to Figure III.B-10. If two thirds of the turbine life is available for this type of transition, approximately 6000 to 7000 of these rapid transitions can be tolerated over the life of the turbine. Not all cloud passage transients would not have as severe an impact on turbine life. For the commercial plant, several minutes will pass before the entire collector field will be obscured by clouds. Also, smaller clouds will cause only partial obscurations and partial load reductions. Including these mitigating factors, a thirty year turbine life is predicted for the 160 MWe commercial turbine.

Control valve operation and sequencing is an area where the GE admission turbine differs from turbines with external storage steam control valves such as the induction turbine.

One major reason for selecting the admission turbine is the relatively efficient part load performance achieved using steam from storage. Each admission valve feeds an arc of turbine blading as shown in Figure III.B-11. By individually sequencing the opening and closing of the valves, part loads can be achieved with the blading still operating close to its maximum efficiency point. This is in direct contrast to the induction turbine, where steam is externally throttled before it enters the turbine. In the latter case, heat rate penalties are encountered at part loads.

An additional benefit of the admission turbine approach is that a relatively good temperature match is achieved over the entire load range between steam exhausting the high pressure turbine section and steam admitted from storage. This minimizes internal thermal stresses in the turbine during the transitions between operation on receiver steam and storage steam.

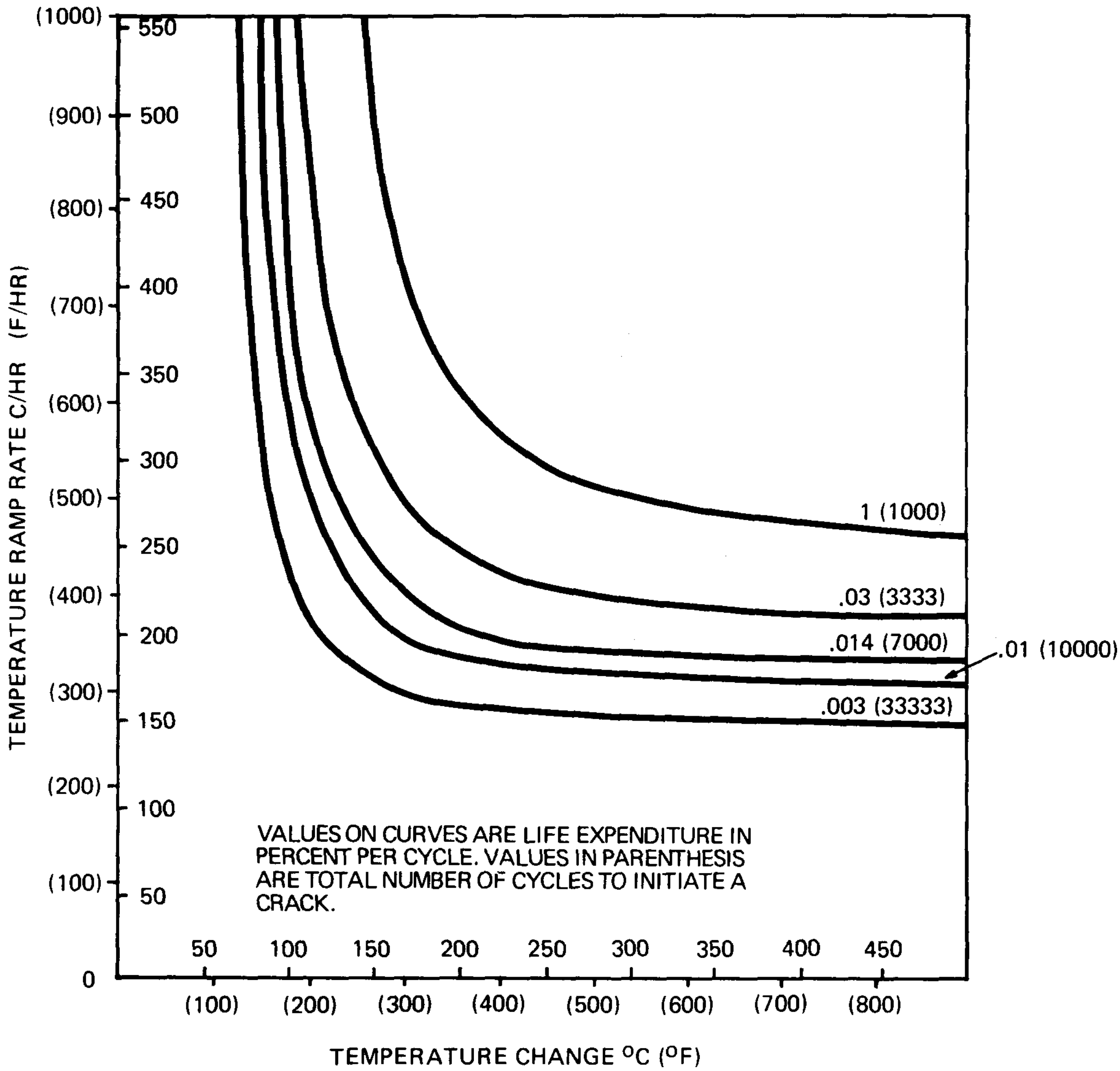


Figure III.B - 10 CYCLIC LIFE CURVES FOR 160 MWe COMMERCIAL TURBINE

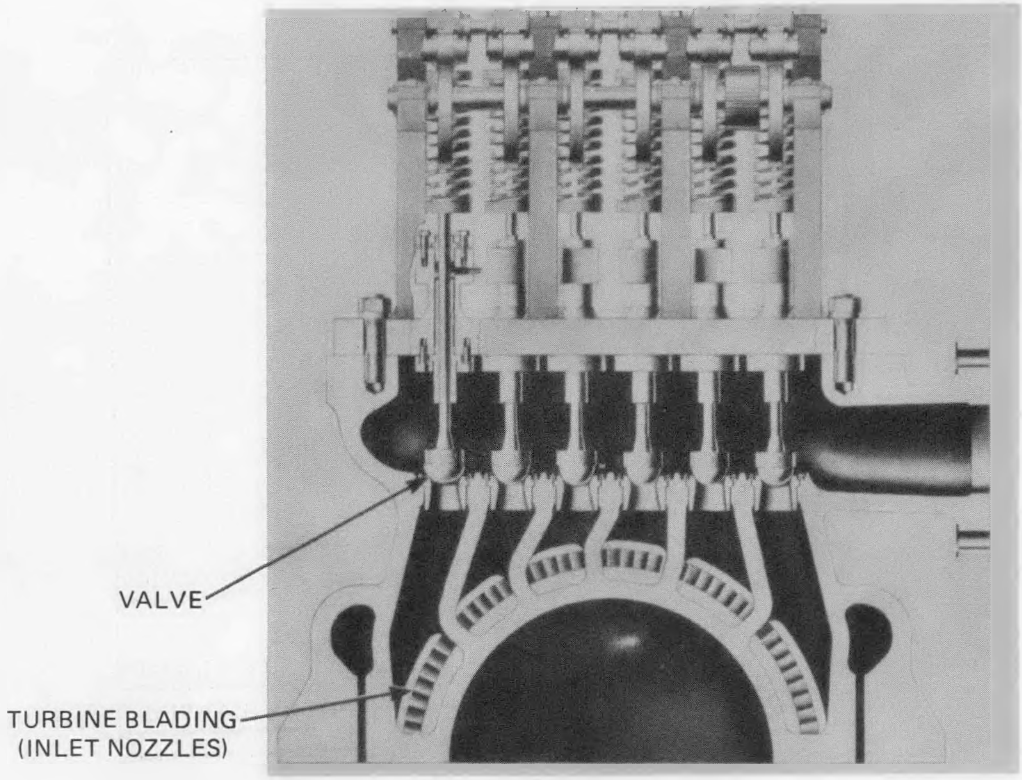


Figure III.B - 11 PARTIAL ARC CONTROL VALVE OPERATION

If desired, the admission valves could be electronically blocked open when the unit is running with receiver steam only. This mode of operation would permit somewhat more efficient part load operation with receiver steam.

Partial arc valve control is also used at the receiver steam inlet for both admission and induction turbine applications.

d. Commercial EPGS Performance - A summary of commercial EPGS performance is presented in Table II.-1 in Section II of this volume.

Curves showing the turbine cycle gross efficiency versus ambient wet bulb temperature for receiver steam and TSS steam operation is provided in Figures III.B-12 and III.B-13. These data were generated with a Bechtel turbine cycle performance computer code using GE supplied efficiency data as input. These curves, together with the EPGS auxiliary loads shown in Figure III.B-14, and auxiliary load data from other subsystems, can be used to calculate estimated commercial plant performance under a wide range of conditions.

The curves are based on a turbine cycle with inlet conditions of 9 411 kPa(1 365 psia), 510 C (950 F) for receiver steam and 2 859 kPa(414.7 psia), 427 C (800 F) for storage steam. Heat balance diagrams of the turbine cycle as received from GE are provided as Figures III.B-5 and III.B-6.

The data presented are for a conceptual design. EPGS components were selected using typical designs encountered in current power plant practice. While the data are internally consistent, they do not represent an optimized design. Improvements in the cost effectiveness of the commercial EPGS can be expected to result from detailed cost trades involving an actual plant site.

The results shown for admission steam in Figure III.B-13 require some explanation, since gross conversion efficiency at 90 MWe exceeds that at full load. The explanation of this effect lies in considering the magnitude of two competing effects. As turbine load decreases, overall turbine efficiency also decreases. However, for a given wet bulb temperature, decreases in turbine load result in a decrease in condenser pressure which in turn increases efficiency. Where the efficiency effects of reduced condenser pressure exceed the effects of decreased turbine efficiency, the turbine part load efficiency exceeds the full load efficiency. In the case of receiver steam operation shown in Figure III.B-12, efficiency decreases in the high pressure turbine section mask these effects.

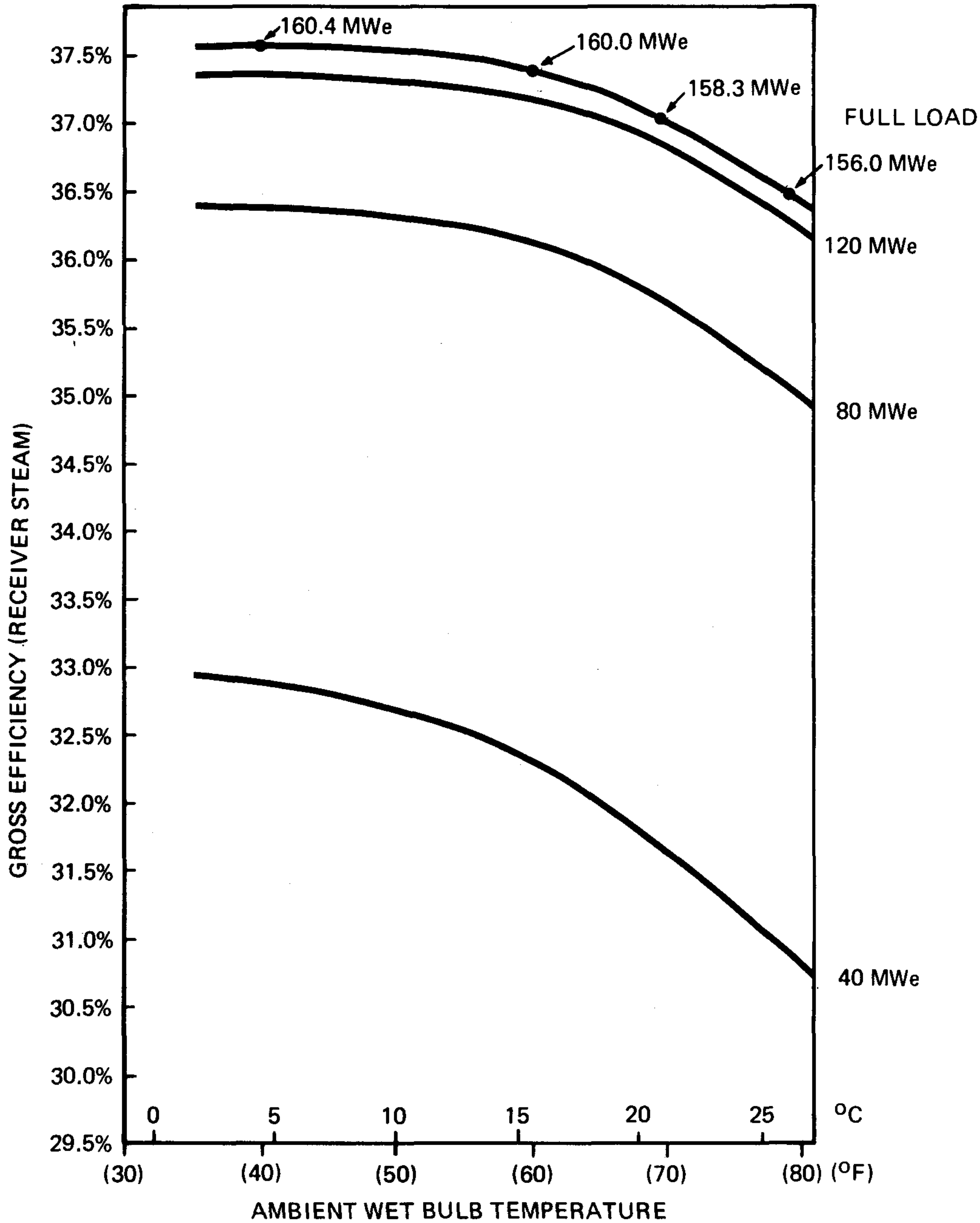


Figure III.B - 12 CONVERSION EFFICIENCY AS FUNCTION OF AMBIENT TEMPERATURE AT DIFFERENT POWER LEVELS, ON RECIEVER STEAM

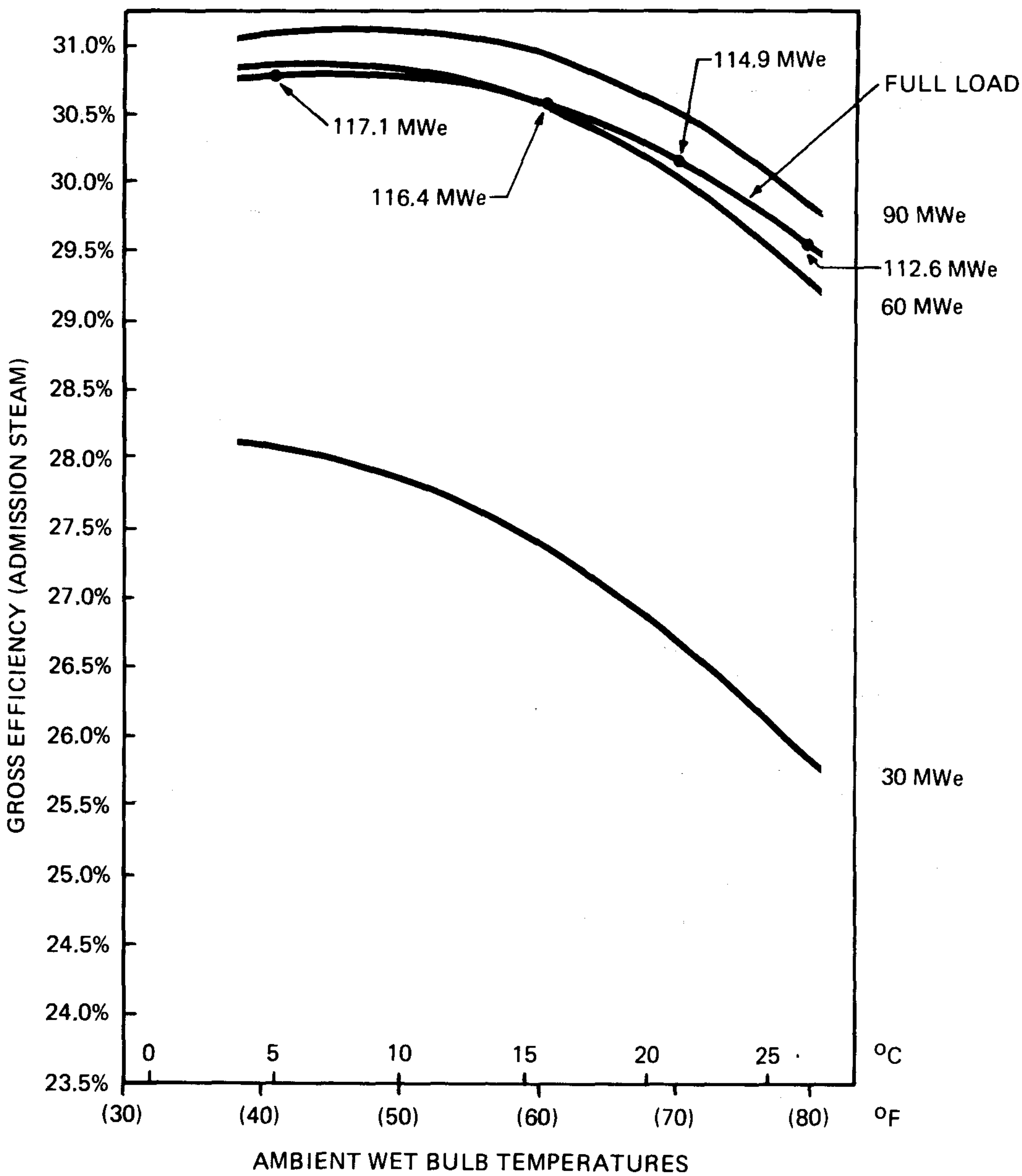


Figure III.B - 13 CONVERSION EFFICIENCY AS FUNCTION OF AMBIENT TEMPERATURE AT DIFFERENT LEVELS, TURBINE ON ADMISSION STEAM

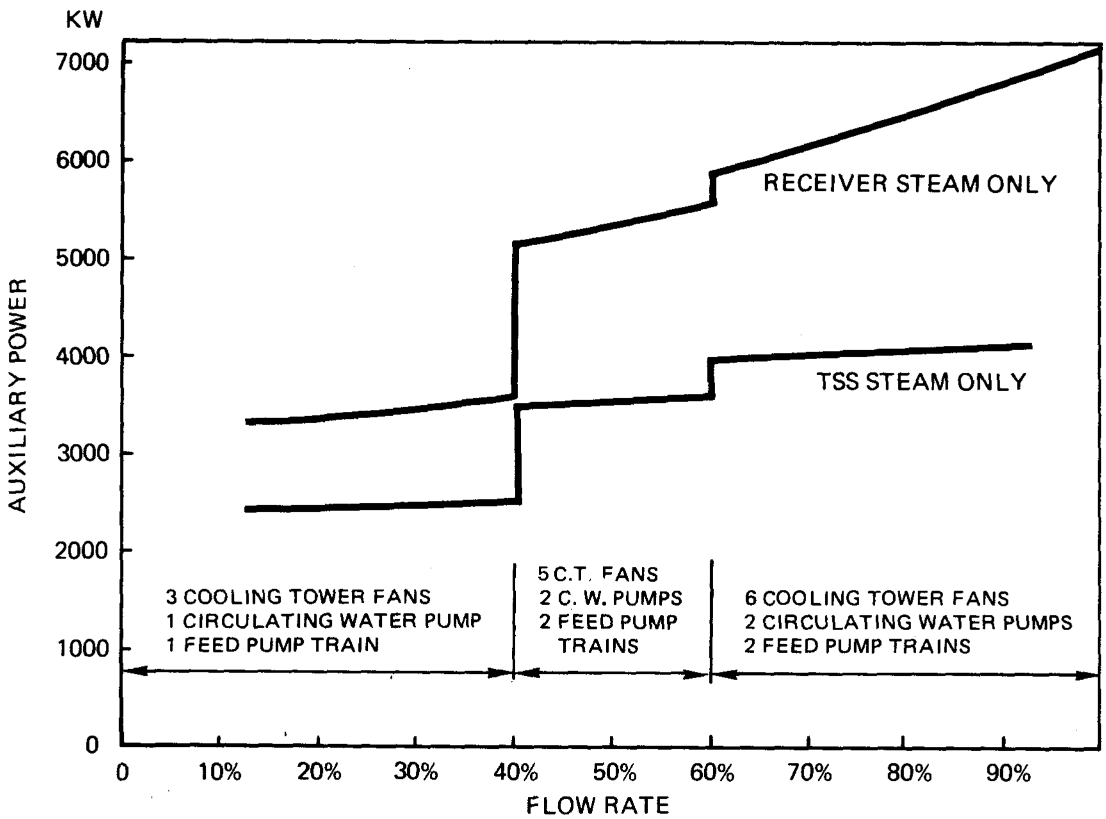


Figure III.B - 14 EPGS AUXILIARY POWER REQUIREMENTS VERSUS TURBINE FLOW RATES

4. Roads and Drainage

The road system for the Commercial Plant is designed to provide access to the building and equipment area for operation, maintenance, and service vehicles. In addition to the medium-duty roads provided for the main plant buildings and equipment area, soil surface roads have been designed for the collector field service and maintenance.

Paved road surface within the collector field has been reduced to minimize environmental impact and cost. In order to service all heliostats for washing, calibration, and maintenance, service vehicles must be able to traverse each row in the collector field.

In order to mitigate potential environmental effects, the use of low-tire-pressure, off-road vehicles for collector field servicing is recommended.

Road pavements should be designed to meet anticipated vehicular loads using the State of Calif. Div. of Highways Procedures.

Grading and collector field surface treatment will be minimized. Rainwater runoff will be in accord with the natural grade within each collector field and catch basins will be provided in some of the unused 23 acre triangular areas between Commercial Plant modules where accumulated runoff can evaporate or percolate down into the water table. This solution will be acceptable for a desert area where significant runoff is infrequent. If a commercial site is chosen in an area with moderate rainfall the grading and drainage system requirements may be more extensive.

5. Building Arrangement

For the conceptual design the turbine-generator and other major EPGS components are assumed to be located in an open air turbine building structure: Design sketches of the building are shown in Drawings P-2003, Sheets 1 and 2. (Appendix C)

Laydown space and a bridge crane, for turbine disassembly are located on the deck at elevation 24 ft-0 in. Major pumps and other major equipment are located on the base slab at elevation 0 ft-6 in. Closed (shell and tube) feedwater heaters are located in the necks of the two condensers in order to conserve building volume. Platforms are provided to permit access to the heaters for maintenance and control adjustments. The deaerator is located at an elevation above the turbine in order to provide the required suction head for the booster pumps. Space at elevation 24 ft-0 in. below the deaerator can also be used for EPGS equipment.

Other major buildings required for the Commercial Plant include an Administration and Control Building and a Maintenance Building. The Administration and Control Building includes space for the control room; engineering, supervision, and clerical offices; chemical and instrument labs; conference rooms, and guest facilities. This building could be a simple prefab structure if cost considerations outweigh architectural considerations in the Commercial Plant design. A building 22.9 by 30.5 m (75 x 100 ft) is planned for these functions. The Maintenance Building is a 30.5 by 76.2 m (100 x 250 ft) structure with an unfinished interior similar to a "Butler" building.

6. Electrical, Grounding and Lightning Protection

The electrical systems for the Commercial Plant will be of standard power plant design.

The collector field electrical distribution system will be similar to the pilot plant with the exception being that a primary distribution voltage of 13.8 kV rather than 4.16 kV may be prefered. Grounding and lightning protection systems will be identical to those in the Pilot Plant. Protection of equipment and personnel against direct lightning strikes, lightning induced transient overvoltages and other abnormal occurrances, is provided by the grounding and lightning protection system. The system consists of direct buried bare copper conductor and ground grids located in all heliostat fields and at the EPGS and TSS locations. All heliostat frames, equipment, and structures are bonded to the ground grid system. In addition, metal air terminals are located on the top of each receiver tower, to provide protection against direct lightning strikes. Electrical transmission and distribution lines and transformers are provided with surge arrestors where they might be subjected to transient overvoltage conditions.

7. Controls

For the conceptual design effort, controls within the EPGS have been assumed to follow current utility design practices. Control of the turbine-generator is accomplished using a standard package furnished by the manufacturer. Other equipment, such as feedwater heaters, the cooling towers, and the main condenser, use local control loops as required for proper operation. Local control of packaged components, such as the air compressor and demineralizers, is assumed to be furnished with the equipment. Use of the plant computer is limited to data logging rather than direct control of the EPGS.

C. DESIGN RELIABILITY, TECHNICAL RISK, AND SAFETY

1. Design Reliability

Equipment supplied for use in a commercial scale EPGS will follow proven industrial and utility design practices. No technological innovation or significant new designs would be required to accomplish the design objectives. For this reason, reliability of commercial EPGS equipment is expected to match or exceed reliability of similar equipment in comparably sized fossil fueled plants. With appropriate redundancy incorporated into the design, the commercial EPGS should equal the reliability of the Pilot Plant.

2. Technical Risk

Technical risk for the commercial EPGS would be comparable with the risk associated with the construction of a similar fossil fueled power plant. Since 150 MWe fossil power plants have been built for at least 20 years, risks in the EPGS area will be very small.

3. Safety

Safety within the commercial EPGS will compare with safety of contemporary fossil fueled power plants. No additional hazardous materials or processes are anticipated. State, local, and national standards, as well as insurance company requirements, will be factors controlling safety in the design.

D. ENVIRONMENTAL IMPACT

Although the design studies of central receiver solar power plants are showing that environmental impacts are not serious, there are some environmental aspects which must be considered in the design of any size solar plant, and especially in the design of a commercial scale plant. The aspects which should be considered include:

1. Land Use
2. Micro-climatology.
3. Erosion.
4. Cooling tower discharges.
5. Effluents.
6. Biological impact.
7. Aesthetic impact.

The following paragraphs consider each of these aspects briefly:

1. Land Use - The 150 MWe Commercial Plant will require the dedicated use of approximately 1500 acres of land. This land will not be available for other purposes during the life of the plant. Reclamation of the land to its natural state will require a significant capital expenditure for removal of heliostat foundations and wiring in all the collector field areas and for removal of the receiver towers and other plant equipment in the modules and the plant equipment areas. In general, it is anticipated that desert lands previously unused by man will be selected for the commercial plant sites.

2. Micro-climatology - Additional research, including observations at the Pilot Plant, will be required to determine the nature and significance of any alterations caused by the Commercial Plant. The heliostats in each collector field will keep a significant portion of the normal solar insolation from reaching the ground surface by reflecting the solar radiation back to the receiver at the top of the receiver tower. The temperature of the ground surface and, therefore, of the surface level air can be expected to be lower than it otherwise would be. Whether natural convection or movement by normal winds will negate this effect are issues which require further research. Another potential micro-climatological impact will be the increase in local and downwind humidity due to the moisture in the cooling tower air effluent.

3. Erosion - The present concept for the development of Commercial Plant modules does not include extensive paving in the collector fields. This decision was based on the consideration of Inyokern, California, as the probable plant site. If a site with significantly higher annual rainfall is actually selected, the use of the natural terrain drainage patterns may not be feasible. There are some paved roads on the collector field peripheries and in the plant equipment areas. These alterations to the natural drainage patterns could be significant in influencing drainage and erosion patterns in an area with even moderate rainfall. In addition, the site specific soil properties will require a detailed study of potential erosion versus rainfall quantity or rates before any final conclusions can be drawn on the need for a more sophisticated civil design for drainage and erosion control.

4. Cooling Tower Discharges - The airborne effluent from the Commercial Plant cooling tower will contain approximately 126 kg/s (1.0 x 10^6 lb./hr.) of evaporated water and 17.6 kg/s (140,000 lb./hr.) of suspended water droplets. The evaporated water will not contain suspended impurities but can cause significant increases in humidity levels in the vicinity or downwind of the cooling tower. The suspended water droplets in the tower effluent are carried aloft by the velocity of the cooling tower discharge air. This suspended water contains the concentrated solids (salts) found in the cooling tower water. The water droplets will deposit (drift fall out) within a few thousand feet of the tower depending on wind velocities and atmospheric conditions. This polluted water could cause some negative impact to plants or animals in the vicinity of the cooling tower. Such impact could, of course, be minimized by purifying the cooling tower feedwater before adding.

   The other cooling tower effluent is blowdown water containing the same concentrated solids found in the drift fallout. This liquid effluent is much easier to contain than the airborne water droplets, and the plans call for its diversion to an evaporation pond where the solid waste will eventually precipitate out on the bottom of the pond.

5. Effluents -

   - Acid Waste - These wastes are generated in the plant chemistry lab as a result of testing to maintain the proper plant chemical balance. The acid wastes are placed in a holding tank adjacent to the lab where they are neutralized by the addition of a strong base. The neutralized waste is then dumped to sanitary waste.

   - Sanitary Waste - The operating staff for the Commercial Plant is not expected to exceed 20 persons. For this number, the environmental impact as well as the costs can be minimized by using a septic tank system near the Administration and Control Building. If toilet facilities are determined to be required at remote modules for maintenance personnel, the use of portable chemical controlled holding tank toilets will probably prove to be the most cost-effective option.

   - Oily Waste - Oily wastes from the EPGS can be treated with an inclined plate separater. Sludge can then be hauled off site for disposal at an approved location. The water from the separation process can then be routed to the evaporation pond.

- Receiver Blowdown - Each of the 15 plant modules will have continuous blowdown. The maximum rate for all 15 modules will be 54,000 kg/hr (120,000 lb./hr.) This flow will be either reprocessed or routed to evaporation ponds depending on environmental consideratons as they relate to the site and site economics.

6. Biological Impact - In areas directly shaded by the heliostats, the surface solar insolation will be practically eliminated. Any plants and many animals in these areas will be eliminated. No other significant biological impacts are anticipated for areas not actually paved or covered by structures.

7. Aesthetic Impact - The 112 m (367 foot) receiver towers will be dominant landscape additions in any area but particularly in desert areas such as Inyokern considered for the Commercial Plant.

   Other plant features, including the heliostats, TSS tanks and heat exchangers, and plant buildings, will also be visible from great distances. In the design of the receiver towers and other buildings, consideration has been given to providing a pleasing appearance. Tower and building exteriors will be of a material and a color to blend as much as possible with the surrounding landscape. For plant visitors, the solar plant must present a clean and efficient appearance. By considering these aesthetically pleasing aspects in the design, the aesthetic intrusion into the area will be minimized. However for some persons or from some aspects, the Commercial Plant will not be visually pleasing.

In conclusion, it appears that environmental effects of the Commercial Plant will be at acceptable levels. All of the aspects which could cause negative impact should be considered in the preliminary and final designs in order to minimize and to mitigate, insofar as practicable, the negative impacts. To accomplish this end, it is expected that a significant level of effort will be devoted to these considerations prior to the preparation of an Environmental Impact Statement (EIS).

IV. PILOT PLANT ELECTRIC POWER GENERATION SUBSYSTEM

A. INTRODUCTION

The Pilot Plant Electric Power Generation Subsystem (EPGS) converts thermal energy in the form of steam flow from the receiver or thermal storage into electrical power usable in a utility grid network. The major EPGS requirements are summarized as follows:

- Convert the Receiver Subsystem thermal output into 10 MWe net of electrical power at 2:00 pm on the day of worst solar insolation,

- Convert the Thermal Storage Subsystem (TSS) output into 7 MWe net of electrical power or,

- Convert simultaneous thermal outputs from the receiver and the TSS into at least 7 MWe net of electrical power, and

- Condition the working fluid (i.e., pressurize, heat, deaerate, treat chemically, etc., the condensate) and return it to the other subsystems, and

- Respond to transient conditions rapidly enough to avoid adverse effects to the operation of all subsystems.

The first three requirements are specified by ERDA to occur at an ambient site wet bulb temperature of 23 C (74 F).

The Pilot Plant EPGS design presented in this section evolved through several stages including conceptual design, optimization, and preliminary design. During conceptual design, efforts were directed toward developing basic concepts and verifying availability of required equipment. The design developed during this period confirmed the feasibility of the pilot plant EPGS. The conceptual design effort was previouly reported in the April 1976 Summary Report, and the February 1977 Annual Progress Report.

Following the conceptual design effort, the EPGS was subjected to a series of optimization studies which traded costs of equipment changes within the EPGS against resulting cost changes in other plant subsystems. These efforts were reported in the February 1977 Annual Progress Report, and are summarized below in Section IV.B-2.

Proceeding from the optimization phase, completion of design documents constituting a preliminary design was undertaken. These documents form the basis of this report and are included in Appendices A, B, C and E.

The documents are arranged to permit their removal and independent use, if desired.

B. DESIGN DISCUSSION

1. EPGS Parameters and Performance

EPGS performance using receiver and storage steam is summarized in Table II-1. at the front of this volume. These data are based on a cycle consisting of a 12.5 MWe GE admission turbine with wet condenser cooling and four stages of feedwater heating as shown in Figure IV.B-1. Flows, pressures, and temperatures at points shown in Figure IV.B-1 are shown in Tables IV.B-1 and IV.B-2 for the basic receiver steam and storage modes of operation.

The turbine cycle presented is based on General Electric Co. (GE) supplied data with minor modifications to the feedwater heater train to increase feedwater temperature approximately 3 C (5 F). The higher feedwater temperature results in a 32 kJ/kw-hr (30 Btu/kw-hr) improvement in gross heat rate over the GE base data. The reasons for making this change are discussed in Section IV. B-3d.

a. Cycle Configuration - For receiver operation, steam at 9 411 kPa (1365 psia), 510 C (950 F) enters the turbine through the line labelled 3 in Figure IV.B-1. The steam expands through the turbine high pressure section to 2 859 kPa (414.7 psia) where admission valves internal to the turbine regulate the intermediate pressure. The admission steam line (labeled 4) is brought in immediately upstream of the admission valves. During normal receiver steam operation, there is no flow in the admission line. Flow from the admission valves passes through the turbine low pressure section, and is condensed to liquid in the condenser. The liquid is then pumped by the condensate pumps through the low pressure feedwater heater to the deaerator. The booster pumps then pump the feedwater through the high pressure heaters to the suction of the low pressure feedwater pumps. For receiver steam operation, the feedwater is then pumped by the high pressure feedwater pumps to the receiver.

Operation from storage, using the admission steam line, is similar to receiver operation except that all steam is supplied by the line labeled 4 in Figure IV.B-1, and the low pressure and high pressure feedwater pumps are not required. Under this operating mode, feedwater is returned to the TSS by the booster pumps through the line labeled 31. For admission steam operation, approximately 6 800 kg/hr (15,000 lb/hr) of steam is bypassed from the admission steam line to the inlet of the high pressure section. This flow cools the high pressure blading which is not active under this mode

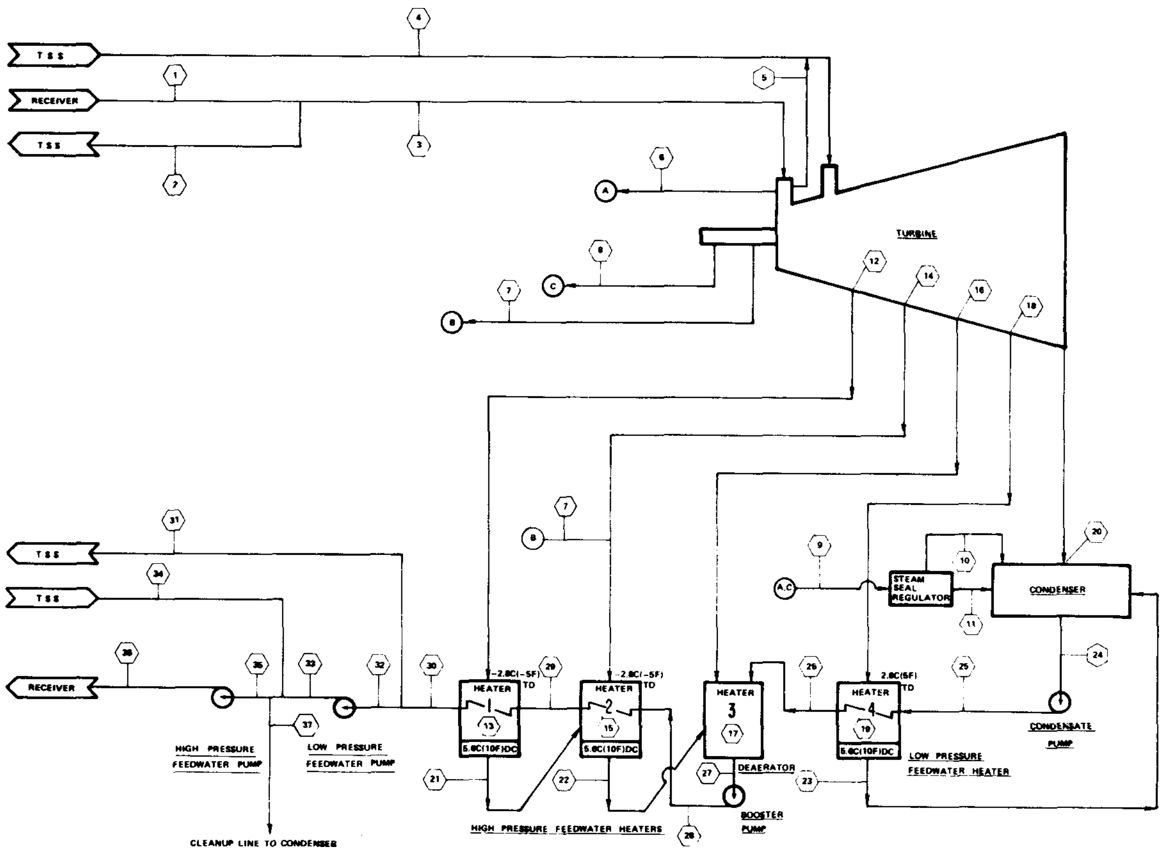


FIGURE IV.B–1 PILOT PLANT TURBINE CYCLE FLOW DIAGRAM

NOTE: POINT IDENTIFICATION REFERS TO FIGURE IV.B–1

ERDA DESIGN POINT, 10MWE NET PLANT OUTPUT GENERATION FROM RECEIVER ALONE (10.955MWE GROSS)

POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
FLOW	1000 KG/HR	47 145	0	47 145	0	0 397	0 269	2 841	0.494	0.762	0.295	0 468	3.590	3.590	0.068	6.500	2.675	47 145	2.931
	1000 LBM/HR	103 936	0	103.936	0	0 875	0 593	6.263	1.089	1.681	0 650	1 031	7 915	7 915	0 151	14.329	5.898	103.936	6.461
PRESSURE	KPA	9411	—	9411	—	9411	9411	6136	6136	131 00	131 00	131 00	2012 79	1912 19	821 17	780.07	268.69	255 31	81.22
	PSIA	1365 00	—	1365 00	—	1365 00	1365 00	890 00	890.00	19 00	19 00	19 00	291 93	277 34	119 10	113.14	38.97	37.03	11 78
TEMPERATURE	C	510.00	—	510.00	—	510 00	510.00	—	—	—	—	—	347 48	210 12	253.71	169.37	154.10	128.12	93.92
	F	950 00	—	950 00	—	950.00	950 00	—	—	—	—	—	657 47	410.21	488.67	336.87	309.38	262 62	201 06
ENTHALPY	KJ/KG	3406.85	—	3406 85	—	3406.85	3406.85	3333.16	3333 16	3359.14	3359.14	3359.14	3132.77	—	2957 70	—	2771 68	—	2606 61
	BTU/LBM	1464.68	—	1464 68	—	1464.68	1464 68	1433.00	1433.00	1444.17	1444.17	1444.17	1346.85	—	1271.58	—	1191.61	—	1120.64

POINT		19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37
FLOW	1000 KG/HR	2.931	34.277	3.590	6.500	2.931	37 970	37.970	37.970	47.146	47 146	47.146	47.146	0	47 146	47.146	0	47 146	47 146	0
	1000 LBM/HR	6.461	75.567	7 915	14.329	6.461	83.709	83.709	83.709	103.936	103.936	103.936	103.936	0	103 936	103.936	0	103.936	103.936	0
PRESSURE	KPA	77.15	9 816	1912 19	780.07	77 15	9 816	689.48	689.48	256.24	4826.33	4826.33	4826.33	—	4826.33	7685.59	—	7685.59	15,407.71	—
	PSIA	11.19	1.424	277 34	113.14	11.19	1 424	100.00	100.00	37 02	700 00	700.00	700.00	—	700.00	1114.70	—	1114.70	2234.70	—
TEMPERATURE	C	92.54	45.48	177 71	134 85	51.27	45 48	45.71	89 77	128 12	129.29	172 15	212.89	—	212.89	213.86	—	213.86	216.53	—
	F	198.58	113.86	351.87	274.73	124 28	113.86	114.28	193.58	262.61	264.73	341.87	415.21	—	415.21	416 95	—	416.95	421.76	—
ENTHALPY	KJ/KG	—	2376.88	753.48	567 36	214.62	190.36	191.34	375.96	538.28	546.40	730.71	911 91	—	911 91	917 26	—	917.26	931.91	—
	BTU/LBM	—	1021.88	323.94	243.92	92 27	81.84	82.26	161.63	231.42	234.91	314.15	392.05	—	392.06	394.35	—	394.35	400.65	—

$$\text{GROSS HEAT RATE} = \frac{103{,}936\ (1464.68\ \ 400.65)}{10{,}966} = 10{,}095\ \text{Btu / Kwh} = 10{,}651\ \text{KJ / Kwh}$$

TABLE IV.B–1

CYCLE PARAMETERS FOR ERDA 10 MWe DESIGN POINT (RECEIVER STEAM)

NOTE: POINT IDENTIFICATION REFERS TO FIGURE IV.B–1

ERDA DESIGN POINT, 7 MWE NET PLANT OUTPUT GENERATION FROM TSS ALONE(7.770MWE GROSS)

POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
FLOW	1000 KG/HR	0	0	0	41 954	0	0	1 106	0 486	0 486	0 295	0 171	3 157	3 157	1.611	5 874	2.306	41.954	2 499
	1000 LBM/HR	0	0	0	92 492	0	0	2 437	1 028	1 028	0 650	0 378	6 961	6 961	3.552	12 950	5.084	92 492	5 510
PRESSURE	KPA	–	–	–	2859 26	–	–	2859 26	2859.26	131 00	131 00	131 00	1989 21	1870.75	766 25	726 98	250 69	238 14	74 05
	PSIA	–	–	–	414 70	–	–	414 70	414 70	19.00	19 00	19 00	285 61	271 33	110 99	105 44	36 36	34.54	10 74
TEMPERATURE	C	–	–	–	426.67	–	–	426.67	426.67	–	–	–	399 99	209 02	293 91	166.48	187 17	125 84	91 43
	F	–	–	–	800 00	–	–	800 00	800 00	–	–	–	751 98	408 24	561 04	331 66	368 91	258 51	196.58
ENTHALPY	KJ/KG	–	–	–	3294 56	–	–	3294.56	3294.56	3294.56	3294.56	3294 56	3249 17	–	3045.29	–	2841 70	–	2680.56
	BTU/LBM		–	–	1416 40	–	–	1416 40	1416 40	1416 40	1416.40	1416.40	1396 89	–	1309 24	–	1221 71	–	1143 83

POINT		19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37
FLOW	1000 KG/HR	2 499	30 808	3 157	5 874	2 499	33 774	33 774	33 774	41 954	41 954	41 954	41 954	41 954	0	0	0	0	0	0
	1000 LBM/HR	5 510	67 919	6 961	12 950	5 510	74 458	74 458	74 458	92 492	92 492	92 492	92 492	92.492	0	0	0	0	0	0
PRESSURE	KPA	70 33	8 9742	1870 75	726 98	70 33	8 9742	689 48	689 48	238 14	4826 33	4826 33	4826 33	4826 33		–	–	–	–	–
	PSIA	10 20	1 3016	271 33	105 44	10 20	1 3016	100 00	100 00	34 54	700 00	700 00	700 00	700 00						–
TEMPERATURE	C	49 52	43 73	174 82	132 57	49 52	43 73	43 96	87 30	125 84	127 01	169 27	211 80	211 80		–	–	–	–	–
	F	121 13	110 72	346 68	270.62	121 13	110 72	111 13	169 14	258 51	260 62	338.66	413 24	413 24	–	–	–	–	–	–
ENTHALPY	KJ/KG	–	2422 44	740 81	557 57	207 29	183 08	184 03	386.58	528.56	538 70	718.16	906.93	906 93	–	–	–	–	–	–
	BTU/LBM	–	1041 46	318.49	239 71	89 12	78 70	79 12	157 17	227 24	230.74	308.75	389 91	389 91	–	–	–	–	–	–

GROSS HEAT RATE $= \frac{92,492(1416.40 - 389.91)}{7,770} = 12,220$ Btu / Kw hr = 12,893 KJ / Kw hr

TABLE IV.B–2

CYCLE PARAMETERS FOR ERDA 7 MWe DESIGN POINT (TSS STEAM)

of operation. The cooling bypass line is not shown on Figure IV.B-1. Some windage loss occurs in cooling the high pressure section blades, but much of the loss is recovered as the cooling steam mixes with the bulk of the admission flow and expands through the low pressure section of the turbine.

Performance curves useful in calculating Pilot Plant EPGS performance under a wide range of operating conditions are shown as Figures IV. B-2, -3, -4, and -5. These curves were used in representing EPGS performance in the Martin Marietta Pilot Plant simulation computer code.

b. Turbine-Generator Startup and Shutdown Considerations - When questioned on the subject of startup of the turbine-generator, GE stated that they currently permit the turbine owner to determine the starting rate using thermocouples in the turbine shell and a life cycle curve as guides. If repeated rapid starts are conducted, turbine life is considerably shortened.

A cyclic life curve applicable to the Pilot Plant turbine is shown in Figure IV.B-6. Because of the smaller mass of metal, the Pilot Plant turbine can be subjected to more rapid temperature transients without affecting life expectancy than the commercial turbine described in Section III.B-3b. A typical daily "hot" startup curve for the Pilot Plant turbine is shown in Figure IV.B-7. Assuming a required 167C (300 F) warmup following sychronization, the startup curve permits more than the 10,000 starts required for a 30 year plant life. No allowance for prewarming of the turbine shell is included in the curve. If starts faster than the approximately 50 minutes shown are desired, prewarming or a more rapid expenditure of the turbine life could be used for that purpose.

Starts from cooler plant ambient conditions require more time, depending on the elapsed time since turbine shutdown. For a "warm" turbine 600 F below its operating temperature, approximately one hour and 20 minutes following sychronization would be required to bring the turbine to full load in a manner consistent with the life expenditures assumed for a hot start. Considering the time required to sychronize the unit, a total elaped time of one hour and 40 minutes is required to complete a warm start.

If the turbine is at cold ambient conditions of approximately 70 F, a warmup time of three hours, following an extended sychronization time of one hour would give a cold start time of approximately four hours. This type of a start would require a life expenditure of the turbine consistent with the hot and warm starts described above.

An additional feature in which the Pilot Plant turbine differs from the Commercial Plant turbine is the amount of cyclic life expenditure resulting from a transition to admission steam from receiver steam and back. This type of transient is likely to occur during rapid cloud passage. Two factors favor the Pilot Plant turbine in this regard. First, the temperature change at the admission steam

NOTE:

THIS PERFORMANCE CURVE INCLUDING THE EFFECTS OF 4 STAGES OF FEEDWATER HEATING

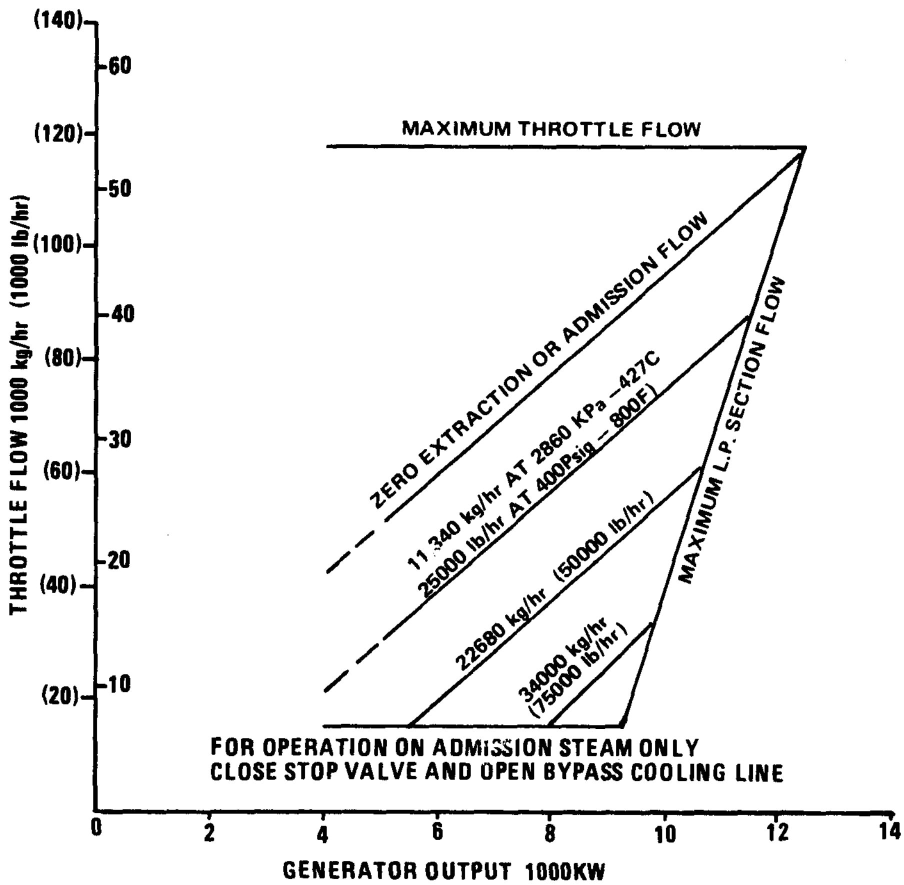


FIGURE IV.B–2 TURBINE GROSS GENERATION VERSUS THROTTLE STEAM FLOW

NOTE: APPARENT LOW PRESSURE SECTION FLOW IS DEFINED AS THE SUM OF THE THROTTLE FLOW AND ADMISSION FLOW

FIGURES ON CURVES DENOTE VALUES OF ADMISSION FLOW

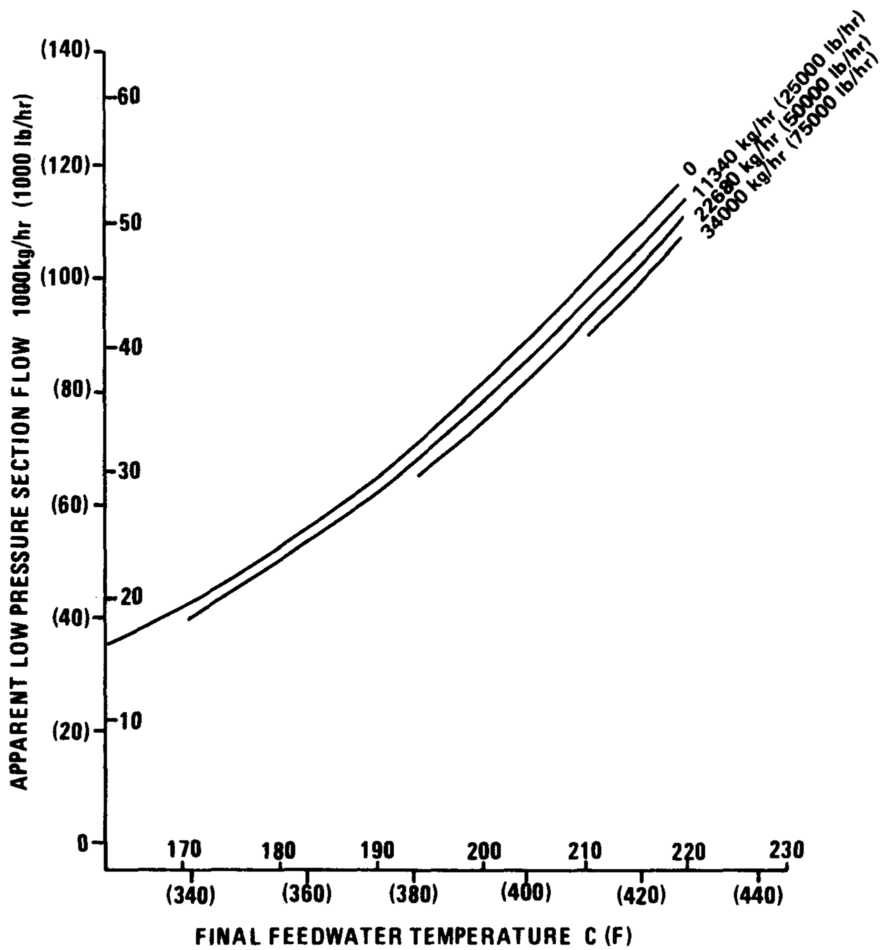


FIGURE IV.B–3 FINAL FEEDWATER TEMPERATURE VERSUS LOW PRESSURE SECTION FLOW

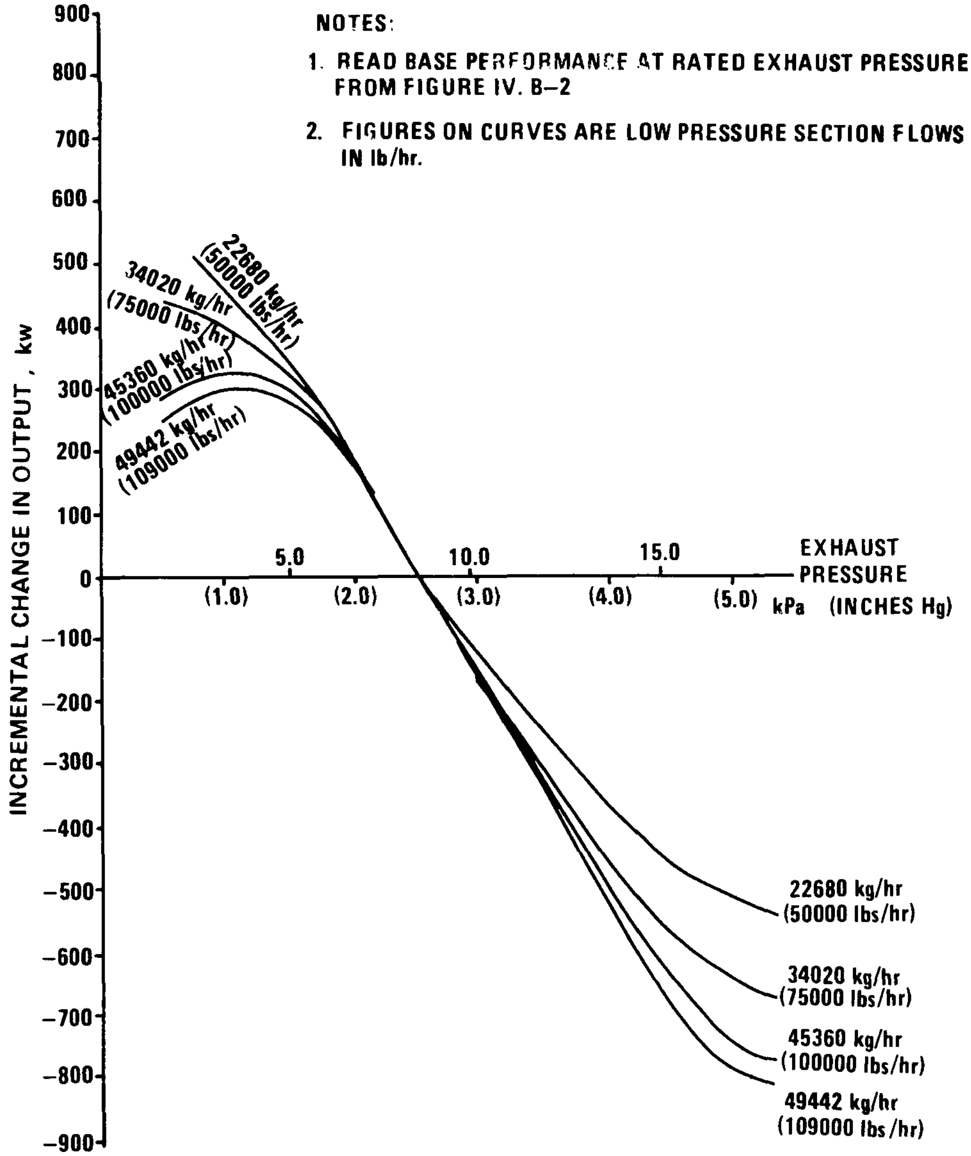
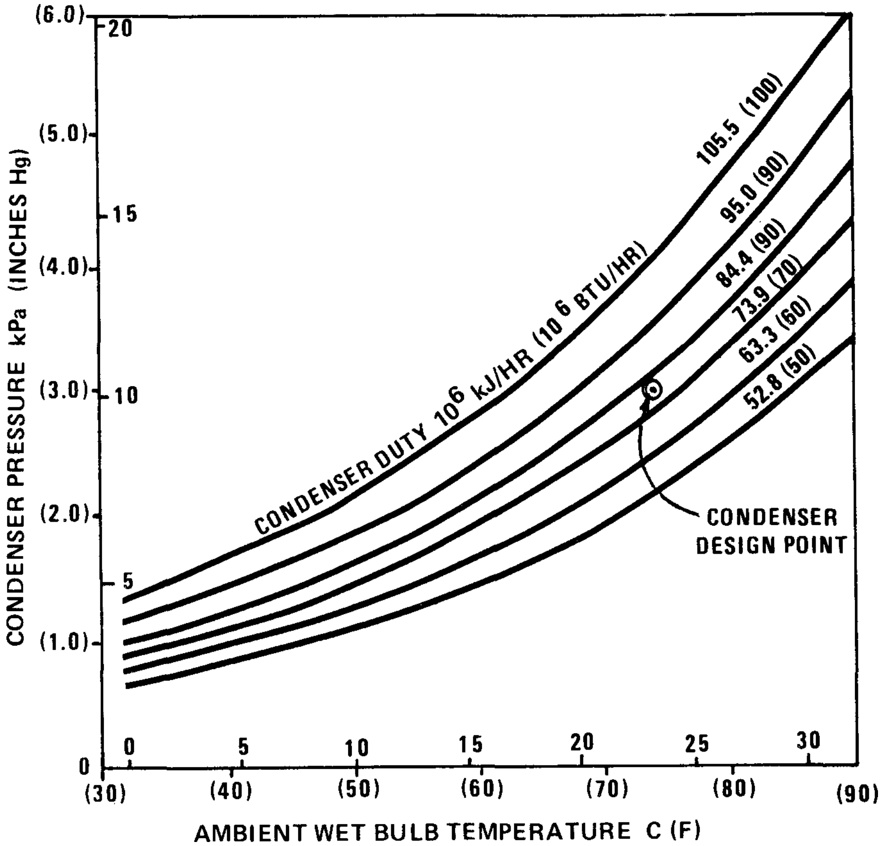


FIGURE IV.B–4 EXHAUST PRESSURE CORRECTION CURVES



NOTES:

1. COOLING TOWER APPROACH ASSUMED TO BE 6C (10F) THROUGH OUT THE RANGE
2. COOLING WATER FLOW RATE IS CONSTANT AT 360 l/s (5700GPM)
3. CONDENSER TUBES ARE 7/8INCH DIAMETER 18 GAUGE ADMIRALTY METAL
4. CONDENSER PERFORMANCE BASED ON HEAT EXCHANGE INSTITUTE STANDARDS

Figure IV.B-5 Condenser Performance as a Function of Wet Bulb Temperature

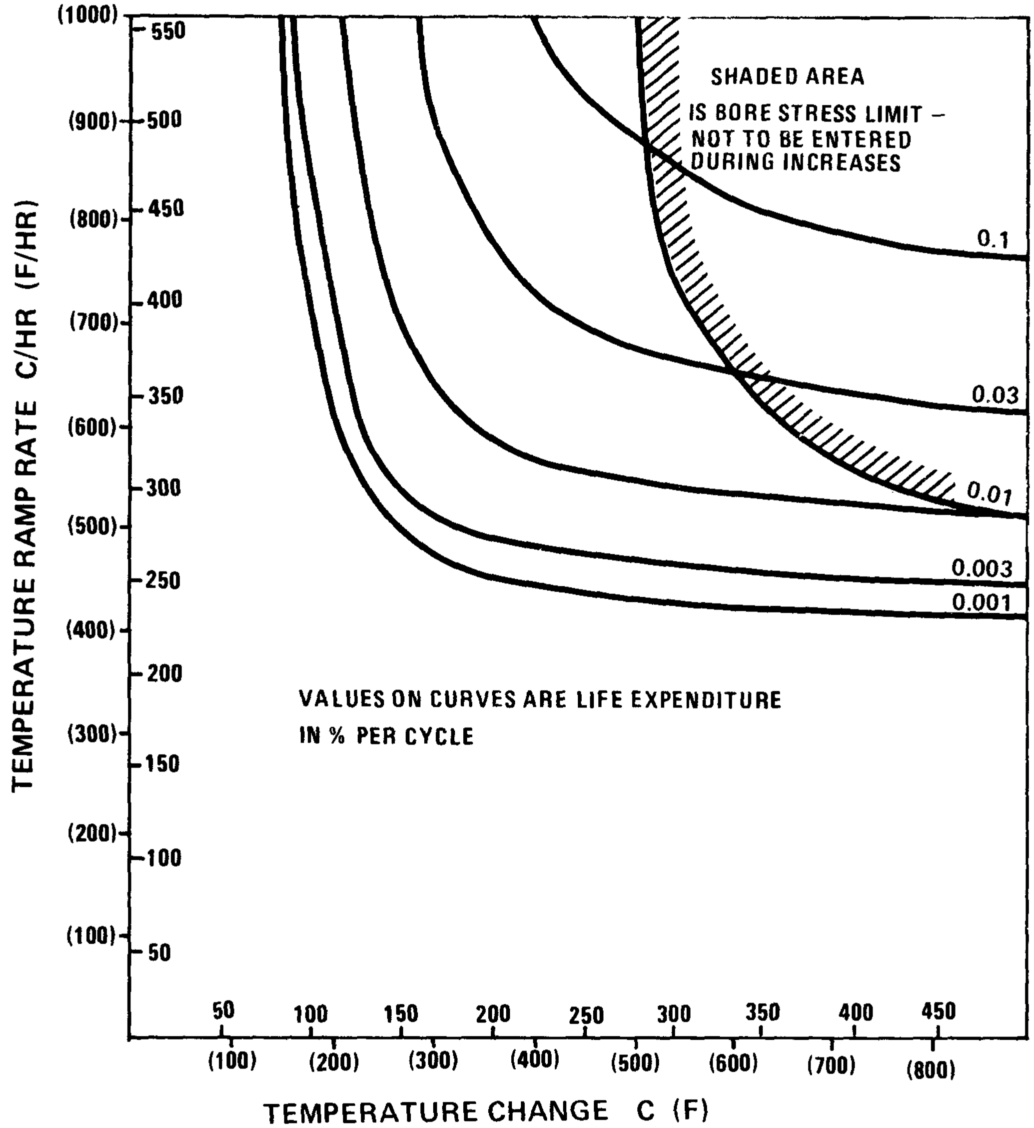


FIGURE IV.B–6 CYCLIC LIFE CURVE APPLICABLE TO 12.5 MWe

PILOT PLANT TURBINE

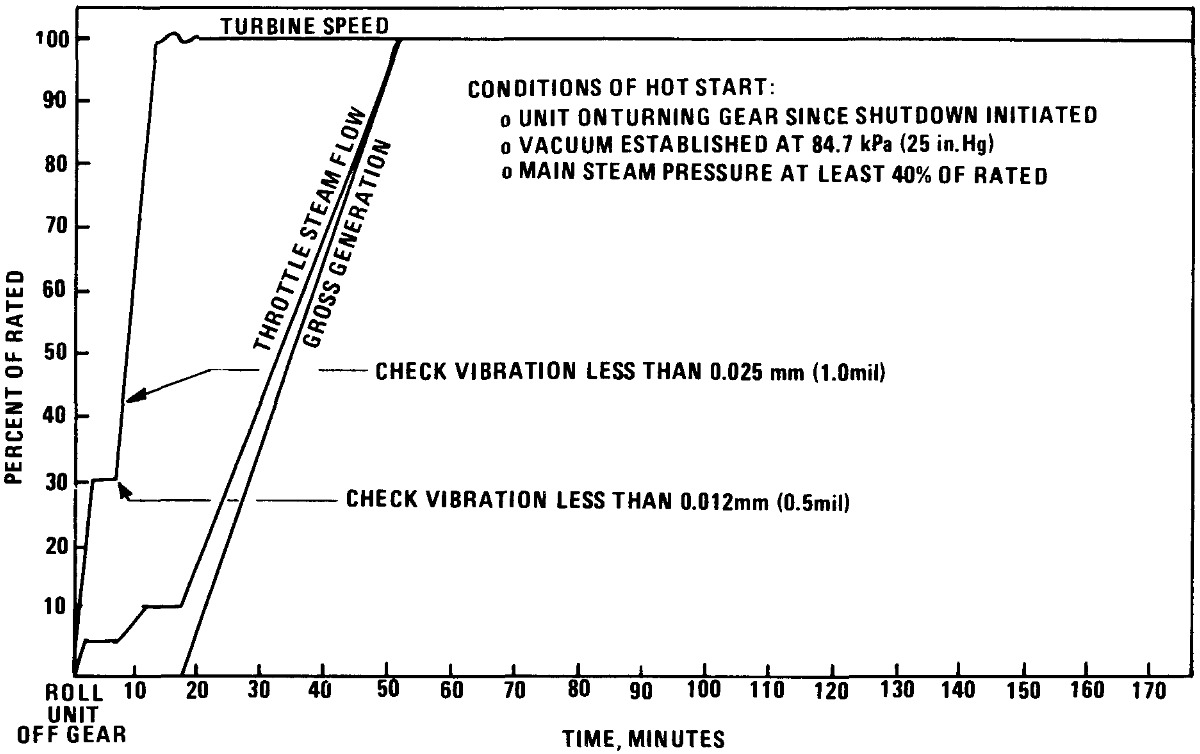


FIGURE IV.B–7 PREDICTED TURBINE STARTING AND LOADING CURVES FOR PILOT PLANT TURBINE
(DAILY HOT START)

inlet during the transient is 57 C (100 F) rather than the 78 C (140 F) for the commercial machine as discussed in Section III. B-3c. Secondly, with the smaller metal mass, the percentage life expenditure for each transition is much smaller than for the commercial machine. As shown in Figure IV.B-6 a 57 C (100 F) temperature change cycle can be tolerated almost indefinitely. This means that automatic transition to admission steam can be considered for cloud passage transients for the Pilot Plant without concern for effects on turbine life.

Shutdown of the turbine should be accomplished in a manner which minimizes cooling of the turbine. A rapid ramp down in generator load, followed by closing of the turbine stop valves and opening of the generator breaker will serve to accomplish this goal.

c. EPGS Auxiliary Loads - As shown in Table II-2, at the front of this volume, Pilot Plant EPGS auxiliary power requirements have been broken into three basic groups: fixed loads, variable loads, and loads associated with feedwater pumping. Feedwater pumping requires the largest portion of the EPGS auxiliary power. This demand decreases with turbine load, reaching a lower limit as the pumps begin to operate on their minimum flow recirculation loops. The exact value of this minimum power requirement is a function of the pumps chosen, but lies in the 30-50% range of the loads shown.

Variable loads include equipment which is cycled on and off during the diurnal cycle in order to meet the operational requirements of the plant. Included in this category are such items as the cooling tower fans and the circulating water pumps, which are normally shutdown at night. These auxiliary loads in this category vary with the mode of operation as shown in Table II-2.

The fixed loads shown in Table II-2 represent equipment which is more or less independent of the plant operating mode. The equipment either runs continuously or periodically cycles on and off to maintain automatically preset operating parameters. Included in this category are such items as the plant heating, ventilating and air conditioning, and plant lighting.

2. Turbine Selection

For consistency with Commercial Plant design, a 3600 rpm GE admission type turbine has been included in the Pilot Plant EPGS design. Performance for the turbine is presented in Table II-1. The turbine chosen has the lowest standard GE rating capacity (12.5MWe) which meets ERDA design requirements for the Pilot Plant. Inlet steam conditions and other operating parameters were chosen to match those of the Commercial Plant. The turbine and its associated control system will permit accurate simulation of all Commercial Plant operating modes. In addition, by adding an external control valve and blocking the internal admission valves open, the admission turbine could also be used to simulate an induction type turbine.

For the Pilot Plant, several turbine manufacturers besides GE can provide small admission (usually known as automatic extraction) type turbines. Manufacturers contacted who could provide the turbine included De Laval, Turbodyne, and Siemens. Aside from GE, only Siemens currently manufactures commercial scale (160 MWe) turbines suitable for solar applications.

As an alternative to the admission turbine approach for the Pilot Plant, Siemens provided technical data for a high speed (9000 rpm) induction type turbine. The high rotational speed permits more efficient turbine blading in the Pilot Plant size range, but requires a reduction gear to drive the electrical generator. Data for the proposed turbine are shown in Table IV.B-3 for operating points near those required for 10 MWe net output on receiver steam and 7 MWe net output on storage steam. The heat rate using receiver steam is better than that for a lower speed (3600 rpm) turbine. However, because the external storage steam inlet valve acts as a full arc inlet to the turbine low pressure section, the heat rate for storage operation is poorer than that for a similarly sized admission turbine operating at the same electrical load.

Siemens states that their approach results in a less expensive turbine than the admission type turbine, which they also manufacture. For the commercial size turbine, Siemens would normally provide a 3600 rpm induction design, rather than the 9000 rpm machine advocated for the Pilot Plant. A discussion of the applicability of the induction turbine to commercial plants is included in Section III.B-3b.

3. Optimization Studies

Determination of cycle parameters such as turbine inlet pressures and temperatures involved subsystem cost trades based on both Commercial and Pilot Plant considerations. Because several subsystems were often involved, the overall contractor, Martin Marietta, performed several of the studies using subsystem performance and cost data provided by Bechtel and other contractors. Within a given subsystem, cost trade studies were performed by the responsible contractor. A summary of the studies pertinent to the EPGS is presented below.

To facilitate the optimization, an existing Bechtel computer code was modified using in-house funds to permit calcalation of turbine cycle performance of the Pilot Plant. GE cooperated by providing the data necessary to complete the program modifications. The program was then used to calculate the performance changes caused by the variation of selected cycle parameters.

Table IV B-3

Performance of High Speed Induction Turbine

	11 MWe (gross) Receiver Steam Operation	8 MWe (gross) Storage Steam Operation
Gross Heat Rate kJ/kw-hr (Btu/Kw-hr)	10483 (9936)	13753 (13036)
Inlet Steam Flow kg/hr (lb/hr)	46,800 (103,176)	46,800 (103,176)
Inlet Steam Pressure kPa (psig)	9410 (1350)	2860 (400)
Inlet Steam Temperature C (F)	510 (950)	426 (800)
Number of Stages of Feedwater Heating	4	4
Feedwater Temperature C (F)	220 (428)	220 (428)
Condenser Pressure, kPa (Inches HgA)	8.5 (2.5)	8.5 (2.5)

a. Turbine Receiver Steam Inlet Conditions - Selection of the 9 411 KPa(1350 psig), 510 C(950 F) receiver steam inlet conditions by Martin Marietta involved consideration of the receiver, the turbine-generator, and the TSS. Receiver metallurgy and design, turbine metallurgy and design, and TSS hot oil temperatures all have an influence on this selection. Studies indicated that the turbine-generator was not the limiting factor in design pressure determination. Commercial and Pilot Plant turbines of the GE admission design could be built with single wall casings up to 10 100 kPa (1465 psia), which is 690 kPa (100 psi) above the pressure selected by Martin Marietta. Turbines could also be built for higher pressure ratings, but their casings would be more sensitive to diurnal thermal cycling encountered in solar operation.

The 510 C (950 F) turbine inlet temperature for receiver steam operation is based on recommendations from GE and other turbine manufacturers. For turbines subjected to cyclic service, metallurgical considerations indicate a temperature limit of 510 C (950 F) is a prudent maximum for the available alloys and manufacturing techniques. Coincidently, the receiver has similar temperature limitations, so that, even if the turbine temperature limit were relaxed, a significant increase in design temperatures would not result.

During the pressure and temperature selection studies, guidance regarding the effects of these variables on commercial and Pilot Plant EPGS performance was provided to Martin Marietta by GE and Bechtel.

b. Turbine Admission Steam Inlet Conditions - Like receiver steam conditions, determination of turbine admission steam inlet conditions of 2859 kPa(414.7 psia), 427 C(800 F) required coordination of cost trades among several subsystems. For this reason Martin Marietta also coordinated the determination of these conditions. Cost trades involved include direct effects upon the EPGS and TSS system costs, and strong indirect effects on the total costs for receivers and collectors, especially when the Commercial Plant is considered.

Within the EPGS, the cost of the turbine-generator and associated equipment was found to be relatively insensitive to admission steam conditions. A study of the turbine expansion line indicated that a 427 C (800 F) inlet temperature provided a relatively good temperature match to internal turbine steam temperaturer over the admission pressure range of 2859 kPa to 4238 kPa (414.7 to 614.7 psia). This knowledge, and guidance regarding the effects of changing admission steam temperature and pressure on EPGS performance, were provided to Martin Marietta for use in the selection study.

c. Condenser and Heat Rejection System Selection - During initial phases of the optimization studies, air cooled condensers were used to assure maximum plant siting flexibility. This option is still open, especially with regard to commercial facilities.
An ERDA letter dated Nov. 3, 1976 stated that an adequate water

supply would be available at the Pilot Plant site for wet cooling of the condenser. Accordingly, the EPGS design was changed to include a conventional water cooled condenser, mechanical draft wet cooling towers, and associated piping and pumps. In addition the turbine design was changed by GE to better utilize the lower condenser pressures associated with wet cooling. The turbine design change consisted of lengthening the last stage blading of the turbine from 0.254 m (10 inches) to 0.290 m (11.4 inches). The change from dry to wet cooling improved the turbine gross heat rate by 5 to 6 percent, depending on the particular operating condition under consideration.

d. <u>Feedwater Heater Optimization</u> - Feedwater heater train performance was studied to find the preferred number of stages, and optimum surface areas. Performance was calculated using the modified turbine cycle heat balance program; the conceptual turbine cycle was used as a basis. Performance gains and losses were traded against costs in the EPGS, the TSS, and the Collector Subsystem. Feedwater heater cost differentials were based on data supplied by two feedwater heater manufacturers. Results of the study have been applied to the current turbine cycle and are an integral portion of the performance data shown in Table II-1.

Specific recommendations regarding feedwater heaters included the following:

- Use of four stages of feedwater heating
- Sizing of heater surface areas to produce the terminal temperature differences and drain cooler approach temperatures indicated in Figure IV.B-1.

Computer performance calculations and cost data were used to compare three, four and five stages of feedwater heating. Results indicated that the conceptual design selection of four stages was appropriate, and should not be changed from the conceptual design.

Heater surface areas were then examined in a separate study using similar techniques to determine optimum terminal temperature differences and drain cooler approach temperatures.

Feedwater heater terminal temperature difference is a measure of heater overall performance, and is defined as the difference in temperature between steam condensing in the heater shell and feedwater leaving the heater. For a heater with a condensing zone but no desuperheating zone, such as the lowest pressure heater, the theoretical maximum performance would be acheived with a terminal difference of 0 C (0 F). This performance is not economic in practice, however, because the heat transfer surface required tends toward infinity. For heaters with desuperheating zones, such as the higher pressure heaters, negative terminal differences are possible.

Drain cooler approach temperature is defined as the difference in temperature between drains (condensate) leaving the feedwater heater shell and feedwater entering the heater. It is a measure of drain cooler performance. Approach temperature is usually limited to a minimum of 5.6 C (10 F) in practice. Lowering of approach temperatures below 5.6 C (10 F) could be achieved by use of a drain cooler external to the heater; however, results indicated that there would be no economic advantage to do so.

e. Pump Selection Studies - Three pump optimization studies were undertaken to determine the most economic configuration of the Pilot Plant EPGS feedwater system, including:

- The possible elimination of the low pressure feedwater pumps from the EPGS

- The study of two full capacity pumps vs. three half capacity pumps each for the condensate pumps, booster pumps, and high pressure boiler feedwater pumps

- A comparison of centrifugal vs. reciprocating pumps

The first study was directed at the possibility that plant complexity, and thus overall plant costs, could be minimized by reducing the number of EPGS pumps in series. The second study was based on the consideration that larger power plants often utilize three pumps in parallel for each service, with less than full capacity in each pump. These two alternatives were analyzed on the assumption of equal reliability, i.e., either system could function with a single pump out of service. Finally, reciprocating pumps were evaluated for possible reductions in capital cost and pumping power requirements.

Study of the elimination of the low pressure feedwater pumps indicated a strong possibility that these pumps could be eliminated during the final design phase. However, for preliminary design purposes, these pumps were retained to assure maximum flexibility within the EPGS. Two factors which influence the inclusion of the pumps in the cycle are the following:

- If a large pressure difference exists between the TSS supply pressure for the discharge mode and the feedwater return pressure for the TSS charge mode, the low pressure feedwater pumps serve to minimize required system throttling losses and thus increase plant efficiency.

- Pump selection is often a factor of a pump manufacturer's available off-the-shelf components. Depending on the pressure levels determined during final design, some manufacturers may be able to offer a lower bid price by including the low pressure feed pumps.

These factors aside, the elimination of the low pressure pumps would result in a less complex cycle with lower piping costs, and would release building volume for other uses. Unless strong economic incentives are found during final design the pumps should be eliminated from the cycle arrangement.

The study of two full capacity vs. three half-capacity pump trains showed the two train arrangement to be the most cost-effective. The efficiency of the full-capacity pumps was found to be better at the ERDA 10 MWe and 7 MWe design point operating conditions. In addition, the unit cost for full and half capacity pumps in the general size range was found to be about the same, giving a definite advantage to the full capacity pumps.

On the basis of preliminary design results obtained from one pump manufacturer for reciprocating and centrifugal high pressure boiler feedwater pumps, centrifugal pumps are recommened for the EPGS feedwater system in lieu of reciprocating pumps.

One major reason for selecting centrifugal pumps is that centrifugal pumps would likely be installed in a commercial scaled-up version of the 10 MWe solar Pilot Plant. Selection of centrifugal pumps over reciprocating pumps for the Pilot Plant would thus allow better prediction of EPGS feedwater system operating characteristics for the larger plant.

Additional disadvantages of reciprocating pumps cited by the manufacturer were: approximately 10 percent higher pump and motor costs, a pump horsepower requirement of approximately 600 kW (800 hp) as compared to approximately 300 kW (400 hp) for a centrifugal pump at high pressure feed pump rating conditions, and a size of approximately 2 m (6 ft) width x 3 m (10 ft) height x 9 m (24 ft) length, as compared to 0.6 m (2ft) x 1 m (3 ft) x 2 m (6 ft) for a centrifugal pump. In addition, a greater maintenance requirement is expected by reciprocating pumps.

The high pressure feed pumps were selected for this analysis because they represent the largest capital cost and require the greatest pump power in the cycle. Although condensate pumps and booster pumps were not considered in the study, the results are considered applicable to the entire cycle.

C. DESIGN DESCRIPTION

1. Introduction

A major effort during the preliminary design phase was directed toward developing design documents for the mechanical, electrical, and control systems within the Pilot Plant EPGS. These documents extend and update the conceptual design as presented in earlier reports. Goals of the design effort were the following:

- Provide information and data useful in more accurate estimation of Pilot Plant costs

- Provide a basis for ERDA evaluation of the EPGS design as presented by the Martin Marietta team

- Provide documentation of the EPGS preliminary design for use in developing the final design.

This report section is intended to introduce the completed preliminary design, and provide guidance regarding the contents of the design documents which are included as appendices to this volume.

2. Design Documents

The design documents developed for the preliminary design are provided in the appendices, and they are representative of the design documents normally prepared by Bechtel for conventional power plants. These documents are:

- System descriptions (Appendix A)

- System diagrams (Appendix C)

- Flow diagrams (Appendix C)

- Control mode diagram (Appendix C)

- Electrical single line diagrams (Appendix C)

- General arrangement drawings (Appendix C)

- Mechanical and electrical equipment list (Appendix E)

System design detail varies from system to system, with emphasis being placed on the components and systems directly associated with electric power generation.

Since in all likelihood the Pilot Plant will be built using current U.S. engineering and construction practices, the design material presented in the Appendices places emphasis on currently used English engineering units. The use of metric units in these documents could lead to confusion regarding intent during the final design phase and were therefore avoided.

The system description documents contained in Appendix A include sections covering system functions, design bases, operating modes, and equipment data. Also included is a "Design Notes" section in which the system designer directly transmits information that may be of use to a reviewer or to the final designer.

System diagrams included in Appendix C are modeled after the piping and instrumentation diagrams (P&IDs) normally prepared in power plant design work. The system diagrams differ from P&IDs in that no individual sequence numbering of valves and instruments, which is primarily of interest in final design coordination, has been undertaken. During final design, the system diagrams could be easily expanded to become P&IDs.

Flow diagrams are design tools intended to show the overall flow paths, rates, temperatures, pressures, and are the bases for system diagrams or P&IDs. Flow diagrams have been developed for the Main Steam and Feedwater Systems as well as the Plant Support Systems. In the latter case, they also serve as schematic representations of those systems for which system diagrams were not preparaed.

A control mode diagram, indicating the approach for controlling the EPGS, is presented in a form similar to computer flow charts, allowing ready adaptation if desired of the EPGS controls to computer controlled startups, mode changes, and shutdowns. In addition, the diagrams assure that adequate control provisions are included in the design for all operational modes, whether manual or automatic modes are selected. This diagram is an exception in that the method of presentation was developed specially for the EPGS preliminary design. The normal method of presentation for power plant design, logic diagrams employing Boolian logic symbols, were found to be lengthy and difficult to read at the preliminary design level.

The electrical single line diagrams facilitate equipment identification and cost estimates and also permit analyses of the effects of electrical component failure on the availability of the plant. These diagrams, like the system diagrams, are slightly simplified versions of the final design documents, and could be easily expanded during final design.

The general arrangement drawings show the positions of various major pieces of equipment within the EPGS structure. These drawings permit detailed coordination of relative positions of equipment within the structure in order to assure both proper and efficient operation of the equipment. For the preliminary design, these drawings also facilitate more accurate cost estimates of the structure.

A mechanical and electrical equipment list is included in Appendix E. This list can be used as an aid in locating specific pieces of equipment on the drawings.

3. EPGS Systems and Support Systems

The system breakdown chosen for the Pilot Plant preliminary design is the following:

- Main steam system, including the turbine-generator, main condenser, and associated equipment.

- Feedwater system, including feedwater heaters, feedwater pumps, and other components involved in processing and treating the receiver feedwater.

- Plant support systems, including component cooling water, compressed air, fire protection, and similar support systems normally associated with similar industrial facilities.

- Electrical system, including the main generator, switchgear, transformers, and similar electrical components.

- Control systems, including turbine generator controls and other controls that lie within the boundaries of the EPGS.

The first two systems are directly involved with the power generating functions of the plant. The remaining systems, while they are an integral part of EPGS operation, also provide support functions for other portions of the plant. These systems and their relationship to the EPGS are discussed below.

a. Main Steam System - The turbine-generator and its support equipment comprise the major portion of the Main Steam System. Included are the turbine-generator, the turbine steam seal system, the turbine control system, the turbine lube oil system, and associated piping and valves. Also included in the preliminary design are the main condenser, the circulating water system, and the cooling tower. A detailed discussion of this system and is operation is included in System Description SD-4 in Appendix A. The pertinent System Diagram M-1366, is found in Appendix C. Operating conditon can be found on Flow Diagram M-1381 in Appendix C.

For purposes of preliminary design, the GE turbine was chosen as typical. GE cooperated by supplying drawings and data for recently manufactured units which closely resemble the turbine projected for use in the Pilot Plant.

In the event a GE turbine is not chosen during final design, the systems described can be viewed as a turbine manufacturers' typical design, since most items shown will be furnished in one form or another by any turbine manufacturer selected. Other items (pumps, cooling towers, etc) can also be view as typical designs pending selection of a supplier.

b. Feedwater System - The Feedwater system consists primarily of the feedwater pumps, the feedwater heaters, the condensate demineralizer and associated piping and valves. This system heats and conditions the feedwater returning to the receiver or the TSS. System Description SD-5 in Appendix A provides detailed information on the system.

Design details and operating parameters can be found on Drawings M-1367 and M-1381 in Appendix C.

As stated in Section IV.B-3 the low pressure feedwater pumps P 103 A and B are strong candidates for elimination during the final design phase.

c. Plant Support Systems - The normal support systems associated with an industrial facility have been considered together in a single System Description, SD-3, included in Appendix A. These systems support both the EPGS and other Balance of Plant equipment. Flow diagrams for these systems are included as Drawings M-1382 through M-1391 in Appendix C.

Systems included in this category are the following:

- Demineralized makeup water supply system
- Component cooling water system
- Compressed air system
- Plant heating, ventilation, and air conditioning system
- Cranes and hoists
- Fire protection system
- Domestic water system
- Sanitary drainage system
- Acid waste system
- Oily waste system
- Auxiliary boiler

Because of the conventional nature of these systems, the preliminary design effort has been limited to preliminary determination of major system parameters. Refinement of design details for actual site conditions is expected during final design.

d. Electrical System - Like the plant support systems, the Electrical System serves both the EPGS and other Balance of Plant components. The primary EPGS component considered to be included in the system is the main generator. System Description SD-1 included in Appendix A gives a detailed description of this system. Electrical single line diagrams E-1368, sheets 1 through 8 which cover this system are included in Appendix C.

e. Control System - The EPGS Control System is centered around the control system of the turbine-generator. A description of the turbine controls and other controls assumed for preliminary design are included System Description SD-2 in Appendix A. A diagrams illustrating the EPGS control modes is included in Appendix C as drawing C&I 1369.

4. EPGS Arrangement

Arrangement of the equipment within the Pilot Plant EPGS structure is shown in Figures IV.C-1 and 2. Further sectional views are included in Appendix C as drawings P-1362, sheets 1 and 2.

The EPGS structure contains the turbine-generator and much of the mechanical, control, and electrical equipment associated with electrical power production. The equipment is arranged for simplicity and efficiency while considering the physical limitations imposed on the design by the equipment characteristics.

The ground floor shown in Figure IV.C-1 contains the feedwater pumps, electrical gear, and other support equipment which can be conveniently located at this plant elevation. This location was chosen for the feedwater pumps to maximize the suction head available to the pumps. In the case of the condensate pumps, this level provides the only possible location since saturated liquid condensed in the condenser hotwell is the working fluid. The suction head required to pump this fluid is achieved by suspending the impellers of the vertical centrifugal pumps in openings provided in the base slab.

The electrical gear and other equipment are placed on the ground floor in order to achieve weather protection which would not be achieved in more open areas of the plant. If during final design this area were opened by removing the protective siding from the design, an upgrading of all gear to outdoor ratings would be required.

Rollup doors are placed adjacent to the pumps and the condenser tube pull space to facilitate equipment maintenance.

The operating floor shown on Figure IV.C-2 contains the turbine-generator, the closed feedwater heaters (E 101, 102, 104) and the condensate demineralizer. The turbine-generator is located

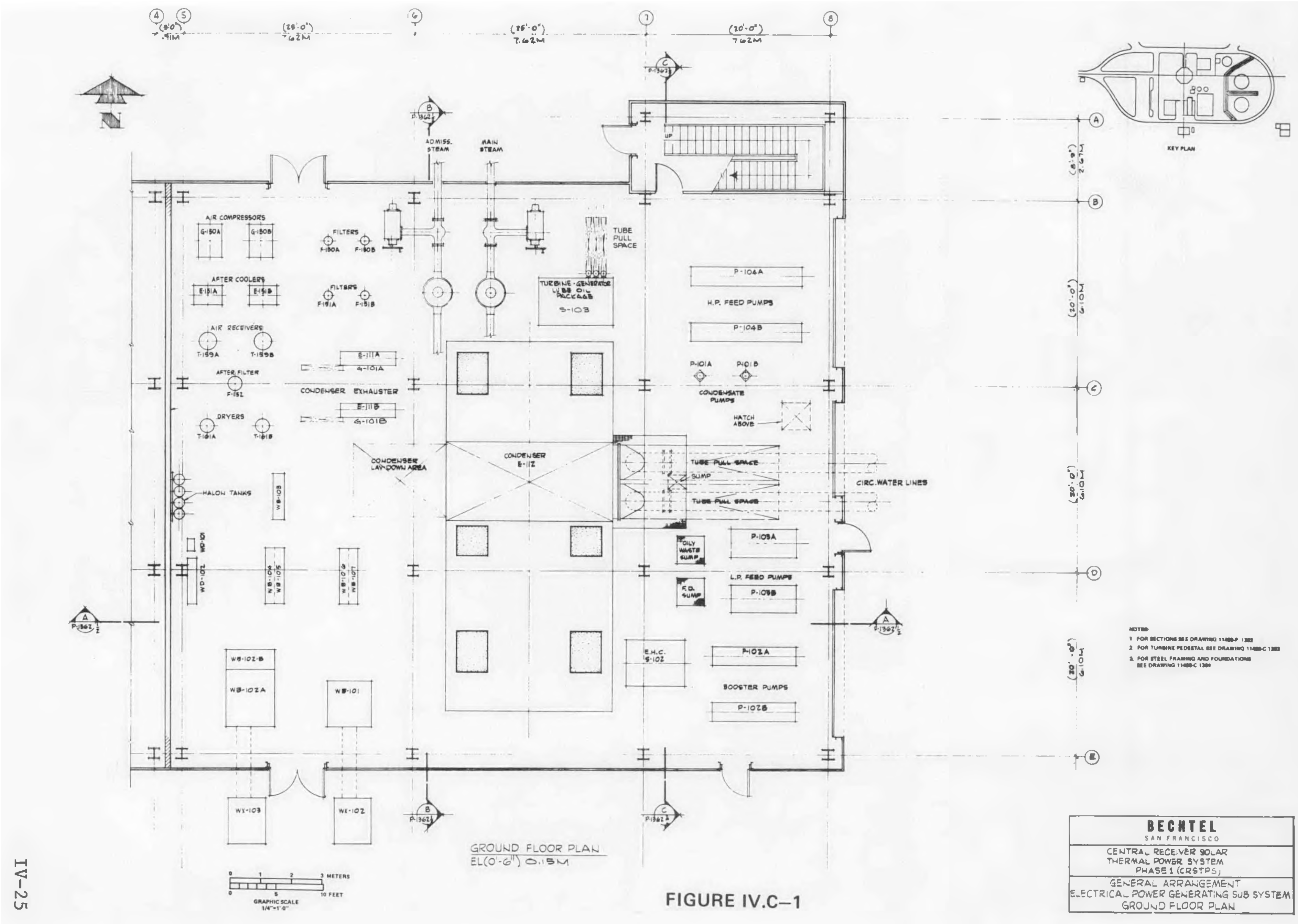
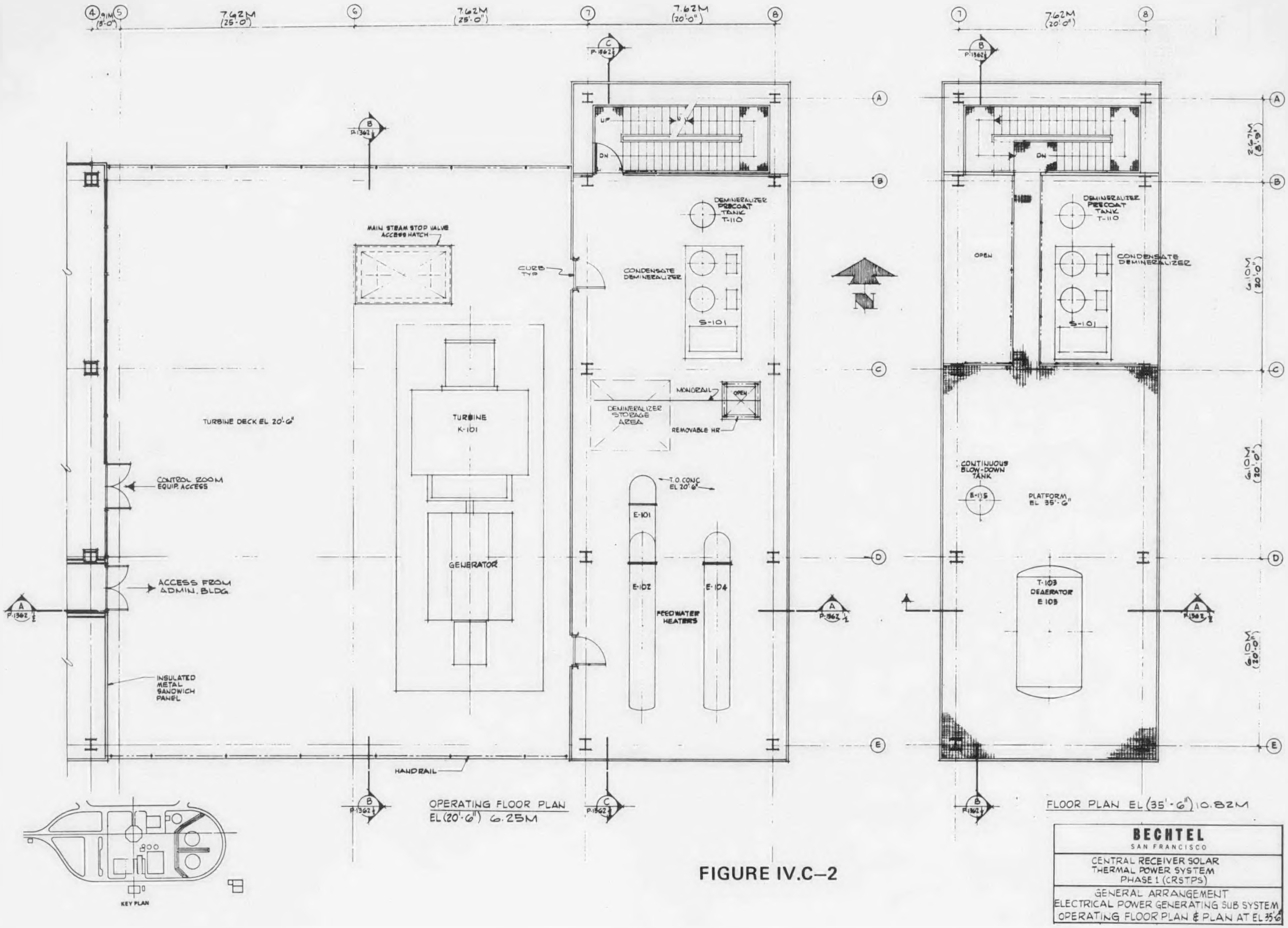

GROUND FLOOR PLAN
EL(0'-6") 0.15M
BECHTEL
SAN FRANCISCO
CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM PHASE 1 (CRSTPS)
GENERAL ARRANGEMENT
ELECTRICAL POWER GENERATING SUB SYSTEM
GROUND FLOOR PLAN
KEY PLAN
AIR COMPRESSORS
AFTER COOLERS
AIR RECEIVERS
AFTER FILTER
DRYERS
FILTERS
CONDENSER EXHAUSTER
HALON TANKS
ADMISS. STEAM
MAIN STEAM
TUBE PULL SPACE
TURBINE-GENERATOR LUBE OIL PACKAGE
S-103
CONDENSER LAY-DOWN AREA
CONDENSER E-112
H.P. FEED PUMPS
P-104A
P-104B
P-101A
P-101B
CONDENSATE PUMPS
HATCH ABOVE
SUMP
CIRC. WATER LINES
OILY WASTE SUMP
F.D. SUMP
L.P. FEED PUMPS
P-103A
P-103B
E.H.C. S-102
BOOSTER PUMPS
P-102A
P-102B
WB-102-B
WB-102A
WB-101
WX-103
WX-102
GRAPHIC SCALE 1/4"=1'-0"
METERS
FEET
NOTES:
1. FOR SECTIONS SEE DRAWING 11488-P 1362
2. FOR TURBINE PEDESTAL SEE DRAWING 11488-C 1362
3. FOR STEEL FRAMING AND FOUNDATIONS SEE DRAWING 11488-C 1364

FIGURE IV.C–1



OPERATING FLOOR PLAN
EL (20'-6") 6.25M
FLOOR PLAN EL (35'-6") 10.82M
TURBINE DECK EL 20'-6"
MAIN STEAM STOP VALVE ACCESS HATCH
TURBINE
K-101
GENERATOR
CONTROL ROOM EQUIP. ACCESS
ACCESS FROM ADMIN. BLDG.
INSULATED METAL SANDWICH PANEL
HANDRAIL
CURB TYP
DEMINERALIZER PRECOAT TANK
T-110
CONDENSATE DEMINERALIZER
S-101
MONORAIL
OPEN
DEMINERALIZER STORAGE AREA
REMOVABLE HR
T.O. CONC EL 20'-6"
E-101
E-102
E-104
FEEDWATER HEATERS
UP
DN
CONTINUOUS BLOW-DOWN TANK
E-115
PLATFORM EL 35'-6"
T-103
DEAERATOR
E 103
N
7.62M (25'-0")
7.62M (20'-0")
.91M (3'-0")
2.67M (8'-9")
6.10M (20'-0")
KEY PLAN
BECHTEL
SAN FRANCISCO
CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM PHASE 1 (CRSTPS)
GENERAL ARRANGEMENT
ELECTRICAL POWER GENERATING SUB SYSTEM
OPERATING FLOOR PLAN & PLAN AT EL 35'6"

FIGURE IV.C–2

on an open deck which provides laydown space for turbine disassembly, while the remainder of the equipment is located in a closed bay at the end of the structure.

The open location of the turbine-generator facilitates maintenance and disassembly using a portable crane. Laydown space for for parts removed during disassembly is provided on the open deck.

Location of the feedwater heaters and condensate demineralizer as shown provides several advantages when compared to alternate designs. First, since the feedwater pumps are immediately below, short piping and control wiring runs within the building are assured. In addition the feedwater heater location assures sufficient gravity head to drive feedwater heater dump lines to the condenser, especially at low plant loads when pressure differentials within the cycle are comparatively small.

The upper level of the EPGS structure shown at the right of Figure IV. C-2 houses the deaerating feedwater heater E-103 and the continuous blowdown tank E-115. The deaerator is located at an elevation approximately 10 m (33 ft) above the booster pumps in order to assure the minimum suction head required by the booster pumps. Attempts to place the deaerator at a lower elevation would result in pump cavitation and subsequent damage.

The continuous blowdown tank is located in the vicinity of the deaerator in order to permit steam and heat recovery as the blowdown liquid flashes into steam in the blowdown tank. Steam produced in the blowdown tank is piped to the deaerator where it serves to heat feedwater. The alternate steam vent for the blowdown can easily be routed through the roof of the structure at this elevation.

5. Startup Test Plan

During preliminary design, a preliminary test plan covering startup of the EPGS was also developed. This plan is included as Appendix B. The plan covers the startup of the EPGS beginning with the turnover of equipment from the construction contractor through normal plant operations.

D. RELIABILITY, TECHNICAL RISK, AND SAFETY

1. Reliability

A high level of reliability for the Pilot Plant EPGS has been assured by providing redundancy for major active plant components such as pumps. In addition many passive components such as heat exchangers are provided with full capacity spares. Where the plant can be operated without a component in service, which is the case with the closed feedwater heaters, bypasses are provided to permit continued operation of the plant.

Normally, the turbine-generator manufacturer includes as standard equipment spares for vital support equipment. Such spares are provided for the lube oil pumps, the hydraulic fluid pumps, and various heat exchangers. Some items, such as spare seal steam exhausters can be ordered as optional extras.

One situation where full capacity redundancy is not provided is the circulating water pumps which circulate water from the cooling tower to the condenser. Redundancy in the area was considered unnecessary since failure of a pump during normally encountered ambient wet bulb temperature conditions results in a comparatively small derating of the plant capacity.

An additional effect favoring EPGS reliability and availability is the ability to repair and maintain equipment during overnight shutdowns. Any equipment which fails during daily operational cycles can be repaired with minimum impact on plant availability during the next nightly shutdown.

2. Technical Risk

The Pilot Plant EPGS resembles in many respects the small steam electric power plants found at industrial facilities such as remote pulp mills and chemical plants. For this reason virtually all EPGS component designs are backed with a substantial amount of engineering and operational experience. This tends to minimize technical risk associated with the EPGS.

The only area where some risk may be encountered is in the area of turbine controls and their interactions with adjacent subsystems. Even this area is not without experience, however, since some industrial facilities regularly operate their automatic extraction turbines in the admission turbine mode in order to utilize excess process steam. The experience of the turbine manufacturer in these instances will be directly applicable to admission steam operations with the pilot plant turbine.

Pumps and other equipment in the EPGS fall well within the existing range of supply of equipment manufacturers. Minimum technical risk is anticipated if normal procurement practices are followed.

3. Safety

Safety within the EPGS is expected to be comparable with industrial power facilities of similar size. No new processes or new hazardous substances are indicated by the EPGS preliminary design. Pertinent state, local, and national regulations, as well as insurance company requirements, will act to assure safety of the operating personnel. The preliminary design indicates that no hazard to the general public is present within the EPGS.

V. PILOT PLANT BALANCE OF PLANT

A. INTRODUCTION

The preliminary design for the Central Receiver Solar Thermal Pilot Plant (CRSTPP) is divided into five major subsystems; namely, the Collector, Receiver, Thermal Storage Subsystem (TSS), Master Control, and Electrical Power Generation Subsystem (EPGS).

To provide for the civil arrangement of these major subsystems as well as the interfaces of piping, wiring, and roadways between them, an additional design category was designated as Balance of Plant (BOP). Also included in BOP are all special structures and site developments that are not specifically included as part of the subsystem designs. Accordingly, the material presented in this section covers the plot plan, main roads, drains, buildings, plant electrical, EPGS and BOP controls, piping, and other plant support systems.

Collector field wiring, drainage, and roads are not included here since these features represent a significant part of the plant total cost that can be attributed to the collector subsystem. Other BOP systems described here are either not easily segmented to apply to specific plant subsystems or they are not considered to be major cost factors of those subsystem.

Subsections are also included here for the convenience of the reviewer, covering design bases, reliability, technical risk, and safety.

B. DESIGN DESCRIPTIONS

1. Architectural Considerations

In developing a preliminary design responsive to the ERDA design criteria, the opportunity existed to address the architectural considerations of this first solar power plant. In addition to introducing these considerations into the plant design features, an artist's rendering of the Martin Marietta preliminary design pilot plant has been prepared under the project architect's supervision. This rendering is included here as Figure V.B-1.

The uniqueness of this plant, designed to produce electric power from solar energy, is identifiable by the major elements of the system--the horizontal field of mirrors (collectors) and the vertical receiver tower. The symmetrical and axial relationship of these elements forms the principal design feature.

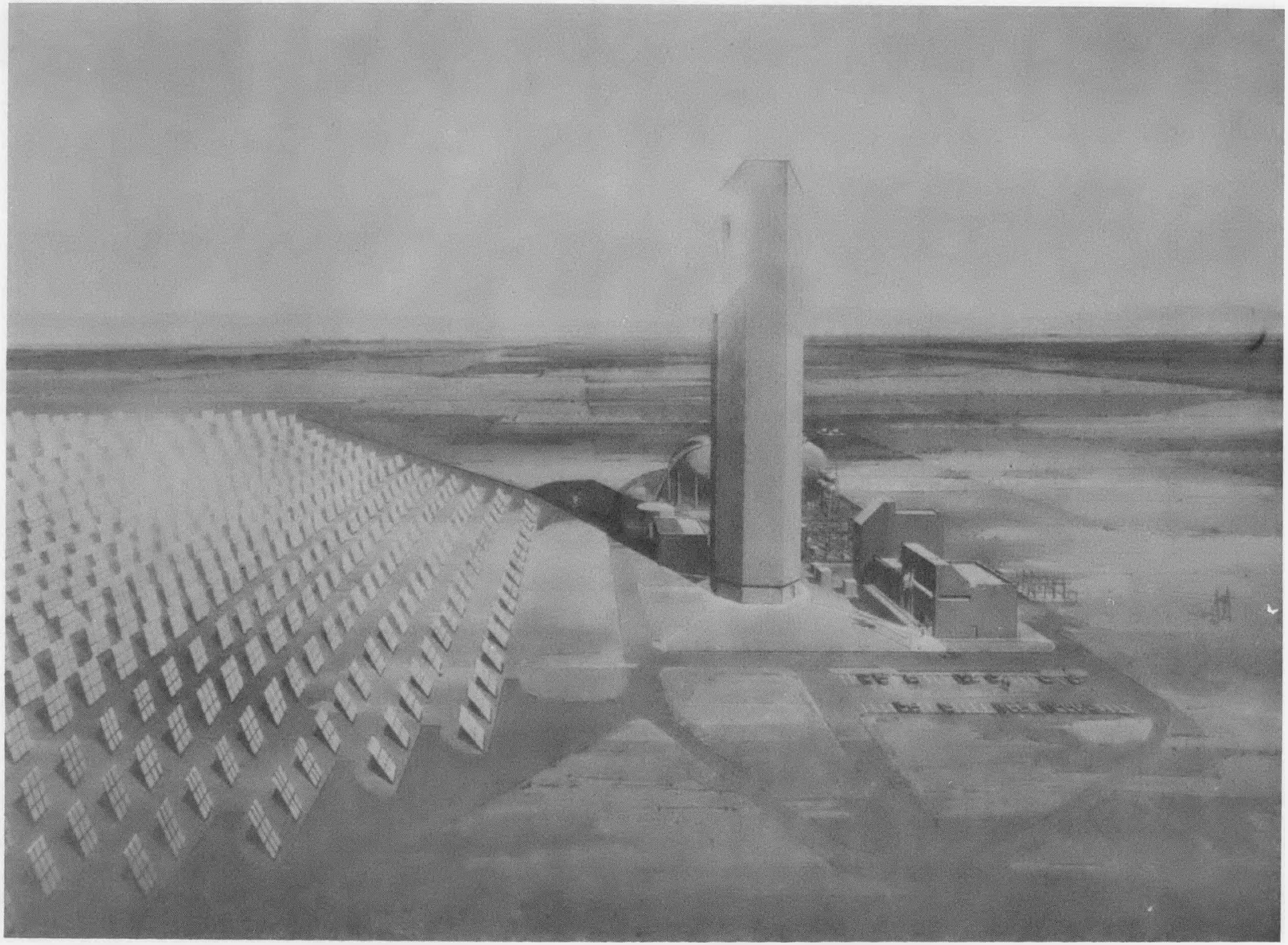


Figure V.B-1 Architectural Rendering

- Design Goal - The architectural design goal was to provide a consistent and appropriate level of quality necessary to meet the functional requirements and aesthetic needs of the facility. Effort has been made to make the plant aesthetically compatible with the environment. In the pilot plant layout, consideration has also been given to the ultimate joining of many such plant modules into a commercial plant.

- Site - The axial and symmetrical relationship of the major elements is recognized and reinforced by other elements such as roads, buildings and process equipment, such as tanks and piping. The tower is the point of visual orientation to the site, and the main road into the plant site is aligned with its east/west axis. The approach to the site provides an uninterrupted view of the collector field, the receiver tower and the administration and control building. The complete process of power generation--collectors, receiver, turbine-generator, and transmission lines--is perceived in one panorama. Process equipment is placed in the rear behind structures, and organized around the axial concept. Primary facilities are serviced by a loop road that also connects to the collector field access road.

- Administration and Control Building - A two-story facility houses the control room on the second floor. From this vantage point, an operator can survey the heliostats, the tower and the turbine-generator. Personnel and equipment doors link the control room to the turbine operating level.

  Administrative spaces, offices and personnel facilities are arranged according to function. Exterior adjustable shades are provided on the south windows to minimize unwanted solar heat gain, while heat from roof-mounted solar collectors provides space heating and hot water. The turbine-generator facility is designed as a separate but contiguous building with the operating level of the turbine aligned with the control room level.

- Receiver Tower - As the dominant vertical element of the plant, rising 111.6 m (366 ft), the tower is visible from nearby communities and roads serving the region. Its unique octagonal shape offers a dynamic image as the sun sequentially illuminates the eight facets of the tower. The deep ribbed prefinished siding accentuates the vertical character of the tower.

- Ancillary Facilities - Service buildings and process facilities are compatible with the major structures in the use of exterior finishes and color.

- o <u>Environmental Aesthetics</u> - Through careful consideration of building arrangement, architectural style, and surface color, intrusion into the aesthetic environment will be minimized. Aesthetic change occurs when industrial facilities are located on grassroots sites and, to a lesser degree, when the site is of an industrialized character. Selection of a non-obtrusive color can allow a facility such as the pilot plant to blend with the landscape. The tower panels will be colored at the supplier's factory in Fluropon-Citation Gold and other plant buildings and the oil tanks will be painted in Antique Bronze. The Citation Gold is a light sand color which will be highly reflective of stray solar radiation. Care in architectural design and layout will further reduce the potential adverse visual effect that such a facility could have.

2. Plot Plan

A plot plan suitable for a Pilot Plant preliminary design has been developed, and this also represents the conceptual Commercial Plant Collector/Receiver module. Figure V.B-2 shows the key features of this plot plan. The basic geometric arrangement of the receiver tower and heliostat field are identical for the Commercial and Pilot Plant designs. This arrangement is dictated by the optimization of heliostat locations to the north-facing receiver tower. Factors that affected this arrangement include:

- The number of heliostats
- The size of each heliostat
- Tower height
- Tower Shadow
- Receiver aperture size
- Heliostat blocking
- Heliostat shading
- Loss due to distance of heliostat from the receiver

Paved road surface within the collector field has been reduced to minimize environmental impact and cost. To service all heliostats for washing, calibration, and maintenance, service vehicles must be able to traverse each row in the collector field. To provide this amount of paved road surface would necessitate paving 25 to 50 percent of the collector field area. The cost of roads would be very high, and habitat changes for local flora and fauna would be very significant with such a large paved area. Channeling and disbursement of precipitation runoff from such a paved area would also present a problem. To reduce costs and to mitigate these effects by reducing paved surfaces, paving has not been specified for collector

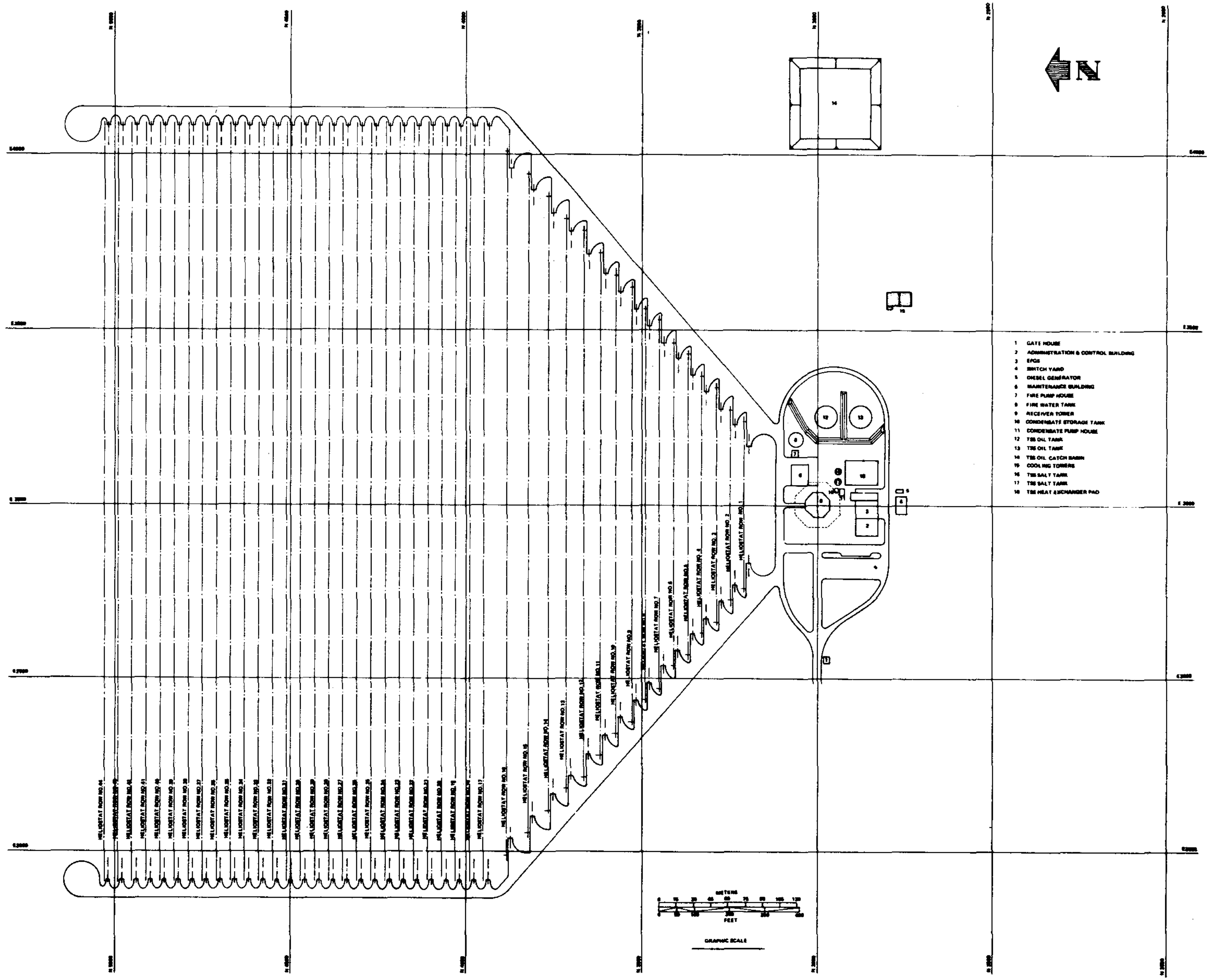


FIGURE V.B–2 PLOT PLAN

field internal maintenance access ways, and the use of low-tire-pressure vehicles for collector field servicing is planned. Figure V.B-2 shows paved peripheral roads around the collector field with turning radii dipping toward the center of the field at each row but without paved roads in the center of the field. This road configuration will permit service vehicles to perform their turns on paved surface to avoid the soil scrubbing that would result from turns on bare ground surfaces.

Plot plan features exclusive to the Pilot Plant include the following:

- A TSS arrangement is shown for a 3-hour storage system providing 2 860 kPa (400 psig), 700 K (800 F) admission steam to the turbine. The location of oil and salt tanks and supporting equipment has been arranged with safety and fire protection considerations, with a view toward minimizing the lengths of interface piping to the EPGS or receiver tower, and with the idea of placing the equipment in a location where it will not be prominently visible.

- The EPGS building and the administration and control building have been placed in a prominent location which is easily accessible to the entrance road and parking lot and permits viewing of a portion of the collector field as well as the receiver tower. The two buildings are attached for operational and service convenience, and the control room has a view of the turbine-generator area.

- The wet cooling tower is located south-east of the turbine building at a distance and location required by design considerations. This subject is discussed in greater detail in section V.B-9.

- The drain basin and dikes required in case of TSS oil tank leakage have been lcoated in such a position that shallow gravity flow channels from the oil tanks can be provided for oil spills. The necessity for a drainage basin for the TSS oil rather than a full-capacity diked area around the tanks is dictated by the high temperature of the oil, and the need to drain is away from the building. The flash point temperature for Caloria HT 43 is 478 K (400 F). Since the oil will be more than 311 K (100 F) above this temperature, exposure to a spark or flame will cause ignition of the oil. The possible burning of 5 678 m^3 (1.5 million gal.) of this oil within a short distance from occupied buildings would create a requirement for more expensive design features for protection of equipment and personnel in these buildings than has been provided.

The drain basin is located at N 2,450, E 4,150 (plant coordinates). The excavation for the drain basin will accommodate 5 678 m^3 (1.5 million) gallons of fluid. The drainage system is designed for a discharge of 0.28 m /s (10 cfs).

- A sanitary sewer line is located so that the end of work is at N 2,680, E 1,795, and a 15 centimeter (6 in.) diameter vitrified clay pipe is used to convey flow by gravity to the last manhole at the above plant coordinates. The potable and makeup supply line begins where a tee connection is made to the existing Clearwater Plant well water supply line. One well is located near the tee connection.

- The maintenance building shop is located in a position that permits easy access to the collector field, as well as to EPGS, TSS, and receiver equipment. It will not appear as a prominent plant feature when viewed from the administration and control building.

- A paved drive-through road around the process equipment area provides convenient access to all equipment areas and also permits TSS oil trucks to move through the plant and fill or drain TSS tanks without the necessity for turnaround.

- A periphery fence 1.8 m (6 ft) high of 6-gauge galvanized chain links has been designated to surround the entire plant. Line posts of 5 cm (2 in.) diameter are set on 3 m (10 ft) centers with a top of three barbed-wire strands.

- Overall, the orderly geometric arrangement of structures and equipment has been made with architectural consideration to provide a pleasing appearance from near or distant vantage points.

3. Plant Arrangement

The locations and orientation of buildings and other major process equipment within the plant have been dictated largely by design interface requirements. Figure V.B-3 illustrates this arrangement.

First, the receiver tower aperture centerline must be 64 m (210 ft) south of the most southerly row of heliostats. This design basis was dictated by Martin Marietta collector efficiency calculations and is a common factor for the pilot plant and commercial plant layouts.

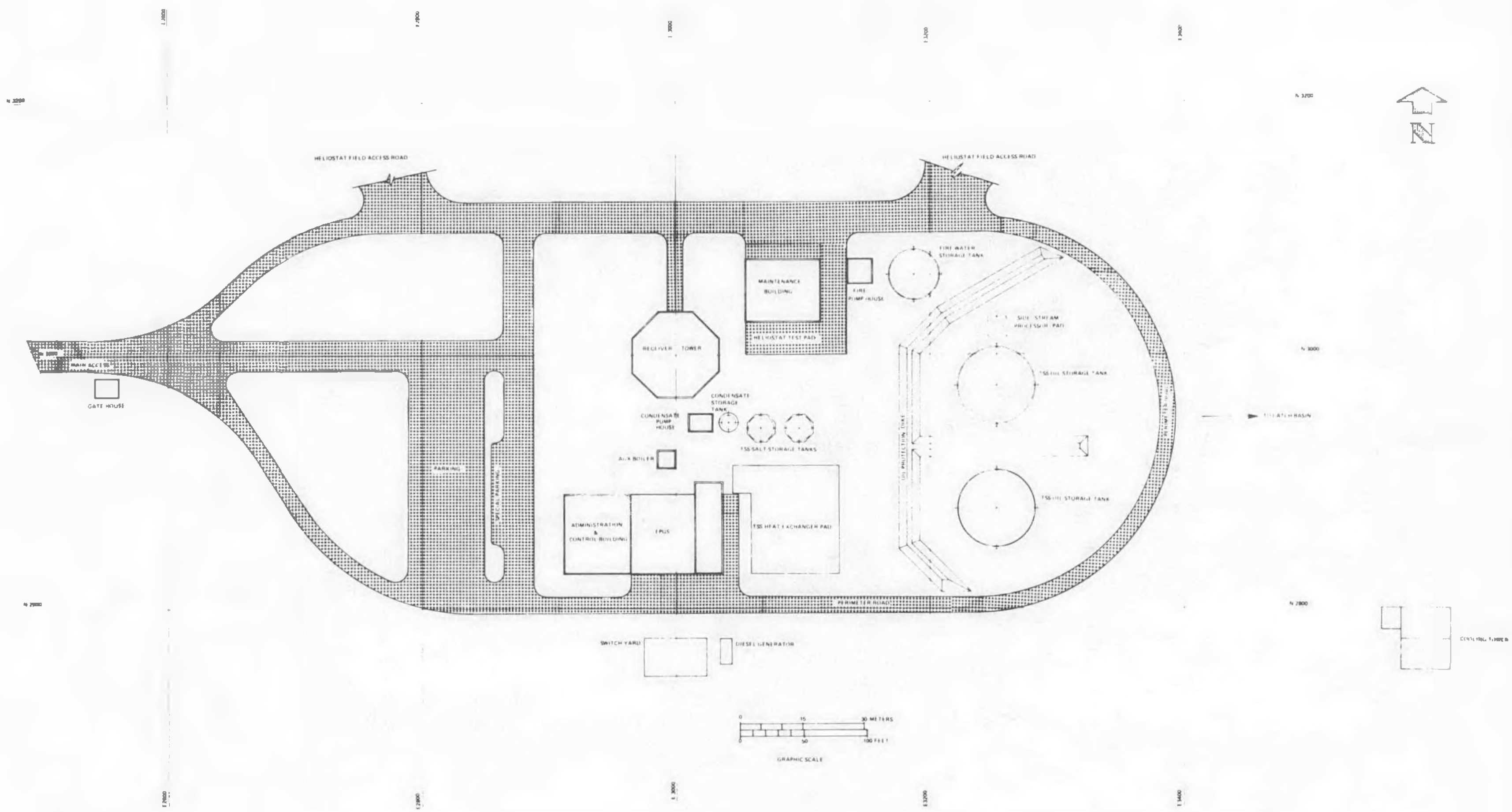


FIGURE V.B–3 PLANT ARRANGEMENT

The EPGS building is located as close to the receiver tower as possible without inducing foundation loads from the EPGS pedestal foundation into the tower's octagonal foundation pad. During design optimization, several types of foundations were considered in each case. By minimizing the distance between the EPGS and the tower, a significant reduction in piping lengths and costs was achieved relative to the conceptual design configuration. Steam and feedwater line lengths were reduced by 50 m (165 ft) and 61 m (200 ft), respectively, by this process.

Administration and control functions have been combined into a single building for ease of communications during the critical testing period planned for the pilot plant. This decision might well be different for a plant that is designed primarily for commercial power generation. The control room is located immediately adjacent to the turbine deck of the EPGS building, and in an orientation that permits the operators to have a view of the principal functional features of the plant. The orientation of the control room influenced the orientation of both the administration and control building and the EPGS building within the constraints necessary to maintain minimum pipe lengths. Figures V.B-1 and V.B-3 illustrate this arrangement and orientation.

A maintenance building is located west of the tower and adjacent to the process equipment area perimeter road. This location permits convenient access from the service road and close access to plant features where frequent maintanance activities will occur. It is anticipated that heliostat mirror washing will proceed during evenings and that the maintenance building will serve as a base for this operation. The building and the equipment associated with the maintenance functions is not as readily visible from the administration and control building as other plant features. This is considered to be an aesthetic advantage favoring the location.

Thermal Storage Subsystem(TSS) equipment and tanks are located as close to the receiver tower and EPGS building as fire safety considerations will permit. For a volume of 5 678 m (1.5 million gal) of oil at temperatures exceeding the flash point temperature, a clear distance to the nearest major structure is required by NFPA regulations. This distance was held to approximately 30.5 m (100 ft) to reduce piping lengths and costs. Dikes are located between the oil tanks and other buildings or equipment to channel oil spills away from the equipment area.

An access road enters the process equipment area from the south and the west as shown on drawing C-1710, included in Appendix C. This road location is responsive to the actual Barstow site location but has been oriented for convenient traffic flow. A parking area is located to the west of the administration and control building to minimize vehicle traffic within the process equipment area. This location for the parking area will be convenient for operating, test, and administrative personnel as well as for visitors. The road continues around the perimeter of the process equipment area, providing easy maneuvering for TSS oil fill tank trucks or other operating and maintenance vehicles requiring access to the plant equipment. This orientation will also provide flexible access for fire fighting or emergency vehicles.

An auxiliary fossil fueled boiler is located between the EPGS building and the receiver tower. This boiler provides a maximum flow rate of .378 kg/s (3000 lb/hr) of 489 K (420 F), 2 170 kPa (300 psig) steam for nighttime turbine sealing and for morning pegging of the deaerator.

The auxiliary diesel generator is located south of the south perimeter road just east of the switchyard.

A wet cooling tower is located southeast of the equipment area in a position where most of the drift fallout from evaporated cooling tower water or the cooling tower plume will be carried away from the heliostat field by prevailing winds. The distance to the tower is a tradeoff design solution between the distance that would be necessary to ensure that most drift fallout would occur before reaching the heliostats and the additional pipe length between the tower and the turbine discharge. For a site such as Barstow, with wind from the west quadrant 70 percent of the time, a lesser distance is feasible than would be the case if wind directions were more variable. The distance shown on Figure V.B-2 is 164 m (539 ft). This location should be reassessed during final design based on a more extensive cost analysis.

The main transformer station for the Pilot Plant is located south of the EPGS building in a convenient location for continuing the distribution system on to the southeast toward the Coolwater Plants. Drawing P-1701, showing these arrangements in included in Appendix C.

4. Roads and Drainage

The road system for the Pilot Plant is designed to provide access to the all areas for operation, maintenance, and service vehicles. In addition to the medium-duty roads provided for the process equipment area, soil cement roads have been designed for access to the collector field. These soil cement roads and field drainage are properly a part of the collector system and are described in Volume III. This section covers the asphaltic concrete roads and drains that service the process equipment area and provide access to the overall plant.

The Pilot Plant site near Barstow has a slight slope of 0.25 percent in a northeasterly direction. Only limited grading will be required in the process equipment area to channel rainfall drainage east into the diked area around the TSS oil storage tanks or north around the west side of the collector field. Runoff drained into the oil drainage system will flow into the drainage basin, where it will be permitted to evaporate. The annual rainfall at Barstow is only 7.6 cm (3 in.) according to California Highway Department data, and the design storm will have an intensity of 2 cm (.8 in.) per hour, with a time of concentration of 10 minutes. This storm may result in temporary local ponding of the storm drainage facilities, but they will be adequate to prevent flooding of any facilities.

Pipe culverts will be of galvanized, corrugated metal pipe of not less than 20 cm (8 in.) diameter. Ditches will have 0.61 m (2 ft) bottom width, a minimum depth of 0.30 m (1 ft), and a minimum slope of 0.3 percent.

Road pavements have been designed to meet the anticipated vehicular loads. State of California Division of Highways procedures have been used in this design. If the upper 15 cm (6 in.) of in-place material has a relative compaction of less than 90 percent in the paving area or area under the roadway, it should be compacted until a minimum relative compaction of 90 percent is attained. Excavation quantities will be based upon the excavation of ditches, culverts and 15 cm (6 in.) of stripping under roadway and 30 cm (1 ft) of compacted fill under roadways.

The plant access road is designed to accommodate a 5-axle truck with minimum Annual Daily Traffic. This road has a 7.3 m (24 ft) wide asphaltic concrete pavement and 1.2 m (4 ft) wide shoulders. Geometric design is based on the following vehicle operating design speeds:

- Outside the plant limits--48 km/hr (30 mph)
- Inside the plant limits--16 km/hr (10 mph)

Roads within the equipment area are designed to accommodate a 5-axle truck with minimum Annual Daily Trafic. These roads have a minimum width of 3.66 m (12 ft) asphaltic concrete pavement and 0.62 m (2 ft) wide shoulders. The design speed is 16 km/hr (10 mph). Drawing C-1710 in Appendix C shows plot grading, roads, and underground lines.

5. Building Foundations and Turbine Pedestal

The foundation design criteria and soil parameters for the various structures are based on the limited site data provided for the Barstow site and referred to in Appendix D. These foundation design criteria and soil parameters are preliminary in nature and a detailed investigation at the site will be required prior to final design.

a. Administration and Control and EPGS Buildings - Based on the soil information available, footing foundations can be used for columns located in the administration and control building and the EPGS building. The given data show the top 1.52 m (5 ft) of silty sand deposit is in a moderately firm condition but will become weaker when wet. Therefore if the footings are to be founded within the upper 1.52 m (5 ft) of soils, provisions must be made to keep moisture away from the foundation grade during and after construction. If this is one, a net allowable bearing pressure of 71.8 kPa (1,500 psf) can be used for the design of spread footings founded at a minimum depth of 0.61 m (2 ft) below the lowest adjacent final grade.

If no provisions are made to keep moisture away from the foundation grade, then footing foundations should be founded on the firm soils located at a depth of 1.52 m (5 ft) below the present ground surface. As indicated by the soil data, footings founded on these soils can be designed for an allowable bearing pressure of 239 kPa (5,000 psf). In the event that site excavations are made, the footing levels should be located so that the footings are at a minimum depth of 0.61 m (2 ft) below the lowest adjacent final grade.

As an alternative, the top 1.52 m (5 ft) of soil at the foundation locations can be removed and the excavation backfilled with compacted material. For this alernative a net allowable bearing pressure of 192 kPa (4,000 psf) can be used at a minimum foundation depth of 0.61 m (2 ft) below the lowest adjacent final grade.

Using the above recommendations, differential settlement between adjacent columns is not expected to exceed 12.7 mm (0.5 in.) for column loads of up to 45 350 Kg (100,000 lbs).

The column footing foundations used in the building designs are considered to be protected from moisture during and after construction. Figure V.B-4 illustrates a typical footing foundation.

b. Turbine Pedestal Structure - The turbine-generator pedestal supports the turbine and the generator. It is located in the center of the EPGS building. The height of 6.3 m (20.5 ft), plan dimensions of 4.8 m (15.8 ft) wide, and 11.5 m (37.8 ft) long for the preliminary pedestal were fixed per the guildlines set by General Electric in their manual "Foundation Design & Construction Recommendations for Lynn-Built Steam Turbine Generators." Openings under the turbine were adjusted to suit the condenser selected after discussions with suppliers.

To simplify and reduce the cost of pedestal construction, some intermediate beams and haunches found in the GE guidelines were not included. Various sections of beams and columns were analyzed to

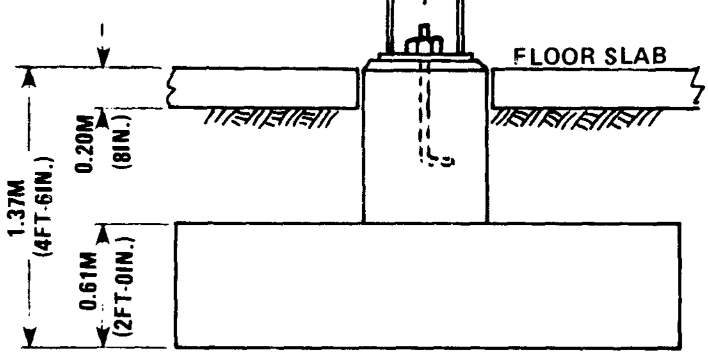


FIGURE V.B–4 TYPICAL COLUMN FOUNDATION

determine the preliminary design configuration chosen with the natural frequency of the foundation above the operating frequency of the turbine-generator. The three transverse frames have frequencies 14 to 18 percent above the operating frequency of the turbine-generator. The vertical and horizontal amplitudes are also satisfactory. Concrete strength of 27.58 MPa (4,000 psi) was used in the pad's design. For seismic analysis, a peak ground acceleration of 0.25 g was used in accord with ERDA design criteria.

The foundation mat dimensions were kept at 5.5 m (18 ft) wide, and 12.2 m (40 ft) long, and 1.4 m (4.5 ft) deep due to consideration of three factors:

- Analysis of the pedestal is based on the assumption that the columns are fixed at the base.

- Reduction of eccentricity between center of gravity of the masses and center of gravity of the foundation.

- To meet ERDA soil criteria, the foundation was taken 1.2 m (4 ft) below grade.

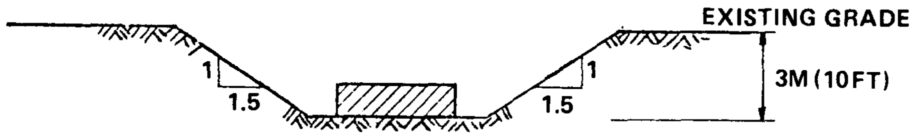
Drawing C-1363 shows the completed design, and is included in Appendix C to Volume VI.

c. Turbine Pedestal Foundation - The turbine-generator including the condenser weighs approximately 1.36 x 10^5 Kg (300 kips). The superstructure will weigh about 2.40 x 10^5 Kg (530 kips). Dimensions for the foundation mat are given above. With these minimum foundation dimensions, the net applied bearing pressure due to dead load is 72 kPa (1,500 psf). The gross applied bearing pressure is 105 kPa (2,200 psf).

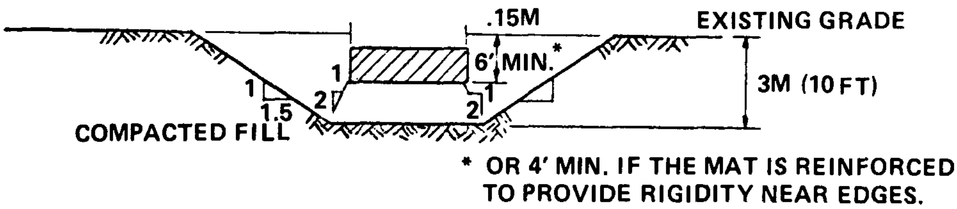
The soil information provided appears to indicate that the upper 3.04 m (10 ft) of soil is of doubtful quality for the support of equipment subject to vibration. In view of the importance of the equipment, special foundation treatment is required.

Three alternatives for foundation treatment have been considered and are discussed briefly in the following paragraphs. In each case, the plan dimensions of the foundation mat are those indicated above. The sketches for these three alternatives are shown in Figure V.B-5. Any of the three alternatives would be accpetable; however, there are advantages and disadvantages for each.

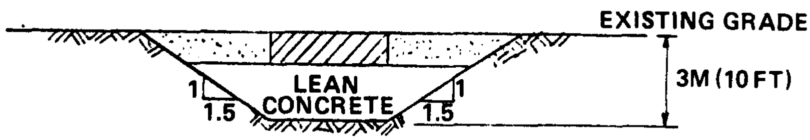
- Alternative 1 - The first alternative considered was to excavate the silty and sandy soils to a depth of 3.04 m (10 ft) and found the mat at this level. The advantages



ALTERNATIVE 1



ALTERNATIVE 2



ALTERNATIVE 3

FIGURE V.B–5 TURBINE PEDESTAL FOUNDATION of this alternative are that the foundation is directly supported on firmer soil, and essentially no preparation of the foundation soils is required. The disadvantage is that the height of the pedestals would have to be increased unless the machinery could be lowered, which is not convenient.

- Alternative 2 - The second alternative was to excavate the top 3.04 m (10 ft) of soil, backfill to design grade with heavily compacted fill, and support the mat on the compacted fill. The foundation mat should have a minimum embedment of 1.8 m (6 ft) measured from the bottom of the mat to the adjacent final grade unless the mat is specially reinforced to provide greater rigidity near the edges where the foundation soils tend to be less stiff. In addition, the bottom of the excavation should be extended 0.31 m (1 ft) for every 0.62 m (2 ft) of fill placed beneath the foundation. The granular soil removed from excavation can be used as backfill material provided it is compacted to an average of 95 percent of the maximum dry intensity determined determined in accordance with ASTM specification D-1557. This is a high degree of compaction which will require close control. The compaction requirements, together with the minimum embedment requirement, could be relaxed somewhat if a more clayey backfill material is available. The advantage of this alternative is that the foundation level would not have to be lowered as was the case in alternative 1. The disadvantage is that it requires closely controlled backfilling in a fairly confined area.

- Alternative 3 - The third alternative was to excavate the top 3.04 m (10 ft) of soil and replace it with lean concrete up to the bottom of the foundation. The bottom of the excavation should have dimensions at least as large as the size of the foundation mat. To take the advantage of high damping, the foundation mat should be connected to the lean concrete mat if possible. The advantage of this alternative is that a massive foundation would be provided, which would be insensitive to vibration. Also, construction would be very simple, easy to control, and would require no special construction equipment. A disadvantage of this alternative is that it would be more costly than the other alternatives.

Based on minimum cost, alternative 1 was selected.

Foundation settlements at this site, under static loads, will occur almost immediately after the load is first applied. The behavior of the foundation under vibratory loading conditions should be investigated during final design by means of a dynamic analysis. Recommended parameters for such an analysis are given below.

- Soil Parameters for Dynamic Analysis

  - Shear Modulus - For an approximate analysis of a lumped-parameter system, a shear modulus value of 103 MPa (15 ksi) at 4.3 m (14 ft) depth can be used to determine the spring constant.

    The dynamic shear moduli of compacted fill and in situ soil for the different foundation alternatives are tabulated in Table V.B-1.

  - Damping Ratio - The damping ratio varies with the mass of structure and foundation, Poisson's Ratio and unit weight of soil, and vibration modes. The damping ratio obtained through the half-space theory and corresponding analogs for rigid circular footings are available in Table A-2 and Figure 7-19, of Richart et al Reference 2, Appendix H.

6. Administration and Control Building

The administration and control building is a two-story structure immediately adjacent to the EPGS building and providing easy access to all other equipment. The functions of administration and plant control have been combined in a single structure for several reasons based on system design criteria:

- A test planning and analysis center is required near the control room.

- Offices are required for engineers planning and supervising solar unique system development over a period of years

- An unusually large operating crew for a 10 MWe plant of three or four men will be required during testing phases.

- Access to the operational details of the plant is desirable for temporary visitors from ERDA and other program test and management organizations participating in the test phases.

Table V.B-1 Shear Modulus

Alternative	Depth[1] m	Depth[1] (ft)	Poisson's Ratio	Shear Modulus[2] Without Influence of Structure Load MPa	(Ksi)	With Influence[3] of Structure Load MPa	(Ksi)
1	3.0	(10)	0.3	103	(15)	145	(21)
	4.6	(15)	0.3	131	(19)	159	(23)
2	1.8	(6)	0.33	68.9	(10)[4]	138	(20)[4]
	3.0	(10)	0.33	96.5	(14)[4]	124	(18)[4]
	3.0	(10)	0.3	103	(15)	138	(20)
	4.6	(15)	0.3	131	(19)	152	(22)
3	3.0	(10)	0.3	103	(15)	138	(20)
	4.6	(15)	0.3	131	(19)	152	(22)

NOTES:

1. The shear modulus values at depths other than the above designated depths can be interpolated linearly.

2. All values tabulated correspond to a strain level of 10^{-4} (10^{-2} percent) based on the value given by Sandia Laboratories, and should be adjusted for the actual strain level using the Seed and Idriss curve (Reference 1, Appendix H).

3. The shear modulus value was adjusted taking into account the additional confinement due to a gross vertical pressure of 15.2 MPa (2.2 ksf) applied by the structure and foundation.

4. Values for compacted fill were calculated by the Seed and Idriss relation (Reference 1, Appendix H), assuming a relative density of 75 percent.

Figure V.B-6 provides the building plan view. An open-air laydown deck in the EPGS building at the same level as the control room provides clear visual and physical access to the turbine-generator. The operators' view from the control room will include the turbine deck, collector field, receiver tower, and TSS equipment.

A lobby adjacent to the control room permits accommodation of visitors without physical access to the control room. A glass partition will be provided between the lobby and control room to permit visitors to view the control room as well as those plant features visible from the control room. This feature has been included in the design of the Pilot Plant due to the probable high level of public and government attention that this first solar electric power plant can be expected to command. Visitors can be accommodated with this building layout without interfering with the principal goal of the plant: to obtain operating data and experience.

The control room layout, shown in Figure V.B-7, includes space adequate for the controls associated with the EPGS, TSS, receiver, and collectors, as well as the master control subsystem. This layout is still very preliminary, and rearrangements are expected. An operating staff of three to four persons is anticipated inside the control room. The large size of this control room will accommodate the abnormally large operating staff required during the pilot plant testing period.

The administration and control building is a simple braced-steel building. The dimensions are 22.9 m (75 ft) long and 18.3 m (60 ft) wide. The building is located on the west side of the EPGS building. It has three 7.6 m (25 ft) bays in an east-west direction and three 6.1 m (20 ft) bays in a north-south direction, and two floors. On the ground floor are located two laboratories, one multi-purpose room, one battery room, one room for cable spreading, one office, one clerical room, a foyer, a lobby, staircase and elevator, and other necessary facilities.

A control room is located on the second floor (called the operating floor) with one door opening directly onto the turbine laydown area. Also on this floor are a planning and analysis center, a shift superintendent's office, a lobby, four engineering offices, and support facilities. The floor elevations are the same as those of the EPGS building.

The building is insulated and has H. H. Robertson's 4-inch deep Magna Rib cladding on the outside surface, supported by girts 3.04 m (10 ft) wide and 8.84 m (29 ft) high, at every 3.81 m (12.5 ft). The exterior cladding of the EPGS building is the same.

The foundations of columns have been designed per the ACI code and a safe bearing capacity of 192 kPa (4,000 psf) at 1.22 m (4 ft)

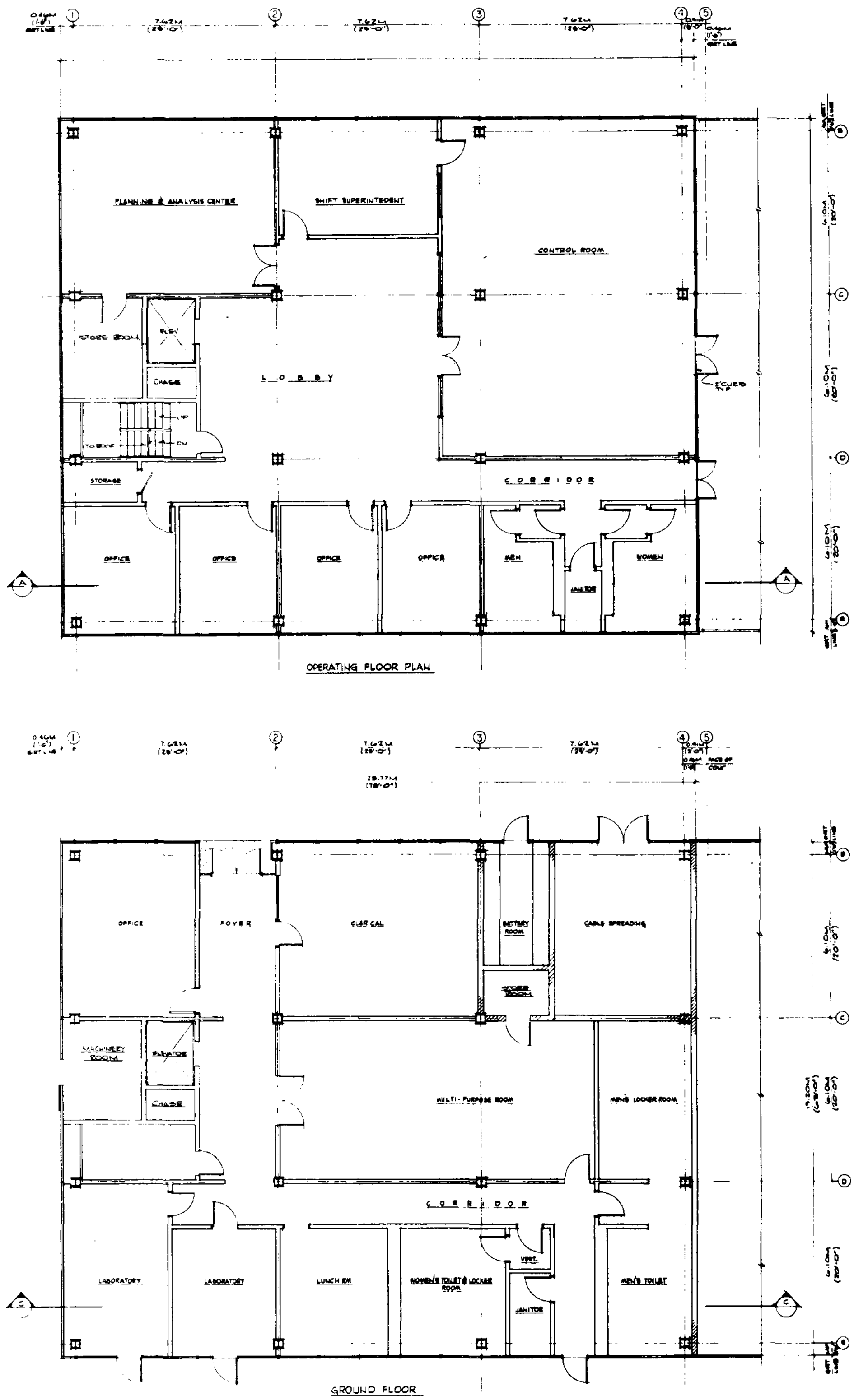


FIGURE V.B–6 ADMINISTRATION AND CONTROL BUILDING

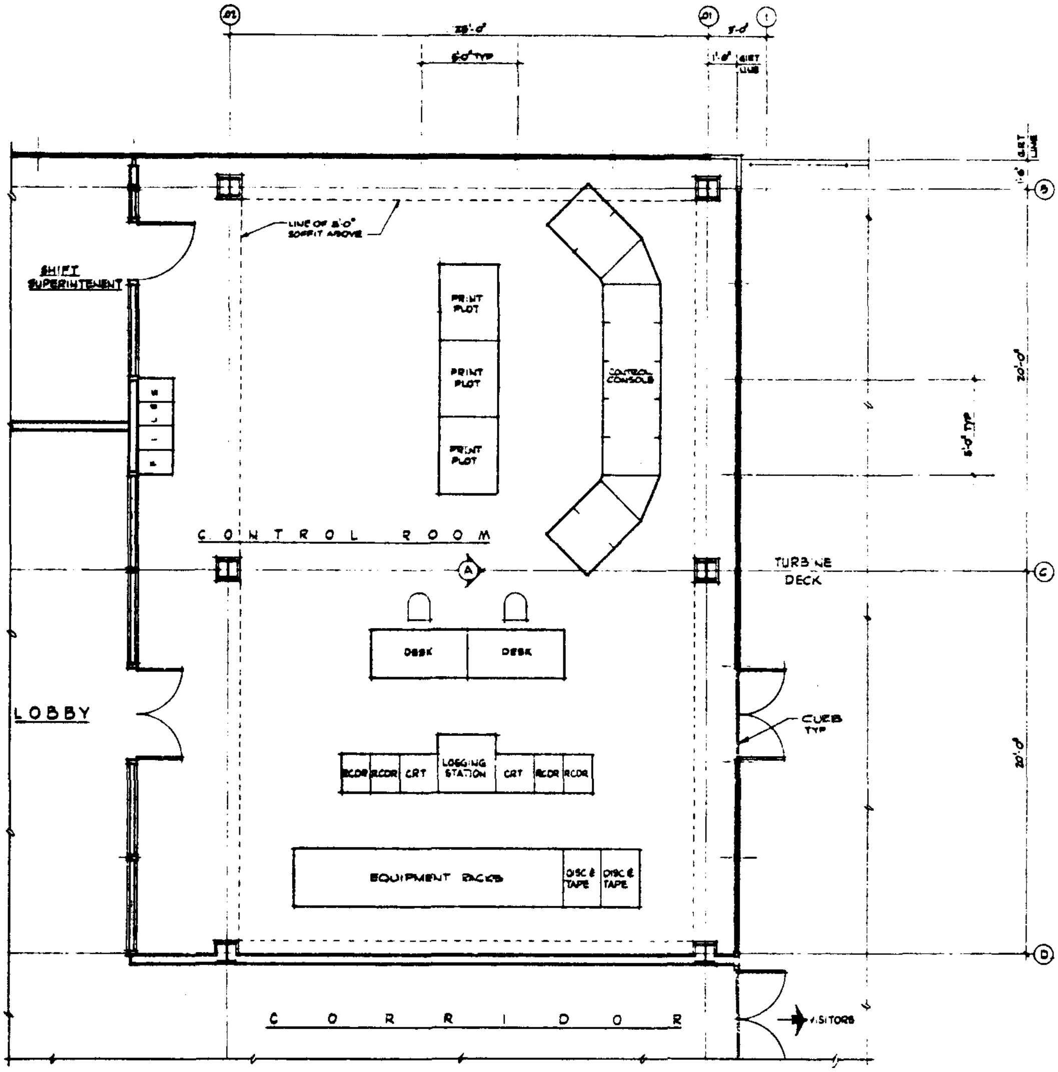


FIGURE V.B–7 CONTROL ROOM LAYOUT

depth has been assumed. During seismic analysis, the allowable stresses were increased by 33 percent. The peak ground acceleration due to earthquakes was assumed as 0.25 g. Figure V.B-4 shows a typical column foundation.

Wind forces were calculated per ANSI code for exposure "C." Vertical braces have been located in such a way that these do not interfere with openings. There are no horizontal braces because concrete floors act as shear diaphragms. The ground floor is 10.3 cm (8 in.) thick reinforced concrete slab. The operating floor is made up of H. H. Robertson's 3-inch QL-99-18 gauge metal deck with 11.4 cm (4.5 in.) thick normal weight concrete poured above the flutes. Wire mesh is provided 2.54 cm (1 in.) below the top of concrete as shrinkage and temperature reinforcing. In addition, the metal decking will be fastened to the top flanges of the supporting steel beams with tack welds so that the floor acts as a shear diaphragm.

The control room has a .91 m (3 ft) sunken (depressed) floor to provide cable laying space. There will be a false floor covering the cables. A live load of 9.6 kPa (200 psf) for computer room has been assumed. For the remaining floor, a live load of 4.8 kPa (100 psf) was assumed.

The roof is built of H. H. Robertson's QL-3-18 gauge steel with 6.4 cm (2.5 in.) thick normal weight concrete poured over the flutes. There will be a wire mesh placed 2.54 cm (1 in.) below the top of the concrete to accommodate shrinkage and temperature stresses. The decking will be tack welded to the top flanges of the supporting beams to act as a shear diaphragm. This surface will be covered with 5-ply felt and gravel to assure an absolute moisture-proof roof over the control room. The live load on the roof was taken as 0.96 kPa (20 psf).

Solar collectors are located on the building roof. These collectors provide solar hot water and space heating for administration and control building heating.

A steel staircase and a hydraulically operated elevator are provided in the center of the west face of the building. Drawings P-1704 and P-1707 show floor plan details and are included in Appendix C.

7. EPGS Building Structure

This building is designed as a functional platform for the EPGS equipment. The turbine pedestal is the principal controlling feature around which the other equipment has been arranged. The basis for the equipment arrangement and suitable descriptions are provided in Section IV of Volume VI dealing with the EPGS Pilot Plant design. This subsection covers the structural design aspects of the building only, as shown in Drawings P-1361 and P-1362, included in Appendix C.

The EPGS building measures 18.3 m (60 ft) wide and 21.3 m (70 ft) long, is three storied, and is located south of the receiver tower. The building has three 6.1 m (20 ft) bays in the north-south direction and two 7.6 m (25 ft) bays in the east-west direction. Starting from west to east, the building height above grade is 6.3 m (20.5 ft) for the western 15.2 m (50 ft), and 15.4 m (50.5 ft) for the remaining 6.1 m (20 ft).

On the second floor is the laydown area for repair and maintenance of the turbine and the generator. The second floor elevation was kept at 6.3 m (20.6 ft) to accommodate the turbine-generator pedestal selected. Subsection V.B-5 above discusses this selection. The building is designed as a braced structure.

The foundations of columns were designed per ACI code and a safe bearing capacity of 191.5 kPa (4,000 psf) at a 1.2 m (4 ft) depth has been assumed. The allowable stresses for wind and seismic forces were increased by 33 percent for the design of the structural members per the Uniform Building Code (UBC). Ground acceleration due to earthquake was taken as 0.25 g per the ERDA design criteria.

The building is not insulated but has H. H. Robertson's 4-inch deep Magna Rib cladding, supported by girts 3.04 m (10 ft) in height and 8.84 m (24 ft) in width, spaced every 3.8 m (12.5 ft).

Wind forces were calculated per ANSI code for exposure "C". While providing vertical braces, due consideration has been given to ease of operation and movement of maintenance vehicles. All the vertical braces are "temporarily" removable if required for maintenance.

The ground floor is a 10.3 cm (8 in.) thick reinforced concrete slab with 7.6 cm (3 in.) flexible material around the turbine-generator foundation mat to reduce the propagation of vibrations. The second floor is made up of H. H. Robertson's 3-inch QL-99-18 gauge metal deck with 11.4 cm (4.5 in.) thich nominal weight concrete poured above the flutes. Wire mesh is provided 2.54 cm (1 in.) below the top of the concrete for shrinkage and temperature stress reinforcing. In addition, the metal decking will be fastened to the top flanges of the supporting steel beams with tack welds so that the floor acts as a shear diaphragm. The reason for such a thick floor is that the western half of this floor is designated as a laydown area. The upper half of the turbine casing weighs close to 19 500 Kg (43 kips). There is no horizontal bracing at this level. The second floor has a gap of 3.8 cm (1.5 in.) all around the turbine-generator pedestal to allow for vibrations. The third floor, which will not be used frequently, is built up of 4.5 cm (1.75 in.) by 1.9 cm (0.75 in.) Irving grating Type 1WB and has horizontal bracing. The roof is built up of H. H. Robertson's 3.81 cm (1.5 in.) metal decking with

5-ply felt and gravel. Live loads of 958 Pa (20 psf) have been assumed for the roof, and 4 788 Pa (100 psf) for the second and third floors. Dead loads have been taken from H. H. Robertson's catalogs.

Access to all the floors has been provided by a separate stairwell, 2.67 m (8 ft 9 in.) in width and 6.1 m (20 ft) in length, located outside of the building in the northeast corner. This stairwell provides easy access to the in-air system, pumps, piping and other equipment. Pulling of the condenser tubes will not interfere with the stairs. There are three large equipment doors in the center of the three bays in the east side of the building.

8. Maintenance Building

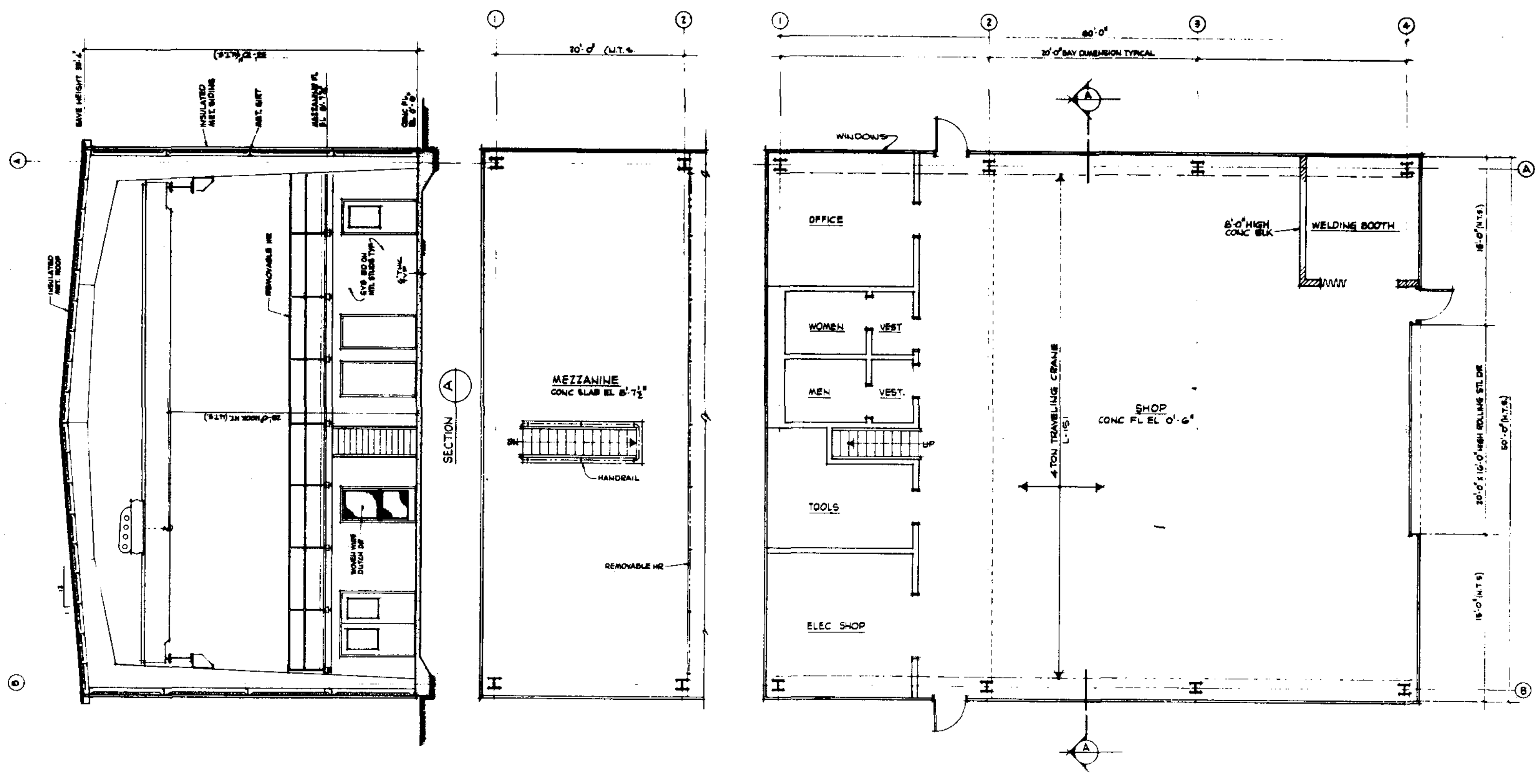
The location of the maintenance building was selected to permit easy access to all major facilities. The location is partially shielded from the administration and control building by the receiver tower.

The maintenance building preliminary design for the pilot plant is a simple steel frame "Butler" type fabricated building. See Figure V.B-8, for details. The dimensions of 15.9 m (52 ft) wide and 18.9 m (62 ft) long are adequate to meet the anticipated inside maintenance requirements for heliostats as well as pumps, motors, and miscellaneous small components. It is expected that maintenance of major components such as the turbine, and generator will be performed on the turbine deck or at a supplier's factory. Washing of heliostat mirror surfaces will be performed in the collector field. Standard tools for these tasks will be stored in the maintenance building tool crib. Large special tools and vehicles will be stored outside, adjacent to the building.

A traveling bridge crane with a capacity of 3 600 kg (8,000 lbs) has been included in the design. Smaller portable hoists will be provided as standard tools.

Interior walls of the building will not be finished or insulated. Personnel and vehicle doors are provided as required for the largest anticipated vehicle and load that must enter the building. This will be a tractor and lowboy trailer with one heliostat yoke and mirror assembly in an upright position. The requirement has dictated that a vehicle door 4.88 m (16 ft) wide and 7.32 m (24 ft) high be provided.

The building floor and surrounding pad is 15.2 cm (6 in.) thick, 20.7 MPa (3,000 psi) portland cement concrete. This surface is suitable for support of the maximum anticipated vehicle weight of 4 535 kg (10,000 lbs) distributed over six tires of a 6.6 m (21.5 ft) wheelbase trailer (tractor wheelbase is 2.8 m (9 ft 3 in.).



MEZZANINE PLAN

GROUND FLOOR PLAN

FIGURE V.B–8 MAINTENANCE BUILDING

Air cooling is provided by a single 5.7 m^3/s (12,000 cfm) evaporative cooler. This type of cooling is common for both homes and shops in arid areas such as Barstow, California.

An office for the maintenance supervisor is provided in the building. Tool records, maintenance instructions, vendors' manuals, vehicle records, and personnel files related to the inside and outside maintenance functions will be kept in this office.

The tool crib will be used for storage of tools used in the building as well as tools used in other areas of the plant. Large tools may be stored on the outside pad or in the building mezzanine.

Work area inside the building is provided for bench repairs of motors, pumps, valves, and small equipment, as well as a larger area for laydown and repair of a single heliostat yoke and mirror assembly.

Power is provided for standard overhead shop lighting as well as bench tools and lighting. A 480-277V, 225A-3 phase supply with stepdown to 208-120V-3 phase at 225A is provided.

Shop air is provided from the EPGS air compressor. A supply of air at 722 Pa (90 psig) at 400.25 m /min. (25 cfm) is available for air-operated tools, cleaning, and vehicle maintenance.

Lightning protection for all buildings is provided from a circling ground grid and the cone of protection from the receiver tower lightning rod. Section V.B-11 of this volume deals with this system in more detail.

Drawing P-1708 included in Appendix C provides details of the building plan.

9. Cooling Tower

This structure is a commercial type wet cooling tower available from several suppliers. The decision to employ wet cooling rather than a dry cooling system came as a result of the availability of adequate water for the pilot plant at the selected site. There are some significant advantages that result in EPGS performance when wet cooling is employed.

The turbine discharge pressure can be maintained at a lower level than with dry cooling. This permits use of a larger turbine overall expansion ratio and improved efficiency through longer last stage turbine blades. In addition, the maintenance of full plant power output at higher ambient temperatures is permitted. The implications of these advantages in overall plant efficiency and cost are discussed in detail in Section IV of this volume. There are however, some engineering design concerns that go with the application of wet cooling and these are discussed here. These concerns will warrant further investigation during final design.

Considering a simple mass flow balance of a cooling tower loop, for normal operation, the cooling tower makeup flow balances the water losses from the cooling loop. These losses can be attributed to three separate factors: evaporation loss, drift losses, and blowdown flow; they will be approximately 36 000 kg/hr (80,000 lb/hr) in a 10 MWe plant. Concerns associated with these losses are listed below:

a. Evaporation Loss - Since wet cooling towers rely on the latent heat of vaporization of water to remove heat, large quantities of water are vaporized and carried away from the tower. If the surrounding atmosphere is already relatively saturated with water vapor, the vapor from the cooling tower will begin to recondense, forming a visible plume that could shadow the heliostat field. Even if no visible plume forms, the addition of the unsymmetrical water vapor molecules to the atmosphere in the area of the heliostat field could attenuate insolation.

b. Drift Losses - In addition to evaporation losses, a small percentage (approximately 0.005 percent) of the circulating water cascading over the cooling tower fill becomes airborne in the form of drift droplets. These droplets tend to be heavier than those formed in a cooling tower plume, and they settle to ground level much closer to the tower. Since these droplets contain the concentrated dissolved solids of the circulating water, they could, depending on the wind direction, foul mirror surfaces in the heliostat field.

c. Blowdown - As water is evaporated to reject the heat, the remaining water tends to build up a concentration of dissolved solids. To limit this buildup, some circulating water is bled off in the form of blowdown. Because of the concentration of dissolved solids in this blowdown water and its somewhat elevated temperature, its disposal requires a system designed to minimize environmental impact.

d. Mitigating Design Features - Mitigation of potentially detrimental effects is provided for in plant design as follows:

- Plume location for the Barstow site is controlled by locating the cooling tower at the southwest corner of the pilot plant so that the prevailing west winds will blow the plume away from the heliostats.

- Drift fallout in the heliostat field has also been minimized by locating the tower downwind from the prevailing wind direction. As wind direction varies between seasons, there may still be periods when drift will be in the direction of the heliostat field.

- Approximately 60 percent of the drift fallout from the cooling tower of the 10 MWe plant will occur in the first 213 m (700 ft). Impact in the heliostat field due to adverse wind direction conditions has been reduced by setting the cooling tower back by this distance.

- Drift will be reduced by specifying that proper baffling be included in the cooling tower discharge structure. Such baffles can be provided as features of commercially available cooling towers.

- Blowdown water treatment systems will be provided to reduce the discharge impurities. In addition, blowdown water from the cooling tower can be piped to the TSS oil drain basin or to existing Coolwater Plant evaporation ponds to minimize the surface areas where potential pollution exists.

Drawing P-1370 and P-1371 in Appendix C show the cooling tower and foundation. The structure is wood with foundations suitable for use in the Barstow soil conditions.

e. Environmental Considerations - The volume and total dissolved solids (TDS) content of the cooling tower blowdown will vary with the chemical consituents of the makeup water available at the site and the operation mode. However, because of the elevated TDS concentration, this liquid waste discharge cannot be released to the environment. Instead, this waste stream can be routed to the TSS drain basin where it can evaporate without the environmental effects that could result from discharge to surface or groundwater.

10. Piping System

a. Introduction - This subsection summarizes the design features, criteria, and operating characteristics of the main steam pipe, admission steam pipe, and the feedwater pipe as determined by the preliminary engineering effort.

The successful operation of the pilot plant requires coordinated design of the main steam pipe, admission steam pipe, and feedwater pipe and the following interconnected systems:

- EPGS
- Receiver Subsystem
- Thermal Storage Subsystem (TSS)
- Master Control Subsystem
- Balance of Plant (BOP)

For complete understanding of the details and the modes of interactions, the design descriptions of the these subsystems should also be reviewed.

The function of the main steam piping is to carry superheated steam from the receiver to the EPGS turbine and the TSS desuperheater. The functions of the feedwater piping is to carry feedwater from the EPGS high pressure boiler feedwater pump (P-104A or B) to the receiver. The function of the admission steam piping is to carry superheated steam from the Thermal Storage Subsystem TSS superheater to the EPGS turbine.

b. Design Descriptions - Design of the main steam, admission steam and the feedwater piping is primarily based on criteria and considerations such as flow rates, velocities, pressures, temperatures, thermal expansion, seismic requirements, material strength allowables, and the hanger system. Allowances for erosion and corrosion have also been made. The major consideration for selection of the steam and feedwater pipe sizes was the acceptable line pressure loss under the maximum flow rate.

The pressure drop of flowing fluids in pipes was calculated with the Darcy formula (from Reference 3, Appendix H).

Pipeline sizes increase or decrease has a direct impact on the pressure loss in the steam lines and the feedwater line. The pressure loss is a combination of friction and elevation head losses. The total friction head loss and the associated effective length of the pipe is a result of the accumulated friction losses due to the number and type of valves, the number of pipe elbows and expansion loop bends, and friction loss in the actual pipe length. Variations of pressure losses in the main steam line and the feedwater line are presented in Figure V.B-9 as a function of pipe size.

The sizing of pipe requires analyzing the economic trade-off between the higher capital cost for a larger pipe, and the higher pressure drop for a smaller pipe. For the feedwater piping, the plant costs and the cost of pump power have been evaluated against the capital cost for piping.

The main steam piping design has source pressure at the receiver which is ample for the turbine inlet pressure specified. The admission steam piping was sized to minimize line pressure loss to the turbine.

From the above background, alternative considerations, design evolution, and specific turbine inlet pressure requirements, the design state points for steam and feedwater pipe sizes at the receiver, EPGS, and TSS were determined (see Table V.B-2). In addition, the

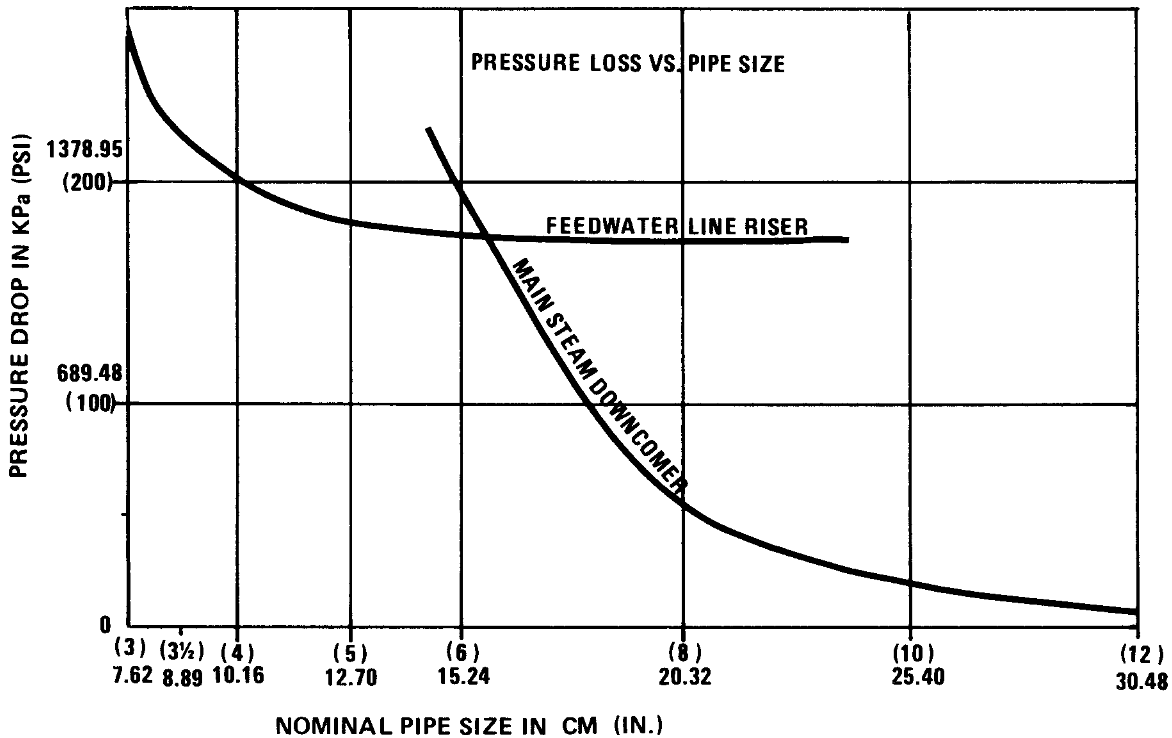


FIGURE V.B–9 PIPING LOSSES

Table V.B-2 Piping System Design Data (State Points)

Feedwater			
At Pump	Flow Rate	= 69 386 Kg/h	(153,000 lb/h) max.
	Pressure	= 13.4 MPa	(1,925 psig)
	Temperature	= 539 K	(510 F)
At Receiver	Flow Rate	= 69 386 Kg/h	(153,000 lb/h)
	Pressure	= 119.9 MPa	(1,725 psig)
	Temperature	= 536 K	(505 F)
Main Steam			
At Receiver	Flow Rate	= 69 386 Kg/h	(153,000 lb/h) max.
	Pressure	= 9.75 MPa	(1,400 psig)*
	Temperature	= 789 K	(960 F)
At Turbine	Flow Rate	= 69 386 Kg/h	(153,000 lb/h)
	Pressure	= 9.41 MPa	(1,350 psig)
	Temperature	= 783 K	(950 F)
At TSS	Flow Rate	= 53 196 Kg/h	(117,300 lb/h) max.
	Pressure	= 8.86 MPa	(1,270 psig)
	Temperature	= 780 K	(945 F) min.
Admission Steam			
At TSS Superheater	Flow Rate	= 42 856 Kg/h	(94,500 lb/h) max.
	Pressure	= 3.00 MPa	(420 psig)
	Temperature	= 701 K	(802 F):[705 K (810 F max.)]
At Turbine	Flow Rate	= 42 856 Kg/h	(94,500 lb/h) max.
	Pressure	= 2.86 MPa	(400 psig)
	Temperature	= 700 K	(800 F) min. T = 1 K (2 F)

*Corresponding pressure for Commercial Plant = 107.9 MPa (1,550 psig) pipes were sized to produce steam and water velocities acceptable in standard industrial practice for similar applications (see Table V.B-3)

The pipe sizes selected and specified are 10 in. nominal diameter for the admission steam line and 4 in. nominal diameter for the feedwater run. This line pressures and temperature losses presented in Table IV.B-2, determine pipe wall and pipe insulation thicknesses. More specifically, the main steam line is a 2.25 percent chrome and 1 percent moly, nominal 20.3 cm (8 in.) diameter Schedule 120 pipe with a 15.2 cm (6 in.) calcium silicate insulation. The total temperature loss of this pipe is 5.6 K (1 F) of which 1.7 K (3 F) is associated with the 345 kPa (50 psi) pressure loss. The insulation is sized to limit the remaining loss to 3.9 K (7 F). The admission steam line is a 1.25 percent chrome and 0.5 percent moly nominal 10 in. diameter Schedule 40 pipe with a 25.4 cm (10 in.) calcium silicate insulation. The feedwater line is a carbon steel nominal 4 in. diameter Schedule 80 pipe with a 2.54 cm (1 in.) calcium silicate insulation. Calcium silicate is standard insulation material used in power plant piping and it is more economical than alternative materials such as mineral wool and fiberglass.

During pilot plant operation, to simulate the commercial module conditions, an orifice will be installed at the receiver discharge to increase the piping pressure drop to 1 379 kPa (200 psi) to more closely simulate the commercial plant receiver operating pressure and losses predicted due to the more remotely located modules. During such simulation testing, the receiver discharge pressure will be 10.78 MPa (1,550 psig).

Table V.B-3 Steam and Feedwater Velocities

Steam and Feedwater Velocities (Standard Industrial Practice)		
Water	2.1 - 3.0 m/s	(7 - 10 ft/sec)
Low-Pressure Steam (Max.)	61 m/s	(200 ft/sec)
High-Pressure Steam (Max.)	46 m/s	(150 ft/sec)

c. Stress Analysis of Piping and Piping Supports - A major piping structural design concern has been thermal process cycling. The pipe systems are designed to be sufficiently flexible to accommodate the thermal growth and expansion which occurs in thermal process cycling. Design criteria used are included in Table V-B-4. The expansion loop design depends on the pipe size, schedule, and temperature range. Since the pressure drop depends on the number of bends and total pipe length, the pipe size depends on the expansion loop design. Therefore, design of pipe size and expansion loop parameters has been an iterative process. In the preliminary design piping layouts (Drawings M-1543 and M-1544 in Appendix C), initial thermal expansion calculations, as well as plant design and piping analysis on hangers and supports, were involved in producing the piping arrangement.

The piping design for the receiver tower riser and downcomer was validated under the rules of ANSI B31.1 Power Piping Code. Calculations for flexibility and load distributions, considering thermal expansion, supported weight, seismic effects, and wind loading were conducted using Bechtel ME-101 computer program. ME-101 has been verified and validated against comparable industry-accepted benchmark programs. Applicable codes and standards such as ANSI B31.1 and the ASME Boiler and Pressure Vessel Code have been used to determine material selection, design allowable stresses, allowable range for cyclic thermal expansion stresses, and other design criteria. Yard piping expansion loop lengths, bend radii, and support design details were selected to be similar to those resulting from the ME-101 piping analysis for the tower piping, but a separate computer analysis was not conducted, as this detail is not warranted in the preliminary design phase.

ME-101 is a finite element computer program which performs linear elastic analysis of piping systems using standard beam theory techniques. ANSI B31.1 Power Piping Code and the ASME BPV Code are incorporated. Computation of flexibility factors, stress intensification factors, and stresses was included. Seismic analysis was based on standard normal mode techniques and used response spectrum data. Differential seismic anchor movement analysis and effective weight calculation of restraints and anchors was also provided.

Table V.B-4 Piping Design Criteria

	Pressure		Temperature	
	Normal Operating	Design	Normal Operating	Design
Main Steam	9.75 MPa (1,400 psig)	9.93 MPa (1,425 psig)	789 K (960 F)	800 K (980 F)
Admission Steam	3.00 MPa (420 psig)	3.17 MPa (445 psig)	705 K (810 F)	717 K (830 F)
Feedwater	13.4 MPa (1,925 psig)	13.89 MPa (2,000 psig)	539 K (510 F)	550 K (530 F)

The reaction effects on all terminal points caused by thermal process cycling were addressed and adequately designed for. In design of the supports and restraints, the effects of gravity, thermal expansion, seismic loading, and wind loading were considered. The effects of these loads and their reactions on the tower, receiver, turbine, and other plant equipment have been considered. The design and selection of pipe hangers and supports included the determination of hanger locations, determination of thermal movement of the piping at each hanger location, the calculation of hanger loads, and the selection of hanger types; i.e., spring assembly, either of the constant support or variable spring type, rigid assembly, etc. In conjunction with the seismic load analysis, the piping design included the provision, location, and incorporation of shock absorbing arrestors (snubbers). The snubbers prevent shock forces from causing damaging motions by becoming a load carrying member between the piping and support structure the instant a force sufficient to cause abnormal motion is initiated. However, for normal thermal motion, the snubbers telescope freely through their operating stroke.

The final configurations are presented on the following drawings which can be found in Appendix C:

- Subsystem Piping Interface Flow Diagram--M-1553
- Subsystem Piping Interface Piping and Instrumentation--M-1552
- Receiver Tower Crossections--P-1541
- Yard Piping--P-1554
- Main Steam Stress Isometric (Tower)--P-1550
- Main STeam and Admission Steam Stress Isometric (Yard)--P-1551

The final design of piping systems will require a more elaborate set of functions similar to the process covered by Figure IV.B-10.

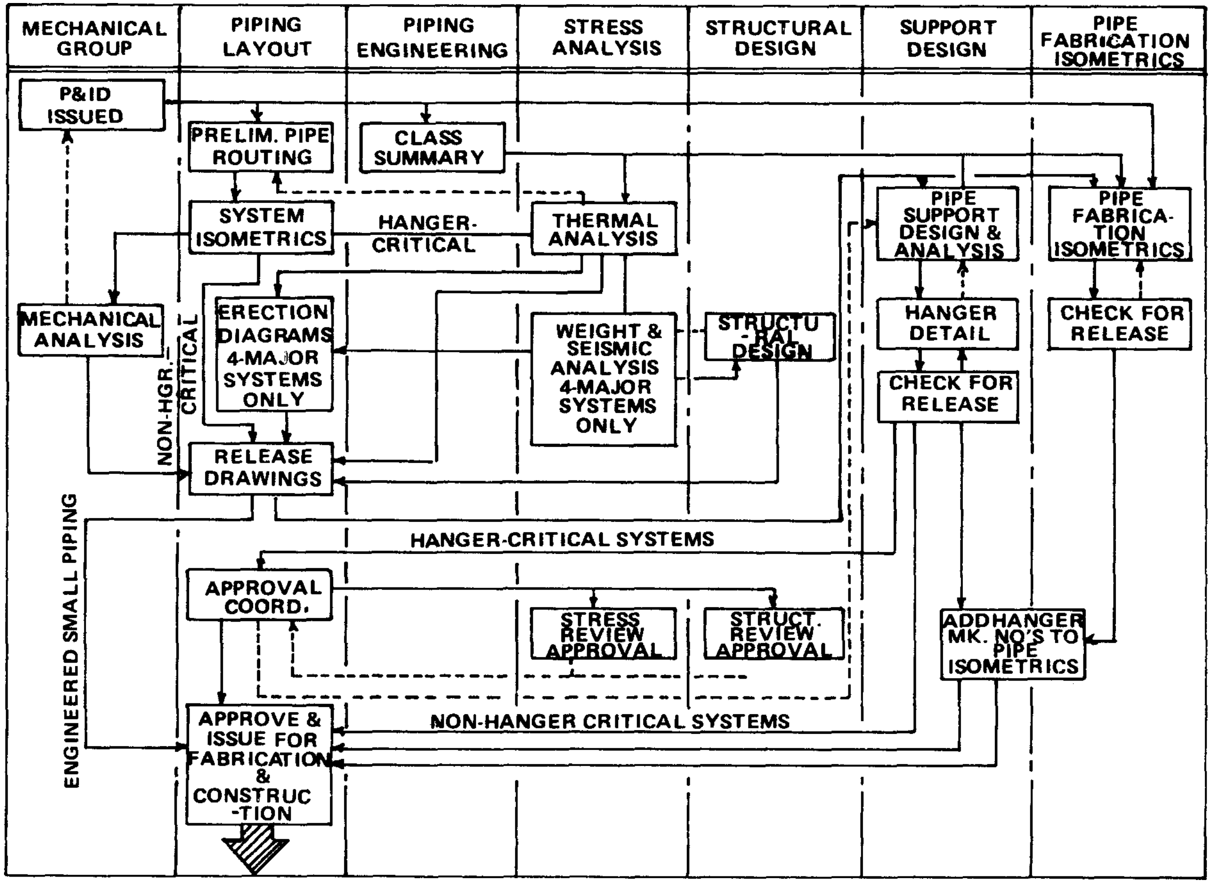


FIGURE IV. B-10 PLANT DESIGN PIPING FUNCTIONS

11. Electrical System and Lightning Protection System

All BOP loads, including the receiver tower, TSS, service building, etc., are served by the EPGS auxiliary load distribution system. This system is described in Appendix A, and on Drawing E-1368, sheets 1 through 8 in Appendix C.

Power for all loads is supplied through the 480 volt motor control center and/or 480 volt switchgear buses, which are located in an electrical equipment room in the turbine-generator building. The sources of power to the 480 volt distribution system are the main generator during normal daytime operation and the host utility grid during overnight shutdown.

Standby power is supplied by a 480 volt onsite diesel generator to maintain operation of essential loads such as the receiver door and tower elevator during loss of all normal power supplies. A 125 Vdc system and 120-240 Vac uninterruptable power supply are also included in the design to provide power for emergency lighting and critical instrumentation circuits.

All loads are supplied by cable feeders installed in either underground duct banks or in rigid conduit when above ground.

An overall plant grounding system is provided for protection against faults in electrical equipment, lightning, and static electricity. It consists of eight deep ground wells (drilled to the water table) and inter-connected with #4/0 AWG direct buried bare copper wire, forming an overall grounding grid (see Drawing E-1709 in Appendix C). This grid is electrically bonded to both the collector field and EPGS grounding systems.

Protection agains direct lightning strokes is provided by eight metal air terminals installed on the top of the receiver tower. All air terminals are connected to the metal framing of the tower which in turn is connected to the grounding grid via four connections at its base. All equipment, vessels, and metal structures are electrically bonded to the grounding system to prevent the occurrence of side flashes.

12. Thermal Storage Subsystem Layout

The TSS is an integral part of the pilot plant. It must supply steam to the EPGS turbine admission inlet at temperatures and pressures within the turbine admission conditions specified, and it must accept steam from the Receiver Subsystem at the receiver's output conditions. Its controls must be integrated with the remainder of the plant, and it must serve as a buffering device to smooth steam flow rates in some operating modes.

The TSS layout is designed to accommodate maximum TSS efficiency while still permitting minimum pipe lengths from the EPGS and Receiver Tower to the TSS equipment. The TSS charging main steam and discharging admission steam piping interfaces are located close to the TSS desuperheater and superheater components, at approximately the first pipe support outboard of the TSS equipment control or isolation valve. The TSS charging and discharging feedwater pipes from the subcooler and preheater interface with the EPGS at the perimeter of the turbine building.

Bechtel architectural and engineering design services were provided to Georgia Institute of Technology at Atlanta to assist with design optimization of the TSS. The specific tasks accomplished were:

- The system arrangement layout-thermal storage drawing was evaluated for concept and provision of criteria on the piping location and type of bends, fixed points, and piping supports. Evaluation of components and equipment layout was evaluated as a system and for interface with the BOP.

- Piping stress isometric drawings were evaluated. Review was conducted on the preliminary stress analysis of the piping system, the modeling, and the stress calculations.

- Requirements were established and defined for:

    - Flow (Process) diagrams--charge and discharge
    - Piping and instrumentation drawing (P&ID)
    - Piping and mechanical (Equipment) drawing (P&M)
    - Piping stress isometric drawings

- Wind Loading Criteria were established per ANSI A 58.1 (pages 18 and 23).

- Seismic criteria at ground level accelerations were established with resulting amplication at elevated component heights (desuperheater, superheater, oil tanks, etc.).

- Design requirements for the foundation and foundation layout for the oil tanks, salt tanks, and heat exchangers were addressed. The specific site soil bearing allowables at 1.6 m (5 ft) and 3.04 m (10 ft) depths were investigated.

The separation of heated oil tanks and the distance from oil storage tanks to other major equipment (salt tanks, heat exchangers, electric pump motors) has been dictated by the NFPA fire underwriters regulations, OSHA, and American Petroleum Institute for tanks containing oil at temperatures exceeding the flash point temperature.

Arrangement of TSS equipment within the constraints of the fire safety considerations has been controlled by the system charge and discharge flow process, the process hydraulic (elevation) profiles, piping thermal expansion loop requirements, component number and sizes, and the requirements for size, height, and location of dikes and drainage channels.

Safety and fire protection is provided by a plant perimeter firewater line loop. Two water fog and spray (foam) "monitor" nozzle stations are located on 15.2 m (50 ft) elevated stations near the oil storage tanks. As required by safety codes, the elevated temperature hydrocarbon oil tanks are closed and provided with a nitrogen cover gas inerting system.

A convenient fill station will be provided at the east side of the TSS equipment area to permit easy truck access to the oil tanks. Environmental impact was also considered because with the storage and use of large quantities of hydrocarbons, such as Caloria HT 43, the potential exists for accidental release to the environment. Design features intended to provide fire protection also serve to contain the hydrocarbons. A diked spill containment basin has been incorporated in the design to contain the hydrocarbons in the event of a tank leak or rupture.

13. Fire Protection

Fire protection for the pilot plant process equipment area is provided by a perimeter firewater line loop operated from a pump house located between the maintenance building and the TSS equipment. The fire pump is a 200 hp diesel driven unit capable of pumping 94.4 kg/sec (750,000 lb/hr) at a line delivery pressure of 963kPa (125 psig). This perimeter fire pipeline can supply water in either direction on the loop. Safety shutoff valves located at six positions on the loop ensure that water can flow to a fire location in either a clockwise or counter-clockwise direction without loss of function caused by a single pipe break. Two foam "monitor" nozzle stations are located on elevated stations near the TSS oil storage tanks as mentioned above.

The firewater flow rate and pressure is adequate to provide protection for any two buildings or major structures burning at one time, with the exception of the receiver tower. Since there will be limited access to the receiver tower during operation, no firewater requirement exists at the top of the tower. Instead, this area will be protected with portable fire extinguishers located at three places in the tower top area and every 15 m (50 ft) in elevation in the tower stairwell. In addition, personnel safety booths are provided in the tower stairwell every 15 m in elevation. These personnel safety booths provide a safe temporary haven for personnel in the tower in the event of a steam line rupture or a fire.

The perimeter fire loop provides protection for the EPGS, administration and control, and maintenance buildings. In addition, several portable fire extinguishers are located in these buildings. Adequate emergency fire exits are also provided in these buildings in compliance with the NFPA Guide to OSHA Fire Protection Regulations (Reference 4, Appendix H).

The Plant Support System Description in Appendix A describes the fire protection system in greater detail.

14. Controls

Controls for the EPGS and BOP are covered in a control system description included in Appendix A. These subsystems permit operation of the EPGS and BOP in all required plant operating modes. These are:

1. Overnight shutdown
2. Morning startup and synchronization
3. Continued warmup and loading
4. Normal daytime operation
5. Afternoon operation
6. Evening operation
7. Passing cloud transients
8. Receiver steam charging TSS with heliostats limiting
9. Receiver steam to condenser
10. Receiver steam to TSS with heliostats limiting; TSS steam to the condenser
11. Receiver steam to TSS with excess to the condenser; TSS discharge steam to the condenser
12. Receiver steam to TSS, TSS discharge steam to the turbine
13. Receiver steam to turbine and TSS with excess to condenser
14. Receiver steam to turbine and excess to TSS
15. Receiver steam to TSS with heliostats controlling flow
16. Receiver steam to turbine with heliostats controlling flow
17. Receiver steam to turbine with heliostats controlling initial pressure
18. Receiver steam to TSS with excess to the condenser and turbine shutdown
19. Receiver steam to TSS and to turbine with TSS discharge steam to turbine
20. TSS discharge steam to the condenser
21. Receiver steam to turbine with excess to condenser and TSS discharge steam to turbine
22. Receiver steam to turbine with excess to TSS and TSS discharge steam to turbine
23. Receiver steam to turbine with excess to condenser
24. Receiver steam to turbine with excess to condenser

25. Receiver steam to turbine with excess to condenser (Alternative to mode 24)
26. Receiver steam to turbine with some to TSS and excess to condenser

The EPGS Control System Description is described in more detail in Section IV.C-3 and Appendix A.

15. Plant Support Subsystems

Plant support subsystems are covered in detail in a system description included in Appendix A. These subsystems include:

1. Demineralized Water Makeup Supply System
2. Component Cooling Water System
3. Compressed Air System
4. Plant Heating, Ventilation, and Air Conditioning System
5. Cranes and Hoists
6. Fire Protection System
7. Domestic Water System
8. Sanitary Drainage System
9. Acid Waste System
10. Oily Waste System
11. Auxiliary Boiler System

All of the subsystems are required to support the EPGS and BOP systems.

C. DESIGN RELIABILITY, TECHNICAL RISK, AND SAFETY

1. Design Reliability

The pilot plant preliminary design for the BOP has been performed within the general program requirement to employ "state-of-the-art" design and to use commercially available components wherever possible. This was possible for the BOP because the components are not solar unique, but are utilized for the civil arrangement of the major subsystems and the physical interfaces between piping, wiring, and roadways of the subsystems. As a result of this use of standard design practices and components, the reliability of BOP systems and structures can be expected to be very high. All components and facilities are expected to be capable of serving their function throughout the life of the plant with normal maintenance. Since the maintenance can be performed in evening hours during the pilot plant's nightly shutdown period, no loss of plant availability is anticipated. BOP systems which contain mechanical equipment are subject to some possibility of breakdown. Valves, pumps, or motors will require repairs or replacement in some cases. By employing a program of regular monitoring for valve leaks, pump vibrations, or motor heating, the operators can locate faulty equipment prior to functional failure in most cases. Where such diagnosis can be made, repairs and replacement can be performed during the nightly shutdown periods, as with the facilities, and no loss of plant availability will result.

Due to these factors, the reliability of the BOP structures and components can be expected to exceed that of a similar fossil-fueled power plant and the BOP portions of the pilot plant should be available for use during 95 percent of daylight hours.

2. Technical Risk

The use of standard design practice and commercially available components in the Pilot Plant BOP preliminary design has resulted in minimal technical risk. The designs provided in the BOP section can be finalized and the systems constructed with very high confidence that all design functions will be met.

3. Safety

Buildings have been designed to UBC, NFPA, OSHA, ANSI, and ASCE standards for structures of these types. No unusual hazards to employees or visitors will be caused by these structures. Piping will be insulated against heat loss and as a result, outside surfaces of pipes will not be dangerously hot. Steam leaks from valves or mechanical equipment are possible and could provide a hazard for anyone in proximity to such a leak. Normal industrial safety training and practices will be followed to insure that employees are aware of potential hazards and that visitors are escorted in the plant.

Glare from misdirected heliostats has been considered as a potential hazard for personnel in the control room where windows permit a view of the collector field. A tinted-glass will be used in the windows to reduce the hazard, but operating personnel must be made aware of the potential risk. The heliostat control system has been designed with a goal of minimizing the potential of stray heliostat reflections. Consequently, this hazard is not considered to be great.

VI. MASTER CONTROL SUBSYSTEM

A. INTRODUCTION

As in a conventional power plant, operation of the solar thermal pilot plant will be carried out by the control operators. The operators are assisted in this important function by the pilot plant master control system (MCS). The MCS is modeled after a typical control system in a fossil fuel power plant, and design of the controls is strongly influenced by several discussions with power plant control operators. The MCS is a system which is simple, is user oriented, and is a system which employs state of the art hardwired control logic. The master controlsystem is comprised of the subsystem controls, the plant control system element, and the data handling system. The rational for the general design of the master control system stems from the character of the pilot plant itself and its operating characteristics. By industry standards, the plant is small (10 MWe), and elaborate controls are not required.

1. Master Control System Features

The MCS enables the control operators to safely control plant operations. Features of this master control system are:

a. Controls are maximized within subsystems, and subsystem control is essentially autonomous.
b. The MCS has emergency control capability to respond immediately to subsystem alarm conditions (by susbsystem control elements), and to initiate a response to system level alarm conditions.
c. The MCS provides a capability to coordinate system level operations by control through subsystem control elements.
d. Integrated pilot plant operations are accomplished by manually implementing written procedures which define operational profiles and sequences for steady state mode control and for transition between modes.

2. Subsystem Controls

To the maximum extent possible, plant control capabilities reside within the subsystem controls, and these controls are integrated by a system level control element designated the plant control system (PCS). Subsystem controls perform the majority of the plant control functions inasmuch as these controls have been designed to maintain stable operations over the wide range of conditions expected during a plant's daily operational cycle. The receiver subsystem (RS), thermal storage subsystem (TSS), and electrical power generation subsystem (EPGS) controls are all implemented with conventional hardwired logic and controllers. The heliostats are controlled by a minicomputer, and that control represents the only computer controlled element of the pilot plant. Because of the critical nature of heliostat control, the collector subsystem control minicomputer is backed up by the data handling system (DHS) minicomputer. Details of the subsystems' controls are found in the appropriate subsystem volumes of this report. A discussion of the interfaces between the subsystem controls, the PCS and the data handling system will be found later in this section.

3. Plant Control System (PCS)

The PCS coordinates the subsystem controls and provides a system level emergency response capability to the operators. Specifically, the PCS is a plant control element whose major functions are to:

a. Implement certain system level emergency actions automatically and provide control operators with the capability to manually command certain system level emergency actions;
b. Display subsystem alarm status;
c. Provide control operators with the capability to enable or disable certain major subsystem functions during operational sequencing;
d. Provide control operators with the capability to establish plant control configurations--
    1) configure emergency action logic,
    2) set data acquisition rates,
    3) display plant mode or mode transition status.

Physically the plant control system element is similar to a subsystem's controls but simpler in appearance and functions. The PCS is housed in an electronics rack the panels of which contain displays of plant alarm status and displays of the current mode in which the plant is operating (or the modes between which the plant is transitioning). The panel also contains a sequencing section with switches which enable or disable appropriate subsystem functions. Perhaps the most important PCS panel contains the system level emergency action controls. Behind the PCS panels reside the relatively simple logic circuits which carry out the various PCS functions. The several subsystem control racks and the data handling system are tied together at the PCS rack by a series of interconnecting cables.

4. MCS Definition

Figure VI.A-1 is a simplified schematic showing major control elements of the pilot plant and defining the MCS as those elements within the heavy dashed lines. In this figure, "boxes" represent functional elements of the plant; for example, "TSS" represents the entire thermal storage field hardware, and "TSS control" represents the TSS control logic. The arrows (and "bubbles") represent interfaces between the functional elements. The basic flow of the plant--from sunlight to electrical power--is represented by the open arrows proceeding from the collector subsystem (CS), to receiver subsystem (RS), to thermal storage subsystem (TSS) and/or the electrical power generation subsystem (EPGS). The source of control of each functional element is indicated by the interface arrow pointing to the top of each box.

The MCS encompasses all subsystem control elements, the PCS as well as the data handling and data logging functions. It should be emphasized that the data handling system has been designed to be completely independent of the controls. That is, if the DHS were removed, the plant control activities would continue unaltered.

5. The Control Room Philosphy

The basic philosophy underlying the master control system design is that absolute control of the plant is in the hands of the control operators. To understand how this philosophy is implemented, consider the control room environment and specifically the control console layout. Reference is made to the set of subsystems' controls and PCS as the control console, and the design considers each segment of the console to be a more-or-less free standing rack of controls; the racks are assembled side by side to form the console. The CS segment will consist of a video (CRT) display with keyboard and a teletypewriter nearby. The RS, PCS, EPGS, and TSS console segments follow, in that order, with the PCS and EPGS control segments contiguous and centrally located, a reflection of their criticality in the plant operation. Each of the subsystem control segments will contain displays and control devices to accomplish essentially autonomous operation of that subsystem to the degree the subsystem can be so operated. The PCS segment will provide system level displays and control capability to the operators.

The design rationale for the PCS control element derives in part from human factors considerations, from the pilot plant's design philosophy and from the plant's operational process.

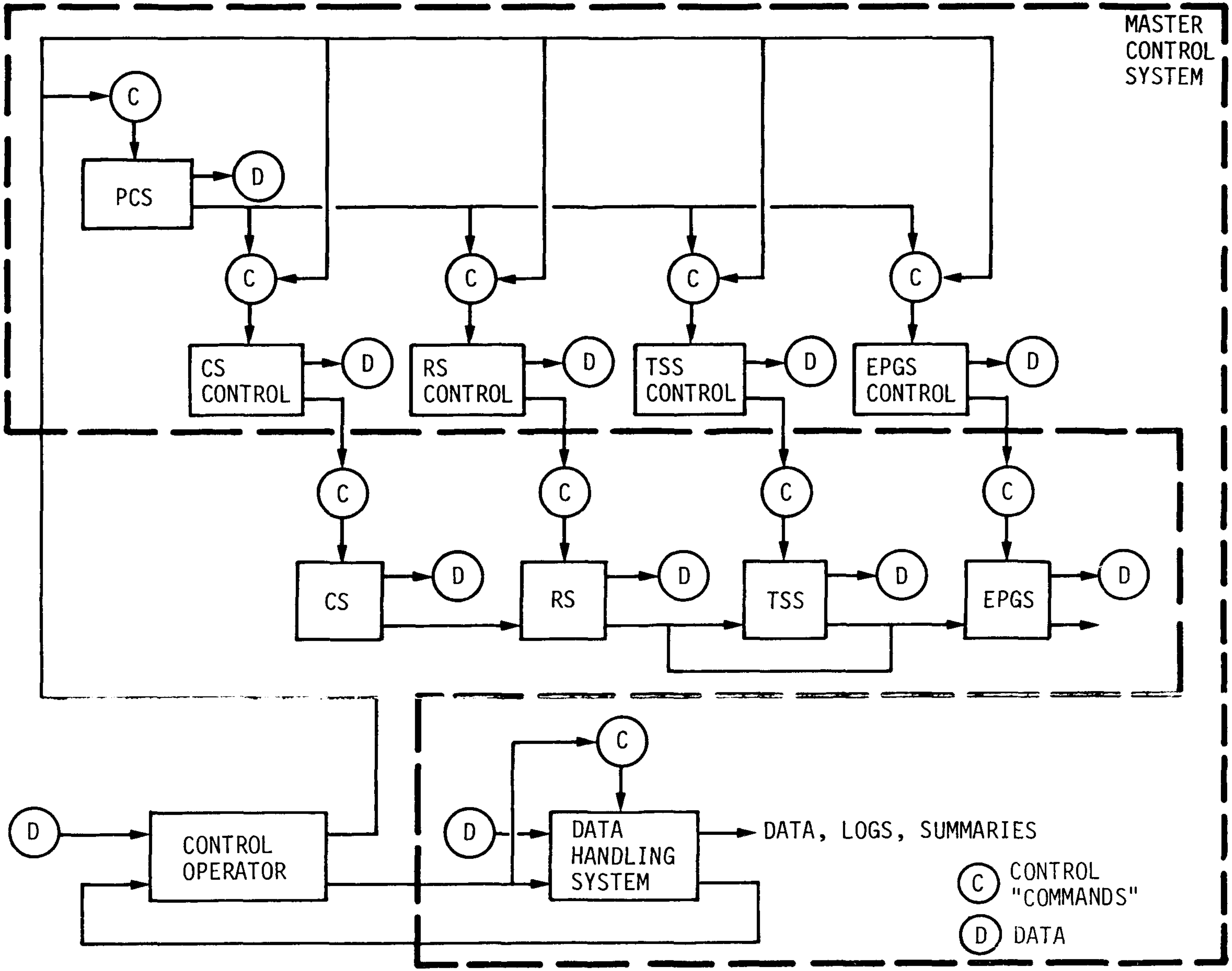


Figure VI.A-1 Pilot Plant Schematic Defining Master Control System

a. Human Factors - Operation and control of the pilot plant for a daily cycle involves the control of several operating modes and transitions between modes. The control console--the control operators "handle" on the plant--has in the PCS and EPGS segments, a centralized location from which to determine overall plant status and a display capability to efficiently guide the operators' attention to the source of an alarm condition. If an alarm occurs within a subsystem, the control operators can step to the subsystem controls and make appropriate adjustments. If a system level alarm ocurrs, the control operator can implement some major system level emergency responses from the PCS and/or the subsystem controls.

b. Design Philosophy - As has been indicated, the pilot plant will be designed by subsystems (with appropriate integration). Each subsystem's controls requires some level of interplay with the controls of other subsystems, and some of these interconnections are a function of plant operating mode. For example, emergency response to a turbine trip would be different, for the case in which the turbine is operating on main steam only, from the case in which the turbine is operating on main and admission steam. The control logic for reacting at the system level to major emergency/alarm conditions, such as a turbine trip, resides within the PCS control elements, and the PCS logic is reconfigured as required by the control operator to match each plant operating condition. Then when a turbine trip condition is initiated by the EPGS controls, the alarm status is transmitted to the PCS control element which, being properly configured, immediately implements the appropriate actions through the other subsystem control elements.

c. Operational Process - In the operation of the plant, the control operators will implement (follow) specific procedures which will be written and available in notebook format. These procedures will assist the operator in following the correct operational sequences including configuring and controlling the plant for 8 "steady state" modes and transitions between those modes. Most of the time the plant will be operated following a basic daily cycle involving three or four modes and a similar number of mode transitions. Occassionally the operators will be required to follow a different plan, and the written procedures along with the PCS capabilities will assist the operators in accomplishing these less frequent routines. The sequencing functions of the PCS--the enable/disable capabilities--will provide a checking function and a back-up to the procedures. The control operator will configure the PCS before changing modes and will "disable" certain subsystem functions. Then, when the appropriate prerequisites have been accomplished according to the procedure, the subsystem function is "enabled" allowing the control operator to proceed and not inadvertently get out of sequence.

6. Operational Cycles, Modes and Mode Transitions

Aside from the energy source for a solar plant, the predominate characteristic which distinguishes a solar power plant from a conventional power plant is the solar plant's diurnal operational cycle as contrasted to the more or less constant operation of a conventional plant. The solar plant goes through a daily set of operations:

- startup
- normal operations (including)
  - change mode
- shutdown
- maintenance

Maintenance will be accomplished in parallel or after plant shutdown. A normal operational cycle involves getting the plant into one of several "steady state" modes and causing the plant to change from one mode to another. As an example consider Figure VI.A-2 which schematically depicts the power output from a single daily operational cycle. The "C", "R", "T", and "E" represent the collector, receiver, thermal storage and electrical power generation subsystems respectively. To accomplish the required power output the plant will be configured in different steady state modes during the cycle. "Steady state" is used to indicate that the plant configuration is constant, but the output from each subsystem may vary considerably. For instance, Mode I will see the collector subsystem output and hence the receiver output follow the diurnal solar flux. Normally, once a steady state mode has been established the control settings will not need to be changed, since the subsystem controls are designed to allow the subsystems and the system to "track" the changing solar flux.

These characteristics of steady state mode control and transitions between modes are fundamental to the plant's control design. In fact the total capability of the plant can be defined in terms of eight steady state modes and transitions between these modes. Figure VI.A-3 lists the eight modes, seven of which are active modes representing various configurations in which the plant can be operated, and Mode VIII which is the passive overnight mode. It is anticipated that for normal operations, only a few of the eight modes will be used. It should be emphasized that the eight modes

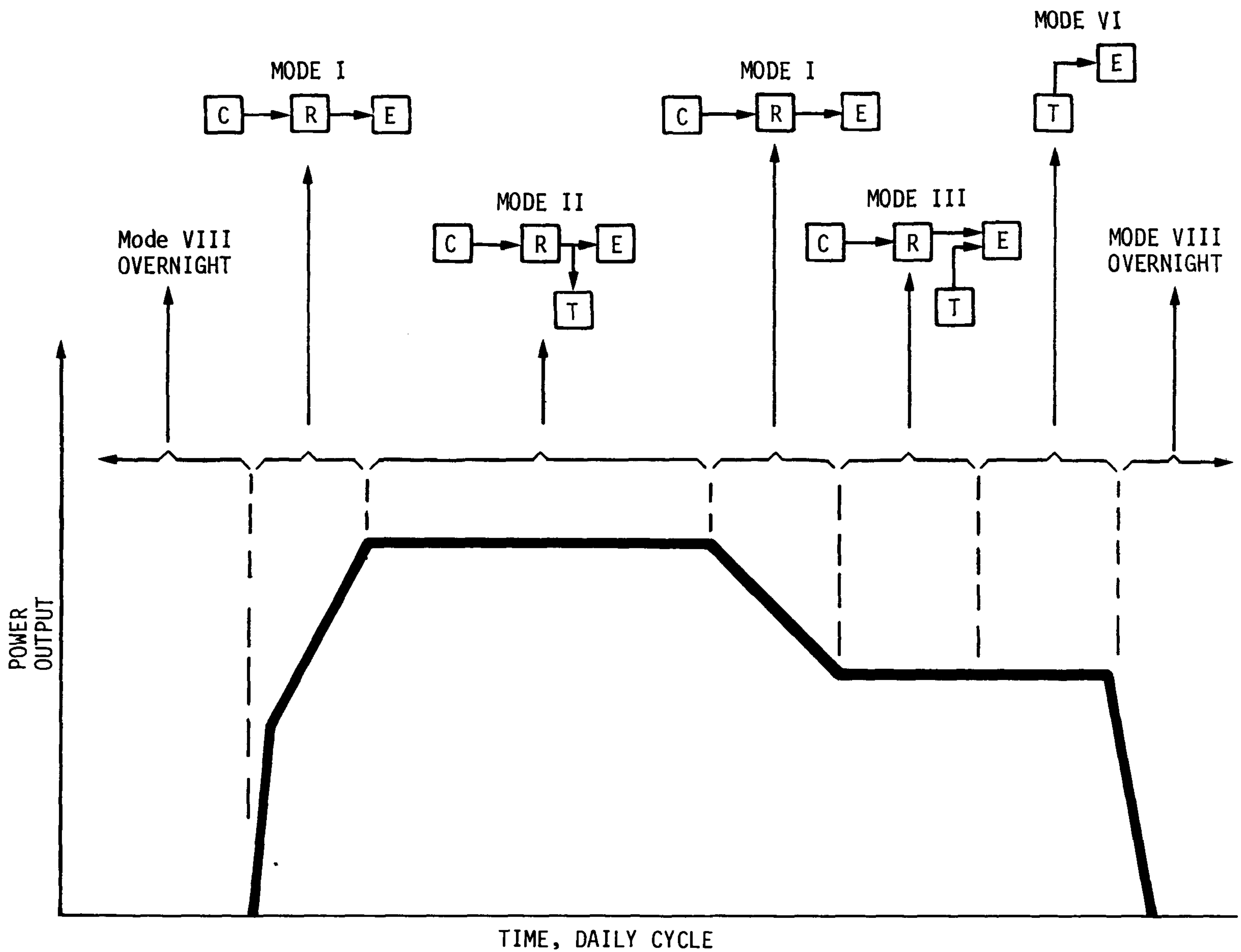


Figure VI.A-2 Schematic Representation of Operational Modes During a Daily Cycle

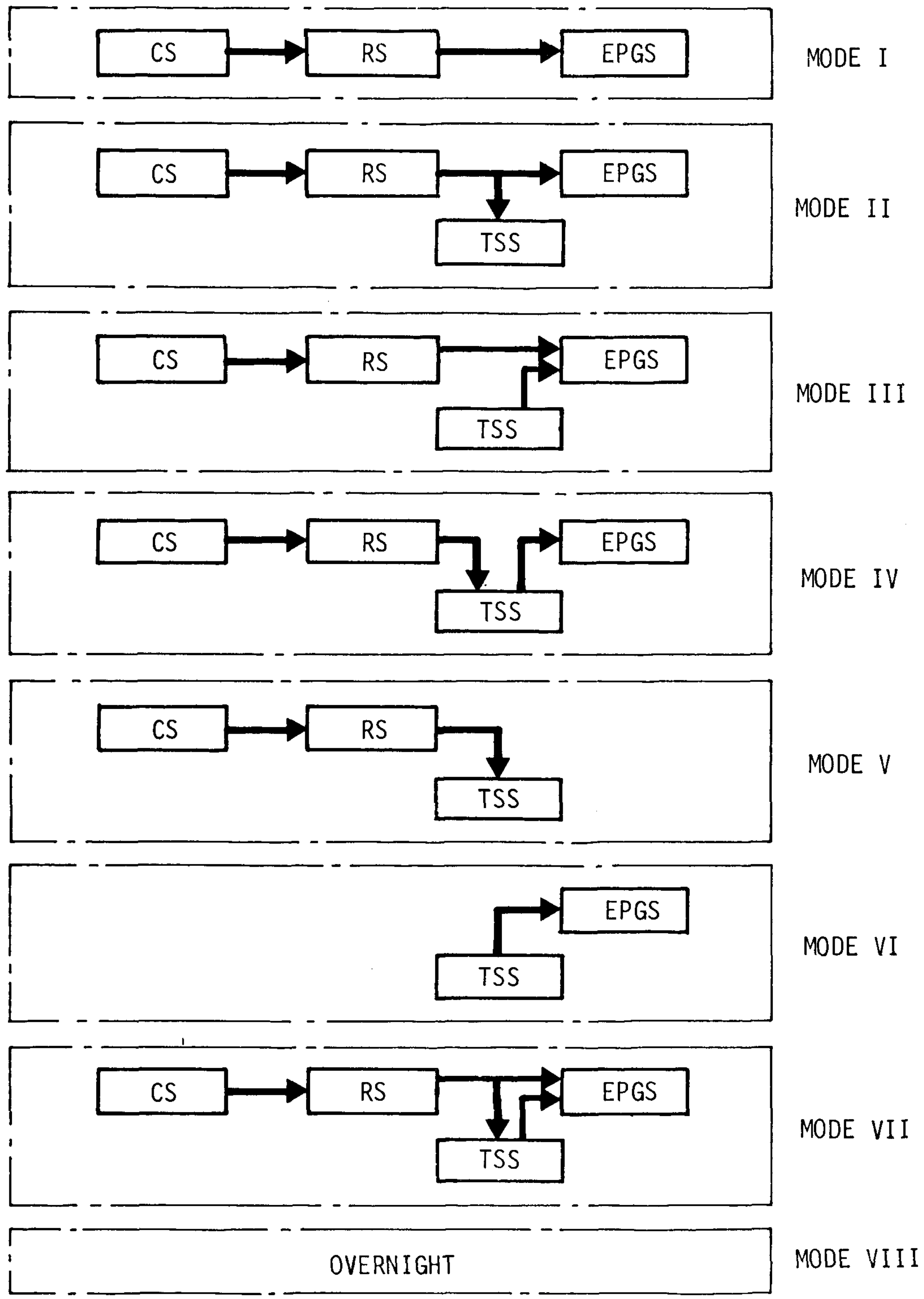


Figure VI.A-3 Pilot Plant Steady-State Modes are system level modes; each of the subsystems will be configured in appropriate subsystem modes, combinations of which produce the eight plant modes. Table VI.A-1 lists the various subsystem modes and the corresponding symbolic descriptions which are used in Table VI.A-2.

An interesting result of the need for the plant to operate in several modes and therefore the requirement that the plant transition between the eight modes is that there are 56 unique mode transitions. This is a characteristic of any solar power plant made up of the same subsystems contained in the pilot plant, and is not a result of any particular design. Table VI.A-2 presents a system mode transition matrix which represents the set of transitions which must be accomplished by the subsystems in order to implement any plant mode transition. As an example, to reconfigure the plant from Mode I to Mode II, the thermal storage subsystem would be brought from the overnight mode (TM1) to the charge mode (TM2).

As was stated previously, the plan to be followed by the control operators for control of the plant in a steady state mode or during a mode transition will be documented in procedures. This implies, then, that there will be on the order of 64 nominal procedures: eight for the steady state modes, and 56 for mode transitions.

7. Data Handling

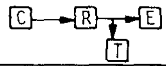
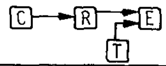
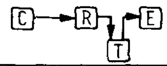
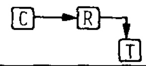
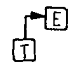
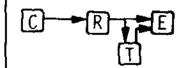
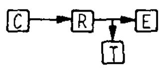
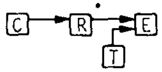
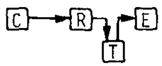
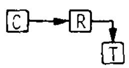
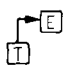
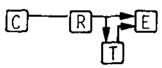
A major portion of the pilot plant's data handling will be implemented using a minicomputer with disc mass storage capabilities. This approach recognizes the capabilities of digital computer systems to handle efficiently the moderate to large quantities of data generated by the solar thermal pilot plant in a cost effective manner. In addition to using the digital computer, some of the plant's data display and "logging" will be accomplished using strip chart or other pen recorders.

The data handling system computer functions as the backup to the CS control computer, and this concept is seen most clearly when a CS control computer anomaly is detected. The data handling activities are suspended while the collector subsystem control software is loaded on the redundant computer by the control operator, and heliostat control is continued from the back-up machine. The plant's automatic data logging capability is diminished until the CS control computer capability has been restored.

TABLE VI.A-1 SUBSYSTEM STEADY STATE MODES

COLLECTOR	
CM1	stow
CM2	operational
CM3	non-operational
RECEIVER	
RM1	overnight
RM2	operational
RM3	non-operational
THERMAL STORAGE	
TM1	overnight
TM2	charge
TM3	discharge
TM4	charge & discharge
TM5	non-operational
ELECTRICAL POWER GENERATION	
EM1	overnight
EM2	main steam
EM3	admission steam
EM4	main and admission steam
EM5	no turbine/generator
EM6	non-operational

Table VI.A-2 System Mode Transition Matrix

FROM \ TO	I 	II 	III 	IV 	V 	VI 	VII 	VIII OVERNIGHT
I 		TM1 → TM2	TM1 → TM3 EM2 → EM4	TM1 → TM4 EM2 → EM3	TM1 → TM2 EM2 → EM5	CM2 → CM1 RM2 → RM1 TM1 → TM3 EM2 → EM3	TM1 → TM4 EM2 → EM4	CM2 → CM1 RM2 → RM1 EM2 → EM1
II 	TM2 → TM1		TM2 → TM3 EM2 → EM4	TM2 → TM4 EM2 → EM3	EM2 → EM5	CM2 → CM1 RM2 → RM1 TM2 → TM3 EM2 → EM3	TM2 → TM4 EM2 → EM4	CM2 → CM1 RM2 → RM1 TM2 → TM1 EM2 → EM1
III 	TM3 → TM1 EM4 → EM2	TM3 → TM2 EM4 → EM2		TM3 → TM4 EM4 → EM3	TM3 → TM2 EM4 → EM5	CM2 → CM1 RM2 → RM1 EM4 → EM3	TM3 → TM4	CM2 → CM1 RM2 → RM1 TM3 → TM1 EM4 → EM1
IV 	TM4 → TM1 EM3 → EM2	TM4 → TM2 EM3 → EM2	TM4 → TM3 EM3 → EM4		TM4 → TM2 EM3 → EM5	CM2 → CM1 RM2 → RM1 TM4 → TM3	EM3 → EM4	CM2 → CM1 RM2 → RM1 TM4 → TM1 EM3 → EM1
V 	TM2 → TM1 EM5 → EM2	EM5 → EM2	TM2 → TM3 EM5 → EM4	TM2 → TM4 EM5 → EM3		CM2 → CM1 RM2 → RM1 TM2 → TM3 EM5 → EM3	TM2 → TM4 EM5 → EM4	CM2 → CM1 RM2 → RM1 TM2 → TM1 EM5 → EM1
VI 	CM1 → CM2 RM1 → RM2 TM3 → TM1 EM3 → EM2	CM1 → CM2 RM1 → RM2 TM3 → TM2 EM3 → EM2	CM1 → CM2 RM1 → RM2 EM3 → EM4	CM1 → CM2 RM1 → RM2 TM3 → TM4	CM1 → CM2 RM1 → RM2 TM3 → TM2 EM3 → EM5		CM1 → CM2 RM1 → RM2 TM3 → TM4 EM3 → EM4	TM3 → TM1 EM3 → EM1
VII 	TM4 → TM1 EM4 → EM2	TM4 → TM2 EM4 → EM2	TM4 → TM3	EM4 → EM3	TM4 → TM2 EM4 → EM5	CM2 → CM1 RM2 → RM1 TM4 → TM3 EM4 → EM3		CM2 → CM1 RM2 → RM1 TM4 → TM1 EM4 → EM1
VIII OVERNIGHT	CM1 → CM2 RM1 → RM2 EM1 → EM2	CM1 → CM2 RM1 → RM2 TM1 → TM2 EM1 → EM2	CM1 → CM2 RM1 → RM2 TM1 → TM3 EM1 → EM4	CM1 → CM2 RM1 → RM2 TM1 → TM4 EM1 → EM3	CM1 → CM2 RM1 → RM2 TM1 → TM2 EM1 → EM5	TM1 → TM3 EM1 → EM3	CM1 → CM2 RM1 → RM2 TM1 → TM4 EM1 → EM4	

8. MCS Requirements Summary

The preceeding introductory material reflects the two basic MCS requirements:

a. Controls - To provide the capability for the control operators to safely control the entire plant operations in all modes and mode transitions, and to detect, alarm, and respond to emergency conditions;

b. Data Handling - To acquire, process, store and retrieve, and output data for all plant elements. Data processing includes production of logs, summaries, performance calculations, and archival data.

The remainder of this section will consider these two requirements in more detail.

B. CONTROLS

1. Control Functions

General functions required of the subsystem controls and the PCS have been established, based on the operational cycle described previously. Table VI.B-1 outlines these functions for the four subsystems in general and for the PCS. Specifically, this table indicates that for the nominal cycle (start-up, normal operations, mode change and shut-down) the subsystem controls have similar functions of steady state control, mode transition control, and display functions. The PCS coordinates sequencing by its capability to enable/disable subsystem functions, and the PCS has a system status display function. For non-nominal operations, that is alarm conditions, the subsystem and PCS functions are somewhat more involved. To understand the emergency action activities better, two states of alarm have been defined: subsystem alarm and system alarm. Each level of alarm has a different response by the control system.

a. Subsystem Alarm - A subsystem alarm is the out-of-limit condition within any subsystem which, when it occurs, requires an action by the subsystem but requires no action by any other subsystem to correct the condition, and which requires no immediate action by any other subsystem in response to the condition. (A condition within a subsystem which causes a subsystem alarm may cause, in time, a system alarm due to degradation of the subsystem's performance, but the subsystem's alarm condition cannot

TABLE VI.B-1 PILOT PLANT CONTROL FUNCTIONS

PLANT OPERATION	CONTROL FUNCTIONS	
	SUBSYSTEM CONTROLS	PLANT CONTROL SYSTEM
Start-up	- checkout and initialize subsystem controls - implement mode transition procedure - respond to PCS enable/disable constraints - monitor and display subsystem status	- checkout PCS and configure for mode transition - implement mode transition procedure - enable/disable appropriate subsystem functions - display system status - inform DHS of PCS configuration
Normal Operation	- maintain steady state control - maintain and display subsystem status	- configure PCS for steady state control - display system - inform DHS of PCS configuration
Mode Change	- implement mode transition procedure - respond to PCS enable/disable constraints - monitor and display subsystem status	- configure PCS for mode transition - enable/disable appropriate subsystem functions - display system status - inform DHS of PCS configuration
Shut-down	- implement mode transition procedure - respond to PCS enable/disable constraints - monitor and display subsystem status	- configure PCS for mode transition - enable/disable appropriate subsystem functions - implement mode transition procedure - display system status - inform DHS of PCS configuration

TABLE VI.B-1 CONTINUED

PLANT OPERATION	SUBSYSTEM CONTROLS	PLANT CONTROL SYSTEM
Emergency Action	- respond to PCS emergency command - monitor, detect, respond to and display subsystem alarm condition - inform PCS of subsystem alarm status - monitor, detect, respond to and display subsystem generated system alarm condition - inform PCS of system alarm condition - inform DHS of subsystem alarm status	- respond to system alarm condition - implement PCS emergency commands - display system alarm status - display subsystem alarm status - inform DHS of PCS alarm status

be corrected by action to any other subsystem's controls, nor does the condition require a timely response by any other subsystem's controls.)

All subsystem alarms are:

1) detected by subsystem control element;
2) displayed by subsystem control display element;
3) transmitted to PCS as alarm status only;
4) displayed by PCS display element as subsystem alarm;
5) are responded to:
    a) manually by control operator, or
    b) automatically by design (if required) by subsystem controls.

b. System Alarm - A system alarm is the out-of-limit condition within any subsystem which, when it occurs, requires a response by two or more subsystem controls.

All system alarms are:

1) detected by subsystem control element;
2) displayed by subsystem control display element;
3) transmitted to PCS;
4) displayed by PCS display element;
5) are responded to either:
    a) manually by control operator, or
    b) automatically by design (if required) by PCS through appropriate subsystem controls.

2. MCS Configuration and Interfaces

The configuration and interfaces implied by the general subsystem and PCS requirements, and the data handling system interfaces are explicated in Figure VI.B-1. In this figure is depicted the control operators, PCS, DHS, and a typical subsystem---its field hardware and subsystem controls. The balance of the MCS design will be described in terms of this figure.

The subsystem field hardware produces data which are routed to the subsystem controls located primarily in the control building on the subsystems controls console. The field data are also logged by the DHS. The subsystem field hardware is controlled by subsystem controls. This subsystem control element in turn produces alarm data which are logged by the DHS and which are fed to the PCS for display or for initiation of system emergency actions. In turn the subsystem control element is controlled automatically by sequencing and alarm signals from the PCS, and manually by the control operators' control settings.

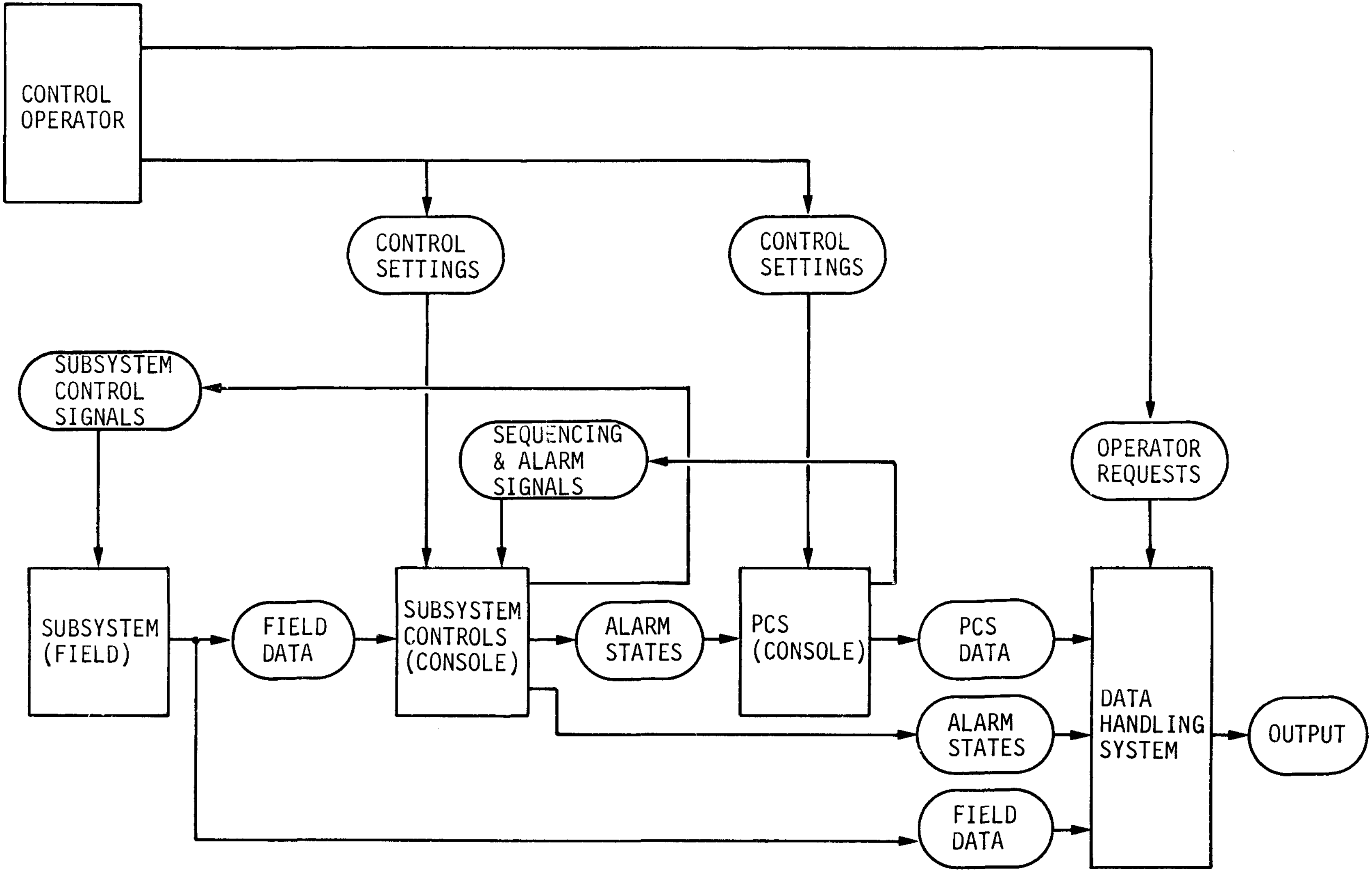


Figure VI.B-1 Simplified Schematic - Pilot Plant MCS Interfaces

The PCS similarly produces alarm status and sequencing data to be logged by the DHS, and the PCS is controlled manually by the control operators' control settings. To round out the MCS configuration, the DHS receives all the data, and produces logs and summaries upon operator request. It should be emphasized again that the DHS is a parallel and separable element of the MCS; control of the plant is completely independent of the DHS.

3. PCS Interfaces

Additional detail of the PCS structure and the several PCS interfaces are detailed in Figure VI.B-2. As the figure shows the PCS is comprised of four logic elements which implement the four PCS control functions outlined in the introduction, namely:

a. plant configuration
b. emergency action
c. subsystem alarm status
d. sequencing

A more detailed electronics block diagram of the PCS logic is given in Figure VI.B-3. The plant configuration logic is set by the control operator to indicate whether the plant is in a steady state mode or mode transition and also to display which steady state mode (or the modes between which transition is occurring). This logic will drive the displays, but of greater importance the logic will cause the emergency action logic element to be properly configured for any mode-peculiar immediate response. Additionally the plant configuration logic status will be logged by the DHS and will be used by the DHS to establish data acquisition rates. (Some data acquisition rates are greater during mode transitions than during steady state control.) The plant configuration logic-to-DHS interface is implemented with a 16 bit parallel data bus, and the DHS will sample the contents of the 16 bit PCS register on a schedule determined by the DHS.

The emergency action logic is enabled manually by the control operators or automatically by alarm signals from any of the four subsystem controls. Alarm conditions having automatic response are those which require system response times on the order of milliseconds. Examples are: turbine trip and low feedwater pump pressure. The emergency actions which can be implemented manually from the PCS panel are major system safing actions. These PCS actions are redundant to subsystem control capability and are located on the PCS panel to enable rapid operator response to system alarm conditions. Typical PCS emergency action functions are:

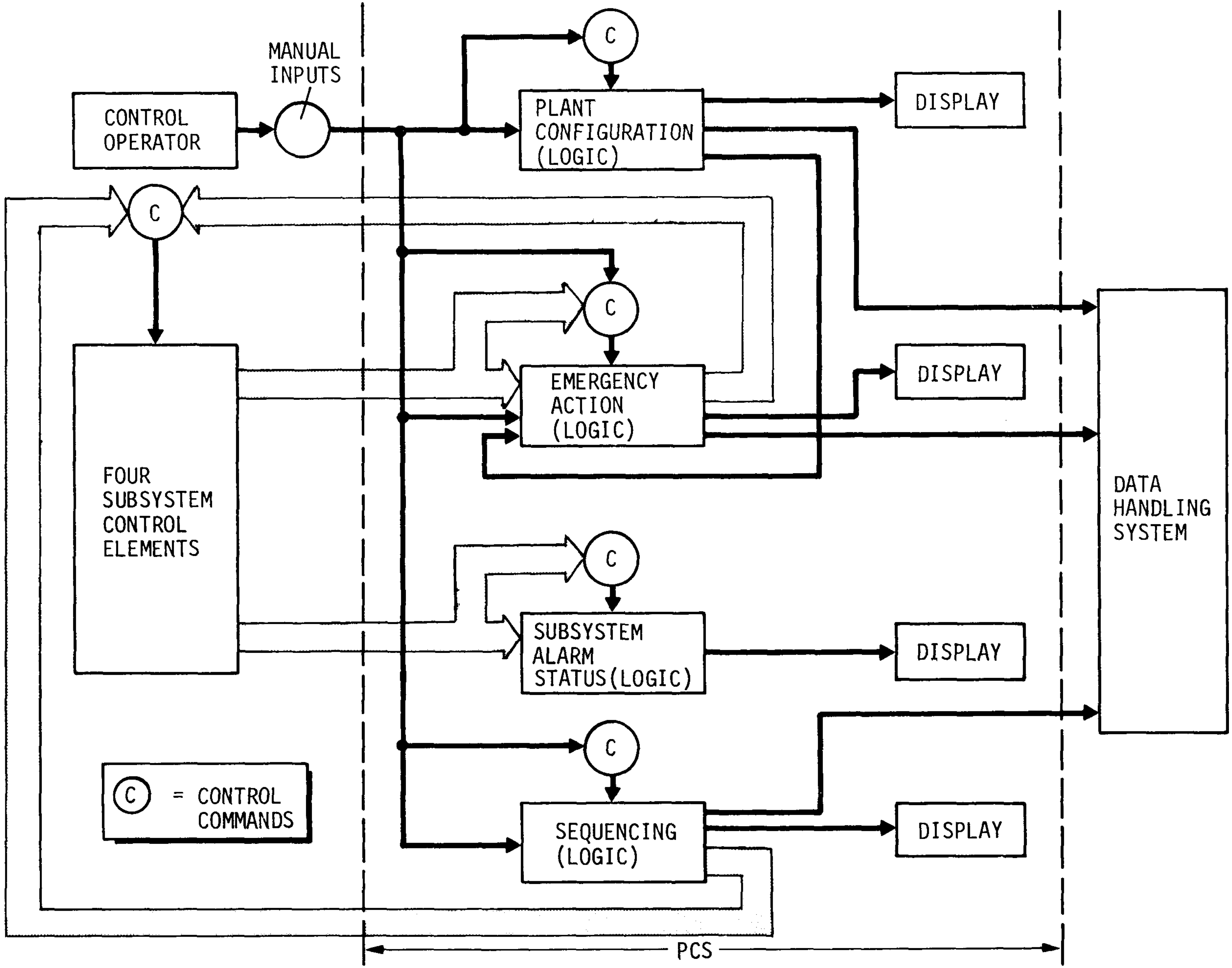


Figure VI.B-2 Plant Control System Interfaces

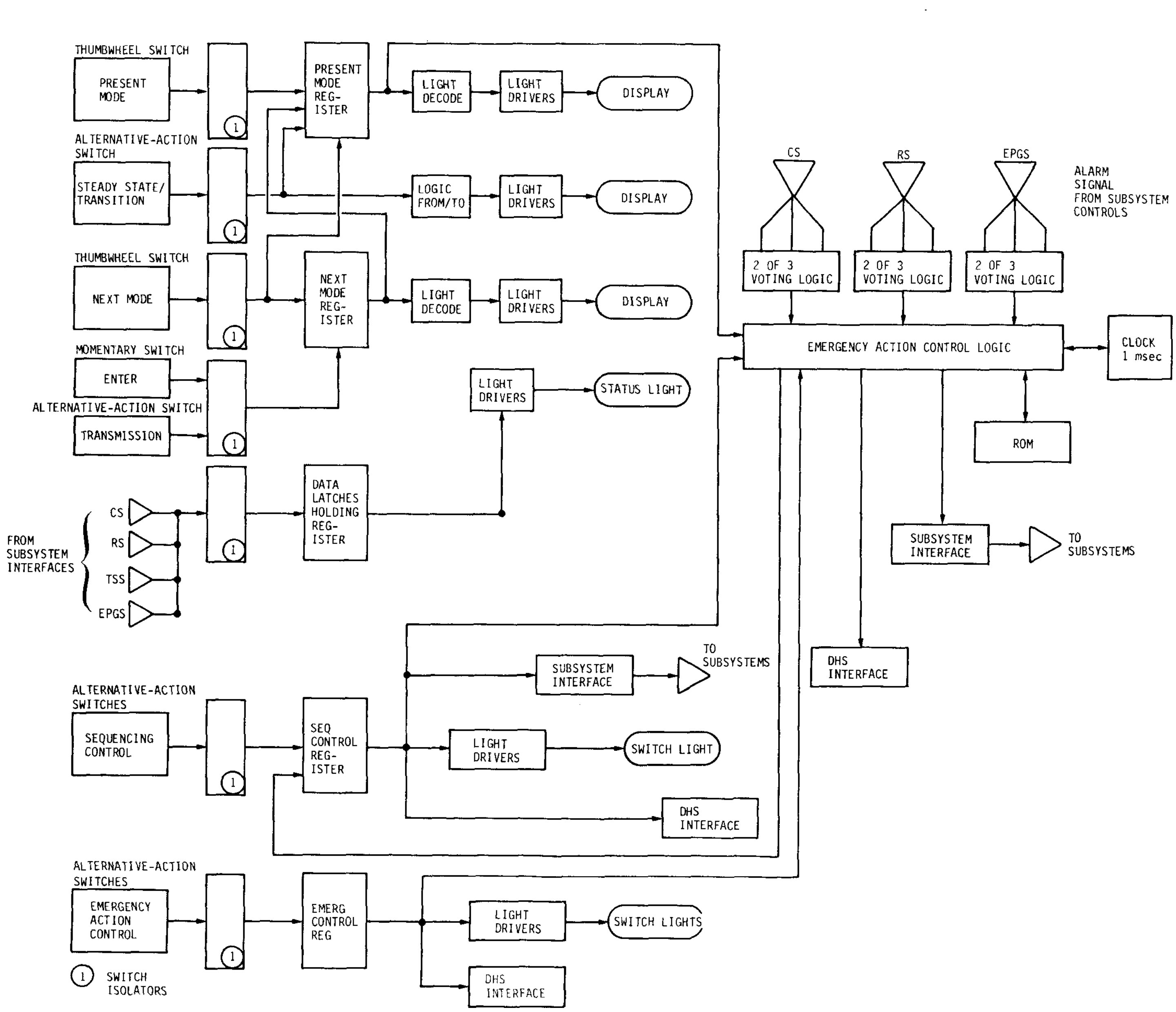


Figure VI.B-3 Plant Control System Electronics Block Diagram

- heliostats to standby
- receiver doors close
- receiver steam stop
- TSS discharge stop
- TSS charge stop
- turbine trip
- generator breaker trip

As has been stated, any of these seven functions can be initiated manually from the PCS panel by the control operator, and one or more of these functions are initiated automatically in response to system alarm conditions triggered by alarm signals from subsystem controls. Figure IV.B-4 presents the functional block diagram for this emergency action control logic. The status of the PCS emergency controls are displayed on the PCS control panel, and the status is logged by the DHS. The emergency action logic-to-DHS interface is implemented with a 16 bit parallel data bus and a store and transmit logic element in the PCS. Figure VI.B-5 details this interface to the DHS. When an emergency action logic signal is received from a subsystem, the PCS stores that information in a register file and raises a logic state (flag) to the DHS which reads the register contents. Although the DHS treats the alarm flag as a top priority interrupt, it is possible for the PCS to store more than one alarm message before the register is read by the DHS. Likewise, when the PCS responds to a subsystem generated system alarm, or when the control operator manually commands a system alarm, the PCS command signal is stored in the register and the PCS-to-DHS flag is raised.

The alarm status of each subsystem is summarized on the PCS display panel. Specifically some 12 subsystem conditions are displayed as "green" or "red". There is no action taken by the PCS logic other than to identify to the control operator the current alarm status of the major subsystem components. The alarm summary conditions are:

Collector
- computer status
- field status

Receiver
- superheater status
- steam drum status
- tower temperature status

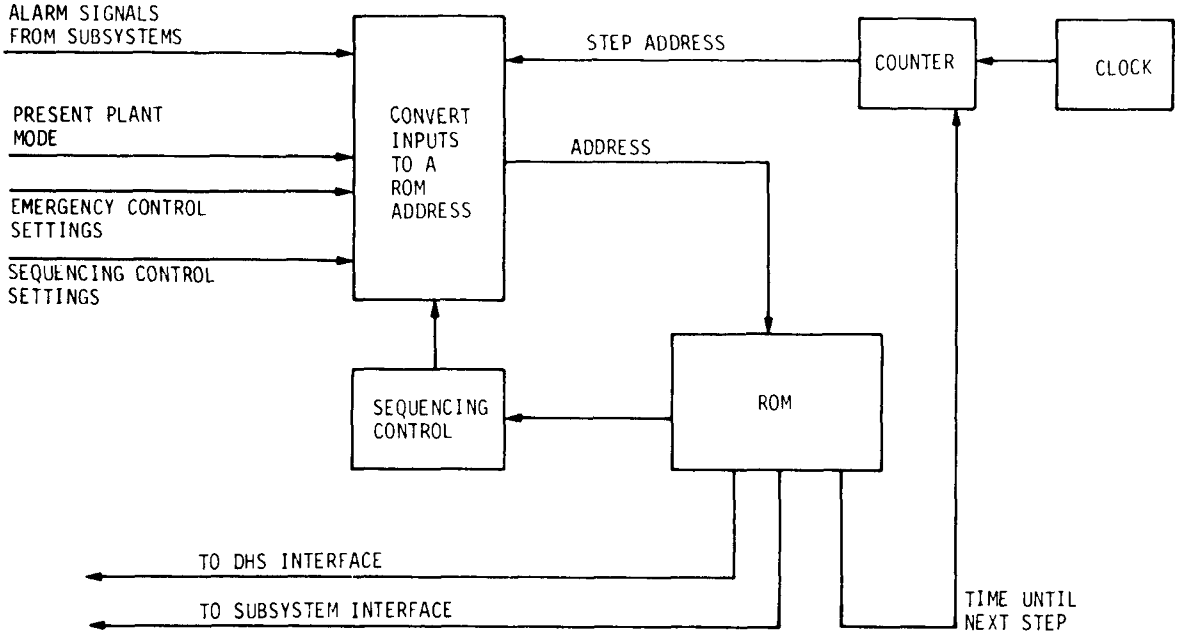


Figure VI.B-4 Emergency Action Control Logic Functional Diagram

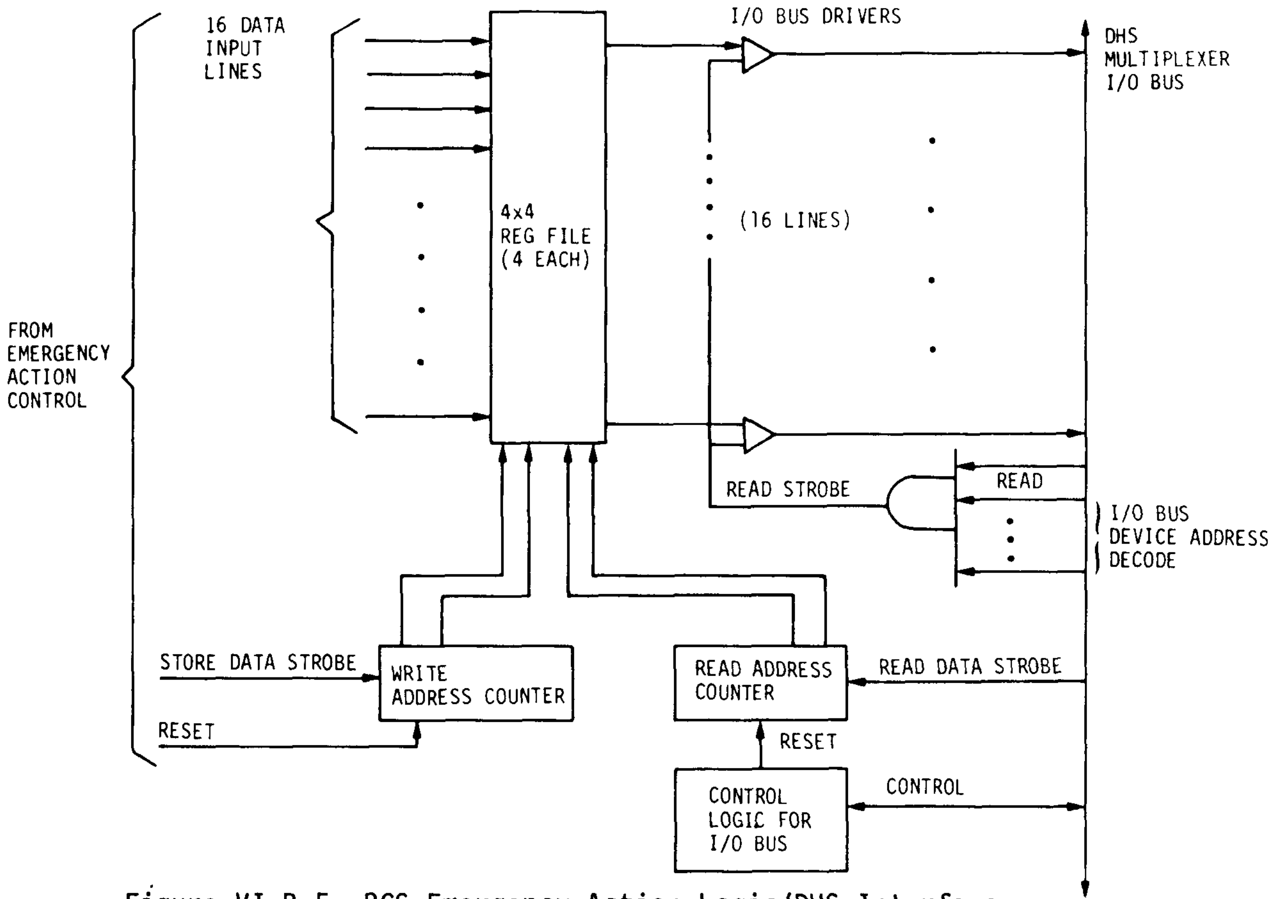


Figure VI.B-5 PCS Emergency Action Logic/DHS Interface

Thermal Storage
- charge status
- discharge status
- oil level status
- salt level status

Electrical Power Generation
- turbine/generator status
- feedwater/condenser status
- power conditioning status

The final logic function of the PCS is the sequencing logic. These are essentially switches which enable or disable some 12 subsystem functions. The states are set manually by the control operators based on procedures, are displayed on the PCS panel, and are logged by the DHS. The sequencing logic-to-DHS interface is implemented with a 16 bit parallel data bus, and the DHS will sample the contents of the 16 bit register on a schedule determined by the DHS. Most importantly the logic states control the subsystems controls by allowing or disallowing certain actions to be implemented by the subsystem controls. However, enabling a subsystem function from the PCS panel does not cause that subsystem function to occur; it merely allows that subsystem function to occur when it is so commanded from the subsystem controls. The 12 enable/disable functions are:

Collector
- on target command

Receiver
- receiver doors open
- feedwater flow

Thermal Storage
- charge, steam open
- discharge, feedwater open
- oil flow
- salt flow

Electrical Power Generation
- main steam open
- main steam by-pass open
- admission steam open
- admission steam by-pass open
- generator breaker close

It should be noted that emergency commands will override the enable/disable functions as required.

4. Subsystem Controls Interfaces

The majority of the subsystems controls interfaces have been identified in the context of the preceeding discussions; this section summarizes these interfaces.

a. Subsystem Control/Subsystem Field Hardware - Most of the subsystems' control functions are associated with subsystem field hardware. The field hardware produces control data signals which are carried to the subsystem controls, and the subsystem controls in turn send control signals to the field hardware. These control functions are described in more detail in the appropriate subsystem volumes.

b. Subsystem Control/PCS Interface

1) Subsystem to PCS - The alarm and alarm status interface between the subsystems and the PCS are hardwired on a one-function/one-signal basis. That is, each subsystem emergency alarm state which requires immediate system level (PCS) response will result in a single logic control signal to the PCS. The control signals will, in fact, be implemented redundantly using one-out-of-two or two-out-of-three voting logic in the PCS. Typical two-out-of-three voting logic is depicted in Figure VI.B-6.

2) PCS to Subsystem - The control command signals from the PCS to each subsystem will also be implemented on a hardwired, one-function/one-signal basis. It should be recalled that the total number of hardwired emergency actions emanating from the PCS is small, and the number of interconnections is also small. However, one emergency command from the PCS may result in several discrete commands being sent. For example more than one valve will be commanded to change state in response to a feedwater pressure low condition.

c. Subsystem Control Alarm/DHS Interface - When any control parameter is determined to be in an alarm condition by the subsystem controls, this information is transmitted to the DHS. When a parameter which has been in alarm clears, this information is also transmitted to the DHS. Specifically, when either of these conditions is detected by a subsystem's controls, the subsystem raises a flag to the DHS and stores the information in a

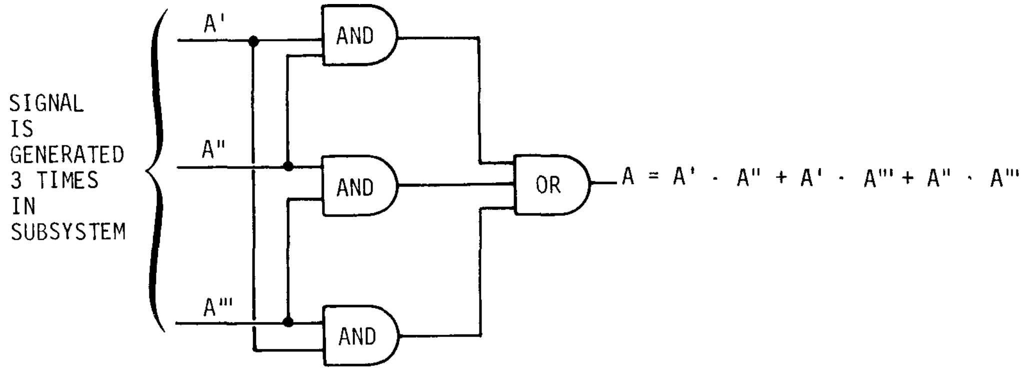


Figure VI.B-6 Two-Out-of-Three Voting Logic Schematic

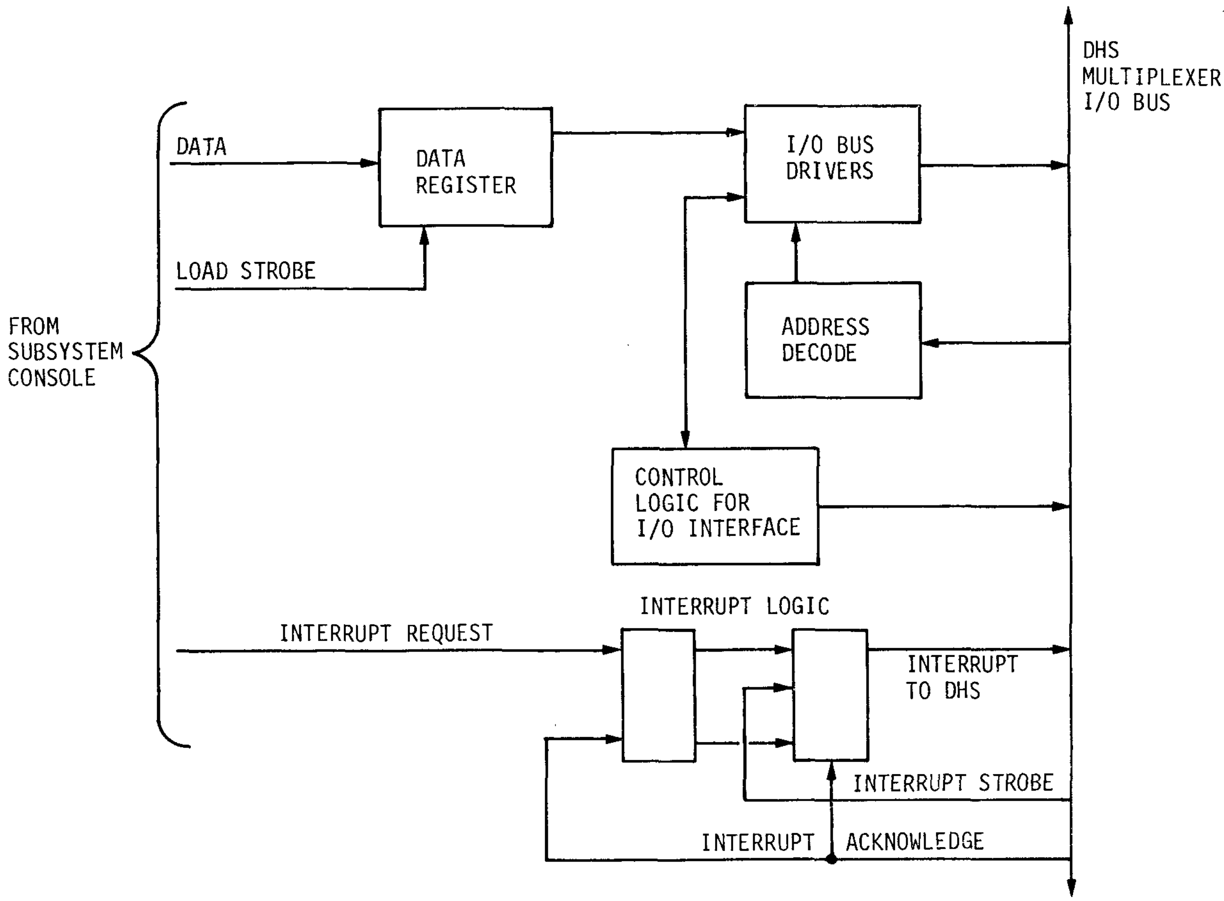


Figure VI.B-7 Typical Interface-Subsystem Control to Data Handling System register file; subsequently the DHS reads the register contents. A typical interface between a subsystem control element and the DHS is shown in Figure VI.B-7, and the contents of the alarm data for all subsystems is described in Table VI.B-2.

An exception to the above interface description is the implementation of the CS to DHS interface where no hardware register is required. When the CS control minicomputer has any data to transfer to the DHS, the computer raises a flag and the DHS responds and reads the data. This communication interface is used for alarm data or CS field data. Once the DHS has received the data, it decides what the data are--alarm or field data--and processes them accordingly. The CS computer interrupt to the DHS has the highest external interrupt priority within the DHS in order to facilitate data transfer from the CS and to minimize the impact on the basic control function of the CS computer by the handling of data.

d. Subsystem Field Data/DHS Interface - The bulk of the data from a subsystem's field hardware is sent to the control building where it is routed to the subsystem's control panel. A small fraction of a subsystem's data generated in the field is used only in the field for control purposes and is not returned to the control building. An example of this latter type is the data going to the RS steam temperature control element located in the RS tower near the boiler. Of the data returned to the control building, most are logged by the DHS; and only data received in the control building can be so logged. The primary path for field data is to the subsystems controls--the DHS logging function is a parallel activity which "taps" the control data line, to acquire the data to be logged. (This parallel tap is shown in the next section, Figure VI.C-2, as the three subsystem/ DHS data interface boxes.) These interface units, detailed in Figures VI.B-8 and VI.B-9, contain random access memory (RAM) devices into which a complete set of data is stored. The contents of a RAM are ready by the DHS, and this reading function is initiated by a scheduler which is internal to the DHS.

Data from the RS and TSS are multiplexed and transmitted from the field hardware to the control building. The data are acquired in the field, converted to digital signals, multiplexed and transmitted serially to the control building where the subsystems' controls demultiplex the data and drive the appropriate console control and display devices. The DHS acquires the data as it is demultiplexed and stores it in the interface unit's RAM. The function which writes the set of data to the RAM is slaved to

TABLE VI.B-2

SUBSYSTEMS CONTROL ALARM DATA/DHS INTERFACE DESCRIPTION

Subsystem	Condition	Data Transfer
CS	heliostat alarm	heliostat ID alarm type auto stow other
	heliostat alarm clear	heliostat ID heliostat status stow operational standby operational track non-operational
	field segment alarm	field segment or repeater ID
	field segment alarm clear	field segment or repeater ID status operational non-operational
RS TSS EPGS	parameter alarm	parameter ID alarm Hi Lo
	parameter clear	parameter ID

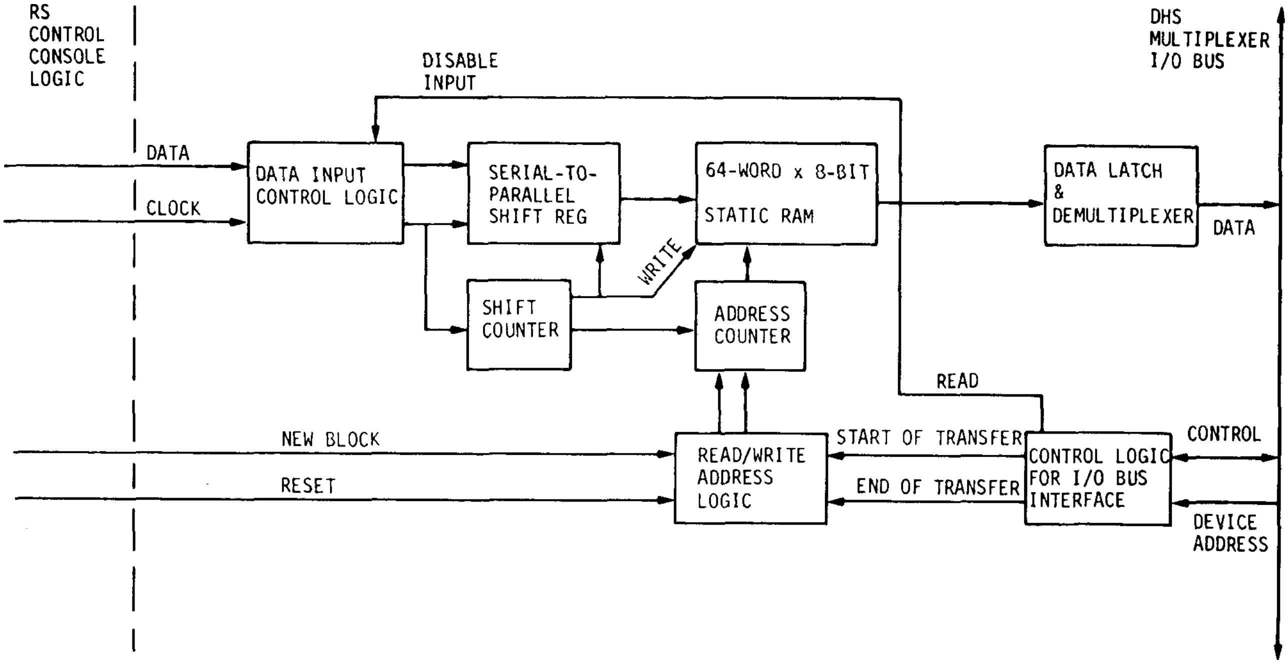


Figure VI.B-8 RS/DHS Data Interface Unit

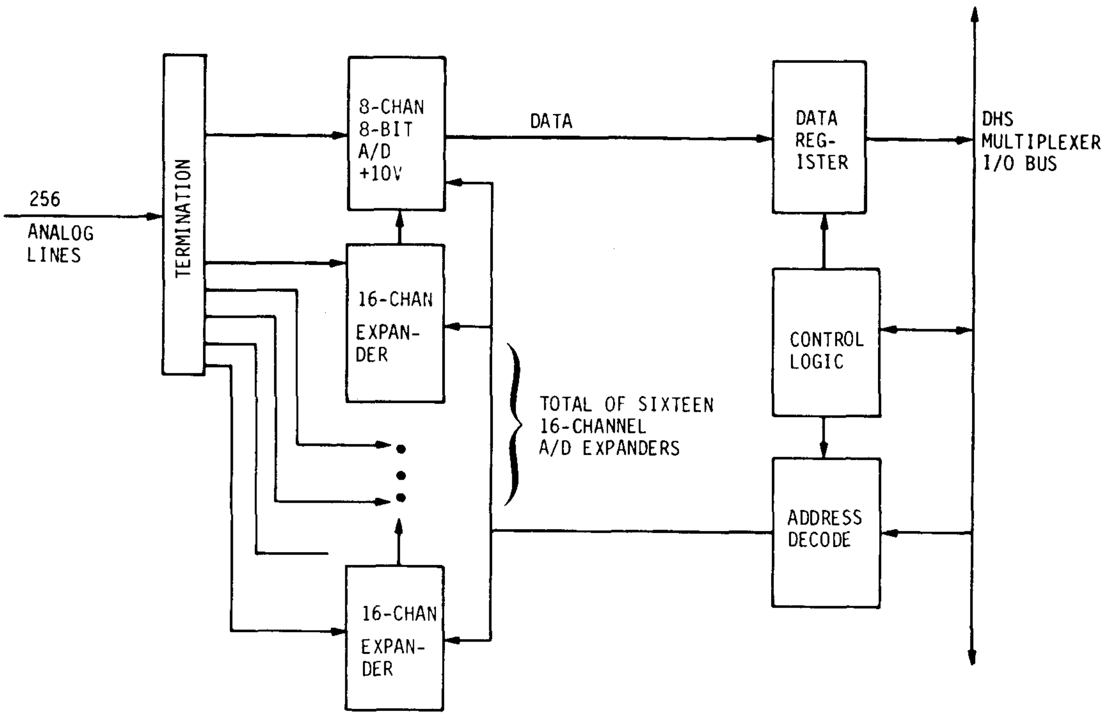


Figure VI.B-9 EPGS/DHS Data Interface Unit the frequency of data transmission from the field to the control building. Although the set of data is sent from the field to the control building on the order of once a second, the DHS reads the RAM contents and logs a single set of data much less often.

Since data from the EPGS to control building is hardwired analog data, the EPGS/DHS interface unit converts the analog data to digital, and transmits it to the DHS computer when commanded by the DHS to do so.

C. DATA HANDLING

The data handling system minicomputer and periperals used in conjunction with the collector subsystem controls is shown in Figure VI.C-1. As previously pointed out, the DHS computer serves as backup to the CS control computer. Typically, the video display (CRT), a teletypewriter (TTY), and one disc mass storage unit will be dedicated to the DHS computer. The printer and tape drive are shared as needed,with the CS control activity having priority over any data handling activities.

The data handling system has two major functions: data logging; and the production of summaries, printed logs, and some performance calculations. These input and output functions are stated as data handling system requirements in Table VI. C-1.

TABLE VI.C-1 DATA HANDLING SYSTEM REQUIREMENTS

- log daily cycle field data from subsystems
- log daily cycle alarm data from subsystems and from PCS
- log daily cycle PCS status data
- output logs, summaries, and performance calculations on demand
- output archival data on demand.

Apparent from these requirements is the concept that the DHS operates on a daily cycle. In general, data are not carried over from day to day. The DHS is initiated at the start of a cycle, it collects data for that cycle, it produces any logs or summaries on demand from the control operators, and it produces a set of archival data from that cycle. The only carryover betweeen cycles is a set of calibration data which allows the DHS to convert raw field data to engineering data.

The acquisition of data by the DHS computer and storage of that data on a disc mass storage device are termed data logging. The subsequent retrieval of that data from mass storage and the printing or writing to tape of the data are characterized generally as output. Since the ultimate purpose behind logging is to out-

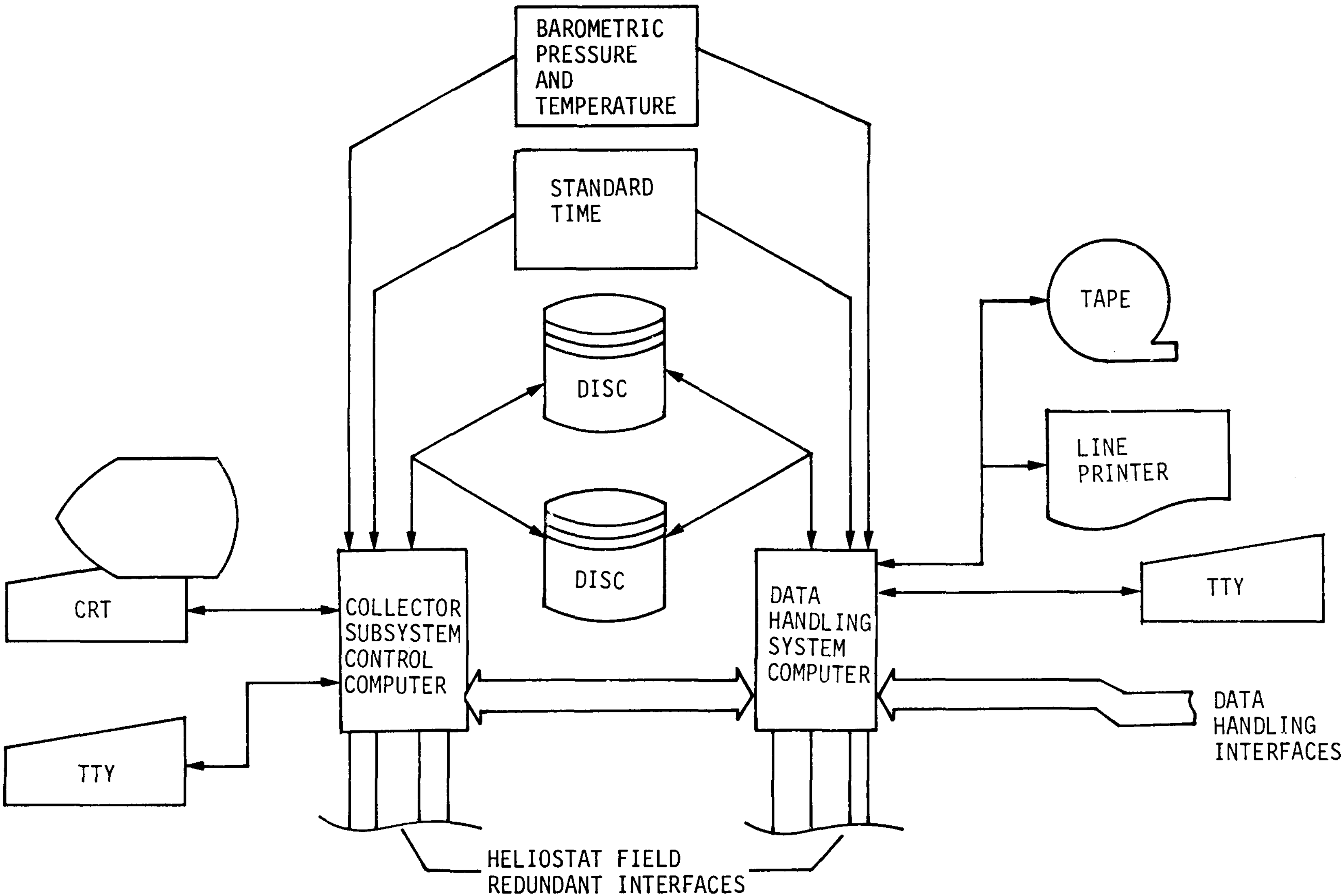


Figure VI.C-1 Pilot Plant Redundant Computer Configuration put the data for use by the control operators and others, the DHS output will be discussed next and then the DHS logging capabilities.

If during the planned but undefined two year test program, instrumentation requirements above those necessary to control and operate the plant are identified, additional data acquisition and data handling capability may be required. The present DHS hardware and software systems have room for significant growth in total data quantity, and moderate growth in data acquisition rates. Off-line processing, processing after the daily cycle is complete, has considerable room for growth with appropriate software additions.

1. Data Handling System Output

The set of outputs from the DHS is outlined in Table VI.C-2. This table is intended to sketch the types of output, which the DHS will generate, by title, a brief description of the output contents, and an indication of the size of the output or size constraints on the program. These outputs are generated upon operator demand. One automated output, initiated by operator demand, is the fourth entry, alarm log-automatic. This output, once initiated, will type on the teletypewritter (TTY) any parameter which is in alarm and then, when the alarm clears, will so indicated on the TTY. Each of the outputs is associated with a software routine and these relationships will be summarized later.

a. Data Parmeter Output Format - Most of the output will involve printing the values of various plant data parameters accompanied by some associated information. The standard line of output will contain the following information:

- time
- measurement ID
- value
- units
- description.

An example might be:

14:32/30   R2014   956DEGF   RCVR SUPERHEAT NO. 14

TABLE VI.C-2 PILOT PLANT DATA HANDLING SYSTEM OUTPUT SUMMARY

OUTPUT NAME	DESCRIPTION	OUTPUT DEVICE	SIZE
<u>LOGS</u>			
1. System Log	hourly and daily plant summary	printer	30 parameters max.
2. Trip History Log	constantly updated most recent 5 min. log of EPGS Parameters (1/sec. sampling)	printer	20 parameters max.
3. Alarm Log-Demand	all parameters currently in alarm	printer	100 parameters max.
4. Alarm Log-Automatic	each alarm as it occurs, and each alarm as it clears	TTY	continuous
<u>SUMMARIES</u>			
5. Single Point Summary	list of all values for a single parameter between time TSTART & TSTOP specified by operator	printer or TTY	Any logged parameter
6. Class Point Summary	list of all values for a class of parameters, listed by time, between time TSTART & TSTOP specified by operator	printer or TTY	20 parameters max.
7. Data Transform Summary	List of the data transform information for a set of one or more measurements current at a specified time.	printer or TTY	10 parameters max.
8. Performance Calculations	performance calculations CS - heliostats operational (CSOPS) RS - RS power totals (RSPWR) TSS - TSS energy totals (TSNRG) EPGS - turbine heat rate (EHEAT)	printer	N/A

TABLE VI.C-2 CONTINUED

OUTPUT NAME	DESCRIPTION	OUTPUT DEVICE	SIZE
SUMMARIES (CONT.)			
9. PCS Summary - A	list of time sequence of automatic emergency commands: subsystem to PCS PCS to subsystem between time TSTART & TSTOP	printer or TTY	N/A
10. PCS Summary - B	list of status of PCS enable/disable states between time TSTART & TSTOP	printer or TTY	N/A
11. PCS Summary - C	list of time sequence of plant steady state modes and mode transitions between TSTART & TSTOP	printer or TTY	N/A
12. ARCHIVAL			
Print			
System Log	hourly and daily summary	printer	1 page
Tape			
System Log	hourly and daily summary	tape	all archival
Alarm Log	log of alarms and clear by time	tape	data fit on
Data Log	log of all logged field data by ID and time	tape	less than one
Data Transform	log of initial transform and updates	tape	reel

The time the measurement was logged is given in hours, minutes, and seconds. The measurement ID is a unique identifier associated with each plant measurement; in this case the R indicates the receiver subsystem and the 2000 series might indicate temperature measurements. The engineering units are in degrees Fahrenheit (DEGF), and the measurement is described in fewer than 25 characters. Each page of output will be captioned with a title and the date. This output format implies several things about the internal handling of data. All field data will be logged as raw binary data; that is, the data will indicate the transducer output (+3.72 volts) and will not be translated to engineering values (956 DEGF) until it is printed. Associated with each logged value will be the ID and time of logging. The time and ID will be added by the DHS as the data are logged. When a particular parameter is to be output, a transformation table, stored on disc, will be addressed. This transformation data will be stored by ID and will contain the information to allow conversion of the raw datum to an engineering value plus the units (DEGF) and descriptive (RCVR SUPERHEAT NO. 14) character data. Conversion from raw data to engineering data can be accomplished by straight line fit, second or third order fit, or table lookup as required by the data. The transformation table can be updated during operation and a summary of the transformation table contents is available (see line 7, Table VI.C-2) to the operator. Also implied by the output is the existence of a plant measurement list. Generation of this list will be an important element of the integration activity for the plant.

b. Output Logs - Aside from the archival data, the DHS produces three output logs. The system log is a cumulative record of significant plant performance parameters logged each hour and summarized at the end of a daily cycle. The data is logged automatically by the DHS computer and is available to the operator upon demand; that is, the operator may request a printout of the hourly logs available at the time of the request.

The trip history log is a log of critical EPGS parameters, acquired every second and retained for five minutes, As new data is acquired, the older data is overwritten. If a trip occurs, the operator can request a printout of the log to assist him in rconstructing the events.

As will be described in the section on data logging, alarm data is stored on mass storage and available to the operator. The automatic mode has been described above; the demand mode prints all parameters currently in alarm.

c. Output Summaries - The single point and class point summaries are fairly self-explanatory. For any time period during a cycle, the period being specified by the operator, a single parameter ID or class of IDs can be printed.

We have already described the data transformation summary as a capability provided the operator to list the contents of the transform table and to update the table as required. We anticipate this review and update capability will be used most extensively during the early stages of the pilot plant integration and test.

Summary data on a day's operation of each of the subsystems is available through four subroutines of the performance program. The performance calculations are based on a daily cycle's logged data.

Parenthetic acronyms in the table refer to the software subroutine names. The CS program provides a time history of operational heliostats by field segment. The RS program lists the total power output from the receiver and the time profile of power output. A listing of total energy stored in oil and in salt is provided for the TSS, and an estimate of the number of kilowatt-hours of admission steam available from the TSS is also presented. Heat rate calculations are made for the EPGS.

The PCS summary provides a listing of PCS status, for a time interval of the daily cycle, describing: (a) the emergency commands to and from the PCS; (b) the PCS sequencing (enable/disable) states; and (c) the pilot plant configuration as a function of time.

d. Archival Data - To maintain a record of the pilot plant's operational performance, the DHS has the capability to produce a daily set of archival data consisting of a one page printed summary (system log) and a single reel of nine track, 800 bits per inch tape. The total set of logged data will easily fit on one reel of tape, and if it is desired to maintain an archive of plant data, the storage of one or two sheets of printout and a tape reel a day is quite convenient.

2. Data Handling System Logging

The DHS logs data from three sources:

- field data;
- alarm data;
- plant status data.

Each of these will be discussed in turn. The interfaces between the DHS and the several data sources are summarized in Figure VI.C-2. Characteristics of these interfaces have been described previously: the PCS to DHS interfaces in section VI.B-3; the subsystem to DHS interface in section VI.B-4.

a. Field Data Logging - Table VI.C-3 summarizes the general field data logging characteristics indicating the number of parameters and the logging frequency during plant mode transition and during steady state mode control. Heliostat status information is logged in a special compact format, and the remaining data are logged with time, ID, and raw value. The duration column in the table indicates the expected maximum number of hours, in a daily cycle, of mode transition or steady state mode control in which the subsystems will be configured. The information in this table allows sizing of the data storage requirements, and it is estimated that a daily cycle of field data will require less than 1.5 Mbytes of disc storage.

Based on the plant status information acquired by the DHS from the PCS, the DHS schedules acquisition of data from each subsystem on a regular basis using the schedule (SCHEDL) subroutine. When the scheduled time to acquire data from the TSS or RS arrives, the DHS initiates a data acquisition subroutine (DATIN) which acquires the data from the appropriate subsystem/DHS data interface unit, time tags the block of data and stores the data on the disc data file (DATFIL). EPGS data acquisition--analog to digital conversion and transmission to the DHS--is initiated by the same DATIN subroutine. When the CS transmits a block of data, the scheduling program determines if the data should be stored or not. If they are to be stored, DATIN logs the data on disc along with the time of logging.

b. Alarm Data Logging - As described in Section IV.B-3 and VI.B-4, alarm data flags are transmitted to the DHS from the PCS, EPGS, TSS, and RS. When an alarm interrupt is received, the DHS scheduler

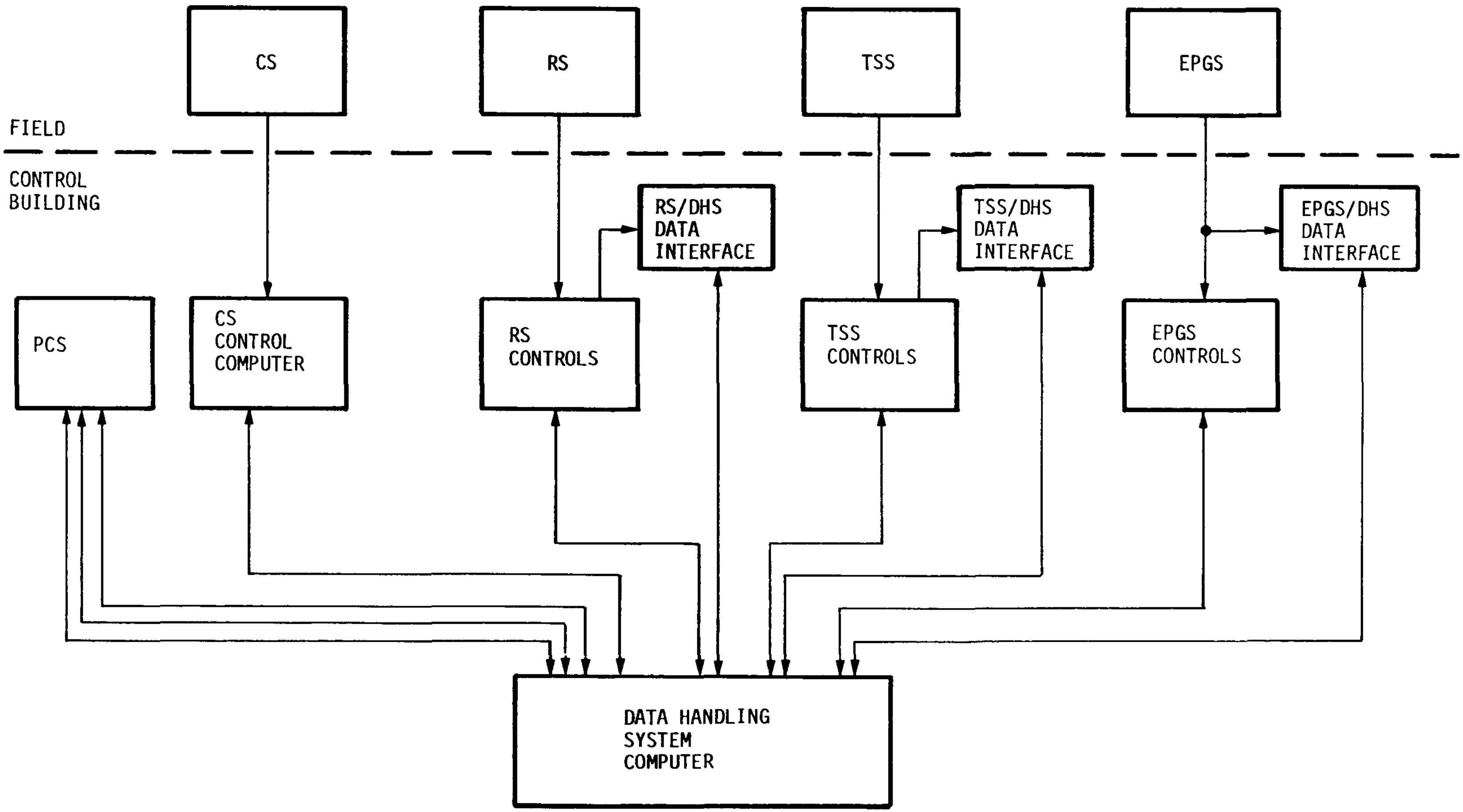


Figure VI.C-2 Pilot Plant - Data Handling System Interfaces

TABLE VI.C-3 DATA HANDLING SYSTEM - GENERAL DATA LOGGING CHARACTERISTICS

		MODE TRANSITION		MODE TRANSITION	
SUBSYSTEM	NUMBER OF PARAMETERS	DURATION	FREQUENCY	DURATION	FREQUENCY
Collector	1600 (a)	1 hr.	1/min.	9 hr.	1/5 min.
Receiver	150	1/3 hr.	1/min.	9 hr.	1/5 min.
Thermal Storage	50	1 hr.	1/min.	8 hr.	1/15 min.
Electrical Power Generation	250 (20) (b)	1 hr. (1 hr.)	1/min. (1/sec.)	9 hr. (9 hr.)	1/5 min. (1/sec.)

(a) Status of heliostats is logged in a special compact formate (4 bits per heliostat)

(b) Twenty trip log summary parameters are logged, 1/sec. for five minutes only.

initiates the alarm logging program (ALRMIN) which acquires the ID of the parameter in alarm or the PCS emergency commands and logs those data in the disc alarm file (ALRMFL) along with the time the alarm data were stored. Alarm clear data are handled similarly. Alarm data and field data both are received from the CS control computer. Once the data reside in the DHS, the DHS decides that the data are alarm data and uses ALRMIN to log the data.

c. Plant Status Data Logging - In a fashion very similar to the logging of field data, the DHS schedules the acquisition and logging of PCS status data using the program PCSIN. If the plant mode or mode transition state, or the enable/disable sequencing states have changed since the last time the PCS status was logged, the new status is logged along with the time of logging.

3. Data Handling System Software

The data handling system software is a straightforward real-time and batch processing system easily implemented on a dedicated mini-computer. The data acquisition rates are low, and the volume of data handled in any one acquisition step and during a cycle is small relative to the capabilities of the backup computer and disc configuration. Figure VI.C-3 depicts the structure of the software system the design of which emphasizes a modular system with simple interfaces. In particular, the internal priority structure is clearly defined, and as a result no critical timing constraints can occur. The software design also reflects the DHS philosophy which has been emphasized throughout; namely that data acquisition is an operation parallel to and separable from the fundamental plant control activities. The software implementation approach employs top-down programming with all coding, test and checkout being performed on the hardware which will be installed in the plant.

The three tables which follow define the software set, the file set, and indicate the real time data handling characteristics. Table VI.C-4 lists the 15 software programs required to acquire and log the data real time and to produce the output upon operator demand; the files to which data are written are listed in Table VI.C-5; and an indication of the structure of the real time files, software and interrupt priorities is given in Table VI.C-6.

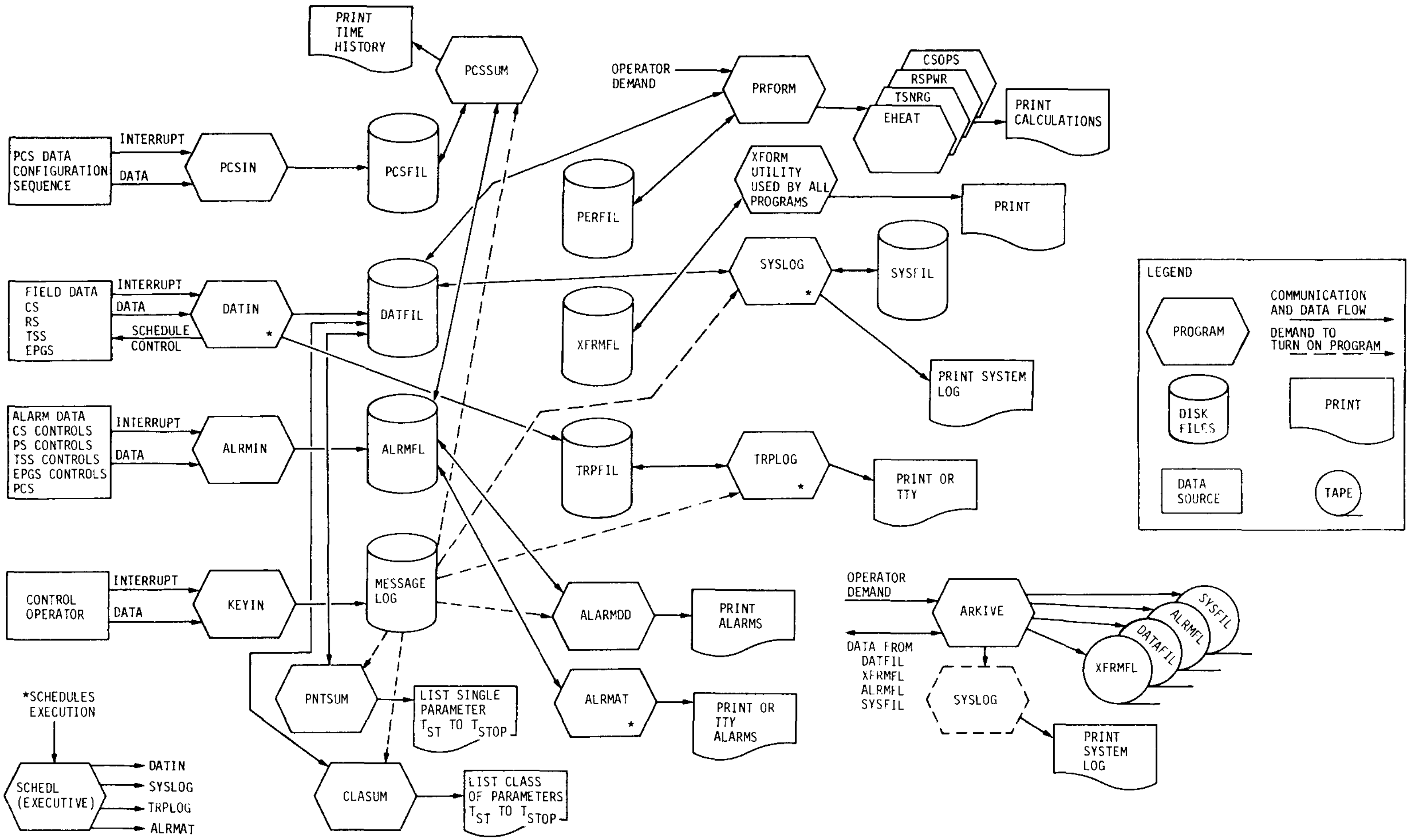


Figure VI.C-3 Data Handling System Software

TABLE VI.C-4 DATA HANDLING SYSTEM SOFTWARE SET

Real Time Data Acquisition Software	
PCSIN	PCS status
ALRMIN	alarm input
DATIN	data input
KEYIN	operator input
SCHEDL	data acquisition scheduling
Operator Demand Software - Output	
SYSLOG	system log
TRPLOG	trip history log
ALRMDD	alarm summary log - demand
ALRMAT	alarm summary log - automatic
PNTSUM	single point summary
CLASUM	class point summary
XFORM	data transformations
PRFORM	performance calculations
CSOPS	heliostats operational
RSPWR	RS power totals
TSNRG	TSS energy totals
EHEAT	EPGS turbine heat rate
PCSSUM	PCS summary A, B, C
ARKIVE	archival data print and tape

TABLE VI.C-5 DATA HANDLING SYSTEM FILE DEFINITIONS

DATFIL	data log file
SYSFIL	system log file
ALRMFL	alarm log file
XFRMFL	transform data base
PERFIL	performance calculation data base
PSCFIL	PSC log file
TRPFIL	trip log file

TABLE IV.C-6 REAL TIME DATA HANDLING CHARACTERISTICS

DATA SOURCE	DATA SINK	SOFTWARE	INTERRUPT SOURCE	INTERRUPT PRIORITY
ALARM				
CS control computer	ALRMFL	ALRMIN	CS control computer	1
RS controls	ALRMFL	ALRMIN	RS controls	2
TSS controls	ALRMFL	ALRMIN	TSS controls	2
EPGS controls	ALRMFL	ALRMIN	EPGS controls	2
PCS emergency action logic	ALRMFL	ALRMIN	PCS emergency action logic	2
PCS STATUS				
PCS sequencing logic	PCSFIL	PCSIN	PCS logic	4
PCS plant configuration logic	PCSFIL	PCSIN	PCS logic	4
FIELD DATA				
CS control computer	DATFIL	DATIN	CS control computer	1
RS/DHS data interface	DATFIL	DATIN	SCHEDL	3
TSS/DHS data interface	DATFIL	DATIN	SCHEDL	3
EPGS/DHS data interface	DATFIL	DATIN	SCHEDL	3

D. SUMMARY

The MCS is a system which is simple and is user oriented. Its design is based on the operational characteristics of the solar thermal power pilot plant--the daily cycle and the control of steady state modes or transitions between those modes. Controls are maximized with the subsystems and subsystem controls are essentially autonomous being coordinated by the PCS. The design is patterned after the control philosophy used by the utilities in conventional power plants--the control operators run the plant supported by the MCS. Implementation of the design has been by state-of-the art hardwired control logic for all control elements except the collector subsystem controls which use a dedicated mini-computer. All critical control elements are implemented redundantly: hardwired controls employ redundant voting logic, and the collector control computer is backed up by the data handling system computer. Provision is made to acquire all data necessary for operations and control and to make that data easily available to the control operators on shift or for later reference. In short, the MCS is the set of tools which the control operators use to safely and efficiently run the solar thermal power pilot plant.

APPENDIX A
SYSTEM DESCRIPTIONS

SYSTEM DESCRIPTION

FOR

BALANCE OF PLANT

ELECTRICAL SYSTEM

FOR

CENTRAL RECEIVER SOLAR THERMAL

POWER SYSTEM, PHASE 1

MARTIN MARIETTA CORPORATION

DENVER, COLORADO

BY

BECHTEL CORPORATION

SAN FRANCISCO, CALIFORNIA

No.	DATE	REVISIONS	BY	CH'K	APPR
0	4/1/77	Issued for Preliminary Design Report	DJR	JAK	NV

ORIGIN			
R & E	BECHTEL	CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM PHASE 1	JOB No. 11480; System Description SD-1; REV. 0; SHEET i OF 9

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1.0 SYSTEM FUNCTIONS

The Balance of Plant (BOP) and Electrical Power Generation Subsystem (EPGS) electrical system:

- Converts turbine shaft work into electrical energy.
- Supplies power to plant auxiliary loads.
- Delivers net power generation to the utility grid during normal daytime and extended evening operation, and supplies utility power to plant auxiliary loads during morning startup, evening shutdown, and overnight standby.
- Supplies standby and emergency power from onsite sources to essential loads during loss of normal power supply.

2.0 DESIGN BASES

2.1 ERDA Design Bases

None.

2.2 Other Design Bases

The design bases for the plant electrical system are established by the power and reliability requirements of the plant systems and equipment it must support. The system is designed for simplicity of operation, ease of maintenance, and economic equipment selection without compromising overall plant reliability.

2.3 Codes and Standards

Systems and equipment will comply with all applicable ANSI, NEMA, and IEEE codes and standards, as well as state and local codes governing utility-owned facilities of this type.

3.0 SYSTEM OPERATION

Single-line diagrams of the plant electrical system are presented in Drawing E-1368 Sheets 1 thru 8. The system consists of the following components:

- Main generator
- 13.8 kV station switchgear
- Main transformer
- Auxiliary load transformers
- Auxiliary load distribution system
- Standby and emergency power supplies

The main generator is rated at 12.5 MW (15.625 MVA at 0.8 power factor) and operates at 13.8 kV. The generator output is delivered to the 13.8 kV station switchgear bus via the main generator circuit breaker. This switchgear consists of the main generator breaker, the main transformer breaker, and two auxiliary load transformer feeder breakers, all housed in an outdoor, non-walk-in-type enclosure located below the turbine pedestal.

The main transformer provides the electrical interface between the plant and the utility grid. It is rated 13.8/34.5 kV, 12 MVA, and is oil-immersed, self-cooled. The 34.5 kV incoming utility line is connected to a 600 A, 3-phase, group-operated disconnect switch, which is in turn connected to the transformer primary terminals via a 3-phase, 600 A fuse.

A 3-phase lightning arrestor is provided to protect the transformer against voltage surges.

Plant auxiliary load power is supplied by two 480-volt secondary unit substations and six 480-volt motor control centers. The secondary unit substation transformers are rated at 1,000 kVA each, and are oil-immersed, self-cooled. These transformers are located just outside the electrical switchgear room, which houses the load center switchgear and motor control centers. The transformer primaries receive power from the 13.8 kV switchgear via underground cable feeders, step it down to 480 volts, and deliver it to the 480-volt switchgear buses via nonsegregated bus ducts. Loads above 100 horsepower (100 kVA) are connected directly to the 480-volt switchgear, while loads below 100 horsepower are supplied by the motor control centers, which are in turn connected to the 480-volt switchgear. Control power, lighting, and other small loads requiring 120-volt power are supplied through distribution transformers fed by the motor control centers.

Power transfer between the two 480-volt switchgear buses is accomplished via the normally open tie breaker. The tie breaker is electrically interlocked to prevent its closure while both main bus breakers are closed and is included to provide maintenance flexibility only.

Standby power is supplied by a 480-volt, 250 kW, diesel generator. The diesel generator is constantly maintained in a ready state. Auxiliary oil heaters and other appurtenances are provided as required. In addition, the generator is routinely started at periodic intervals to insure its availability. A 125-volt dc supply is provided to power essential loads, including the computer inverter and emergency lighting circuits. Under normal conditions, dc power is supplied by a 365 A battery charger. The charger can draw power either from an auxiliary load transformer or from the standby diesel generator. A one-hour battery is included to supply essential loads during diesel generator startup, or if the generator fails to start.

A grounding system is provided for protection against faults in electrical equipment, lightning, and static electricity. It consists of five deep ground wells (drilled to the water table) interconnected with #4/0 bare copper wire, forming an overall interconnected grounding grid (see Drawing E-1709).

A central ground point is established in the control building for the grounding of instruments, instrument power supplies, the computer, etc. The central ground point consists of a separate ground well located outside the control building and a continuous loop of insulated #4/0 cable routed from the ground well through the control room panels and back to the ground well. The central ground point is connected to the power plant grounding system via a #4/0 insulated cable, at one point only.

Protection against direct lightning strokes is provided to ensure the safety of personnel and equipment. This protection consists of eight metal air terminals installed on the top of the receiver tower. All air terminals are connected to the metal framing of the tower which is in turn connected to the plant grounding grid via four connections at its base. All EPGS and thermal storage subsystem structures and equipment are located within the cone of protection established by the receiver tower, however, to prevent side flashes, all building steel, tanks, and other equipment are bonded to the plant grounding system.

The collector field power distribution, grounding, and lightning protection systems are discussed in the collector subsystem section of this report.

3.1 Normal Operation

During normal daytime operation, power from the main generator supplies the plant auxiliary loads via the 13.8 kV switchgear and auxiliary power distribution system with the surplus generation being delivered to the utility grid. The 480-volt tie breaker is maintained in the open position, and the total auxiliary load is distributed as equally as possible between the two auxiliary load transformers. Where duplicate mechanical equipment rated at 100 percent of capacity is provided, appropriate operator selection of running and standby units ensures a balanced load. In addition, all large redundant loads, such as high-pressure feedwater and booster pumps, which are feed directly from the 480-volt switchgear buses, are electrically interlocked to insure that only one motor of each redundant pair is running at any one time. Sufficient transformer capacity is provided to allow the automatic start of any standby unit without disruption of service. However, full plant operation from a single auxiliary load transformer is not possible. Reliability of transformers and the more than adequate maintenance time afforded by nightly shutdowns eliminate the need for a backup power supply.

As shown in Drawing E-1368, Sheet 1 essential loads that are also required for normal operation are supplied by one of the secondary unit substation load center buses via a normally closed tie breaker.

Electrical equipment protection and metering provisions include, but are not limited to the following:

a) Main Generator

   1) Relays

- Phase overcurrent
- Negative phase sequence
- Reverse power (motoring)
- Cycle overvoltage
- Under frequency
- Out of step
- Loss of field
- Ground overcurrent
- Differential
- Voltage balance
- Neutral overcurrent

2) Metering

- Watthour meter
- Var meter
- Phase ammeter
- Voltmeter
- Watt/Var recorder
- Totalizer
- Exciter voltmeter
- Exciter ammeter
- Frequency meter
- Synchronizing system

b) Main Transformer

1) Relays

- Differential
- Sudden pressure
- Phase overcurrent
- Ground overcurrent

2) Metering

- Watthour meter
- Var meter
- Phase ammeter
- Totalizer

c) Auxiliary Load Transformers

1) Relays

- Differential
- Phase overcurrent
- Ground overcurrent

2) Metering

- Wattmeter
- Var meter
- Watthour meter
- Phase ammeter

d) 13.8kV Station Bus

1) Relays

- Differential
- Phase overcurrent
- Undervoltage

2) Metering

- Phase ammeter
- Voltmeter
- Zero sequence ammeter

3.2 Evening Shutdown

During evening operation, as the quantity of energy remaining in the Thermal Storage Subsystem reaches a predetermined lower limit, the generator planned load to trip sequence is initiated. As the generator output is reduced, it continues to supply auxiliary load power until it can no longer meet the load demand. At this point, offsite utility power begins to supply the load, via the main transformer, in parallel with the generator. The generator circuit breaker is then opened, and the turbine-generator is shut down and secured for the night. Auxiliary electrical loads that are required for overnight operation, such as seal steam, lighting, and control systems, will continue to be supplied by the utility feeder.

The overnight load demand can be supplied from either auxiliary load transformer by closing the 480-volt bus tie breaker. This allows inspection and rountine maintenance to be performed on either transformer, as required.

3.3 Morning Startup

During morning startup, the generator circuit breaker remains open, and auxiliary load power is supplied by the utility grid as plant systems are readied for normal daytime operation. When the generator has been brought up to speed and voltage and has been synchronized to the bus, the generator breaker is closed. At this point, the generator output can be controlled to supply auxiliary load requirements and deliver excess power to the utility grid.

3.4 Abnormal Occurrences

Abnormal occurrences affecting the electrical system can be divided into three catagories, as follows:

- Loss of all normal power supply (i.e., main generator and offsite utility supply)
- Load rejection
- Loss of main generator

Loss of all normal power supply might be caused by a natural disaster such as earthquake, fire, or storm, or by a 13.8 kV bus fault. On loss of 13.8 kV bus voltage, the diesel generator receives an automatic start signal. As soon as the generator is up to speed and ready to accept the load, which takes about 10 seconds, the normally closed tie breaker on the essential load bus opens, and the diesel generator breaker closes (see the Drawing E-1368 Sheet 1), supplying power to all loads required for an orderly plant shutdown. These loads include heliostat slewing motors, the receiver door operator, and the battery charger. Appropriate computer routines control the collector field to insure that not more than 162 heliostats are stowing simultaneously, limiting the maximum collector field demand to 103 kVA. The diesel generator breaker and bus tie breaker are electrically interlocked to prevent them from being closed at the same time. During the diesel generator startup period, or if the generator fails to start, the dc loads, including emergency lighting, emergency turbine lube oil pump, fire jockey pump, control systems, and the computer uninterruptible power supply, are supplied by the station battery. When diesel power is available, the battery charger reassumes supply of the dc loads and recharges the battery. The generator continues to run until manually shut down.

A load rejection causes the main transformer circuit breaker to open, isolating the plant from the utility grid. If turbine-generator stability can be maintained, the main generator remains in operation to supply auxiliary load power until the cause of the load rejection is determined. Immediately following load rejection, the diesel generator receives a start command and remains running, should it be required. If the cause of the load rejection is momentary in nature, it can be cleared and normal operation resumed by reconnecting the main transformer to the grid. The diesel generator is then manually shut down. If a prolonged outage is foreseen, or if the turbine generator trips due to instability, the unit is shut down, with the diesel generator suppling standby power as described above.

Loss of onsite generation may result from either a turbine or generator trip. Upon loss of generation, the main generator breaker will open, and the utility feeder will pick up the supply of auxiliary loads. The diesel generator will start and remain ready to accept the load if required.

If utility power is lost during overnight operation, the diesel generator will automatically start in order to maintain operation of essential equipment and battery charge.

4.0 DESIGN NOTES

The purpose of this section is to identify design areas which will require further refinement or study during the final design phase.

For the preliminary design, a transmission voltage level of 34.5kV has been assumed for transmission of power to the host utility. In addition, internal plant power distribution at 120V, 480V, 4160V, and 13.8 kV levels has been assumed. During final design the distribution voltage preferences of the host utility should be considered.

The preliminary design includes a single emergency diesel generator. During final design, further consideration should be given to the diesel's reliability and the economic impacts of a failure of the diesel to start. If additional protection is warranted, consideration should be given to inclusion of a redundant generator, or the inclusion of a steam driven emergency generation or feedwater pump.

Because of the potentially arid site conditions, special care should be directed during final design to assure that ventilation and dust protection for electrical equipment is adequate. This applies to both indoor and outdoor equipment.

5.0 EQUIPMENT DATA

5.1 Main Transformer, WX-101

Quantity	1
Voltage	13.8 kV/34.5 kV
Phase	3
Rating	12 MVA
Cooling	OA
Impedance	6% on 12 MVA base

5.2 13.8 kV Station Switchgear, WA-101

Quantity	1
Voltage	13.8 kV
Bus Rating	1,200 A
Circuit Breaker	Five 1,200 A continuous, 500 MVA interrupting
Enclosure	Outdoor, non-walk-in

5.3 Auxiliary Load Transformers, WX-102, WX-103

Quantity	2
Voltage	13.8 kV/480 volt
Phase	3
Rating	1,000 kVA
Cooling	OA
Impedance	6.75% on 1,000 kVA base

5.4 120-Volt Auxiliary Load Transformer, WX-104

Quantity	1
Voltage	480 V/120-208 V
Phase	3
Rating	30 kVA
Cooling	AA

5.5 120-Volt Auxiliary Load Transformer, WX-105

Quantity	1
Voltage	480 V/120-208 V
Phase	3
Rating	75 kVA
Cooling	AA

5.6 480-Volt Auxiliary Load Switchgear, WB-101

Quantity	1
Voltage	480 V
Bus Rating	1,200 A
Main Breaker	one 1,600 A, electrically operated
Motor Starter Breakers	Six 600 A, electrically operated
Circuit Feeder Breakers	Three 600 A, electrically operated
Tie Breaker	One 1,600 A, electrically operated

5.7 480-Volt Auxiliary Load Switchgear, WB-102A

Quantity	1
Voltage	480 V
Bus Rating	1,200 A
Main Breaker	One 1,600 A, electrically operated
Motor Starter Breakers	Five 600 A, electrically operated
Circuit Feeder Breakers	Two 600 A, electrically operated
Tie Breaker	One 600 A, electrically operated

5.8 480-Volt Essential Load Switchgear, WB-102B

Quantity	1
Voltage	480 V
Bus Rating	600 A
Diesel Generator Breaker	One 600 A, electrically operated
Circuit Feeder Breakers	Two 600 A, electrically operated

5.9 480-Volt Motor Control Center, WB-103, WB-104, WB-105, WB-106, WB-107

Quantity	5
Voltage	480 V
Bus Rating	600 A
Combination Motor Starters	As required by Drawing E-1368 Sheets 3-7
Circuit Feeder Beakers	As required by Drawing E-1368 Sheets 3-7
Short Circuit Current	22,000A sym

5.10 480-Volt Motor Control Center, WB-108

Quantity	1
Voltage	480 V
Bus Rating	225 A
Combination Motor Starters	As required by Drawing E-1368 Sheet 2
Circuit Feeder Breakers	As required by Drawing E-1368 Sheet 2
Short Circuit Current	22,000A gym

5.11 Standby Diesel Generator, K-102

Quantity	1
Voltage	480 V
Rating	250 kW @ 0.8 P.F.

5.12 Battery Charger, WD-101

Quantity	1
Input Voltage	480 V ac, 3 phase
Output Voltage	125 V dc
Rating	365 A dc

5.13 DC Motor Control Center, WD-102

Quantity	1
Voltage	125 V dc
Bus Rating	600 A
Combination Motor Starters	As required per Drawing E-1368 Sheet 7
Circuit Feeder Breakers	As required per Drawing E-1368 Sheet 7

5.14 Station Battery, WD-103

Quantity	1
Voltage	125 V dc
Capacity	370 Ah
Number of Cells	60
Cell type	lead-calcium

5.15 UPS Inverter, WY-101

Quantity	1
Input Voltage	125 V dc
Output Voltage	120/240 V ac, 1 phase
Output Frequency	60 Hz
Rating	20 kW

SYSTEM DESCRIPTION

FOR

ELECTRIC POWER GENERATION SUBSYSTEM

CONTROL SYSTEM

FOR

CENTRAL RECEIVER SOLAR THERMAL

POWER SYSTEM, PHASE 1

MARTIN MARIETTA CORPORATION

DENVER, COLORADO

BY

BECHTEL CORPORATION

SAN FRANCISCO, CALIFORNIA

No.	DATE	REVISIONS	BY	CH'K	APPR
0	4/1/77	Issued for Preliminary Design Report	AFM	JAR	MV

ORIGIN			
R & E	BECHTEL	CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM PHASE 1	JOB No. 11480
			System Description SD-2 — REV. 0
			SHEET i OF 19

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CONTENTS (Continued)

1.0 FUNCTION

The Electrical Power Generation Subsystem (EPGS) control system performs two interrelated functions. The first is the control operation of the EPGS in conjunction with the other subsystems in all operating and testing modes. The second is the protection of the turbine-generator in a manner that is acceptable to the machine manufacturer, in order to meet his warrantee requirements. Control of major variables will originate in the Master Control Subsystem (MCS).

2.0 DESIGN BASES

2.1 ERDA Design Bases

ERDA requires that the Central Receiver Solar Thermal Power System be capable of producing 10 MWe net electrical power when generating from the Receiver Subsystem alone at 2:00 PM on the day of lowest thermal input, coincident with a maximum ambient wet bulb temperature of 74 F. The control system is capable of automatic operation to achieve this design objective (see Modes 4 and 24, Section 3.2.4 and 3.3.18).

When generating from the Thermal Storage Subsystem (TSS) alone, ERDA requires that the Central Receiver Solar Thermal Power System be capable of producing 7 MWe net electrical power. The control system is capable of automatic operation to achieve this design objective (see Mode 6, Section 3.2.6).

2.2 Other Design Bases

The following design bases were included to insure reliable operation and optimum performance:

- Turbine-Generator Controls. To the extent possible, turbine-generator controls should utilize the turbine-generator manufacturer's standard design package with available standard options.

- Operational Requirements. Operational mode changes and transient conditions should be controlled automatically where feasible. Existing and potential control interfaces with the Master Control Subsystem (MCS) will be considered in the EPGS control design.

- Location of Controls. All major controls will be displayed in and controlled from the plant control room. Minor controls not requiring checking more often than once per shift, such as pressure regulators in the auxiliary lube oil systems, relief valves, and local indicators and gauges can be local.

- Computer Functions. All alarms and trips will be monitored and printed out, with the time, by the computer in the control room. Other data, such as flows, pressures, and temperatures, will also be logged by the computer on demand and periodically.

- Control Signals. All controls operating into the MCS will be electrical or electronic. Pneumatic controls may be used in local control loops. All control valves will be pneumatically operated, except for hydraulic controls at the turbine-generator.

- Controls for Equipment Packages. Controls for plant facilities equipment such as air compressors, deionizers and water treating will be normally purchased with the equipment.

- MCS Interfaces. All measurements for transmission to the MCS will have controls purchased with the equipment if specialized systems are available. This will be finalized in detail design at the time the vendor for the equipment is selected.

2.3 Codes and Standards

In addition to the codes and standards outlined in the other system descriptions, the following are especially applicable to this system:

- All applicable Standards and Recommended Practices of the Instrument Society of America (ISA)

- ANSI-Y-32.20-1975, Instrumentation Symbols and Identification, (Formerly ISA-S5.1)

- ANSI-MC-96.1-1975, Temperature Measurement Thermocouples, (Formerly ISA-S1.1 through 1.5)

3.0 SYSTEM OPERATION

3.1 Local and Packaged Control Systems

To complete the preliminary design of the EPGS control system, some assumptions regarding the nature of control packages within the EPGS and within adjacent subsystems were required. This section summarizes the assumptions that were made for the preliminary design. During final design, some adaptation and modification of the preliminary design is expected as more specific design information becomes available. The preliminary EPGS control design presented in Sections 3.2 and 3.3 is based on the local control configurations described in this section.

3.1.1 Turbine-Generator Controls

For purposes of preliminary design, the General Electric Standard Electro-Hydraulic Control (EHC) System with some standard options was considered. This system consists of the following:

- Load/speed control package with load limiting capabilities operating on main (receiver) steam control valves (standard item)

- Extraction/Admission Pressure controller with flow limiting capabilities (Standard Item)

- Initial Pressure Controller to Control main (receiver) steam pressure (optional extra)

- Load/speed control package with load limiting capabilities operating on admission (storage) steam (optional extra)

- Flow control package with main and admission control valve stroke limiting capabilities (standard item)

- Admission steam stop valves (optional extra)

This configuration is based on designs previously supplied by GE for automatic extraction turbines that were operated in the admission steam mode. The basic GE EHC system is described in GE publication GEK-14411 (Reference 1). An additional option not shown in previous GE designs, which would be useful in meeting the solar plant design objectives is a main steam flow limiter. This limiter would operate on the initial pressure controller in a manner similar to the flow limiter on the extraction/admission pressure controller.

A key factor in the EPGS control philosophy is the fact that the normal turbine control system is capable of controlling only two simultaneous variables. This is because the main (receiver) steam control valves (designated V1 by GE) and the admission (storage) steam control valves (V2) will each respond to control based on a single independent variable. The available control combinations are the following:

- Turbine electrical load (V1 in load/speed control) and admission pressure (V2 in extraction/admission pressure control)

- Receiver steam pressure (V1 in initial pressure control) and admission pressure (V2 in pressure control)

- Receiver steam pressure (V1 in initial pressure control) and electrical load (V2 in load/speed control)

When the load/speed control option is in use for valves V1 or V2, the steam inlet pressure to that valve must be externally controlled either by the main steam pressure controller or by the TSS internal controllers.

The proposed uses of the turbine EHC control features are described in Sections 3.2 and 3.3 as each applicable control mode is discussed.

3.1.2 Receiver Subsystem and Main Steam Line Controls

For purposes of the EPGS control design, a three-element drum level control system was assumed within the Receiver Subsystem as shown in Martin Marietta Drawing SEPS 1000000 (Reference 2). Valve number identification used in this description is also in accordance with Reference 2. Valve identification is also included in Drawings M-1366, M-1367 and M-1552. A pressure transmitter and flow transmitter providing inputs to control the TSS charge rate via valve FCV13 were also assumed in accordance with the drawings. The pressure and flow transmitters operate in the following manner:

- The pressure transmitter is capable of providing an input to control main steam line pressure via action of valve FCV13. The steam line pressure is maintained by routing steam to the TSS, thus indirectly setting the TSS charging rate. The intent of this control mode is to route steam not being used by the turbine-generator to the TSS.

- The same or a parallel pressure transmitter provides an input to the bypass valve PCV2. The bypass controller routes steam to the main condenser when the pressure rises somewhat above the pressure control point for valve FCV13, as described above.

- In a separate mode of operation, the flow transmitter in the TSS charging steam line (upstream of valve FCV13) can be used as an input to control flow to the TSS via FCV13. In this mode, main steam line pressure is maintained by the turbine initial pressure controller.

3.1.3 Thermal Storage Subsystem (TSS) Controls

In general, the TSS is controlled by regulating the flow rates of the oil and molten salt storage media in response to internal TSS pressures and temperatures. The methods of controlling TSS charging rates are outlined in Section 3.1.2 above. For purposes of preliminary design, the TSS discharge control is assumed to be accomplished in three separate manners:

- With the turbine-generator setting the TSS discharge steam demand via the turbine's load/speed control mode, the TSS maintains internal steam drum pressure and superheat temperatures via internal controllers.

- With an externally applied load signal to valve FCV10 setting the TSS discharge rate, the turbine operates in its extraction/admission pressure control mode to maintain TSS system pressure.

- When the turbine is not available, the TSS can be discharged to the condenser via valve PCV8 using steam flow in the discharge line as the controlling parameter. TSS steam pressure is controlled by varying oil flow via valve FCV10.

3.2 EPGS Normal Operating Modes

For preliminary design purposes, the plant is assumed to cycle through seven modes on a daily basis. Mode identification numbers correspond to numbers shown on the EPGS Control Mode and System Status Diagram, Drawing C and I-1369.

3.2.1 Overnight Standby (Mode 1)

The Collector Subsystem, the Receiver Subsystem, and the TSS are shut down. The seal steam system is operating. The turbine-generator is on turning gear with vacuum maintained. The feedwater system pumps are all shut down. The seal steam pump and auxiliary boiler, the lube oil system, and the full flow demineralizer holding pumps are operating. The main circulating pumps and daytime operation component cooling water pumps are off. The continuous duty component cooling water and pony circulating pumps are on. The cooling tower fans are off. The main circulating water inlet valve to the condenser is closed, and its bypass valve is open.

3.2.2 Morning Startup and Synchronization (Mode 2)

At sunup, the systems that were shut down for the night are started up. The BOP systems are all operating except the daytime component cooling water pump, which is then started. The circulating water pumps are started, and the condenser inlet valve is opened. The circulating water pony pump is stopped. The feedwater system pumps are started, and feedwater is circulated through the cleanup line. The on-line demineralizer holding pumps will stop automatically when there is sufficient pressure drop.

The turbine lube oil, hydraulic oil, seal steam, and condenser vacuum systems are already operating. The turbine is rolling on the turning gear. As insolation begins, the receiver steam begins to flow and is sent to the condenser through PCV2 until it has reached the turbine holding temperature.

When the receiver steam reaches the turbine minimum temperature and pressure, SV3 is opened. SV4 and SV6 remain closed and the turbine warmup begins. Procedures and rate of warming provided by the turbine manufacturer will be followed.

The turbine is rolled off the turning gear, accelerated using the load/speed control system to operating speed, and is held at speed ready for sychronization.

3.2.3 Continued Turbine Warmup and Generator Loading (Mode 3)

As soon as the generator is synchronized, the turbine is operated on load control in conjunction with the load/speed controller, and the ramp to full load is completed. Excess steam is routed via valve FCV13 to the TSS by the main steam header pressure controller.

3.2.4 Normal Daytime Operation (Mode 4)

Several options are available for this operating mode. For example, this mode could be a continuation of the control methods used in Mode 3 above. If additonal control loops are added (at extra cost), this mode could also be adapted to control automatically the transition to and from storage steam during cloud induced transients and loss of insolation in the evening.

To obtain this automatic transfer between steam sources, the turbine is placed in the initial pressure control mode, with inlet flow limited to prevent interaction with the main steam pressure controller. The TSS discharge heat exchangers are placed in a hot standby configuration by opening valves SV4 and SV6 and starting the appropriate TSS pumps. As insolation fails, the receiver outlet pressure drops and the turbine main steam control valves close to maintain the receiver pressure. Charging of the TSS is stopped at FCV13 in a similar manner. At this point, the TSS is commanded to pick up the load until insolation is restored.

The source of this external command signal, and the configuration of the turbine admission steam controls in this mode should be further studied during final design. A discussion of the available alternatives for accomplishing the automatic transition between alternate steam sources is discussed in Section 4.0.

For purposes of preliminary design, Mode 4 is assumed to work during cloud induced transients in the following manner:

- The turbine is placed in initial pressure control with receiver steam inlet flow limited by an internal flow limiter within the turbine EHC system to achieve 10 MWe net output.

- The tubine EHC extraction/admission pressure controller is placed in its normal pressure control mode.

- Low-pressure turbine output power is measured via a pressure transmitter, which measures an appropriate stage pressure in the low-pressure turbine section.

- The pressure transmitter is calibrated such that if the low-pressure turbine output power falls below a set level (corresponding to a pressure controller set point) the hot oil flow in the TSS is increased via valve FCV10, and the TSS steam flow boosts the turbine stage pressure to its set point, restoring the low-pressure section power.

- When the cloud has passed, the initial pressure controller reopens the main steam inlet valves, and as the steam flow from the receiver is restored, the pressure controller reduces TSS oil flow accordingly.

For this mode of operation, the turbine must be tied to a stiff utility electrical grid for generator frequency control. In addition, this mode performs best when design admission steam temperatures equal or exceed the normal turbine high-pressure section exhaust temperatures as is the case for the Martin Marietta design. An anti-reset-windup device will probably be required for the stage pressure control loop to prevent delayed TSS response because of pressure controller saturation during prolonged receiver steam operating periods. In addition, it may be necessary to add a threshold limit in the stage pressure control loop to assure that the TSS is loaded only when the steam demand meets the minimum flow required for stable TSS operation.

3.2.5 Afternoon Operation (Decreasing Insolation -- Mode 5)

With the controls set in the Mode 4 configuration (see Section 3.2.4), no change is required to accommodate the gradual reduction of insolation and of main steam flow from the receiver. Depending on the operator's preference, he can continue in this mode and use some TSS steam to maintain load, or he can reduce his load setting in steps and continue charging the TSS at a higher rate. When the receiver outlet temperature starts to fall, the operator must prepare to switch controls to isolate the TSS charging and the main steam to the turbine to protect the equipment and conserve maximum heat in the TSS.

3.2.6 Evening Operation (No Insolation -- Mode 6)

When the superheat temperature falls to the determined limit for TSS charging, SV5 and SV8 must be closed and the main steam pressure control maintained by bypass valve PCV2. When it reaches the manufacturer's recommended minimum temperature for the turbine inlet, SV3 must be closed. The main steam pressure controller sends the steam into the condenser via PCV2 until the heliostats are defocused. Then the receiver doors are closed, and SV1, SV2, SV9, and SV10 are closed to isolate the receiver to conserve heat. The EHC turbine controls remain temporarily as they were with turbine admission steam valves on pressure control. The high-pressure feedwater and low-pressure feedwater pumps are shut down. The turbine is then switched to the load/speed control mode, and the TSS is switched to internal steam pressure control.

3.2.7 Passing Cloud Transients (Reduced Insolation -- Mode 7)

The controls are configured as in Modes 4 and 5. The rise and fall of main steam flow result in increases and decreases of the charging steam to the TSS. When the receiver steam pressure falls, the controls act as described in Section 3.2.4 to admit more TSS steam to the turbine to maintain a predetermined load. The TSS will supply enough steam to hold load at 7 MWe net.

As insolation increases enough to start opening the main steam control values, the power will rise again to the previous controller set points.

3.3 Research and Testing Operations (Modes 8 through 26)

3.3.1 General

From the description of operation in Modes 4, 5, 6, and 7, it appears that most operating will occur in those control configurations. However, to be certain that this is the best way to operate and to obtain data for the design of a commercial size facility, provision has been made, if the EHC modifications are acceptable to GE, for operating automatically in several other control modes.

Modes 8 and 10 use manual regulation of the number of focused heliostats to limit receiver steam production below maximum as other variables are studied. Modes 9 and 11 allow the collectors, receiver, condenser, and feedwater systems to be operated with the turbine and TSS shut down. Modes 15, 16, and 17 provide for testing automatic control of the collector field derived from other controls if desired.

When the TSS is shut down, Modes 23, 24, and 25 allow operation of the collectors, receiver, and EPGS. Mode 12 permits upcoupled operation of the receiver and the EPGS, using the TSS as a buffer. Mode 13 permits charge of the TSS at a fixed rate independent of turbine output. Mode 14 allows operation of the turbine and charging of the TSS simultaneously without using TSS steam. Modes 18 and 19 allow for evaluation of charging the TSS at various rates on flow control. Modes 20, 21, and 22 provide for evaluation of discharging the TSS at various rates on flow control.

In addition, it will be possible to determine whether or not any of these modes is better than others. For instance, Mode 25 may work well enough to be used in the morning startup instead of Mode 2.

3.3.2 Receiver Steam to TSS Charging with Heliostats Limiting (Mode 8)

In this mode, the steam from the receiver goes via valve FCV13 to the TSS, charging on main steam pressure control. The operator manually limits the steam generation rate by setting the number of focusing heliostats. SV3 and SV4 are closed, and the turbine is not operating.

3.3.3 Receiver Steam to Condenser (Mode 9)

In this mode, the receiver steam goes to the condenser on main steam pressure control via valve PCV2. SV3, SV5 and SV8 are closed.

3.3.4 Receiver Steam to TSS, with Heliostats Limiting, and TSS Steam to Condenser (Mode 10)

In this mode, the receiver steam goes to the TSS via valve FCV13 on main steam pressure control. The operator manually limits the steam generation rate by setting the number of focusing heliostats. SV3 and SV4 are closed, and the turbine is not operating. TSS discharge steam is sent to the condenser on flow control via valve PCV-8.

3.3.5 Receiver Steam to TSS, with Excess to Condenser, and TSS Steam to Condenser (Mode 11)

In this mode, the receiver steam goes to the TSS on flow control, and the excess goes to the condenser on main steam pressure control. SV3 and SV4 are closed, and the turbine is not operating. TSS discharge steam goes to the condenser via valve PCV8 on flow control.

3.3.6 Receiver Steam to TSS and TSS Steam to Turbine (Mode 12)

In this mode, the receiver steam goes to the TSS on main steam pressure control. If desired, the operator manually limits the steam generation rate by setting the number of focusing heliostats. SV3 is closed, and no main steam is going to the turbine. SV4 is open, and the turbine is operating on TSS steam on either load/speed or extraction/admission pressure control. This mode may be used to isolate the turbine from the receiver when a large number of passing cloud transients are anticipated.

3.3.7 Receiver Steam to Turbine and TSS, with Excess to Condenser (Mode 13)

In this mode, the receiver steam charges the TSS on flow control and supplies steam to the turbine on initial pressure control. The excess steam goes to the condenser on main steam pressure control via valve PCV2.

3.3.8 Receiver Steam to Turbine, with Excess to TSS (Mode 14)

In this mode, the receiver steam goes to the turbine on load/speed control. The excess goes to the TSS on flow control; SV4 and SV6 are closed; and the TSS is not ready to discharge. Valve PCV2 acts to limit pressure excursions by bypassing excess steam to the condenser.

3.3.9 Receiver Steam to TSS, with Heliostats Controlling Flow (Mode 15)

In this mode, receiver steam is admitted to the TSS with valve FCV13 controlling main steam line pressure. The TSS charging line flow transmitter is controlling the steam flow automatically by regulating the number of focusing heliostats, using the computer as a controller; SV3, SV4 and SV6 are closed; and the turbine is not operating. As a safety device, the main steam pressure controller can admit steam to the condenser via valve PCV2, if excess receiver steam is generated.

3.3.10 Receiver Steam to Turbine, with Heliostats Controlling Load (Mode 16)

In this mode, the receiver steam goes to the turbine on initial pressure control. The turbine load/speed controller or an external load controller controls the electrical load by regulating the number of focusing heliostats, using the computer as a controller. The main steam flow limiter will override the initial pressure control to protect the turbine in the event that load control with computer control does not prevent overloading. As a safety device, the main steam pressure controller will admit steam to the condenser if the flow limiter controller overrides the initial pressure controller and causes a pressure rise in the main steam header. SV4, SV5, SV6, and SV8 are closed, the and TSS is not operating.

3.3.11 Receiver Steam to Turbine, with Heliostats Controlling Initial Pressure (Mode 17)

In this mode, the receiver steam goes to the turbine with the main steam control valves on load/speed control. The main steam pressure controller controls the main steam inlet (initial) pressure by regulating the number of focusing heliostats, using the computer as a controller. As a safety device, the main steam pressure controller can admit steam to the condenser via PCV2, if excess steam is generated. This mode is capable of meeting the ERDA 10 MWe design operating point (Section 2.1) if regulation is adequate.

3.3.12 Receiver Steam to TSS, with Excess to Condenser, and Turbine Shut Down (Mode 18)

In this mode, receiver steam charges the TSS on flow control via valve FCV13. The excess steam goes to the condenser on main steam pressure control via valve PCV2. SV3 and SV4 are closed, and the turbine is not operating.

3.3.13 Receiver Steam to TSS and Turbine, with TSS Steam to Turbine (Mode 19)

In this mode, the receiver steam charges the TSS on flow control and supplies steam to the turbine on initial pressure control. TSS discharge steam also goes to the turbine, and the admission valves are on load/speed control. As a safety device, the main steam pressure controller can admit steam to the condenser using valve PCV2 if there is excess receiver steam and if the main steam flow overrides the turbine initial pressure controls.

3.3.14 TSS Steam to Condenser (Mode 20)

Discharging of the TSS steam to the condenser is accomplished at controlled rates when everything else is shutdown except the feedwater system. The TSS discharge flow transmitter controls valve PCV8 via a flow controller; SV6 is open to admit feedwater. This mode could be useful in removing all heat from the TSS for cold shutdown or maintenance. Feedwater temperature will drop slowly, and this can continue until the feedwater temperature approaches the circulating water temperature and TSS discharge steam pressure reaches subatmospheric pressure.

3.3.15 Receiver Steam to Turbine, with Excess to Condenser, and TSS Discharge Steam to Turbine (Mode 21)

In this mode, the receiver steam goes to the turbine on load/speed control, with the excess to the condenser using PCV2 on main steam pressure control. SV5 and SV8 are closed, and the TSS charging is shut down by setting the charging flow controller to zero. TSS steam is admitted to the turbine on extraction/admission pressure control by placing an external load signal on the TSS. This external signal could be achieved by placing the turbine stage pressure controller (see Mode 4) in manual and using it to control TSS discharge flows.

3.3.16 Receiver Steam to Turbine, with Excess Charging TSS, and TSS Discharge Steam to Turbine (Mode 22)

In this mode, the receiver steam goes to the turbine on load/speed control, with the excess to the TSS on main steam pressure control, all SV's are open. The TSS is charging on main steam pressure control and discharging based on an external load signal, and the turbine is using both steam inlets. This mode differs from Mode 4 in that receiver steam is the controlling load, and the admission steam discharge rate is fixed externally.

3.3.17 Receiver Steam to Turbine, with Excess to Condenser (Mode 23)

In this mode, the receiver steam goes to the turbine on initial pressure control with the excess to the condenser using PCV2 on main steam pressure control. SV4, SV5, SV6, and SV8 are closed, and the TSS is shut down. This enables the receiver to generate above the set load, if desired, to test the collector receiver system while making the design load of power. The heat rejection capacity of the condenser used for final design must be checked if this mode is to be utilized.

3.3.18 Receiver Steam to Turbine, with Excess to Condenser, Alt. 1 (Mode 24)

This mode is similar to Mode 23 except that the receiver steam is on load/speed control, and the excess steam routed to the condenser on main steam pressure control.

3.3.19 Receiver Steam to Turbine, with Excess to Condenser, Alt. 2 (Mode 25)

This mode is like Mode 24, except that the main steam valve stroke is manually limited via the valve servo-amplifier with the excess steam routed to the condenser on main steam pressure control.

3.3.20 Receiver Steam to Turbine, with Some Excess to TSS and the Rest to Condenser (Mode 26)

This mode is the same as Mode 23, except that some receiver steam is being admitted to the TSS on flow control. SV4 and SV6 are closed, and SV5 and SV8 are open. This mode allows for charging the TSS at various flow rates while making design power.

3.4 Overnight Shutdown Procedure

3.4.1 Steam System

At the end of the evening operation (Mode 6), the turbine load is decreased using the load/speed controller, and the turbine is taken off line in accordance with the manufacturer's instructions. It will remain on turning gear all night. The lube oil system, the seal steam systems, and the condenser vacuum continue operating. The circulating water pony pump is turned on, the condenser inlet bypass valve is opened, and the inlet main valve is closed. The circulating pumps and the daytime component cooling water pumps are turned off, and the cooling tower fans are also turned off.

3.4.2 Feedwater System

At the end of daytime operation, the operator enters Mode 6. He defocuses the heliostats, closes the receiver, and stops the high-pressure and low-pressure feedwater pumps.

At the end of Mode 6 operation, the turbine is taken out of service (see 3.4.1). The bleeder trip valves on the extractions to the heaters close. The condensate, condensate transfer, and booster pumps are turned off, and the auxiliary boiler feed pump P-108 is turned on. Pegging steam to the deaerator is turned off.

The auxiliary boiler pump draws directly from the condenser hotwell. If the level changes enough overnight, the operator can run a transfer pump or condensate pump to adjust the level in the hotwell.

3.4.3 Balance of Plant Systems (BOP)

The daytime operation component cooling water pump will be turned off during the overnight period. The continuous operation pump will remain on. All other balance of plant systems will remain in operation in the overnight status.

3.5 Startup

3.5.1 Initial Plant Startup and Testing

The procedure for initial startup and testing, following construction, is contained in a separate report, Reference 3.

3.5.2 Startup from Cold Shutdown

The procedures for starting the steam system, the feedwater system, and the balance of plant are found in their respective system descriptions. When power and compressed air are available, any air headers that were shut off can be opened. All filter regulators should be drained to empty the bowl and assure that air is present.

Control valves that have not been operated in two weeks should be stroked manually to assure that no malfunctions will occur. All steam leads to instruments should be checked to assure that they are full of condensate. The control system is then ready for startup.

3.5.3 Startup from Overnight Standby

The procedure is outlined in Section 3.2.2.

3.5.4 Startup from Hot Standby

The procedure to be used will depend on the reason for hot standby. Assuming that all balance of plant systems and the feedwater and steam systems remain in operation, with the steam going to the condenser, the startup then begins in Mode 2 and proceeds to synchronization by the manufacturer's procedure. As soon as the generator is on line, warmup continues and ramps to full load at the rate set by the machine temperatures.

3.6 Balance of Plant Controls

In general, the balance of plant systems will be purchased as complete systems, with instruments and controls furnished with the equipment. Most compressors and pumps will have a 100 percent redundant unit, with controls to start the spare automatically if the running unit fails. For descriptions of the equipment packages, see the plant support systems description Reference 4. Automatic pump and compressor starts are listed in Section 3.7.3.

3.7 Abnormal Occurrences

3.7.1 General

The main turbine-generator system has many protective circuits that alarm trip to protect the machine. Redundancy is provided to protect against loss of lube oil and hydraulic control oil. Redundant pumps, automatically started, are provided for component cooling water, vacuum, and most balance of plant systems. The emergency lube oil pump and the seal steam pump operate from the station battery 125-volt dc system. Critical controls, including the computers and the EHC controls, are powered from the turbine speed generator and also from the inverter of the uninterruptible power supply system. The balance of the controls are powered from the emergency ac bus.

3.7.2 Turbine-Generator Protection

The following example is taken from the GE Bulletin GEI-90368D, Reference 5.

- General. Turbine-generators are equipped with control systems and auxiliary components both for normal online operation and for protection during unusual turbine-generator operation or unusual plant circumstances that could result in damage to the turbine-generator.

  The turbine has two independent speed control systems. The operating load/speed control is designed for normal control and is capable of limiting overspeed below the emergency trip speed following a sudden rated load rejection by the generator. The emergency trip system is designed to limit overspeed if the load/speed system malfunctions. It is also used to remove rapidly the load when such action is necessary.

First closing the inlet stop valves and then tripping the generator breaker minimizes the possiblity of overspeed and is preferable to simultaneous trip or tripping the breaker first.

A turbine-generator trip is a serious event and will cause major upsets in the receiver and the TSS (if operating). Operating procedures combined with the protection system described herein should help prevent sudden trips.

- Simultaneous Turbine and Generator Trips. The following protective devices will trip the simultaneous trip relay that operates the emergency trip solenoid and opens the generator breaker.

  - Generator differential relay
  - Generator stator ground relay
  - Main transformer differential relay
  - Main transformer ground relay
  - Generator bus fault relays

- Sequential Turbine and Generator Trips. The following protective devices should be arranged to trip the turbine hydraulic stop valves. Limit switches on the stop valves operate through the logic system to open the generator breaker.

  - Low bearing oil failure trip
  - Turbine overspeed trip
  - Manual mechanical trip button

  The above group dumps the trip valves hydraulic system directly. The following devices operate through the emergency trip solenoid.

  - Low vacuum trip
  - High exhaust hood temperature trip
  - Thrust bearing failure trip
  - Remote emergency trip push buttons
  - Sequential trip relay
  - Simultaneous trip relay
  - Loss of excitation relay
  - Phase-over current relays
  - Cycle-over voltage relay

- Backup Relays. The need for backup relays to protect the power distribution system, generator, etc. and whether they should be applied to simultaneous trip or sequential trip circuitry will be determined in the detailed design phase.

3.7.3 Automatic Pump and Compressor Starts

Automatic starting of the redundant equipment will be provided for the following:

- Condenser vacuum pumps
- Turbine lube oil pump (3)
- Hydraulic power unit
- Condensate pump
- Booster pump
- Low-pressure feed pump
- High-pressure feed pump
- Daytime component cooling water pump
- Continuous component cooling water pump
- Air compressor
- Makeup demineralized water pump
- Domestic water booster pump
- Oily waste transfer pump
- Domestic hot water pump
- Well water pump (3)
- Full flow demineralizer holding pumps (2)

3.7.4 Electrical System Controls and Protective Relays

In addition to the relays and trips listed in Section 3.7.2, other metering, relays, and trips are provided as described in the EPGS electrical system description, Reference 6.

4.0 DESIGN NOTES

Several aspects of EPGS control design will require careful attention during the final design phase when detailed information from equipment suppliers becomes available. This is especially true to Mode 4, Section 3.2.4, and the experimental modes discussed in Section 3.3. Some of the points requiring further investigation during final design are discussed below.

The assumed design for Mode 4 used a turbine stage pressure signal to measure low-pressure turbine output power. One alternative means of accomplishing that mode of operation would be to provide an external electrical load controller that would act on valve FCV10 in the TSS to maintain turbine-generator output at a predetermined minimum level. The input for the controller would be electrical in nature and would probably permit more precise control of the unit electrical generation. Otherwise, the remainder of the description of operation of that mode would remain valid.

The external electrical controller approach has application in alternative TSS schemes, where the TSS turbine throttle conditions require greater storage steam flows than the low-pressure turbine normally receives under receiver steam operations. In this case, low-pressure turbine operating stage pressures may be higher for storage operations than for receiver steam operations. This would make it difficult to apply turbine stage pressure as a measure of low-pressure turbine output power.

Extending the concept of an external electrical load controller one step further, it may be desirable to develop an external load coordinator that would operate on the TSS via valve FCV10 and on the turbine's initial pressure control via a flow limiter to achieve separate preset electrical loads for both receiver and storage operations. This would permit accurate automatic load control, while the turbine was acting only to control main steam and admission steam pressures. Excess steam would be routed to the TSS using main steam pressure control. Some consideration should be given to including such electrical load control routines in the plant computer.

Another alternative to Modes 4, 5, and 7 would consist of placing the turbine in load/speed control on receiver steam, but providing an initial pressure override so that if main steam pressure dropped below a preset level, the turbine would automatically switch to initial pressure control at the preset pressure level. This method would have less tendency to interfere with the main steam pressure controller.

Finally, during final design, the determination may be made that main steam temperature drop is a faster, more reliable indication of cloud passage than a decrease in steam pressure. If this determination is made, the general approach to Mode 4 could remain the same, except the closure of the turbine high passure control valves would be initiated by a temperature transient rather that a pressure transient.

Once the final turbine-generator control system is selected, consideration should be given to the use of turbine runback and setback circuits to mitigate the effect of transients. These control circuits are included in some turbine control system designs and their application is left to the buyer. Typically, when triggered these circuits are capable of adjusting the turbine load to a preset level at a preset rate. This permits the plant to react automatically to equipment failures and other transient conditions. One potential use of the circuits would be an alternative approach to Mode 7, passing cloud transients.

With 26 potential control modes available, care must be given during final design to achieving "bumpless" transfers between modes. While not all modes may be retained in the final design, manual or automatic transfer among several modes seems a likely occurrence.

In general, it appears that the turbine load/speed controls have specific application to loading and unloading the turbine during startup and shutdowns. Once the turbine is at operating load, the turbine will be switched to initial pressure control to make it more responsive to receiver transients such as cloud passage. Once in this mode, care should be given to assure stable main steam pressure control.

As mentioned in Section 3.2.4, a flow limiter acting on the turbine main steam inlet valves limits valve stroke and prevents interaction with the main steam pressure controller. Such interaction could lead to pressure control instabilities if not coordinated properly. With the turbine flow limited, the turbine will be unable to respond to increases in main steam pressure, and the main steam flow controller will act to maintain the pressure by opening FCV13 or PCV2 to relieve pressure as appropriate. In this control mode, it may be desirable to add a main steam excessive pressure trip to the turbine-generator to protect the unit during a failure of the main steam pressure controller. In may also be desirable during final design to add a set of atmospheric dump valves to the main steam header to limit pressure excursions and to prevent lifting of safety valves following a unit trip. The action of the dump valves could be coordinated via main steam pressure control to be the last level of pressure control before the main steam safety valves lift.

Consideration of the problems associated with coordination of the sequential action of valves FCV13, PCV2, and the atmospheric dump valves (if included) suggests that a single reliable main steam pressure signal will minimize instrument calibration and drift problems. Consideration should be given during final design to a main steam pressure signal based on an "auctioneered" two-out-of-three logic in which three independent pressure signals are compared with the highest of the two most comparable signals being chosen as the output signal. This arrangement will permit failure of a single pressure transmitter, while still maintaining an unambiguous main steam pressure signal.

5.0 EQUIPMENT DATA

- All control signals to the Master Control Subsystem (MCS) will be electrical (no pneumatic signals). The signals for the EHC system will be those that are standard for the turbine manufacturer. All transmitted analog signals will be 4 to 20 milliamps direct current powered from a central power supply in the MCS.

- On-off logic status signals will be 120 volts ac or 125 or 240 volts dc in accordance with the power company's standards. Low-voltage indication and supervisory signals (such as 24 volts dc) may be selected in the detail design.

- All controls other than the EHC and the digital systems will be purchased from a single manufacturer. The controls entering the TSS hazardous area shall be intrinsically safe as defined by the National Electrical Code.

- Pneumatic control signals shall be 3 to 15 psi gauge pressure.

6.0 REFERENCES

1. General Electric, "Electrohydraulic Control System," Pamphlet GEK-14411, General Electric Company, Lynn, Massachusetts

2. Schematic Drawing, Martin Marietta Drawing SEPS 1000000

3. EPGS Preliminary Startup Test Plan, Bechtel, 1977

4. System Description for Plant Support Systems SD-3, Bechtel, 1977

5. General Electric, "Recommended Practices for Protective Relaying, Electric Motors and Electric Control Circuits," Pamplet GEI-90368D, General Electric Company, Lynn, Massachusetts

6. System Description for Electrical System SD-1, Bechtel, 1977

SYSTEM DESCRIPTION

FOR

BALANCE OF PLANT

PLANT SUPPORT SYSTEMS

FOR

CENTRAL RECEIVER SOLAR THERMAL

POWER SYSTEM, PHASE 1

MARTIN MARIETTA CORPORATION

DENVER, COLORADO

BY

BECHTEL CORPORATION

SAN FRANCISCO, CALIFORNIA

No.	DATE	REVISIONS	BY	CH'K	APPR
0	4/1/77	Issued for Preliminary Design Report	DLN	JAK	NV

ORIGIN			
R & E	BECHTEL	CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM PHASE 1	JOB No. 11480
			System Description SD-3 — REV. 0
			SHEET i OF 53

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1.0 SCOPE OF DESCRIPTION

Plant support systems include those systems required for support of EPGS power generation functions. These include the following:

- Demineralized water makeup supply system
- Component cooling water system
- Compressed air system
- Plant heating, ventilation, and air conditioning system
- Cranes and hoists
- Fire protection system
- Domestic water system
- Sanitary drainage system
- Acid waste system
- Oily waste system
- Auxiliary boiler

These systems comprise the normal support systems provided for any industrial facility, and the system configurations generally follow long established design practice. For this reason, sufficient detail is given to define each system, but the detail is not as complete as provided for those systems directly associated with power generation. The subsequent sections provide a description of each system listed above.

2.0 DEMINERALIZED WATER MAKEUP SUPPLY SYSTEM

2.1 System Function

The demineralized water makeup supply system (see Drawing M-1382) fills all plant demineralized water makeup requirements.

2.2 Design Bases

2.2.1 ERDA Design Bases

ERDA site criteria, Reference 2-1, state that demineralization of makeup water will be required.

2.2.2 Other Design Bases

The demineralized water makeup supply system will be designed to meet the following system parameters:

- The system will provide demineralized water as needed for plant water makeup requirements.

- The system will provide for storage and transfer of demineralized water and for replacement of resin beds.

- The demineralized water will meet the purity requirements of the plant end uses. Typical requirements (which must be verified during final design) are as follows:

Conductivity @ 25 C	2.0 microsiemens/cm
Total dissolved solids	0.1 ppm
Silica	0.2 ppm
Chlorides	0.15 ppm as Cl ions
Fluorides	0.15 ppm as F ions
pH	6.0 to 8.0
Particulates	25 microns

- The system will operate with automatic controls and will require only normal maintenance services.

- The system will provide redundancy of critical system components to prevent system shutdown in the event of component failure.

- Typical plant makeup water requirements (to be confirmed during final design) are as follows:

  - Feedwater system initial fill

  - Thermal Storage Subsystem initial fill

  - Receiver Subsystem initial fill

- Washing of heliostats
- Normal operational makeup water requirements
- Initial system cleaning and flushing
- General cleanup
- Hydro testing during construction
- Regeneration of demineralizer beds

Normal EPGS operational makeup water requirements are estimated to consume approximately 500 gallons per day. Mirror washing has been estimated by Martin Marietta (via telephone 3/8/77) to consume 45,000 gallons per month.

- The system will operate for approximately 8 hours to fill its local storage tank.
- During processing, if the capacity of storage tank T-158 is exceeded, the excess will be routed to condensate storage tank T-101 or to mirror wash tank T-164.

2.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Pumps and motors	Hydraulic Institute Standards, National Electrical Manufacturers Association (NEMA)
	Institute of Electrical and Electronics Engineers (IEEE)
Storage tank	American Society of Mechanical Engineers, (ASME) Boiler and Pressure Vessel Code, Section VIII, Division I
Valves and piping	Amercian National Standards Institute (ANSI) B 31.1
Demineralizer	ASME Boiler and Pressure Vessel Code, Section VIII, Division I

2.3 System Operation

2.3.1 Normal Operation

The demineralized water makeup supply system shown in Drawing M-1382 consists of the following major components:*

*The first four items are supplied skid-mounted by the vendor.

- One full - capacity prefilter, F-153
- One full - capacity chlorine filter, F-154
- One full - capacity demineralizer, S-151
- Two full - capacity recirculation filters
- One full - capacity demineralized water storage tank, T-158
- Two full - capacity demineralized water transfer pumps, P-158A, P-158B
- Associated piping and valves

The system takes supply from a source to be determined during final design.

Water flows from the source through the prefilter (F-153), through the chlorine filter (F-154), through the demineralizer (S-151) for deionization, and then to the demineralized water storage tank (T-158). Flow through the demineralizers is controlled by a valve located at the inlet of the demineralized water storage tank. A controller throttles the flow control valve in response to the demineralized water storage tank level signal.

The demineralized water transfer pump (P-158A or P-158B) transfers the deionized water as required by the plant. If water in the demineralized water storage tank does not intitially meet quality requirements, it is recirculated through the recirculation prefilter and demineralizer until the required quality is met.

The demineralizer trains are equipped with control systems that automatically initiate a service rinse if required during operation and take the demineralizer train out of service if its exhaustion is indicated by the flow totalizer, high silica level, or high conductivity. An alarm indicates exhaustion of the train. The regeneration of an exhausted train is initiated manually. A selector switch permits regeneration of the anion, the cation, or both ion exchangers in a train. The regeneration steps are controlled by an adjustable timer. During regeneration, flow, concentration of regeneration chemicals, conductivity, and temperature are monitored parameters that are not within specification cause an alarm and interrupt the regeneration sequence. After completion of the regeneration, the train remains on standby and is placed in service manually.

The regeneration waste from the demineralizers is collected in the neutralizing tank. The waste is mixed by air bubbling. The neutralization of waste is controlled manually and monitored by a pH indicator. Neutralized waste is disposed of by a method to be determined during final design.

The predominant system material is Saran or polypropylene-lined carbon steel. Concentrated chemical lines are of carbon steel. The demineralizer tanks are lined with corrosion resistant material.

2.3.2 Overnight Shutdown

The system runs in batch process operation and is not shut down during normal nightly plant shutdowns.

2.3.3 Startup

The system runs in batch process tyoe operation and is not started up and shut down on a daily basis.

2.3.4 Abnormal Occurrences

Two 100 percent capacity transfer pumps (P-158A and P-158B), fed by separate power supplies, supply demineralized water to the plant as required.

The paragraph describing regeneration in Section 2.3.1 covers other abnormal operating responses of the system.

2.4 Design Notes

The following site-sensitive parameters should be determined during the final design:

- Demineralized water makeup supply source and quality
- Required demineralized water supply quantity and quality

The following items should also be considered during final design:

- If demineralized water supply requirements are physically separated by great distances, consider separate transfer pumps for each source requirement.
- If demineralized water supply requirements are intermittent, consider a manual transfer of demineralized water from the storage tank to final use point.

2.5 Equipment Data

2.5.1 Prefilter for Demineralizer, F-153

Quantity	One full - capacity unit
Flow	4 gpm
Pressure	45 psig

2.5.2 Chlorine Filter for Demineralizer, F-154

Quantity	One full - capacity unit
Flow	4 gpm
Pressure	45 psig

2.5.3 Demineralizer, S-151

Quantity	One full - capacity unit
Flow	4 gpm
Pressure	45 psig
Demineralized Water Specifications:	
Conductivity @ 25 C	2.0 microsiemens/cm
Total dissolved solids	0.1 ppm
Silica	0.2 ppm
Chlorides	0.15 ppm as Cl ions
Fluorides	0.15 ppm as F ions
pH	6.0 to 8.0
Particulates	25 microns

2.5.4 Demineralized Water Storage Tank, T-158

Quantity	One full - capacity unit
Capacity	2000 gallons
Pressure	45 psig

2.5.5 Demineralized Water Transfer Pumps, P-158A, P-158B

Quantity	Two full - capacity units
Flow	3 gpm
Head	50 ft water
Motor Size	1 hp

2.6 Reference

2-1 Letter ERDA (Du Val) to Martin Marietta (Blake), regarding Pilot Plant Site Parameters, dated November 3, 1976.

3.0 COMPONENT COOLING WATER SYSTEM

3.1 System Function

The component cooling water system (see Drawing M-1383) provides cooling for various components of the main power cycle and its auxiliary systems. These systems include the following:

- Condenser exhauster cooling
- Air compressor jacket cooling
- Turbine control lube oil cooler
- Turbine lube oil coolers
- Main generator air coolers
- Boiler feedwater pump lube oil coolers
- Booster pump lube oil coolers
- HVAC condenser
- Miscellaneous loads, including sample coolers and other loads not yet defined

3.2 Design Bases

3.2.1 ERDA Design Bases

Maximum design wet bulb temperature of 74 F (Reference 3-1)

3.2.2 Other Design Bases

- o GE input data for the following components (based on data supplied for similar units):

	Component	Flow	Approx. Heat Load, per Unit, Btu/hr
(1/2)*	EHC cooler (E-106A,B)	15 gpm, 84-104 F	150,000
(2/3)	Turbine oil cooler (E-105A,B,C)	145 gpm, 84-86 F	150,000
(4/4)	Generator coolers (E107A,B,C,D)	26 gpm, 84-99 F	200,000

*Typical notation: one operating unit; two units total.

- Other components flows and heat loads:

	Component	Flow	Approx. Heat Load, per Unit, Btu/hr
(1/2)	Air compressor jacket cooling (G-150A,B)	1.0 gpm, 84-124 F	20,000
(1/2)	High Pressure feedwater pump lube oil coller (E-109A,B)	5 gpm, 84-104 F	50,000
(1/2)	Low Pressure feedwater Pump lube oil cooler (E-116A,B)	4 gpm, 84-104 F	40,000
(1/2)	Booster pump lube oil cooler (E-110A,B)	4 gpm, 84-104 F	40,000
(1/1)	HVAC condenser heat rejection (S-153)	64 gpm, 84-94 F	320,000
(1/2)	Condenser Exhauster Seal Water Coolers (E-111A,B)	75 gpm, (84-119 F)	1,312,500

- The principal system parameters include the following:

  - The system is based on the use of cooling water.

  - The entering and leaving water temperatures are 84 and 97.34 F, respectively.

  - The outdoor maximum wet bulb design is 74 F.

  - One loop is designed for continuous operation and services the following components:

Component	Flow (gpm)	Heat Load (Btu/hr)
Air compressor jacket	1	20,000
Air compressor jacket	1	-
HVAC condenser heat rejection	64	320,000
Condenser exhauster	75	1,312,500
Condenser exhauster	75	1,312,500

Subtotals	216	2,965,000
20 percent margin	44	593,000
Total	260	3,558,000

- The other loop is designed for daytime operation only and services the following components:

Component	Flow (gpm)	Heat Load (Btu/hr)
Generator cooler	26	200,000
Generator cooler	26	200,000
Generator cooler	26	200,000
Generator cooler	26	200,000
HP feed pump lube oil cooler	5	50,000
HP feed pump lube oil cooler	5	0
LP feed pump lube oil cooler	4	40,000
LP feed pump lube oil cooler	4	0
Booster feed pump lube oil cooler	4	40,000
Booster feed pump lube oil cooler	4	0
EHC cooler	15	150,000
Turbine oil cooler	145	150,000
Turbine oil cooler	145	150,000
Subtotals	435	1,380,000
20 percent margin	87	276,000
Totals	522	1,656,000

- Both loops draw cooling water from the circulating water pump discharge line and return heated water to the circulating water return line to the cooling tower. The combined flows and loads for both loops are: 5,214,000 Btu/hr heat load, consisting of 782 gpm of 84 F entering water and 97.34 F leaving water; these figures include a 20 percent design margin on flow and heat loads.

3.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Water pumps	Hydraulic Institute Standards (HIS)

Water piping, valves, and fittings	ANSI B 31.1, "Standard Code for Pressure Piping"

3.3 System Operation

3.3.1 Normal Operation

The continuous operation loop supplies cooling water to the air compressor's jacket, condenser exhausters, and HVAC condenser. One of two full-capacity pumps (P-151A and B) operates. The daytime operation loop supplies cooling water to the other terminals. One of two full-capacity pumps (P-150A and B) operates. All terminals have manual isolation valves and a balancing cock to provide for system balancing. In addition, the HVAC condenser employs a three-way mixing valve to maintain a minimum inlet temperature of approximately 80 F.

3.3.2 Overnight Shutdown

The continuous operation loop runs continuously and is not started up and shut down on a daily basis. The daytime operation loop normally runs only during power generating operations and is shut down during normal nightly plant shutdowns by stopping the pumps.

3.3.3 Startup

The daytime operation loop is started up by manually starting one of the two full-capacity pumps.

3.3.4 Abnormal Occurrences

For each loop, a pressure switch in each discharge line automatically starts the full-capacity standby pump if the pressure drops below its set point. A low pressure alarm is also automatically annunciated in the control room.

3.4 Design Notes

All listed data should be verified during final design. Depending on the terminal units' water-side pressure drop, it may be advisable to use a secondary pumping system on some or all of the terminal units. The relative pressure drops of the main and branch piping versus the terminal units' pressure drop will affect this decision.

Drawing M-1383 does not necessarily show the sequence of takeoffs for the various terminals. This will be determined during final design and should be based on the terminal units' relative layout location and the most economical piping layout. Consideration must also be given to ease of system balancing in arranging the piping layout.

For this preliminary design, it was assumed that both loops would operate in essentially a constant design waterflow mode at each pump.

If final design requirements dictate a modulating flow on some or all of the terminal units, the use of minimum recirculation lines around the pumps, or the use of two-way, pressure-controlled valves at the ends of the piping systems should be investigated.

The location of the pumps with respect to the connection points to the circulating water lines should be checked to ensure proper NPSH availabiity for all modes of operation.

The final component cooling water fluid composition should be verified during final design to prevent freeze-up during a winter design day.

The predominant system material is carbon steel, painted.

3.5 Equipment Data

3.5.1 Continuous Operation Pumps, P-151A and B

Quantity	Two full-capacity units
Capacity	260 gpm
Head	100 ft TDH
Motor size, each	10 hp

3.5.2 Daytime Operation Pumps, P-150A and B

Quantity	two full-capacity units
Capacity	522 gpm
Head	100 ft TDH
Motor size, each	20 hp

3.6 Reference

3-1 Letter; Sandia (Skinrood) to Martin Marietta (Blake) regarding clarification of site parameters, dated November 8, 1976.

4.0 COMPRESSED AIR SYSTEM

4.1 System Function

The compressed air system (see Drawing M-1384) provides service air and instrument air for plant use, as required. Typical plant use requirements are pneumatic valves, tools, and control instrumentation devices.

4.2 Design Bases

4.2.1 ERDA Design Bases

None.

4.2.2 Other Design Bases

The system will be designed to provide a reliable, continuous supply of filtered, dry, and essentially oil-free instrument air and service air for plant requirements. Instrument air will be oil-free, filtered, and dried to a dew point -40 F at 100 psig.

Compressors will be rated at 125 psig discharge pressure to ensure 100 psig air pressure at the after-filter outlet. Two full-capacity compressors are to be sized with adequate capacity for: (1) maximum expected instrument air demand, (2) air dryer purge requirements, (3) extra air requirements when end-use devices become worn and demand more air, and (4) allowances for service air use.

Individual air receiver storage capacity will be adequate to supply instrument air requirements during the period required for the one full-capacity standby compressor to come up to pressur in the event of an operating compressor failure or 30 seconds, whichever is longer. Each compressor unit will be powered from a separate electrical bus.

System capacity requirements will be determined as follows:

- Air consumption of each constant cycle instrument will be totaled, and a margin of about 15 percent added.
- Air consumption of nonconstant cycle instruments, such as cylinder actuators, will be totaled, and a use factor of about 35 percent applied.
- Service air requirements will be determined.
- The sum of the air consumption of these three types will determine the design capacity of the instrument air system.

4.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Air receivers and instrument air dryers piping	ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 ANSI B 31.1, Power Piping
Compressed air equipment	Occupational Safety and Health Act, (OSHA) 29 CFR 1910, Subpart M

4.3 System Operation

4.3.1 Normal Operation

One of the two full-capacity air compressors supplies compressed air at 125 psig to its respective aftercooler. The two aftercoolers are connected in parallel by a common header that feeds two full-capacity air receivers. The two air receivers are then connected in parallel by a common header that branches into the instrument air and service air subsystems. The predominant system piping material is carbon steel.

For the instrument air subsystem, compressed air from the air receivers is further processed through an air filter, instrument air dryer (one drying and one reactivating), and an afterfilter. This instrument air then passes to a separate instrument air header for distribution to the instrument air piping system, where the air pressure is reduced by pressure regulators as required.

For the service air subsystem, compressed air from the two full-capacity receivers is further processed through two full-capacity (parallel-mounted) air filters. Utility air is supplied to each building and to main equipment areas as required.

During normal plant operation, one of the two air compressors is selected as the lead compressor for continuous operation. The lead compressor is automatically loaded or unloaded in response to the instrument air system pressure or service air system pressure. The other air compressor serves as a standby. The standby compressor starts automatically if the lead compressor fails or if its continuous operation cannot meet the instrument air system and service air system demand.

The system is also provided with a pressure-control isolation valve in the service air subsystem. If both compressors operating cannot maintain a discharge pressure of 100 psig, the service air subsystem is isolated, and all the compressed air is diverted to the instrument air subsystem.

Malfunction of the lead compressor, startup of the standby compressor, and system malfunction or abnormal condition are annunciated in the control room.

The compressed instrument and service air, after passing through the aftercoolers, is delivered to the two respective air receivers. The service air is filtered and then conveyed separately for direct distribution to the service outlets located throughout the plant. The instrument air, normally received from the instrument air receiver, is dried and processed to the required cleanliness and dew point and then passed to the instrument air header for distribution to the instrument air piping system. Air pressure is reduced by pressure regulators as required. A dew point indicator, installed downstream from each dryer train, will monitor the exit dew point temperature and actuate an alarm on high dew point.

The instrument air dryer cycles between two desiccant chambers; one serves as a drying medium, while the other is undergoing a reactivation process. During the drying cycle, the desiccant absorbs moisture from the incoming air stream. During the reactivation cycle, a small portion of the dry gas is passed over the desiccant at approximately atmospheric pressure, creating an environment in which the desiccant will give up the previously absorbed moisture to reach equilibrium.

The required instrument air quality is maintained by the following features:

- A filter-silencer installed at each compressor air intake
- Nonlubricated single-stage, double-acting, belt-driven compressors
- Aftercoolers to remove excess moisture
- Dual-column desiccant air dryers with filters located at both ends of each dryer
- Additional filters in all branch lines to instruments and valves

4.3.2 Overnight Shutdown

The system runs continuously and is not shut down during nightly plant shutdowns.

4.3.3 Startup

Since the system normally runs continuously, it is not started up and shut down on a daily basis.

4.3.4 Abnormal Occurrences

Because backup system components (compressors, aftercoolers, receivers, and filters) and separate sources of electrical power are provided, failure of a component, or an electric power supply, will not interrupt the continuous operation of the compressed air system.

The two air compressors are fed by separate electrical power sources.

If one operating compressor is not capable of maintaining required system pressure, this condition is alarmed in the control room, and the second (full-capacity standby) compressor automatically starts.

4.4 Design Notes

Consideration of separate instrument air and service air compressors may be analyzed in the final design, depending on relative service air and instrument air requirements.

Many details of final design (such as drain trap connections from receivers, tanks, etc. to plumbing drainage system) are not shown on the flow diagram; these must be thoroughly investigated during final design.

4.5 Equipment Data

Only typical expected sizes (order-of-magnitude) are shown and must be verified during final design.

4.5.1 Air Compressor, G-150A, G-150B

Quantity	Two full-capacity units
Discharge pressure	125 psig
Capacity	50 scfm
Motor size	20 hp

4.5.2 Aftercooler, E-151A, E-151B

Quantity	Two full-capacity units
Operating pressure	125 psig
Capacity	50 scfm

4.5.3 Instrument Air Receiver, T-159A, T-159B

Quantity	Two full-capacity units
Operating Pressure	125 psig
Capacity	25 ft^3

4.5.4 Service Air Filter, F-150A, F-150B

Quantity	Two full-capacity units
Operating pressure	125 psig
Capacity	25 scfm
Particulate Size	Not applicable-used for oil droplet removal

4.5.5 Instrument Air Prefilter, F151A, F-151B

Quantity	Two full-capacity units
Operating Pressure	125 psig
Capacity	25 scfm
Particulate Size	20 microns

4.5.6 Instrument Air Dryers, T-161A, T-161B

Quantity	One full-capacity unit One drying cell and one reactivating cell
Capacity	25 scfm
Operating pressure	125 psig

4.5.7 Instrument Air Afterfilter, F-152

Quantity	One full-capacity unit
Capacity	25 scfm
Operating pressure	125 psig
Particulate Size	10 microns

5.0 PLANT HEATING, VENTILATING, AND AIR CONDITIONING SYSTEM

5.1 System Function

The plant heating, ventilating, and air conditioning (HVAC) system Drawing M-1385) provides the following:

- o A suitable environment for the comfort and safety of plant personnel and for the operability of plant equipment during normal operation and during periods while the plant is shutdown
- o Sufficient ventilation air

5.2 Design Bases

5.2.1 ERDA Design Bases (References 5-1 and 5-2)

Maximum ambient wet bulb temperature will be 74 F, and maximum ambient dry bulb temperature will be 110 F.

5.2.2 Other Design Bases

The plant HVAC system will be designed to meet the following system parameters and requirements:

- The system will maintain the control building at 72($\pm$2) F, and 50($\pm$15) percent relative humidity on a year-round basis.
- The system will maintain the maintenance building below a maximum of 88 F during the summer cooling season and above a minimum of 68($\pm$2) F during the winter heating season.
- The system will maintain the control building and maintenance building at a slightly positive pressure (approximately 0.1 inch, water gauge) to inhibit infiltration of outdoor air.
- The system will meet all local and national codes regarding ventilation rates, cleanliness, energy consumption, and other applicable parameters. The energy-conservation standards of ASHRAE Standard 90-75 (Reference 5-3) should be further considered during final design.
- Since the turbine building is normally unoccupied, and since the equipment housed in this building will be designed to withstand the expected temperature extremes at the site, no heating or cooling equipment will be required in this structure. Ventilation for the turbine building will be analyzed in the final design.
- The HVAC systems for the control building and the maintenance building will be independent of each other.

- In addition, the system will include a packaged computer room HVAC system to maintain the computer control room environment within the limits recommended by the computer manufacturer. This system will be redundant to the portion of control building HVAC system serving the computer and the control room.

- The system will make use of solar energy where economically justified to minimize utility and operating costs.

- The preliminary design bases for equipment sizing are listed below:

  Control Building

  Cooling design load -- 21.7 tons
  Heating design load -- 140,000 Btu/hr
  Supply Air Rate -- 6,200 cfm

  Hot water flow (17 gpm) is based on 30 F hot water differential temperature (115 F-85 F).

  Water-cooled condenser

  Heat rejection to component cooling water system -- 320,000 Btu/hr

  Condenser water flow (64 gpm) is based on 10 F water differential temperature (84 F-94 F).

  Standby control room packaged air conditioning unit has a capacity of 5 tons.

  Miscellaneous exhaust fans required for toilet areas, labs, locker rooms, etc. are not shown in this preliminary design; they must be considered in the final design.

  Maintenance Building

  Summer design outside wet-bulb temperature -- 74 F

  Summer design supply air dry-bulb temperature to conditioned space -- 77.6 F

  Cooling load -- 9.0 tons

  Heating Load -- 144,000 Btu/hr

  Solar Heating System

  The solar collector field will cover approximately one third (750 ft^2) of the roof of the control building. Collectors will be mounted at a tilt angle equal to site latitude plus 10 degrees.

For preliminary sizing, the supplemental electric heater for the thermal storage tank is based on the following:

Source	Heat load (Btu/hr)
Control Building Space Heating	140,000
Domestic Water Heating	33,000
Total	173,000

Electric Heater Size:

$$\text{Size} = \frac{173,000}{3,413} = \underline{50} \quad \text{kW}$$

Flat plate collectors, commercially available from major manufacturers will be used. The thermal storage tank size is preliminarily sized at 1.5 gallons per square foot of collector area, or 1,125 gallons (1.5 x 750).

5.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Fans	Air Moving and Conditioning Association (AMCA) Standard 210, "Test Methods for Air Moving Devices"
Central station air handling units	Air Conditioning and Refrigeration Institute (ARI) 430, "Standard for Central Station Air Handling Units"
Chilled water cooling coils	ARI 410, "Standard for Forced-Circulation Air-Cooling and Air-Heating Coils"
Electric heating coils	National Electric Code
	Underwriters' Laboratories (UL) 1096, "Standard for Safety, Electric Air Heating Equipment"
	National Fire Protection Association, (NFPA) 90A, "Standard for Air-Conditioning and Ventilation Systems"
	NFPA 90B, "Standard for Installation of Warm Air Heating and Air-Conditioning Systems"

Filters, roughing and moderate efficiency	UL-900, "Air Filter Units," Class American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) 52-68, "Method of Testing Air Cleaning Devices Used in General Ventilation for Removing Particulate Matter"
Ductwork	Sheet Metal and Air Conditioning Contractor's National Association (SMACNA), "Duct Manual and Sheet Metal Construction for Ventilation and Air Conditioning Systems," Section I (Low Velocity) and Section II (High Velocity)
Chilled water piping, valves, and fittings	ANSI B31.1, "Standard Code for Pressure Piping"
Water chillers	ARI 590-62, "Standard for Reciprocating Water-Chilling Packages"

5.3 System Operation

5.3.1 Normal Operation

A completely factory-assembled air conditioning unit maintains the control building (see Drawing M-1385) within design temperature limits. This packaged unit includes the following components:

- Complete refrigeration system consisting of a water-cooled condensing section, reciprocating compressor, direct-expansion cooling coil, all refrigerant piping, and accessories
- Complete operating and safety controls
- Hot water preheat coil
- Filter section
- Supply fan with automatically controlled variable inlet vanes
- Return-exhaust fan with automatically controlled variable inlet vanes
- Outside air-return air-exhaust air (OA-RA-EA) section complete with automatically controlled dampers
- Minimum outdoor air ventilation section
- Unit status control panel mounted in the control room

The unit controls the refrigeration system to allow compressor operation only when the outside air temperature is above design supply air temperature (approximately 55 F). Compressor cylinder unloaders load and unload the compressor in response to refrigeration load.

At outside air temperature below design supply air temperature (approximately 55 F), the refrigeration section is locked out and the OA-RA-EA damper section is modulated to maintain the design supply air temperature (an "economizer" free-cooling feature). A three-way mixing valve around the hot water preheat coil is also controlled to maintain the design supply air temperature.

The supply fan is controlled with automatically modulating inlet vanes to maintain required system static pressure at the variable-air-volume terminal units. The return-exhaust fan is controlled to follow the supply fan air flow rate and maintain sufficient space pressurization to inhibit infiltration of outdoor air.

Thermostats in the individual zones control the variable-air-volume terminal units by first throttling their air flow to a minimum value (approximately 35 percent of design air flow) and then reheating the air with a hot water reheat coil; this sequence of operation occurs as zone cooling loads diminish.

For the maintenance building (see Drawing M-1385), an air washer provides evaporative cooling during the summer. A fan exhausts air from the building to maintain a once-through ventilation system for summer cooling. Winter heating for the maintenance building is provided by electric unit heaters spaced throughout the building to supply uniform heating.

The heating system for the control building (see Drawing M-1385) consists of a flat-plate solar collector field mounted on the roof of the control building. To prevent winter freezing of the solar panels, the system shall use an automatic drain-back feature to drain the collectors whenever outside dry bulb temperature drops below approximately 34 F.

A supplemental electric heating coil section is provided in the solar thermal storage tank as a backup source of heating in the event of thermal storage tank depletion.

A hot water transfer pump provides hot water to the heating coils in the variable-air-volume reheat coils and the hot water preheat coil in the supply air handling unit serving the control building. The thermal storage tank also provides preheat for the domestic hot water system.

5.3.2 Overnight Shutdown

The plant HVAC system runs continuously and is not shut down during nightly plant shutdowns.

5.3.3 Startup

Since the system runs continuously, it is not started up and shut down on a daily basis.

5.3.4 Abnormal Occurrences

In the event of a control building HVAC component failure that prevents the control room from being maintained at design conditions, a 5 ton computer room air conditioning unit, mounted free-standing in the control room, can be manually started. This system is a direct-expansion split system with an outdoor-mounted, air-cooled condensing unit connected through refrigerant suction and liquid lines to the computer room air conditioning unit.

If the thermal storage tank is depleted, the supplemental electric heating element will be automatically started to maintain required design hot water supply temperature.

5.4 Design Notes

The maintenance building cooling system is based on a summer design wetbulb temperature of 74 F, which results in a leaving air dry-bulb temperature (from the evaporative cooling supply unit) of 77.6 F. The use of other systems (mechanical refrigeration, D-X, etc.) should be seriously considered if a number of the following conditions are encountered during the final design stages:

- If an inside summer design temperature lower than 88 F dry-bulb is selected.
- If the inside summer relative humidity is to be controlled.
- If process systems inside the maintenance building require large amounts of outside air on a year-round basis.
- If it is desired to reduce the supply air flow rate.
- If process systems inside the maintenance building require that many thermal zones be incorporated in the final design.

Depending on final site selection and cost considerations, the following systems may be considered:

- Replace hot water reheat coils in the variable-air-volume terminal units with electric reheat coils.
- Replace the reheat coils in the variable-air-volume terminals with perimeter baseboard heaters.
- Replace the variable-air-volume system with a constant volume, temperature reset system; this type of system may be advisable if large amounts of outside air are required.

- Provide a totally solar-powered HVAC system, if economically feasible.

- Replace the water-solar system with an air-solar system.

The electrical heating coil in the storage tank may be replaced by a hot water, fossil-fuel boiler arrangement if fossil fuels (natural gas, butane, fuel oil) are available at the site.

A water-to-water heat pump may also be considered for both the maintenance and control building cooling systems if final site ambient conditions favor this approach.

Many details of the solar system design are not shown (such as slopes of lines, etc.). These items should be addressed in final design.

All preliminary design bases (Sections 5.2.1 and 5.2.2) should be verified in final design.

5.5 Equipment Data

5.5.1 Solar Collector Field, F-152

Quantity	Cover roof of control building
Orientation	South
Tilt angle	Site latitude plus 10 degrees
Total square footage	750 sq ft^2 (approx.)
Type	Flat-plate
Leaving water temperature	170 F (approx.)
Water flow rate (based on 0.02 gpm per square foot of collectors)	15 gpm
Pumped fluid	Water

5.5.2 Solar Hot Water Thermal Storage Tank, T-162

Quantity	One full-capacity unit
Size	1125 gallons
Supplemental electric heater size	50 kW

5.5.3 Computer Room Air Conditioning Unit -- Control Building, S-155

Quantity	One full-capacity standby unit
Size	5 refrig. tons
Type	Self-contained computer-room air conditioning unit with all operating safety controls, 5 tons, 2,500 cfm

5.5.4 Computer Room Air-Cooled Condensing Unit, S-154

Quantity	One full-capacity standby unit
Rating	75,000 Btu/hr heat rejection with 110 F entering air, 5 hp
Type	Air-cooled condensing unit

5.5.5 Control Building Packaged Supply Air Handing Unit, S-152

Quantity	One full-capacity unit
Refrigeration capacity	21.7 tons
Compressor draw	24 kW
Supply fan	6,200 cfm at 4 inches, water gauge; 7-1/2 hp
Return-exhaust fan	6,000 cfm at 1 inch, water gauge; 2 hp

Appurtenances:

- Water-cooled condensing unit section
- Direct-expansion cooling coil and complete refrigeration piping and accessories
- Complete operating and safety controls
- Hot water preheat coil
- Filter section
- "Economizer" free-cooling section

5.5.6 Control Building Variable-Air-Volume Units, S-157

Quantity	As required
Type	High-velocity variable-air-volume terminals with hot water reheat coils

5.5.7 Control Building Miscellaneous Fans

Quantity	To be determined in final design

5.5.8 Maintenance Building Cooling Unit, S-156

Quantity	One full-capacity unit
Type	Evaporative cooling
Fan air flow	12,000 cfm
Fan static pressure	3 inches, water gauge
Fan motor size	10 hp
Water pump motor size	1 hp

5.5.9 Maintenance Building Exhaust Fan, G-153

Quantity	One full-capacity unit
Type	Centrifugal, belt-driven
Fan air flow	12,000 cfm
Motor size	3 hp

5.5.10 Maintenance Building Unit Heaters, E-153

Quantity	As required
Type	Propeller fan type, electric unit heaters
Total heating capacity	144,000 Btu/hr

5.5.11 Hot Water System Circulating Pumps

Control Building Solar Collector Field Circulating Pump	Duty: 15 gpm at 30 ft head, 1/2 hp
Control Building System Circulating Pump, P-161	Duty: 17 gpm at 30 ft head, 1/2 hp

5.6 <u>References</u>

5-1 Letter: ERDA (DuVal) to Martin Marietta (Blake) regarding Pilot Plant site parameters, dated November 3, 1976.

5-2 Letter: Sandia (Skinrood) to Martin Marietta (Blake) regarding clarification of site parameters, dated November 8, 1976.

5-3 ASHRAE Standard 90-75, "Energy Conservation in New Building Design," 1975 or latest revision.

6.0 CRANES AND HOISTS

6.1 System Function

This system provides for hoisting and moving equipment as necessary for plant maintenance.

6.2 Design Bases

6.2.1 ERDA Design Bases

None.

6.2.2 Other Design Bases

- Hoisting equipment ratings are to be determined from weights of components to be handled.
- All buildings will be designed to permit access of portable hoisting equipment through doors and openings into areas where equipment must be hoisted.
- Except for the maintenance building and the full-flow demineralizer area in the EPGS structure, no permanent hoisting equipment is proposed; portable equipment will be used to accomplish other required lifts.
- Maximum turbine-generator construction lifts, based on data from a similar unit (see References 6-1 and 6-2), are the following:

Generator stator	52,000 pounds
Turbine upper casing	42,900 pounds

6.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Jacks	ANSI B 30.1
Overhead and gantry cranes	ANSI B 30.2.0 OSHA 1910-179
Slings	ANSI B 30.9
Hooks	ANSI B 30.10
Monorail systems and underhung cranes	ANSI B 30.11
Overhead hoists	ANSI B 30.16-1973
Single girder top running cranes	ANSI B 30.17
General	NEMA Industrial Controls and Standards (5CS)

Regulations or Rules goyerning Hoisting Equipment for State or Commonwealth where plant is located.

6.3 System Operation

6.3.1 Normal Operation

Day-to-day maintenance lifts are facilitated by a portable 5-ton A-frame hoist L-150, which can be moved to the equipment under repair. Roll-up doors and working clearances permit the hoist to be located as required.

Larger lifts, such as turbine-generator disassembly and repair, require offsite portable cranes, which may be rented or supplied by the utility. Access to the turbine is simplified by its outdoor location. Laydown space for turbine-generator disassembly is provided on the operating deck area outside the control room.

The maintenance building design includes a four-ton capacity overhead crane, L-151, for handling of heliostat assemblies and similar activities. A one-ton rated monorail hoist, L-152, is provided at elevation 20 in the EPGS structure to facilitate handling of stored demineralizer resins.

6.3.2 Abnormal Occurrences

In the event that a major lift is required after construction lifting equipment is removed from the site, portable cranes and temporary cribbing will be used as required to accomplish the lift.

6.4 Design Notes

Discussions with General Electric indicate that the portable crane approach has been sucessfully applied to turbine-generators of the size under consideration. GE states that under some circumstances it may be necessary to attach a chain fall or similar device to the hook of the portable crane in order to achieve the control sensitivity desired.

Careful attention must be paid during final design to assure that the 5-ton portable hoist can be properly used. Piping and raceways under the operating deck must be routed with hoist use in mind.

6.5 Equipment Data

6.5.1 Hoist, L-150

Quantity	One
Type	portable A-frame
Rating	5 tons (approx.)

6.5.2 Overhead Crane, L-151

Quantity	One

Type	Overhead bridge
Rating	4 tons

6.5.3 Demineralizer Monorail Hoist

Quantity	One
Type	Overhead monorail
Rating	One-ton

6.6 References

6.6.1 GE Drawing 783E147, "Mechanical Outline - 15,625 kVA," dated 3/5/72.

6.6.2 GE Drawing 7556E43, "Outline", Revision B, dated 4/19/72.

7.0 FIRE PROTECTION SYSTEM

7.1 System Function

The fire protection system (see Drawing M-1386) provides emergency fire protection for all plant areas, buildings, and structures.

7.2 Design Bases

7.2.1 ERDA Design Bases

None.

7.2.2 Other Design Bases

The fire protection system (FPS) will be designed to provide the following subsystems, components, and equipment:

- Automatic fire protection water supply, with a minimum capacity of 1,500 gpm at 100 psig for a minimum duration of two hours.
- Underground fire main loop to distribute water to points of use.
- Fire hydrants at convenient points, with no area of the plant more than 300 feet from at least two hydrants.
- Automatic sprinklers with discharge density of 0.30 gpm per square foot in areas of EPGS subject to potential fires from oil leakage and spills.
- Deluge system in cooling tower, if it is of combustible construction or with combustible fill.
- Foam-water deluge system to blanket entire area containing combustible heat transfer fluid pumps, heat exchangers, and associated equipment.
- Wet standpipe hose stations throughout the EPGS and administration control building and shop.
- Halon 1301 total flooding extinguishing system in the cable spreading and relay room.
- Portable fire extinguishers throughout the plant buildings and structures.
- Large diameter fire hose, nozzles, and accessories in suitable storage facilities to provide hose stream protection to all plant buildings, tanks, and other structures.

- Early warning fire detection system for areas of concentrated electrical cabling, relays, and controls

- Additional systems and equipment as required by fire hazard analysis during final design stages

7.2.3 Codes and Standards

Item	Applicable Codes, Grides, or Standards
System design	NFPA Codes and Standards Factory Mutual Engineering -- Data Sheets
System components	UL Fire Protection Equipment List Factory Mutual System -- Approval Guide

7.3 System Operation

7.3.1 Normal Operation

The fire protection system is maintained in a standby mode at all times.

- Water Supply. FPS water is supplied to the fire main loop from a source or sources to be determined during the final design. The water supply automatically maintains pressure up to the points of use and delivers the required quantity on demend.

- Fire Hydrants. The fire hydrants are manually operated. Each hydrant is capable of delivering two 250-gpm hose streams through 150-foot hose lines. Any two hydrants can be operated simultaneously to provide four effective hose streams for protection of the heat transfer fluid storage tanks and other structures and buildings.

- Automatic Sprinklers. Fire main pressure is maintained up to the fusible link sprinkler heads. Heat from a fire melts the fusible links and allows water to be discharged from all affected sprinklers. Water flow actuates a local alarm and is annunciated in the control room. Water continues to flow until it is manually shut off.

- Deluge System. Fire main pressure is maintained up to the closed deluge valve. Heat from a fire actuates the thermal detection system, causing the deluge valve to actuate. Water is discharged through all nozzles in the system. Water flow actuates a local alarm and is annuniciated in the control room. Water continues to flow until it is manually shut off.

- Foam-Water Deluge System. Fire main pressure is maintained up to the closed system control valve. Water flow in the system causes foam concentrate to be inducted into the water stream through a proportioning device. The solution of foam concentrate and water is discharged through aspirating type nozzles and mixes with air to produce a foam. The foam density will vary between 0.125 and 0.33, permitting floatation on oil surfaces for effective blanketing of oil spills. The system is designed to operate for a period of 10 minutes, after which it is manually shut off.

- Wet Standpipe System. Fire main pressure is maintained up to the closed hose station valve. Hose racks and reels provide storage of sufficient 1-1/2 inch hose to reach all areas of the buildings containing the system.

- Portable Fire Extinguishers. Portable extinguishers are carried or wheeled to the scene of a fire and manually discharged.

- Halon 1301 System. Heat from a fire actuates the thermal detectors, which in turn release Halon 1301 from pressurized storage cylinders. The discharged gas totally floods the space and initiates local and control room alarms.

- Early Warning Fire Detection System. The fire detection system detects a fire by various sensors suitable for the hazard. Thermal detectors detect a rapid rise in the ambient air or attainment of a high ambient temperature. Ionization detectors detect invisible products of combustion, and photoelectric detectors detect visible smoke. Infared and ultraviolet detectors detect flame. The selection of detectors is dependent on final plant design considerations. The system activates audible alarms in the area and annunciates in the control room.

7.3.2 Overnight Shutdown

The FPS is constantly in a standby operating mode and is not shut down during normal nightly plant shutdowns.

7.3.3 Startup

The FPS is not normally shut down and started up on a daily basis.

7.3.4 Abnormal Occurrences

The abnormal occurrences affecting the FPS are fire, loss of water supply, pipe breaks, and inadvertent discharge.

Operation in the event of fire is described in Section 7.3.1, above.

In the event of loss of water supply, emergency fire protection is provided by portable fire extinguishers.

In the event of a pipe break in the fire main loop, sectional control valves permit the break to be isolated in such a manner that no more than two hydrants will be out of service. In the event of a pipe break in other water supplied portions of the FPS, the system is isolated, and emergency protection is provided by hose streams and portable extinguishers. A pipe break in the Halon 1301 system causes no personnel hazards since the piping is not pressurized.

Inadvertent operation of water supplied portions of the FPS causes no adverse effects since sufficient drainage is provided to dispose of any discharged water. Inadvertent discharge of the Halon 1301 system causes no adverse effects, since the agent is nontoxic for short periods of time and a full-capacity reserve supply is provided for emergencies.

7.4 Design Notes

The final design of the FPS must consider the final plant design and other site-sensitive parameters.

7.4.1 Water Supply

A water supply capable of delivering 1,500 gpm at 100 psig can be provided by any of the following:

- Municipal water system of full capacity
- Municipal water system capable of supplying 2,250 gpm at a residual pressure of 20 psig minimum, with a booster pump capable of augmenting the pressure to 100 psig at a flow of 1,500 gpm
- Onsite storage tank, reservoir, or natural body of water and a fire pump rated at 1,500 gpm at 100 psig. The storage capacity should be in excess of 180,000 gallons for a two hour supply at rated pump capacity. The pump should be diesel engine driven or motor driven with two reliable sources of power available. Consideration should be given to providing two full-capacity pumps, one diesel and one electric motor driven. For preliminary design, these pumps have been assigned tag numbers P164A and P164B.

7.4.2 Fire Main Loop

The location of the water supply connection and the final plant layout design will determine the optimum routing of the loop and the location of hydrants and sectional control valves.

7.4.3 Foam-Water Deluge System

The foam-water deluge system can be either manually actuated or automatically controlled by a deluge valve actuated by thermal or flame detectors. A fire hazard analysis of the final design of the heat transfer equipment will determine the advisability of either a manually or automatically actuated system.

7.4.4 Deluge Systems

The deluge valve for the cooling tower deluge system may be located at the tower. In the event additional deluge systems are proposed in the vicinity of the EPGS, a single manifold serving the wet standpipe and all the deluge systems may prove more economical, especially if protection from freezing is required.

7.4.5 Additional Systems and Equipment

A fire hazard analysis during the final design stages may indicate the need for additonal systems and equipment as follows:

- Deluge systems for transformers
- Deluge system for turbine generator lube oil equipment
- Sprinkler system for diesel-driven fire pump room
- Portable monitor for one-man operation of large hose streams
- Portable foam equipment and large-capacity wheeled dry chemical extinguishers
- Sprinkler system for diesel-driven emergency electrical generator

7.5 Equipment Data

7.5.1 Fire Water Pumps, P164A, B

Quantity	Two full-capacity
Capacity	1,500 gpm
Head	300 ft TDH
Driver capacity	200 hp
Driver type - P164A	Diesel
P164B	Electric Motor

7.5.2 Underground Fire Main Loop

Pipe	Cement-lined ductile iron pressure pipe, Class 22, with mechanical joint fittings
Valves	Non-rising stem gate valves with indicator posts
Hydrants	Dry barrel type with two 2-1/2 inch individually valved outlets
Hydrant block valves	Non-rising stem gate valves with curb boxes

7.5.3 Sprinkler System

Pipe	Schedule 40 black carbon steel with black cast iron screwed fittings
Sprinklers	Standard 1/2 inch orifice sprinklers
Control valve	Variable pressure alarm valve with water motor alarm and accessories

7.5.4 Deluge Systems

Pipe	Schedule 40 galvanized carbon steel with galvanized malleable iron fittings
Nozzles	Standard open sprinklers, cooling tower nozzles, or solid cone spray nozzles as appropriate
Control valve	Deluge valve with water motor alarm and accessories
Detection system	Rate compensated electrical or rate-of-rise pneumatic detectors or pilot sprinklers compatable with the deluge valve and the protected hazard

7.5.5 Foam Deluge System

Pipe	Same as 7.5.3
Nozzles	Foam-water sprinklers
Control valve	Manual OS&Y gate valve or deluge valve, depending on final design; deluge valve same as 7.5.3
Detection System	If deluge valve used, same as 7.5.3 with possible substitution of flame detection in lieu of thermal
Foam storage and injection system	Pressure proportioning tanks with integral or separate venturi type proportioner.
Foam concentrate	AFFF concentrate, dry chemical compatible

7.5.6 Wet Standpipe System

Pipe	Schedule 40 black carbon steel pipe, with black cast iron screwed fittings
Hose	1-1/2 inch woven single-jacket polyester, neoprene lined, with rocker lug couplings

Nozzle	1-1/2 inch, adjustable from 30 to 90 degrees, suitable for use on Class C fires
Hose reel	Semiautomatic type, 75-foot capacity, with suitable 1-1/2 inch approved hose valve
Hose rack	Semiautomatic type, 75-foot capacity, with suitable 1-1/2 inch approved hose valve
Hose rack cabinet	Semirecessed type, or weatherproof surface mounted type, with space for portable extinguisher; break-glass type door with cylinder lock and trip bar

7.5.7 Halon 1301 Extinguishing System

Storage facilities	Sufficient high-pressure Halon 1301 cylinders manifolded to provide one main bank and one reserve bank, with provisions for manual switchover
Storage capacity	A minimum of 235 pounds of Halon 1301 for each bank
Piping	Schedule 40 galvanized steel pipe, with 300 pound galvanized malleable iron fittings
Proprietary equipment	Nozzles, releasing devices, detection system, controls, and alarms
Detectors	Rate-compensated thermal detectors

7.5.8 Early Warning Fire Detection System

Detectors	Rate-compensated thermal detectors Dual-chamber ionization detectors Photoelectric smoke detectors Infrared flame detectors Ultraviolet flame detectors
Controls and alarms	Fire indicating units, zone indicating units and local alarm bells conforming to NFPA No. 72 A with supervised circuitry

7.5.9 Hose Houses and Equipment

Hose houses	Approved prefabricated metal hose houses with shelves and brackets for hose and equipment; one hose house for each hydrant

Hose	2-1/2 inch double-jacket polyester neoprene lined labeled fire hose, coupled NST in 50-foot lengths; minimum of 300 feet per hydrant 1-1/2 inch single-jacket woven polyester neoprene lined fire hose coupled NST in 50-foot lengths; 100 feet per hydrant
Hose house equipment	Each hose house shall contain the following additional equipment: 2 underwriters playpipes, 2-1/2 x 30 inches 2 adjustable fog nozzles, 1-1/2 inch 1 gated wye, 2-1/2 x 1-1/2 x 1-1/2 inches 1 pick head fire axe 1 pinch point crow bar 6 universal spanners, 2-1/2 inches 2 universal spanners, 1-1/2 inches 2 hydrant wrenches 2 playpipe holders 2 hose and ladder straps 6 rubber hose washers, 2-1/2 inches 2 rubber hose washers, 1-1/2 inches
Portable monitor	Stang Firefly, four-wheeled, portable monitor Model BB0880-1, complete with hose rack, inlet check valves, and Stang adjustable fog nozzle Model 3729AC-2

7.5.10 Portable Fire Extinguishers

Carbon dioxide	Nominal 15 lb capacity, rating 10-B:C
Dry chemical	Nominal 20 lb capacity, rating 4-A, 40-B:C
Wheeled dry chemical	Nominal 125 lb capacity, rating 320-B:C

8.0 DOMESTIC WATER SYSTEM

8.1 System Function

The domestic water system (see Drawing M-1387) provides domestic water required by plant personnel for all drinking, cooking, washing, and lavatory purposes.

8.2 Design Bases

8.2.1 ERDA Design Bases

None

8.2.2 Other Design Bases

The domestic water system will be designed to meet the following system parameters:

- It will provide domestic water to all points of use at the quantity, flow rate, flow pressure, flow velocity, and temperature desired.
- It will provide a safe source of potable water for personnel on plant property by protecting against all sources of potential contamination, particularly those due to cross-connections.
- All water contacting surfaces in the system will be of materials specifically approved for conveyance or storage of domestic water.
- The system will be designed to operate with automatic controls and will require only normal inspection and maintenance services.

8.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Hydro pneumatic tank	ASME Boiler and Pressure Vessel Code, Section VIII, Division I,
Pumps and motors	HIS NFPA 70, National Electrical Code
Controls	NEMA ICS 1970, NFPA 70, National Electrical Code
Approved materials for plumbing	IAPMO Uniform Plumbing Code, 1976 Edition

System design	IAPMO Uniform Plumbing Code, 1976 Edition OSHA 29CFR1910, Subpart J, Sanitation and Subpart K, Medical Services and First Aid
Domestic water heater	UL 174 NFPA 70, National Electrical Code NEMA ICS 1970

8.3 System Operation

8.3.1 Normal Operation

Assuming a total 24 hour plant personnel strength of 50 persons during early plant life, and a per capita daily allowance of 35 gallons of domestic water, a storage tank of 3,500 gallons capacity is provided. The storage tank is located at grade, conveniently close to the building housing the water pressure boosting equipment. The boosting equipment takes its supply from the storage tank and distributes the domestic water to the points of use, as needed.

8.3.2 Overnight Shutdown

The system runs continuously and is not shut down during scheduled nightly plant shutdowns.

8.3.3 System Startup

The Uniform Plumbing Code requirements for installation, testing, and inspection of the completed system apply. After receipt of a certificate of approval from the administrative authority having jurisdiction, the system is disinfected and placed in service.

8.3.4 Abnormal Occurrences

Abnormal occurrences resulting in component or system failure activate an alarm, which may register visually or audibly in the control room. The following occurrences are abnormal:

- Loss of electrical power results in complete shutdown until power is restored.

- Pump failure for reasons other than loss of electrical power results in component failure without system shut down.

- Receipt of a low water level signal from the storage tank causes the control to stop booster equipment operation, resulting in complete shutdown until satisfactory water level in the storage tank is restored.

- For leakage or rupture of piping or pressure vessels, automatic alarm to the control room, or even locally, is not feasible. This condition may result in complete shutdown, or partial shutdown if the affected section can be isolated until repairs are made.

8.4 Design Notes

The preliminary design of the domestic water system is based on the assumption that water will be supplied from a relatively low-pressure source (well or distant water main). Equipment to boost pressures to usable levels has been included in the design. If adequate pressure is available at the actual site, the following equipment can be eliminated:

Booster tank	T-150
Booster pumps	P-152 A,B
Air compressor	G-151
Water storage tank	T-151

With the current design, if chlorination of domestic water is required, a small diaphragm pump can be mounted on storage tank T-151 to meter a hypochlorite solution into the tank, as required.

8.5 Equipment Data

8.5.1 Hydropneumatic Domestic Water Pressure Booster Tank, T-150

Quantity	One
Type	150 psig, ASME Section VIII, Div. 1
Lining	Copper
Capacity	900 gallons

8.5.2 Hydropneumatic Domestic Water Pressure Booster Pump, P-152A and B

Quantity	Two
Type "B" (HI)	Centrifugal, horizontal split case
Design capacity (each)	50 gpm
Total discharge head	139 ft of water (60 psig)
Driver	Electric motor
Horsepower (approximate)	7-1/2 hp

8.5.3 Hydropneumatic Domestic Water Pressure Booster Air Compressor, G-151

Quantity	One
Type (horizontal tank mounted)	Air cooled, automatic single stage
Design capacity	3.0 scfm
Pressure	120 to 150 psig
Driver	Electric motor
Horsepower (approximate)	1 hp

8.5.4 Hydropneumatic Domestic Water Pressure Booster System Controller

Quantity	One
Type (two pumps and air supply)	Automatic pressure-level control
Automatic alternator	Alternates and controls operation of both pumps

8.5.5 Domestic Water Heater, T-152

Quantity	One
Type	Electric, storage
Interior	Glass lined
Storage capacity	52 gallons
Recovery capacity	25 gph

8.5.6 Domestic Water Storage Tank, T-151

Quantity	One
Type	150 psig, ASME Section VIII, Div. 1
Lining	Copper
Capacity	3,500 gallons

8.5.7 Domestic Hot Water Recirculating Pump, P-153

Quantity	One
Type	Centrifugal, in-line mounted
Rating	5 gpm at 20 feet TDH
Driver	Electric motor
Horsepower (approximate)	1/2 hp

8.5.8 Domestic Water Heater (Maintenance Building), T-163

Quantity	One
Type	Electric, storage
Interior	Glass lined
Storage capacity	30 gallons
Recovery capacity	12 gph

9.0 SANITARY DRAINAGE SYSTEM

9.1 System Function

The sanitary drainage system collects sanitary wastes and conveys them to the sewage treatment facility (see Drawing M-1388).

9.2 Design Bases

9.2.1 ERDA Design Bases

None.

9.2.2 Other Design Bases

The sanitary drainage system will be designed to meet the following system parameters:

- It will collect sanitary wastes discharged by plumbing fixtures and convey them to the plant sewage treatment facility or to a designated point of disposal offsite, as applicable.
- System piping will be sized to flow half-full under design loads. System flow will be gravity induced.
- Materials of construction and installation will be in accordance with the requirements of the Uniform Plumbing Code.
- Wastes containing glycol or oil, or any other flammable, toxic, or corrosive substance will be excluded from the sanitary drainage system.
- The plant sewage treatment facility (if provided) and the yard sanitary sewer are a part of the civil engineering design. They will not be included in the sanitary drainage system discussed in this description. However, coordination must take place between mechanical and civil disciplines before system design is finalized.

9.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Plumbing fixtures	IAPMO Uniform Plumbing Code, 1976 Edition
Plumbing design, installation, and approved materials	IAPMO Uniform Plumbing Code, 1976 Edition OSHA 29CFR 1910, Subpart J, Sanitation
Pumps and motors	HIS NFPA 70, National Electrical Code

Controls	NEMA ICS (1970), NFPA 70, National Electrical Code
Piping	IAPMO Uniform Plumbing Code, 1976 Edition

9.3 System Operation

9.3.1 Normal Operation

Liquid wastes generated by plumbing fixture operation, accidental spillage, and leakage are collected and routed through the sanitary drainage system piping to the applicable point of treatment or disposal, which is reached via the yard sanitary sewer (see Section 9.2.2).

9.3.2 Overnight Shutdown

The system runs continuously and is not shut down during scheduled nightly plant shutdowns.

9.3.3 System Startup

The Uniform Plumbing Code requirements for installation, testing, and inspection of the completed system apply. After receipt of a certificate of approval from the administrative authority having jurisdiction, the system is placed in service.

9.3.4 Abnormal Occurrences

Abnormal occurrences resulting in component or system failure activate an alarm, which may register visually or audibly in the control room. The following occurrences are abnormal:

- With loss of electrical power, the sump pumps (if installed) will be inoperative until power is restored. Rising liquid level in the sump (if installed) actuates the alarm signal. The sanitary drainage system remains in continuous use except in the event of a failure of the domestic water system supply to the plumbing fixtures. Sanitary waste backup at the sump (if installed) could result in some flooding if the condition is not corrected.

- Pump failure for reasons other than loss of electrical power results in component failure without system shutdown. There is no alarm signal unless inflow to sump exceeds the standby pump's capacity.

9.4 Design Notes

The sanitary drainage system component ratings and capacities are estimates based or preliminary layout drawings. Further refinement of the design during the final design phase is expected.

9.5 Equipment Data

The sanitary drainage system consists of standard, locally available components. Major components (excluding piping) are the following:

Equipment	Quantity	
Water closets	8	
Closet carriers	4	
Men's urinals	4	
Urinal carriers	4	
Lavatory	6	
Water coolers	2	
Service sink	1	
Floor drains	6	(approx.)
Floor cleanout	4	(approx.)
Kitchen sink	1	
Sanitary drainage sump, T-153 (optional)	1	
Duplex sump pump, P-154 A, B (optional)	1	

Piping will be ASTM A74 or ANSI 112.5.1 extra heavy cast iron soil piping inside and outside of buildings. Where appropriate, vitrified clay pipe will also be used outside of buildings.

10.0 ACID WASTE SYSTEM

10.1 System Function

The acid waste system (see Drawing M-1389) collects acid and other corrosive wastes, routes them through an acid neutralizing basin and discharges the treated wastes to the sanitary drainage system.

10.2 Design Bases

10.2.1 ERDA Design Bases

None.

10.2.2 Other Design Bases

The acid waste system will be designed to meet the following system parameters:

- It will collect corrosive wastes discharged from laboratory sink, cup sinks, utensil washer, and floor drains and will route them to an acid neutralizing basin. The treated effluent from the acid neutralizing basin will be discharged through a connection, to the sanitary drainage system, located outside the building.
- System piping will be sized to flow half-full under design loads. System flow will be gravity induced.
- Materials of construction and installation will be in accordance with the requirements of the Uniform Plumbing Code.
- Wastes containing oil or glycol will be excluded from the acid waste system.
- No connections between the acid waste system and any other system will be permitted at any point upstream from the effluent connection from the acid neutralizing basin.

10.2.3 Codes and Standards

Components	Applicable Codes, Guides and Standards
Plumbing design, installation, and approved materials	IAPMO Uniform Plumbing Code, 1976 Edition
Sinks and laboratory glass washer	Scientific Apparatus Makers Association Standards
Piping and floor drains	IAPMO Uniform Plumbing Code, 1976 Edition

10.3 System Operation

10.3.1 Normal Operation

Liquid wastes of an acid or corrosive nature generated as a result of laboratory procedures in the administration and control building are collected, neutralized, and routed to the sanitary drainage system. The collected wastes are routed through an acid neutralizing basin of conventional design. Effluent from the acid neutralizing basin enters the sanitary drainage system at a point outside the building.

10.3.2 Overnight Shutdown

The system runs continuously and is not shut down during scheduled nightly plant shutdowns.

10.3.3 System Startup

The Uniform Plumbing Code requirements for installation, testing, and inspection of the completed system apply. After receipt of a certificate of approval from the administrative authority having jurisdiction, the system is placed in service.

10.3.4 Abnormal Occurrences

Abnormal occurrences resulting in whole or partial system failure will be avoided or minimized by regular inspection of the system and its components. No alarms are activated by affected equipment. Leakage and spillage are anticipated and therefore are not considered abnormal. The following occurrences are abnormal:

- Blockage of a portion of the drainage piping, resulting in local backup and flooding of the laboratory floor.
- Failure to provide timely replacement of the calcium carbonate ($CaCO_3$) charge in the acid neutralizing basin. Neglecting to maintain an adequate quantity of available calcium for neutralization of acids will result in corrosive attack on the piping of the sanitary drainage system and, inevitably, its failure.

10.4 Design Notes

The acid waste system component ratings and capacities are estimates based on examination of the preliminary plant arrangement drawings. Further refinement of design during the final design phase is expected.

10.5 Equipment Data

Equipment for acid waste treatment consists of the following:

Equipment	Quantity
Laboratory sink (epoxy resin)	1
Cup sink (epoxy resin)	1
Floor drains	2
Laboratory glass washer	1
Neutralizing basin, T-157 (polyethylene, 55-gallon capacity)	1

Acid waste piping inside and outside the building will be high-silicon cast iron, in accordance with ASTM A518 or ASTM A74. Where applicable outside buildings, extra strength vitrified clay pipe will be used.

11.0 OILY WASTE SYSTEM

11.1 System Function

The oily waste system collects liquid wastes from sources having the potential for contributing oil to the wastes and routes the collected wastes through an oil-water separator (see Drawing M-1390).

11.2 Design Bases

11.2.1 ERDA Design Bases

None.

11.2.2 Other Design Bases

The oily waste system will be designed to meet the following system parameters:

- It will collect oil wastes from areas in the plant that have the potential for contributing oil to drains. Principal collection points are floor drains near EPGS equipment and the TSS heat exchanger pad drains.
- System piping will be sized to flow half-full under design loads. System flow will be gravity induced except where plant site topography may require installation of a lift station.
- Materials of construction and installation will be in accordance with the requirements of the Uniform Plumbing Code.
- Wastes containing detergents, corrosives, glycol, or sanitary waste will be excluded from the oily waste system.
- Oil concentrations in treated wastewater will be in accordance with the limiting standards of the Environmental Protection Agency (EPA) as set forth in 40 CFR 423.
- Recovered waste oil shall be stored for safe offsite disposal or for salvage, at the option of the owner.

11.2.3 Codes and Standards

Components	Applicable Codes, Guides, and Standards
Plumbing design, installation, and approved materials	IAPMO Uniform Plumbing Code, 1976 Edition NFPA 30, Flammable and Combustible Liquids Code
Floor drains	IAPMO Uniform Plumbing Code, 1976 Edition

Pumps and motors	HIS NFPA 70, National Electrical Code
Controls	NEMA ICS (1970), NFPA 70, National Electrical Code
Piping	IAPMO Uniform Plumbing Code, 1976 Edition

11.3 System Operation

11.3.1 Normal Operation

Liquid wastes are collected from sources having a potential for contributing oil, such as specific floor drains in the EPGS structure. The collected wastes are routed to an oil-water separating facility via a stabilizing chamber. The chamber serves to quell turbulence and to promote settlement of entrained solids and the rise of free oil to the surface. Mechanical emulsifications of oil are treated in the oil-water separator. Waste oil is stored for optional salvage or offsite disposal. Wastewater with oil concentrations in accordance with EPA requirements is stored in a holding pond or disposed of offsite.

11.3.2 Overnight Shutdown

The system runs continuously and is not shut down during scheduled nightly plant shutdowns.

11.3.3 System Startup

The Uniform Plumbing Code requirements for installation, testing, and inspection of the completed system apply. After receipt of a certificate of approval from the administrative authority having jurisdiction, the system is placed in service.

11.3.4 Abnormal Occurrences

Abnormal occurrences resulting in full or partial failure of the oil-water separator facility will activate an alarm, which may register visually or audibly in the control room. Alarm signals indicating that operator attention is required during normal operating conditions, no malfunction having occurred, are included in this category. The following occurrences are abnormal:

- Loss of electrical power to pumping equipment and controls. Properly located sensors in each liquid compartment of the inclined plate separator will activate an alarm signal.
- High liquid level conditions, resulting in alarm activation. This may be caused by failure of one or more pumps due to mechanical breakdown.

- Effluent water from the oil-water separating facility with an oil concentration in excess of EPA requirements (see Section 11.2.2). This will cause the oil-water separation facility to recycle the effluent automatically and will activate an alarm signal at the same time.

- A sensor in the waste oil storage tank will activate an alarm to inform the operator that the tank is nearly at full capacity and the oil should be removed.

- The stabilizing chamber has the capability for alarm activation if design high liquid level is exceeded and also if the pH concentration is less than 6.0 or greater than 8.0.

11.4 Design Notes

The oily waste system component ratings and capacities and pipe sizes may require adjustment, if other design criteria and data replace those assumed.

11.5 Equipment Data

11.5.1 Stabilizing Chamber, T-154

Quantity	One
Type	Rectangular, concrete-lined, 11,000-gallon capacity
Cover	Concrete slab

11.5.2 Foot Valves

Quantity	Two
Location (transfer pump suction)	In stabilizing chamber
Material	Cast iron body, bronze trim and screen

11.5.3 Inclined Plate Separator and Accessory Equipment Package, S-150

Quantity	One
Type	Skid-mounted package unit

11.5.4 Interconnecting Wiring, Controls, and Piping

These are an integral part of the package.

11.5.5 Oily Waste Transfer Pumps, Stabilizing Chamber to Separator, P-155A and B

Quantity	Two
Installation	Duplex (automatically alternated)
Type	Positive displacement

Design capacity rating (each)	50 gpm
Total discharge head (HI)	30 feet TDH
Driver	Electric motor
Horsepower (each), minimum	5 hp

11.5.6 Oil-in-Water Monitoring Unit

Quantity	One
Type	Infrared light absorption principle
Oil concentration direct	0 to 100 ppm
Strip-chart record	30-day, continuous
Design flow rate through unit	10 gpm
Analysis independent of solids level	Yes
Generated signals transmission capability	Provided
Power supply (20 amperes)	115 V, single-phase, 60 Hz
Inlet (oily waste) connection	1-inch nominal pipe size
Outlet (oily waste) connection	1-inch nominal pipe size

11.5.7 Sludge Pump, P-156

Quantity	One
Type	Positive displacement
Design capacity rating	10 gpm
Total discharge head	20 feet
Driver	Electric motor
Horsepower	Fractional

11.5.8 Treated Water Pump, P-157

Quantity	One
Type	Certrifugal
Design capacity rating	25 gpm
Total discharge head	20 feet
Driver	Electric motor
Horsepower	Fractional

11.5.9 Sludge Storage Tank, T-155

Quantity	One
Type	Carbon steel
Capacity	50 gallons

11.5.10 Waste Oil Storage Tank, T-156

Quantity	One
Type	Carbon steel
Capacity	50 gallons

12.0 AUXILIARY BOILER

12.1 System Function

The auxiliary boiler provides process steam during overnight shutdowns and prolonged unit outages.

12.2 Design Bases

12.2.1 ERDA Design Bases

None.

12.2.2 Other Design Bases

The auxiliary boiler shall be sized to meet the following, not necessarily simultaneous, process steam demands:

TSS Salt Heat Tracing	3,000 lb/hr maximum
	1,000 lb/hr average
Deaerator Steam Blanketing	500 lb/hr average
Turbine Steam Seal System	1,500 lb/hr maximum
	750 lb/hr average

In order to meet heat tracing temperature requirements in the Thermal Storage Subsystem (TSS), the steam produced by the boiler shall be at least 420 F.

The boiler will be fueled by the most convenient locally available fossil fuel such as fuel oil, butane, or natural gas.

12.2.3 Codes and Standards

Components	Applicable Codes, Guides, or Standards
Boiler, Pump, and Safety Valves	ASME Boiler and Pressure Vessel Code, Section I, Power Boilers
Valves and Piping	ANSI B31.1

12.3 System Operation

12.3.1 Normal Operation

The auxiliary boiler arrangement is shown on Drawing M-1391. During normal plant operations, the boiler is shutdown, and the required process steam is drawn from the turbine steam piping upstream of the turbine stop valves as shown in system Drawing M-1366. As the evening shutdown approaches, the fossil-fueled auxiliary boiler is manually started in anticipation of overnight auxiliary steam demands.

12.3.2 Overnight Shutdown

As the plant is secured for overnight shutdown, auxiliary boiler steam demands increase. Feedwater to the boiler is supplied from the condenser hotwell via the auxiliary boiler feedpump (see Drawing M-1366). During overnight shutdown, the turbine is placed on turning gear while maintaining condenser vacuum and associated turbine steam seals. All EPGS condensate and feedwater pumps are shutdown, and the deaerating feedwater heater is placed under a steam blanket slightly above atmospheric pressure to prevent oxygen from entering the feedwater in the deaerator. Steam is also provided to heat trace molten salt lines in the TSS.

The approximate overnight steam demands in this mode are as follows:

Turbine steam seals	750- 1,500 lb/hr
Deaerator steam blanket	500 lb/hr
TSS heat tracing	1,000 lb/hr
Total Demand	2250- 3,000 lb/hr

The quantity of steam required to seal the turbine is dependent upon the age and condition of the seals.

This operating mode continues until morning when plant startup operations are initiated.

12.3.3 EPGS Startup

As morning approaches, the EPGS is prepared for operation. The auxiliary steam supply to the deaerator, steam seals, and TSS heat tracing is replaced with steam from the receiver or the TSS. The auxiliary boiler is then shut down.

12.3.4 Abnormal Occurences

Should the auxiliary boiler fail or run out of fuel, operator action to drain and isolate heat traced molten salt lines in the TSS will be required. The rate of heat loss from the molten salt storage tanks is low enough to allow time for repair or refueling of the boiler.

In the event of loss of offsite power feed, heat tracing steam to the TSS is maintained by placing the auxiliary boiler controls on the emergency diesel power bus.

Protective devices required by the ASME Power Boiler Code assure safe operation of the boiler equipment. As an added safety feature, the boiler and fuel are located in an area away from important plant structures.

12.4 Design Notes

If feedwater deaeration is required, before receiver steam becomes available for deaerator pegging, the deaerator could be converted to a vacuum degasifier by adding a small steam jet air ejector or vacuum pump in parallel with the normal atmospheric vent shown on Drawing M-1367. This would permit feedwater deaeration with a comparitively small expenditure of auxiliary steam or electric power during startup. However, feedwater temperatures resulting from this approach would be approximately 80 to 100 F. If steam temperatures of 420 F are not required, the auxiliary boiler design pressure could be lowered from 300 psig to a more standard 150 psig pressure.

During final design, consideration should also be given to including an electric boiler rather than a fossil boiler in the design. The electric boiler, while minimizing capital cost and simplifying design, has significantly higher operating costs.

12.5 Equipment Data

12.5.1 Auxiliary Boiler, S-105

Flow capacity	3000 lb/hr
Operating pressure	300 psig
Steam temperature	420 F (saturated)
Fuel	Fossil (oil, liquid petroleum gas or natural gas)

12.5.2 Auxiliary Boiler Feedpump, P-108

Flow capacity	6 gpm
Total developed head	800 ft water
Motor size	3 hp

SYSTEM DESCRIPTION

FOR

ELECTRIC POWER GENERATION SUBSYSTEM

MAIN STEAM SYSTEM

FOR

CENTRAL RECEIVER SOLAR THERMAL

POWER SYSTEM, PHASE 1

MARTIN MARIETTA CORPORATION

DENVER, COLORADO

BY

BECHTEL CORPORATION

SAN FRANCISCO, CALIFORNIA

No.	DATE	REVISIONS	BY	CH'K	APPR
0	4/1/77	Issued for Preliminary Design Report	JHW	JAK	NW

ORIGIN	CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM PHASE 1	JOB No. 11480	
R & E		System Description SD- 4	REV. 0
		SHEET i OF 25	

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1.0 SYSTEM FUNCTIONS

The Main Steam System (MSS) converts the thermal energy derived from the Receiver Subsystem or the Thermal Storage Subsystem (TSS) of the Central Receiver Solar Thermal Pilot Plant to electric power. In addition, the system supplies cooling water to condense the turbine exhaust steam and to serve as heat sink for the plant heating and ventilating equipment as well as other auxiliary cooling functions.

2.0 DESIGN BASES

2.1 ERDA Design Bases

2.1.1 Power Rating

The EPGS must deliver a net power of 10 MWe when operating with steam supplied by the Receiver Subsystem. The minimum generating capacity, during operation with steam supplied from the TSS, is 7 MWe.

2.1.2 Rating Conditions

The system design is based on heat dissipation in wet cooling towers. The design basis maximum ambient wet bulb temperature is 74 F (Reference 1). Below this level, the MSS is designed to operate satisfactorily over wet bulb temperatures expected the year around.

2.1.3 Commercial-Scale Applicability

The pilot plant serves as a prototype of one module for future commercial-scale solar power plants. To the extent feasible, the design and operating conditions should simulate potential commercial installations. Material and equipment selection should consider applicability to plants of about 150 MWe capacity.

2.1.4 Site Criteria

Site-specific features of the design are based on hypothetical site data furnished in Reference 1 and 2. These features must be verified against the characteristics of the actual selected site (see Section 4.1).

2.1.5 Plant Design Life

System components subject to wear, corrosion damage, or other time-dependent deterioration are designed for 30-year service life, with special consideration of the cyclic conditions typical for solar plant application.

2.2 Other Design Bases

2.2.1 Operating Modes

Normal EPGS operating modes include:

- Cold shutdown
- Startup
- Hot standby
- Power generation at receiver steam conditions
- Power generation at TSS steam conditions
- Power generation using receiver and TSS steam simultaneously

The system and its controls must be capable of adjusting the operating parameters to:

- Follow the normal daily insolation cycle
- Follow the generator load
- Compensate for temporary variations of insolation such as would result from passage of intermittent clouds
- Follow the seasonal and diurnal variation of wet bulb temperatures

2.2.2 Interface Conditions

Normal interface conditions include:

- Receiver steam at turbine stop valve:
  - Pressure -- 1,365 psia
  - Temperature -- 950 F
- TSS steam at admission stop valve:
  - Pressure -- 414.7 psia
  - Temperature -- 800 F
- Auxiliary and heating and ventilating cooling rate:
  - 6×10^6 Btu/hr (Reference 3)

- Cooling water makeup:
  - Available flow rate -- site dependent
  - Water chemistry -- site dependent

Manufacturer recommended limits of boiler water quality based on drum water analyses:

- Total solids -- 500 ppm
- OH alkalinity -- 25 ppm
- Silica -- 5 ppm
- Phosphate -- 20 ppm
- Hydrazine -- 10 ppm
- Hardness -- undetectable
- Chlorides -- 20 ppm

2.2.3 Seismic and Natural Phenomena

Unless local municipal regulations require otherwise, the design is to be based on seismic and wind conditions specified in the Site Criteria (Section 2.1.4) and is to meet the requirements of the Uniform Building Code.

2.2.4 Line Sizing

The EPGS piping is sized for steam and water velocities used in common industrial practice for similar application. Unless special vendor requirements or process applications indicate otherwise, the following average values were used as design bases:

- Water -- 7-10 ft/sec
- Low-pressure steam (max.) -- 200 ft/sec
- High-pressure steam (max.) -- 150 ft/sec
- Vacuum (0-5 psia) -- 500 ft/sec

2.2.5 Materials of Construction

Piping and equipment exposed to process steam and condensate must be manufactured from materials suitable for service with water chemistry as defined in Section 2.2.2. Unless service conditions require special considerations, such as wear resistance or thermal conductivity, components and piping are to be made of appropriate grades of carbon steel. Materials for cooling water service are selected for compatibility with the chemistry of the makeup water source (see Section 2.1.4). Insulation and thermal lagging is to be noncombustible or fire retardant and usable for 950 F service.

2.2.6 Codes and Standards

The design, manufacture, installation, inspection, and testing of EPGS equipment are performed in conformance with applicable sections of the following codes and standards:

• Piping, valves, and fittings	ANSI B-31.1, Code for Power Piping
• Tank and vessels (except turbine)	ASME, Section VIII, Unfired Pressure Vessels
• Pumps	Standards of Hydraulic Institute
• Condenser	Heat Exchange Institute Standards for Steam Surface Condensers
• Other heat exchanger	Standards of Tubular Exchanger Manufacturers
• Fire Protection	NFPA Standards Association

Manufacturers' practices, where justified by prolonged sucessful service, may be used in special applications (e.g., the turbine-generator) in lieu of national codes and standards.

2.2.7 Local and Federal Regulations

Construction and operation of the EPGS complies with applicable local and state regulations and regulations from federal agencies such as OSHA, EPA, etc.

3.0 SYSTEM OPERATION

The descriptions of operation given in this section relate mainly to the mechanical system. The necessary control components, the functioning of these components, and details of the control logic are shown in the EPGS Control System Description (Reference 4).

3.1 Steam System

3.1.1 Overall System Configuration

The Main Steam System consists primarily of the turbine-generator and its associated piping as well as support equipment shown in the Main Steam System diagram, Drawing M-1366. Besides the turbine-generator, the system definition also includes the main condenser and its associated circulating water equipment. The system interfaces with the EPGS feedwater system (see Reference 5), the water system, the Receiver Subsystem, and the Thermal Storage Subsystem.

Separate piping from the receiver and TSS bring the steam to the turbine stop valves. During warmup, bypass lines upstream from these valves permit dumping the steam, after desuperheating, directly to the condenser. The receiver steam is piped to the main stop valve (high-pressure section). The TSS steam line is connected to the admission steam stop valve (low-pressure section). High-pressure and admission steam flows to the turbine are regulated by control valves on signal from the turbine-generator master control. The turbine has four automatic extraction openings serving the feedwater heaters. Bleeder trip valves in the higher pressure extraction lines and a check valve in the low-pressure line prevent reverse steam flow on turbine trip. Without these, the energy stored in the feedwater system would be dissipated in overspeeding the turbine.

The turbine exhaust is condensed in a water cooled condenser unit. In addition to this main steam flow, the condenser also receives steam and condensate from a large number of vents and leakoff points. Accumulation of noncondensable gases in the condenser is prevented by the operation of the vacuum pump of the condenser exhauster unit.

A blowdown tank is provided to eliminate the accumulated soluble and suspended solids from the receiver steam drum and the TSS steam drum. The tank has connections to discharge the flashoff to the deaerator or to vent it to the atmosphere. The remaining water can be routed to the condenser or to the circulating water system. The valve controlling the blowdown rate is designed for severe service. The water discharge is controlled to maintain a constant level in the tank.

3.1.2 Equipment and Component Requirements

The turbine-generator selected for the plant is a standard size (12.5 MWe), single automatic extraction unit manufactured by the General Electric Company. The unit is capable of operating in all modes required for the pilot plant, and similar designs are available in the 100 to 200 MWe range for use in a commercial-size solar power plant.

The prescribed turbine-generator operating modes are:

- High-pressure (receiver) steam feed only. Power delivered varies with steam flow from the Receiver Subsystem at constant turbine inlet pressure.

- High-pressure (receiver) steam feed only. Power delivery constant at intermediate level.

- High-pressure (receiver) steam and admission pressure (TSS) steam feed simultaneously. Maximum power delivery limited by the turbine low-pressure section flow capacity.

- Admission pressure (TSS) steam feed only. Power delivery constant at 7 MWe net or less.

- Programmed load reduction. Turbine operating on admission steam alone.

- Hot standby operation. Turbine operating on turning gear.

- Startup and synchronization. Turbine operating on high-pressure or admission steam.

- Cold standby operation. Only 460 volts 60 Hz ac power available to maintain essential services and monitoring.

The turbine-generator is expected to cycle daily through combinations of the modes listed. Over the design life of the plant, this represents about 10,000 cycles. There will be approximately 40,000 cycles, each involving receiver steam and admission steam operations. Cold standby operation will occur about 1,000 times during the plant life. Characteristics and functional parameters of the turbine-generator and related equipment are listed in Section 5.1. Detailed descriptions of the unit and auxiliary systems furnished by the manufacturer are given in Section 3.3.

<u>The condenser</u> is a standard commercial design available from various manufacturers. It is connected to the turbine exhaust hood through an expansion joint to accommodate differential thermal expansion. The design selected for the pilot plant is a water cooled, single-pressure, cross-flow unit with four-pass water tube configuration. The four-pass arrangement places both the inlet and outlet connections on the same side, thereby simplifying the water pipe runs. The pass length was chosen to fit the condenser within the structural members of the turbine foundation. Cooling water flow to the condenser is unregulated, and thus the water inlet temperature and the temperature range will change according to the load and the ambient conditions. Steam pressure in the condenser will also vary accordingly. Design bases and characteristic parameters of the condenser are shown in Section 5.2.

<u>The condenser exhauster</u> vacuum pump is a two-stage, liquid ring design available as a standard manufactured package. Both stages are mounted on the same shaft and are driven by a single electric motor. The packaged unit, mounted on a common base, consists of the pump and the following auxiliaries:

- Liquid separator with sight gauge and automatic makeup valve

- Motor coupling and guard

- Inlet check valve
- Air outlet check valve with test handle
- Seal water cooling heat exchanger

Functional characteristics of the exhauster are given in Section 5.3. To assure continuity of service, two exhauster units are required.

The auxiliary boiler feed pump is a small-capacity, electric motor driven, centrifugal pump. It is used to convey water from the condenser hotwell to the auxiliary boiler during hot standby and system startup operations. Characteristics of the pump are included in Section 5.5.

The blowdown tank is a vertical pressure vessel receiving continous blowdown flow from the receiver and TSS steam drums. The water inlet is tangential and is equipped with an impingement wear plate. Steam vent and water discharge nozzles are provided as well as a nozzle for bottom connection. Characteristics of the tank are given in Section 5.6.

The desuperheater is a vertical pressure vessel used to quench the receiver or TSS steam before feeding it to the condenser. The component is operated daily, predominantly during startup periods when the steam is bypassed around the turbine. The vessel has a water spray header and has a large nozzle to exhaust the steam to the condenser. A drain connection is provided to remove the excess water. Data of this component is included in Section 5.6.

3.1.3 Steam System Operation -- Normal Modes

In contrast to base loaded central stations, the operation of the pilot plant is characterized by daily cycles from standby to full power and back to standby. Steam to power the turbine is also cycled daily between the receiver and the TSS. Longer standby and shutdown operations are envisioned during cloudy seasons.

3.1.3.1 Operation from Receiver Alone

In this mode, the steam flow to the turbine is regulated to maintain a constant pressure in the receiver. Flow variations essentially follow the solar energy input to the receiver. The power delivered to the generator shaft varies with the steam flow and with the condenser backpressure. The latter, in turn, is dependent on the ambient wet bulb temperature, since the cooling water flow rate is not adjustable. The admission (TSS) steam stop valve is closed for this mode of operation.

It is noted that adequate frequency regulation, in this mode, is dependent on a stiff utility power grid that can load the generator according to the available solar energy.

The EPGS can operate in this mode if the following interfacing systems are operating and are able to attain the required operating levels:

- Collector Subsystem
- Receiver Subsystem
- Feedwater System
- Circulating Water System
- Component Cooling Water System
- Seal Steam Regulator
- Seal Steam Exhauster
- Condenser Exhauster
- Hydraulic Power Unit
- Lube Oil Package
- Plant and System Controls
- Auxiliary Electric Power
- Electrical Power Grid

A special case of operation from the receiver alone occurs when a portion of the receiver steam is diverted to charge the TSS during peak insolation. In this mode, the generator delivers a constant power at a predetermined level, and the high-pressure turbine control valve is set in the generator follow mode. In other respects, this operation is the same as described above.

3.1.3.2 Operation from TSS Alone

In this mode of operation, the steam flow to the turbine is controlled to deliver a specified continuous generator output (7 MWe or less, depending on power grid demand), until the available stored energy is exhausted or the passing of clouds permits return to operation from the receiver. The TSS steam is fed via an admission opening to the low-pressure section of the turbine. The admission stop valve is wide open and the high pressure (receiver steam) stop valve is closed. The admission control valves are placed in the load control mode. (See Control System description, Reference 4, for details of turbine control modes.) A steam bypass line feeding steam to cool the inactive high-pressure section of the turbine is open, diverting about 15,000 lb/hr admission steam for this purpose.

Because of a reduced load on the condenser in this operating mode, the condenser cooling water temperatures, even with a constant ambient wet bulb temperature, are lowered. This produces lower condenser pressures and corresponding improvements in the performance of the turbine.

The list of interfacing systems, operating in this mode, is the same as that given in Section 3.1.3.1, except that the TSS is added and the Receiver Subsystem is deleted.

3.1.3.3 Generating from Receiver and TSS Concurrently

In this mode of operation, which occurs mainly in the afternoon hours when the solar energy is declining, the turbine draws steam from both sources. The high-pressure turbine control valve is set to maintain a constant upstream steam pressure in the receiver steam loop, and the admission control valve is set to the load. The condenser backpressure is reduced as the turbine load decreases due to the lower condensing load and the lower cooling water temperature.

The list of interfacing systems that are operational in this mode is the same as given in Section 3.1.3.1, except that the TSS is added.

3.1.3.4 Charging TSS and Operating Turbine on Admission Steam

The capability for this operating mode permits the operator to stabilize power generation when the steam delivery from the receiver fluctuates. For example, this occurs when cumulus clouds obscure the sun for short periods of time. For the Main Steam System this mode is identical to operation on TSS alone, as described in Section 3.1.3.2. The interfacing systems needed to operate in this mode are the same as in Section 3.1.3.1, except the TSS is added to the list.

3.1.3.5 Hot Standby

When electric power generation is interrupted for several hours, which can occur for a variety of reasons, the EPGS is placed in hot standby status. The most obvious reasons are overnight shutdown after the TSS has been exhausted or short duration maintenance on other parts of the plant.

To achieve this condition, both the high-pressure and admission stop valves are closed. The turbine is kept slowly rotating on turning gear. Seal gland flow is maintained using steam generated in the auxiliary seal steam boiler. The condenser exhausters continue to operate. Interfacing systems required during hot standby are:

- Seal steam generator
- Seal steam regulator
- Seal steam exhauster
- Condenser exhauster
- Lube oil package
- Plant and system controls
- Circulating water system
- Component cooling water system
- Auxiliary electric power

3.1.3.6 Cold Shutdown and Cold Start

If the plant is not expected to operate for several days due to overcast conditions or due to maintenance and repair activities, the Main Steam System is completely shut down. To achieve this condition, the generator is taken off the grid, the steam flow to the turbine is interrupted by closing the stop valves, and the unit is allowed to come to stand still. The hydraulic power unit and the lube oil package is shut off when the turbine stops. The steam remaining in the system is allowed to condense, and the hotwell water is transferred to the condensate storage tanks. At the end of this operation, the condenser exhauster is stopped and the cooling water flow is switched to auxiliary operation. The flow through the condenser is stopped. The system components and piping gradually cool to ambient conditions.

Prior to startup of a cold system, the operability of auxiliary systems is verified. The hydraulic power unit and the lube oil package are started up, and minimum operating temperatures are established. When steam becomes available from the receiver or the TSS, cooling water flow through the condenser is established, and the steam seal system is put in operating status. Evacuation of the condenser is started by using the exhausters in the hogging mode. The initial steam flow is used to heat up the steam system. This flow is diverted around the turbine to the desuperheater and is dumped to the condenser after quenching. When nominal start up conditions have been achieved, the process described in Section 3.1.3.7 is used to startup the plant and bring the generator on line.

3.1.3.7 Turbine Startup, Synchronization, and Generator Loading

Startup, as part of the normal operating cycle, is accomplished by using receiver steam. The means for starting up from TSS steam under special circumstances are also provided. During the early part of the daily cycle, while the TSS is being charged from the receiver, the turbine and the required auxiliaries operate in the hot standby mode. Prior to initiation of turbine startup, all the systems listed in Section 3.2.1 are brought up to normal operation. Steam flows are started to gradually warm up the piping system. The initial steam flow is routed around the condenser and is dumped to the condenser after desuperheating.

When the monitoring instrumentation shows that all systems have achieved nominal operating levels, the high-pressure control valves are set to the speed/load control mode, and the high-pressure stop valve is opened. The turbine is accelerated from turning gear to synchronous speed along a preplanned speed-time profile. When the turbine achieves rated speed, the generator is synchronized and tied to the electric grid. The generator loading is increased, using the load control mode, until all the steam produced in the receiver is being used to generate electric power. At this point, the control valves can be switched to the upsteam pressure control mode, or if TSS charging is desired, the turbine steam consumption can be limited.

3.1.3.8 Blowdown

This operation is continuous when either the receiver or the TSS boiler is operating. The blowdown rate is governed by the blowdown valve, which is designed for severe service. When expanded through the valve, part of the blowdown flashes to steam. Under normal condition, this steam is vented to the deaerator. If chemical analysis shows high ammonia concentration due to breakdown of the hydrazine, the steam is manually diverted to the atmospheric vent. The remaining water is routed to the condenser for processing by the full flow demineralizer. The water flow is manually diverted to the circulating water system if it contains impurities not controllable by the feedwater treatment.

3.2 Cooling Water System

3.2.1 Overall System Description

This system is used to reject the waste heat from the steam system condenser, from various auxiliary systems, and from heating and ventilating loads. The water distribution piping is fed from the cooling tower basin. The main branch of the piping carries water to the condenser water box. Lines serving the component cooling water system branch off from the main run at a location within the EPGS structure. Cooling water flow to the condenser is essentially constant.

Warm water discharged from the condenser and the water heated by the auxiliary loads are collected in the return header and piped to the mechanical draft cooling tower. A modulating valve is available to balance the tower flow to each of two cells. To assure reliable cooling water flow during plant operation, the systems have two 50 percent capacity circulating pumps.

When the turbine is shut down, the cooling requirements are comparatively small. A small capacity pony pump is used to circulate the water during such periods. To limit the water flow through the condenser in this mode, a block valve and a smaller diameter bypass line with a flow control valve are provided in the main circulating water pipe.

The source of makeup water is dependent on conditions at the actual site. The specified site conditions (Ref. 2) stipulate the existence of an aquifer 500 feet below the surface. Three wells sunk into this aquifer, each capable of supplying 50 percent of the makeup requirements, have been assumed for the current design. The pumps supply a single pipe line and operate on a low-level signal from the tower basin.

Provision for filtering, biocide additions, and potential chemical treatment are deferred until actual site conditions are known (see Section 4.1). Water quality and possible environmental considerations govern the selection of the number of cycles of concentration.

3.2.2 Equipment and Component Requirements

The cooling towers are induced draft-type wet units. One manufacturer recommends a two-cell configuration with a flow balancing valve to distribute the water flow between the cells. The towers are sized to dissipate waste heat from all cooling loads in the plant against a design basis ambient wet bulb temperature of 74 F. This parameter and the tower design are subject to verification once the conditions at the actual site are known (see Section 4.1). The tower basin is assumed to be at an elevation that permits gravity draining of the water inventory when the circulating pumps are turned off. The basin depth of 4 feet, attainable with the standard tower support, gives a capacity of 55,000 gallons.

At lower ambient temperature conditions, one or both fans may be turned off. At design wet bulb conditions, the towers can reach 15 to 20 percent of design cooling capacity if operating in a natural convection mode.

Characteristics of the cooling towers are listed in Section 5.4.

The main circulating water pumps lift the circulating water from the tower basin and provide the head to overcome static as well as friction losses in the distribution piping and in heat exchange equipment. The characteristics listed in Section 5.5 are tentative and are based on a nominal loss of 80 feet of head for the assumed site conditions (see Section 4.1).

A pony pump is used to maintain cooling water flow when only auxiliary cooling is required. Pump capacity is based on the assumption that full flow is directed to auxiliary loads. Water flow to the auxiliary loads represents about 15 percent of design flow.

Water makeup pumps are required to pump well water to the cooling tower basin to maintain its water level. Characteristics are based on an assumed head requirement of 500 feet (see Section 4.1).

3.2.3 System Operation

Condenser cooling is the normal mode of operation, although the smaller fraction of plant life is spent in this mode. Operation is initiated by manually starting the main circulating pumps and (except when freeze prevention measures are required) the tower fans. In the daily plant startup sequence, full water circulation is established before the turbine stop valves are opened. Once the main circulating pump is at full speed, the pony pump is manually stopped, and the condenser supply valve is opened.

The cooling water circulation rate is essentially constant. The tower basin water temperature directly follows the variation of the condensing load and the changes in wet bulb temperature. A stepped increment of cooling control can be exercised by shutting off one or both fans or by taking one of the cells off the line.

At the end of the daily power generating cycle, when the condenser is no longer required to condense turbine exhaust steam, the pony pump is turned on, and the tower fan and main circulating pump are turned off in preparation for switching to hot standby operation.

Auxiliary cooling operation occurs during hot standby or cold shutdown operation. It is established by manually turning on the pony pump, closing the stop check valve to the condenser, adjusting the bypass flow, and taking the main circulating pump as well as the tower fans off the line. One of the tower cells may also be taken off the line. If the steam system is on hot standby with continuing steam seal flow, a small amount of cooling water flow to the condenser is maintained to satisfy this limited condensing load.

Tower basin makeup is an automatic operation. When the basin level drops to the low-level set point, the level switch energizes the well pumps. They are turned off at the high-level set point. The intake strainers require periodic inspection and cleanout.

Chemical addition and blowdown system operation will be developed after water quality data for the actual site become available.

Tower basin draining, filling, and desilting are infrequent operations, depending largely on atmospheric conditions at the site. On indication of significant sedimentation in the basin or of poor cooling performance, the tower fill is hosed down, and the silt is removed from the basin by mechanical means or by vacuuming.

3.3 Auxiliary System

3.3.1 Steam Seal System

This system supplies steam at 3 to 4 psig to the turbine and valve seal glands to prevent air inleakage or excessive outleakage of process steam. Components of this system, except the steam supply, are furnished by the turbine manufacturer.

Since this system must remain operational during startup and hot standby, the steam necessary for these phases of operation is generated in a separate boiler. A small water pump, taking suction from the condenser hotwell, supplies the water to this boiler. During normal operation, the leakoff from the high-pressure seal is adequate to supply the other seals, and thus the operation of the auxiliary boiler can be terminated.

The function of the steam seal regulator, which is furnished by the turbine manufacturer, is to regulate the pressure at the seal glands. To accomplish this, tne regulator either admits steam to the system or dumps enough to maintain the specified pressure at the gland. Excess steam is piped to the condenser. Operation of this system is required at all times except during cold shutdown.

3.3.2 Gland Exhauster System

The function of this system, which is furnished by the turbine manufacturer, is to collect and dispose of the air leaking past the outer seal glands and steam escaping through the inner glands. To accomplish this, the vacuum pump maintains a slight vacuum (3 to 5 inches of H_2O) in the vent cavity.

The basic system consists of a vertical, motor-driven vacuum pump and water spray chamber connected to the leakoff piping in the packing gland. Adjustable dampers balance the leakage flow from the glands. The spray chamber uses water from the plant water system. The collected air is vented to the atmosphere, and the overflow water is dumped to the drain. A water-loop seal prevents the water from backing up into the leakoff piping, should the vacuum pump fail. Strainers in the spray water and in the pump suction line prevent clogging due to entrained solids.

The system is started up by opening the spray water supply valve and starting the vacuum pump. Operation of this system is required at all times except during cold shutdown.

3.3.3 Condenser Exhauster Unit

During normal operation, the system purchased separately from the turbine removes noncondensables and thereby maintains the condenser vacuum. The exhauster is also capable of evacuating the turbine cavity and the steam side of the condenser before startup. To assure operating continuity, two full-capacity, parallel units are connected to the air outlet of the condenser. Each unit consists of a liquid-seal, two-stage, electric-motor-driven vacuum pump, a water-cooled aftercooler, and an air separator. Backflow preventers are included upstream from the pumps and in the air discharge vent. A rotometer is provided to indicate exhaust airflow. A reservoir with automatic makeup valve is provided to maintain sump water inventory. For hogging (initial vacuum pull), both units can be operated simultaneously to reduce the time required for evacuation. During normal operation, one unit is running and the other is on standby. A pressure switch furnished with the units activates the standby unit if the condenser pressure exceeds the set point.

To start the units, the cooling water flow is established at 75 gpm, and the makeup water shutoff valve is opened. When the water in the pump reaches the required level, the pump motor is manually started. Once in operating status, the units function automatically.

Operation of these units is required at all times when the condenser is held under vacuum.

3.3.4 Hydraulic Power Unit

This unit supplies high-pressure hydraulic fluid to actuate the turbine stop and control valves. It operates in conjunction with the turbine electrohydraulic control system. The unit is supplied by the turbine manufacturer.

The main components of the unit include a central fluid reservoir, two independent pumping systems, water coolers, and a pair of nitrogen powered accumulators. Auxiliaries such as air dryer, space heater, and auxiliary filter units are also included and are mounted on a common stand with the main components. Operation of the turbine controls requires a continuous supply of the hydraulic fluid. This is assured by providing a fully redundant pumping train. The pumps are backed up by bladder-type fluid accumulators kept under pressure with nitrogen. At any given time, only one of the pumping trains operates, but the standby train is automatically started by a pressure switch on indication of loss of pressure. For normal operation, the fluid is maintained at 95 F to 100 F temperature. Temperature sensors in the reservoir actuate the cooling water flow control valve to maintain this temperature range. If the oil temperature drops below 65 F during long shutdowns, the reservoir and bladder temperature is raised by use of a space heater located near the components. An air dryer limits the moisture content of the air blanketing the fluid in the reservoir. The fluid is kept free of dirt by filters in the discharge line of each pump and by an upstream strainer. Operation of this system is required continuously during times of steam flow to the turbine.

3.3.5 Lube Oil Package

This system circulates lubricating fluid to the turbine and generator bearings to dispose of friction heat generated at these bearings. The package is supplied by the turbine-generator manufacturer.

Normal oil circulation is provided by one of two full-capacity ac motor-driven vertical pumps taking suction from the oil reservoir. The other pump is on standby to pick up the load should the operating unit fail to maintain the required oil pressure. In the event of power failure, a third, dc motor-driven pump can pick up the load. A regulator valve maintains the lube oil manifold pressure at 25 psig. The oil returning from the bearings is passed through the coils of a three-section cooler by gravity flow. Two of the three sections can provide adequate cooling; the third section supplies spare capacity or can be removed for maintenance if necessary. The air space above the oil in the reservoir is vented by a vapor extractor blower. The entrained vapor is extracted from the discharge and is returned to the reservoir.

When chemical analysis and/or visual inspection shows excessive impurities, the oil quality in the system is restored by draining and cleaning out the reservoir and refilling it with fresh oil. The discharged oil is returned to the supplier for purification.

Operation of the system is required at all times when the turbine is rotating either at operating speed or on turning gear.

3.4 Infrequent and Emergency Operations

3.4.1 Loss of Turbine Steam Pressure

This condition results from malfunction of the receiver or TSS steam circuitry. If the turbine flow is controlled on upstream pressure, the control valve closes trying to maintain the set point pressure, and the generator is tripped by protective devices that prevent "motorizing" the generator. The main stop valve closes, and the turbine is placed on hot standby, rotating on turning gear. If the turbine flow is controlled to maintain constant power output, the control valve opens but is unable to maintain the necessary steam flow, and the unit loses speed. As above, the generator is tripped by the "anti-motorizing" devices.

On loss of condensing load, the circulating water temperature range diminishes. The cooling tower fans are shut off, and water circulation is switched to pony pump operation to maintain cooling in the remaining systems.

The EPGS is expected to sustain no damage that would prevent resumption of operation once the steam flow is reestablished.

3.4.2 Loss of Steam Seal Supply

All but a momentary loss of the steam seal flow requires a shutdown of the EPGS. If steam flow to the glands cannot be maintained, air enters at the low-pressure seal, and the steam outleakage increases at the high-pressure seal. The condenser exhauster pressure switch senses the increased pressure and starts the operation of the standby unit.

Normally, it is expected that adequate time is available for orderly shedding of the generator load and shutting down of the turbine.

3.4.3 Loss of Condenser Cooling

The circulating water system is highly reliable, with redundancy in the circulating pumps and ability to operate on only one of two cooling tower sections if necessary. Thus, complete loss of condenser cooling can occur only if there is a major pipe break or prolonged loss of the auxiliary power transformers.

If cooling is lost, the condenser pressure begins to rise. At a pressure of about 5.5 inches of Hg, the high-pressure alarm is set off. If the alarm is ignored and the pressure rises to approximately 10 inches of Hg, the turbine automatically trips. If the pressure continues to rise, the atmospheric relief valve opens at a still safe pressure of 10 psig, and the steam is released to the atmosphere. If the turbine is operating on receiver steam, the steam flow is diverted to the TSS or to the atmosphere and further steps are taken to shut the unit down. The turbine is kept rotating on turning gear in hot standby mode until further decisions are made in light of diagnostic findings.

3.4.4 Loss of Generator Load

If the electric load of the generator is suddenly lost due to some malfunction in the system, the turbine tends to overspeed. A two-level protective system is provided to trip the turbine and to prevent destruction due to excessive speed. Details of these protective systems are given in Reference 4.

3.4.5 Loss of Turbine Speed Regulation

The effects of the loss of speed regulation on the main steam system are similar to the loss of generator load, and the same protective devices that are indicated in Section 3.4.4 act to prevent damage to this system.

3.4.6 Loss of Site Power

Loss of site power causes the turbine to trip. Depending on the duration of the outage, the system is brought to a hot (short outage) or a cold (prolonged outage) standby condition. Once the integrity of the electrical system is restored, the serviceability of the auxiliary systems is verified, and the main steam system is started up in accordance with the applicable normal procedures (see Sections 3.1.3.6 and 3.1.3.7).

3.4.7 Loss of Auxiliary Systems

As shown in Section 3.1.3, productive operation of the turbine generator requires concurrent satisfactory operation of:

- The hydraulic power unit
- The lube oil package
- The condenser exhauster unit

These systems are designed to be highly reliable and to retain serviceability long enough to permit orderly shutdown of the EPGS. All of these systems have redundant standby capability to maintain service should the operating equipment malfunction or be disabled. The electric drive of the hydraulic power unit is backed up by pneumatic pressure, and the lube oil package has an energency dc driven oil pump so that, during loss of site power, it will remain operational long enough to shut down the turbine generator.

3.4.8 Seismic Event

The effects of seismic events will be evaluated during final design. It is expected that the plant will remain operational during and after minor tremors. After major quakes, the plant will be shutdown and not started again until certain diagnostic tests and inspections have shown the plant to be safely operable. Even large, destructive events will not create plant conditions harmful to public health and safety.

4.0 DESIGN NOTES

The purpose of this section is to outline certain additional studies to be conducted during detailed design before the final configuration is frozen.

4.1 Site-Specific Design Requirements

The preliminary design of the EPGS was developed around a set of assumed site characteristics, which are described in References 1 and 2. System design and component features, selected on the basis of these data, must be checked against the specifics of the actual site as summarized in Table 1.

4.2 Design of Cooling Towers to Minimize Drift and Vapor Clouds

While the wet condenser cooling system offers advantages over air cooling in cycle efficiency and in lower initial investment, potential drawbacks related to mirror shading by the vapor plume under adverse wind conditions and deterioriation of reflectivity of the mirror field due to drift fallout must be further evaluated. The problem is present in the pilot plant and may be of major significance in the commercial plants. The evaluation programs should consist of the following major activities:

1. Assessment of plume and surface fouling problems on the basis of actual data. Items to consider include the distance between collector field and cooling towers, cooling water chemistry, cloud opacity, impingement of high intensity radiant heat on clouds, and drift diversion due to convective effects near the mirrors.

2. Economic evaluation of modified tower designs, such as wet-dry cooling towers and increased distance between cooling tower and collector field.

3. Economic evaluation of mirror washing systems.

4. Potential modification of site selection criteria placing a premium on locations with highly directional daytime winds.

4.3 System Reaction to Foreseen and Unforeseen Changes in Insolation

Analog or digital computer studies are needed to define the system control requirements for accommodating the probable variation in solar energy falling onto the collector field, considering thermal inertia built into the system.

4.4 Alternative Condenser Configurations

The condenser chosen for the preliminary design is a typical unit. During final design, some consideration should be given to available alternative configurations. One possible arrangement is to place the condenser tubes parallel rather than perpendicular to the turbine centerline. This would permit longer tubes to be used and would at the same time reduce the number of tube passes. A resulting advantage would be lower pressure drop in the circulating water system. A possible disadvantage of this scheme is that larger pull spaces would be required to replace tubes. A second possibility is an option offered by condenser manufacturers in which the turbine pedestal and the condenser are combined into a single structure. Cost and maintenance considerations could rule out this approach.

Table 1

DESIGN VERIFICATION TO INCORPORATE DATA OF THE ACTUAL PLANT SITE

Site Parameter	Design Feature to Verify
Climatology	
Range of dry bulb temperature	Cooling water system design load for heating and ventilating; auxiliary cooling; freeze protection
Range of wet bulb temperature	Cooling tower approach temperature and temperature range; cooling tower sizing; condenser sizing.
Wind rose (frequency and speed form for each direction)	Site arrangement; cooling tower distance to collector field; design wind velocity and gust factor.
Precipitation (seasonal variation, force density, duration)	Personnel and equipment protection; runoff and overflow protection
Hydrology	
Surface water, river flow, reservoir capacity	Source of makeup water; need for water storage; makeup pump capacity, screening, and filtering requirements
Well water, subterranean aquifers	Capacity, depth, and locations of wells
Water chemistry	Condenser tube material selection; need for chemical and biocide treatment; cycles of concentration
Receiving body for wastewater	Cooling tower blowdown treatment
Topography	
Site elevations	Cooling water system circulating provisions, pumping head requirements
Geology	
Soil strength characteristics	Turbine-generator; cooling tower; turbine foundation design
Seismicity	Seismic design bases

5.0 EQUIPMENT DATA

5.1 Turbine-Generator, K101

Manufacturer	General Electric Company
Name plate rating	12.5 MWe
Operating speed	3,600 rpm
Generator output voltage (60 Hz, ac)	13.8 kV
Steam flow at 10 MWe net[a] (receiver steam)	1.04×10^5 lb/hr
at 7 MWe net[b] (admission operation)	0.92×10^5 lb/hr
Gross heat rate at 10 MWe net[a] (receiver steam)	10,177 Btu/kW-hr
at 7 MWe net[b] (admission operation)	12,220 Btu/kW-hr
Turbine control	Electro-Hydraulic
Exhaust pressure (normal range)	1 to 5 in. Hg.
Overall dimensions without condenser	
Length	40 ft-5 in.
Width	12 ft-6 in.
Height	10 ft-1 in.
Installed weight	151 tons

Auxiliaries furnished by vendor include control valves, governor, EHC, hydraulic power unit, lube oil, electrical components.[c]

5.2 Condenser, E112

Design duty	74×10^6 Btu/hr
Total heat transfer area	7,800 ft^2
Design point conditions	
Steam pressure	3 in. Hg
Waterside pressure drop	10.7 psig
Cooling water temperature	
Inlet	84 F
Range	26 F
Shell design pressure	Full vacuum

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[a] Corresponding to 10.955 MWe gross.
[b] Corresponding to 7.770 MWe gross.
[c] See Electrical System Design Description, (Reference 6).

Overall dimensions	
Length	23.5 ft
Width	6.5 ft
Height	11 ft
Installed empty weight	30 tons

5.3 Condenser Exhausters, G101A, B

Type	Liquid ring, two-stage
Number required	2
Holding capacity at 2 in. Hg	5.5 scfm
at 4 in. Hg	8 scfm
Hogging capacity at 1 atmosphere	175 scfm
at 1/3 atmosphere	50 scfm
Time to evacuate 1,000 ft^3 to 4 in. Hg absolute	60 min
Power at holding	13 hp
Power at hogging	23 hp
Pump speed	1,170 rpm
Cooling water requirement	75 gpm
Overall dimensions	
Length	73 in.
Width	34 in.
Height	41 in.
Operating weight	2,400 lb

5.4 Cooling Towers, E113A, B

Type of cells	Induced draft, vertical discharge, double-flow
Number of cells	2
Design duty	80×10^6 Btu/hr
Design wet bulb temperature	74 F
Approach temperature	10 F
Temperature range	25 F
Fan hp per cell	100 hp

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SYSTEM DESCRIPTION

FOR

ELECTRIC POWER GENERATION SUBSYSTEM

FEEDWATER SYSTEM

FOR

CENTRAL RECEIVER SOLAR THERMAL

POWER SYSTEM PHASE 1

MARTIN MARIETTA CORPORATION

DENVER, COLORADO

BY

BECHTEL CORPORATION

SAN FRANCISCO, CALIFORNIA

No.	DATE	REVISIONS	BY	CH'K	APPR
0	4/1/77	Issued for Preliminary Design Report	CRH	JAK	NW

ORIGIN			
R & E	BECHTEL	CENTRAL RECEIVER SOLAR THERMAL POWER SYSTEM PHASE 1	JOB No. 11480
			System Description SD-5 — REV. 0
			SHEET 1 OF 22

G1000897-01
BPC-20242

TABLE OF CONTENT (Cont'd.)

TABLES

1.0 SYSTEM FUNCTIONS

The EPGS feedwater system supplies feedwater of suitable quality to the Receiver and Thermal Storage Subsystems and provides regenerative heating of the water to optimize plant efficiency.

2.0 DESIGN BASES

2.1 ERDA Design Bases

ERDA requires that the Central Receiver Solar Thermal Power System be capable of producing 10 MWe net electrical power when generating from the Receiver Subsystem alone at 2:00 PM on the day of lowest thermal input, coincident with a maximum ambient wet bulb temperature of 74 F. The feedwater system is capable of delivering water to the receiver at the required purity, flow rate, pressure, and temperature so that this design objective can be achieved.

When generating from the Thermal Storage Subsystem (TSS) alone, ERDA requires that the Central Receiver Solar Thermal Power System be capable of producing 7 MWe net electrical power. The feedwater system is capable of delivering feedwater to the TSS at the required purity, flow rate, pressure, and temperature so that this design objective can be achieved.

2.2 Other Design Bases

2.2.1 Performance and Operational Requirements

The system is designed to supply feedwater to the receiver or TSS under all normal, steady-state plant operating modes as listed below and under transient conditions caused by cloud passage or plant load changes:

- Generating from receiver and charging TSS
- Generating from receiver alone, up to maximum turbine-generator output on receiver steam
- Generating from receiver and TSS
- Generating from TSS alone, up to maximum turbine-generator output on TSS steam
- Receiver charging TSS (turbine not operating)
- Generating from TSS alone while receiver charges TSS

Table 1

FEEDWATER CHEMISTRY OPERATING LIMITS

Variable	Operating Limit[1]
Iron	10 ppb or less
Copper	5 ppb or less
Oxygen	7 ppb or less[2]
Hardness	Undetectable[3]
pH	9.2 to 9.4
Hydrazine (residual)	20 ppb or less

Notes:

(1) Water chemistry limits are not necessarily met during startup and are for steady-state operating conditions only.

(2) Undetectable by carmine-indigo color comparator.

(3) Undetectable using ASTM procedure D 1126, Method B.

2.2.1.1 Water Quality

Feedwater chemistry operating limits for the receiver, which are established by References 1 and 2, are listed in Table 1.

2.2.1.2 Flow Rates, Pressures, and Temperatures

Main process flow rates, pressures, and temperatures are given in flow Diagram M-1281 for the plant steady-state operating modes described in Section 2.2.1 and the ERDA design bases described in Section 2.1.

2.2.2 Limiting Parameters

The plant will trip if receiver steam drum water level drops below the minimum required level or if steam drum overpressure occurs. The plant is limited to part-load operation whenever a feedwater heater is removed from service (see Section 3.4.4) and cannot operate with the deaerating feedwater heater out of service.

2.2.3 Material Requirements

Demineralized makeup water piping, valves, and fittings, the condensate storage tank, deaerator trays and spray nozzles, and feedwater heater tubes are stainless steel. All remaining piping, valves, fittings, and pressure vessel boundaries are carbon steel.

2.2.4 Tests and Inspections

Piping, valves, and fittings are tested and inspected in accordance with applicable sections of ANSI B-31.1, Power Piping Code. Feedwater heaters and the deaerator are shop hydrotested to ASME Code, Section VIII requirements. Pumps are tested and inspected in accordance with Hydraulic Institute Standards and manufacturer's recommendations.

2.2.5 Line Sizing

The criteria used for sizing system piping, which are based on experience from similar power plants, are listed in Table 2.

2.2.6 System Considerations

In order to meet the overall EPGS availability criterion stated in Reference 3, capability must exist to achieve full-load plant operation with part or all of one feedwater pumping train out of service. Accordingly, two full-capacity pumping trains are provided.

All pumps are furnished with removable startup strainers to prevent entrance of foreign matter and damage to the pumps during initial plant startup.

A single train of feedwater heaters is provided, with a feedwater bypass around each individual heater. The single heater train is justified over multiple-train configurations by the cost savings realized in the heat exchangers and their associated piping, valves, and instrumentation, and by the simplicity gained in EPGS layout and operability. The bypasses facilitate achievement of required EPGS availability by allowing continued plant operation at reduced load and thermal efficiency with any heater except the deaerator taken out of service (see Section 3.4.4).

Table 2

SIZING CRITERIA FOR FEEDWATER SYSTEM PIPING

Service	Sizing Criteria
Condensate and Booster Pump Suctions	Approximately 5 ft/sec velocity(1)
Feedwater	Approximately 10 ft/sec velocity(2)
Feedwater Heater Drains and High-Level Drains	Approximately 5 ft/sec velocity(3)
Pump Minimum Flow Recirculation and Miscellaneous Water Services	Approximately 5-10 ft/sec velocity
Steam	See Reference 1

Notes:

(1) Piping pressure drop and NPSH available at the pumps should be evaluated once piping isometrics are available.

(2) Four-inch nominal piping was selected for the majority of the feedwater system on the basis of feedwater riser optimization studies. Reference 4 outlines the optimization procedure.

(3) Piping pressure drop should be evaluated once piping isometrics are available to ensure adequate drainage capability and no flashing upstream of control valves.

(4) A minimum pipe size of 1 inch was assumed.

Two flow paths are available for removing condensed extraction steam from the shells of the closed feedwater heaters. The primary drain paths are arranged to cascade from Heater 1 to Heater 2 to the deaerator, and from Heater 4 to the condenser (heaters including the deaerator are numbered from 1 to 4 in order of decreasing shell-side pressure). Alternate drain lines are available to dump drains directly to the condenser in the event that the primary drain lines are unable to drain the heaters adequately.

Two condensate demineralizer trains are furnished, piped in parallel, each with the capability of passing full feedwater flow for short periods of time while the other is being precoated with new resins.

Manual maintenance valves are provided on all pumps, feedwater heaters, and condensate demineralizers for on-line maintenance of that equipment. Each pump can be isolated as a unit with its suction strainer, discharge check valve, and minimum flow recirculation system, allowing maintenance to proceed on any of those items with the other full-capacity pump in the system running. Feedwater heaters can be isolated and bypassed on the tube (feedwater) side, as noted above, and also on the shell side as a unit with the drain removal system to allow maintenance on heater internals, level controls, or control valves. Either demineralizer vessel can be valved out for maintenance or precoating with new resins while the remaining vessel handles full feedwater flow.

Control valves for such services as pump minimum flow recirculation and feedwater heater cascading drains and dumps are located as close to the vessel receiving process fluid as practicable to minimize the amount of downstream piping that may be subjected to flashing (two-phase) flow.

2.2.7 Condensate Pumps

Condensate pump rating conditions are based on plant operation at the turbine-generator rated output of 12.5 MWe gross generating from receiver alone (see Drawing M-1381). Each pump is rated at full flow capacity, including an allowance for receiver blowdown. The head developed by each pump is sufficient to overcome static head and frictional resistance in the low-pressure feedwater heater, condensate demineralizers, and associated piping, and to deliver feedwater to the deaerator through its level control valve. Vertical, canned suction centrifugal pumps are selected for condensate service to accommodate the low NPSH available from the condenser hotwell.

2.2.8 Condensate Storage Tank and Transfer Pumps

The condensate storage tank serves as the major surge vessel for the EPGS during plant load changes and eliminates the need for continuous makeup demineralizer system operation to compensate for process water losses. Storage capacity is set at approximately 5,000 gallons, which is equivalent to approximately 2 days of makeup demineralizer operation at 2 gpm (Reference 4), and may be adequate to completely fill the EPGS and feedwater riser from a dry layup condition.

Condensate transfer pumps are provided to overcome static head and frictional resistance in the condensate makeup line, so that water can be delivered from condensate storage to the condenser hotwell at a reasonable rate. Each pump is sized to feed the entire contents of the condensate storage tank to the condenser hotwell within a period of 100 minutes.

2.2.9 Condensate Demineralizers

A mixed resin, "Powdex" -type condensate demineralizer package is recommended. Cation resins are necessary to remove corrosion products originating in the EPGS and elsewhere, whereas anion resins are necessary to remove impurities resulting from condenser tube leakage from the "wet" cooling system. The demineralizers have a full-flow capacity corresponding to that required for turbine-generator maximum output on receiver steam, plus a margin for blowdown.

2.2.10 Deaerator and Storage Tank

The deaerator is designed to heat and deaerate the feedwater flow corresponding to turbine-generator rated output generating from the receiver alone, including an allowance for receiver blowdown. Dissolved oxygen content of the deaerator effluent is less than 0.005 cubic centimeter per liter, which is in accordance with Heat Exchange Institute Standards.

The deaerator storage tank is designed to retain an inventory of condensate below high-high water level equivalent to that produced in the deaerator during 5 minutes of operation at rated capacity. This capacity protects the booster pumps from running dry during changes in EPGS water inventory and may allow booster pump trips and automatic restarts without tripping the plant (see Section 3.4.3). Designs are available in this size range in which the deaerator and its storage compartment are located within a single pressure vessel. Such designs would eliminate the need for a separate storage tank and possibly reduce headroom requirements.

2.2.11 Booster Pumps

Booster pump rating conditions are based on turbine-generator maximum output of 7 MWe gross generating from TSS alone (see Drawing M-1381). The head developed by each pump is sufficient to overcome static head and frictional resistance in the piping between the deaerator and TSS and in the two high-pressure feedwater heaters and to deliver water to the TSS through its discharge flow control valve. The inlet pressure to the control valve is at least 620 psig, which allows the ERDA design point described in Section 2.1.2 to be achieved at a turbine admission pressure of 400 psig without operation of the feedwater pumps (see Section 4.1).

The pumps are specified to have a runout capability corresponding to turbine-generator rated output generating from receiver alone plus an allowance for blowdown. The head-capacity characteristics of centrifugal pumps available for booster service are such that NPSH delivered to the low-pressure feedwater pump suction should be adequate at booster pump runout flow; therefore, pumping head requirements need not be specified at this operating point.

Horizontal centrifugal pumps are selected for the booster pumps, although vertical designs are available from some manufacturers.

2.2.12 Feedwater Heaters, Vents, and Drains

The feedwater heaters are designed for regenerative heating of EPGS feedwater to approximately 425 F measured at the low-pressure feedwater pump suction at turbine-generator rated output conditions generating from the receiver alone. Four stages of heating are furnished, including the deaerator (see Section 2.2.11). Heaters 1 and 2 have desuperheating zones in addition to the condensing and drain subcooling zones furnished on all closed heaters.

Each heat exchanger shell is vented to the condenser to prevent the accumulation of noncondensable gases, thereby maintaining design performance and minimizing corrosion. Minimum venting capacity of approximately 0.5 percent of rated steam flow is provided per heater, in accordance with Heat Exchange Institute Standards.

Primary feedwater heater drain lines are sized to pass the drain flows corresponding to heater rating conditions plus allowances for system surges. Each secondary drain line is sized to pass the greater of primary drain line rated flow or 10 percent of rated feedwater flow caused by hypothetical feedwater heater tube leakage (see Section 3.4.4). Secondary drain lines are also the primary drain paths at low generating loads, when insufficient pressure exists between heater shells to support the preferred arrangement of cascading drains described in Section 2.2.6.

2.2.13 Low-Pressure Feedwater Pumps

The rated capacity of the low-pressure feedwater pump is based on the turbine-generator rated output on receiver steam and includes a margin for blowdown. Pump head is based on consideration of the receiver charging TSS mode of plant operation (see Section 3.2.2). In order to ensure that TSS condensate can be returned to the receiver via the high-pressure feedwater pump, low-pressure feedwater pump discharge pressure must not exceed approximately 1115 psia, which assumes charging at the maximum rate of 117,300 lb/hr and reasonable TSS piping, heat exchanger, and control valve pressure losses. Maximum low-pressure feedwater pump discharge occurs with the pump on minimum flow recirculation; hence, pump selection becomes a matter of choosing the appropriate impeller diameter and number of stages so that a discharge pressure of approximately 1115 psia is not exceeded when the pump is on mimimum flow recirculation (see Section 4.0). Preliminary examination of characteristic curves of centrifugal pumps available for this service indicates that a total head of approximately 650 feet can be expected at pump rated flow.

2.2.14 High-Pressure Feedwater Pumps

The high-pressure feedwater pump rating conditions are based on plant operation at maximum receiver output of 160,000 lb/hr, which occurs during periods of maximum insolation. A 3 percent allowance is included on pump rated flow for receiver blowdown. The head developed by each pump is sufficient to overcome static head and frictional resistance in the feedwater riser and to deliver feedwater to the receiver steam drum through its feedwater inlet flow control valve.

2.3 Codes and Standards

Piping, valves, fittings, and associated supports meet ANSI B-31.1, Power Piping Code requirements. Mechanical equipment is designed and built in accordance with the codes and standards listed in Table 3.

Table 3

CODES AND STANDARDS FOR MECHANICAL EQUIPMENT

Service	Applicable Codes and Standards
Pumps	Hydraulic Institute Standards
Deaerator and Storage Tank	ASME Code, Section VIII and Heat Exchange Institute Standards and Typical Specifications for Deaerators
Feedwater Heaters	ASME Code, Section VIII and Heat Exchange Institute Standards for Closed Feedwater Heaters
Condensate Storage Tank	API Standard 650, Welded Steel Tanks for Oil Storage

3.0 SYSTEM OPERATION

3.1 Normal Operation

3.1.1 Generating From Receiver and Charging Thermal Storage Subsystem

This mode of plant operation occurs during periods of high insolation when energy input from the receiver exceeds that required by the turbine-generator to achieve its rated output of 12.5 MWe gross, or during periods of TSS performance testing when the turbine-generator is purposely operated below rated load and the balance of receiver thermal output is routed to the TSS.

Turbine exhaust steam from the power generation process is condensed and then collected in the condenser hotwell (see Drawing M-1367). Condensate is drawn from the hotwell by one of the two 100 percent capacity condensate pumps and pumped through the condensate pump discharge header, condensate demineralizers, and low-pressure feedwater heater 4 to the deaerator. Feedwater is demineralized to remove corrosion products and condenser tube leak impurities, and then heated regeneratively by condensing saturated steam from the turbine and subcooling it in feedwater heater 4. Shell-side condensate from the heater is drained to the condenser. A valve in the drain line controls shell-side water level to ensure that the subcooling zone is submerged at all times.

Feedwater from the outlet of heater 4 passes to the deaerator through a level control valve that maintains desired water level in the deaerator storage tank. This flow and incoming cascading drains from high-pressure feedwater heater 2 are heated to saturation and deaerated utilizing superheated extraction steam and shaft seal leakoffs from the turbine. Blowdown tank flashoff is also routed to the dearator to recover much of the energy available from this source. Air that has accumulated in the feedwater and a small amount of steam are vented to the atmosphere. The deaerated water flows by gravity to the deaerator storage tank, which is vented back to the deaerator to maintain equal pressures.

Deaerated feedwater is drawn from deaerator storage by one of the two 100 percent capacity booster pumps and pumped through the high-pressure feedwater heaters to the EPGS-TSS discharge interface point at the suction of the low-pressure feedwater pumps. Operation of the high-pressure heaters is similar to that of low-pressure heater 4, except that desuperheating zones remove superheat from the turbine extraction steam before the steam enters the heater condensing zone. Shell-side drains are subcooled and returned to the deaerator by a cascading arrangement from heater 1 to heater 2 to the deaerator. Subcooling the drains improves cycle efficiency and minimizes the possibility of flashing in the drain lines.

At full load operation, the booster pump raises feedwater pressure to approximately 555 psia at the low-pressure feedwater pump suction. In turn, one of the two feed pumps raises pressure to approximately 785 psia at the EPGS-TSS charge interface point at the suction of the high-pressure feedwater pumps. At this interface point, feedwater from the outlet of the low-pressure feedwater pump mixes with return condensate from the TSS, after the latter has passed through the TSS charge feedwater control valve. Both streams are sufficiently subcooled to prevent flashing and cavitation in the high-pressure feedwater pump suction.

One of the two 100 percent capacity high-pressure feedwater pumps discharges the combined EPGS-TSS flow through the feedwater riser and the receiver feedwater inlet flow control valve to the receiver steam drum to complete the feedwater cycle. The flow control valve is modulated by a three-element controller provided with the receiver.

Prior to entering the receiver, feedwater is treated with hydrazine to scavenge residual oxygen and with ammonia for pH adjustment. Water chemistry is monitored downstream from the feedwater pump discharge. Noncondensable gases that would otherwise accumulate on the shell side of the feedwater heaters and blanket heat transfer surfaces are vented continuously to the condenser through individual, orificed vent lines. The condensate pump suction barrels are vented individually to the condenser to prevent accumulation of vapors and loss of NPSH (booster pumps and feedwater pumps are self-venting).

3.1.2 Generating From Receiver Alone

In this operating mode, the turbine accepts all of the steam generated in the receiver up to the maximum flow rate capability of the turbine. The feedwater system operates much as it does with the plant generating from the receiver and charging the TSS (see Section 3.1.1), except that condensate is not returned from the TSS, and all feedwater to the receiver originates in the EPGS.

The constant speed centrifugal pumps provided with the feedwater system have rising head-capacity curves (i.e., as flow decreases, pumping head increases), whereas the feedwater system frictional resistance has the opposite characteristic. As a result, as the turbine-generator load is reduced below rated, more pressure is available in the feedwater than is required to deliver it to the receiver. The receiver feedwater inlet flow control valve must dissipate the excess pressure as control valve throttling losses to meet receiver requirements.

At low loads, turbine cycle flows and pressures become so small that certain design provisions must be made to allow satisfactory operation of the feedwater system. First of all, the condensate, booster, and feedwater pumps must be protected in the event that system flow requirements are less than pump minimum flow requirements. Individual minimum flow recirculation lines are provided for this purpose. In the case of the booster pumps and feedwater pumps, the control valves in the recirculation lines are designated for severe service due to the high discharge pressures developed by those pumps.

The deaerator is pegged automatically at slightly above atmospheric pressure if turbine extraction steam is not available at a higher pressure. This provision prevents air inleakage to the deaerator and associated piping. Pegging steam must be made available during startup and shutdown operations from the TSS and the Receiver Subsystem.

Finally, the secondary shell-side drain line provided on feedwater heater 4 is designed to bypass the subcooling zone and dump heater drains directly to the condenser by gravity. This drain operates when insufficient pressure exists in the heater shell to overcome subcooling zone frictional losses and drive drains into the condenser.

3.1.3 Generating From Receiver and Thermal Storage Subsystems

The EPGS is required to supplement receiver steam with TSS steam whenever the desired load cannot be maintained on receiver steam alone, such as during anticipated cloud passage transients or late in the day.

The feedwater system serves the function of delivering feedwater to both the receiver and TSS in this operating mode. Thus, operation is similar to that described in Section 3.1.1 for generating from the receiver and charging the TSS, except that feedwater is delivered to the TSS rather than accepted from it. The booster pump develops sufficient pressure at the EPGS-TSS discharge interface point to allow 400 psig steam to be delivered to the turbine admission, taking into account TSS control valve throttling losses and piping and heat exchanger frictional losses. Feedwater flow to the TSS is through the TSS charge feedwater control valve controlled by a three-element controller furnished with the TSS. Flow to the receiver is controlled in the usual manner, as described in Section 3.1.1.

3.1.4 Generating From Thermal Storage Subsystem Alone

Generating from the TSS alone occurs when the receiver is unavailable as a steam source. In this mode of operation, the system is not required to deliver feedwater to the receiver; therefore, the low- and high-pressure feedwater pumps may be shut off.

The TSS discharge flow control valve is subjected to increasing throttling losses with decreasing load, similar to those experienced by the receiver feedwater inlet flow control valve when generating from receiver steam (see Section 3.1.2).

3.1.5 Generating From Thermal Storage Subsystem while Simultaneouly Charging Storage

During daytime operations, when a large number of passing clouds are likely to temporarily interrupt insolation, the plant can be placed in a configuration with the TSS in simultaneous charge and discharge modes. This uncouples the receiver from the turbine-generator and permits consistent electrical generation without load swing transients induced by cloud passage. For the feedwater system this operation is similar to the operation described for generating from the TSS alone (Section 3.1.4), except that a high-pressure and a low-pressure feedwater pump are also required to feed the receiver.

3.2 Startup

3.2.1 Receiver Startup

Startup of the Receiver Subsystem cannot proceed until the availability of feedwater from the EPGS is established. This process is a sequential one. First, one condensate pump is started and automatically placed on minimum flow recirculation. Condenser hotwell level is adjusted to within its normal operating range by automatic operation of condensate makeup and reject lines. On low level, condensate storage tank water is pumped to the hotwell by one or both of the condensate transfer pumps. If the hotwell level exceeds the operating range, a control valve is opened to reject water to condensate storage. Heat input from the condensate pump to the recirculating water is rejected in the condenser.

Next, one booster pump is started and automatically placed on recirculation. As a result, the control valve at the inlet to the deaerator opens to establish deaerator storage tank level, the condensate pump minimum flow recirculation valve closes, and the processes of feedwater demineralization and deaeration begin. For the latter, pegging steam must be available from the the receiver or the TSS. If necessary, condensate storage tank inventory can be increased by injection of demineralized water from the makeup demineralizer system.

The next step involves startup of a low-pressure feedwater pump and automatic operation of the feedwater cleanup line. Feedwater flow is controlled to a value greater than the minimum flow requirement of the feed pump to avoid operation of the pump recirculation system. The booster pump recirculation valve closes, and a cleanup loop is established through the high-pressure feedwater heaters. If desired, the feedwater flow rate can be increased from the contro room to improve cleanup effectiveness. Note that it may also be possible to operate this system without the low-pressure feedwater pumps in operation, if pump operating limitations are compatible.

Finally, a high-pressure feedwater pump can be operated, causing its recirculation line to open and the feedwater cleanup line to close unless overridden from the control room. Hydrazine and ammonia are injected into the water to scavenge oxygen and control pH, respectively.

The receiver can begin to generate steam for heating the TSS steam lines, and feedwater delivery to the receiver can begin once the feedwater system has been established in the standby mode. Initiall the feedwater may contain an abnormal amount of corrosion products originating mostly in the TSS and feedwater riser as a consequence of overnight shutdown. Maximum blowdown rates may be desirable until most of the corrosion products have been removed. TSS condensate can be blown down directly to the condenser to allow subsequent processing in the condensate demineralizers.

3.2.2 Receiver Charging Thermal Storage Subsystem

The plant is placed in the receiver charging storage mode once receiver steam meets TSS requirements. Condensate resulting from the charging process passes through the TSS charge feedwater control valve and can be blown down directly to the condenser, as described in the previous section, until water quality is acceptable. When this is the case, the TSS cleanup line is closed, and condensate is returned to the receiver via the high-pressure feedwater pump. At low charging flows, the high-pressure feedwater pump minimum flow recirculation line protects the pump from running below its operating range. Condensate, booster, and low-pressure feedwater pumps must be operating in order to return recirculation flow to the system and to compensate for receiver blowdown losses.

At higher charging flows, the feedwater cleanup line opens automatically to establish pressure at the EPGS-TSS charge interface point and to accommodate changes in TSS and receiver water inventories. Without this provision, the interface point would be subject to wide pressure variations, and unstable operation of the TSS and receiver control systems would result. Pressure is established by controlling flow through the low-pressure feedwater pump to a value slightly greater than the setpoint of the pump minimum flow recirculation system. Unnecessary operation of the recirculation system is thereby avoided.

3.2.3 Turbine-Generator Startup

This operation consists of heating the EPGS steam lines and rolling, synchronizing, and loading the turbine-generator (Reference 5). The feedwater system supplies water to the receiver so that steam can be generated for these purposes. Operation is similar to that described in the previous section for receiver charging TSS, except that a greater proportion of the feedwater flow may originate in the EPGS.

Prior to rolling the turbine, feedwater heaters are placed in service and vented to the condenser. Startup vent lines are provided to bypass heater operating vents and allow rapid purging of noncondensables that may be present as a result of overnight shutdown. Heater level controls are checked, and, once the turbine-generator is loaded, the heaters begin extracting steam for regenerative feedwater heating. Heater drains are initially dumped to the condenser for subsequent processing of accumulated corrosion products in the condensate demineralizers.

Eventually, all feedwater flow originates in the EPGS as this subsystem becomes capable of accepting the entire receiver steam flow.

3.3 Overnight Shutdown

Running the EPGS in the recycle mode during overnight shutdown is possible, but it is not recommended since substantial pumping power would be required. Instead, the system should be kept as air tight as possible and should run in the recycle mode for only a minimal amount of time just prior to receiver startup, as described in Section 3.2.1. Deaerator vents must be closed and a steam blanket imposed on the deaerator using auxiliary boiler steam. Feedwater heaters may be isolated and steam blanketed on the shell-side during overnight shutdown. The feedwater riser must be isolated to prevent it from draining.

3.4 Abnormal Occurrences

3.4.1 Turbine-Generator Trip

A turbine-generator trip initiates closure of bleeder trip valves in the feedwater heater and deaerator extraction lines (Reference 1). In the event that offsite power is lost coincident with turbine-generator trip, feedwater pumping capability is lost, and the receiver or TSS must be tripped. However, if power is available, this capability may be retained depending on the initial load and whether or not the booster pump can withstand transient NPSH decay caused by isolation of the deaerator from its extraction. Lack of sufficient NPSH could cause the booster pump head to decrease to the point where the feedwater pumps trip on low suction pressure and pumping capability is lost. Several methods exist for ensuring adequate booster pump NPSH under transient conditions. For example, a portion of the feedwater entering the deaerator could be bypassed directly to the booster pump suction to subcool water entering the pump from the deaerator storage tank. This problem should be considered in more detail in the final design phase.

3.4.2 Water Level Surges

Abnormal water level in the condenser hotwell or the condensate or deaerator storage tanks can be caused by system surges, changes in EPGS water inventory during plant load changes, or equipment failure. Automatic protective devices are provided in the design of the feedwater system to correct abnormal water levels if possible, alert the plant operator to the situation, and protect major equipment such as the turbine-generator if the corrective actions taken are ineffective.

High water level in the condenser hotwell is normally corrected by dumping water to condensate storage through the condensate reject line provided for this purpose. A low hotwell level signal normally starts one of the condensate transfer pumps to supply makeup water from condensate storage. In the event that level continues to fall, an alarm sounds in the control room to allow the operator to take additional corrective action.

Level surges to low-low level result in tripping of the condensate pump to prevent it from running dry.

The atmospheric pressure condensate storage tank has an overflow line for high water level, a controller to initiate makeup demineralizer flow on low level, and a trip device to protect the condensate transfer pumps from running dry on low-low level. The deaerator is provided with an overflow to the hotwell to automatically correct high water level, a high-high level controller that automatically shuts off incoming extraction steam, pegging steam, blowdown tank flashoff, and feedwater heater drains to prevent water from entering the turbine, and a low-low level trip to protect the booster pumps from running dry. The latter device also trips the feedwater pumps and receiver due to lack of feedwater availability.

3.4.3 Condensate Pump, Booster Pump, and Feedwater Pump Trips

Low suction vessel water level and low suction pressure trips are provided for protection of the condensate pumps, booster pumps, and feedwater pumps. As discussed in Section 3.4.2, the low water level trips protect the condensate pumps and booster pumps from running dry. In addition, the feedwater pumps are provided with low suction pressure trips set so that, at maximum feedwater pumping temperatures, the NPSH requirements of the pumps are met. In the event that a pump trips out on other than low water level or suction pressure, provisions are made for automatic start of the idle pump of the set when actuated by a low discharge pressure controller.

Surge capacity is provided in the condenser hotwell, deaerator storage tank, receiver, and the TSS so that the plant does not trip during most transients. The most difficult transient occurs when a booster pump trips. This, in turn, causes the feedwater pumps to trip, the second booster pump to start, and then the low- and high-pressure feedwater pumps to start to reestablish the cycle.

Warmup orifices are provided on the booster pumps and feedwater pumps to keep idle pumps at operating temperature so that they can be brought into service quickly. The orifices are designed to bypass a small portion of the feedwater flow around the discharge check valve, through the casing, and into the suction line of an idle pump without causing reverse rotation of the pump.

3.4.4 Feedwater Heater and Drain Removal System Malfunctions

Feedwater heater and drain removal system malfunctions are usually the result of massive feedwater heater tube leakage or drain control valve failures that cause the water level in the heater shell to rise or fall outside the normal operating range.

A massive tube leak can increase heater shell-side flow to beyond that drainable by the primary drain line. This is due to the fact that feedwater on the tube side can leak into the shell because it is at a greater pressure than the shell-side steam and condensate. Consequently, the water level rises, and the secondary drain line opens to dump excess flow to the condenser. If the level continues to rise and the secondary drain line control valve approaches the fully open position, an alarm sounds in the control room to call operator attention to the situation.

If the primary drain line control valve loses its controlling signal, it fails closed, and, as in the case above, the water level rises. The secondary drain line dumps heater drains to the condenser, and an alarm sounds in the control room.

In either of the cases above, if the drain removal system is unable to control water level and a high-high level is attained, all heater extraction and incoming drain flows are shut off automatically to prevent water induction to the turbine. An alarm sounds in the control room to indicate this condition. Water induction could cause severe damage to the turbine rotating parts and casing. Therefore, in accordance with the recommendations of Reference 6, the system is designed so that no single failure of equipment results in water entering the turbine.

Finally, loss of signal to the secondary drain control valve of a heater causes the valve to fail open, dumping all drains to the condenser. The primary drain control valve closes; however, heater level can be expected to fall, and a low water level alarm will sound in the control room. Low level in a heater shell can cause drainage of the heater subcooling zone, allowing steam to enter that zone.

Manual maintenance valves are provided on the heaters and their drain lines to allow on-line maintenance of malfunctioning equipment. On its tube side, each heater can be isolated and bypassed to allow repair of tube leaks, generally by plugging. Removal of heaters from service necessitates turbine-generator load reductions. The shell side of each heater can be isolated together with the shell drain lines to allow repair of heater internals, drain controls, or drain control valves. This activity requires that the heaters be bypassed on the feedwater side; therefore, load reductions are again required.

Tube-side thermal relief valves are provided on all heaters to protect them from overpressure resulting from water expansion when the feedwater side is isolated. Since heater shell-side design pressures are less than feedwater-side pressures, shell-side relief valves are also provided to prevent overpressurization resulting from tube leakage with the shell-side isolated.

4.0 DESIGN NOTES

Determination of low-pressure feedwater pump rated head is somewhat complicated by the fact that it is dependent on booster pump head-capacity characteristics. To ensure that TSS condensate can always be returned to the suction of the high-pressure feedwater pump, the maximum discharge pressure of the low-pressure feedwater pump must not exceed approximately 1,100 psig. Maximum discharge pressure occurs with the pump on minimum flow recirculation, and therefore booster pump head must be known at this condition before the feed pump can be sized. The low-pressure feedwater pump rating conditions shown in Section 5.7 are based on preliminary booster pump characteristics available from one pump manufacturer. When the pumps are procured, the head-capacity curves should be checked to ensure that the maximum discharge pressure criterion is still satisfied. If not, the control setpoint of the feedwater cleanup line could be reset to a slightly different value, or the rated head (number of stages or impeller diameter) of the feed pumps could be modified.

The requirement for the low-pressure feedwater pumps in the cycle is a function of the required supply and return pressures of the TSS. If during final design these pressures are found to be sufficiently close together, the low-pressure feedwater pumps could be eliminated without significant performance and economic penalties. This would simplify the cycle arrangement and eliminate piping and space requirements associated with the pumps. The low-pressure feedwater pumps have been retained in the preliminary design to assure maximum flexibility.

The high-pressure feedwater pumps must also be checked for adequate head at pump rating conditions. The data shown in Section 5.8 are based on an assumed suction pressure of approximately 785 psia. Again, if booster and low-pressure feedwater pumps differ significantly from the assumed characteristics, then high-pressure feedwater pump rated head must be corrected for the new suction conditions.

5.0 EQUIPMENT DATA[1]

5.1 Condensate Pumps and Drivers, P-101A,B

Type	Vertical Centrifugal
Suction Pressure	3.5 psia
Suction Temperature	109 F
NPSH Available	5 ft
Total Head	275 ft
Capacity	200 gpm/pump

Drivers:

Type	Motor
Speed	3,550 rpm
Horsepower	25 hp

5.2 <u>Condensate Storage Tank T-101</u>

Type	Horizontal
Capacity	5,000 gallons
Design Pressure	Atmospheric
Design Temperature	180 F

5.3 <u>Condensate Transfer Pumps, P-113A,B</u>

Type	Horizontal Centrifugal
Suction Pressure	20 psia
Suction Temperature	60 F
NPSH Available	45 ft
Total Head	100 ft
Capacity	50 gpm/pump

Drivers:

Type	Motor
Speed	3,550 rpm
Horsepower	2.5 hp

5.4 <u>Condensate Demineralizer, S-101</u>

Type	Mixed Resin, Powdex Type
Capacity	200 gpm(2)
Effluent Water Purity	See note(3)
Design Pressure	200 psig
Design Temperature	140 F

5.5 Deaerator and Storage Tank, E-103, T-103

Type	Horizontal, Tray Type
Capacity	125,000 lb/hr[4]
Duty (10^6 Btu/hr)	6.79
Effluent Dissolved Oxygen Content	0.005 cc/liter
Storage Capacity	1,325 gallons
Design Pressure	50 psig
Design Temperature	300 F

5.6 Booster Pumps and Drivers, P-102A,B

Type	Horizontal or Vertical Centrifugal
Suction Pressure	47 psia
Suction Temperature	258 F
NPSH Available	30 ft
Total Head	1,520 ft
Capacity	205 gpm/pump[5]
Drivers:	
Type	Motor
Speed	3,550 rpm
Horsepower	150 hp

5.7 Feedwater Heaters, E-101, 102, 104

Heater Numbers		E-101	E-102	E-104
Type		Horizontal Closed		Horizontal Closed
Duty (10^6 Btu/hr)		9.59	9.63	8.48
Terminal Temperature Difference		-5 F	-5 F	5 F
Drain Cooler Approach Temperature		10 F	10 F	10 F
Design Pressure (psig)	Tube Side	800	800	200
	Shell Side	400	150	50
Design Temperature:	Tube Side (6)	450	370	300
	Shell Side (7)	750	860	300

5.8 Low-Pressure Feedwater Pumps and Drivers, P-103A,B

Type	Horizontal or Vertical Centrifugal
Suction Pressure	555 psia
Suction Temperature	432 F
NPSH Available	555 ft
Total Head	650 ft
Capacity	295 gpm/pump
Drivers:	
Type	Motor
Speed	3,550 rpm
Horespower	75 hp

5.9 High-Pressure Feedwater Pumps and Drivers, P-104A,B

Type	Horizontal or Vertical Centrifugal
Suction Pressure	785 psia
Suction Temperature	442 F
NPSH Available	1,090 ft
Total Head	3,100 ft
Capacity	380 gpm/pump
Drivers:	
Type	Motor
Speed	3,550 rpm
Horsepower	400 hp

Notes:

(1) All values are preliminary and should be checked during the final design phase.

(2) Either demineralizer vessel is capable of handling full capacity for short periods of time while the other vessel is being precoated with new resins.

(3) Effluent water purity is dependent upon demineralizer manufacturer selected and site water characteristics. Effluent purity must be such that the requirements of Table 1 are satisfied.

Notes (Continued)

(4) Does not include extraction steam flow required for deaeration.

(5) Pumps must also have a runout capability of 265 gpm/pump (see Section 2.2.11).

(6) On heaters 1 and 2, applies to tubes outside desuperheating zone only. Tubes inside desuperheating zone designed for temperature 35 F higher than saturation temperature corresponding to shell-side design pressure.

(7) On heaters 1 and 2, this temperature applies to shell shirt only. Design temperature of main shell barrel equal to saturation temperature at design pressure.

6.0 REFERENCES

1. "Feedwater Specifications for Pilot Plant Central Receiver," Foster Wheeler letter dated 9/16/75.

2. "Central Receiver Solar Thermal Pilot Plant Feedwater Chemistry Specifications," Bechtel letter dated 11/3/76.

3. Electrical Power Generation Subsystem Design Criteria for the Preliminary Design of a Central Receiver Solar Thermal Power System Pilot Plant, Rev. B, prepared by Martin Marietta Corporation.

4. System Description for Plant Support Systems, SD-3, Bechtel 1977.

5. System Description for EPGS Main Steam System, SD-1, Bechtel 1977.

6. "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation," ASME Standard No. TWDPS-1, July 1972.

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APPENDIX B
TEST PLAN REPORT

I. INTRODUCTION

This report summarizes a preliminary startup test plan developed for the Electrical Power Generation Subsystem (EPGS) and other balance-of-plant systems of the 10 MWe Central Receiver Solar Thermal Power System Pilot Plant.

The objective of the report is to outline a practicable preliminary plan for the initial startup and testing of installed EPGS systems and components. The plan covers the several normal and necessary aspects of startup planning and scheduling, component inspection and testing, initial system operations, and initial EPGS power operations.

A. REPORT ORGANIZATION

The report consists of six main sections. Section II addresses planning and scheduling and includes a preliminary EPGS startup schedule and an estimate of required manpower for EPGS startup. The general nature of startup activities that may be required for any EPGS "startup system" is discussed in Section III, with particular emphasis on the important interface between construction and startup activities. Section IV discusses many of the startup tests and procedures used for conventional steam power plants, with comments on their applicability to the EPGS. The necessary sequence of events constituting the preliminary EPGS startup plan for the developed EPGS and Pilot Plant subsystems' design is described in Section V. Section VI concludes the report with a short discussion of special equipment necessary for startup, testing, or maintenance of the EPGS components and systems.

B. DESIGN BASES

The preliminary EPGS startup plan and schedule presented in this report are based on the preliminary design of the EPGS, of the other balance-of-plant systems, and of the other Pilot Plant subsystems, as reflected in the following referenced documents:

- Drawing No. SEPS 1000000; "Schematic"; Rev. F, 3-4-77; Martin Marietta.
- System Description (SD-1) for EPGS Main Steam System; Bechtel Corp.
- System Description (SD-5) for EPGS Feedwater System; Bechtel Corp.
- System Description (SD-3) for Plant Support Systems; Bechtel Corp.

- System Description (SD-4) for Electrical System; Bechtel Corp.
- System Description (SD-2) for Control Systems; Bechtel Corp.

II PLANNING AND SCHEDULING

A. STARTUP PLANNING

1. General

Startup of the Electrical Power Generation Subsystem (EPGS), as well as of the entire Pilot Plant, is a function performed by the Owner. However, startup is a complex task, and the Owner may choose to supplement his organization by contracting experts to assist with the specialized nature of startup operations. Although administratively and technically distinct from the engineering and construction phase of the project, startup overlaps the construction schedule, and extensive coordination is required to effect smooth turnovers of equipment and ready the plant for initial on-line power operation within schedule and to budget.

To achieve a sucessful startup, other more conventional power plant experience has demonstrated the value of placing a startup member on the project team early in the final design and construction phase. He will review engineering drawings and contribute to the project design by providing input on startup operations and maintenance. He must also make sure that adequate provisions are engineered into the permanent plant systems to accommodate temporary facilities required for startup (e.g. jumper piping, etc.).

As the project proceeds during the several months prior to scheduled field startup activities, a field Startup Engineer should be assigned. He would supervise the preparation of contracts and manuals for startup, including administrative and technical procedures and startup testing procedures. He would prepare a time startup schedule in coordination with the status of actual Pilot Plant construction and the owner's planned operating schedule.

2. EPGS Construction and Startup Interface

The EPGS is a vital part of the Pilot Plant startup. Partial operation of the EPGS is necessary to support initial off-line operation of the receiver and thermal storage subsystems. In turn, turbine roll is then one of the final steps before the plant is ready for initial power operations. Thus, delay of the EPGS startup would most likely cause the initial power operation date to be late.

To maintain the project schedule, the interfaces between startup and construction activities in all the Pilot Plant subsystems must be recognized and planned well in advance. Typical activity interfaces are discussed in Section III. Briefly, construction will install and visually check out items, but generally, they will not operate equipment as part of their tests. Construction releases equipment to the Owner on a completed "system" basis for calibration, testing, and operation. Typical startup tests and procedures are discussed in Section IV.

B. EPGS STARTUP SCHEDULE AND KEY EVENTS

The preliminary EPGS startup schedule shown in Figure II.B-1 indicates an overall startup duration of approximately 40 weeks beginning with initial energization of the permanent plant electrical power supply bus, and concluding with initial on-line power operation of the EPGS and the total Pilot Plant.

The estimated 40-week duration is based upon Bechtel's experience in conventional power plant startups, modified to reflect the special or unique requirements of the Pilot Plant. For example, the fact that the major EPGS equipment is smaller than that used in conventional power plants was considered, although this advantage is somewhat offset by the unique design and operation features of the plant. Additionally, because the 10 MWe Pilot Plant is a first-of-a-kind plant there will be a requirement for startup, testing, and documentation beyond that normally anticipated for conventional plants of a proven design.

Figure II.B-1 also shows a preliminary breakdown of EPGS "startup systems" and the relative sequence and durations of startup activities for the individual startup systems. The sequence of these individual system activities can be compared to the occurrence of indicated "key events" in the startup of the EPGS and other Pilot Plant subsystems. A brief discussion of the sequence of the major EPGS startup system activities and key events is presented in Section V.

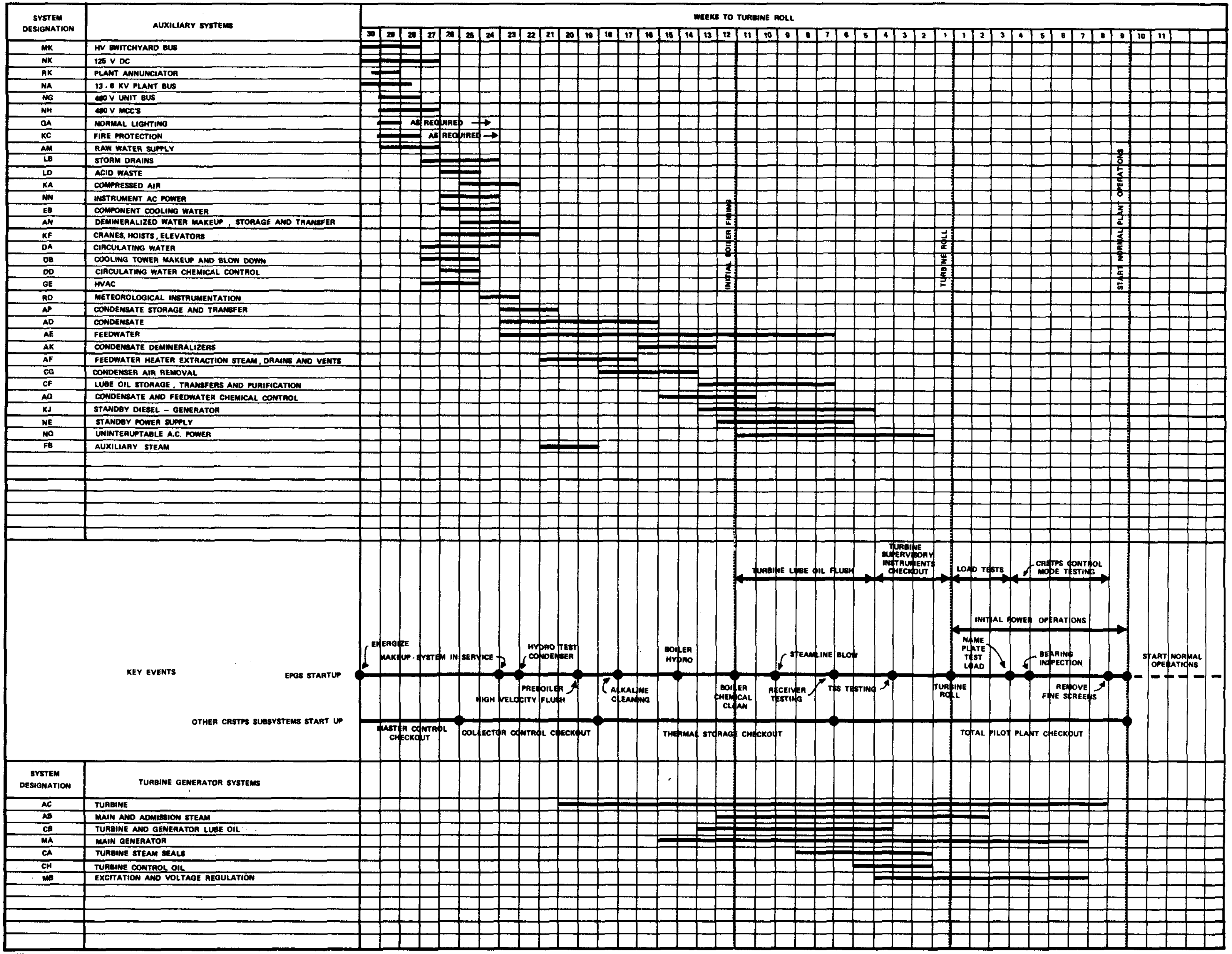
It is apparent from Figure II.B-1 that the EPGS startup becomes functionally interactive with other Pilot Plant subsystems at about 16 weeks before turbine roll, and that the scope and complexity of this functional integration increases up to the actual turbine roll date. It is not possible in this preliminary design phase to develop for the EPGS a detailed startup schedule that accommodates the specific and as yet undefined startup requirements of the other Pilot Plant subsystems. However, during the detailed design phase of the project, it will be necessary to develop for the Pilot Plant a detailed sequential startup schedule that provides for the specific startup requirements of each subsystem.

C. MANPOWER REQUIREMENTS

A preliminary EPGS startup manpower buildup schedule is shown in Figure II.C-1. The estimated manpower requirement for EPGS startup is consistent with Bechtel experience on other power plants, modified to account for size differences; it does not include manpower requirements for the collector, receiver, and thermal storage subsystems. The estimated average weekly manpower is based on

SYSTEM STARTUP SCHEDULE AND KEY EVENTS

FIGURE II.B–1



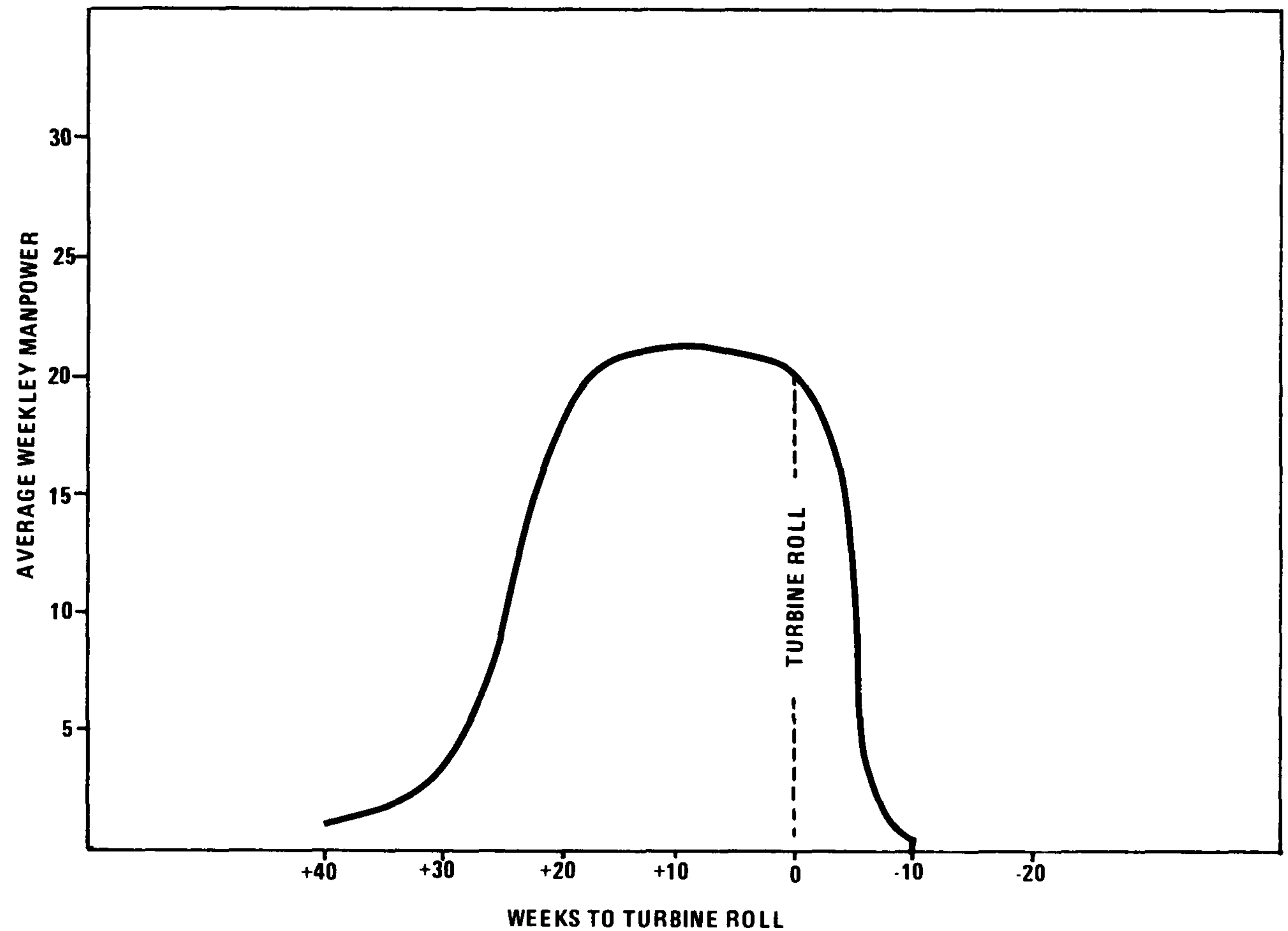


FIGURE II. C–1 ELECTRICAL POWER GENERATION SUBSYSTEM MANPOWER FOR STARTUP an assumed 40-hour work week. The peak manpower requirement is estimated to occur 20 weeks before turbine roll. Peak manpower is 1.3 times the average weekly manpower.

The manpower estimate includes startup engineers and assisting craftsmen. Approximately 30,000 manhours are estimated as being required; of these, about 10,000 will be performed by startup engineers and 20,000 by assisting crafts.

III. TYPICAL EPGS STARTUP ACTIVITIES

A. GENERAL

A review of the developed preliminary design of the EPGS portion of the Pilot Plant indicates that, with respect to initial startup and operation, the EPGS is conventional in nature. Prior constructor and Owner experience in the startup and operation of conventional steam electric power plants will be directly applicable to the EPGS, and the use of unusual or previously untried testing or operational procedures should not be necessary.

This section presents a discussion of the general sequence of events that may typically be required to bring any "startup system" within the EPGS from completion of construction to normal operational status. As an example of the several activities that may be involved, a generalized startup activity flow chart for a typical EPGS system is shown in Figure III.A-1. The overall sequence of events in the EPGS startup can be conveniently divided into five startup phases as follows:

- Finish Construction
- Construction Testing
- Component Inspection and Testing
- Initial System Operation
- Initial Power Operation

An activity interface diagram for startup of the EPGS is shown in Figure III.A-2, which lists many of the specific activities normally associated with each of the five phases of startup. With respect to an effective division of responsibility and administration of work, an activity interface diagram such as Figure III.A-2 is useful for clearly defining the interface between construction group and startup/Owner activities.

The general nature of activities within each of the five startup phases of Figure III.A-2 is briefly discussed in the remainder of this section. It is inherent in this discussion that construction and startup activities interface and proceed on a "startup system" basis, or other than on a piece meal "equipment" or "component" basis. This is necessary so that, to the extent possible, complete and totally functional systems can be brought to operational status as required for normal integrated operation.

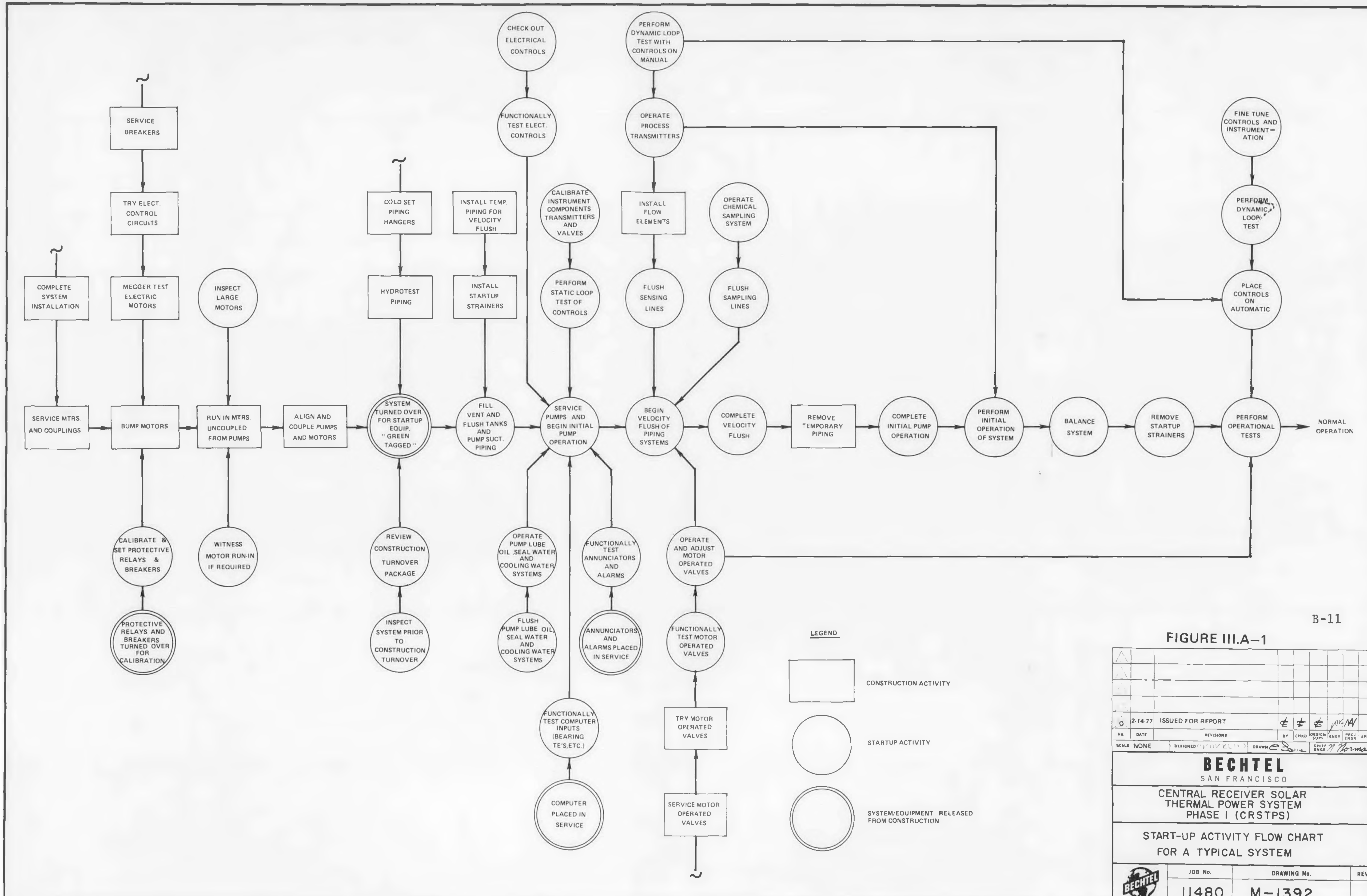


FIGURE III.A-1

SCALING RULES — SIZE E

CONSTRUCTION PROGRAM — STARTUP PROGRAM

CONSTRUCTION GROUP - RESPONSIBLE FOR FINISH CONSTRUCTION AND CONSTRUCTION TESTING PHASES
ADMINISTERS SAFETY TAGGING PROGRAM

OWNER - MONITORS CONSTRUCTION AND CONSTRUCTION TESTING AS DESIRED AND PERFORMS
CERTAIN CONSTRUCTION TESTING FUNCTIONS AS NOTED BELOW

STARTUP GROUP - PROVIDES COORDINATION AND TECHNICAL SUPPORT SERVICES

OWNER RESPONSIBLE FOR COMPONENT INSPECTION AND TESTING INITIAL SYSTEM OPERATION AND NORMAL OPERATION PHASES
ADMINISTERS OWNER SAFETY TAGGING AND CLEARANCE PROGRAM

STARTUP GROUP PROVIDES COORDINATION AND TECHNICAL SUPPORT SERVICES

CONSTRUCTION GROUP - PERFORMS CERTAIN COMPONENT TESTING AND INSPECTION, INITIAL SYSTEM OPERATION AND NORMAL OPERATION FUNCTIONS AS NOTED BELOW

EQUIPMENT NOT TO BE OPERATED - MEN WORKING - RED TAG

FINISH CONSTRUCTION PHASE (I)

PREPARE SYSTEM COMPLETION WORKLISTS	CHECK OUT INSTALLATIONS TO APPROVED DWGS SPECS	COMPLETE DATA SHTS TEST RECORDS DOCUMENTATION	MAKE AS BUILT DWGS
ADMINISTER SAFETY TAGGING PROGRAM	PERFORM REMEDIAL WORK ON SYSTEMS RETURNED FROM OWNER		
COMPLETE PROCESS PIPING	INSTALL VENTS DRAINS AND TRAPS	COMPLETE INSTR PIPING AND TUBING	INSTALL INSTRUMENTS
SERVICE ADJUST AND LUBRICATE EQUIPMENT	SCHEDULE VENDOR SERVICE ON EQUIPMENT	PERFORM COLD ALIGNMENTS	CLEAN AND INSPECT PIPING AND EQUIPMENT
INSTALL AT LEAST ROUGH INSULATION	LOAD / PRECOAT INITIAL DEMIN RESIN CHARGES	SERVICE AND FILL TRANSFORMERS	ALIGN AND MAKE UP COUPLINGS
CHECK OUT HTR OVERLOADS AND BRKRS ON 220 AND 440 VAC MTRS		SERVICE MOTOR OPERATED VALVES (MOV'S)	
COMPLETE WIRES CABLE RUNS	CHECK OUT WIRING CABLE RUNS AND CONNECTIONS	TEST OUTDOOR EQUIP FOR WATER TIGHTNESS	MECHANICALLY CHECK OUT SWITCHGEAR AND INTERLOCKS
	INSTALL TEMP PIPING FOR VEL FLUSHING AND CHEM CLEANING	INSTALL TEMP STARTUP EQUIP AS REQ'D	REMOVE ORIFICE PL INTERNALS AS REQ'D
PREPARE FOR VEL FLUSHING AND CHEM CLEANING	PREPARE FOR STEAM BLOWDOWN	PREPARE FOR OIL FLUSHING	
INSTALL STARTUP STRAINERS	COLD SET PIPE HANGERS		MONITOR FINISH CONSTR AS DESIRED (NOTE 1)

COMPONENT/SYSTEM → READY FOR CONSTRUCTION TESTING

EQUIPMENT BEING TESTED - YELLOW TAG

CONSTRUCTION TESTING PHASE (II)

	INTERFACE WITH STARTUP ON SYSTEMS AND COMP READY FOR TURNOVER	COMPLETE DATA SHTS TEST RECORDS DOCUMENTATION	
ADMINISTER SAFETY TAGGING PROGRAM	TEST SYST AND COMPONENTS RETURNED FROM OWNER FOR REMEDIAL WORK	DEBUG SYST WITH CONSTRUCTION DEFICIENCIES	DEBUG SYST WITH ENGINEERING DEFICIENCIES
SCHED VENDORS FOR CHECKOUT TEST AND TRY OF CONTROL PACKAGES	TEST POLARITY OF CONTROL AND POWER CONNECTIONS	INITIALLY ENERGIZE CONTROL CIRCUITS	INITIALLY TRY ELECT CONTROL CIRCUITS
INITIALLY TRY ALARM CIRCUITS	INITIALLY TRY INTERLOCKS AND SIMULATE TRIPS	OPERATE SWITCHES AND PUSHBUTTONS FOR TEST ONLY	MEGGER EQUIPMENT
CALIBRATE AND SET METERS AND RELAYS (NOTE 1)	TEST CT'S PT'S AND SECONDARY CIRCUITS (NOTE 1)		TEST POWER TRANSFORMERS AND MAJOR ELECTRICAL EQUIPMENT
TRY POWER CIRCUITS W/BKRS IN TEST POS OR W/PWR LEADS LIFTED		BUMP MOTORS FOR ROTATION (NOTE 2)	
RUN IN AND VIBR TEST MTRS UNCOUPLED (NOTE 3)	ALIGN AND COUPLE MOTORS AND PUMPS		MECHANICALLY SET LIMIT SWITCHES
MECHAN TRY MOV'S FOR TORQUE SET AND ADJ LIMIT SWITCHES		PERFORM NON - DESTRUCTIVE TESTING	PERFORM PIPING LEAK TESTS
PERFORM HYDROTESTS	STROKE MANUAL VALVES	PERFORM OIL FLUSHES	
MONITOR CONST TESTING AS DESIRED (NOTE 1)	INSPECT SYST PRYOR TO CONSTR TURNOVER (NOTE 1)	REVIEW CONSTR TURNOVER PACKAGE (NOTE 1)	

COMPONENT/SYSTEM → READY FOR STARTUP

EQUIPMENT TURNED OVER FOR STARTUP - GREEN TAG

COMPONENT INSPECTION AND TESTING PHASE (III)

INITIATE INCOMPLETE WORK AND DEFICIENCY LISTS	WALK DOWN SYST CHECK OUT INSTALL TO APPROVED DWGS, SPECS	COMPLETE DATA SHTS TEST RECORDS DOCUMENTATION		ACCEPT CUSTODY OF PERM PLANT SYSTEM AND COMPONENTS
	PROVIDE CLEARANCE TO CONSTR FOR REMEDIAL WORK	DEBUG SYSTEM COMPONENTS WITH DEFICIENCIES	COMMUNICATE DESIGN PROBS TO ENG'R'G FOR RESOLUTION	
COMPLETE PREP FOR VEL FLUSHING AND CHEM CLNG (NOTE 4)	CHECK OUT STARTUP STRAINERS AND DIFF PRESS GAUGES	FLUSH PUMP LUBE OIL SEAL WATER AND COOLING WATER SYSTEMS	OPERATE PUMP LUBE OIL SEAL WATER AND COOLING WATER SYSTEMS	
PLACE BKRS IN TEST POS OR LIFT POWER LEADS	REENERGIZE CONTROL CIRCUITS	SCHEDULE VENDORS FOR FUNC TESTING OF CONTR PACKAGES	TEST AND TRY SAFETY AND PROTECTION SCHEMES	FUNCTIONALLY TEST COMPUTER INPUTS
RETRY CONTROLS ALARMS AND INTERLOCKS AS REQ'D	CALIBRATE INSTRUMENTS	STROKE CONTROL VALVES	TUNE INSTR AND CONTROLS AS SYSTEMS	REMEGGER EQUIPMENT AS REQ'D
PERFORM ROUTINE MAINT ON EQUIPMENT AND SYSTEMS	LINE UP SYSTEM FOR OPERATION		INIT ENERGIZE MAJOR POWER SUPPLY SYSTEM AND MAKE PHASE CHECKS	RACK IN AND OPERATE BREAKERS
SCHEDULE VENDORS FOR INITIAL EQUIPMENT OPERATION	BEGIN COMPONENT TESTS	BUMP MOTORS FOR ROTATION (NOTE 2)	ELECTRICALLY TRY MOV'S	MAKE FINAL ADJ ON TORQUE SWITCH SETTINGS
	SUPPLY CHEM GASES AND FLUIDS AS REQUIRED	PERFORM FLUSHING AND CHEM CLEANING USING PERM PLANT EQUIP	OPERATE PERM PLANT EQUIP FOR OIL FLUSHING	FLUSH SAMPLING LINES
MONITOR WATER CHEMISTRY	FLUSH SENSING LINES	COMPLETE VELOCITY FLUSH		REMOVE TEMP PIPING AND EQUIP USED FOR FLUSHING (NOTE 5)
REINSTALL ORIFICE PL AND EQUIP INTERNALS (NOTE 5)		RUN IN AND VIBR TEST ROTATING EQUIPMENT	COMPLETE COMPONENT TESTS	PROVIDE CRAFT SUPPORT AS REQ'D (NOTE 5)

SYSTEM READY FOR → INITIAL OPERATION

INITIAL SYSTEM OPERATION (IV)

OPERATE AND MONITOR PERMANENT PLANT EQUIP AND SYSTEMS	COMPLETE DATA SHTS TEST RECORDS DOCUMENTATION
RECORD AND MAINTAIN OPERATING RECORDS	PROVIDE CLEARANCE TO CONSTR FOR REMEDIAL WORK
DEBUG SYSTEM AND COMPONENTS WITH DEFICIENCIES	COMMUNICATE DESIGN PROBS TO ENG'R'G FOR RESOLUTION
OPERATE PROCESS TRANSMITTERS	VERIFY SAFETY AND PROTECTION SCHEMES
VERIFY ANNUNCIATORS AND TRIPS	MAINTAIN SYSTEM IN LAYUP OR ON RECIRC
PERFORM CONDENSER LEAK TEST	COMPLETE INSULATION PAINTING ETC (NOTE 5)
BALANCE HEATING AND VENTILATING EQUIPMENT	REMOVE STARTUP STRAINERS
VERIFY CONTROL CIRCUITS AND INTERLOCKS	PLACE CONTROLS ON AUTOMATIC
CALIBRATE AND TUNE INSTR AND CONTROLS AS SYST	PERFORM PREOPERATIONAL TESTING
PROVIDE CRAFT SUPPORT AS REQ'D (NOTE 5)	VERIFY THAT SYSTEM OPERATE PER DESIGN INTENT

EPGS READY FOR INITIAL → OPERATION AS A UNIT

INITIAL POWER OPERATION (V)

RECORD PIPING HANGER HOT SETTINGS AND ADJ AS REQ'D (NOTE 4)
PERFORM HOT ALIGNMENTS
CHECK OUT THERMAL EXPANSION
MONITOR WATER CHEMISTRY
FINE TUNE CONTROLS AND INSTRUMENTATION
ROLL AND SYNCHRONIZE TURBINE GENERATOR
PERFORM TURBINE OVERSPEED TRIP TESTS
VERIFY THAT SYSTEMS OPERATE PER DESIGN INTENT

EPGS READY FOR → NORMAL OPERATIONAL PERFORMANCE TESTING

NOTES

1 OWNER / STARTUP GROUP ACTIVITY
ALL OTHER ACTIVITIES IN THIS DESIGN PHASE ARE CONSTRUCTION GROUP ACTIVITIES

2 CONSTRUCTION GROUP BUMPS MOTORS HAVING ONLY THERMAL OVERLOADS FOR PROTECTION
OWNER BUMPS MOTORS HAVING CURRENT AND POTENTIAL TRANSFORMER RELAYS FOR PROTECTION

3 OWNER / STARTUP GROUP INSPECT LARGE MOTORS AND WITNESS RUN-IN IF REQUIRED

4 CONSTRUCTION GROUP / OWNER / STARTUP GROUP JOINT ACTIVITY

5 CONSTRUCTION GROUP ACTIVITY
ALL OTHER ACTIVITIES IN THIS DESIGN PHASE ARE OWNER / START-UP GROUP ACTIVITIES

FIGURE III.A-2

0 2-16-77 ISSUED FOR REPORT

NO. DATE REVISIONS BY CHKD DESIGN SUPV ENGR PROJ ENGR APPD

SCALE NONE DESIGNED DRAWN K A CHIEF ENGR

BECHTEL
SAN FRANCISCO

CENTRAL RECEIVER SOLAR
THERMAL POWER SYSTEM
PHASE I (CRSTPS)

ACTIVITY INTERFACE DIAGRAM
FOR STARTUP OF EPGS

JOB No 11480 — DRAWING No. M-1393 — REV 0

H G F E D C B A — 8 7 6 5 4 3 2 1

34 x 44 "E" SIZE

B. FINISH CONSTRUCTION PHASE

During the finish construction phase, the construction group completes the installation of system equipment and prepares each system for construction testing. The Owner may elect to have personnel present to inspect and document the results of various activities during this phase.

Initially, the construction group prepares system completion worklists to serve as a basis for all subsequent planning and scheduling activities. Upon completion of construction, systems are visually inspected and modified as necessary to ensure installation to approved drawings, specifications, codes, and standards. Data sheets, test records, and other required documentation are filled out, and system "as built" drawings are made. The construction group also performs remedial work on components and systems returned from the owner with deficiencies. A list of typical construction group responsibilities is provided in the activity interface diagram of Figure III.A-2.

C. CONSTRUCTION TESTING PHASE AND SAFETY TAGGING

Construction testing ensures that equipment and systems are ready for release to the Owner for startup. Typical activities are listed in Figure III.A-2. The majority of these activities are the construction group's responsibility, with the exceptions of calibrating and setting protective relays and breakers, preturnover system inspection and turnover package review, which are Owner's responsibilities. Again, the Owner may elect to have personnel present for inspection and documentation of the work results.

Throughout the construction testing phase, the construction group must administer an effective safety tagging procedure to protect plant personnel and equipment. This administrative procedure is intended to ensure the safety of personnel and the protection of equipment during finish construction and construction testing and after release of equipment to the Owner.

The safety tagging procedure is implemented at such time as piping systems are pressurized from permanent or temporary sources in preparation for hydrotesting, velocity flushing, chemical cleaning, etc., or when permanent electrical equipment is energized. Tags are placed on valves, circuit breakers, motor starters, and local and remote control switches, push buttons, etc. After a system has been tagged, it must always have tags of one form or another to indicate the status of construction, testing, or operation. Placement and removal of tags is the responsibility of the Safety Tagging Administrator. Upon request for safety conditions by a construction craft, this person undertakes the following actions:

- Fills out both portions of the tag
- Establishes the safe conditions requested

- Places the large portion of the tag on the proper equipment or component and documents this in a Project Safety Tagging Log

- Turns over the small portion of the tag to the construction craft making the protection request

When the work has been completed, the construction craft returns the small portion of the tag to the Safety Tagging Administrator, who then removes the large portion of the tag from the equipment or component and notes the clearance in his log. A separate tag must be used for each craft requesting safe conditions.

Three types of tags are used, depending upon the safety conditions to be established. Red tags designate that construction or repair work is in progress and that operation of equipment or the associated system could result in injury to personnel. Yellow tags designate that equipment or systems are under test either by construction or the Owner. Green tags designate that equipment has been turned over to the Owner for operation, and warn personnel that piping may be pressurized, vessels may be full of process fluid, circuits may be energized, or that equipment may start at any time.

At the conclusion of successful construction testing, the equipment, controls, etc., must be turned over to the Owner as part of a completed startup system package in order to permit smooth and orderly testing and operation of the equipment on a systematic basis during subsequent phases of the startup plan.

D. COMPONENT INSPECTION AND TESTING PHASE

In this startup phase, the Owner accepts custody of permanent plant systems and components and verifies that construction work is complete, that system components have been properly installed, that controls and instrumentation have been calibrated, and that all components function properly. The construction group provides craft support as required during component inspection and testing, such as in preparing systems for velocity flushing and chemical cleaning, coupling rotating equipment after motor run-in tests, installing flow elements, and removing temporary piping. Typical activities are listed in Figure III.A-2.

Initially, the Owner visually inspects systems to verify that installations are in accordance with approved drawings, specifications, etc. Throughout the testing phase, the required data sheets and test records are filled out, incomplete work and deficiency lists are initiated, and systems or components with deficiencies are debugged. Design problems are referred to the responsible engineering organization for resolution, and equipment is turned back to the construction group for remedial work as appropriate.

E. INITIAL SYSTEM OPERATION PHASE

During initial system operation, the Owner verifies that individual startup systems of functional parts thereof operate safely and properly, and , to the extent possible, that systems and components meet design intent. Typical activities are listed in Figure III.A-2 and discussed in Section V. The construction group furnishes craft support as required for completing insulation, painting, etc.

Several of the supporting tests and procedures typically used in conventional plant startups, which would also be applicable to the EPGS component inspection and testing phase, are discussed in Section IV. At tne conclusion of this phase, equipment is ready for initial operations as part of a total startup system.

An example of initial EPGS "system" operation might be the operation of the condensate and feedwater system, including the condensate demineralizer, to provide receiver feedwater during receiver boilout or main steam line blowdown activities. Subsequently, virtually the entire EPGS would be operating, with the exception of the turbine-generator and extraction steam systems, to support initial operation and testing of the receiver and thermal storage subsystems and the master control system.

The Owner operates and monitors permanent plant equipment and systems and completes the required test records and other documentation. Equipment and systems with deficiencies are debugged, and design problems are communicated to the responsible engineering organization for resolution. Clearance is given to the construction group for remedial work as necessary.

F. INITIAL POWER OPERATION PHASE

Initial power operation involves operation of the total EPGS as a power generating unit for the first time. It includes initial turbine roll, synchronization to the utility grid, turbine overspeed test, and power testing to demonstrate that the EPGS can be operated throughout its entire load range. Upon successful completion of these initial power operations, the plant is ready for normal operations and long-term performance and evaluation testing of the entire Pilot Plant.

For the purposes of this report, and with respect to the overall EPGS startup plan, the EPGS startup is complete with the sucessful accomplishment of the initial power operation phase. It is recognized that the 10 MWe Pilot Plant may then continue in normal operations for several years of testing and evaluation which will contribute to the development of efficient and cost effective designs for a commercial size plant. Some of the tests and evaluation studies that may be performed during normal operation are discussed in Section V.D.

IV. STARTUP TESTS AND PROCEDURES

Many of the tests and procedures required for startup of the EPGS are described in this section. Additional tests or procedures may be required as dictated by the final design of the EPGS and its functional integration with the other Pilot Plant subsystems. All of the procedures described are conventional in nature and are commonly used in the startup of fossil-fueled steam-electric power plants.

A. MECHANICAL TESTS AND PROCEDURES

1. Pressure Tests

Pressure tests are performed to verify the pressure boundary integrity of mechanical systems and components as required by the governing design specifications, codes, and standards. These tests are normally completed during the finish construction phase.

Hydrostatic testing employs a working fluid such as water to pressurize the system or component under test at 150 percent of its maximum allowable working pressure. To obtain acceptable results, leakage and deformation must not exceed the limits extablished in the design documents. For example, the majority of EPGS piping and unfired pressure vessels must satisfy ANSI B-31.1, Power Piping Code, and ASME Boiler and Pressure Vessel Code, Section VIII, requirements, respectively. Excessive leakage or deformation indicates the need for repair, or replacement and retesting.

Pneumatic testing is similar to hydrostatic testing, except that a gas such as air or nitrogen is used as the working fluid. The system is subjected to 125 percent of its maximum allowable working pressure. The absolute limit on pressure is generally set lower than for hydrotests due to relatively larger amount of energy which can be stored in a compressible fluid, and the attendant safety hazard in the event of boundary failure.

Static tests are performed on piping and vessels that cannot be isolated from atmospheric pressure, an example being the EPGS condensate storage tank. To demonstrate boundary integrity, a working fluid is used to apply pressure equivalent to the maximum possible static head in the system.

It is good practice to perform low-pressure leak tests to verify system tightness prior to the hydrostatic and pneumatic testing described above. Leak tests are conducted at less than system operating pressure, or below the setting of any installed relieving device, and generally do not satisfy code requirements.

Certain special precautions must be taken for protection of personnal and equipment during pressure testing. Some of these precautions are as follows:

- Prior to test, the system to be tested must be visually inspected and boundaries and safety barriers established.

- Piping and components should be provided with additional supports or restraints if loads under test will exceed design support loads. An example is a gas or vapor handling system to undergo hydrotest. In this case, temporary supports may be needed due to the added weight of the test fluid.

- Permanent instrumentation not capable of withstanding full test pressures should be disconnected from the system.

- Systems interfacing with one under test should be vented to prevent buildup of pressure if a boundary device leaks.

- For steel vessels and components that may be subject to brittle fracture at low temperatures, test temperatures must be maintained above the nil ductility transition temperature of the given material.

- For hydrostatic testing, vents should be placed at all high points to purge air from the system during system fill.

- Water used for hydrotesting should meet established water chemistry requirements (see Section IV.A.6) in order to minimize corrosion.

- Close inspection of a system undergoing test should not be conducted while the system is at full test pressure.

- Minor leakage across seals, gaskets, and valve seats may be acceptable provided it does not exceed acceptance limits or the capacity of test equipment to maintain system pressure.

Test equipment typically required to perform pressure testing includes hydrostatic test pumps, calibrated pressure gauges, pressure regulators, and relief valves. Care must be taken to ensure that the flow capability of relieving devices is greater than that of the pressurizing equipment.

A pressure test schedule will be developed during final design of the EPGS to list those component requiring pressure testing in the field. It is probable that even the largest of the Pilot Plant EPGS components, such as the condenser, can be pressure tested prior to shipment from the factory and will not require field testing. This may not be the case for the largest EPGS components in a commercial sized plant, where field assembly of some components may be required.

2. <u>Startup Strainers</u>

Startup strainers are protective devices that are temporarily installed in pump suction piping to collect any gravel, pipe scale, weld spatter, and other foreign material that may remain in piping and vessels after construction. Design of the various EPGS systems includes provision for installation and monitoring of startup strainers at appropriate locations. Strainer mesh size is determined from a judgement of the largest size particle that can cause damage to the equipment. Stainless steel mesh material is preferable in systems where rusting may be a problem.

In order to ensure effective utilization of startup strainers, a number of operating procedures should be observed. Strainers should not be removed from a system until full design flow has been achieved and evidence clearly shows that they are no longer required. They should be reinstalled whenever additional piping or equipment modifications could result in the presence of foreign matter. Installation of, operation with, and cleaning of strainers is particularly important in high-pressure, high-temperature systems, and diligent operator surveillance is desirable. Strainers left unmonitored can become plugged and may ultimately collapse, causing damage to the equipment. Finally, strainers should be inspected and cleaned as necessary at regular intervals and at the conclusion of velocity flushing (see Section IV.A.7), regardless of strainer differential pressure readings.

A tab or other easily identifiable marking should be provided on the piping to indicate that the strainer is in place.

3. <u>Rotating Equipment Vibration Tests</u>

The objective of rotating equipment vibration tests is to measure and report vibration, determine if the readings are within acceptable limits, and assist in determining the causes of excessive vibration. The tests apply mainly to turbines, centrifugal pumps, axial and centrifugal fans, and electric motors. Acceptable vibration limits are generally specified by the equipment manufacturer or in published standards such as Hydraulic Institute Standards for centrifugal pumps and NEMA Standards for electric motors.

Vibration measurements are usually not taken on rotating equipment requiring less than approximately 50 horsepower, unless preliminary observations by visual and hand contact methods suggest the possibility of a problem. On larger equipment, the driver is tested initially with a calibrated, hand-held probe, followed by testing of the complete coupled equipment assembly.

Some of the common causes of excessive vibration are imbalance, misalignment, eccentricity, bearing flaws, excessive bearing clearances, improper selection of lubricating oil, oil whip, looseness, and resonance.

4. Flushing of Lubricating Oil Systems

High-velocity oil flushing is intended to remove rust and foreign material from the lubricating oil systems that are furnished with major mechanical equipment such as the turbine-generator. Specific oil flushing procedures are ofter required by the manufacturers of such equipment.

Prior to initial oil fill, the bearings and oil tanks are hand cleared. Temporary piping is installed to bypass bearings, and temporary strainers are inserted at appropriate locations. The control, oil pumping, heating, and cooling systems are then made operable. If pumps in the system are being operated for the first time, the precautions of Section IV.A.5 for pump operation should be observed.

To maximize effectiveness of the oil flushing operation, the temperature of the oil may be varied rapidly. The resulting expansion and contraction of piping helps loosen rust and contaminant particles adhering to the piping inner walls. Cold oil with its relatively high viscosity is capable of carrying away the larger particles and debris, whereas hot oil flows at higher relative velocities and thereby improves scrubbing action. High-pressure air may be injected into the system at certain points in order to further increase velocities and turbulence. Finally, welded joints may be vibrated to loosen slag and weld spatter for removal by the temporary strainers and the permanant oil filtering equipment.

Acceptable oil flushing results are obtained when the accumulation rate of foreign material on strainers has become nearly constant over time; the total accumulation at each inspection is less than a specified amount, and individual particles are smaller than an acceptable size.

5. Operation of Pumps

Prior to initial power operation of the Pilot Plant, the status of the various EPGS systems may be such that complete checkout and testing of any given pump cannot be accomplished at normal operating conditions. Nevertheless, pumps can be inspected and run in to identify potential problems as early as possible.

A number of activities must be completed prior to initial pump operation. The pump and driver must be installed and aligned in accordance with manufacturer's requirements. Controls and protective devices must be calibrated and functionally tested. Pump lubricating oil, seal water, and cooling water systems must be placed in service. Pump suction piping must be filled, the suction valve opened, the pump vented and filled, and the pump drain opened to flush out any internal debris. Depending on the system design, it may be necessary to start the pump with its discharge valve closed or only partially open.

For safety reasons, the initial pump start should be controlled at a local control station if possible. Remote controls can be checked out and tested after the initial pump run-in. Pumps should not be run without protective and supervisory controls functional or with any of those devices bypassed or defeated, unless temporary additional protection is installed. Pumps should not be operated outside recommended performance limits, such as with less than required net positive suction head (NPSH) or at below minimum recommended flow. If extended periods of operation at other than pump design flow are anticipated, the supplier should be consulted to verify that such operation can be tolerated. Frequent starting of pumps must be minimized when large motors are involved.

Field performance testing of pumps if necessary may be conducted in accordance with Hydraulic Institute Standards. System resistance should be varied to simulate as many of the normal operating modes as possible within startup limitations.

Most of the EPGS pumps will be of a manufacturer's standard design, and certified pump performance data will be available as a result of prior factory testing. In such cases, formal pump performance testing should not be required during startup activities.

6. Water Quality and System Cleanliness Requirements

System water quality and cleanliness are important throughout the course of startup, particularly during such activities as pressure testing, velocity flushing, and wet layup. Proper water quality minimizes the possibility of damage to equipment due to corrosion or the presence of foreign matter, and it facilitates attainment of water chemistry limits necessary for full power operation.

It is usually unnecessary to provide high-purity makeup water to all startup systems. Therefore, several grades for purity can be established to meet differing startup system requirements. Highest purity water is obtained from the plant makeup demineralizer system. Demineralizer effluent typically has a pH range of 6 to 8, is low in conductivity and dissolved solids, and contains no oil, turbidity, or sediment. The most important uses of high-purity water are in the main steam, condensate, and feedwater systems.

Next in order of water purity is the filtered raw water supply to the makeup demineralizer system. Filtered raw water may also be provided to domestic water systems that require only moderate water purity. River or well water provided as makeup to the EPGS circulating water system may be of lower quality and may require chemical treatment to prevent organic fouling in the circulating water and component cooling water systems.

Detailed water purity specifications will be developed during final design based on actual system requirements. Each startup system may be classified, and startup water demand estimated for consideration in sizing the plant makeup demineralizer and water treatment systems. It is possible that a system sized for normal plant operation may be inadequate during startup, causing unnecessary startup delays.

7. <u>Velocity Flushing and Chemical Cleaning</u>

Velocity flushing uses clean water under pressure to remove contamination from piping and equipment. Velocity flushing should be carried out on all piping systems wherever practicable. Chemical cleaning involves circulation of hot alkaline solution to remove oil, grease, and other contaminants not removed by velocity flushing.

a. <u>Velocity Flushing</u>. Numerous prerequisites must be satisfied prior to system velocity flushing. Temporary piping and restraints must be installed. The piping arrangement should preclude splashing, spraying, or flooding of nearby equipment. Restraints for any open-ended piping should be capable of withstanding the jet force of the discharging fluid, and extra restraints may be required for permanent piping. High-point vents and low-point drains must be available as required to facilitate filling and draining. The entire system should be leak tested. Valve spools should be installed, sumps cleared, and sump pumps placed in service. System pumps and their sealing, cooling water, lubricating oil, and control systems must be preliminarily checked out.

Pump suction piping should be internally inspected or flushed before the pumps are started for the first time. If the water source is a vessel (condenser hotwell, condensate storage tank, or deaerator storage tank), that vessel should be hand cleaned and hosed down prior to initial fill. Pump discharge piping can be flushed using the installed pumps. Main process lines are flushed first with the branch lines closed. Branch lines, vents, drains, and instrument connections are then flushed. Because velocity flushing often affords the first opportunity to run a pump in its designated system, care should be taken to ensure that the pump is operated within design limits and that the pump operating procedure outlined in Section IV.A.5 is followed. The design of most of the EPGS systems includes redundant pumps, and sufficient pumping capacity is therefore available to attain greater than system rated flows and velocities. Flushing through control valves, heat exchangers, and filters downstream from long piping runs should be avoided. Risers should be flushed in the direction of gravity, if possible.

Detailed velocity flushing procedures will be developed on a system-by-system basis in the EPGS final design. A velocity flush record should be completed during startup specifying the quality of water used, duration of flush, and qualitative evaluation of the results.

b. Chemical Cleaning. In certain systems where a high degree of cleanliness is required, chemical cleaning may be employed to supplement velocity flushing. Carbon steel piping in the condensate, feedwater, and main steam systems is a typical example.

Consideration must be given to the compatibility of component materials with the cleaning fluids. Stainless steel components, such as the condensate storage tank and demineralized makeup water piping, are generally excluded from chemical cleaning. Chemical concentrations must be controlled so that maximum tolerable concentrations are not exceeded. The solution may be circulated hot to obtain the most effective results. Considerations should be given to personnel safety when handling chemical solutions.

Cleaning solutions should be monitored for contaminants on a regular basis until water chemistry levels off. Sampling points should be located to give representative results and should not be located at dead-end sections of piping or in high-velocity regions. At the conclusion of cleaning, the system should be flushed with demineralized water until conductivity falls off to an acceptable level. All flow paths, low points, instrument connections, and dead legs should be flushed to ensure that all cleaning solution is displaced. Hydrazine and ammonia may be added to scavenge oxygen and adjust pH before placing the system in wet layup status. An alternative is to drain the system and lay it up dry with a nitrogen blanket.

There are a number of chemical cleaning solutions available. Alkaline solutions are usually based on phosphate salts, effective in the removal of oil based compounds. Acid or chelate solutions are effective in the removal of mill scale, rust, and weld spatter. During final design, the manufacturer's recommendations regarding the system should be considered in determining which cleaning method is to be used.

Acceptable methods for disposal of chemical cleaning solutions must also be considered. A detailed system-by-system chemical cleaning procedure must be developed during the EPGS final design.

8. Cleaning of Steam Piping

a. Turbine Main Piping and Admission Steam Piping. In the startup of conventional fossil-fueled steam plants, it is standard practice to conduct a series of steam blows through the superheater section of the boiler and through any piping that will carry steam to the turbine. The steam blow procedure is accomplished prior to initial turbine roll in order to remove any foreign material, weld spatter, or mill scale that might otherwise be carried, with damaging results, from the superheater and piping into the turbine. Steam is generated in the boiler at less than design pressure and blown down to atmospheric pressure to follow a path through the superheater, main steam lines, turbine stop valves, a temporary steam blow valve, and temporary exhaust piping.

The preliminary startup plan for the EPGS includes a similar steam blow procedure for the 10 MWe Pilot Plant, using steam generated by solar heat in the receiver subsystem. Because the Pilot Plant includes a Thermal Storage Subsystem (TSS), that also generates steam for admission to the turbine, steam blows will also be performed through the steam lines to and from the TSS using steam generated in the receiver.

Preparation for steam blow includes the installation of temporary turbine stop valve blowdown covers, temporary jumper piping as required, temporary exhaust piping, and the temporary motor-driven steam blow valve. All temporary piping, valving, and fittings must be rated for the maximum pressure and temperature conditions expected for steam blowing. Temporary piping supports and restraints must be designed to resist safely the maximum reaction forces developed by steam blowing. Low-point steam line drains must be temporarily piped to a visible discharge area to permit verification of free drainage and a dry fine condition prior to initating a blow. Permanent steam line instrumentation not required during steam blow should be valved off, and steam line flow orifice plates must be removed. A steam blow exhaust silencer may be required, depending on the proximity of the site to inhabited areas. Temporary piping must exhaust in the direction of an area where the impact of any debris projectiles resulting from the steam blow would cause no damage, and this area must be restricted from personnel access prior to blowing. Personnel hearing protectors should be available for use during the blows.

The steam blow procedure is initiated by establishing normal receiver drum water level, focusing a portion of the heliostat field, and slowly raising boiler pressure with the superheater outlet valve open and the steam blow valve closed. Free thermal expansion of all steam lines should be verified. If the superheater is not totally drainable, it will be necessary to hold at a low pressure level, with the superheater vents open, to boil out the superheater. Permanent and temporary steam lines are warmed by drain flow and by opening a small bypass valve around the steam blow valve. A short duration blow should be performed at low pressure to verify operability of the steam blow valve and integrity of the total steam piping system and restraints. Boiler pressure is then increased to a predetermined initial steam blow pressure. The steam blow valve is opened, the blow proceeds until boiler pressure decays to the terminal steam blow pressure, and the steam blow valve is closed. Boiler pressure is again increased to the initial steam blow pressure for another blow, and the procedure continues.

The terminal blowing pressure is predetermined by calculation as the minimum pressure required to assure that the minimum velocity heat (fluid density times velocity squared) in the flow path during the blow exceeds the maximum velocity head that could occur in the normal flow path during normal maximum full load operation. By this criterion, blowing at less than terminal pressure would not be effective in dislodging and sweeping away particles that could otherwise be dislodged in normal operation. Temporary steam blow piping must be large enough to assure that choked (sonic) flow does not prevent achieving the minimum necessary velocity head at a reasonable value for terminal blowing pressure. Initial blowing pressure is selected in consideration of a number of factors, including required pressure rating for temporary piping, time duration of blow desired, and ability to control and maintain boiler pressure above terminal pressure with the initial receiver heat flux available from the heliostat field. It is possible that a long-duration, continuous blow can be controlled above terminal pressure. However, there is a cleaning advantage obtained from the piping thermal expansion and contraction associated with intermittent shorter blows.

The effectiveness of the steam blow procedure is determined through the use of polished steel test targets which are inserted in the temporary exhaust piping. A blow is conducted with a clean target in place, and the resultant extent of particle impingement pitting is representative of piping cleanliness. The steam blow procedure should continue until an unpitted target is produced.

During the steam blowing operation, the receiver drum water level is maintained and controlled by feedwater makeup from the EPGS, drained if necessary by drum blowdown via the permanent continuous drum blowdown system which drains to the EPGS condenser. Receiver feedwater is heated and deaerated in the EPGS deaerator by pegging steam from an auxiliary steam source. The entire EPGS condensate and feedwater system must be operating. Sealing steam is not required for the turbine during this operation, and it is not necessary to establish condenser vacuum. Operation of the makeup demineralizer system is required to replace the condensate used in making the steam blows.

b. Water Conservation. The large amount of condensate consumed in the steam blow procedure and the rate at which it is consumed may severely tax the capacity of the condensate storage tanks and the makeup demineralizer in the EPGS, resulting in delays while condensate is made up. Moreover, an equal amount of raw water to the makeup demineralizers is required. During final design of the EPGS, when the site-related availability of water is known, consideration may be given to a modified steam line cleaning procedure that would considerably alleviate these potential water use problems. The modified procedure involves the use of an organic chelating agent in the superheater and steam lines to loosen rust, mill scale, and weld spatter prior to steam blowing. Vertan 675, produced by Dow Chemical Company, is one such chelate that has been successfully used in conventional plants to reduce dramatically the extent of steam blowing required. Vertan 675 has a pH of 8 and is safely compatible with stainless steel superheater tubing and piping. The use of such innovative, and relatively more expensive, startup procedures may be essential for water conservation in the startup of a commercial size power plant.

c. Other EPGS Steam Line Cleaning. Other steam piping systems in the EPGS will not require as high a standard of cleanliness as the turbine main and admission steam piping described above. Turbine seal steam piping will be routinely blown out using either main steam or an auxiliary steam source. Depending on final piping design, the turbine extraction steam lines may be blown out using main or auxiliary steam and temporary jumper piping, although this is not essential. Steam line instrument tubing to pressure, flow, and sampling instruments will be routinely blown out using the valves provided at the instruments.

B. ELECTRICAL TESTS AND PROCEDURES

1. Insulation Resistance Megger Testing

Meggering is performed to verify the integrity of electrical equipment insulation. It is applied to motors, power cables, circuit breakers, and high voltage switchgear, but not to transformers, insulators, and capacitors, which have separate test procedures. The test is usually conducted during the construction testing phase, but may be repeated later in startup if a motor has not been operated for an extended period of time, or if electrical equipment has been exposed to excessive moisture.

Before testing, normal precautions must be undertaken for personnel safety and equipment protection. The equipment must be deenergized, free of dust and moisture, and in a safe condition. Danger signs must be posted, and the test area roped off. Rubber gloves should be worn at all stages of the test. Prior to the test, a calibrated megger of proper output voltage is selected, and test equipment enclosures and frames are grounded. The megger is connected, and insulation temperature, relative humidity, and other test conditions are recorded. The megger is then operated, and the leakage current is recorded after a given time period; often one minute for low-voltage equipment and longer for high-voltage equipment. Each electrical phase is meggered both to ground and phase-to-phase. To pass the test, the measured resistance, when corrected to a standard temperature, must be greater than a value that is a function of rated voltage; or the ratio of resistance at the end of the test to that at some earlier time must exceed a value that is a function of insulation type. IEEE standards can be consulted for further details. Unacceptable readings will result in additional testing to identify and correct the problem.

At the conclusion of testing, all equipment should be grounded to remove accumulated static charge.

2. Checkout and Testing of Switchgear and Circuit Breakers

Switchgear and circuit breakers are checked out and tested prior to energization to ensure that the equipment meets design specifications and that breakers will function properly in service. Meggering equipment, a breaker test set, and timing instrumentation are required to perform the tests.

Initially, equipment is inspected for dirt, oil, grease, water, or other foreign matter. Nameplate data is checked against design specifications. Protective relays are checked out and tested in accordance with the procedure described in Section IV.B.6 for meter and relay tests. Verification is obtained that breaker main contacts, arcing contacts, mechanical and electrical trip and close linkages, arc chutes, auxiliary switches, etc. have been previously checked, serviced, and adjusted as necessary.

For final testing, the breaker is placed in "test" position and connected to the breaker test set. The breaker is operated electrically and adjusted as necessary for proper opening and trip times, trip voltage, and minimum close voltage. Overcurrent trip settings are verified by simulating normal and overload phase currents via the phase current transformers. Short and long time delays are measured and checked against system requirements.

Molded case breakers are checked for short and long time delays, minimum trip currents, and times. If a combination breaker-starter assembly has starter thermal or mechanical overloads, these devices may be tested separately.

3. Checkout and Testing of Control Panels

Electrical control panels and cabinets must be checked out and tested prior to energization to ensure that these devices are clean, terminal connections are proper, and insulation resistance is satisfactory.

Several prerequisites must be satisfied prior to testing. Supply breakers are tested using the procedure outlined in Section IV.B.2, space heaters are examined for proper operation, and panel internal ventilation and lighting, where provided, are verified as adequate. Protective circuits, meters, and relays are verified as functional (see Section IV.B.6), and low impedance ground circuits are disconnected to allow for megger testing. Electrical connection diagrams, vendor instruction manuals, and layout drawings are consulted as necessary.

The control panel or cabinet is visually inspected to verify cleanliness and adequacy of terminal connections, with no accidentally grounded connections. Nameplate data is checked. Next, the bus or cabling is meggered both to ground and phase-to-phase. Ground connections are checked for continuity, and dc systems for polarity. Finally, distribution breakers are verified as being open prior to energization.

4. Power Transformer Tests

The objectives of power transformer testing are to verify that transformers provide the correct output voltage and polarity, that they have adequate insulation, that they are clean, and that all protective circuits and auxiliary systems are functional.

The first step of testing involves visual inspection of the equipment and checkout of auxiliary systems. Equipment is inspected for physical damage, dirt, oil, grease, moisture, and application of protective coating. Tightness of bushings, covers, doors, and bus bars is verified. Nameplate date and proper phase labeling are checked. Transformer oil is tested and filled to the proper level, and the system is checked for leaks. Nitrogen pressure is checked and adjusted as necessary. If transformer oil pumps are provided, they can be tested in accordance with the procedure of Section IV.A.5. Cooling fans are similarly tested. Temperature control devices are calibrated and qualified in accordance with Section IV.C.2 requirements for checkout and testing of control loops.

Next, protective devices are made functional. Relays and current and potential transformers are tested to the startup technical procedure for meters and relays (see Section IV.B.6). Current and potential transformers are also inspected for proper connection of windings to the correct transformer phase. Lightning arrestors are examined for proper construction and then meggered. Annunciators are placed in service and checked for proper operation and setpoints, and all control circuits are made functional. Ratio, megger, circuit continuity, polarity, and winding resistance tests are then performed on the transformers. Finally, cabling may be tested to ensure satisfactory phase termination, insulation resistance, winding resistance, and polarity. Prior to transformer energization, necessary fire protection equipment must be operational, and adequate warning signs and barriers posted for personnel protection.

5. Operation of Motors

Motor operating tests are intended to verify that electric motors are wired to run in the proper direction, that vibration is not excessive, and that running currents are essentially balanced between motor leads at less than rated current. These tests are performed after the motor and its associated control and protective systems have been released from construction and the circuitry has been verified as acceptable according to the startup technical procedure described in Section IV.C.2 for checkout and testing of control loops. Necessary test equipment includes clamp-on ammeters, voltmeters, and vibration detectors.

To initiate motor testing, the motor must be uncoupled from driven equipment, if necessary (see Section IV.B.1). The motor is then rotated manually if possible to verify that the rotor is free, and lubrication levels are checked. Next, the motor is electrically bumped to verify proper direction of rotation. The motor is then energized for initial run-in. Currents, voltages, acceleration and coast-down times, winding and bearing temperatures, speed, oil pressure, and vibration are measured and recorded as appropriate. Operation of motor heaters is verified.

After initial run-in, the motor is aligned and coupled to the driven equipment. When the associated system is in operational status and the motor is operating under normal load, the normal motor current, bearing temperatures, and vibration are verified.

6. Meter and Relay Tests

The objectives of meter and relay tests are to verify that all protective relays, electrical meters, potential and current transformers, and associated circuitry function as required. This includes calibrating each component to the required setting and testing for proper installation and mechanical operation.

Relays can be removed from the installed equipment and tested in the instrument shop. Nameplate data is recorded, and the devices are inspected for cleanliness, defective parts, and shipping damage. The possiblity of internal shorts to the frame is checked. Set points are tested and calibrated. Relays are then reinstalled in the proper equipment and sealed to prevent unauthorized setting changes.

Electrical instruments are disconnected from their associated circuits and connected to an instrument transformer for testing. Nameplate data is recorded, and the devices are inspected for cleanliness and damage. Continuity is checked, and each instrument is calibrated. Then, the device is rewired in place, fusing is checked, and documentation is completed. Documentation should include nameplate data, the test procedure and equipment used, calibration input and output measurements, and displayed readouts. Measurements should be recorded for "as found" and "as set" conditions.

Potential transformer tests include inspection for cleanliness, verification of nameplate information, and measurement of winding resistance, polarity, and turn ratio. Polarity is determined by flashing the primary with a battery and noting the deflection of a voltmeter connected to the transformer secondary. Turn ratio is measured using a known ac source. Finally, the transformer primary is energized and the secondary checked to verify that all meters and relays receive the required voltage. The transformer is returned to service, and documentation is completed.

Current transformers are checked out and tested in a manner similar to potential transformers, but with an ammeter instead of voltmeter.

7. Energization of Electrical Equipment

The EPGS energization program is intended to facilitate safe, orderly initial energization of the main power system. This includes correct phase sequence on supply buses, correct phase angles between all power supplies that can be paralleled, proper voltage transformation, proper operation of circuit breakers, and successful preenergization functional testing of all electrical equipment, meters, and relays. The main generator and diesel-generator may be energized according to separate procedures or vendor's detailed instructions, and are not considered here. Load shedding, automatic transfer, and similar tests are generally conducted during the initial power operation phase of startup, since sufficient load is generally not available during the energization program to allow complete testing.

Prior to energization, several prerequisites must be satisfied. References such as single-line diagrams, schematics, system phasing and sequencing diagrams, and single-line meter and relay diagrams should be consulted. Danger signs should be posted in the vicinity of equipment to be energized, and barriers erected to prevent unauthorized traffic. Protective equipment, relays, control room annunciators, and fire protection equipment must be operable. Distribution breakers to be energized must be racked out and tagged out in compliance with project safety tagging and clearance procedures. Potential transformers are either defused or racked out, except on buses to be energized. It may be desirable to remegger buses to ensure insulation integrity.

EPGS energization proceeds on a system-by system basis. Typical systems are 125 Vdc, 13.8 kV, 480 Vac load centers, 480 Vac motor control centers, 120 Vac, and main and unit auxiliary transformers. Voltages are checked for conformance to design tolerances, phase sequence, and angles, and all equipment is examined to verify proper operation. It may be necessary to defeat certain electrical interlocks to permit closure of breakers at various stages of the energization program. Upon successful completion of testing, the electrical power system is placed in its normal lineup, with green tags indicating that the equipment is under control of the Owner.

Documentation should include a component test summary sheet that identifies the tests to which each system component was subjected, data sheets for recording electrical meter readings, and a system status summary sheet that indicates the required system status at the conclusion of the energization program.

C. INSTRUMENTATION AND CONTROL TESTS AND CALIBRATION

All in-line instrumentation components, such as flow meters, pitot tubes, and flanged control valves, should be removed from piping vessels to prevent damage during startup flushing, chemical cleaning, or steam blowing of the lines. Weld-end control valves should have the internals removed. Other instruments should be either disconnected or valved off from the line. When hydrotesting, flushing, chemical cleaning, etc. are complete, the instrumentation is reinstalled or connected, and testing and calibration can begin.

1. Control Valve Testing

Control valve tests are conducted to verify that valve assemblies and associated hardware are complete and clean, that valves open and close within the required times, and that positioners, limit switches, and indicators function correctly.

To prepare a control valve for testing, electrical power and instrument air must be made available, electrical power circuit protective devices must be properly installed and active, and air lines must be clean and leak tight. Typical test equipment includes voltmeters, ammeters, and auxiliary power supply, an electrical signal generator, and calibrated pressure gauges.

Valve assemblies are initially examined for cleanliness, physical damage, removal of packing and shipping materials, and adequate lubrication of linkages, stem, and bearings. Valve exhaust and vent ports are verified as being clear. Electrical cables are inspected for correct labeling, and conduits for proper sealing. The valve is also checked for mounting in the proper direction with respect to flow and for suitability for the service as determined from nameplate data.

After completion of the above, tests are conducted to verify that supply air pressure is correct, that position indicating devices indicate the actual valve position, and that electrical solenoids and limit switches function properly. Functional tests are then made on transducers and positioners without flow in the process system to verify proper operation. Valves are operated with a simulated control signal to check response times, valve travel, hysteresis, and local and remote position indication. Problems such as binding, improper seating, or loose connections are corrected.

2. <u>Control Loop Testing</u>

The checkout and testing of control loops ensures that components such as transmitters, indicators, recorders, and controllers are properly installed and correctly interconnected. The basic functions of the instruments are tested, and correct control action is verified.

To prepare a control loop for testing, electrical power and instrument air must be available, electrical circuit protective devices must be properly installed and activated, and air lines must be clean and leak-tight. The instrument air system must be in operation. Typical test equipment includes a precision milliampmeter, voltmeter, auxilliary or permanent power supply, electrical signal generator, and a pneumatic calibration kit.

Instruments are inspected for cleanliness and damage, physical mounting, proper process connection, and whether protection. Electrical wiring is tested for continuity, shorts, ground, overload protection, and proper terminal connections prior to turning on the power.

Supply and signal air tubing is checked for proper connection on pneumatic instruments, and the air is turned on.

Control loop power is turned on. Correct interconnections and rough calibrations are checked by raising the transmitter output in several steps via a simulated transmitter input. The associated receiving instruments should follow these changes. The proper operation of alarms and trip switches and the proper control action of controllers is verified. Initial controller settings are made during loop calibration (see Section IV.C.3).

3. Calibration and Initial Response Settings

Following control valve testing and control loop testing, the calibration of all measuring, indicating, recording, and controlling instruments are rechecked. Setpoints of all alarm and trip switches are retested and their action verified. Controller control modes (gain, integral, derivative) are set at initial settings that are known to be stable. All controllers are set on "manual," and the proper normal setpoint is indicated with a marker. Manual adjustment of the controller setpoint can be used to position valves during initial process system operation.

4. Initial Control Loop Operation and Fine Tuning

During initial process system operation, the control loop components will become responsive to the working fluid flow, pressure, temperature, etc. Manual adjustments of controller setpoints can be used initially to position control valves as required for various startup procedures. Subsequently, controllers can be placed on "auto." The ability of control loops to operate automatically as required in response to changing process conditions is observed. Stability and response times are checked, and observed controller settings are adjusted and fine tuned to obtain optimum response over the full control range. Instrument indications are checked for consistency and accuracy thoughout the loop. Finally, a control loop data sheet is completed to document final settings and results.

5. Turbine-Generator Trip Checks

Turbine-generator trip checks must be performed just prior to the initial turbine roll in order to verify that the turbine stop and control valves will automatically close and that the generator breaker will automatically open as required in response to an operator-initiated trip or any abnormal event requiring such action.

Automatic closure of bleeder trip valves in the turbine extraction steam lines as a result of a turbine trip is also verified. It is also appropriate to make a final verification of the proper response of control room alarms, annunciators, and sequence-of-events recorder during the trip check sequence.

In order to perform the trip checks, the main and admission steam isolation valves must be closed, and the turbine hydraulic control oil unit must be operating. It may be necessary to simulate some of the inputs required to satisfy the turbine reset interlocks. The turbine is reset, and the stop and control valves are opened. With the generator breaker in the test position, the inputs necessary to satisfy the breaker "close" interlocks (excitation, etc.) are simulated and the breaker is "closed". One of the turbine-generator trip events is then either simulated or made to occur in fact (eg: trip all bearing oil pumps), which should cause all turbine stop and control valves to close immediately and the generator breaker to open. These trip actions are verified, the trip event is cleared, the turbine is reset again, generator breaker closed again, and a new trip event tested. The procedure continues until all turbine-generator trip events have been successfully checked and verified.

6. Turbine Emergency Overspeed Test

It is mandatory startup practice to test the operation and accuracy of the setting of the turbine emergency overspeed trip device by actually overspeeding the turbine. This test must of course be performed after initial turbine roll, and the turbine manufacturer may require that the turbine be operated at a specified load for a specified period of time just prior to overspeeding in order to ensure thorough heating and ductility of the rotor assembly. In this case, load is removed after the specified load run, the turbine-generator is tripped and then reset, and speed is slowly increased to the specified overspeed trip setting. Normally, the emergency overspeed trip device must trip the turbine at the specified overspeed trip setting (with tolerances) on two consecutive trials to pass the test. The overspeed trip setting is typically on the order of about 10 percent above rated synchronous speed for the machine.

It is standard practice to repeat the overspeed test after any subsequent major turbine outage, or if any work is performed on the turbine governing equipment or hydraulic control oil unit.

V. PRELIMINARY EPGS STARTUP PLAN

A. GENERAL

The activities, tests, and sequence of events briefly described in this section constitute a preliminary but practicable plan for startup of the 10 MWe Pilot Plant as a whole, and the EPGS in particular. With the exception of certain operational tests of the Collector, Receiver, and Thermal Storage Subsystems, all other activities involving EPGS startup and operation are conventional and are common practice in the startup of fossil-fueled steam power plants.

The discussion is necessarily limited to only the major EPGS components and systems. Although a series sequence of events is described, many of the activities overlap in time, as indicated on the startup schedule, Figure II.B-1 of Section II. The startup tests and procedures previously described in Section IV should be referred to for a further explanation of many of the operations mentioned in the startup plan (e.g., for pump operation, see Section IV.A.5).

Discussion of the startup plan follows the order of the construction/startup activity interface diagram, Figure III.A-2 of Section III, starting at the completion of construction testing and proceeding through the initial power operations that complete the startup plan. Additional tests and operations that may be performed in normal operation are also described, but these are not considered to be part of the startup plan.

B. EPGS COMPONENT INSPECTION, TESTING, AND INITIAL SYSTEM OPERATION

It is assumed that temporary electrical power, water, and compressed air supplies are already in place and have been used as necessary for construction of the Pilot Plant. These temporary supplies will be used as necessary to support initial startup of the permanent EPGS power, water, and air supplies and other support facilities. The following EPGS startup system activities are required in order to provide plant support for all subsequent EPGS startup activities.

1. Initial Support Facilities

a. Raw Water Supply and Fire Protection

- Run in well water pumps (if used), or presume test and flush piping from municipal water supply.

- Fill and static test fire water storage tank.

- Run in fire pumps and test auto-start controls; flush and pressure test plant fire protection piping; checkout and test main and unit transformers' deluge valves.

b. Plant Power Supply

- Backfeed and test main transformer from utility grid; energize the plant 13.8 kV bus.

- Energize and test unit transformers; energize plant 480 V buses.

- Energize and test 480 V motor control centers and load centers.

- If not already completed using temporary power, energize and test 125 Vdc system (rectifier, battery charger); charge and test station batteries; energize and test inverter, dc control circuits, and uninterruptable ac circuits as required.

HVAC and Domestic Facilities

- Start up and balance turbine building and administration building HVAC systems.

- Flush and pressure test domestic water systems, and place then in service.

2. Circulating Water System

- Flush raw water makeup piping to cooling tower; fill cooling tower basin; check out and place makeup level controls in service.

- Flush and check out cooling tower fire protection deluge valves.

- Run in circulating water pony pump to fill and leak test circulating water piping.

- Perform condenser tube static leak test and water box pressure test.

- Run in main circulating water pumps to flush circulating water piping; perform circulating water system hydraulic shock (water hammer) tests; drain and clean cooling tower basin and condenser water boxes as required.

- Check out circulating water chemical treatment and blowdown systems and place them in service.

- Run in cooling tower fans.

3. Component Cooling Water

- Run main circulating water pump.
- Flush circulating water supply piping to component cooling water pumps; run in component cooling water pumps to flush main supply/return piping via temporary jumper piping; flush branch supply piping disconnected from equipment.
- Adjust and initially balance branch piping flows.
- Romove startup strainers.

4. Compressed Air

- Run component cooling water pump.
- Run in air compressors to blow out air lines to receivers; pressurize receiver, and set compresor unloading controls; blow out service air headers; blow out instrument air headers via jumper around air dryers.
- Set up, run in, and test instrument air dryers.
- Place compressor controls on auto and test.

Demineralized Water Makeup and Condensate Storage

- Fill and static test condensate storage tank with raw water via temporary jumper piping.
- Run in condensate transfer pumps to flush transfer piping to the condenser hotwell and to the full flow condensate demineralizer precoat tank.
- Flush raw water supply to makeup demineralizers, and flush makeup demineralizer supply line to condensate storage tank via temporary jumper.
- Drain all piping.
- Checkout, run in, and test makeup demineralizer.
- Check out and place makeup demineralizer water sampling equipment in service.
- Fill condensate storage tank with demineralized water.

6. <u>Condensate and Feedwater Velocity Flush</u>

- Install temporary piping as required.

- Clean condenser hotwell.

- Fill and static test condenser to level of turbine exhaust flange expansion joint, using raw water supply via temporary piping; drain condenser to hotwell level.

- Perform initial run-in of condensate pumps or recirculation to condenser; run condensate pumps to flush condensate piping to deaerator, bypassing condensate demineralizers and low pressure feedwater heater No. 4; gravity flush deaerator drain/overflow piping to condenser.

- Gravity flush booster pump suction piping from deaerator to waste; connect booster pump suction piping; perform initial run-in of booster pumps on recirculation to condenser.

- Run condensate pumps and booster pumps, with manual control of deaerator level, to perform velocity flush of main feedwater piping to receiver feedwater inlet shutoff valve; flush through jumper piping to main steam line and down to turbine main steam isolation valve; flush through main steam bypass valve to condenser. Bypass low-pressure and high-pressure feedwater pumps and high-pressure feedwater heaters during this flush.

- Position valving as necessary to velocity flush the feedwater supply piping to the TSS and the condensate return piping from the TSS; flush feedwater cleanup line piping to the condenser.

- Remove, clean, and replace all startup strainers.

7. <u>Condensate and Feedwater Chemical Cleaning</u>

- Install temporary chemical mixing equipment; install and check out temporary chemical cleaning heater using auxiliary steam heating source.

- Install temporary chemical vapor barrier at turbine exhaust if required.

- Mix and inject chemical to condenser hotwell.

- Run condensate and booster pumps to continuously circulate hot chemical cleaning solution though all velocity flush paths, positioning valves as necessary to cover all flow paths. Begin chemical sampling; continue circulation.

- Verify leveling-off of chemical concentration, iron concentration, and pH; cease operation; drain entire system to waste (to evaporation pond via neutralizing basin if required).

- Fill condenser hotwell with demineralized water; run condensate and booster pumps, and position valves as necessary to flush all chemical cleaning flow paths to waste; flush though tube side of all feedwater heaters; flush all low point drains and dead ends; sample as necessary to verify clean flush of all chemical solution.

- Drain entire system; remove temporary piping; restore permanent condensate and feedwater piping, valving, and instrumentation; hand clean condenser hotwell and deaerator; install deaerator trays if applicable.

8. <u>Feedwater Pumps</u>

- Fill condenser hotwell with demineralized water; run condensate and booster pumps with deaerator level control on auto.

- Perform initial run-in of low-pressure feedwater pumps low-pressure feedwater pumps on recirculation to condenser.

- Run low-pressure feedwater pumps to perform initial run-in of high-pressure feedwater pumps high-pressure feedwater pumps on recirculation to condenser. Adjust cleanup line flow to condenser for proper control of high-pressure feedwater pumps suction pressure.

9. <u>Condensate Demineralizers</u>

- Perform high-voltage spark testing of rubber-lined demineralizer vessels to locate pinhole leaks; load resins; start up condensate demineralizers with flow of demineralized water from condensate pumps, initially dumping effluent to waste until throughput water quality is verified.

- Perform design flow water quality test of condensate demineralizers with flow from condensate pumps through feedwater system cleanup line to condenser.

10. <u>Receiver Boilout</u>

- Fill boiler and superheater with demineralized water from the EPGS, using receiver inlet flow control valve.

- Perform receiver hydrostatic test if not performed earlier.

- Perform boilout with heat from the collector subsystem in accordance with receiver manufacturers' requirements. If boilout is at low pressure, operate only condensate and booster pumps, bypassing the low-and high-pressure feedwater pumps to conserve pumping power.

- Provide demineralized water from the EPGS for receiver rinses.

- Drain boilout solution and rise water to waste, with neutralization as required.

- Provide similar EPGS services for boiler acid cleaning if required.

11. <u>Steam Blowing</u>

- Install temporary steam blow piping, valving, and supports.

- Operate EPGS feedwater and auxiliary steam systems to provide deaerated drum makeup during the steam blow procedure.

- Perform steam blows on receiver superheater, main steam lines, and admission steam lines, using the steam line cleaning procedure described in Section IV.A.8.

- Remove temporary piping, and restore permanent piping arrangement and instrumentation.

12. <u>Collector/Receiver/Master Control Testing</u>

- Operate the EPGS circulating water system and cooling towers, feedwater, and auxiliary steam systems as necessary to provide deaerated feedwater and condenser heat rejection for collector/receiver/control operational testing as required. Receiver steam produced is dumped to the condenser via the main steam turbine bypass valve and the main steam bypass desuperheater.

- Fine tune the drum level three-element feedwater controls.

- Fine tune bypass valve control.

- Use available main steam or auxiliary steam to blow out turbine sealing steam piping.

- Run in sealing steam exhauster.

- Place turbine on turning gear. The turbine-generator bearing lube oil system oil flush (see Section IV.A.4), as well as the flush and checkout of the turbine hydraulic control oil unit, have not been described. These activities are required prior to turning gear operation and would be routinely accomplished prior to this time.

- Check out and adjust turbine seal steam regulator, and apply turbine sealing steam; verify control of sealing steam pressure and leakoff pressure, using both main steam and auxiliary steam sources.

- Operate condenser exhauster to pull condenser vacuum with turbine sealed. Verify hogging and holding modes of operation for condenser exhauster and capability to pull design condenser vacuum.

13. <u>Collector/Receiver/TSS/Control Testing</u>

- Operate the EPGS circulating water system and cooling towers, feedwater, and auxiliary steam systems as necessary to provide deaerated feedwater to the receiver and the TSS for collector/receiver/TSS/control operational testing. The Main steam and admission steam produced is dumped to the condenser via the respective turbine bypass valves.

- Fine tune bypass valve controls.

- Fine tune TSS three-element feedwater control.

- Verify and fine turn overall EPGS feedwater flow and pressure control for the several separate and combined TSS charge/discharge normal operation modes.

Note: The above sequency assumes that no TSS boilout is required.

C. EPGS INITIAL POWER OPERATIONS

1. <u>Initial Turbine Roll</u>

- Perform turbine-generator trip checks (see Section IV.C.5).

- Place turbine on turning gear.

- Operate entire EPGS with exception of turbine-generator.

- Establish receiver and main steam pressure; warm main steam lines to required degree of main steam superheat via flow through the main steam turbine bypass valve and the turbine main steam stop valve before-seat drain.

- Apply turbine sealing steam, and pull condenser vacuum.

- Reset turbine trip circuits, and open turbine main steam stop valve; admit sufficient receiver steam to the turbine via the main steam control values to roll the turbine off turning gear; immediately check for turbine rubs and vibration; manually trip turbine to verify turbine trip functions.

- Reset turbine; reroll turbine, and gradually increase speed in accordance with turbine manufacturer' recommendations; check vibration, bearing temperature, and turbine sector/casing differental expansion at each speed increment.

- Upon achieving turbine-generator synchronous speed, verify acceptable vibration, bearing temperatures, and differential expansion prior to initial generator synchronization to the utility grid.

2. <u>Initial Generator Synchronization</u>

- Establish turbine-generator at approximately rated synchronous speed.

- Verify preliminary settings of turbine pre-emergency overspeed protection and emergency overspeed trip device.

- Checkout generator excitation system; close generator field breaker; adjust generator excitation for generator terminal voltage equal to line voltage.

- Obtain clearance from utility system load dispatcher to synchronize the pilot plant to the utility grid.

- Using the synchroscope and the turbine speed contoller, adjust turbine-generator speed (frequency) equal to line frequency, with incoming generator phase rotation approaching the running line phase rotation from the "generator slow" side; when speed is synchronized in phase, close the generator breaker, using the breaker control switch.

- Increase turbine main steam flow slightly to generate minimum load necessary to prevent generator no-load (reverse power or anti-motoring) relays from initiating a turbine trip; monitor turbine exhaust hood for excessive temperature.

- Increase turbine-generator load gradually, in accordance with the manufacturers' recommendations, to the specified minimum pre-overspeed test load.

- Record and verify acceptable differential pressure on turbine stop valve fine screens.

- Sequentially valve-in extraction steam flow to feedwater heaters as load increases and extraction stage pressure becomes available; verify proper setting of heater level controls and operation of heater drain and dump valves.

- Hold at specified load for specified heat soak period; verify acceptable generator stator temperatures and differentials; reduce load, and trip turbine-generator.

- Reset turbine, gradually increase to greater than synchronous speed; calibrate pre-emergency overspeed protection and temporarily lock it out; increase speed further to perform emergency overspeed test (see Section IV.C.6).

3. <u>Full load and Operating Mode Tests</u>

The initial turbine roll, synchronization, and overspeed testing is performed using main steam from the Receiver Subsystem. After completion of overspeed testing, the EPGS will be operated throughout its full load range to fine turn controls and verify operability in the "normal" operating modes, which includes turbine operation on admission steam from the TSS. Operation and control of the EPGS in these normal modes and the capability of transferring from one mode of control to another was preliminarily tested as described in Sections V.B.12 and V.B.13 without turbine-generator operation. During operating mode testing, the turbine-generator automatic synchronizer will be used, and its ability to bring the turbine to exact synchronous speed in phase with the grid, to close the generator breaker, and to apply minimum load will be verified.

Upon completion of EPGS operations at up to full load electrical output using normal operating modes, the fine screens in the turbine stop valves will be removed. Removal of turbine fine screens is the final event in the initial power operations phase of EPGS startup.

D. NORMAL OPERATION

For the purposes of this report, the completion of initial power operations concludes the overall EPGS startup plan. During subsequent "normal operation", the total Pilot Plant may be operated for "acceptance tests" to verify its capability to meet the ERDA design criteria established for the final system design. Additional operating mode tests may also be conducted to determine the most responsive and efficient operating and control modes under various daily and seasonal insolation conditions. Operating modes, designed research and testing may be evaluated over an extended period of time during normal operation. A formal turbine performance test may be conducted in accordance with the ANSI/ASME Performance Test Code for Steam Turbines (PTC-6, 1976). These activities would be conducted in fulfillment of the technical objective for which the Pilot Plant will be built, and they were therefore considered to be a part of normal operation.

Additional long-term studies in conjunction with normal operation of the Pilot Plant may consider the following:

- Hourly and daily net electrical generation versus insolation

- Effect of hourly and seasonal insolation variation on system efficiency

- Daily load factor and capacity factor

- Component reliability

- System and plant availability

- Operating costs

- Maintenance costs

- Water consumption and other environmental effects

VI. SPECIAL SUPPORT EQUIPMENT FOR STARTUP, TESTING, AND MAINTENANCE

The developed EPGS preliminary design and preliminary startup plan have been reviewed to identify any special equipment or simulators that would be required for startup testing and maintenence of the EPGS components and controls. This review has indicated that the standard tools, equipment, and instrumentation normally used in the startup, testing, and maintenence of conventional fossil-fueled steam power plants will also be required for the EPGS. With one possible exception, there is no identified need for special tools, equipment, instrumentation, or simulators for EPGS startup and maintenence.

The one possible exception is the need for an auxiliary source of steam to provide feedwater heating and deaeration for the steam blow procedure discussed in Section IV.A.8, and for the collector/receiver/TSS/control operational testing discussed in Sections V.B.12 and V.B.13. An auxiliary heating steam source might also be used for the chemical cleaning procedure discussed in Sections IV.A.6 and V.B.7. The EPGS preliminary design includes provision for a permanent auxiliary steam source (electric or fossil-fueled boiler, or piping to an existing steam source). If during final design there is no permanent auxiliary steam source included and available for the EPGS startup, a small electric or fossil-fueled boiler may be rented for use as required.

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